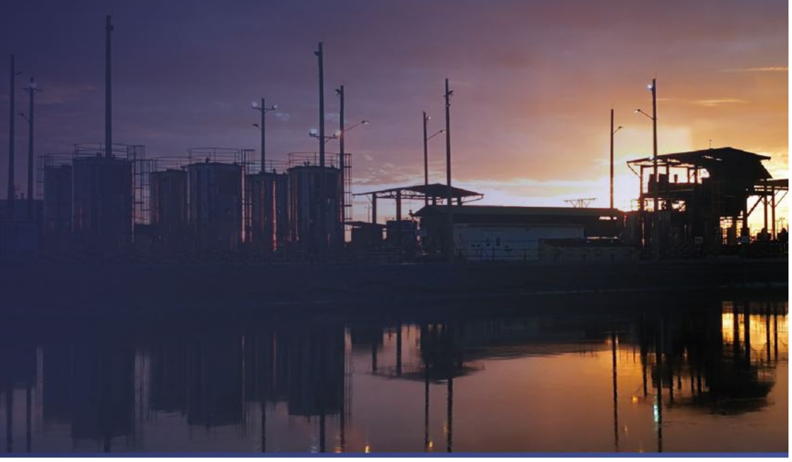
FRONTERA ENERGY

# MANAGEMENT DISCUSSION & ANALYSIS

Aug 10, 2023

For the three and six months ended June 30, 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 and six months ended June 30, 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.sedarplus.ca 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 20.*

*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 in this MD&A 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

| | | Q2 2023 | Q1 2023 | Q2 2022 | Six months ended June 30 2023 | Six months ended June 30 2022 |
|---|---|---|---|---|---|---|
| **Operational Results** | | | | | | |
| Heavy crude oil production [1] | (bbl/d) | 24,051 | 22,270 | 21,455 | 23,165 | 21,335 |
| Light and medium crude oil combined production [1] | (bbl/d) | 15,188 | 16,518 | 17,348 | 15,849 | 17,298 |
| Total crude oil production | (bbl/d) | 39,239 | 38,788 | 38,803 | 39,014 | 38,633 |
| Conventional natural gas production [1] | (mcf/d) | 5,626 | 8,590 | 10,374 | 7,102 | 9,952 |
| Natural gas liquids production [1] | (boe/d) | 1,823 | 1,291 | 963 | 1,558 | 965 |
| Total production [2] | (boe/d) [3] | 42,049 | 41,586 | 41,586 | 41,818 | 41,343 |
| Total inventory balance | (bbl) | 1,434,508 | 1,611,201 | 1,423,695 | 1,434,508 | 1,423,695 |
| Brent price reference | ($/bbl) | 77.73 | 82.10 | 111.98 | 79.91 | 104.94 |
| Oil and gas sales, net of purchases [4] [5] | ($/boe) | 67.91 | 69.07 | 102.80 | 68.43 | 96.96 |
| Realized loss on risk management contracts [6] | ($/boe) | (0.80) | (1.16) | (1.15) | (0.96) | (1.11) |
| Royalties [6] | ($/boe) | (3.02) | (3.36) | (10.57) | (3.18) | (9.21) |
| Net sales realized price [4] [5] | ($/boe) | 64.09 | 64.55 | 91.08 | 64.29 | 86.64 |
| Production costs [5] [6] | ($/boe) | (14.01) | (12.07) | (12.51) | (13.05) | (12.92) |
| Transportation costs [5] [6] | ($/boe) | (11.40) | (11.20) | (10.80) | (11.30) | (10.26) |
| Operating netback per boe [4] | ($/boe) | 38.68 | 41.28 | 67.77 | 39.94 | 63.46 |
| **Financial Results** | | | | | | |
| Oil & gas sales, net of purchases [7] | ($M) | 221,218 | 189,120 | 311,253 | 410,338 | 539,781 |
| Realized loss on risk management contracts | ($M) | (2,600) | (3,175) | (3,476) | (5,775) | (6,158) |
| Royalties | ($M) | (9,837) | (9,213) | (32,018) | (19,050) | (51,262) |
| Net sales [7] | ($M) | 208,781 | 176,732 | 275,759 | 385,513 | 482,361 |
| Net income (loss) [8] | ($M) | 80,207 | (11,330) | 13,484 | 68,877 | 115,712 |
| Per share – basic | ($) | 0.94 | (0.13) | 0.14 | 0.81 | 1.23 |
| Per share – diluted | ($) | 0.92 | (0.13) | 0.14 | 0.79 | 1.20 |
| General and administrative | ($M) | 12,422 | 12,669 | 15,097 | 25,091 | 29,753 |
| Outstanding Common Shares | Number of Shares | 85,188,573 | 85,188,573 | 92,676,495 | 85,188,573 | 92,676,495 |
| Operating EBITDA [7] | ($M) | 116,461 | 91,922 | 190,678 | 208,383 | 323,676 |
| Cash provided by operating activities | ($M) | 183,560 | 845 | 246,615 | 184,405 | 361,363 |
| Capital expenditures [7] | ($M) | 154,860 | 131,452 | 93,835 | 286,312 | 207,380 |
| Cash and cash equivalents – unrestricted | ($M) | 180,294 | 162,272 | 295,098 | 180,294 | 295,098 |
| Restricted cash short and long-term [9] | ($M) | 33,485 | 30,877 | 57,975 | 33,485 | 57,975 |
| Total cash [9] | ($M) | 213,779 | 193,149 | 353,073 | 213,779 | 353,073 |
| Total debt and lease liabilities [9] | ($M) | 532,273 | 519,471 | 535,454 | 532,273 | 535,454 |
| Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [10] | ($M) | 415,395 | 400,361 | 473,095 | 415,395 | 473,095 |
| Net debt (excluding Unrestricted Subsidiaries) [10] | ($M) | 286,675 | 279,843 | 231,913 | 286,675 | 231,913 |

(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 crude oil 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 34.
(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 34.
(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 20.
(5) 2022 prior period figures are different compared with those previously reported as a result of the exclusion of Promotora Agricola de los Llanos S.A. ("**ProAgrollanos**") revenues and, production and transportation costs.
(6) Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(7) 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 20.
(8) Net income (loss) attributable to equity holders of the Company.
(9) Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(10) "**Unrestricted Subsidiaries**" 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 25.

## Performance Highlights

### Frontera's Three Core Businesses

Frontera's three core businesses include: (1) its Colombia and Ecuador Upstream onshore business, (2) its standalone and growing Midstream Colombia business, and (3) its potentially transformational Guyana Exploration offshore business. The Company is focused on unlocking shareholder value from its businesses and is committed to providing greater clarity and insight through its various disclosures, including but not limited to its quarterly press releases, financial statements and this management's discussion and analysis.

### Second Quarter 2023

Frontera's second quarter results were in-line with the Company's 2023 capital and production guidance. Frontera delivered average daily production of 42,049 boe/d (consisting of 24,051 bbl/d of heavy crude oil, 15,188 bbl/d of light and medium crude oil combined, 5,626 mcf/d of conventional natural gas and 1,823 boe/d of natural gas liquids), generated $116.5 million of operating EBITDA and invested $154.9 million in capital expenditures including $72.8 million on the Wei-1 well offshore Guyana, $38.9 million on development drilling in the Quifa, CPE-6 and Cubiro blocks, $13.4 million on exploration activities in Colombia and Ecuador and $25.6 million on development facilities including lines of flow in CPE-6, civil engineering activities for solar plant and maintenance in the SAARA project.

The Company's higher production in the second quarter was mainly as a result of successful development drilling in the Company's Quifa and CPE-6 blocks, and the start-up of injection facilities in the VIM-1 block partially offset by decreases in light and medium crude oil and conventional natural gas production due to natural declines and the return of the Neiva and Orito blocks following the completion of the blocks' production contracts, which contributed approximately 670 boe/d.In addition, natural gas liquids production grew by 41% to 1,823 boe/d through increased gas reinjection at VIM-1. Subsequent to the quarter, the Company achieved record production at CPE-6 of 6,177 bbl/d.

Increasing water handling capacity at Quifa is key to Frontera's efforts to grow production in the block. The Company's current water handling capacity is approximately 1.6 million bwpd. In 2023, Frontera began commissioning its reverse osmosis water treatment facility ("**SAARA**", previously Agrocascada). As of July 2023, the plant has processed 7.6 million barrels of water, a five-fold increase in just one quarter, providing irrigation source water to the Company's nearby ProAgrollanos palm oil plantation.

During the quarter, the Company released its 2022 Sustainability Report, which highlighted significant achievements and set forth its ESG targets for 2023. In 2022, Frontera surpassed its ESG goals, achieving a strong 102% overall compliance. This accomplishment underscores the Company's dedication to aligning its business objectives with ESG goals, demonstrating that responsible corporate stewardship and robust business performance are mutually reinforcing.

For 2023, Frontera has set ambitious ESG targets, including (i) neutralizing 52% of GHG (greenhouse gas) emissions through carbon credits, (ii) inaugurating its first solar farm at block CPE6, (iii) commissioning one of its most important circular economy projects with its SAARA water treatment facility, (iv) recycling 15% of water required in operational activities and (v) preserving an additional 1,000 hectares of biological corridors in Casanare and Meta.

Operationally, in the second quarter of 2023, the Company drilled 19 development wells in Quifa, CPE-6 and Cubiro, and 23 well interventions, this compares with 17 development wells and 17 well interventions in the prior quarter. In 2023, the Company intends to drill 55 gross development wells. Currently, the Company has 2 drilling rigs and 1 workover rig active at its Quifa, CPE-6, Corcel/Guatiquia and Mapache blocks in Colombia.

Frontera, along with its joint venture (the "Joint Venture") partner, CGX, announced that the Joint Venture has discovered oil at the Wei-1 well, located on the Corentyne block, approximately 200 kilometers offshore from Georgetown, Guyana. The Wei-1 well revealed 210 feet of hydrocarbon-bearing sands in the Santonian horizon confirmed by wireline logs and extensive core samples. The rock and fluid properties of the Santonian are currently being analyzed by an independent third-party laboratory to define net pay and a basis for the evaluation of this interval. This discovery follows the Company's previous Kawa-1 discovery in 2022.

Following the safe and successful completion of Wei-1 well drilling operations, Frontera and CGX have entered into an agreement the (the "**JOA Amending Agreement**") to amend the Joint Operating Agreement originally signed between a subsidiary of Frontera and CGX on January 30, 2019 (as amended from time to time), effectively farming into the Corentyne block to cover the unexpected additional costs of the Wei-1 well due to delays associated with the late release of the rig by a third-party, costs associated with a lost sampling tool, and the drilling of the bypass well. The transactions contemplated by the JOA Amending Agreement remain subject to regulatory approvals, including approval of the TSX Venture Exchange.

