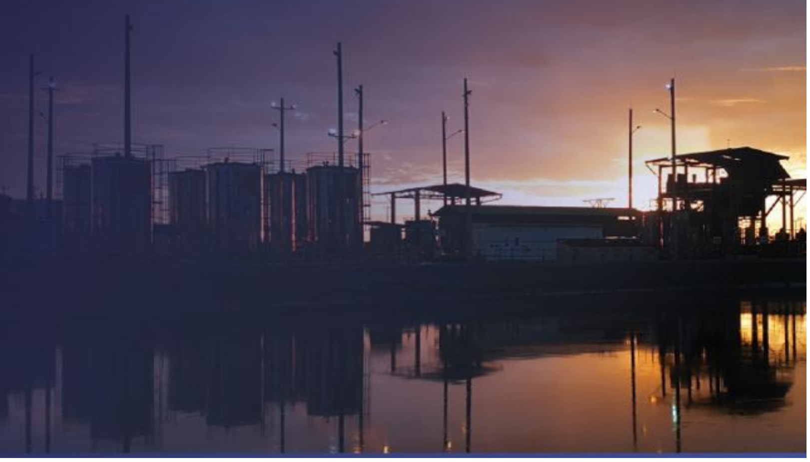

FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

May 3, 2023
For the three months ended March 31, 2023

*Frontera Energy Corporation ("**Frontera**" , "**FEC**" 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, production, transportation, storage, and sale of crude oil and conventional natural gas in South America, including related investments in both upstream and midstream facilities, 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 2000, 222 – 3 Avenue SW, Calgary, Alberta, Canada, T2P 0B4.*

Legal Notice – Forward-Looking Information

*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 Consolidated Financial Statements and related notes for the three months ended March 31, 2023 and 2022 ("**Interim Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and its Annual Information Form (**"AIF"**), have been filed with Canadian securities regulatory authorities and are 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 financial 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 non-IFRS financial measures are described in greater detail under the heading "Non-IFRS and Other Financial Measures" section on page 18.*

*This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to activities, events or developments that the Company believes, expects or anticipates will or may occur in the future. Forward-looking information in this MD&A includes, without limitation, statements regarding estimates and/or assumptions in respect of the oil price environment, current and expected impacts of the COVID-19 pandemic, actions of the Organization of Petroleum Exporting Countries ("**OPEC+**") and the impact of the Russia-Ukraine conflict, 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 conventional 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, cost savings, including General and Administrative ("**G&A**") expense savings, and the impact thereof and obtaining regulatory approvals. Forward-looking information is often identified by words or phrases such as "may", "could", "would", "might", "will", "expects," "anticipates," "plans," "estimates," "projects," "forecasts," "believes," "intends," "possible," "probable," "scheduled," "goal", "objective", or similar words or phrases. All information other than historical fact is forward-looking information.*

Forward-looking information reflects the current expectations, assumptions and beliefs of the Company based on information currently available to it and considers the Company's experience and its perception of historical trends, including expectations and assumptions relating to commodity prices and interest and foreign exchange rates; the current and potential adverse impacts of the COVID-19 pandemic, including the status of the pandemic and future waves and any associated policies around current business restrictions; the performance of assets and equipment; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour, services and infrastructure; and the development and execution of projects.

Although the Company believes that the assumptions inherent in the forward-looking information are reasonable, forward-looking information is not a guarantee of future performance and accordingly undue reliance should not be placed on such information. Forward-looking information is subject to a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to the Company. The actual results of the Company may differ materially from those expressed or implied by the forward-looking information, and even if such actual results are realized or substantially realized, there can be no assurance that they will have the expected consequences to, or effects on, the Company. Factors that could cause actual results or events to differ materially from current expectations include, among other things: volatility in market prices for oil and natural gas; the duration and spread of the COVID-19 pandemic and its severity, the success of the Company's program to manage COVID-19; the Russia-Ukraine conflict; uncertainties associated with estimating and establishing oil and natural gas reserves and resources; liabilities inherent with the exploration, development, exploitation and reclamation of oil and natural gas; uncertainty of estimates of capital and operating costs, production estimates and estimated economic return; increases or changes to transportation costs; expectations regarding the Company's ability to raise capital and to continually add reserves through acquisition and development; the Company's ability to access additional financing; the ability of the Company to maintain its credit ratings; the ability of the Company to: meet its financial obligations and minimum commitments, fund capital expenditures and comply with covenants contained in the agreements that govern indebtedness; political developments in the countries where the Company operates; the uncertainties involved in interpreting drilling results and other geological data; geological, technical, drilling and processing problems; timing on receipt of government approvals; fluctuations in foreign exchange or interest rates and stock market volatility.

All forward-looking information speaks only as of the date on which it is made and the Company disclaims any intent or obligation to update any forward-looking information, whether as a result of new information, future events or otherwise, unless required pursuant to applicable laws. Risks, uncertainties, assumptions and other factors that could cause actual results to differ materially from those anticipated in the forward-looking information 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 consider 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 constitute future oriented financial information and financial outlook information (collectively, "**FOFI**") within the meaning of applicable Canadian securities laws. 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 management's reasonable estimates and judgments; however, actual results of the Company's operations and the resulting 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 2023	Q4 2022	Q1 2022
Operational Results				
Heavy crude oil production [1]	(bbl/d)	22,270	22,144	21,214
Light and medium crude oil production [1]	(bbl/d)	16,518	17,073	17,248
Total crude oil production	(bbl/d)	38,788	39,217	38,462
Conventional natural gas production [1]	(mcf/d)	8,590	9,097	9,530
Natural gas liquids production [1]	(boe/d)	1,291	993	966
Total production [2]	(boe/d) [3]	41,586	41,806	41,100
Total inventory balance	(bbl)	1,611,201	1,238,780	1,434,111
Oil and gas sales, net of purchases [4]	($/boe)	69.16	82.67	90.12
Realized loss on risk management contracts [5]	($/boe)	(1.16)	(1.32)	(1.06)
Royalties [5]	($/boe)	(3.36)	(6.04)	(7.58)
Other dilution costs [5]	($/boe)	(0.09)	(0.07)	(0.12)
Net sales realized price [4]	($/boe)	64.55	75.24	81.36
Production costs [5]	($/boe)	(12.07)	(11.56)	(13.34)
Transportation costs [5]	($/boe)	(11.20)	(10.55)	(9.72)
Operating netback per boe [4]	($/boe)	41.28	53.13	58.30
Financial Results				
Oil & gas sales, net of purchases [6]	($M)	189,376	261,059	228,826
Realized loss on risk management contracts	($M)	(3,175)	(4,182)	(2,682)
Royalties	($M)	(9,213)	(19,076)	(19,244)
Other dilution costs	($M)	(256)	(235)	(298)
Net sales [6]	($M)	176,732	237,566	206,602
Net (loss) income [7]	($M)	(11,330)	197,796	102,228
Per share – basic	($)	(0.13)	2.29	1.08
Per share – diluted	($)	(0.13)	2.25	1.05
General and administrative	($M)	12,669	12,761	14,656
Outstanding Common Shares	Number of Shares	85,188,573	85,592,075	94,070,294
Operating EBITDA [6]	($M)	91,922	144,994	132,998
Cash provided by operating activities	($M)	845	138,312	114,748
Capital expenditures [6]	($M)	131,452	134,165	113,545
Cash and cash equivalents – unrestricted	($M)	162,272	289,845	257,373
Restricted cash short and long-term [8]	($M)	30,877	23,202	66,146
Total cash [8]	($M)	193,149	313,047	323,519
Total debt and lease liabilities [8]	($M)	519,471	511,552	558,281
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [9]	($M)	400,361	407,808	410,161
Net debt (excluding Unrestricted Subsidiaries) [9]	($M)	279,843	178,534	199,303

[1] References to heavy crude oil, light and medium crude oil combined, conventional natural gas and natural gas liquids in the above table and elsewhere in this MD&A refer to the heavy crude oil, light and medium crude oil combined, conventional natural gas and natural gas liquids, respectively, product types as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

[2] Represents W.I. production before royalties. Refer to the "Further Disclosures" section on page 31.

[3] Boe has been expressed using the 5.7 to 1 Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy. Refer to the "Further Disclosures - Boe Conversion" section on page 31.

[4] Non-IFRS ratio (equivalent to a "non-GAAP ratio", as defined in National Instrument 52-112 - *Non-GAAP and Other Financial Measures Disclosure ("***NI 52-112***"*). Refer to the "Non-IFRS and Other Financial Measures" section on page 18.

[5] Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 18.

[6] Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 18.

[7] Net (loss) income attributable to equity holders of the Company.

[8] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 18.

[9] "**Unrestricted Subsidiaries**" as of March 31, 2023, include CGX Energy Inc.("**CGX**"), listed on the TSX Venture Exchange under the trading symbol "OYL", Frontera ODL Holding Corp., including its subsidiary Pipeline Investment Ltd. ("**PIL**"), Frontera BIC Holding Ltd., and Frontera Bahía Holding Ltd. ("**Frontera Bahia**"), including its subsidiary Sociedad Portuaria Puerto Bahia S.A ("**Puerto Bahia**"). On April 11, 2023, Frontera Energy Guyana Holding Ltd. and Frontera Energy Guyana Corp. were designated as unrestricted subsidiaries. Refer to the "Liquidity and Capital Resources" section on page 24.

Performance Highlights

First Quarter 2023

Frontera's first quarter results were in-line with the Company's 2023 capital and production guidance. Frontera delivered average daily production of 41,586 boe/d (consisting of 22,270 bbl/d of heavy crude oil, 16,518 bbl/d of light and medium crude oil combined, 8,590 mcf/d of conventional natural gas and 1,291 boe/d of natural gas liquids), generated $91.9 million of operating EBITDA and invested $131.5 million in capital expenditures including $75.3 million on the Wei-1 well offshore Guyana, $32.0 million on development drilling in the Quifa, Cajua, CPE-6 and Cubiro blocks, $12.4 million on exploration activities in Colombia and Ecuador and $8.6 million on development facilities including construction of a storage tank in the CPE-6 block and the expansion of fluid transfer and the interconnection of fields in the Quifa block.

Building on the operational momentum of the first quarter, the Company is already delivering higher average production due to better than expected performance from new Cajua wells where crude grows average heavy oil production is 4,860 bbl/d, higher VIM-1 liquids and NGL production, better performance at CPE-6, Coralillo 1 and 3 as well as the Tapiti-1 well. The Company also increased natural gas liquids production 30% compared to the prior quarter as it continues to diversify its our production mix. The Company expects improved profitability throughout the rest of the year as it advances its development portfolio in Colombia and Ecuador, increases Quifa and CPE-6 water-handling infrastructure and facilities laying the foundation for the Company's path to grow production to 50,000 boe/d, leverages its advantaged transportation and logistics structure to maximize realized prices and matures its self-sustaining and growing midstream business.

Increasing water handling capacity at Quifa is key to Frontera's efforts to grow production at Quifa. The Company's current water handling capacity is approximately 1.5 million bwpd. In 2023, Frontera began commissioning SAARA (previously Agrocascada), its reverse osmosis water treatment facility *("***SAARA***")*. As of April 2023, the plant has already processed 1.5 million barrels of water as part of its commissioning program, providing irrigation source water to the Company's nearby Promotora Agricola de los Llanos S.A. ("**ProAgrollanos**") palm oil plantation.

During the quarter, Frontera was recognized for a third consecutive year by Ethisphere as one of the World's Most Ethical Companies in 2023. The Company was added to the 2023 Bloomberg Gender-Equality Index, achieved ISO certification in Ecuador and was recognized by Friendly Biz for our LGBT+ friendly workplace.

Under the Company's normal course issuer bid ("**NCIB**"), which expired on March 16, 2023, Frontera repurchased approximately $0.5 million of the Company's Common Shares for cancellation during the first quarter of 2023 for approximately $4.2 million. In total, the Company repurchased 4,270,100 Common Shares for cancellation through the NCIB.

Operationally, in the first quarter of 2023, the Company drilled 17 development wells at Quifa, Cajua, CPE-6 and Cubiro blocks. This compares to 17 development wells in the prior quarter. In 2023, the Company intends to drill 55 gross development wells. Currently, the Company has 5 drilling rigs and 2 workover rigs active at its Quifa, CPE-6, Cubiro and Corcel/Guatiquia blocks in Colombia.

