# MANAGEMENT DISCUSSION & ANALYSIS

November 13, 2025

For the three and nine months ended September 30, 2025



*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 strategic investments in both upstream and infrastructure 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 1030, 140 – 4 Avenue SW, Calgary, Alberta, Canada, T2P 3N3.*

*This Management's Discussion and Analysis ("**MD&A**") is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying Interim Condensed Consolidated Financial Statements and related notes for the three and nine months ended September 30, 2025 and 2024 (the **"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 25.*

*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 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 and includes, without limitation, statements regarding the Company's performance, including the performance of its subsidiaries, expectations about strategies and goals, expected industry, market and economic conditions, estimates and/or assumptions in respect of the oil price environment, the U.S. trade tariffs affecting on numerous countries including Colombia, the impact of international conflicts including the Russia-Ukraine conflict and related sanctions, the expected sale of the Company's Ecuador assets; the ability of the Joint Venture to reach an agreement with the Government of Guyana in respect of the Joint Venture's interest in the agreements relating to the Corentyne block, the expected impact of measures that the Company has taken and continues to take or may take in response to these events, the Company's goal of enhancing the value of its Common Shares and consideration forms of strategic initiatives (including the Restructuring Plan, as defined herein) and transactions in connection therewith, the timing of the payment of the remaining declared dividend from ODL (as defined below), expectations regarding the 2025 capital and production guidance, the completion and operational timing of the connection project between Puerto Bahia (as defined below) and Reficar (as defined below), and LPG joint venture, the water handling capacity at SAARA (as defined below), the expected completion date for pre-drilling and drilling activities for the Guapo-1 exploratory well, 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 intentions of the Company with regard to its capital allocation decisions, 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 plan, cost savings, including General and Administrative ("**G&A**") expense savings, and thereof), operating EBITDA, production costs, transportation costs, the restructuring and the impact thereof and obtaining regulatory approvals.*

*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; access to capital markets; 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; the development and execution of projects; and any health security or similar situation.*

*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 U.S. trade tariffs affecting on numerous countries including Colombia; the impact of the Russia-Ukraine conflict and the conflict in the Middle East and economic sanctions related thereto; actions of the Organization of Petroleum Exporting Countries ("OPEC+"); the risk that the sale of the Ecuador assets is not completed; actions by other third parties including customers, suppliers, industry partners or relevant governmental or regulatory authorities; 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 complete strategic initiatives or transactions to enhance the value of its common shares and the timing thereof, the Company's intent to consider future shareholder initiatives including a potential future separation of interest in one or more subsidiaries or in assets of the Company, whether in on or a series of transactions; the expected impact of the Company's qualification for the OTCQX® Best Market marks and the commencement of trading thereunder, the expected production for November and the rest of 2025, the expected benefits of the reorganization to simplify corporate structure, 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; measures the Company may take in response to pandemics or similar events; and fluctuations in foreign exchange or interest rates and stock market volatility. In addition, no assurance can be given that an agreement will be reached with the Government of Guyana in respect of the Company and its joint venture partner's interests in, and the petroleum prospecting license for, the Corentyne block, or as to the results of any ongoing discussions or legal processes relating to such matters.*