As part of the JOA Amending Agreement, CGX will transfer 4.7% of its participating interest in the Corentyne block to Frontera in exchange for Frontera funding CGX's additional expected outstanding share of the Joint Venture's costs associated with the Wei-1 well (the "CGX Corentyne Block Expenses") for up to $16.5 million. As a result of the JOA Amending Agreement, if the full

4.7% participating interest is transferred by CGX and not re-assigned, the Company will have a 72.7% participating interest and CGX will have a 27.3% participating interest in the Corentyne block.

Subsequent to the quarter the Company's majority owned subsidiary, Puerto Bahía, and Refinería de Cartagena S.A.S. ("**Reficar**") have entered into an agreement (the "**Connection Agreement**") to connect Puerto Bahia's port facility and Reficar's Cartagena refinery (the "**Cartagena Refinery**") via a 6.8-kilometre, 18-inch bi-directional hydrocarbon flowline allowing for the transportation of crude oil and other hydrocarbons between Puerto Bahía´s port facility and the Cartagena Refinery. The connection will be built, operated and maintained by Puerto Bahia and will have a capacity of up to 84,000 barrels per day. The connection will be capable of handling imported and domestically produced crudes. Construction of the connection is expected to begin in second half of the year and take approximately 12-18 months to complete at an anticipated total cost of approximately $30.0 million.

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

### Financials and Operational Results

- Production averaged 42,049 boe/d in the second quarter of 2023 (consisting of 24,051 bbl/d of heavy crude oil, 15,188 bbl/d of light and medium crude oil combined, 5,626 mcf/d of conventional natural gas and 1,823 boe/d of natural gas liquids), increased compared to 41,586 boe/d in the prior quarter (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), and an increase compared to 41,586 boe/d in the second quarter of 2022 (consisting of 21,455 bbl/d of heavy crude oil, 17,348 bbl/d of light and medium crude oil combined, 10,374 mcf/d of conventional natural gas and 963 boe/d of natural gas liquids).
- Cash provided by operating activities was $183.6 million in the second quarter of 2023, compared with $0.8 million in the prior quarter, and $246.6 million in the second quarter of 2022. The Company reported a total cash position of $213.8 million, including $33.5 million of restricted cash, as at June 30, 2023, compared with a total cash position of $353.1 million, including $58.0 million of restricted cash, as at June 30, 2022.
- The Company recorded a net income(1) of $80.2 million ($0.92/share(2)) in the second quarter of 2023, compared with net loss of $11.3 million ($0.13/share(2)) in the prior quarter and net income(1) of $13.5 million ($0.14/share(2)) in the second quarter of 2022.
- Capital expenditures were $154.9 million in the second quarter of 2023, compared with $131.5 million in the prior quarter and $93.8 million in the second quarter of 2022.
- Operating EBITDA was $116.5 million in the second quarter of 2023, compared with $91.9 million in the prior quarter and $190.7 million in the second quarter of 2022.
- Operating netback was $38.68/boe in the second quarter of 2023, compared with $41.28/boe in the prior quarter and $67.77/boe in the second quarter of 2022.

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

(2) Per Common Share on a diluted basis.

## 2. GUIDANCE

The following table reports the Company´s actual results for the six months ended June 30, 2023, against the full year 2023 guidance metrics as released on February 1, 2023.

| | | 2023 | |
|---|---|---|---|
| | | Guidance | Actual |
| Average Daily Production[(1)] | boe/d | 40,000 - 43,000 | 41,818 |
| Production Costs[(2)] | $/boe | 12.50 - 13.50 | 13.05 |
| Transportation Costs[(3)] | $/boe | 10.50 - 11.50 | 11.30 |
| Operating EBITDA[(4)] at $75/bbl[(5)] | $MM | 375 - 425 | |
| Operating EBITDA[(4)] at $80/bbl[(5)] | $MM | 425 - 475 | 208.4 |
| Operating EBITDA[(4)] at $85/bbl[(5)] | $MM | 475 - 525 | |
| Development Drilling | $MM | 110 - 130 | 70.9 |
| Development Facilities | $MM | 75 - 85 | 34.2 |
| Colombia and Ecuador Exploration | $MM | 50 - 60 | 25.7 |
| Colombia Infrastructure[(6)] | $MM | 5 - 10 | 1.2 |
| Other[(7)] | $MM | 25 - 30 | 5.6 |
| Total Colombia and Ecuador Capital Expenditures | $MM | 265 - 315 | 137.6 |
| Guyana Exploration [(8)] | $MM | 150 - 165 | 148.7 |
| Total Capital Expenditure[(9)] | $MM | 415 - 480 | 286.3 |

(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. Unexpected foreign exchange changes can impact actual results. See “Risk and Uncertainties”
(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 June 13, 2023. Please refer to Capital Expenditure section on page 14 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 34 for details of the Company’s net production.

| | | Production | | | | |
|---|---|---|---|---|---|---|
| | | | | | Six months ended June 30 | |
| **Producing blocks in Colombia** | | **Q2 2023** | **Q1 2023** | **Q2 2022** | **2023** | **2022** |
| Heavy crude oil | (bbl/d) | 24,051 | 22,270 | 21,455 | 23,165 | 21,335 |
| Light and medium crude oil combined | (bbl/d) | 14,575 | 15,513 | 16,738 | 15,041 | 16,853 |
| Conventional natural gas | (mcf/d) | 5,626 | 8,590 | 10,374 | 7,102 | 9,952 |
| Natural gas liquids | (boe/d) | 1,823 | 1,291 | 963 | 1,558 | 965 |
| **Total production Colombia** | **(boe/d)** | **41,436** | **40,581** | **40,976** | **41,010** | **40,899** |
| **Producing blocks in Ecuador** | | | | | | |
| Light and medium crude oil combined | (bbl/d) | 613 | 1,005 | 610 | 808 | 445 |
| **Total production Ecuador** | **(bbl/d)** | **613** | **1,005** | **610** | **808** | **445** |
| **Total production** | **(boe/d)** | **42,049** | **41,586** | **41,586** | **41,818** | **41,343** |

### Colombia

For the three months ended June 30, 2023, production in Colombia increased 855 bbl/d compared to the prior quarter. Higher production was mainly as a result of the successful development drilling in the Quifa and CPE-6 blocks, and the start-up of injection facilities in the VIM1 block, respectively. This was partially offset by a reduction in production of the Company's light and medium crude oil combined and conventional natural gas due to a natural decline and the return of the Neiva and Orito blocks following the completion of the block's production contracts, which contributed approximately 670 boe/d.

Compared to the three and six months ended June 30, 2022, production increased by 460 bbl/d and 111 bbl/d, respectively, mainly due to: (i) heavy crude oil increases by 12% and 9%, respectively, due to production increases in the Quifa and CPE-6 blocks from the good development drilling campaign and the reactivation of the Sabanero block, (ii) increased production of natural gas liquids by 89% and 61%, respectively, in the VIM-1 block as a result of the development of the facilities in the block. Increases were partially offset by lower production in light and medium crude oil combined and conventional natural gas primarily due to natural decline and the finalization of the Neiva and Orito blocks production contracts.

### Ecuador

Production in Ecuador for the three months ended June 30, 2023, was 613 bbl/d, of light and medium crude oil combined, compared to 1,005 bbl/d in the prior quarter. Compared with the second quarter of 2022 the production was comparable. For the six months ended June 30, 2023, production increased by 82%, compared with the same period of 2022, mainly due to the completion of the third exploration well, Yin1, at the Perico block. In addition, at the Espejo block (Frontera 50% W.I., and non-operator), the Pashuri-1 well began production in October 2022.

## 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.

| | | | | | Six months ended June 30 | |
|---|---|---|---|---|---|---|
| | | Q2 2023 | Q1 2023 | Q2 2022 | 2023 | 2022 |
| **Production** | (boe/d) | **42,049** | **41,586** | **41,586** | **41,818** | **41,344** |
| Royalties in-kind Colombia | (boe/d) | (4,163) | (4,220) | (5,646) | (4,190) | (4,993) |
| Royalties in-kind Ecuador [(1)] | (boe/d) | (180) | (298) | (262) | (239) | (180) |
| **Net production** | (boe/d) | **37,706** | **37,068** | **35,678** | **37,389** | **36,171** |
| Oil inventory draw (build) | (boe/d) | 1,941 | (4,138) | 115 | (1,082) | (3,406) |
| Overlift (settlement) | (boe/d) | 2 | (4) | 14 | (1) | 2 |
| Volumes purchased | (boe/d) | 7,691 | 7,984 | 4,084 | 7,838 | 4,037 |
| Other inventory movements [(2)] | (boe/d) | (2,471) | (2,847) | (1,835) | (2,658) | (1,771) |
| **Sales volumes** | (boe/d) | **44,869** | **38,063** | **38,056** | **41,486** | **35,033** |
| Sale of volumes purchased | (boe/d) | (9,070) | (7,639) | (4,783) | (8,358) | (4,277) |
| **Sales volumes, net of purchases** | (boe/d) | **35,799** | **30,424** | **33,273** | **33,128** | **30,756** |
| Oil sales volumes | (bbl/d) | 34,827 | 28,970 | 31,461 | 31,916 | 28,994 |
| Conventional natural gas sales volumes | (mcf/d) | 5,540 | 8,288 | 10,328 | 6,908 | 10,042 |
| **Total oil and conventional natural gas sales volumes, net of purchases** | (boe/d) | **35,799** | **30,424** | **33,273** | **33,128** | **30,756** |
| **Inventory balance** | | | | | | |
| Colombia | (bbl) | 881,758 | 1,032,876 | 922,719 | 881,758 | 922,719 |
| Peru | (bbl) | 480,200 | 480,200 | 480,200 | 480,200 | 480,200 |
| Ecuador | (bbl) | 72,550 | 98,125 | 20,776 | 72,550 | **20,776** |
| **Inventory ending balance** | **(bbl)** | **1,434,508** | **1,611,201** | **1,423,695** | **1,434,508** | **1,423,695** |

(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, increased 8% for the three and six months ended June 30, 2023, compared with the same periods of 2022, and increased by 18% compared with the prior quarter. The increase was mainly due to additional oil production and inventory drawn.