Consistent with its strategic priorities, the Company successfully refinanced Puerto Bahía's existing legacy project finance debt, via a new $120 million loan facility with a group of lenders led by Macquarie Capital, which extended the tenor of the borrowings and provided for up to $30 million in additional funding to pursue strategic investment opportunities within its Midstream business. With the refinancing complete, Frontera's standalone midstream business is fully capitalized with funding to grow. Subsequent to the quarter, the Company designated Frontera Energy Guyana Holding Ltd. and Frontera Energy Guyana Corp. as unrestricted subsidiaries and released Frontera Energy Guyana Corp. as a note guarantor for its senior bonds due 2028. The designation is a positive forward step as the Company nears the completion of its exploration obligations in Guyana and supports ongoing capital discipline.

The Company remains focused on aligning its Upstream, Midstream and Guyana core businesses to achieve the Company's strategic priorities and unlock shareholder value.

During the quarter, Frontera and its Joint Venture partner spud the Wei-1 well and we are currently at 19,142 feet. We have encountered oil-bearing intervals so far and are currently drilling ahead to our planned total depth.

Frontera's Three Core Businesses

Frontera has three core businesses: (1) its Colombia and Ecuador Upstream Onshore business, (2) its standalone and growing Colombia Midstream business, and (3) its potentially transformational Guyana Exploration business offshore. The Company is focused on unlocking shareholder value from its business and is committed to providing greater clarity and insight through its various disclosures including its quarterly press releases, Financial Statements and this Management Discussion and Analysis document. Please see the Midstream Colombia section beginning on page 16 for more information.

Financials and Operational Results

- Production averaged 41,586 boe/d in the first quarter of 2023 (consisting of 22,270 bbl/d of heavy crude oil, 16,518 bbl/d of light and medium crude oil combined, 8,590 mcf/d of conventional natural gas and 1,291 boe/d of natural gas liquids), compared with 41,806 boe/d in the prior quarter (consisting of 22,144 bbl/d of heavy crude oil, 17,073 bbl/d of light and medium crude oil, 9,097 mcf/d of conventional natural gas and 993 boe/d of natural gas liquids), and an increase compared to 41,100 boe/d in the first quarter of 2022 (consisting of 21,214 bbl/d of heavy crude oil, 17,248 bbl/d of light and medium crude oil, 9,530 mcf/d of conventional natural gas and 966 boe/d of natural gas liquids).
- Cash provided by operating activities was $0.8 million in the first quarter of 2023, compared with $138.3 million in the prior quarter, and $114.7 million in the first quarter of 2022. The Company reported a total cash position of $193.1 million, including $30.9 million of restricted cash, as at March 31, 2023, compared with a total cash position of $323.5 million, including $66.1 million of restricted cash, as at March 31, 2022.
- The Company recorded a net loss[1] of $11.3 million ($0.13/share[1]) in the first quarter of 2023, compared with net income of $197.8 million ($2.25/share[2]) in the prior quarter and net income[1] of $102.2 million ($1.05/share[2]) in the first quarter of 2022.
- Capital expenditures were $131.5 million in the first quarter of 2023, compared with $134.2 million in the prior quarter and $113.5 million in the first quarter of 2022.
- Operating EBITDA was $91.9 million in the first quarter of 2023, compared with $145.0 million in the prior quarter and $133.0 million in the first quarter of 2022.
- Operating netback was $41.28/boe in the first quarter of 2023, compared with $53.13/boe in the prior quarter and $58.30/boe in the first quarter of 2022.

(1) Net (loss) income attributable to equity holders of the Company.
(2) Per Common Share on a diluted basis.

2. GUIDANCE

The following table reports the Company´s full year 2023 guidance metrics as released on February 1, 2023.

		2023	
		Guidance	Actual
Average Daily Production[1]	boe/d	40,000 - 43,000	41,586
Production Costs[2]	$/boe	$12.50 - $13.50	$12.07
Transportation Costs[3]	$/boe	$10.50 - $11.50	$11.20
Operating EBITDA[4] at $75/bbl[5]	$MM	$375 - $425	
Operating EBITDA[4] at $80/bbl[5]	$MM	$425 - $475	$91.9
Operating EBITDA[4] at $85/bbl[5]	$MM	$475 - $525	
Development Drilling	$MM	$110 - $130	$32.0
Development Facilities	$MM	$75 - $85	$8.6
Colombia and Ecuador Exploration	$MM	$50 - $60	$12.4
Colombia Infrastructure[6]	$MM	$5-10	$0.4
Other[7]	$MM	$25-30	$2.8
Total Colombia and Ecuador Capital Expenditures	$MM	$265 - $315	$56.2
Guyana Exploration [8]	$MM	$135 - $160	$75.3
Total Capital Expenditure[9]	$MM	$400 - $475	$131.5

(1) The Company's 2023 average production guidance range does not include in-kind royalties, operational consumption, quality volumetric compensation or potential production from successful exploration activities planned in 2023.
(2) Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures". Per-barrel metric on a share before royalties basis; excludes costs related to ProAgrollanos.
(3) Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures". Calculated using net production after royalties.
(4) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures'.
(5) Current Guidance Operating EBITDA calculated at Brent $80/bbl and COP/USD exchange rate of 4600:1.
(6) Colombian Infrastructure refers to Puerto Bahia capital expenditures.
(7) Other includes the CPE-6 solar plant project, investment in equipment covered by insurance proceeds, investment in new technologies and HSEQ.
(8) Guidance for Capital Expenditure of Guyana Exploration was updated on May 3, 2023. Please refer to Capital Expenditure section on page 13 for further information on Guyana Exploration activities.
(9) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). See "Non-IFRS Financial and Other Measures." Capital expenditures excludes decommissioning expenses (approximately $14 million).

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company's operations in Colombia and Ecuador. Refer to the "**Further Disclosures**" section on page 31 for details of the Company's net production.

		Production		
Producing blocks in Colombia		**Q1 2023**	**Q4 2022**	**Q1 2022**
Heavy crude oil	(bbl/d)	22,270	22,144	21,214
Light and medium crude oil	(bbl/d)	15,513	15,827	16,969
Conventional natural gas	(mcf/d)	8,590	9,097	9,530
Natural gas liquids	(boe/d)	1,291	993	966
Total production Colombia	**(boe/d)**	**40,581**	**40,560**	**40,821**
Producing blocks in Ecuador				
Light and medium crude oil	(bbl/d)	1,005	1,246	279
Total production Ecuador	**(bbl/d)**	**1,005**	**1,246**	**279**
Total production	**(boe/d)**	**41,586**	**41,806**	**41,100**

Colombia

For the three months ended March 31, 2023, natural gas liquids production increased by 30% compared with the prior quarter due to higher production in the El Dificil and VIM-1 blocks. In addition, production of heavy crude oil increased 126 bbl/d compared with the prior quarter due to 5 new producing wells in the Cajua block, offset by the blockades in early February of the road in Puerto Gaitán (Meta Department), which impacted production in the CPE-6 and Quifa blocks. The Company temporarily suspended production in these blocks, decreasing production by 11,500 boe/d net during and after the blockades as operations resumed. Natural gas liquids and heavy oil production increases were partially offset during the quarter by lower light and medium crude oil and conventional natural gas production of 2% and 6% respectively, mainly due to natural declines and the voluntary shut-in of production in the La Creciente block.

Compared to the first quarter of 2022, production of heavy crude oil increased by 5% mainly due to increased production in the Cajua block and the reactivation of the Sabanero block. Production of natural gas liquids increased by 34% due to the acquisition of an additional 35% W.I. in the El Dificil block in April 2022. Light and medium crude oil and conventional natural gas production decreased by 9% and 10% respectively, mainly due to natural declines and the voluntary shut-in of production in the La Creciente block.

Ecuador

Production in Ecuador for the three months ended March 31, 2023, was 1,005 bbl/d, of light and medium crude oil. Production in Ecuador began during the first quarter of 2022 after discoveries at the Jandaya-1 and Tui-1 wells. Following the completion of the third exploration well, Yin-1, on June 16, 2022, at the Perico block, the three wells have been producing light and medium crude oil since the end of the second quarter of 2022. At the Espejo block (Frontera 50% W.I., and non-operator), the Pashuri-1 well began production in October 2022. The decrease in production, compared to the prior quarter of 2022, was mainly due to water cut increases in Perico block.

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 2023	Q4 2022	Q1 2022
Production	(boe/d)	**41,586**	**41,806**	**41,100**
Royalties in-kind Colombia	(boe/d)	(4,220)	(4,630)	(4,334)
Royalties in-kind Ecuador [1]	(boe/d)	(298)	(427)	(98)
Net production	(boe/d)	**37,068**	**36,749**	**36,668**
Oil inventory draw (build)	(boe/d)	(4,138)	(1,199)	(6,967)
Overlift (settlement)	(boe/d)	(4)	(12)	(10)
Volumes purchased	(boe/d)	7,984	9,587	3,990
Other inventory movements [2]	(boe/d)	(2,847)	(2,894)	(1,704)
Sales volumes	(boe/d)	**38,063**	**42,231**	**31,977**
Sale of volumes purchased	(boe/d)	(7,639)	(7,908)	(3,766)
Sales volumes, net of purchases	(boe/d)	**30,424**	**34,323**	**28,211**
Oil sales volumes	(bbl/d)	28,970	32,642	26,500
Conventional natural gas sales volumes	(mcf/d)	8,288	9,582	9,753
Total oil and conventional natural gas sales volumes, net of purchases	(boe/d)	**30,424**	**34,323**	**28,211**
Inventory balance				
Colombia	(bbl)	1,032,876	683,416	937,583
Peru	(bbl)	480,200	480,200	480,200
Ecuador	(bbl)	98,125	75,164	16,328
Inventory ending balance	**(bbl)**	**1,611,201**	**1,238,780**	**1,434,111**

[1] The Company reports the share of production retained by the government of Ecuador as royalties paid in-kind.
[2] Mainly corresponds to operational consumption and quality volumetric compensation.

Sales volumes, net of purchases, for the three months ended March 31, 2023, decreased by 11% compared with the prior quarter of 2022, mainly due to one less cargo sold in Coveñas, which resulted in inventory build up in Colombia, the Company actively manages its volumes and inventory build was subsequently sold in the second quarter of 2023. In comparison to the first quarter of 2022, sales volumes, net of purchases, increased by 8% due to one additional cargo sold in Puerto Bahia during the first quarter of 2023. Additionally, the Company began exporting production from Ecuador in the second quarter 2022, which amounted to an average of 478 bbl/d of light and medium crude oil combined during the three months ended March 31, 2023.

Colombia Royalties PAP

The Company makes high price clause participation ("**PAP**") payments to Ecopetrol S.A. ("**Ecopetrol**") and the Agencia Nacional de Hidrocarburos ("**ANH**") on production from the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo, Arrendajo and CPE-6 blocks. Until last year, the PAP was paid in cash for all blocks except for those relating to the Quifa block, which were paid using in-kind volumes from production. However, beginning in 2023, the ANH changed the payment method for PAP, requiring in-kind payments for all blocks, except for CPE-6 and Guatiquia blocks.

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 2023	Q4 2022	Q1 2022
PAP in cash	(bbl/d)	793	1,928	1,933
PAP in kind	(bbl/d)	1,460	2,459	2,027
PAP	**(bbl/d)**	**2,253**	**4,387**	**3,960**
% Production		**5.4 %**	**10.5 %**	**9.6 %**

For the three months ended March 31, 2023, PAP decreased compared with the same period of 2022 and the prior quarter, primarily due to a lower WTI oil benchmark price and the road blockades in the Quifa and CPE-6 blocks.

Realized and Reference Prices

		Q1 2023	Q4 2022	Q1 2022
Reference price				
Brent	($/bbl)	82.10	88.63	97.90
Average realized prices				
Realized oil price, net of purchases	($/bbl)	71.19	85.58	94.35
Realized conventional natural gas price	($/mcf)	5.04	4.61	4.32
Net sales realized price				
Oil and gas sales, net of purchases (1)	($/boe)	69.16	82.67	90.12
Realized loss on risk management contracts(2) (3)	($/boe)	(1.16)	(1.32)	(1.06)
Royalties (2)	($/boe)	(3.36)	(6.04)	(7.58)
Other dilution costs (2)	($/boe)	(0.09)	(0.07)	(0.12)
Net sales realized price (1)	**($/boe)**	**64.55**	**75.24**	**81.36**

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
(3) Includes put premiums paid for the position expired during the period.