*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 *

| | | Q3 2025 | Q2 2025 | Q3 2024 | Nine months ended September 30 2025 | Nine months ended September 30 2024 |
|---|---|---|---|---|---|---|
| **Operational Results from Continuing Operations** | | | | | | |
| Heavy crude oil production [(1)] | (bbl/d) | 27,078 | 27,535 | 25,312 | 27,259 | 24,520 |
| Light and medium crude oil combined production [(1)] | (bbl/d) | 9,235 | 9,850 | 11,018 | 9,538 | 11,016 |
| Total crude oil production | (bbl/d) | 36,313 | 37,385 | 36,330 | 36,797 | 35,536 |
| Conventional natural gas production [(1)] | (mcf/d) | 4,406 | 3,118 | 3,192 | 3,272 | 3,494 |
| Natural gas liquids production [(1)] | (boe/d) [(3)] | 1,848 | 1,846 | 1,950 | 1,869 | 1,792 |
| Total production Colombia [(2)] | (boe/d) [(3)] | 38,934 | 39,778 | 38,840 | 39,240 | 37,941 |
| Total inventory balance of Colombia and Peru | (bbl) | 919,914 | 1,109,347 | 1,257,358 | 919,914 | 1,257,358 |
| Brent price reference | ($/bbl) | 68.17 | 66.71 | 78.71 | 69.91 | 81.82 |
| Produced crude oil and gas sales [(4)] | ($/boe) | 64.40 | 63.18 | 71.13 | 65.37 | 75.12 |
| Purchased crude net margin [(4)(5)] | ($/boe) | (2.70) | (3.65) | (3.59) | (3.41) | (3.14) |
| Oil and gas sales, net of purchases [(4)(5)] | ($/boe) | 61.70 | 59.53 | 67.54 | 61.96 | 71.98 |
| (Loss) gain on oil price risk management contracts [(6)(7)] | ($/boe) | (1.20) | 0.16 | (0.47) | (0.84) | (1.03) |
| Royalties [(6)] | ($/boe) | (0.78) | (0.71) | (0.80) | (0.81) | (1.43) |
| Net sales realized price [(4)(5)] | ($/boe) | 59.72 | 58.98 | 66.27 | 60.31 | 69.52 |
| Production costs (excluding energy costs), net of realized FX hedge impact [(4)] | ($/boe) | (8.46) | (8.89) | (8.89) | (9.10) | (10.03) |
| Energy costs, net of realized FX hedge impact [(4)] | ($/boe) | (5.56) | (4.75) | (5.25) | (5.25) | (5.19) |
| Transportation costs, net of realized FX hedge impact [(4)(5)] | ($/boe) | (11.72) | (11.81) | (12.59) | (12.02) | (11.88) |
| Operating netback from Continuing Operations per boe [(4)(5)] | ($/boe) | 33.98 | 33.53 | 39.54 | 33.94 | 42.42 |
| **Financial Results** | | | | | | |
| Oil & gas sales, net of purchases [(8)] | ($M) | 194,153 | 165,439 | 203,017 | 550,506 | 608,475 |
| (Loss) gain on oil price risk management contracts [(7)] | ($M) | (3,784) | 431 | (1,425) | (7,494) | (8,710) |
| Royalties | ($M) | (2,454) | (1,965) | (2,412) | (7,207) | (12,105) |
| Net sales [(8)] | ($M) | 187,915 | 163,905 | 199,180 | 535,805 | 587,660 |
| Net income (loss) for the period from continuing operations [(9)] | ($M) | 28,235 | (410,857) | 16,923 | (357,007) | 1,857 |
| Net (loss) income for the period from discontinued operations | ($M) | (2,818) | (44,355) | (335) | (45,264) | 3,382 |
| Net income (loss) for the period [(9)] | ($M) | 25,417 | (455,212) | 16,588 | (402,271) | 5,239 |
| Per share – diluted from continuing operations | ($) | 0.38 | (5.32) | 0.19 | (4.73) | 0.02 |
| Per share – diluted from discontinued operations | ($) | (0.04) | (0.57) | — | (0.60) | 0.04 |
| General and administrative | ($M) | 14,877 | 14,021 | 12,473 | 42,276 | 38,472 |
| Outstanding Common Shares | Number of Shares | 69,833,514 | 77,295,478 | 84,167,856 | 69,833,514 | 84,167,856 |
| Operating EBITDA from continuing operations [(8)] | ($M) | 86,585 | 73,489 | 96,494 | 239,122 | 295,498 |
| Cash provided by operating activities | ($M) | 115,034 | 41,786 | 124,058 | 226,957 | 339,461 |
| Capital expenditures [(8)] | ($M) | 50,859 | 58,967 | 74,872 | 155,946 | 206,140 |
| Cash and cash equivalents – unrestricted | ($M) | 158,614 | 184,860 | 205,572 | 158,614 | 205,572 |
| Restricted cash short and long-term [(10)] | ($M) | 13,437 | 12,679 | 34,752 | 13,437 | 34,752 |
| Total cash [(10)] | ($M) | 172,051 | 197,539 | 240,324 | 172,051 | 240,324 |
| Total debt and lease liabilities [(10)] | ($M) | 532,789 | 535,346 | 531,235 | 532,789 | 531,235 |
| Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [(11)] | ($M) | 357,228 | 353,764 | 415,387 | 357,228 | 415,387 |
| Net debt (excluding Unrestricted Subsidiaries) [(11)] | ($M) | 252,640 | 204,671 | 267,043 | 252,640 | 267,043 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

(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 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.*

(2) Represents W.I. production before royalties. Refer to the "Further Disclosures" section on page 42 for further details.

(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 42 for further details.

(4) Non-IFRS ratio is 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 25 for further details.

(5) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(6) Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 25 for further details.

(7) Includes the net effect of put premiums paid for expired positions and positive cash settlements received from oil price contracts during the period. Refer to the "(Loss) gain on Risk Management Contracts" section on page 16 for further details.

(8) 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 25 for further details.

(9) Income (loss) attributable to equity holders of the Company.

(10) Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 25 for further details.

(11) "**Unrestricted Subsidiaries**" include CGX Energy Inc. ("**CGX**"), listed on the TSX Venture Exchange under the trading symbol "OYL"; FEC ODL Holdings Corp., including its subsidiary, Frontera Pipeline Investment AG ("**FPI**", formerly named Pipeline Investment Ltd); Frontera BIC Holding Ltd.; Frontera Energy Guyana Holding Ltd.; Frontera Energy Guyana Corp.; and Frontera Bahía Holding Ltd., including Sociedad Portuaria Puerto Bahia S.A ("**Puerto Bahia**"). Refer to the "Liquidity and Capital Resources" section on page 32 for further details.

## Performance Highlights

Frontera's corporate strategy focuses on maximizing value through its portfolio of energy and infrastructure related assets via its three core businesses:

- **Colombian Upstream Onshore**: cash flow-focused production and reserves management from large, long-life onshore Colombia operations with a strong commitment to responsible and sustainable business practices;
- **Infrastructure Colombia**: profitable and significant Colombian infrastructure footprint uniquely positioned to capture growth from emerging opportunities across the value chain providing stable, long-term revenue streams; and
- **Guyana Exploration**: offshore Guyana opportunity for a potential Maastrichtian-based, stand-alone commercial development, with upside and future opportunities in deeper geological zones.

**Third Quarter of 2025**

In the third quarter, Frontera remained focused on enforcing capital discipline, driving savings and efficiency to navigate lower commodity prices. During the quarter, the Company generated $86.6 million in Operating EBITDA from continuing operations, generated Adjusted Infrastructure EBITDA of $30.4 million and $115.0 million in cash provided by operating activities, extended its crude oil hedges through the first half of 2026 and ended the quarter with $172.1 million of total cash (including restricted cash), underscoring its strong balance sheet.