## 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, during the year 2023, the ANH changed the payment method for PAP, requiring in-kind payments for all blocks, except for the CPE-6, Guatiquia (Yatay field) and Cubiro (Copa A) 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).

| | | | | | Six months ended June 30 | |
|---|---|---|---|---|---|---|
| | | Q2 2023 | Q1 2023 | Q2 2022 | 2023 | 2022 |
| PAP in cash | (bbl/d) | 733 | 793 | 2,622 | 763 | 2,279 |
| PAP in kind | (bbl/d) | 2,303 | 1,460 | 3,363 | 1,884 | 2,699 |
| **PAP** | **(bbl/d)** | 3,036 | **2,253** | **5,985** | 2,647 | **4,978** |
| **% Production** | | **7.2 %** | **5.4 %** | **14.4 %** | **6.3 %** | **12.0 %** |

For the three and six months ended June 30, 2023, PAP in cash decreased compared with the same periods of 2022, mainly due to a change in the payment method required by ANH. PAP in kind increased compared with the prior quarter due to the road blockades in the Quifa and CPE-6 blocks which impacted production in early February. Compare with the same periods of 2022, the PAP decreased due to a lower WTI oil benchmark price.

## Realized and Reference Prices

| | | | | | Six months ended June 30 | |
|---|---|---|---|---|---|---|
| | | Q2 2023 | Q1 2023 | Q2 2022 | 2023 | 2022 |
| **Reference price** | | | | | | |
| Brent | ($/bbl) | 77.73 | 82.10 | 111.98 | 79.91 | 104.94 |
| **Average realized prices** | | | | | | |
| Realized oil price, net of purchases | ($/bbl) | 68.88 | 71.09 | 107.22 | 69.90 | 101.32 |
| Realized conventional natural gas price | ($/mcf) | 5.65 | 5.04 | 4.55 | 5.29 | 4.44 |
| **Net sales realized price** | | | | | | |
| Oil and gas sales, net of purchases [(1)] | ($/boe) | 67.91 | 69.07 | 102.80 | 68.43 | 96.96 |
| Realized loss on risk management contracts[(2) (3)] | ($/boe) | (0.80) | (1.16) | (1.15) | (0.96) | (1.11) |
| Royalties [(2)] | ($/boe) | (3.02) | (3.36) | (10.57) | (3.18) | (9.21) |
| **Net sales realized price [(1)]** | **($/boe)** | **64.09** | **64.55** | **91.08** | **64.29** | **86.64** |

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(3) Includes put premiums paid for the position expired during the period.

The average Brent benchmark oil price during the three and six months ended June 30, 2023, decreased by 31% and 24%, respectively, compared to the same periods of 2022. In comparison to the first quarter of 2023, the average Brent benchmark oil price decreased by 5%. The decrease in crude oil prices during 2023 compared with the same period of 2022, was mainly due to: (i) a potential recession in the main worldwide economies and a decoupling of US/European and Chinese economies which negatively impacted market expectations regarding worldwide economies and expectations for future crude oil price increases, and (ii) the impact of US/European sanctions on Russia's crude oil production was lower than market analysts' assumptions.

For the three and six months ended June 30, 2023, the Company's net sales realized price decreased 30% and 26%, compared to the same periods 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. In comparison to the previous quarter, the Company's net sales realized price decrease from $64.55/boe to $64.09/boe, mainly due to the decrease in the Brent benchmark oil price partially offset by better oil differential prices, from $8.23/bbl to $6.32/bbl, lower royalties and a lower realized loss on risk management contracts.

## Operating Netback

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

| | Q2 2023 | | Q1 2023 | | Q2 2022 | |
|---|---|---|---|---|---|---|
| | $M | ($/boe) | $M | ($/boe) | $M | ($/boe) |
| Net sales realized price (1) | 208,781 | 64.09 | 176,732 | 64.55 | 275,759 | 91.08 |
| Production costs (2) | (53,615) | (14.01) | (45,157) | (12.07) | (47,335) | (12.51) |
| Transportation costs (2) | (39,130) | (11.40) | (37,370) | (11.20) | (35,065) | (10.80) |
| **Operating Netback (1) (3)** | **116,036** | **38.68** | **94,205** | **41.28** | **193,359** | **67.77** |
| | | **(boe/d)** | | **(boe/d)** | | **(boe/d)** |
| **Sales volumes, net of purchases (4)** | | 35,799 | | 30,424 | | 33,273 |
| **Production (5)** | | 42,049 | | 41,586 | | 41,586 |
| **Net production (6)** | | 37,706 | | 37,068 | | 35,678 |

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(3) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(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 34.

The Company's operating netback for the second quarter of 2023 was $38.68/boe, compared to $67.77/boe in the same quarter of 2022. The decrease was as a result of lower net sales realized price, higher transportation costs mainly due to the annual increase of the transportation tariffs and higher production cost, resulting from higher cost of energy due to higher market price and fuel consumption.

In comparison to the first quarter of 2023, the Company's operating netback, decreased from $41.28/boe to $38.68/boe, representing a 6% reduction, mainly due to lower realized price, foreign exchange impacts and increased production cost.

The following table provides a summary of the Company's netbacks for the six months ended June 30, 2023:

| | Six months ended June 30 | | | |
|---|---|---|---|---|
| | 2023 | | 2022 | |
| | $M | ($/boe) | $M | ($/boe) |
| Net sales realized price (1) | 385,513 | 64.29 | 482,361 | 86.64 |
| Production costs (2) | (98,772) | (13.05) | (96,674) | (12.92) |
| Transportation costs (2) | (76,500) | (11.30) | (67,148) | (10.26) |
| **Operating Netback (1) (3)** | **210,241** | **39.94** | **318,539** | **63.46** |
| | | **(boe/d)** | | **(boe/d)** |
| **Sales volumes, net of purchases (4)** | | 33,128 | | 30,756 |
| **Production (5)** | | 41,818 | | 41,343 |
| **Net production (6)** | | 37,389 | | 36,170 |

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(3) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(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 34.

Operating netback for the six months ended June 30, 2023, decreased by 37% from $63.46/boe to $39.94/boe, in the same period of 2022. The decrease was primarily due to increased production costs, foreign exchange impacts and a lower realized price.

## Sales

| ($M) | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| Oil and gas sales, net of purchases [1] | 221,218 | 311,253 | 410,338 | 539,781 |
| Realized loss on risk management contracts [2] | (2,600) | (3,476) | (5,775) | (6,158) |
| Royalties | (9,837) | (32,018) | (19,050) | (51,262) |
| **Net sales [1]** | **208,781** | **275,759** | **385,513** | **482,361** |
| Net sales realized price ($/boe) [3] | 64.08 | 91.08 | 64.29 | 86.64 |

[1] Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
[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 20.

Oil and gas sales, net of purchases, decreased by $90.0 million and $129.4 million for the three and six months ended June 30, 2023, respectively, compared to the same periods of 2022, mainly due to lower Brent benchmark oil prices and higher price differentials partially offset by more barrels sold. (Refer to the "Realized and Reference Prices" section on page 7 for further detail on changes in prices).

Net sales for the three and six months ended June 30, 2023, decreased by $67.0 million and $96.8 million, respectively, compared with the same periods of 2022. The following table describes the various factors that impacted net sales:

| ($M) | Three months ended June 30 | Six months ended June 30 |
|---|---|---|
| | 2023-2022 | 2023-2022 |
| Net sales for the period ended June 30, 2022 | 275,759 | 482,361 |
| Decrease due to 34% lower oil and gas price (YTD 24% lower) | (105,654) | (158,799) |
| Increase due to higher produced volumes sold | 15,619 | 29,356 |
| Increase in realized loss on risk management contracts | 876 | 383 |
| Decrease in royalties | 22,181 | 32,212 |
| **Net sales for the period ended June 30, 2023** | **208,781** | **385,513** |

## Oil and Gas Operating Costs

| ($M) | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| Production costs | 53,615 | 47,335 | 98,772 | 96,674 |
| Transportation costs | 39,130 | 35,065 | 76,500 | 67,148 |
| Post-termination obligation | 6,120 | 6,842 | 6,277 | 7,070 |
| Inventory valuation | (561) | (7,619) | (8,614) | (26,191) |
| **Total oil and gas operating costs** | **98,304** | **81,623** | **172,935** | **144,701** |

Total oil and gas operating costs increased by 20% and 22%, respectively, for the three and six months ended June 30, 2023, compared to the same periods of 2022. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs for the three and six months ended June 30, 2023, increased by 13% and 2%, respectively, compared with the same periods of 2022, primarily due to foreign exchange impacts, higher energy and internal transportation costs, and well services.
- For the three and six months ended June 30, 2023, transportation costs increased by 12% and 14%, respectively, compared to the same periods of 2022, primarily due to higher volumes transported in Colombia and increase in transportation tariffs.
- Post-termination obligation for the three and six months ended June 30, 2023, includes environmental commitments and operational cost related to the relinquishment of the Neiva, Orito, Mapache, Guaduas and La Creciente blocks, in Colombia, while during the same period of 2022, the Company recognized post-termination obligations related to a non-recurring cleaning activities cost provision related to the Block 192, in Peru.
- Inventory valuation for the three and six months ended June 30, 2023, increased by $7.1 million and $17.6 million, respectively, compared with the same periods of 2022, mainly due to the a higher drawn, during the second quarter of 2023, and lower build-up, during the first half of the year 2023, of inventory volumes in Colombia and Ecuador.

## Cost of Purchases

| ($M) | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| Cost of purchases [1] | 66,602 | 53,196 | 125,889 | 88,916 |

[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 20.

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 and six months ended June 30, 2023, the cost of purchases, including the transportation and processing fees for purchased volumes sold, increased by $13.4 million and $37.0 million, respectively, compared with the same periods of 2022, due to additional volumes acquired partially offset by lower Brent benchmark oil prices. The sale of purchased volumes generated an income of $59.9 million and $111.2 million, respectively, for the three and six months ended June 30, 2023.

## Royalties

| ($M) | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| Royalties Colombia | 9,594 | 31,893 | 18,657 | 51,137 |
| Royalties Ecuador | 243 | 125 | 393 | 125 |
| **Royalties** | **9,837** | **32,018** | **19,050** | **51,262** |

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia and Ecuador. For the three and six months ended June 30, 2023, royalties decreased by $22.2 million and $32.2 million, respectively, compared to same periods 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 oil benchmark price was lower during the second quarter of 2023, 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

| ($M) | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| Depletion, depreciation and amortization | 81,389 | 49,510 | 148,102 | 88,294 |

For the three and six months ended June 30, 2023, depletion, depreciation and amortization expense ("**DD&A**") increased by 64% and 68%, respectively, 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, on April 27, 2022.