The average Brent benchmark oil price during the three months ended March 31, 2023, decreased by 7% and 16%, compared to the prior quarter and the same period of 2022, respectively. The decrease in crude oil prices during 2023 compared with the previous quarter was mainly due to: (i) COVID-19 restrictions in China at the beginning of the year negatively affected demand, despite market expectations of a rebound in Chinese demand, (ii) during the fourth quarter of 2022, many companies stored crude oil to preemptively limit the effect of new sanctions on Russian crude oil to be implemented during the first quarter of 2023, however, the impact was lower than expected, and (iii) freight costs increased as a result of the large number of vessels bought/ hired by Russia in response to the crude oil sanctions.

For the three months ended March 31, 2023, the Company's net sales realized price was $64.55/boe. There was a decrease of 14% and 21%, compared to the prior quarter and the same period of 2022, respectively. The decrease in the Company's net sales realized price was driven by the decrease in the Brent benchmark oil price and higher differential prices, partially offset by lower royalties.

Operating Netback

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

	Q1 2023		Q4 2022		Q1 2022	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price (1)	176,732	64.55	237,566	75.24	206,602	81.36
Production costs (2)	(45,157)	(12.07)	(44,465)	(11.56)	(49,339)	(13.34)
Transportation costs (2)	(37,370)	(11.20)	(35,660)	(10.55)	(32,083)	(9.72)
Operating Netback (1) (3)	**94,205**	**41.28**	**157,441**	**53.13**	**125,180**	**58.30**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases (4)		30,424		34,323		28,211
Production (5)		41,586		41,806		41,100
Net production (6)		37,068		36,749		36,668

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
(3) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
(4) Sales volumes, net of purchases, exclude sales of third-party volumes.
(5) Refer to the "Production" section on page 5.
(6) Refer to the "Further Disclosures" section on page 31.

The Company's operating netback for the first quarter of 2023 was $41.28/boe, compared to $58.30/boe in the same quarter of 2022. The decrease was mainly a result of lower net sales realized price and higher transportation costs mainly due to the initiation of a new ship-or-pay contract with Bicentenario de Colombia S.A.S ("**Bicentenario**") and Cenit Transporte y Logistica de Hidrocarburos S.A.S. ("**Cenit**") in May, 2022, as part of the settlement agreement with Bicentenario at the end of 2021. The difference is also due to additional volumes transported and the increase in trucking tariffs for 2023. The Company's operating netback was partially offset by lower production cost per boe, resulting from lower cost of well services, energy and personnel expenses.

In comparison to the fourth quarter of 2022, the Company's operating netback for the first quarter of 2023, decreased from $53.13/boe to $41.28/boe primarily due to lower average Brent benchmark oil prices, higher differentials and increased transportation costs.

Sales

($M)	Three months ended March 31 2023	2022
Oil and gas sales, net of purchases (1)	189,376	228,826
Realized loss on risk management contracts (2)	(3,175)	(2,682)
Royalties	(9,213)	(19,244)
Other dilution cost	(256)	(298)
Net sales (1)	**176,732**	**206,602**
Net sales realized price ($/boe) (3)	64.55	81.36

1. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
2. Includes put premiums paid for the position expired during the period.
3. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.

Oil and gas sales, net of purchases, for the three months ended March 31, 2023, decreased by $39.5 million compared to the same period of 2022, mainly due to lower Brent benchmark oil prices and higher price differentials partially offset by higher barrels sold and lower cash royalties. (Refer to the "Realized and Reference Prices" section on page 7 for further detail on changes in prices)

Net sales for the three months ended March 31, 2023, decreased by $29.9 million compared with the same period of 2022. The following table describes the various factors that impacted net sales:

($M)	Three months ended March 31 2022-2021
Net sales for the period ended March 31, 2022	206,602
Decrease due to 24% lower oil and gas price	(53,225)
Increase due to higher produced volumes sold	13,775
Increase in realized loss on risk management contracts	(493)
Decrease in other dilution costs	42
Decrease in royalties	10,031
Net sales for the period ended March 31, 2023	**176,732**

Oil and Gas Operating Costs

($M)	Three months ended March 31 2023	2022
Production costs	45,157	49,339
Transportation costs	37,370	32,083
Other dilution costs	256	298
Post-termination obligation	157	228
Inventory valuation	(8,053)	(18,572)
Total oil and gas operating costs	**74,887**	**63,376**

For the three months ended March 31, 2023 total oil and gas operating costs increased by 18%, compared to the same period of 2022. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs for the three months ended March 31, 2023, decreased by 8%, compared with the same period of 2022, primarily due to a decrease in well services, energy and personnel expenses, despite high inflation and increased tariffs for products and services. In addition, production costs for the three months ended March 31, 2023, include $1.4 million of production costs from Ecuador.
- For the three months ended March 31, 2023, transportation costs increased by 16%, compared to the same period of 2022, primarily due to higher volumes transported in Colombia and Ecuador, an increase in transportation tariffs and the initiation of

a new ship-or-pay contract with Bicentenario and Cenit in May, 2022, as part of the of the settlement agreement with Bicentenario at the end of 2021.

- Other dilution costs for the three months ended March 31, 2023, were comparable to those for the same period of 2022.
- Post-termination obligation for the three months ended March 31, 2023, were comparable to those for the same period of 2022
- Inventory valuation for the three months ended March 31, 2023, increased by $10.5 million, compared with the same period of 2022, mainly due to the lower build-up of inventory volumes in Colombia and Ecuador.

Cost of Purchases

	Three months ended March 31	
($M)	**2023**	**2022**
Cost of purchases [1]	59,031	35,422

[1] This item is included in oil and gas sales, net of purchases. For further detail refer to the “Non-IFRS and Other Financial Measures” section on page 18.

Cost of purchases corresponds to the cost of third-party hydrocarbon volumes purchased primarily for use in dilution and refining as part of the Company's oil operations and marketing and transportation strategy. For the three months ended March 31, 2023, the cost of purchases, including the transportation and processing fees for purchased volumes sold, increased by $23.6 million, compared with the same period of 2022, due to additional volumes acquired partially offset by lower Brent benchmark oil prices. The sale of purchased volumes generated an income of $51.3 million for the three months ended March 31, 2023.

Royalties

	Three months ended March 31	
($M)	**2023**	**2022**
Royalties Colombia	9,063	19,244
Royalties Ecuador	150	—
Royalties	**9,213**	**19,244**

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia and Ecuador. For the three months ended March 31, 2023, royalties decreased by $10.0 million compared to same period of 2022, due to the change in the royalties payment method from in-cash to in-kind as per the ANH’s request. In addition, the WTI price was lower during the first quarter compared to the same period of 2022. Refer to the “Production Reconciled to Sales Volumes” section on page 6 for further details of royalties PAP paid in-cash and in-kind.

Depletion, Depreciation and Amortization

	Three months ended March 31	
($M)	**2023**	**2022**
Depletion, depreciation and amortization	66,713	38,784

For the three months ended March 31, 2023, depletion, depreciation and amortization expense (“**DD&A**”) increased by 72% compared to the same period of 2022, mainly due to a higher depletable base as a result of an impairment reversal in fourth quarter 2022 and the acquisition of an additional 35% W.I. in the El Dificil block.

Impairment Expense, Exploration Expenses and Others

($M)	Three months ended March 31 2023	2022
Impairment expense:		
Exploration and evaluation assets	15,164	—
Other	1,651	—
Total impairment expense	16,815	—
Exploration expenses of:		
Geological and geophysical costs, and other	387	472
Total exploration expenses	387	472
Expense (recovery) of asset retirement obligations	13,081	(4,429)
Impairment, exploration expenses and other	**30,283**	**(3,957)**

Exploration and Evaluation Assets

During the three months ended March 31, 2023, the Company recorded an impairment charge on exploration and evaluation of assets in Colombia of $15.2 million (2022: $Nil million), as a result of the Company's decision to proceed with steps to relinquish the VIM-22 block, which remains subject to approval by the Agencia Nacional de Hidrocarburos ("**ANH**").

Other

During the three months ended March 31, 2023, the Company recognized other impairment expenses of $1.6 million (2022: $Nil million) related to obsolete inventories and allowance of doubtful account receivables.

Expense (recovery) of asset retirement obligation

When a decrease in the asset retirement obligations exceeds the carrying amount of the related asset, or there is an increase in the asset retirement obligations related to fully impaired or relinquished assets, the change is recognized as a recovery or expense of asset retirement obligations.

During the three months ended March 31, 2023, the Company recognized an asset retirement obligation expense resulting from the acquisition of the remaining 51% W.I. in Block Z1 in Peru from BPZ Resources. During the same period of 2022, a recovery of $4.4 million was recognized.

Subsequent to the quarter, the Company reached an agreement to finalize the sale of Frontera Energy OffShore Perú, the 100% consolidated entity that owns the 100% W.I. in Block Z1, for a payment of $10 million to a third party, subject to completion of certain conditions precedent. As a result of this transaction, the Company expects to no longer recognize any asset retirement obligation related to Block Z1 and to generate a $35.8 million asset retirement obligation recovery once the conditions precedent are satisfied.

Other Operating Costs

($M)	Three months ended March 31 2023	2022
General and administrative	12,669	14,656
Special projects and other cost [1]	2,996	570
Share-based compensation	(160)	5,088
Restructuring, severance and other costs	1,572	331

[1] *Mainly includes costs related to Promotora Agricola de los Llanos S.A., Peru and the SAARA expansion in 2023.*

General and Administrative ("G&A")

For the three months ended March 31, 2023, G&A expenses decreased by 14% compared with the same period of 2022, mainly due to lower personnel costs, professional fees, rent and taxes.

Special projects and other cost

For the three months ended March 31, 2023, increased $2.4 million mainly due to the start of the SAARA.

Share-Based Compensation

For the three months ended March 31, 2023, share-based compensation was an income of $0.2 million compared to an expense of $5.1 million in the same period of 2022, mainly due to the strengthening U.S. dollar and the cancellation of certain share-based compensation. Share-based compensation reflects cash and non-cash charges relating to the vesting of restricted share units ("**RSUs**") and grants of deferred share units ("**DSUs**") under the Company's security-based compensation plan, which are subject to variability from movements in the underlying Common Share price, and the consolidation of stock option expenses from the Company's majority-held subsidiary, CGX.

Restructuring, Severance and Other Costs

For the three months ended March 31, 2023, restructuring, severance and other costs increased by $1.2 million compared with the same period of 2022, mainly due to a higher severance charge relating to the voluntary shut-in of production in the La Creciente block and restructuring cost.

Non-Operating Costs

	Three months ended March 31	
($M)	**2023**	**2022**
Finance income	4,301	607
Finance expenses	(15,221)	(12,235)
Foreign exchange (loss) income	(11,760)	3,642
Other income (loss)	6,305	(6,019)

Finance Income

For the three months ended March 31, 2023, finance income increased by $3.7 million, compared with the same period of 2022, as a result of higher interest rates on the investment trust accounts for abandonment requirements.

Finance Expenses

For the three months ended March 31, 2023, finance expenses increased by $3.0 million, mainly due to higher interest on the 2025 Puerto Bahia Debt (as defined below).

Foreign Exchange (Loss) Income

For the three months ended March 31, 2023, the foreign exchange loss was $11.8 million, as a result of the transfer from the cumulative translation adjustment of the Other Comprehensive Income ("**OCI**") the to Consolidated Statement of Income of a return of capital of Oleoducto de los Llanos S.A. ("**ODL**") for $6.8 million during the first quarter of 2023 and a loss on the translation of the Company's net working capital balances. Foreign exchange rates for the first quarter of 2023 and 2022, were 4,627.27:1 and 3,748.15:1 respectively. This compares with an income of $3.6 million in the same period of 2022.

Other Income (Loss)

For the three months ended March 31, 2023, the Company recognized other income of $6.3 million primarily related to a reversal of the legal claim from the late delivery of production from Quifa block prior to 2014 (for further information refer to the "Commitments and Contractual Obligations" section on page 27), compared to other losses in the same period of $6.0 million related to the recognition of contingencies in Peru.

Loss on Risk Management Contracts

	Three months ended March 31	
($M)	**2023**	**2022**
Premiums paid on risk management contracts settled	(3,175)	(2,682)
Realized loss on risk management contracts	(3,175)	(2,682)
Unrealized gain on risk management contracts [1]	4,825	1,144
Total loss (gain) on risk management contracts	1,650	(1,538)

[1] 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, 2023, the realized loss on risk management contracts was $3.2 million resulting from cash paid for premiums related to put options settled during the period, compared to a loss of $2.7 million in the same period of 2022, primarily from the lower cost of the put premiums settled during the three months ended March 31, 2022.