During the quarter Frontera continued to prioritize operational improvements, reducing its production costs quarter-over-quarter by 5%, driven by the implementation of new field production technologies, continuous optimization, cost reduction in O&M contracts and digital process implementation. The Company also reduced its transportation costs by 1% quarter-over-quarter driven by optimizing our transportation routes and pipeline agreements including the termination of its long term Ocensa P-135 Take or Pay agreement. These improvements were partially offset by increasing energy costs as we processed higher liquids volumes during the quarter. Frontera also simplified its corporate structure during the third quarter, through targeted reorganization initiatives that will improve organizational and operational efficiencies, generating between $10 and $15 million in expected savings in overhead going forward.

Production during the quarter decreased 2%, mainly due to adverse weather conditions, as well as related operational and logistical challenges, which have since been resolved. The 2025 rainy season stands among the most severe in a decade, with well above historical rainfall averages impacting operations. For the nine months ending September 30, Frontera averaged 39,240 boe/d of production, an increase of over 3% compared with the same periods of 2024.

Considering these factors, we have adjusted our 2025 annual Colombia production guidance slightly to 39,000 - 39,500 boe/d. We have also tightened our 2025 capital expenditures guidance, reducing the higher end by around $25 million, to reflect the disciplined approach to capital spending and ability to identify ongoing operational efficiencies.

Subsequent to the quarter, Frontera spudded the high-impact Guapo-1 exploration well at the VIM-1 block, targeting natural gas and condensate. Drilling is expected to be completed by December 2025. The Guapo-1 exploration well has the potential to significantly improve the Company's natural gas reserves, including to potentially provide much needed supply to the Colombian market in the short to medium term and help de-risk nearby contingent prospects.

The Company's standalone and growing Colombian infrastructure business, which includes interests in ODL and Puerto Bahía, together with its partner GASCO, has reached final investment decision on the planned LPG project. The initial phase is being fast-tracked and is expected to be operational in the first half of 2026, helping address supply constraints in Colombia's domestic LPG market. The LPG project is expected to generate between $10 and $15 million in yearly project EBITDA once it reaches its target capacity."

Frontera continues to see strong momentum supporting all areas of this business unit. ODL saw strong quarter-over-quarter volumes and EBITDA growth led by an increase in production associated with Ecopetrol's Caño Sur block. In Puerto Bahía, the port's operating EBITDA was relatively flat quarter over quarter despite a reduction in liquids throughput volumes associated to a third-party trader's exit from the country. The Company is actively seeking to replace the lost volumes. The financial impact of the reduced liquids throughput volumes were offset entirely by a strong performance from our general cargo operations, which saw strong growth in container volumes, that surpassed 3,000 twenty foot equivalent units ("**TEUs**") in September. On SAARA, water management volumes continue to increase and stabilize, reaching an average of approximately 157,000 barrels of water per day processed during the quarter, including reaching a maximum throughput of 230,000 barrels per day, and gaining momentum towards its goal of 250,000 barrels per day.

Over time, Frontera has consistently attracted interest from investors and strategic parties who recognize the distinct strengths and value propositions of the upstream oil and gas and infrastructure businesses. While the upstream oil and gas and infrastructure businesses are complementary, each has distinct operational profiles and life cycles, appealing to different investor bases. To further unlock shareholder value and pursue future consolidation opportunities, the Company is announcing its intention to spin-off its Colombian Infrastructure business. This strategic separation will result in two focused, independent companies, each with clear priorities and tailored strategies. The Company believes the business separation represents a significant opportunity to surface and distribute value to shareholders, not currently reflected in Frontera's market capitalization. The separation, targeted to be completed during the first half of 2026, remains subject to shareholder and regulatory approval.

Frontera continues to prioritize initiatives that drive stakeholder value. Today, the Board declared a quarterly dividend of C$0.0625 per share, or approximately $3.1 million in aggregate, and year to date, the Company has repurchased 385,200 shares via its NCIB (as defined below) program. Over the last twelve months, Frontera has returned over $112 million to shareholders via dividends and share repurchases, including $66.5 million paid to shareholders during the third quarter through a substantial issuer bid, reduced its shares outstanding by 14% since the end of 2024, and successfully repurchased over $80 million of its senior unsecured notes due 2028 reducing the balance outstanding to $314 million, underscoring the Company's commitment to return capital to all its stakeholders.

Frontera announced its qualification for the OTCQX® Best Market, an important milestone that increases the Company's visibility in the United States and reforces its commitment to strong financial disclosure and corporate governance. Trading on OTCQX enhances access to a broader U.S. investor base, including the U.S. retail market, offering shareholders improved liquidity and more efficient participation under the Company's existing TSX reporting framework.

Notably, OTC market activity has represented over 30% of FEC's total share trading over the past five years, highlighting the relevance of the U.S. market to Frontera's investor community. Access to this highest tier of the U.S. OTC markets further strengthens Frontera's ability to reach a broader investor base and enhance long-term value creation. Trading will commence tomorrow, November 14th, under the symbol "FECCF".