## Impairment Expense, Exploration Expenses and Others

| ($M) | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| Impairment expense: | | | | |
| Exploration and evaluation assets | 4,339 | 2,264 | 19,503 | 2,264 |
| Other | 323 | 3,033 | 1,974 | 3,033 |
| Total impairment expense | 4,662 | 5,297 | 21,477 | 5,297 |
| Exploration expenses of: | | | | |
| Geological and geophysical costs, and other | 392 | 480 | 779 | 952 |
| Minimum work commitment paid | — | 919 | — | 919 |
| Total exploration expenses | 392 | 1,399 | 779 | 1,871 |
| Recovery of asset retirement obligations | (40,562) | (1,598) | (27,481) | (6,027) |
| **Impairment, exploration expenses and other** | **(35,508)** | **5,098** | **(5,225)** | **1,141** |

### Exploration and Evaluation Assets

During the three and six months ended June 30, 2023, the Company recorded an impairment charge on exploration and evaluation of assets in Colombia of $4.3 million and $19.5 million, respectively, (2022: $2.3 million and $2.3 million, respectively), 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 ANH.

### Other

During the three and six months ended June 30, 2023, the Company recognized other impairment expenses of $0.3 million and $2.0 million, respectively, related to obsolete inventories and allowance of doubtful account receivables, compared with $3.0 million and $3.0 million, during the three and six months ended June 30, 2022, respectively.

### 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 three and six months ended June 30, 2023, the Company recognized a recovery of asset retirement obligations of $40.6 million and $27.5 million, respectively (2022: $1.6 million and $6.0 million, respectively), mainly as a result of the sale of Frontera Energy Offshore Perú, the 100% consolidated entity that owns the 100% W.I. in Block Z1, for a payment of $7.5 million to a third party. As a result of this transaction, the Company derecognized the asset retirement obligation related to Block Z1 and generate a $37.4 million asset retirement obligation recovery.

## Other Operating Costs

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($M)** | **2023** | **2022** | **2023** | **2022** |
| General and administrative | 12,422 | 15,097 | 25,091 | 29,753 |
| Special projects and other cost [1] | 2,433 | 695 | 5,429 | 1,265 |
| Share-based compensation | 1,035 | (583) | 875 | 4,505 |
| Restructuring, severance and other costs | 1,825 | 1,055 | 3,397 | 1,386 |

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

### General and Administrative ("G&A")

For the three and six months ended June 30, 2023, G&A expenses decreased by 18% and 16%, respectively, compared with the same periods of 2022, mainly due to lower professional fees and personnel costs.

### Special projects and other cost

For the three and six months ended June 30, 2023, special projects and other cost increased by $1.7 million and $4.2 million, respectively, compared with the same periods of 2022.

### Share-Based Compensation

For the three and six months ended June 30, 2023, share-based compensation increased by $1.6 million and decreased by $3.6 million, respectively, compared with the same periods of 2022. During the second quarter of 2023, the increase was mainly due to the recognition of a new grant under the share-based compensation plan at the end of first quarter of 2023, while during the second quarter of 2022, there was an impact due to a decrease in the Common Share price. For the six months ended June 30,2023, the reduction was mainly due to a decrease in the number of outstanding restricted share units ("**RSUs**") granted in 2023 compared to 2022, a decrease in the Common Share price and a weakened dollar. Share-based compensation reflects cash and non-cash charges relating to the vesting of 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 and six months ended June 30, 2023, restructuring, severance and other costs increased by $0.8 million and $2.0 million, respectively, compared with the same periods of 2022, mainly due to an increase in restructuring cost.

## Non-Operating Costs

| ($M) | Three months ended June 30 2023 | 2022 | Six months ended June 30 2023 | 2022 |
|---|---|---|---|---|
| Finance income | 1,472 | 876 | 5,773 | 1,483 |
| Finance expenses | (15,688) | (12,621) | (30,909) | (24,856) |
| Foreign exchange income (loss) | 17,006 | (13,080) | 5,246 | (9,438) |
| Other (loss) income | (716) | (5,062) | 5,589 | (11,081) |

### Finance Income

For the three and six months ended June 30, 2023, finance income increased by $0.6 million and $4.3 million, respectively, compared with the same periods of 2022, as a result of higher interest rates on the investment trust accounts for abandonment requirements.

### Finance Expenses

For the three and six months ended June 30, 2023, finance expenses increased by $3.1 million and $6.1 million, respectively compared with the same periods of 2022, mainly due to higher interest on the PIL Loan Facility (as defined below) compared to the prior 2025 Puerto Bahía Debt (as defined below).

### Foreign Exchange Income (Loss)

For the three months ended June 30, 2023, the foreign exchange income was $17.0 million, as a result of the COP appreciation against the USD, mainly related to the translation of the debt consolidated from PIL Loan Facility. For the six months ended June 30, 2023, foreign exchange income was $5.2 million, as a result of the mentioned above offset by the transfer from the cumulative translation adjustment of the Other Comprehensive Income ("**OCI**") to Consolidated Statement of Income of a return of capital of Oleoducto de los Llanos S.A. (**ODL**") for $6.8 million. This compares with losses of $13.1 million and $9.4 million, respectively, in the same periods of 2022, mainly related to as a result of the COP's depreciation against the USD on the translation of the debt consolidated from Puerto Bahia. Foreign exchange rates for the second quarter of 2023 and 2022, were COP 4,191.28:1 and COP 4,127.47:1, respectively.

### Other (Loss) Income

For the three and six months ended June 30, 2023, the Company recognized other loss of $0.7 million and other income of $5.6 million, respectively. During the second quarter of 2023, the loss was mainly due to recognition of write down of assets, and for the six months ended June 30, 2023, includes the net of the contingencies in the reversal of the legal claim from the late delivery of production from Quifa block prior to 2014. During the same periods of 2022, the Company recognized other losses of $5.1 million and $11.1 million, respectively primarily related to the recognition of contingencies.

## Gain (Loss) on Risk Management Contracts

| ($M) | Three months ended June 30 2023 | 2022 | Six months ended June 30 2023 | 2022 |
|---|---|---|---|---|
| Premiums paid on risk management contracts settled | (2,600) | (3,476) | (5,775) | (6,158) |
| Realized gain on unwinding of risk management contracts[1] | 8,958 | — | 8,958 | — |
| Realized gain (loss) on risk management contracts | 6,358 | (3,476) | 3,183 | (6,158) |
| Unrealized gain (loss) on risk management contracts | 4,057 | (1,797) | 8,882 | (653) |
| **Total gain (loss) on risk management contracts** | 10,415 | (5,273) | 12,065 | (6,811) |

[1] During the second quarter of 2023, the Company recognized a gain of $9.0 million (2022: $Nil) due to the early termination of some zero-cost collars foreign exchange risk management contracts. The Company subsequently re-hedged these monetized positions at updated market strike prices.

For the three and six months ended June 30, 2023, the realized gain on risk management contracts were $6.4 million and $3.2 million respectively, resulting from a gain on unwinding of risk management contracts of foreign exchange currency, compared to a losses of $3.5 million and $6.2 million in the same periods of 2022, primarily from the lower cost of the put premiums settled during the six months ended June 30, 2022.

For the three and six months ended June 30, 2023, the unrealized gain on risk management contracts was $4.1 million and $8.9 million, compared to a loss of $1.8 million and $0.7 million in the same periods 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% up 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.

| | | | | Avg. Strike Prices | Carrying Amount ($M) | |
|---|---|---|---|---|---|---|
| **Type of Instrument** | **Term** | **Benchmark** | **Notional Amount / Volume (bbl)** | **Put $/bbl** | **Assets** | **Liabilities** |
| Put | July 2023 to September 2023 | Brent | 1,260,000 | 70 | 1,610 | — |
| Total as at June 30, 2023 | | | | | 1,610 | — |

Subsequent to June 30, 2023, the Company entered new hedges that protect a portion of the Company's expected production for October and November 2023. The new transactions are as follows:

| | | | | Avg. Strike Prices |
|---|---|---|---|---|
| **Type of Instrument** | **Term** | **Benchmark** | **Notional Amount / Volume (bbl)** | **Put $** |
| Put | October to November 2023 | Brent | 118,000 | 70 |
| Put | October to November 2023 | Brent | 718,000 | 80 |
| | | **Total (bbl)** | **836,000** | |

## Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. As at June 30, 2023, the Company had entered 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 | July to September 2023 | COP / USD | 60,000,000 | 4,320 / 4,907 | 3,302 | — |
| Zero-cost collars | July to December 2023 | COP / USD | 60,000,000 | 4,320 / 4,914 | 2,682 | — |
| Total as at June 30, 2023 | | | | | 5,984 | — |

## Income Tax Expense

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($M)** | **2023** | **2022** | **2023** | **2022** |
| Current income tax expense | (10,801) | (1,025) | (11,808) | (2,578) |
| Deferred income tax recovery (expense) | 8,196 | (90,040) | 1,683 | (75,736) |
| **Total income tax expense** | **(2,605)** | **(91,065)** | **(10,125)** | **(78,314)** |

For the three and six months ended June 30, 2023, the Company recognized a current income tax expense of $10.8 million and $11.8 million, respectively, compared to current income tax expense of $1.0 million and $2.6 million for the same periods of 2022. The expense is mainly from withholding taxes on dividends from investments in associates, recognition of minimum current tax partially offset by tax deductions, a tax assessment from previous years and changes in tax assessments recognized during the 2023.

For the three and six months ended June 30, 2023, deferred income tax recovery was $8.2 million and $1.7 million, respectively, compared to a deferred income tax expense of $90.0 million and $75.7 million for the same periods of 2022. The variation is mainly due to the COP revaluation partially offset  by use of deferred tax assets as taxable profits accrued during the quarters.

## Net Income

| ($M) | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| Net income [(1)] | 80,207 | 13,484 | 68,877 | 115,712 |
| Per share – basic ($) | 0.94 | 0.14 | 0.81 | 1.23 |
| Per share – diluted ($) | 0.92 | 0.14 | 0.79 | 1.20 |

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

The Company reported a net income attributable to equity holders of the Company of $80.2 million for the second quarter of 2023, which included operating income of $55.6 million (including $35.9 million, net of recovery of asset retirement obligations and impairment expenses), $14.3 million of share of income from associates, foreign exchange gain of $17.0 million and finance income of $1.5 million, partially offset by finance expenses of $15.7 million and income tax expenses of $2.6 million. This compared to net income of $13.5 million for the second quarter of 2022, which included operating income of $132.7 million, partially offset by deferred income tax expense of $90.0 million, foreign exchange loss of $13.1 million, finance expense of $12.6 million and loss on risk management contracts of $5.3 million.