For the three months ended March 31, 2023, the unrealized gain on risk management contracts was $4.8 million, compared to a gain of $1.1 million in the same period of 2022, primarily from the reclassification of amounts to realized losses from instruments settled and a decrease in the benchmark forward prices of Brent.

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% to 60% of the estimated production with a tactical approach, using derivative commodity instruments to protect the revenue generation and cash position of the Company, while maximizing the upside. The Company uses only put options which allows it to capture the full upside price benefit while offering efficient downside hedging.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $/bbl**	**Assets**	**Liabilities**
Put	April to June 2023	Brent	1,275,000	70	1,293	—
Total as at March 31, 2023					1,293	—

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations 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, 2023, the Company had entered into new positions of foreign currency derivatives contracts as follows:

				Avg. Put / Call	Carrying Amount	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume in USD**	**Par forward (COP$)**	**Assets**	**Liabilities**
Zero-cost collars	April to June 2023	COP / USD	60,000,000	4,350 / 5,515	$ 178	$ —
Zero-cost collars	July to December 2023	COP / USD	120,000,000	4,800 / 5,364	$ 3,416	$ —
Total as at March 31, 2023					$ 3,594	$ —

Income Tax (Expense) Recovery

	Three months ended March 31	
($M)	**2023**	**2022**
Current income tax expense	(1,007)	(1,553)
Deferred income tax (expense) recovery	(6,513)	14,304
Total income tax (expense) recovery	**(7,520)**	**12,751**

Current income tax expense for the first quarter of 2023 was $1.0 million, compared with $1.6 million in the same quarter of 2022, mainly from withholding taxes on dividends from investments in associates, partially offset by tax deductions and changes in tax assessments recognized during the first quarter of 2023.

Deferred income tax expense for the first quarter of 2023 was $6.5 million, compared with a tax recovery expense of $14.3 million for the same quarter of 2022. The variation is mainly due to the use of deferred tax assets as taxable profits accrued during the quarter, partially offset by the revaluation of the COP during the first quarter of 2023.

Net (Loss) Income

	Three months ended March 31	
($M)	**2023**	**2022**
Net (Loss) Income [1]	(11,330)	102,228
Per share – basic ($)	(0.13)	1.08
Per share – diluted ($)	(0.13)	1.05

[1] Refers to Net (loss) income Attributable to equity holders of the Company.

The Company reported a net loss attributable to equity holders of the Company, of $11.3 million for the first quarter of 2023, which included operating losses of $2.7 million (including $30.3 million in impairment, exploration expenses and other costs), finance expenses of $15.2 million, foreign exchange losses of $11.8 million and income tax expenses of $7.5 million, partially offset by $13.6 million of share of income from associates and finance income of $4.3 million. This compared to net income, attributable to equity holders of the Company, of $102.2 million in the first quarter of 2022, which included operating income of $95.7 million and deferred income tax recovery of $14.3 million, partially offset by finance expenses of $12.2 million.

Capital Expenditures and Acquisitions

	Three months ended March 31	
($M)	**2023**	**2022**
Development drilling	31,998	36,881
Development facilities	8,574	5,994
Colombia and Ecuador exploration	12,365	10,195
Other	3,215	6,967
Total Colombia, Ecuador and other capital expenditures	**56,152**	**60,037**
Guyana exploration and infrastructure	75,300	53,508
Total capital expenditures [(1)]	**131,452**	**113,545**

(1) Non-IFRS financial measure. Refer to the “Non-IFRS and Other Financial Measures" section on page 18.

Capital expenditures for the three months ended March 31, 2023, was $131.5 million, an increase of $17.9 million, compared to the same period of 2022, mainly due to the following:

Development drilling. During the three months ended March 31, 2023, development drilling expenditures decreased by $4.9 million, compared to the same period of 2022, despite of 17 development wells drilled in the Quifa, Cajua, CPE-6 and Cubiro blocks, in the first quarter of 2023, and 14 wells drilled in Quifa, Guatiquia and CPE-6 blocks, in the same period of 2022, drilling cost per well was lower in 2023 due to the type of the wells.

Development facilities. During the three months ended March 31, 2023, development facilities expenditures were $8.6 million compared to $6.0 million during the same period of 2022, mainly related to storage facilities including the construction of a storage tank at CPE-6 block and the expansion of fluid transfer and the interconnection of fields in Quifa block.

Colombia and Ecuador Exploration. During the three months ended March 31, 2023, expenditures related to exploration activities increased by $2.2 million, compared to the same period of 2022. During the first quarter of 2023, two exploration wells were completed, including Magari-1 well in the La Creciente block and Chimi-1 exploration well in the VIM-22 block, and one well was spud, Winner-1, in the VIM-22 block. The Company is undertaking pre-drilling activities for the Yin Sur-1 exploratory well in Ecuador.

Details relating to exploration activities during the three months ended March 31, 2023, in Colombia and Ecuador are as follows:

Colombia. The Company’s exploration focus remains on the Lower Magdalena Valley and Llanos Basins in Colombia. During the first quarter of 2023, initial testing was performed in January 2023 on the Hamaca Norte-1 exploratory well, in the CPE-6 block. An initial seven-day production test produced an average of 50 bbls/d of 10.5 degree API heavy crude oil with 46% of basic sediment and water (“**BSW**”). No pressure build-up was performed. The well is currently in production with 50 bbls/d of 10.5 degree API heavy crude oil with a 60% BSW. At La Creciente block, Frontera spud the Magari-1 well and reached total depth in early January 2023. Gassy water was interpreted in the Ciénaga de Oro formation and the well was plugged and abandoned. At the VIM-22 block, the Chimi-1 and Winner-1 wells were spudded on February 16, 2023 and March 30, 2023 respectively, the interpretation of log while drilling data and integration with drilling data concluded that the wells do not contain net hydrocarbon pay and non-commercial gas was found in Tubara Formation in the first well and in the Porquero in the second well. The wells were plugged and abandoned. Also, at the VIM-22 block, civil works were completed for the Tubara Sur-1 exploratory well. The Company is proceeding with steps to relinquish the VIM-22 block, which remains subject to approval by the ANH. At the Llanos-99 block, the acquisition of 165 square kilometres of 3D seismic was initiated. Land permitting topography and the drilling phase were completed. Operational activity is expected to be complete in May 2023. The Company is working on pre-seismic and pre-drilling activities related to social and environmental impact studies in the Llanos-119, and VIM-46 blocks.

Ecuador. At the Jandaya-1, Tui-1 and Yin-1 exploration wells, in the Perico block (Frontera 50% W.I. and operator), the Company is conducting long-term testing and is preparing the environmental impact assessments in order to obtain a production environmental license. Currently, the Company has drilled three out of four wells required as part of its work commitment on the Perico block. The Company is undertaking pre-drilling activities for the Yin Sur-1 exploratory well, and expects to drill the well during the third quarter.

For the Pashuri-1 and Caracara-1 exploration wells, at the Espejo block (Frontera 50% W.I. and non-operator), preliminary logging information indicated the presence of hydrocarbons in both wells, and further analyses are being carried out. In addition, jointly with the operator, new 3D seismic survey data is being interpreted in order to define the location of the third committed exploratory well.

Other

For the three months ended March 31, 2023, the Company has capitalized other investments of $2.9 million, mainly related to investments in Puerto Bahia and SAARA.

Guyana exploration and infrastructure. During the three months ended March 31, 2023, Guyana exploration and infrastructure expenditures were $75.3 million compared to $53.5 million during the same period of 2022, mainly related to the following:

Exploration. On January 23, 2023, the Company and its majority-owned subsidiary and joint venture partner, CGX (the "**Joint Venture**"), in the Petroleum Prospecting License for the Corentyne block offshore Guyana (the "**PPL**"), spud the Wei-1 well, on the Corentyne block. The Wei-1 well is located approximately 14 kilometres northwest of the Joint Venture's previous Kawa-1 light oil and condensate discovery, approximately 200 kilometres offshore from Georgetown, Guyana. The Wei-1 well, planned to be drilled to a total depth of 20,500 feet, to date has been successfully drilled to a depth of 19,142 feet (5,834 metres).

The Wei-1 well has encountered oil-bearing intervals in the western channel fan complex of the northern portion of the Corentyne block in formations of Maastrichtian and Campanian ages. A comprehensive logging campaign in the Maastrichtian and Campanian intervals indicated the presence of oil, confirmed by downhole analysis. Logging while drilling (LWD) and cuttings indicate the presence of hydrocarbons in the upper portion of the Santonian; fluid samples have not yet been fully obtained. Side-wall core samples will be attempted in the Santonian interval when drilling resumes. Preliminary indications from the secondary targets in the Maastrichtian and Campanian are positive, however no assurance can be given that these activities will ultimately produce hydrocarbons in commercial quantities. While performing additional well logging and data acquisition operations a wireline fluid sampling tool became stuck in the well and was not recovered. An open hole sidetrack will begin shortly from below the last casing point and will progress to the planned total depth. The Joint Venture expects to complete Wei-1 operations within the original 4-5 month timeframe as announced on January 23, 2023.

The Joint Venture has updated its Well total cost estimates to $175-$190 million to successfully reach the target total depth and complete its drilling program. The increase in cost includes the delays associated with the late arrival of the rig, costs associated with fishing and sidetrack operations and associated post well evaluations.

The Government of Guyana has approved an Appraisal Plan for the northern section of the Corentyne block which commenced with the Wei-1 well. Following completion of Wei-1 drilling operations and upon detailed analysis of the results, the Joint Venture may consider future wells per its appraisal program to evaluate possible development feasibility in the Kawa-1 discovery area and throughout the northern section of the Corentyne block. Any future drilling is contingent on positive results at the Wei-1 well and the Joint Venture has no further drilling obligations beyond the Wei-1 well. The Company's investment in the Wei-1 well during the three months ended March 31, 2023 was $75.3 million.

Infrastructure. CGX, Frontera's majority-owned subsidiary, is building a multifunctional port facility adjacent to Crab Island on the eastern bank of the Berbice River in Guyana, 4.8 kilometres from the Atlantic Ocean, called the Berbice Deep Water Port, which will serve as an offshore supply base and a multi-purpose terminal (the "**Guyana Port Project**"). The land for the Guyana Port Project is leased until 2060 and is renewable for an additional term of 50 years.

Selected Quarterly Information

Operational and financial results		2023 Q1	2022 Q4	2022 Q3	2022 Q2	2022 Q1	2021 Q4	2021 Q3	2021 Q2
Heavy crude oil production	(bbl/d)	22,270	22,144	20,945	21,455	21,214	20,912	18,168	17,241
Light and medium crude oil production	(bbl/d)	16,518	17,073	17,428	17,348	17,248	16,300	17,160	17,142
Total crude oil production	(bbl/d)	38,788	39,217	38,373	38,803	38,462	37,212	35,328	34,383
Conventional natural gas production	(mcf/d)	8,590	9,097	9,969	10,374	9,530	4,663	5,033	5,164
Natural gas liquids production	(boe/d)	1,291	993	911	963	966	575	211	393
Total production	(boe/d)	41,586	41,806	41,033	41,586	41,100	38,605	36,422	35,682
Sales volumes, net of purchases	(boe/d)	30,424	34,323	36,660	33,273	28,211	39,001	26,672	34,151
Brent price	($/bbl)	82.10	88.63	97.70	111.98	97.90	79.66	73.23	69.08
Oil and gas sales, net of purchases [(1)] [(3)]	($/boe)	69.16	82.67	90.47	102.92	90.12	75.12	67.13	64.54
Realized loss on risk management contracts [(2)]	($/boe)	(1.16)	(1.32)	(1.30)	(1.15)	(1.06)	(1.87)	(2.68)	(8.00)
Royalties [(2)]	($/boe)	(3.36)	(6.04)	(7.23)	(10.57)	(7.58)	(3.62)	(4.83)	(0.53)
Dilution costs [(2)]	($/boe)	(0.09)	(0.07)	(0.07)	(0.12)	(0.12)	(0.10)	(0.15)	(0.34)
Net sales realized price [(1)] [(3)]	($/boe)	64.55	75.24	81.87	91.08	81.36	69.53	59.47	55.67
Production costs [(2)] [(3)]	($/boe)	(12.07)	(11.56)	(11.20)	(12.51)	(13.34)	(12.71)	(11.44)	(11.72)
Transportation costs [(2)] [(3)]	($/boe)	(11.20)	(10.55)	(10.70)	(10.80)	(9.72)	(9.02)	(10.24)	(11.15)
Operating netback per boe [(1)]	($/boe)	41.28	53.13	59.97	67.77	58.30	47.80	37.79	32.80
Revenue	($M)	250,366	317,568	354,548	344,015	254,627	301,969	182,673	224,685
Net (loss) income [(5)]	($M)	(11,330)	197,796	(26,893)	13,484	102,228	629,376	38,531	(25,648)
Per share – basic ($)	($)	(0.13)	2.29	(0.30)	0.14	1.08	6.60	0.40	(0.26)
Per share – diluted ($)	($)	(0.13)	2.25	(0.30)	0.14	1.05	6.40	0.39	(0.26)
General and administrative	($M)	12,669	12,761	12,549	15,097	14,656	12,144	12,656	14,132
Operating EBITDA [(4)]	($M)	91,922	144,994	173,207	190,678	132,998	148,645	77,304	83,072
Capital expenditures [(4)]	($M)	131,452	134,165	76,018	93,835	113,545	135,458	103,220	61,214

(1) Non-IFRS ratio. Refer to the “Non-IFRS and Other Financial Measures" section on page 18.
(2) Supplementary financial measure. Refer to the “Non-IFRS and Other Financial Measures" section on page 18.
(3) 2022 prior period figures are different compared with those previously reported as a result of the exclusion of ProAgrollanos’ revenues and, production and transportation costs.
(4) Non-IFRS financial measure. Refer to the “Non-IFRS and Other Financial Measures” section on page 18 for further details.
(5) Refers to net (loss) income attributable to equity holders of the Company.