Regarding the Company's Guyana Exploration business, the Government of Guyana, through its counsel, communicated its willingness to participate in a final "Without Prejudice" meeting with Frontera and its partner CGX Energy Inc ("**CGX**" and together the"**Joint Venture**") to discuss the matters in dispute. The Government proposed November 25 or December 2, 2025, as possible dates for this meeting. The Joint Venture remains open to engaging in good faith discussions with the Government.

**Financial and Operational Results**

- Total Colombia production averaged 38,934 boe/d in the third quarter of 2025 (consisting of 27,078 bbl/d of heavy crude oil, 9,235 bbl/d of light and medium crude oil combined, 4,406 mcf/d of conventional natural gas and 1,848 boe/d of natural gas liquids), compared with 39,778 boe/d in the prior quarter (consisting of 27,535 bbl/d of heavy crude oil, 9,850 bbl/d of light and medium crude oil combined, 3,118 mcf/d of conventional natural gas and 1,846 boe/d of natural gas liquids), and compared with 38,840 boe/d in the third quarter of 2024 (consisting of 25,312 bbl/d of heavy crude oil, 11,018 bbl/d of light and medium crude oil combined, 3,192 mcf/d of conventional natural gas and 1,950 boe/d of natural gas liquids).
- Cash provided by operating activities was $115.0 million in the third quarter of 2025, compared with $41.8 million in the prior quarter, and $124.1 million in the third quarter of 2024. The Company reported a total cash position of $172.1 million, including $13.4 million of restricted cash, as at September 30, 2025, compared with a total cash position of $197.5 million, including $12.7 million of restricted cash, as at June 30, 2025, and $240.3 million, including $34.8 million of restricted cash, as at September 30, 2024.
- The Company recorded a net income, attributable to equity holders of the Company, from continuing operations of $28.2 million ($0.38/share[(1)]) in the third quarter of 2025, compared with a net loss, attributable to equity holders of the Company, from continuing operations of $410.9 million, net of a non-cash impairment expenses of $431.9 million ($5.32/share[(1)]) in the prior quarter, and a net income, attributable to equity holders of the Company, from continuing operations of $16.9 million ($0.19/share[(1)]) in the third quarter of 2024.
- Capital expenditures were $50.9 million in the third quarter of 2025, compared with $59.0 million in the prior quarter and $74.9 million in the third quarter of 2024.
- Operating EBITDA from continuing operations was $86.6 million in the third quarter of 2025, compared with $73.5 million in the prior quarter and $96.5 million in the third quarter of 2024.
- Operating netback from continuing operations was $33.98/boe in the third quarter of 2025, compared with $33.53/boe in the prior quarter and $39.54/boe in the third quarter of 2024.
- Infrastructure Colombia Segment (as defined below) income was $15.5 million in the third quarter of 2025, compared with $14.3 million in the prior quarter and $13.1 million in the third quarter of 2024.
- Adjusted Infrastructure EBITDA in the third quarter of 2025 was $30.4 million, compared with $27.1 million in the prior quarter and $26.2 million in the third quarter of 2024.
- Puerto Bahia liquid volumes handled during the third quarter of 2025 were 39,560 bbl/d, compared with 53,280 bbl/d in the prior quarter and 46,964 bbl/d in the third quarter of 2024. Puerto Bahia revenues were $12.0 million in the third quarter of 2025, compared with $11.2 million in the prior quarter and $9.7 million in the third quarter of 2024.
- ODL volumes transported were 241,958 bbl/d in the third quarter of 2025, compared with 235,804 bbl/d in the prior quarter of 2024, and 243,997 bbl/d in the third quarter of 2024.

[(1)] Per Common Share on a diluted basis from continuing operations.

## 2. GUIDANCE

Following the divestment of its non-core assets in Ecuador, the Company has revised its 2025 production guidance to reflect its Colombian operations only.

Production during the quarter decreased 2%, mainly due to adverse weather conditions as well as related operational and logistical challenges, which have since been resolved. The 2025 rainy season stands among the most severe in a decade, with well above historical rainfall averages impacting operations. For the nine months ending September 30, Frontera averaged 39,240 boe/d of production. Considering these factors, Frontera has adjusted its 2025 annual Colombia production guidance slightly to 39,000 - 39,500 boe/d. The Company has also tightened its 2025 capital expenditures guidance, reducing the higher end by around $25 million, to reflect the disciplined approach to capital spending and ability to identify ongoing operational efficiencies.

The following table reports the Company's 2025 updated guidance as well as its actual results for the nine months ended September 30, 2025:

| Guidance Metrics | Unit | 2025 August Guidance | 2025 Updated Guidance | Actual * |
|---|---|---|---|---|
| Average Daily Production (1) | boe/d | 39,500 - 41,000 | 39,000 - 39,500 | 39,240 |
| Production Costs (2)(4) | $/boe | 8.75 - 9.25 | | 9.10 |
| Energy Costs (2)(4) | $/boe | 5.25 - 5.75 | | 5.25 |
| Transportation Costs (3)(4) | $/boe | 12.50 - 13.00 | | 12.02 |
| Operating EBITDA from Continuing Operations (5) at $65/bbl(6) | $MM | 270 - 315 | | 239.1 |
| Operating EBITDA from Continuing Operations (5) at $70/bbl (6) | $MM | 320 - 360 | | |
| Adjusted Infrastructure EBITDA (5) | $MM | 110 - 125 | | 86.1 |
| *Development Drilling* | $MM | 100 - 110 | 95 - 100 | 83.7 |
| *Development Facilities* | $MM | 45 - 65 | 60 - 65 | 42.5 |
| Colombia Development | $MM | 145 - 175 | 155 - 165 | 126.2 |
| Colombia Exploration | $MM | 25 - 35 | 30 - 35 | 14.6 |
| Other (7) | $MM | 10 - 15 | 2 - 5 | 1.9 |
| Total Colombia Capex | $MM | 180 - 225 | 187 - 205 | 142.7 |
| Guyana Exploration | $MM | 1 - 3 | 1 - 3 | 0.4 |
| Colombia Infrastructure | $MM | 15 - 20 | 12 - 15 | 12.9 |
| Total Capital Expenditures from Continuing Operations (5) | $MM | 196 - 248 | 200 - 223 | 156.0 |