For the six months ended June 30, 2023, the Company reported a net income attributable to equity holders of the Company of $68.9 million, which included operating income of $52.9 million, $27.9 million of share of income from associates, gain on risk management contracts of $12.1 million and foreign exchange gain of $5.2 million, partially offset by income tax expenses of $10.1 million and finance expenses of $30.9 million. This compared to a net income of $115.7 million, which included operating income of $228.4 million, partially offset by income tax expenses of $78.3 million, foreign exchange losses of $9.4 million and finance expenses of $24.9 million.

## Capital Expenditures and Acquisitions

| ($M) | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| Development drilling | 38,911 | 39,120 | 70,909 | 76,001 |
| Development facilities | 25,606 | 11,405 | 34,180 | 17,399 |
| Colombia and Ecuador exploration | 13,380 | 10,684 | 25,745 | 20,879 |
| Other | 3,595 | 12,258 | 6,810 | 19,225 |
| **Total Colombia, Ecuador and other capital expenditures** | **81,492** | **73,467** | **137,644** | **133,504** |
| Guyana exploration and infrastructure | 73,368 | 20,368 | 148,668 | 73,876 |
| **Total capital expenditures [(1)]** | **154,860** | **93,835** | **286,312** | **207,380** |

(1) Non-IFRS financial measure. Refer to the “Non-IFRS and Other Financial Measures" section on page 20.

Capital expenditures for the three and six months ended June 30, 2023, were $154.9 million and $286.3 million, respectively, an increase of $61.0 million and $78.9 million, respectively, compared to the same periods of 2022, mainly due to the following:

**Development drilling.** During the three and six months ended June 30, 2023, development drilling expenditures decreased by $0.2 million and $5.1 million, respectively, compared to same periods of 2022. During the second quarter of 2023, 19 development wells were drilled in the Quifa, CPE-6 and Cubiro blocks and one injector well was drilled at the CPE-6 block, while a total of 20 development wells were drilled in the same period of 2022 in the Quifa, CPE-6 and Guatiquia blocks. During the six months ended June 30, 2023, 37 development wells, including 1 injector well, were drilled in the Quifa, CPE-6, Cajua and Cubiro blocks, while a total of 34 development wells drilled in the Quifa, CPE-6 and Guatiquia blocks in the same period of 2022. The cost per well was lower in 2023 due to the type of the wells compared to 2022.

**Development facilities.** During the three and six months ended June 30, 2023, development facilities expenditures increased from $11.4 million to $25.6 million, and from $17.4 million to $34.2 million, respectively, during the same periods of 2022, mainly related to the expansion and improvement of the development facilities in the CPE-6 block, which will double water-handling capacity by the end of 2023 and support additional growth for the field.

**Colombia and Ecuador Exploration.** During the three and six months ended June 30, 2023, expenditures related to exploration activities increased by $2.7 million and $4.9 million, respectively, compared to same periods of 2022. During the second quarter of 2023, two exploration wells were completed, the Winner-1 and Tubara Sur-1 exploration wells, in the VIM-22 block and the acquisition of 3D seismic in the Llanos-99 block, while during the same period of 2022, the Tui-1 and Yin-1 were drilled in Ecuador. Details relating to exploration activities 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 second quarter of 2023 at the VIM-22 block, the Winner-1 and Tubara Sur-1 wells were drilled on April 13, 2023 and April 29, 2023 respectively, the interpretation of log while drilling data and integration with drilling data concluded that the Winner-1 well found non-commercial gas and Tubara Sur-1 well does not contain net hydrocarbon pay, hence, the wells were plugged and abandoned. The company informed the ANH of the relinquishment of the VIM-22 block. At the Llanos-99 block, the acquisition of 163 square kilometers of 3D seismic was finished, currently administrative closure of the project and elaboration of reports to the ANH and Cormacarena are in execution. The Company is working on pre-seismic and pre-drilling activities related to social and environmental studies in the Llanos-119, LLA99, CPE-6 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 Yin-2 appraisal well was drilled in July, discovering 48 feet of net pay in the Lower U sand and 24 feet net pay in the Hollin main formation. The well has been successfully completed with initial production rates of approximately 1,200 bbl/d of 30.5 degree API crude oil. The Company undertook pre-drilling activities and initiated civil works for the Jandiayacu-1 (former Yin Sur-1) exploratory well. Well spud is expected for August 2023.

In the Espejo block (Frontera 50% W.I. and non-operator), in relation to Pashuri-1 and Caracara-1 exploration wells, 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 two pending committed exploratory wells.

**Other**

For the three and six months ended June 30, 2023, the Company has capitalized other investments of $2.8 million and $5.6 million, respectively, mainly related to investments in SAARA and Puerto Bahia.

**Guyana exploration and infrastructure.** During the three and six months ended June 30, 2023, Guyana exploration and infrastructure expenditures were $73.4 million and $148.7 million, respectively, compared to $20.4 million and $73.9 million during the same periods of 2022, mainly related to the following:

**Exploration.** On June 13, 2023, the Company and its majority-owned subsidiary and Joint Venture partner, CGX, in the Petroleum Prospecting License for the Corentyne block offshore Guyana (the "**PPL**"), announced that the Wei-1 well has reached total depth of 20,450 feet and penetrated the primary Santonian targets of the well in the western complex in the northern portion of on the Corentyne block. On June 28, 2023, the Joint Venture announced that it discovered oil at the Wei-1 well. 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 Joint Venture discovered 210 feet of hydrocarbon-bearing sands in the Santonian horizon. The Joint Venture acquired wireline logs and extensive core samples from the Santonian, however, due to a tool failure downhole and a new tool not being available, oil samples were not obtained. The rock and fluid properties of the Santonian are currently being analyzed by an independent third-party laboratory to define net pay and a basis for the evaluation of this interval.

The Joint Venture has encountered an aggregate of approximately 77 feet of net oil pay in the secondary target reservoirs in the Maastrichtian and Campanian. Fluid samples were retrieved from the Campanian and Maastrichtian indicating the presence of light crude in the Campanian and sweet medium crude oil in the Maastrichtian.

The Joint Venture's data acquisition program included wireline logging, MDT fluid samples and sidewall cores throughout the various intervals. During the third quarter of 2023, results will be integrated into the geologic and geophysical models to form an updated view of the entire northern portion of the Corentyne block. The northern portion of the Corentyne block includes the channel complexes discovered by the Kawa-1 and Wei-1 wells, and a prospective central channel complex, which is yet to be evaluated.

The Joint Venture has updated its well total cost estimates to $190 and $195 million to complete the logging runs, finish well operations, and release the rig. The additional costs are primarily due to the lost sampling tool and the drilling of the bypass well.

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.

The Company's investment in the Wei-1 well during the three and six months ended June 30, 2023 was $72.8 million and $148.2 million, respectively.

**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 Q2 | 2023 Q1 | 2022 Q4 | 2022 Q3 | 2022 Q2 | 2022 Q1 | 2021 Q4 | 2021 Q3 |
|---|---|---|---|---|---|---|---|---|---|
| Heavy crude oil production | (bbl/d) | 24,051 | 22,270 | 22,144 | 20,945 | 21,455 | 21,214 | 20,912 | 18,168 |
| Light and medium crude oil combined production | (bbl/d) | 15,188 | 16,518 | 17,073 | 17,428 | 17,348 | 17,248 | 16,300 | 17,160 |
| Total crude oil production | (bbl/d) | 39,239 | 38,788 | 39,217 | 38,373 | 38,803 | 38,462 | 37,212 | 35,328 |
| Conventional natural gas production | (mcf/d) | 5,626 | 8,590 | 9,097 | 9,969 | 10,374 | 9,530 | 4,663 | 5,033 |
| Natural gas liquids production | (boe/d) | 1,823 | 1,291 | 993 | 911 | 963 | 966 | 575 | 211 |
| Total production | (boe/d) | 42,049 | 41,586 | 41,806 | 41,033 | 41,586 | 41,100 | 38,605 | 36,422 |
| Sales volumes, net of purchases | (boe/d) | 35,799 | 30,424 | 34,323 | 36,660 | 33,273 | 28,211 | 39,001 | 26,672 |
| Brent price | ($/bbl) | 77.73 | 82.10 | 88.63 | 97.70 | 111.98 | 97.90 | 79.66 | 73.23 |
| Oil and gas sales, net of purchases [(1) (3)] | ($/boe) | 67.91 | 69.07 | 82.60 | 90.40 | 102.80 | 90.01 | 74.68 | 66.63 |
| Realized loss on risk management contracts [(2)] | ($/boe) | (0.80) | (1.16) | (1.32) | (1.30) | (1.15) | (1.06) | (1.87) | (2.68) |
| Royalties [(2)] | ($/boe) | (3.02) | (3.36) | (6.04) | (7.23) | (10.57) | (7.58) | (3.62) | (4.83) |
| Net sales realized price [(1) (3)] | ($/boe) | 64.09 | 64.55 | 75.24 | 81.87 | 91.08 | 81.37 | 69.19 | 59.12 |
| Production costs [(2) (3)] | ($/boe) | (14.01) | (12.07) | (11.56) | (11.20) | (12.51) | (13.34) | (12.71) | (11.44) |
| Transportation costs [(2) (3)] | ($/boe) | (11.40) | (11.20) | (10.55) | (10.70) | (10.80) | (9.72) | (9.02) | (10.24) |
| Operating netback per boe [(1)] | ($/boe) | 38.68 | 41.28 | 53.13 | 59.97 | 67.77 | 58.30 | 47.80 | 37.79 |
| Revenue | ($M) | 289,869 | 250,366 | 317,568 | 354,548 | 344,015 | 254,627 | 301,969 | 182,673 |
| Net income (loss) [(5)] | ($M) | 80,207 | (11,330) | 197,796 | (26,893) | 13,484 | 102,228 | 629,376 | 38,531 |
| Per share – basic ($) | ($) | 0.94 | (0.13) | 2.29 | (0.30) | 0.14 | 1.08 | 6.60 | 0.40 |
| Per share – diluted ($) | ($) | 0.92 | (0.13) | 2.25 | (0.30) | 0.14 | 1.05 | 6.40 | 0.39 |
| General and administrative | ($M) | 12,422 | 12,669 | 12,761 | 12,549 | 15,097 | 14,656 | 12,144 | 12,656 |
| Operating EBITDA [(4)] | ($M) | 116,461 | 91,922 | 144,994 | 173,207 | 190,678 | 132,998 | 148,645 | 77,304 |
| Capital expenditures [(4)] | ($M) | 154,860 | 131,452 | 134,165 | 76,018 | 93,835 | 113,545 | 135,458 | 103,220 |