Over the past eight quarters, the Company’s sales have fluctuated due to changes in production, movement in Brent benchmark prices, timing of cargo shipments, and fluctuations in crude oil price differentials. Since the first half of 2021, production volumes have increased due to the reactivation of drilling activities, removal of COVID-19 related restrictions that were imposed at the peak of the pandemic in Colombia and the start of oil production in Ecuador. However, during the third quarter of 2022, there was a decrease in production mainly due to maintenance of water disposal facilities at Quifa block, which was completed during the fourth quarter of 2022, and together with record production at CPE-6 block, increased production again during the last quarter of 2022. During the first quarter 2023, production slightly decreased due to blockades of the road in Puerto Gaitán (Meta Department) affecting production in CPE-6 and Quifa blocks. During the last year, transportation costs have increased, mainly due to the initiation of a pipeline take-or-pay commitment that commenced in 2022 as part of the Conciliation Agreement and an annual increase of trucking tariffs for 2023. Production costs have also fluctuated due to exchange rate impacts and increases in tariffs and barrels produced affecting variable costs.

Trends in the Company’s net (loss) income, attributable to Equity Holders of the Company, are also impacted most significantly by the recognition and derecognition of deferred income taxes and expenses or reversal of impairment of oil and gas and E&E assets, DD&A, foreign exchange gain or losses and total loss from risk management contracts that fluctuate mainly with changes in hedging strategies and crude oil benchmark forward prices. Please refer to the Company’s previously issued annual and interim management’s discussion and analysis available on SEDAR at www.sedar.com for further information regarding changes in prior quarters.

Midstream Colombia

Frontera has investment in certain infrastructure and midstream assets, including storage, port and other facilities in Colombia and the Company's investment in pipelines ("**Midstream Colombia Segment**").

The Company's Midstream Colombia Segment includes the following:

Asset	Description	Interest [(1)]	Accounting Method
Puerto Bahia	Bulk liquid storage and import-export terminal	99.80% interest in Puerto Bahia	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/day	100% interest in PIL (which holds a 35% interest in the ODL Pipeline)	Equity Method [(2)]

(1) Interests include both direct and indirect interests.
(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.

Performance Highlights

		Q1 2023	Q4 2022	Q1 2022
Operational and IFRS Results				
Volumes pumped at oil pipeline facility	(bbl/d)	225,792	222,855	203,456
Volumes throughput at port liquids facility	(bbl/d)	63,008	66,717	58,502
Volumes RORO at port general cargo facility	(Units)	30,220	35,596	21,856
Volumes at port Break Bulk Volumes	(Tons/m3)	11,034	17,291	38,993
Segment income	($M)	16,924	14,934	11,426
Segment cash flow from operations activities	($M)	7,608	12,796	17,024
Non IFRS Results [(1)]				
Adjusted Midstream Revenues	($M)	38,231	38,355	23,003
Adjusted Midstream EBITDA	($M)	28,177	26,558	14,395
Adjusted Midstream Cash	($M)	57,985	49,165	34,247
Adjusted Midstream Debt	($M)	127,164	116,173	153,559
Capital Expenditures Midstream Colombia Segment	($M)	305	1,028	354

(1) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 18.

Midstream Colombia Segment Results

The Interim Financial Statements include the following amounts relating to the Midstream Colombia Segment:

	Three months ended March 31	
($M)	**2023**	**2022**
Revenue	11,146	10,332
FEC liquids port facility	1,664	1,452
Third party liquids port facility	5,832	5,358
General cargo	3,650	3,522
Cost	(5,117)	(4,679)
General administrative expenses	(1,342)	(1,671)
Depletion, depreciation and amortization	(1,232)	(1,476)
Restructuring, severance and other costs	(103)	(174)
Puerto Bahia income from operations	3,352	2,332
Share of Income from associates - ODL	13,572	9,094
Segment income	16,924	11,426
Segment cash flow from operations activities	7,608	17,024

The Company's Midstream Colombia Segment income increased by $5.5 million for the three months ended March 31, 2023 to $16.9 million, compared with $11.4 million in the same period of 2022. For the three months ended March 31, 2023, the Puerto Bahia liquids terminal revenues increased by 10% compared with the same period of 2022. The liquids terminal revenues during the first quarter of 2023 and 2022, correspond to 67% and 66% of total revenues, respectively. General cargo terminal revenues increased by 4%, compared with the same period in 2022, due to higher volumes of roll-on/roll-off ("**RORO**") units as result of capturing new car brands.

Cash provided by operating activities of the Midstream Colombia Segment for three months ended March 31, 2023 was $7.6 million compared to $17.0 million in the same period of 2022, with the reduction mainly due to $9.0 million of dividends collected during the first quarter of 2022, while $18.2 million of dividends were collected, following the quarter end, in April 2023.

Non-IFRS Results of Midstream Segment

The following table shows the financial metrics of the Midstream Colombia Segment attributable to Frontera, including the proportional consolidation of the 35% of ODL Investment. Reported adjusted Midstream revenue, adjusted Midstream operating cost and adjusted Midstream general and administrative costs for the Midstream segment reflecting Frontera's 35% interest in the ODL pipeline accounted for using the equity method for consolidated financial statement purposes. Adjusted Midstream EBITDA is a non-IFRS financial measure used to assist in measuring the operating results of the Midstream Colombia Segment business.

	Three months ended March 31	
($M)	**2023**	**2022**
Adjusted Midstream Revenue[1]	38,231	23,003
Adjusted Midstream Operating Cost[1]	(7,741)	(6,296)
Adjusted Midstream General and Administrative[1]	(2,314)	(2,312)
Adjusted Midstream EBITDA[1]	28,177	14,395

[1] Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 18.

The Adjusted Midstream EBITDA for the first quarter of 2023 was $28.2 million compared to $14.4 million in the same period of 2022, as a result of the increase from 59.93% to 100.00% in PIL in September 2022, higher pipeline volumes transported, and higher throughput volumes at the liquids port facility.

ODL Pipeline

The Company, through its 100%-owned subsidiary PIL, has a 35% equity investment in the ODL pipeline, which connects the Rubiales, Quifa, and Llanos-34 blocks to the Monterrey Station or Cusiana Station in the Casanare Department. On September 15, 2022, the Company acquired the remaining 40.07% interest it did not already own of PIL, increasing its ownership interest to 100%.

For the three months ended March 31, 2023, ODL generated $67.1 million of EBITDA and $38.8 million of net income. The ODL results are consolidated through the equity method in the Company's Interim Financial Statements as "Share of income from associates".

The income statement and key balance sheet information from the 100% ODL is as follows:

	Three months ended March 31	
($M)	**2023**	**2022**
Revenue	77,387	60,408
FEC revenue (billed units)	6,910	5,363
Third party liquids port facility	70,477	55,045
Cost	(7,496)	(7,708)
General administrative expenses	(2,778)	(3,056)
Depletion, depreciation and amortization	(5,781)	(7,338)
Other non-operating expense	(1,676)	(2,269)
Income Tax	(20,880)	(14,053)
ODL Net Income	**38,776**	**25,984**

	Three months ended March 31	
($M)	**2023**	**2022**
ODL debt	38,218	49,892
ODL cash and cash equivalents	118,715	79,482

The following table shows the volumes pumped per injection point:

(bbl/d)	Three months ended March 31 2023	2022
At Rubiales Station	154,817	131,653
At Jagüey and Palmeras Station	70,975	71,803
Total	**225,792**	**203,456**

The following table shows the volumes received per block:

(bbl/d)	Three months ended March 31 2023	2022
Rubiales	106,190	94,905
Quifa	27,755	27,011
CPE-6	2,263	1,518
Other blocks	72,696	74,590
Total	**208,904**	**198,024**

For the three months ended March 31, 2023, the Company recognized $13.6 million as its share of income from ODL, which was $4.5 million higher than the same period of 2022, primarily due to the increase in volumes transported and the impact of foreign exchange fluctuations. During the three months ended March 31, 2023, the Company recognized gross dividends of $37.0 million (2022: $40.5 million) and a return of capital of $5.2 million (2022: $3.9 million).

Puerto Bahia

Puerto Bahia owns and operates a multifunctional port facility located in Cartagena, Colombia, which consists of a hydrocarbons terminal and a general cargo terminal adjacent to the Bocachica access channel of the Cartagena Bay, and is strategically located near the Cartagena Refinery. The multipurpose port facility has a total area of 155 hectares, Puerto Bahia´s segment income from operations is mainly generated from service contracts in the liquid terminal with capacity of 2,672,000 barrels, and RORO services in the general cargo terminal.

The following table shows throughput for the liquids port facility at Puerto Bahia:

(bbl/d)	Three months ended March 31 2023	2022
FEC volumes	11,408	12,421
Third party volumes	51,600	46,081
Total	**63,008**	**58,502**

The following table shows the RORO and the break bulk units for the general cargo port facility at Puerto Bahia:

(units - tons/m3)	Three months ended March 31 2023	2022
RORO (units) (1)	30,220	21,856
Break Bulk Volumes (Tons/m3) (2)	11,034	38,993

(1) Carry wheeled cargo, mainly corresponds to cars imported to Colombia.
(2) Other types of cargo different from wheeled cargo.

For the three months ended March 31, 2023, Puerto Bahia has generated $3.4 million of segment income from operations and $4.7 million of EBITDA, which was $1.0 million and $0.7 million, higher respectively, compared to the same period of 2022, driven by increased throughput volumes at the liquids port facility.

Non-IFRS and Other Financial Measures

This MD&A contains various "**non-IFRS financial measures**" (equivalent to "**non-GAAP financial measures**", as such term is defined in NI 52-112), "**non-IFRS ratios**" (equivalent to "**non-GAAP ratios**", as such term is defined in NI 52-112), "**supplementary financial measures**" (as such term is defined in NI 52-112) and "**capital management measures**" (as such term is defined in NI 52-112), which are described in further detail below. Such measures do not have standardized IFRS definitions. The Company's determination of these non-IFRS financial measures may differ from other reporting issuers and they are therefore unlikely to be comparable to similar measures presented by other companies. Furthermore, these financial measures should not be considered in isolation or as a substitute for measures of performance or cash flows as prepared in accordance with IFRS. These financial measures do not replace or supersede any standardized measure under IFRS. Other companies in our industry may calculate these measures differently than we do, limiting their usefulness as comparative measures.

The Company discloses these financial measures, together with measures prepared in accordance with IFRS, because management believes they provide useful information to investors and shareholders, as management uses them to evaluate the operating performance of the Company. These financial measures highlight trends in the Company's core business that may not otherwise be apparent when relying solely on IFRS financial measures. Further, management also uses non-IFRS measures to exclude the impact of certain expenses and income that management does not believe reflect the Company's underlying operating performance. The Company's management also uses non-IFRS measures in order to facilitate operating performance comparisons from period to period and to prepare annual operating budgets and as a measure of the Company's ability to finance its ongoing operations and obligations.