* The figures correspond only to continuing operations, following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

(1) The Company's 2025 updated average production guidance range reflects its gross W.I. production before royalties and does not include in-kind royalties, operational consumption, quality volumetric compensation or potential production from successful exploration activities planned in 2025.
(2) Per-bbl/boe metric on a share before royalties' basis.
(3) Calculated using net production after royalties.
(4) Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 25 for further details.
(5) 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 25 for further details.
(6) 2025 Updated Guidance Operating EBITDA from continuing operations calculated at Brent between $70/bbl and $65/bbl, and COP/USD exchange rate of 4,150:1.
(7) Other includes HSEQ activities and new field production technologies.

## 3. FINANCIAL AND OPERATIONAL RESULTS

### Production

The following table summarizes the average of total gross W.I. production before royalties from the Company's operations. Refer to the "Further Disclosures" section on page 42 for details of the Company's net production:

| | | Production | | | | |
|---|---|---|---|---|---|---|
| | | | | | Nine months ended September 30 | |
| **Production from Continuing Operations:** | | **Q3 2025** | **Q2 2025** | **Q3 2024** | **2025** | **2024** |
| **Producing blocks in Colombia** | | | | | | |
| Heavy crude oil | (bbl/d) | 27,078 | 27,535 | 25,312 | 27,259 | 24,520 |
| Light and medium crude oil combined | (bbl/d) | 9,235 | 9,850 | 11,018 | 9,538 | 11,016 |
| Conventional natural gas | (mcf/d) | 4,406 | 3,118 | 3,192 | 3,272 | 3,494 |
| Natural gas liquids | (boe/d) | 1,848 | 1,846 | 1,950 | 1,869 | 1,792 |
| **Total production Colombia** | **(boe/d)** | **38,934** | **39,778** | **38,840** | **39,240** | **37,941** |
| **Production from Discontinued Operations [1]:** | | | | | | |
| **Producing blocks in Ecuador** | | | | | | |
| Light and medium crude oil combined | (bbl/d) | 940 | 1,277 | 1,776 | 1,226 | 1,637 |
| **Total production Ecuador** | **(bbl/d)** | **940** | **1,277** | **1,776** | **1,226** | **1,637** |

[1] Refer to the "Discontinued Operations" section on page 17 for further details.

For the nine months ended September 30, 2025, average daily production in Colombia increased by 1,299 boe/d compared to the same period of 2024**.** This increase was mainly driven by (i) an increase of 2,739 bbl/d in heavy crude oil production, resulting from the successful development drilling campaigns in the Sabanero, CPE-6 and Quifa blocks, the reactivation of wells in the Sabanero block, water-handling facilities in the CPE-6 block, increased water processing capacity at SAARA, which supports production levels from the Quifa block, and the reactivation of wells in the Sabanero block, and (ii) a natural gas liquids production increase of 4% primarily from the VIM-1 block, as a result of the development of facilities for surface gas compression and handling systems.These increases were partially offset by the decreases in light and medium crude oil combined production by 13% and conventional natural gas production by 6%, both due to natural decline.

For the three months ended September 30, 2025, production in Colombia increased by 94 boe/d, compared to the same period of 2024**,** mainly due to (i) heavy crude oil increases of 1,766 bbl/d, resulting from the successful development drilling campaigns in the CPE-6 and Quifa blocks, improved performance in the Sabanero block, expansion of the capacity of water-handling facilities in the CPE-6 block, and increased water processing capacity at SAARA, supporting production levels in the Quifa block, and (ii) a conventional natural gas production increased of 38%, as a result of commercialized volumes of natural gas from the VIM-1 block. These increases were partially offset by decreases in light and medium crude oil combined production by 16% and natural gas liquids production by 5%, as result of natural decline.

Compared to the previous quarter, production in Colombia decreased by 844 boe/d. Heavy crude oil production declined by 2% during the quarter, mainly due to adverse weather conditions, as well as related operational and logistical challenges, which have since been resolved. The 2025 rainy season stands among the most severe in a decade, with well above historical rainfall averages impacting operations. It was partially offset by increases in conventional natural gas production driven by the commercialization of volumes from the VIM-1 block. Additionally, light and medium crude oil combined production decrease by 6%, primarily due to natural declines.