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 20.
(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 20 for further details.
(5) Refers to net income (loss) 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. Production volumes have increased since the third quarter of 2021, mainly 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 second quarter 2023, production increased as a result of development drilling in the Quifa and CPE-6 blocks, and injection facilities in the VIM1 block, respectively. 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, annual increase of transportation tariffs and exchange rate impacts. 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 income (loss), 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 exploration and evaluation assets, DD&A, foreign exchange gain or losses and gain or losses 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 filed annual and interim management's discussion and analysis available on SEDAR+ at www.sedarplus.ca 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

| | | | | | Six months ended June 30 | |
|---|---|---|---|---|---|---|
| | | Q2 2023 | Q1 2023 | Q2 2022 | 2023 | 2022 |
| **Operational and IFRS Results** | | | | | | |
| Volumes pumped at oil pipeline facility | (bbl/d) | 243,490 | 225,792 | 209,563 | 234,690 | 206,526 |
| Volumes throughput at port liquids facility | (bbl/d) | 73,714 | 63,008 | 64,064 | 68,390 | 61,298 |
| Volumes RORO at port general cargo facility | (Units) | 29,516 | 30,220 | 33,938 | 59,736 | 55,794 |
| Volumes at port Break Bulk Volumes | ( Tons/m3) | 4,782 | 11,034 | 23,013 | 15,816 | 62,006 |
| Segment income | ($M) | 18,218 | 16,924 | 12,748 | 35,142 | 24,174 |
| Segment cash flow from operations activities | ($M) | 20,101 | 7,608 | 14,980 | 27,709 | 32,004 |
| **Non IFRS Results [(1)]** | | | | | | |
| Adjusted Midstream Revenues | ($M) | 43,186 | 38,231 | 25,604 | 81,417 | 48,606 |
| Adjusted Midstream EBITDA | ($M) | 30,361 | 28,177 | 16,352 | 57,951 | 30,071 |
| Adjusted Midstream Cash | ($M) | 42,692 | 57,985 | 34,410 | 42,692 | 34,410 |
| Adjusted Midstream Debt | ($M) | 123,459 | 127,164 | 132,418 | 123,459 | 132,418 |
| Capital Expenditures Midstream Colombia Segment | ($M) | 836 | 363 | 946 | 1,199 | 1,300 |

(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 20.

### Midstream Colombia Segment Results

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

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($M)** | **2023** | **2022** | **2023** | **2022** |
| Revenue | 13,080 | 12,239 | 24,226 | 22,571 |
| FEC liquids port facility | 1,903 | 1,936 | 3,567 | 3,388 |
| Third party liquids port facility | 7,254 | 5,947 | 13,086 | 11,305 |
| General cargo | 3,923 | 4,356 | 7,573 | 7,878 |
| Cost | (5,733) | (5,612) | (10,850) | (10,291) |
| General administrative expenses | (1,455) | (1,082) | (2,797) | (2,753) |
| Depletion, depreciation and amortization | (1,319) | (1,563) | (2,551) | (3,039) |
| Restructuring, severance and other costs | (700) | (882) | (803) | (1,056) |
| **Puerto Bahia income from operations** | **3,873** | **3,100** | **7,225** | **5,432** |
| Share of Income from associates ODL | 14,345 | 9,648 | 27,917 | 18,742 |
| **Segment income** | **18,218** | **12,748** | **35,142** | **24,174** |
| Segment cash flow from operations activities | **20,101** | **14,980** | **27,709** | **32,004** |

The Company's Midstream Colombia Segment income increased by $5.5 million and $11.0 million for the three and six months ended June 30, 2023, respectively, compared with the same periods of 2022. For the three and six months ended June 30, 2023, the Puerto Bahia liquids terminal revenues increased by $1.3 million and $2.0 million, respectively, compared with the same periods of 2022. The liquids terminal revenues during the second quarter of 2023 and 2022, correspond to 70% and 64% of total revenues, respectively. General cargo terminal revenues decreased by 4%, compared with the same period in 2022, due to lower volumes of roll-on/roll-off (“**RORO**”) units.

Cash provided by operating activities of the Midstream Colombia Segment for three months ended June 30, 2023 was $20.1 million, compared to $15.0 million in the same period of 2022, the increase was mainly due to $23.0 million of dividends collected during the second quarter of 2023, while $9.2 million of dividends were collected on same period of 2022. For the six months ended June 30, 2023 was $27.7 million compared to $32.0 in the same period of 2022, the decreased mainly due to fluctuations in working capital partially offset by higher dividends collected.

### 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% equity investment in the ODL pipeline. 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($M)** | **2023** | **2022** | **2023** | **2022** |
| Adjusted Midstream Revenue(1) | 43,186 | 25,604 | 81,417 | 48,606 |
| Adjusted Midstream Operating Cost(1) | (9,307) | (7,367) | (9,307) | (13,663) |
| Adjusted Midstream General and Administrative(1) | (2,803) | (1,885) | (5,117) | (4,197) |
| **Adjusted Midstream EBITDA(1)** | 30,361 | 16,352 | 57,951 | 30,071 |

(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 20.

The Adjusted Midstream EBITDA for the three and six months ended June 30, 2023 increased by $14.0 million and $27.9 million, respectively, compared with the same periods of 2022, as a result of the 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 and six months ended June 30, 2023, ODL generated $69.9 million and $135.3 million of EBITDA, respectively, and $41.0 million and $79.8 million of net income, respectively. 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($M)** | **2023** | **2022** | **2023** | **2022** |
| Revenue | 86,017 | 63,715 | 163,404 | 124,123 |
| FEC revenue (billed units) | 14,789 | 5,178 | 21,699 | 10,541 |
| Third party liquids port facility | 71,228 | 58,537 | 141,705 | 113,582 |
| Cost | (10,212) | (8,366) | (17,708) | (16,074) |
| General administrative expenses | (3,850) | (3,826) | (6,628) | (6,882) |
| Depletion, depreciation and amortization | (6,850) | (8,203) | (12,631) | (15,541) |
| Other non-operating expense | (2,042) | (955) | (3,720) | (3,224) |
| Income Tax | (22,074) | (14,799) | (42,954) | (28,852) |
| **ODL Net Income** | **40,989** | **27,566** | **79,763** | **53,550** |

| **($M)** | **June 30 2023** | **December 2022** |
|---|---|---|
| ODL debt | 41,677 | 37,368 |
| ODL cash and cash equivalents | 43,715 | 65,004 |

The following table shows the volumes pumped per injection point:

| (bbl/d) | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| At Rubiales Station | 170,474 | 138,112 | 162,689 | 134,900 |
| At Jagüey and Palmeras Station | 73,016 | 71,451 | 72,001 | 71,626 |
| **Total** | **243,490** | **209,563** | **234,690** | **206,526** |

The following table shows the volumes received per block:

| (bbl/d) | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| Rubiales | 107,418 | 100,162 | 106,807 | 97,548 |
| Quifa | 31,540 | 28,338 | 29,658 | 27,678 |
| CPE-6 | 1,958 | 643 | 2,110 | 1,078 |
| Other blocks | 86,125 | 76,181 | 79,448 | 75,390 |
| **Total** | **227,041** | **205,324** | **218,023** | **201,694** |

For the three and six months ended June 30, 2023, the Company recognized $14.3 million and $27.9 million, respectively, as its share of income from ODL, which was $4.7 million and $9.2 million higher than the same periods of 2022, primarily due to the increase in volumes transported and the impact of foreign exchange fluctuations. During the three and six months ended June 30, 2023, the Company recognized gross dividends of $Nil and $37.0 million, respectively, (2022: $Nil and $40.5 million, respectively) and recognized a return of capital of $Nil and $5.2 million, respectively (2022: $Nil and $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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| FEC volumes | 14,267 | 11,078 | 12,845 | 11,746 |
| Third party volumes | 59,447 | 52,986 | 55,545 | 49,553 |
| **Total** | **73,714** | **64,064** | **68,390** | **61,298** |

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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2023 | 2022 |
| RORO (units) (1) | 29,516 | 33,938 | 59,736 | 55,794 |
| Break Bulk Volumes (Tons/m3) (2) | 4,782 | 23,013 | 15,816 | 62,006 |

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

For the three and six months ended June 30, 2023, Puerto Bahia has generated $3.9 million and $7.2 million of segment income from operations, respectively, and $5.9 million and $10.6 million of EBITDA, respectively, which was $0.8 million and $1.8 million, higher, respectively, compared to the same periods of 2022, driven by increased throughput volumes at the liquids port facility.

Subsequent to June 30, 2023, Puerto Bahía and Reficar have entered into the Connection Agreement to connect Puerto Bahia's port facility and the Cartagena Refinery via a 6.8-kilometre, 18-inch bi-directional hydrocarbon flowline allowing for the transportation of crude oil and other hydrocarbons between Puerto Bahía's port facility and the Cartagena Refinery. The connection will be built, operated and maintained by Puerto Bahia and will have a capacity of up to 84,000 barrels per day. The connection will be capable of handling imported and domestically produced crudes. Construction of the connection is expected to begin in 2H'23 and take approximately 12-18 months to complete at an anticipated total cost of approximately $30.0 million.

## 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 income to Operating EBITDA:

| ($M) | Three months ended June 30 2023 | Three months ended June 30 2022 | Six months ended June 30 2023 | Six months ended June 30 2022 |
|---|---|---|---|---|
| Net income[(1)] | 80,207 | 13,484 | 68,877 | 115,712 |
| Finance income | (1,472) | (876) | (5,773) | (1,483) |
| Finance expenses | 15,688 | 12,621 | 30,909 | 24,856 |
| Income tax expense | 2,605 | 91,065 | 10,125 | 78,314 |
| Depletion, depreciation and amortization | 81,389 | 49,510 | 148,102 | 88,294 |
| Expense of impairment, recovery of asset retirement obligation and others, net | (35,900) | 4,618 | (6,004) | 189 |
| Post-termination obligation | 6,120 | 6,842 | 6,277 | 7,070 |
| Share-based compensation non-cash portion | 1,035 | (583) | 536 | 4,505 |
| Restructuring, severance and other costs | 1,825 | 1,055 | 3,397 | 1,386 |
| Share of income from associates | (14,345) | (9,648) | (27,917) | (18,742) |
| Foreign exchange (income) loss | (17,006) | 13,080 | (5,246) | 9,438 |
| Other loss (income) | 716 | 5,062 | (5,589) | 11,081 |
| Unrealized (gain) loss on risk management contracts | (4,057) | 1,797 | (8,882) | 653 |
| Non-controlling interests | (344) | 2,651 | (429) | 2,403 |
| **Operating EBITDA** | **116,461** | **190,678** | **208,383** | **323,676** |

(1) Refers to net 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 June 30 2023 | Three months ended June 30 2022 | Six months ended June 30 2023 | Six months ended June 30 2022 |
|---|---|---|---|---|
| **Statements of Cash Flows** | | | | |
| Additions to oil and gas properties, infrastructure port, and plant and equipment | 66,166 | 66,526 | 109,146 | 116,809 |
| Additions to exploration and evaluation assets | 88,924 | 31,302 | 177,870 | 91,724 |
| **Total additions in Statements of Cash Flows** | **155,090** | **97,828** | **287,016** | **208,533** |
| Non-cash adjustments [(1)] | (230) | (3,993) | (704) | (1,153) |
| **Total Capital Expenditures** | **154,860** | **93,835** | **286,312** | **207,380** |
| Capital Expenditures attributable to Midstream Colombia Segment | 836 | 946 | 1,199 | 1,300 |
| Capital Expenditures attributable to other segments different to Midstream | 154,024 | 92,889 | 285,113 | 206,080 |
| **Total Capital Expenditure** | **154,860** | **93,835** | **286,312** | **207,380** |

(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 9.