Set forth below is a description of the non-IFRS financial measures, non-IFRS ratios, supplementary financial measures and capital management measures used in this MD&A.

Non-IFRS Financial Measures

Operating EBITDA

EBITDA is a commonly used non-IFRS financial 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 is a non-IFRS financial measure that represents the operating results of the Company's primary business, excluding the following items: restructuring, severance and other costs, post-termination obligation, payments of minimum work commitments and, 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.

Since the three and six months ended June 30, 2022, the Company changed the composition of its Operating EBITDA calculation to exclude certain unusual or non-recurring items as post-termination obligations and payments of minimum work commitments, which could distort future projections as they are not considered part of the Company's normal course of operations. Operating EBITDA for the full year 2021 was revised to reflect this change, resulting in an increase of $5.0 million from what was previously reported by the Company prior to the three and six months ended June 30, 2022.

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

	Three months ended March 31	
($M)	**2023**	**2022**
Net (loss) income[1]	(11,330)	102,228
Finance income	(4,301)	(607)
Finance expenses	15,221	12,235
Income tax expense (recovery)	7,520	(12,751)
Depletion, depreciation and amortization	66,713	38,784
Expense of impairment, recovery of asset retirement obligation and others	29,896	(4,429)
Post-termination obligation	157	228
Share-based compensation non-cash portion	(499)	5,088
Restructuring, severance and other costs	1,572	331
Share of income from associates	(13,572)	(9,094)
Foreign exchange loss (income)	11,760	(3,642)
Other (income) loss	(6,305)	6,019
Unrealized gain on risk management contracts	(4,825)	(1,144)
Non-controlling interests	(85)	(248)
Operating EBITDA	**91,922**	**132,998**

(1) Refers to net (loss) income attributable to equity holders of the Company.

Capital expenditures

Capital expenditures is a non-IFRS financial measure that reflects the cash and non-cash items used by the Company to invest in capital assets. This financial measure considers oil and gas properties, plant and equipment, infrastructure, exploration and evaluation assets expenditures which are items reconciled to the Company's Statements of Cash Flows for the period.

	Three months ended March 31	
	2023	**2022**
Statements of Cash Flows		
Additions to oil and gas properties, infrastructure port, and plant and equipment	42,980	50,283
Additions to exploration and evaluation assets	88,946	60,422
Total additions in Statements of Cash Flows	**131,926**	**110,705**
Non-cash adjustments [1]	(474)	2,840
Total Capital Expenditures	**131,452**	**113,545**
Capital Expenditures attributable to Midstream Colombia Segment	305	354
Capital Expenditures attributable to other segments different to Midstream Colombia Segment	131,147	113,191
Total Capital Expenditure	**131,452**	**113,545**

[1] Related to material inventory movements, capitalized non-cash items and other adjustments.

Net Sales

Net sales is a non-IFRS financial measure 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 dilution 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 dilution, the cost of which is partially recovered when the blended product is sold. Net sales also exclude sales from port services, as it is not considered part of the oil and gas segment. Refer to the reconciliation in the "Sales" section on page 8.

Operating Netback and Oil and Gas Sales, Net of Purchases

Operating netback is a non-IFRS financial measure and operating netback per boe is a non-IFRS ratio. Operating netback per boe 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 7.

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

Oil and gas sales, net of purchases, is a non-IFRS financial measure that is calculated using oil and gas sales less the cost of volumes purchased from third parties including its transportation and refining cost. Oil and gas sales, net of purchases per boe, is a non-IFRS ratio that is calculated using oil and gas sales, net of purchases divided by the total sales volumes, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended March 31	
	2023	**2022**
Produced crude oil and gas sales ($M) [1]	197,091	232,536
Purchased crude oil and products sales ($M)	51,316	31,712
(-) Cost of purchases ($M) [2]	(59,031)	(35,422)
Oil and gas sales, net of purchases ($M)	**189,376**	**228,826**
Sales volumes, net of purchases - (boe)	2,738,160	2,538,990
Oil and gas sales, net of purchases ($/boe)	69.16	90.12

[1] Excludes sales from port services as they are not part of the oil and gas segment. For further information, refer to the "Midstream Activities" section on page 16.
[2] Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining costs.

Midstream Colombia Calculations

Each of Adjusted Midstream Revenue, Adjusted Midstream Operating Cost and Adjusted Midstream General and Administrative, is a non-IFRS financial measure, and each is used to evaluate the performance of the Midstream Colombia Segment operations. Adjusted Midstream Revenue includes revenues of the Midstream Colombia Segment including ODL's revenue direct participation interest. Adjusted Midstream Operating Cost includes costs of the Midstream Colombia Segment including ODL's cost direct participation interest. Adjusted Midstream General and Administrative includes general and administrative costs of Midstream Colombia Segment including ODL's general and administrative direct participation interest. A reconciliation of each of Adjusted Midstream Revenue, Adjusted Midstream Operating Cost and Adjusted Midstream General and Administrative is provide below.

	Three months ended March 31	
($M) [1]	**2023**	**2022**
Revenue Midstream Colombia Segment	11,146	10,332
Revenue from ODL	77,387	60,408
Direct participation interest in the ODL	35.00 %	20.98 %
Equity adjustment participation of ODL [1]	27,085	12,671
Adjusted Midstream Revenues	**38,231**	**23,003**
Operating cost Midstream Colombia Segment	(5,117)	(4,679)
Operating Cost from ODL	(7,496)	(7,708)
Direct participating interest in the ODL	35.00 %	20.98 %
Equity adjustment participation of ODL [1]	(2,624)	(1,617)
Adjusted Midstream Operating Cost	**(7,741)**	**(6,296)**
General and administrative Midstream Colombia Segment	(1,342)	(1,671)
General and administrative from ODL	(2,778)	(3,056)
Direct participating interest in the ODL	35.00 %	20.98 %
Equity adjustment participation of ODL [1]	(972)	(641)
Adjusted Midstream General and Administrative	**(2,314)**	**(2,312)**

[1] Revenues and expenses related to the ODL are accounted for using the equity method in the Interim Financial Statements.

Adjusted Midstream Cash and Adjusted Midstream Debt is a non-IFRS financial measure or contains a non-IFRS financial measure, and is used to evaluate the performance of the Midstream Colombia Segment cash position and monitor the Midstream Colombia Segment's debt. Adjusted Midstream Cash includes cash of the Midstream Colombia Segment including ODL's cash direct participation interest. Adjusted Midstream Debt includes debt of Midstream Colombia Segment including ODL's debt direct participation interest. A reconciliation of each of Adjusted Midstream Cash and Adjusted Midstream Debt is provide below.

	Three months ended March 31	
($M) [1]	**2023**	**2022**
Cash and cash equivalents - unrestricted	162,272	289,845
Cash and cash equivalents of Non-Midstream Colombia Segment's	(145,837)	(272,270)
Total Cash Midstream Colombia Segment	16,435	17,575
Cash and cash equivalent from ODL	118,715	79,482
Direct participating interest in the ODL	35.00 %	20.98 %
Equity adjustment participation of ODL [1]	41,550	16,672
Adjusted Midstream Cash	**57,985**	**34,247**
Long-term debt	516,999	508,457
Debt of Non-Midstream Colombia Segment's	(403,211)	(365,363)
Total Debt	113,788	143,094
Debt from ODL	38,218	49,892
Direct participating interest in the ODL	35.00 %	20.98 %
Equity adjustment participation of ODL [1]	13,376	10,465
Adjusted Midstream Debt	**127,164**	**153,559**

[1] 35% ODL participation is accounted using the equity method in the Interim Financial Statements, Cash and cash equivalents, and Debt related to the ODL are embedded in the value of the Investment in Associates.

Adjusted Midstream EBITDA

The Adjusted Midstream EBITDA is a non-IFRS financial measure used to assist in measuring the operating results of the Midstream Colombia Segment business. Refer to the Calculation in "Non-IFRS Results of Midstream Segment section on page 17.

Non-IFRS Ratios

Realized oil price, net of purchases, and realized gas price per boe

Realized oil price, net of purchases, and realized gas price per boe are both non-IFRS ratios. Realized oil price, net of purchases, per boe is calculated using oil sales net of purchases, divided by total sales volumes, net of purchases. Realized gas price is calculated using sales from gas production divided by the conventional natural gas sales volumes.

	Three months ended March 31	
	2023	**2022**
Produced crude oil sales ($M)	193,334	228,745
Purchased crude oil and products sales ($M)	51,316	31,712
(-) Cost of purchases ($M)	(59,031)	(35,422)
Conventional natural gas sales ($M)	3,757	3,791
Oil and gas sales, net of purchases ($M) [1]	**189,376**	**228,826**
Sales volumes, net of purchases - (bbl)	2,607,363	2,384,983
Conventional natural gas sales volumes - (mcf)	745,794	878,193
Realized oil price, net of purchases ($/bbl)	71.19	94.35
Realized conventional natural gas price ($/mcf)	5.04	4.32

(1) Non-IFRS financial measure.

Net sales realized price

Net sales realized price is a non-IFRS ratio that is calculated using net sales (including oil and gas sales net of purchases, realized gains and losses from risk management contracts less royalties and dilution costs). Net sales realized price per boe is a non-IFRS ratio which is calculated dividing each component by total sales volumes, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended March 31	
	2023	**2022**
Oil and gas sales, net of purchases ($M) [1]	189,376	228,826
(-) Realized loss on risk management contracts ($M)	(3,175)	(2,682)
(-) Royalties ($M)	(9,213)	(19,244)
(-) Dilution costs ($M)	(256)	(298)
Net sales ($M)	**176,732**	**206,602**
Sales volumes, net of purchases - (boe)	2,738,160	2,538,990
Oil and gas sales, net of purchases ($/boe)	69.16	90.12
Realized loss on risk management contracts [2]	(1.16)	(1.06)
Royalties ($/boe) [2]	(3.36)	(7.58)
Other dilution costs ($/boe) [2]	(0.09)	(0.12)
Net sales realized price ($/boe)	**64.55**	**81.36**

(1) Non-IFRS financial measure.
(2) Supplementary financial measure.

Supplementary Financial Measures

Production cost per boe

Production costs mainly includes lifting costs, activities developed in the blocks, and processes to put the crude oil and gas in sales condition. Production cost per boe is a supplementary financial measure that is calculated using production cost divided by production (before royalties). A reconciliation of this calculation is provided below:

	Three months ended March 31	
	2023	**2022**
Production costs ($M)	45,157	49,339
Production (boe)	3,742,740	3,699,000
Production costs ($/boe)	12.07	13.34

Transportation cost per boe

Transportation costs includes all commercial and logistics costs associated with the sale of produced crude oil and gas such as trucking and pipeline. Transportation cost per boe is a supplementary financial measure that is calculated using transportation cost divided by net production after royalties. A reconciliation of this calculation is provided below:

	Three months ended March 31	
	2023	**2022**
Transportation costs ($M)	37,370	32,083
Net production (boe)	3,336,120	3,300,120
Transportation costs ($/boe)	11.20	9.72

Realized (loss) gain on risk management contracts per boe

Realized (loss) gain on risk management contracts includes the gain or loss during the period, as a result of the Company´s exposure in derivative contracts. Realized (loss) gain on risk management contracts per boe is a supplementary financial measure that is calculated using Realized (loss) gain on risk management contracts divided by total sales volumes, net of purchases.

Royalties per boe

Royalties includes royalties and amounts paid to previous owners of certain blocks in Colombia and cash payments for PAP. Royalties per boe is a supplementary financial measure that is calculated using the royalties divided by total sales volumes, net of purchases.

Other dilution costs per boe

Dilution costs includes all costs associated with the dilution services. Dilution costs per boe is a supplementary financial measure that is calculated using the dilution costs divided by total sales volumes, net of purchases.

NCIB weighted-average price per share

Weighted-average price per share under the NCIB (as defined below) is a supplementary financial measure that corresponds to the weighted-average price of shares purchased under the NCIB during the period. It is calculated using the total amount of common shares repurchased in U.S. dollars divided by the number of Common Shares repurchased.

Capital Management Measures

Net working capital

Net working capital is a capital management measure to describe the liquidity position and ability to meet its short-term liabilities. Net working capital is defined as current assets less current liabilities.