### Production from Continuing Operations Reconciled to Sales Volumes *

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

| | | | | | Nine months ended September 30 | |
|---|---|---|---|---|---|---|
| | | Q3 2025 | Q2 2025 | Q3 2024 | 2025 | 2024 |
| **Production Colombia** | (boe/d) | **38,934** | **39,778** | **38,840** | **39,240** | **37,941** |
| Royalties in-kind Colombia | (boe/d) | (3,413) | (3,484) | (4,788) | (3,563) | (4,558) |
| **Net production Colombia** | (boe/d) | **35,521** | **36,294** | **34,052** | **35,677** | **33,383** |
| Oil inventory draw (build) | (boe/d) | 2,060 | (2,596) | (199) | 228 | (824) |
| Overlift | (boe/d) | 34 | — | — | 8 | — |
| Volumes purchased | (boe/d) | 6,664 | 7,896 | 8,161 | 7,544 | 7,783 |
| Other inventory movements [(1)] | (boe/d) | (2,940) | (2,902) | (2,316) | (2,859) | (2,548) |
| **Sales volumes** | (boe/d) | **41,339** | **38,692** | **39,698** | **40,598** | **37,794** |
| Sale of volumes purchased | (boe/d) | (7,134) | (8,155) | (7,028) | (8,055) | (6,943) |
| **Sales volumes, net of purchases** | (boe/d) | **34,205** | **30,537** | **32,670** | **32,543** | **30,851** |
| Oil sales volumes | (bbl/d) | 33,406 | 30,031 | 32,129 | 31,991 | 30,244 |
| Conventional natural gas sales volumes | (mcf/d) | 4,554 | 2,884 | 3,084 | 3,148 | 3,460 |
| **Total oil and conventional natural gas sales volumes, net of purchases** | **(boe/d)** | **34,205** | **30,537** | **32,670** | **32,543** | **30,851** |
| **Inventory balance** | | | | | | |
| Colombia [(2)] | (bbl) | 439,714 | 629,147 | 777,158 | 439,714 | 777,158 |
| Peru | (bbl) | 480,200 | 480,200 | 480,200 | 480,200 | 480,200 |
| **Inventory ending balance from continuing operations** | **(bbl)** | **919,914** | **1,109,347** | **1,257,358** | **919,914** | **1,257,358** |
| Ecuador | (bbl) | 22,422 | 33,189 | 58,026 | 22,422 | 58,026 |
| **Inventory ending balance from discontinued operations** | **(bbl)** | **22,422** | **33,189** | **58,026** | **22,422** | **58,026** |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

(1) Mainly corresponds to operational consumption and quality volumetric compensation.

(2) Includes 0.35 MMbbl of oil produced and 0.09 MMbbl of diluent in the third quarter of 2025, 0.49 MMbbl of oil produced and 0.14 MMbbl of diluent in the second quarter of 2025, and 0.33 MMbbl of oil produced and 0.45 MMbbl of diluent in the third quarter of 2024.

For the three and nine months ended September 30, 2025, sales volumes, net of purchases, increased by 5% and 5%, respectively, compared to the same periods of 2024. These increases were primarily driven by higher oil production and inventory drawdowns. Compared to the prior quarter, sales volumes, net of purchases, increased by 12% due to inventory drawdown.

## Realized and Reference Prices from Continuing Operations *

| | | Q3 2025 | Q2 2025 | Q3 2024 | Nine months ended September 30 2025 | Nine months ended September 30 2024 |
|---|---|---|---|---|---|---|
| **Reference price** | | | | | | |
| Brent [(1)] | ($/bbl) | 68.17 | 66.71 | 78.71 | 69.91 | 81.82 |
| **Average realized prices** | | | | | | |
| Realized oil price, net of purchases [(2)] | ($/bbl) | 61.95 | 59.97 | 68.03 | 62.31 | 72.71 |
| Realized conventional natural gas price | ($/mcf) | 8.98 | 5.93 | 6.77 | 7.35 | 6.27 |
| **Net sales realized price** | | | | | | |
| Produced crude oil and gas sales [(3)] | ($/boe) | 64.40 | 63.18 | 71.13 | 65.37 | 75.12 |
| Purchased crude net margin [(2)(3)] | ($/boe) | (2.70) | (3.65) | (3.59) | (3.41) | (3.14) |
| Oil and gas sales, net of purchases [(3)] | ($/boe) | 61.70 | 59.53 | 67.54 | 61.96 | 71.98 |
| (Loss) gain on oil price risk management contracts [(4) (5)] | ($/boe) | (1.20) | 0.16 | (0.47) | (0.84) | (1.03) |
| Royalties [(4)] | ($/boe) | (0.78) | (0.71) | (0.80) | (0.81) | (1.43) |
| **Net sales realized price [(3)]** | **($/boe)** | **59.72** | **58.98** | **66.27** | **60.31** | **69.52** |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

(1) Frontera's weighted average Brent price for the three and nine months ended September 30, 2025, was $67.30/bbl and $69.74/bbl, respectively.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(3) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details. Corresponds to the net sales and costs of third-party hydrocarbon volumes purchased primarily for dilution and refining purposes, as part of the Company's oil operations, marketing and transportation strategy.

(4) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details.

(5) Includes the net amount of put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Refer to the "(Loss) gain on Risk Management Contracts" section on page 15 for further details.

The average Brent benchmark oil price during the three and nine months ended September 30, 2025, decreased by 13% and 15%, respectively, compared to the same periods of 2024. Compared with the second quarter of 2025, the average Brent benchmark oil price increased by 2%. The decrease in crude oil prices in 2025 compared with the same periods in 2024 was mainly due to: (i) the OPEC+ unwinding of production cuts, which continues to increase global oil supply, as well as new additional output from Brazil, Guyana, Argentina and Canada; (ii) ongoing tariff negotiations involving the US, EU, Canada, China, Europe and Latin America have negatively impacted market demand sentiment; and (iii) the war risk premium has been lower than anticipated and has not yet materialized. Despite the existing market conditions, during the third quarter of 2025, Frontera was able to keep strong crude oil prices.