### *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 8.

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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2023** | **2022** | **2023** | **2022** |
| Produced crude oil and gas sales ($M) (1) | 227,918 | 316,480 | 425,009 | 549,016 |
| Purchased crude oil and products sales ($M) | 59,902 | 47,968 | 111,218 | 79,680 |
| (-) Cost of purchases ($M) (2) | (66,602) | (53,195) | (125,889) | (88,915) |
| **Oil and gas sales, net of purchases ($M)** | **221,218** | **311,253** | **410,338** | **539,781** |
| Sales volumes, net of purchases - (boe) | 3,257,709 | 3,027,843 | 5,996,168 | 5,566,836 |
| **Oil and gas sales, net of purchases ($/boe)** | 67.91 | 102.80 | 68.43 | 96.96 |

(1) Excludes sales from port services as they are not part of the oil and gas segment. For further information, refer to the "Midstream Colombia" section on page 17.

(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 provided below.

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($M) (1)** | **2023** | **2022** | **2023** | **2022** |
| Revenue Midstream Colombia Segment | 13,080 | 12,239 | 24,226 | 22,571 |
| Revenue from ODL | 86,017 | 63,715 | 163,404 | 124,123 |
| Direct participation interest in the ODL | 35.00 % | 20.98 % | 35.00 % | 20.98 % |
| Equity adjustment participation of ODL (1) | 30,106 | 13,367 | 57,191 | 26,041 |
| **Adjusted Midstream Revenues** | **43,186** | **25,606** | **81,417** | **48,612** |
| | | | | |
| Operating cost Midstream Colombia Segment | (5,733) | (5,612) | (10,850) | (10,291) |
| Operating Cost from ODL | (10,212) | (8,366) | (17,708) | (16,074) |
| Direct participating interest in the ODL | 35.00 % | 20.98 % | 35.00 % | 20.98 % |
| Equity adjustment participation of ODL (1) | (3,574) | (1,755) | (6,198) | (3,372) |
| **Adjusted Midstream Operating Cost** | **(9,307)** | **(7,367)** | **(17,048)** | **(13,663)** |
| | | | | |
| General and administrative Midstream Colombia Segment | (1,455) | (1,082) | (2,797) | (2,753) |
| General and administrative from ODL | (3,850) | (3,826) | (6,628) | (6,882) |
| Direct participating interest in the ODL | 35.00 % | 20.98 % | 35.00 % | 20.98 % |
| Equity adjustment participation of ODL (1) | (1,348) | (803) | (2,320) | (1,444) |
| **Adjusted Midstream General and Administrative** | **(2,803)** | **(1,885)** | **(5,117)** | **(4,197)** |

(1) Revenues and expenses related to the ODL are accounted for using the equity method described in the Note 12 of 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 provided below.

| ($M) [1] | June 30 2023 | December 31 2022 |
|---|---|---|
| Cash and cash equivalents - unrestricted | 180,294 | 289,845 |
| Cash and cash equivalents of Non-Midstream Colombia Segment's | (152,902) | (263,431) |
| Total Cash Midstream Colombia Segment | 27,392 | 26,414 |
| Cash and cash equivalent from ODL | 43,715 | 65,004 |
| Direct participating interest in the ODL | 35.00 % | 20.98 % |
| Equity adjustment participation of ODL [1] | 15,300 | 13,638 |
| **Adjusted Midstream Cash** | **42,692** | **40,052** |
| | | |
| Long-term debt | 535,212 | 508,457 |
| Debt of Non-Midstream Colombia Segment's | (426,340) | (405,363) |
| Total Debt | 108,872 | 103,094 |
| Debt from ODL | 41,677 | 37,368 |
| Direct participating interest in the ODL | 35.00 % | 20.98 % |
| Equity adjustment participation of ODL [1] | 14,587 | 7,840 |
| **Adjusted Midstream Debt** | **123,459** | **110,934** |

[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 18.

## 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | 2023 | 2022 | 2022 | 2021 |
| Produced crude oil sales ($M) | 225,070 | 312,202 | 418,404 | 540,947 |
| Purchased crude oil and products sales ($M) | 59,902 | 47,968 | 111,218 | 79,680 |
| (-) Cost of purchases ($M) | (66,602) | (53,195) | (125,889) | (88,915) |
| Conventional natural gas sales ($M) | 2,848 | 4,278 | 6,605 | 8,069 |
| **Oil and gas sales, net of purchases ($M)** [1] | **221,218** | **311,253** | **410,338** | **539,781** |
| Sales volumes, net of purchases - (bbl) | 3,169,231 | 2,862,947 | 5,776,594 | 5,247,930 |
| Conventional natural gas sales volumes - (mcf) | 504,166 | 939,919 | 1,249,960 | 1,818,112 |
| **Realized oil price, net of purchases ($/bbl)** | 68.88 | 107.22 | 69.90 | 101.32 |
| **Realized conventional natural gas price ($/mcf)** | 5.65 | 4.55 | 5.29 | 4.44 |

[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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2023** | **2022** | **2023** | **2022** |
| Oil and gas sales, net of purchases ($M) [1] | 221,218 | 311,253 | 410,338 | 539,781 |
| (-) Realized loss on risk management contracts ($M) | (2,600) | (3,476) | (5,775) | (6,158) |
| (-) Royalties ($M) | (9,837) | (32,018) | (19,050) | (51,262) |
| **Net sales ($M)** | **208,781** | **275,759** | **385,513** | **482,361** |
| Sales volumes, net of purchases - (boe) | 3,257,709 | 3,027,843 | 5,996,168 | 5,566,836 |
| Oil and gas sales, net of purchases ($/boe) | 67.91 | 102.80 | 68.43 | 96.96 |
| Realized loss on risk management contracts [2] | (0.80) | (1.15) | (0.96) | (1.11) |
| Royalties ($/boe) [2] | (3.02) | (10.57) | (3.18) | (9.21) |
| **Net sales realized price ($/boe)** | **64.09** | **91.08** | **64.29** | **86.64** |

[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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2023** | **2022** | **2023** | **2022** |
| **Production costs ($M)** | 53,615 | 47,335 | 98,772 | 96,674 |
| Production (boe) | 3,826,459 | 3,784,235 | 7,569,058 | 7,480,149 |
| **Production costs ($/boe)** | 14.01 | 12.51 | 13.05 | 12.92 |

### *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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2023** | **2022** | **2023** | **2022** |
| **Transportation costs ($M)** | 39,130 | 35,065 | 76,500 | 67,148 |
| Net production (boe) | 3,431,246 | 3,246,607 | 6,767,409 | 6,543,903 |
| **Transportation costs ($/boe)** | 11.40 | 10.80 | 11.30 | 10.26 |

### *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 of crude oil. 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 sums 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 June 30, 2023, the Company had a total cash balance of $213.8 million (including $33.5 million in restricted cash), which is $99.3 million lower than December 31, 2022. For the six months ended June 30, 2023, the Company generated $184.4 million of cash from operations, which were used to fund cash outflows of $280.2 million for capital expenditures and other investing activities. For the six months ended June 30, 2023, financing activities generated net outflows of $17.5 million, respectively, as a result of $114.9 million from net proceeds from the PIL Loan Facility and $20.0 million from Citibank Working Capital Loan (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, $21.0 million of interest from 2028 Unsecured Notes (as defined below), PIL Loan Facility and PetroSud Debt (as defined below) and other financing charges, $9.1 million toward PIL Loan Facility and PetroSud Debt principal payments, $4.2 million in Common Shares purchased under the NCIB, and $2.1 million in lease payments. As a consequence, the Company's net working capital(1) increased $51.8 million, to a deficit of $57.8 million compared to a deficit of $109.6 million at year-end 2022.

[1] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 20.

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. However, as at June 30, 2023, the net working capital remains negative due to lower cash balance as a result of investments in capital expenditures and because since March 1, 2023, Colombia tax rules increased the self-withholding tax rates related to crude oil extraction and exportation from 4.6% to 9.9%.

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 June 30, 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 June 30, 2023, the Company's restricted cash position was $33.5 million, an increase of $10.3 million from December 31, 2022, primarily due to the constitution of debt service reserve account of PIL Loan Facility.

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 32.

## 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 principal 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 Energy Colombia Corp. ("**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 (the "**Indenture**"). 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 June 30, 2023, the Company is in compliance with all such covenants.

Pursuant to requirements under the Indenture, the Company reports consolidated total indebtedness of $415,395,000 as of June 30, 2023, and for the twelve months ended as of June 30, 2023, consolidated adjusted EBITDA of $521,845,000 and consolidated interest expense of $29,307,000.

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 June 30 2023 |
|---|---|---|
| Short-term and Long-term debt [1] | $ | 421,781 |
| Total lease liabilities [2] | | 1,208 |
| Risk management asset | | (7,594) |
| **Consolidated Total Indebtedness** | | **415,395** |
| (-) Cash and Cash Equivalents [3] | | (128,720) |
| **(=) Net Debt** | **$** | **286,675** |

[1] Excludes $108.9 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 June 30, 2023, 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 provided a $120.0 million loan facility to PIL (the "**PIL Loan Facility**"), secured by substantially all the assets and shares of PIL, the shares of Puerto Bahía held by the Company and assets related to the Puerto Bahia's liquids terminal, and is guaranteed by 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 both tranches of the facility were 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. As at June 30, 2023, the outstanding amount under the PIL Loan Facility was $108.9 million.