Restricted cash short- and long-term

Restricted cash (short- and long-term) is a capital management measure, that sum the short term portion and long-term portion of the cash that the Company has in term deposits that have been escrowed to cover future commitments and future abandonment obligations or insurance collateral for certain contingencies and other matters that are not available for immediate disbursement.

Total cash

Total cash is a capital management measure to describe the total cash and cash equivalents restricted and unrestricted available, is comprised by the cash and cash equivalents and the restricted cash short and long-term.

Total debt and lease liabilities

Total debt and lease liabilities are capital management measures to describe the total financial liabilities of the Company, and is comprised the debt of Unsecured Notes, loans and liabilities from leases of various properties, power generation supply, vehicles and other assets.

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; and
- debt service requirements relating to existing and future debt.
- enhancing shareholder 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 of March 31, 2023, the Company had a total cash balance of $193.1 million (including $30.9 million in restricted cash), which is $124.6 million lower than December 31, 2021. For the three months ended March 31, 2023, the Company generated $0.8 million of cash from operations, which were used to fund cash outflows of $120.3 million for capital expenditures and other investing activities. For the three months ended March 31, 2023, financing activities generated net outflows of $9.8 million as a result of $114.9 million from net proceeds from the PIL Loan Facility (as defined below), $106.2 million toward repayment of the 2025 Puerto Bahia Debt, $8.7 million of constitution debt services reserve account for the PIL Loan Facility, $4.2 million in Common Shares purchased under the NCIB (as defined below), $2.3 million toward 2025 Puerto Bahia Debt interest payments and PetroSud Debt (as defined below) payments, $1.0 million in lease payments and $1.1 million of interest and other financing charges. As a consequence, the Company's net working capital[(1)] increased to a surplus of $8.1 million compared to a deficit of $2.3 million at year-end 2022.

Since 2020, the Company's consolidated net working capital position changed to a deficit due to the acquisition of control in IVI, which resulted in the consolidation of the 2025 Puerto Bahia Debt. As at March 31, 2023, the 2025 Puerto Bahia Debt was fully repaid with funds provided by a $120 million PIL Loan Facility (as defined below).

The Company believes that its net 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, 2023, the main components of restricted cash were long-term abandonment funds as required by the ANH, and restricted funds related to the PIL Loan Facility. 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. As of March 31, 2023, the Company's restricted cash position was $30.9 million, an increase of $7.7 million from December 31, 2022, primarily due to the constitution of debt service reserve account of PIL Loan Facility (as defined below).

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 intends to 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 29.

[1] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures'' section on page 18.

Unsecured Notes

The Company's long-term borrowing consists of the outstanding unsecured notes due on June 21, 2028 (the "**2028 Unsecured Notes**") in the aggregate amount of $400.0 million which were issued on June 21, 2021. The 2028 Unsecured Notes bear interest at a rate of 7.875% per year, payable semi-annually in arrears on June 21 and December 21 of each year, beginning on December 21, 2021. The 2028 Unsecured Notes will mature in June 2028, unless earlier redeemed or repurchased.

Unsecured Notes Covenants

The 2028 Unsecured Notes are senior, unsecured notes and rank equal in right of payment with all existing and future senior unsecured debt. As at March 31, 2022, the 2028 Unsecured Notes were guaranteed by the Company's subsidiaries, Frontera Colombia and Frontera Guyana. On April 11, 2023, the Company designated Frontera Energy Guyana Holding Ltd. ("**Frontera Holding**") and Frontera Guyana as unrestricted subsidiaries and released Frontera Guyana as a note guarantor under the indenture governing the Company's outstanding 2028 Unsecured Notes. Frontera Colombia remains as the sole guarantor of the 2028 Unsecured Notes.

Under the terms of the 2028 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 3.25:1.0 and the consolidated fixed charge ratio(2) is greater than or equal to 2.25:1.0. 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 2028 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, 2023, the Company is in compliance with all such covenants.

Pursuant to requirements under the indenture governing the 2028 Unsecured Notes (the "**Indenture**"), the Company reports consolidated total indebtedness of $400,361,000 as of March 31, 2023, and for the twelve months ended as of March 31, 2023, consolidated adjusted EBITDA of $595,364,000 and consolidated interest expense of $29,766,000.

1. Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the indenture governing the 2028 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 below.
    b. Consolidated adjusted EBITDA is defined as the consolidated net (loss) 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 period ended 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.

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 and certain amounts attributable to the Unrestricted Subsidiaries.

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

($M)	As at March 31 2023
Long-term debt (1)	$ 403,212
Total lease liabilities (2)	2,037
Risk management asset	(4,888)
Consolidated Total Indebtedness	**400,361**
(-) Cash and Cash Equivalents (3)	(120,518)
(=) Net Debt	**$ 279,843**

(1) Excludes $113.8 million of long-term debt attributable to the Unrestricted Subsidiaries.
(2) Excludes $0.4 million of lease liabilities attributable to the Unrestricted Subsidiaries.
(3) Includes cash and cash equivalents attributable to the guarantors as of March 31, 2023, (Frontera Guyana, Frontera Holding, and Frontera Colombia) and the borrower (the Company) according to the Indenture.

Pipeline Investment Loan Facility

On March 27, 2023, PIL, entered into a new credit agreement through which the lender will provide a $120.0 million loan facility to PIL, secured by substantially all the assets and shares of PIL, the shares of Puerto Bahía and assets related to the port's liquids terminal, Frontera Bahía Holding Ltd., and Frontera ODL Holding Corp., the parent company of PIL. The PIL Loan Facility is a 5 year credit facility, which matures in December 2027, pays semi-annually and amortizes during the term of the loan with a scheduled $45.0 million payment due upon maturity. The PIL Loan Facility has two tranches: a $100.0 million amortizing tranche that pays a Secured Overnight Financing Rate ("**SOFR**") 6-month term plus margin of 7.25% per annum and a $20.0 million bullet maturity tranche that pays a fixed rate of 11.00% per annum. The conditions precedent to the PIL Loan Facility were fully satisfied and the facility funded on March 31, 2023.

The PIL Loan Facility was recognized net of an original issue discount of $5.1 million, and directly attributable transaction costs of $1.1 million, primarily related to underwriter fees, legal, register and other professional fees.

The proceeds of the PIL Loan Facility were used to repay in full the 2025 Puerto Bahia Debt maturing in June 2025, which had an outstanding balance plus accrued interest of $106.2 million, pay transaction fees and expenses, and fund a 6-month debt service reserve account. The PIL Loan Facility has no impact on the Company's financial covenant calculations under its 2028 Unsecured Notes.

Puerto Bahia Secured Syndicated Credit Agreement

During the third quarter of 2020, the Company acquired control of IVI which at the time of acquisition held 99.9% of Puerto Bahia.

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**") with an interest at 6-month LIBOR plus 5% which was payable semi-annually and secured by substantially all the assets and shares of Puerto Bahia, is non-recourse to the Company (other than as provided for by the equity contribution agreement ("**ECA**"), and had no impact on the Company's financial covenants under the 2028 Unsecured Notes).

On March 31, 2023, the 2025 Puerto Bahia Debt outstanding amount of $103.1 million plus accrued interest of $3.1 million was fully repaid with the funds provided by the PIL Loan Facility. As at March 31, 2023, Puerto Bahía and Frontera have no obligation under the former Puerto Bahía Syndicated Credit Agreement from October 2013.

PetroSud Loans

On December 30, 2021, the Company acquired 100% of the issued and outstanding shares of PetroSud (for further information refer to Note 4 of the 2022 Annual Consolidated Financial Statements).

On March 15, 2019 and December 20, 2021, PetroSud entered into two credit agreements with Banco Davivienda S.A. for a principal amount of $22.0 million and $2.8 million, respectively (the "**PetroSud Debt**"), both with a maturity date in December 2023. The PetroSud Debt bears interest at 3-month LIBOR plus 4.95%, payable quarterly. The PetroSud Debt is secured by a trust agreement that receives 100% of PetroSud's sales, and contemplates a debt service account for an amount equal to 100% of the next scheduled debt service, and a debt service reserve account for an amount of $2.2 million. As at March 31, 2023, the outstanding amount under the PetroSud Debt was $10.5 million. The PetroSud Debt is subject to certain covenants that require PetroSud to maintain a financial debt to EBITDA ratio of less than or equal to 3.50:1.0 and an operating free cash flow plus the debt reserve account balance to debt service ratio that is greater than or equal to 1.20:1.0. As of March 31, 2023, PetroSud was in compliance with all such covenants.

Letters of Credit

The Company has various uncommitted bilateral letters of credit lines. As of March 31, 2023, the Company had issued letters of credit and guarantees for exploration, operational, and transport commitments totaling $112.4 million (total credit lines of $118.2 million), without cash collateral.

CPE-6 Solar Plant Project Leasing Agreement

During the fourth quarter of 2022, the Company entered into a leasing agreement with Bancolombia S.A. to finance the construction and commissioning of a solar plant project at CPE-6 block (the "**Solar Plant Debt**"). The financing is denominated in COP, in an amount equivalent to US$5.3 million and with a maturity date that is 72 months following the date conditions precedent to the financing are satisfied. The Solar Plant Debt bears interest equivalent to IBR(1) +5.75%, payable monthly. As of March, 31, 2022, there was no outstanding amount under the Solar Plant Debt. The Company is paying a monthly availability fee of 0.35% to Bancolombia for the principal amount that remains undisbursed.

(1) Reference Banking Indicator from the central bank of Colombia ("IBR" for its acronym in Spanish).

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at March 31, 2023, undiscounted by calendar year, are presented below:

As at March 31, 2023 ($M)	2023	2024	2025	2026	2027	2028 and Beyond	Total
Financial obligations							
Long term debt principal and interest	57,959	59,861	57,114	60,155	101,989	415,750	752,828
Lease liabilities	2,133	333	155	—	—	—	2,621
Total financial obligations	**60,092**	**60,194**	**57,269**	**60,155**	**101,989**	**415,750**	**755,449**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	53,388	71,185	35,739	—	—	—	160,312
ODL agreements	12,774	11,845	—	—	—	—	24,619
Other transportation and processing commitments	10,541	11,689	11,630	11,630	3,895	—	49,385
Exploration commitments							
Minimum work commitments (1)	84,088	37,318	53,025	—	—	5,066	179,497
Other commitments							
Operating purchases, leases and community obligations	75,554	15,048	20,413	15,214	10,959	9,335	146,523
Total Commitments	**236,345**	**147,085**	**120,807**	**26,844**	**14,854**	**14,401**	**560,336**

(1) Includes minimum work commitments relating to exploration activities in Colombia and Ecuador until the contractual phase when the Company will decide whether to continue or relinquish the exploration areas. The Company, through its interests in CGX, has other exploration work commitments in Guyana (not included in the table), described below.

Guyana Commitments

As at March 31, 2023, the Company, through its 76.97% interest in CGX and directly through its working interest has certain work commitments under the Petroleum Prospecting License ("**PPL**") for the Corentyne block, offshore Guyana (Frontera 68% W.I. and non-operator). In accordance with the PPL for the Corentyne block, a second exploration well was required to be spud by January 31, 2023, which was extended from the previous expiry date of November 26, 2022. On January 23, 2023, CGX and Frontera, the majority shareholder of CGX and joint venture partner of CGX (the "**Joint Venture**") announced that the Joint Venture had spud the Wei-1 well on the Corentyne block, approximately 200 kilometers offshore from Georgetown, Guyana. In addition, the Government of Guyana has approved an Appraisal Plan for the northern section of the Corentyne block, which commenced with the Wei-1 well. Following completion of Wei-1 drilling operations and upon detailed analysis of the results, the Joint Venture may consider future wells per its appraisal program to evaluate possible development feasibility in the Kawa-1 discovery area and throughout the northern section of the Corentyne block.

In addition, in connection with (i) a drilling contract agreement between Maersk Drilling Holdings Singapore Pte. Ltd. (now NobleCorp.) and CGX Resources Inc. ("**CGX Resources**"), the operator of the Corentyne block, for the provision of a semi-submersible drilling unit owned by NobleCorp. and associated services to drill the Joint Venture's Wei-1 well, and (ii) a services agreement between Schlumberger Guyana Inc. ("**Schlumberger**") and CGX Resources for the provision of certain oilfield services and the supply of related goods and products for the Corentyne block, Frontera entered into a deed of guarantee with each of NobleCorp. and Schlumberger for certain obligations, in each case up to a maximum of $30.0 million and subject to a sliding scale mechanism in connection with payments made under the drilling contract with NobleCorp. or the services agreement with Schlumberger, as applicable.