For the three and nine months ended September 30, 2025, the Company's net sales realized price decreased by $6.55/boe and $9.21/boe, respectively, compared to the same periods of 2024. The decrease was primarily driven by a lower Brent benchmark oil price, partially offset by better oil price differentials and cash royalties paid. Compared with the prior quarter, the Company's net realized sales price increased 1%. The increase was primarily driven by a higher Brent benchmark oil price, stronger oil price differentials, partially offset by premiums paid on oil price risk management contracts.

## Operating Netback from Continuing Operations *

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

| | Q3 2025 | | Q2 2025 | | Q3 2024 | |
|---|---|---|---|---|---|---|
| | $M | ($/boe) | $M | ($/boe) | $M | ($/boe) |
| Net sales realized price [1] | 187,915 | 59.72 | 163,905 | 58.98 | 199,180 | 66.27 |
| Production costs (excluding energy costs), net of realized FX hedge impact [1][2][3] | (30,301) | (8.46) | (32,191) | (8.89) | (31,776) | (8.89) |
| Energy costs, net of realized FX hedge impact [1][2][4] | (19,900) | (5.56) | (17,204) | (4.75) | (18,748) | (5.25) |
| Transportation costs, net of realized FX hedge impact [1][2][4][5] | (38,316) | (11.72) | (39,022) | (11.81) | (39,453) | (12.59) |
| **Operating Netback from Continuing Operations [1][2][6]** | **99,398** | **33.98** | **75,488** | **33.53** | **109,203** | **39.54** |
| | | **(boe/d)** | | **(boe/d)** | | **(boe/d)** |
| **Sales volumes, net of purchases [7]** | | 34,205 | | 30,537 | | 32,670 |
| **Production Colombia [8]** | | 38,934 | | 39,778 | | 38,840 |
| **Net production Colombia [9]** | | 35,521 | | 36,294 | | 34,052 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details.

(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details.

(3) Includes gain of $1.2 million and $43 thousand, from realized FX hedge attributable to production costs for the third quarter of 2025 and the second quarter of 2025, respectively, and a loss of $0.2 million for the third quarter of 2024. See "(Loss) gain on Risk Management Contracts" on page 15 for further details.

(4) Includes gain of $0.7 million, $Nil and loss of $0.1 million from realized FX hedge attributable to energy costs for the third quarter of 2025, the second quarter of 2025, and the third quarter of 2024, respectively. See "(Loss) gain on Risk Management Contracts" on page 15 for further details.

(5) Includes gain of $0.9 million and $Nil from realized FX hedge attributable to transportation costs for the third quarter of 2025 and the second quarter of 2025, respectively, and a loss of $0.1 million for the third quarter of 2024. See "(Loss) gain on Risk Management Contracts" on page 15 for further details.

(6) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(7) Sales volumes, net of purchases, excluding sales of third-party volumes.

(8) Refer to the "Production Colombia" section on page 6 for further details.

(9) Refer to the "Further Disclosures" section on page 42 for further details.

The Company's operating netback from continuing operations for the third quarter of 2025 was $33.98/boe, a decrease from $39.54/boe in the same quarter of 2024, mainly attributable to a lower Brent benchmark oil price. Compared to the second quarter of 2025, operating netback from continuing operations increased from $33.53/boe to $33.98/boe. The Company's operating netback increased quarter-over-quarter mainly due to: (i) a higher net sales realized price, including stronger oil price differentials; (ii) a reduction in production costs (excluding energy costs), net of realized FX hedge impact, was primarily due to new field production technologies, continuous optimization, cost reduction in O&M contracts and digital process implementation, (iii) lower transportation costs, net of realized FX hedge, despite higher transported volumes, transportation cost improved mainly driven by the optimization of the transportation routes and pipeline agreements including the termination of the long-term Ocensa P-135 Take-or-Pay agreement; and (iv) higher energy costs, net of realized FX hedge impact, was mainly due to higher fuel consumption resulting from higher processed production liquid volumes.

The following table provides a summary of the Company's netbacks from continuing operations for the nine months ended September 30, 2025, and 2024:

| | Nine months ended September 30 | | | |
|---|---|---|---|---|
| | 2025 | | 2024 | |
| | $M | ($/boe) | $M | ($/boe) |
| Net sales realized price [1] | 535,805 | 60.31 | 587,660 | 69.52 |
| Production costs (excluding energy costs), net of realized FX hedge impact [1][2][3] | (97,466) | (9.10) | (104,295) | (10.03) |
| Energy costs, net of realized FX hedge impact [1][2][4] | (56,262) | (5.25) | (53,916) | (5.19) |
| Transportation costs, net of realized FX hedge impact [1][2][4][5] | (117,119) | (12.02) | (108,628) | (11.88) |
| **Operating Netback from Continuing Operations [1][2][6]** | **264,958** | **33.94** | **320,821** | **42.42** |
| | | **(boe/d)** | | **(boe/d)** |
| **Sales volumes, net of purchases [7]** | | 32,543 | | 30,851 |
| **Production Colombia [8]** | | 39,240 | | 37,941 |
| **Net production Colombia [9]** | | 35,677 | | 33,383 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details.