## Puerto Bahia Secured Syndicated Credit Agreement

In October 2013, Puerto Bahia entered into a credit agreement with a syndicate of lenders in October 2013 for a $370 million debt facility, maturing in June 2025, for the construction and development of a multipurpose port in the Cartagena Bay (the "**2025 Puerto Bahia Debt**"). 2025 Puerto Bahia Debt had an interest rate of 6-month LIBOR plus 5% payable semi-annually. The 2025 Puerto Bahia Debt was secured by substantially all the assets and shares of Puerto Bahia. The 2025 Puerto Bahia Debt was non-recourse to the Company. 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 June 2023, Puerto Bahía and Frontera have no obligation under the 2025 Puerto Bahia Debt.

## 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 June 30, 2023, the outstanding amount under the PetroSud Debt was $8.7 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 June 30, 2023, PetroSud was in compliance with all such covenants.

### Citibank Working Capital Loan

On June 5, 2023, the company entered into a working capital loan agreement with Citibank NY (the "**Citibank Working Capital Loan**"). The Citibank Working Capital Loan is denominated in USD, for an amount of $20.0 million, and a maturity date of December 7, 2023. The Citibank Working Capital Loan bears interest equivalent to SOFR +4.25%, payable monthly, and amortizates in five equal installments from August to December 2023. Proceeds from this loan were used for general corporate purposes.

### Letters of Credit

The Company has various uncommitted bilateral letters of credit lines. As of June 30, 2023, the Company had issued letters of credit and guarantees for exploration, operational, and transport commitments totaling $119.8 million (total credit lines of $123.3 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. ("**Bancolombia**") 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, for an amount equivalent to $6.1 million as at June 30, 2023, and 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 June 30, 2023, the Company has drawn $1.2 million of the Solar Plant Debt, which has been disbursed from Bancolombia to Enel Colombia S.A. ESP, the developer of the CPE-6 solar plant project. The Company pay 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 June 30, 2023, undiscounted by calendar year, are presented below:

| As at June 30, 2023 ($M) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 and Beyond | Total |
|---|---|---|---|---|---|---|---|
| Long term debt principal and interest | 52,754 | 59,009 | 55,376 | 56,605 | 99,169 | 415,750 | 738,663 |
| Lease liabilities | 1,082 | 378 | 216 | 40 | — | — | 1,716 |
| **Total financial obligations** | **53,836** | **59,387** | **55,592** | **56,645** | **99,169** | **415,750** | **740,379** |
| **Transportation and storage commitments** | | | | | | | |
| Ocensa P-135 ship-or-pay agreement | 35,692 | 71,383 | 35,887 | — | — | — | 142,962 |
| ODL agreements | 8,381 | 8,219 | — | — | — | — | 16,600 |
| Other transportation and processing commitments | 6,919 | 11,610 | 11,550 | 11,550 | 3,877 | — | 45,506 |
| **Exploration commitments** | | | | | | | |
| Minimum work commitments (1) (2) | 43,735 | 43,501 | 53,025 | — | — | 5,066 | 145,327 |
| **Other commitments** | | | | | | | |
| Operating purchases, leases and community obligations | 57,696 | 26,400 | 18,218 | 12,983 | 10,406 | 9,386 | 135,089 |
| **Total Commitments** | **152,423** | **161,113** | **118,680** | **24,533** | **14,283** | **14,452** | **485,484** |

(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.

(2) On July 17, 2023, the Company received a communication from the ANH accepting the termination of the CR1 contract by mutual agreement and without adverse consequences for the parties. CR1 had minimum outstanding commitments for a total of $8.8 million (the Company's net share of such commitment is $5.3 million) at the time of termination. On July 31, 2023, the Company received a communication from the ANH accepting the execution of $7.6 million investment in LLA-7, resulting in a reduction of the commitment in this amount. On August 4, 2023 the Company received an additional communication from the ANH accepting the termination of the COR-24 contract by mutual agreement and without adverse consequences for the parties. COR-24 had minimum outstanding commitments of $5.8 million at the time of termination.

**Guyana Commitments**

As at June 30, 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, 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. The Joint Venture has complied with its exploration commitments under the Corentyne PPL.

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. Each of the parent company guarantees provided by Frontera to secure payment obligations under the NobleCorp. and Schlumberger agreements is limited to a maximum amount of $30 million, provided that (i) in the case of Schlumberger, such maximum amount is automatically reduced in an amount equivalent to any payment received by Schlumberger; and (ii) in the case of NobleCorp. such maximum amount shall be reduced to the extent that NobleCorp receives payments under the Drilling Contract; provided, however, that until there are outstanding payments to be made under the Drilling Contract with NobleCorp, such maximum guaranteed amount shall not be reduced below $8.0 million. As of June 30, 2023, (i) the outstanding balance under the Schlumberger parent company guarantee was $7.7 million; and (ii) the outstanding balance under the NobleCorp contract is of in $9.5 million and therefore the corresponding parent company guarantee continues to be valid up to a maximum amount of $8.0 million. The Company anticipates that during the second half of 2023 the outstanding balance under the NobleCorp and Schlumberger agreements will be fully paid.

As at June 30, 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 $12.7 million, which is expected to be paid during 2023 and early 2024.

**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 inventory crude oil 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. On July 5, 2023, the term of the pledge agreement has been extended up to March 31, 2024, with Ocensa, and up to April 30, 2024, 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 June 30, 2023, the Company has paid and accrued a total $16.5 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 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 upon 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%.

**Ecopetrol - Rubiales Field Disagreement**

The Company has been involved in negotiations with Ecopetrol with respect to disagreements on wind-down costs and expenses, as well as inventory, in connection with the expiration of the Rubiales and Piriri exploration and production contracts in June 2016. On November 22, 2018, the Company filed a lawsuit against Ecopetrol before the Administrative Tribunal of Cundinamarca claiming it is owed $25.3 million. On August 16, 2022, Frontera was served with the admission of the lawsuit against Frontera for over $45.0 million filed by Ecopetrol, and on September 23, 2022, Frontera filed its statement of defense.

On June 30, 2022, Ecopetrol filed a second lawsuit against Frontera claiming approximately $4.1 million and on November 24, 2022, Frontera filed a second lawsuit against Ecopetrol before the Administrative Tribunal of Cundinamarca claiming it is owed $9.0 million.

On December 28, 2022, Frontera and Ecopetrol filed a joint settlement request before the General Attorney Office (the Procuraduría General de la Nación), pursuant to which the parties intend to settle 21 disagreements, including 13 related to Rubiales field disagreements, amounting to approximately $40.0 million in total. As part of the settlement, the parties will set off mutual debts as follows: Frontera will acknowledge that it owes Ecopetrol approximately $9.0 million and Ecopetrol will acknowledge that it owes Frontera approximately $5.0 million. On March 27, 2023, the General Attorney Office issued a favorable opinion concerning the joint settlement agreement. However, due to a mistake in the filing of the joint settlement agreement by the General Attorney Office before the courts, the proceeding was sent to three different judges, one of whom received the filling by error of the General Attorney Office and dismissed the settlement agreement arguing a lack of competence regarding those disagreements, considering that the competence of approving the settlement should fall upon the judges that have full knowledge of the litigation proceeding in accordance with Colombian law. Frontera and Ecopetrol challenged that decision and a final ruling is pending.

## 5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at August 9, 2023:

| | Number |
|---|---|
| Common shares | 85,188,573 |
| Deferred share units ("**DSUs**") (1) | 865,746 |
| Restricted share units ("**RSUs**") (2) | 2,381,007 |

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 and six months ended June 30, 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:

| | Six months ended June 30 |
|---|---|
| | 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 20.

## 6. RELATED-PARTY TRANSACTIONS

The following table provides the total balances outstanding, commitments and transactional amounts with related parties, as at June 30, 2023 and December 31, 2022, and for the three and six months ended June 30, 2023, and 2022, respectively:

| ($M) | | Accounts Receivable | Accounts Payable | Commitments | Three Months Ended June 30 | Six Months Ended June 30 |
|---|---|---|---|---|---|---|
| | | | | | Purchases / Services | |
| ODL | 2023 | 11,045 | 781 | 16,600 | 7,879 | 14,789 |
| | 2022 | — | 2,553 | 31,796 | 5,178 | 10,541 |

The related-party transactions correspond to the ship-or-pay contract for the transportation of crude oil in Colombia for a total commitment of $16.6 million until 2024.

## 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.sedarplus.ca.

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 continues to exist 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 25 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.sedarplus.ca.

## 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, the intervention by members of OPEC reducing oil and gas supplies and the consequences of these events on the certainty of the supply of hydrocarbons in the world. On one hand, these events are supportive of global oil prices. On the other, these events also undermine economic conditions and exacerbate inflation in several economies, directly impacting 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 second 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 June 30, 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 June 30, 2023.

There have been no changes in the Company's ICFR during the quarter ended June 30, 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 June 30, 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:

| | | Net Production | | | | |
|---|---|---|---|---|---|---|
| | | | | | Six months ended June 30 | |
| **Producing blocks in Colombia** | | **Q2 2023** | **Q1 2023** | **Q2 2022** | **2022** | **2021** |
| Heavy crude oil | (bbl/d) | 21,455 | 19,575 | 16,854 | 20,520 | 17,418 |
| Light and medium crude oil combined | (bbl/d) | 13,144 | 14,039 | 15,689 | 13,589 | 15,776 |
| Conventional natural gas | (mcf/d) | 5,626 | 8,590 | 10,374 | 7,102 | 9,952 |
| Natural gas liquids | (boe/d) | 1,687 | 1,240 | 967 | 1,465 | 965 |
| **Net production Colombia** | **(boe/d)** | **37,273** | **36,361** | **35,330** | **36,820** | **35,905** |
| **Producing blocks in Ecuador** | | | | | | |
| Light and medium crude oil combined | (bbl/d) | 433 | 707 | 348 | 569 | 265 |
| **Net production Ecuador** | **(bbl/d)** | **433** | **707** | **348** | **569** | **265** |
| **Total net production** | **(boe/d)** | **37,706** | **37,068** | **35,678** | **37,389** | **36,170** |

### 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 | **COP** | Colombian Pesos |
| **boe/d** | Barrels of oil equivalent per day | **WTI** | West Texas Intermediate |
| **bwpd** | Barrels of water per day | **W.I.** | Working interest |
| **C$** | Canadian dollars | **$** | U.S. dollars |
| **MMbbl** | Millions of oil barrels | **$M** | Thousand U.S. dollars |
| **MMboe** | Millions of barrels of oil equivalent | **$MM** | Million U.S. dollars |
| **Mbbl** | Thousand of oil barrels | **P1** | Proved reserves |
| **Mcf** | Thousand cubic feet | **P2** | Probable reserves |
| **mcf/d** | Thousand cubic feet per day | **2P** | Proved reserves + Probable reserves |
| **m3** | Cubic meter | **Tons** | Tonnes |