As at March 31, 2023, CGX had entered into purchase orders and contracts for the drilling of the Wei-1 well and the Guyana Port Project, pursuant to which the Company has amounts outstanding of $42.0 million, which is expected to be paid during 2023.

Oleoducto Central S.A. ("Ocensa") and Cenit Pledge

In May 2022, a new ship-or-pay contract with Bicentenario and Cenit entered into force, and as a result, the pledged crude oil inventory is stored in Cenit's terminal of Coveñas (TLU-3) instead of Ocensa's terminal. On March 31, 2022, the Company signed a new pledge agreement with Ocensa and Cenit, which guarantees the payment obligations of both contracts, up to $30.0 million and $6.0 million, respectively. The term of the pledge agreement has been amended and extended for the period from April 30, 2023 to September 30, 2023, with Ocensa, and for the period from April 30, 2023 to October 31, 2023, with Cenit.

Other Guarantees and Pledges

As part of the Company's acquisition of Repsol Colombia Oil & Gas Ltd.'s ("**RCOG**") 50% working interest in the CPE-6 block, the Company granted a pledge to RCOG over the production from the CPE-6 block to guarantee the payments, up to a maximum of $48.0 million. Under the farm-out agreement two kinds of payments are set, each contingent on production from this block and each applicable until the maximum payment of $48.0 million is paid: (i) a variable monthly payment, and (ii) three potential production milestone payments of $5.0 million each when 5 million, 10 million and 20 million total barrels production, respectively, are achieved. As at March 31, 2023, the Company has paid and accrued a total of $16.0 million of such amounts under the agreement.

Contingencies

The Company is involved in various claims and litigation arising from 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. Other than as disclosed below, no material changes have occurred regarding the matters disclosed in Note 26 - Commitments and Contingencies of the 2022 Annual Consolidated Financial Statements.

Quifa Late Delivery Volumes Claim

On September 20, 2016, Ecopetrol filed a lawsuit against the Company before the Court alleging that the Company breached the Quifa association agreement due to the alleged late delivery of the volume of crude oil produced during the period between April 3, 2011, and April 14, 2013. Consequently, Ecopetrol requested payment of $8.5 million representing the difference between the value of the barrels of crude oil allegedly not delivered on time, and the value of the barrels of crude oil had on that delivery date. In addition, Ecopetrol requested the Company pay a LIBOR (Six months) +3.25% from the time the delivery was due until the time of the payment.

In March 2021, the Company received notification that the Court had decided in favour of Ecopetrol and awarded $8.5 million, as adjusted by the Consumer Price Index. The Company filed an appeal against the first instance ruling on March 16, 2021. On March 17, 2023, the Council of State issued a final ruling revoking what was decided by the Court in the first instance ruling and stating that statute of limitations barred Ecopetrol's judicial action. In addition, the Council of State ordered Ecopetrol to pay Frontera Colombia judicial costs which amount to approximately $0.3 million. As a result the Company recorded a reversal of a liability provision of $ 9.3 million recognized in 2021.

Puerto Bahia –Tank Construction Related Arbitration

In the course of building its port facility, Puerto Bahia retained the services of Isolux Ingeniería S.A., Tradeco Industrial S.A. de C.V., Tradeco Infraestructura S.A. de C.V ("**CITT**") for the construction of the Hydrocarbons' Terminal, including eight storage tanks and other facilities (the "**EPC Contract**"). CITT failed to comply with the terms of the EPC Contract, including the timely delivery of the work contracted which caused damages to Puerto Bahia, among other contract breaches. As a result, Puerto Bahia proceeded to draw up a letter of credit in the amount of $17.0 million granted by CITT as a guarantee of the EPC Contract (the "**LOC**"). On June 11, 2015, CITT initiated arbitration proceedings under the regulations of the International Chamber of Commerce of Paris, claiming, among other things: (i) the return of the money from the LOC; (ii) recognition of costs incurred during the execution of the EPC Contract due to the stand-by; (iii) the right to extend the contract term as per the changes requested by Puerto Bahia; and (iv) unlawful termination of the EPC Contract. On August 21, 2015, Puerto Bahia filed a counterclaim against CITT for failure to comply with its contractual obligations under the EPC Contract that led it to breach the delivery dates and the agreed schedules, generating over costs, damages, and losses to Puerto Bahia.

On March 1, 2023, the arbitral tribunal issued the arbitral award which (i) denied CITT's claim for an award of $68.4 million for the return of the LOC amount (including interests); (ii) rejected CITT's claim for damages of $14.9 million; (iii) confirmed that Puerto Bahia was entitled to terminate the EPC Contract, enforce the LOC, and charge penalties to CITT; (iv) granted Puerto Bahia a remedy of $24.7 million (i.e., special penalties of $14.4 million plus the termination penalty clause of $10.3 million); and (v) ruled to offset the $17.0 million LOC and $5.6 million awarded by the Tribunal to CITT as compensation for, among others, accepted invoices and procurement services rendered through June 5, 2015, for a final balance of $2.0 million in favour of Puerto Bahia, payable by any CITT member at an annual interest rate of 4%.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at May 2, 2023:

	Number
Common shares	85,188,573
Deferred share units ("**DSUs**") (1)	865,746
Restricted share units ("**RSUs**") (2)	2,424,274

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. DSUs are settled in Common Shares, cash or a combination thereof, as determined by the Compensation and Human Resources Committee of the Board (the "**CHRC**"), in its sole discretion. 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. RSUs are settled in Common Shares, cash or a combination thereof, as determined by the CHRC, in its sole discretion. Vesting terms for RSUs are determined by the CHRC, in its sole discretion, and specified in the award agreement pursuant to which the RSU is granted.

Normal Course Issuer Bid

On March 17, 2022, the Company launched a NCIB, pursuant to which the Company was permitted to purchase for cancellation up to 4,787,976 of its Common Shares during the twelve-month period that commenced on March 17, 2022 and ended on March 16, 2023, representing approximately 10% of the Company's "public float" (as calculated in accordance with TSX rules) as at March 7, 2022.

Purchases subject to the NCIB were carried out pursuant to open market transactions through the facilities of the TSX or alternative trading systems, if eligible, by BMO Nesbitt Burns Inc., on behalf of Frontera in accordance with an automatic share purchase plan and applicable regulatory requirements. During the three months ended March 31, 2023, the Company purchased a total of 461,200 Common Shares. At its expiry on March 16, 2023, the Company repurchased for cancellation a total of 4,270,100 Common Shares under its NCIB for approximately $40.9 million.

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

	Three months ended March 31
	2023
Number of Common Shares repurchased	461,200
Total amount of Common Shares repurchased ($M)	4,170
Weighted-average price per share ($) (1)	9.04

(1) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.

6. RELATED-PARTY TRANSACTIONS

The following tables provide the total balances outstanding, commitments and transactional amounts with related parties, as at March 31, 2023 and December 31, 2022, and for the three months ended March 31, 2023, and 2022, respectively:

($M)		Accounts Receivable	Accounts Payable	Commitments	Three Months Ended March 31 Purchases / Services
ODL	2023	34,816	587	24,619	6,910
	2022	—	2,553	31,796	5,363

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 the 2022 Annual Consolidated Financial Statements, copies of which are available on SEDAR at www.sedar.com.

In addition, the COVID-19 pandemic could have negative impacts on the Company's financial condition, results of operations, and cash flows. Despite successful vaccine rollouts in many jurisdictions, the risk of a resurgence or additional variant strains remains high and could result in continued fluctuations in the price of oil and conventional 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 could have a material adverse effect on the Company's business, financial condition and results of operations. Even as the COVID-19 pandemic subsides, the Company may continue to experience materially adverse impacts to its business as a result of the pandemic's global economic impact, long-term implications and risk of resurgences. 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.

Further, in February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. The outcome of the conflict continues to be uncertain and is having wide-ranging consequences on the world economy. In addition, certain countries, including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which are having far reaching effects on the global economy. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia are creating a significant worldwide supply shortage of oil and natural gas and have led to sustained high worldwide prices of oil and natural gas. A lack of supply and high prices of oil and natural gas is having a significant adverse impact on the world economy, including record high inflation levels. In addition, many Russian companies that provide goods and services for oil exploration and production may have been or may eventually become in the near future, subject to sanctions, or impacted by logistical and financial difficulties, which in turn may result in temporary shortages of certain materials/equipment needed for the oil and natural gas exploration and production. To date, these events have not impacted the Company's ability to carry on business, there have been no significant delays or direct security issues affecting the Company's operations, offices or personnel, and the enacted sanctions have not affected the Company's business.

The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain and the Company continues to monitor the evolving situation.

See the "Liquidity and Capital Resources" section on page 24 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.

The Company also continues to consider all options to enhance the value of its Common Shares and in so doing may consider forms of strategic initiatives or transactions, although there can be no assurance that any such initiative or transaction will occur or if it occurs, the timing thereof.

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 the 2022 Annual Consolidated Financial Statements which are available on SEDAR at www.sedar.com.

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 2022 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 2 of the Interim 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 global economy, including the impact of the Russia Ukraine conflict and the associated volatility in oil prices, could have negative impacts on the Company. The uncertainty these events bring has resulted in a challenging economic environment, with more volatile commodity prices, foreign exchange rates and long-term interest rates. The current global crude oil price environment is being lifted mainly by the Russia-Ukraine conflict and the consequences of these events on the certainty of the supply of hydrocarbons in the world. All of these are undermining economic conditions and exacerbating inflation in several economies and are having a direct impact in the cost of goods and services. This presents uncertainty and risk with respect to 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 the 2022 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. Additionally, in the first quarter of 2023, Management continued to monitor the impacts of COVID-19 on the Company's control environment. These impacts include remote and/or hybrid work environment, oil price environment, cyber threats, IT help desk services response time, health and safety. While there were no changes made to the Company's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting, the Company will continue to monitor and mitigate the risks associated with any changes to its control environment in response to the COVID-19 pandemic.

Management has evaluated the effectiveness of the Company's ICFR as at March 31, 2023.

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 March 31, 2023.

There have been no changes in the Company's ICFR during the quarter ended March 31, 2023, that have materially affected, or are reasonably likely to materially affect, its ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

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 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 March 31, 2023.

10. FURTHER DISCLOSURES

Production Reporting

Production volumes are reported on a Company's W.I. before royalties basis. In Ecuador, the government has a variable share over the total volumes produced under Perico and Espejo joint venture exploration and extraction contracts. The Company has reported this 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:

Producing blocks in Colombia		Net Production Q1 2023	Q4 2022	Q1 2022
Heavy crude oil	(bbl/d)	19,575	18,466	17,987
Light and medium crude oil combined	(bbl/d)	14,039	14,876	15,866
Conventional natural gas	(mcf/d)	8,590	9,092	9,530
Natural gas liquids	(boe/d)	1,240	993	962
Net production Colombia	**(boe/d)**	**36,361**	**35,930**	**36,487**
Producing blocks in Ecuador				
Light and medium crude oil combined	(bbl/d)	707	819	181
Net production Ecuador	**(bbl/d)**	**707**	**819**	**181**
Total net production	**(boe/d)**	**37,068**	**36,749**	**36,668**

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.

Oil and Gas Information Advisories

Reported production levels may not be reflective of sustainable production rates and future production rates may differ materially from the production rates reflected in this MD&A due to, among other factors, difficulties or interruptions encountered during the production of hydrocarbons. Disclosure of well-flow test results included in this MD&A are not necessarily indicative of long-term performance or of ultimate recovery. Where a pressure transient analysis or well-test interpretation has not yet been carried out, as indicated above, the data should be considered preliminary until such analysis or interpretation has been done.

Abbreviations

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

bbl	Oil barrels	**Q**	Quarter
bbl/d	Barrels of oil per day	**USD**	United States dollars
boe	Barrels of oil equivalent	**WTI**	West Texas Intermediate
boe/d	Barrels of oil equivalent per day	**W.I.**	Working interest
COP	Colombian Pesos	**$**	U.S. dollars
C$	Canadian dollars	**$M**	Thousand U.S. dollars
MMbbl	Millions of oil barrels	**$MM**	Million U.S. dollars
MMboe	Millions of barrels of oil equivalent	**P1**	Proved reserves
Mbbl	Thousand of oil barrels	**P2**	Probable reserves
Mcf	Thousand cubic feet	**2P**	Proved reserves + Probable reserves
mcf/d	Thousand cubic feet per day		