(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details.

(3) Includes a gain of $1.2 million and $3.4 million from realized FX hedge attributable to production costs for the nine months ended September 30, 2025, and 2024, respectively. See "(Loss) gain on Risk Management Contracts" on page 15 for further details.

(4) Includes a gain of $0.7 million and $1.3 million from realized FX hedge attributable to energy costs for the nine months ended September 30, 2025, and 2024, respectively. See "(Loss) gain on Risk Management Contracts" on page 15 for further details.

(5) Includes a gain of $0.9 million and $1.0 million from realized FX hedge attributable to transportation costs for the nine months ended September 30, 2025, and 2024, respectively. See "(Loss) gain on Risk Management Contracts" on page 15 for further details.

(6) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(7) Sales volumes, net of purchases, excluding sales of third-party volumes.

(8) Refer to the "Production Colombia" section on page 6 for further details.

(9) Refer to the "Further Disclosures" section on page 42 for further details.

Operating netback from continuing operations for the nine months ended September 30, 2025, was $33.94/boe compared to $42.42/boe in the same period of 2024. The changes were attributed to: (i) a 13% decrease in net sales realized prices; (ii) increased energy costs, net of realized FX hedge impact, due to higher energy use and fuel consumption associated with increased heavy crude oil production levels; (iii) increased transportation costs mainly due to the regular annual increase in transportation tariffs; and (iv) reduced production costs (excluding energy costs), net of realized FX hedge impact, primarily due to new field production technologies, continuous optimization, cost reduction in O&M contracts and digital process implementation.

## Sales from Continuing Operations *

| ($M) | Three months ended September 30 2025 | Three months ended September 30 2024 | Nine months ended September 30 2025 | Nine months ended September 30 2024 |
|---|---|---|---|---|
| Produced crude oil sales | 198,901 | 211,877 | 574,489 | 629,095 |
| Purchased crude net margin (1)(2) | (8,514) | (10,781) | (30,304) | (26,566) |
| Conventional natural gas sales | 3,766 | 1,921 | 6,321 | 5,946 |
| Oil and gas sales, net of purchases (3) | 194,153 | 203,017 | 550,506 | 608,475 |
| Loss on oil price risk management contracts (4) | (3,784) | (1,425) | (7,494) | (8,710) |
| Royalties | (2,454) | (2,412) | (7,207) | (12,105) |
| **Net sales (1)** | **187,915** | **199,180** | **535,805** | **587,660** |
| Net sales realized price ($/boe) (5) | 59.72 | 66.27 | 60.31 | 69.52 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.
(1) Corresponds to the net sales and costs of third-party hydrocarbon volumes purchased primarily for dilution and refining purposes, as part of the Company's oil operations, marketing and transportation strategy.
(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.
(3) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details.
(4) Includes put premiums paid for expired positions. Refer to the "Gain (Loss) on Risk Management Contracts" section on page 16 for further details.
(5) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details.

Oil and gas sales, net of purchases, decreased by $8.9 million and $58.0 million for the three and nine months ended September 30, 2025, compared with the same periods of 2024, mainly due to a lower Brent benchmark oil price (refer to the "Realized and Reference Prices" section on page 8 for further details on price changes). The negative impact was partially offset by the additional volumes produced and improved oil price differentials.

Net sales for the three and nine months ended September 30, 2025, decreased by $11.3 million and $51.9 million, respectively, compared with the same periods of 2024. The following table describes the various factors that impacted net sales:

| ($M) | Three months ended September 30 2024 to 2025 | Nine months ended September 30 2024 to 2025 |
|---|---|---|
| Net sales for the period ended September 30, 2024 | 199,180 | 587,660 |
| Decreased due to 9% lower oil and gas price (YTD 14% lower) | (17,564) | (84,674) |
| Increase due to variance of total produced volumes sold | 8,700 | 26,705 |
| (Increase) decrease in royalties | (42) | 4,898 |
| (Increase) decrease in oil price risk management contracts, net (1) | (2,359) | 1,216 |
| **Net sales for the period ended September 30, 2025** | **187,915** | **535,805** |

(1) Includes the net amount of put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Refer to the "(Loss) gain on Risk Management Contracts" section on page 15 for further details.

## Oil and Gas Operating Costs from Continuing Operations *

| ($M) | Three months ended September 30 2025 | Three months ended September 30 2024 | Nine months ended September 30 2025 | Nine months ended September 30 2024 |
|---|---|---|---|---|
| Transportation costs | 38,407 | 38,779 | 115,882 | 108,096 |
| Production costs (excluding energy costs) | 29,831 | 31,007 | 94,803 | 107,066 |
| Energy costs | 20,589 | 18,664 | 56,951 | 55,183 |
| Trunkline costs and others | 295 | 3,829 | 2,814 | 3,829 |
| Inventory valuation | 3,737 | 3,591 | (1,171) | (739) |
| Post-termination costs | 2,708 | (314) | 2,599 | (128) |
| **Total oil and gas operating costs** | **95,567** | **95,556** | **271,878** | **273,307** |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

During the three and nine months ended September 30, 2025, total oil and gas operating costs increased by $11 thousand and decreased $1.4 million, respectively, compared with the same periods of 2024. The variance in total oil and gas operating costs was mainly due to the following:

- For the three months ended September 30, 2025, transportation costs decreased by 1% compared with the same period of 2024, despite higher transported volumes, transportation cost improved mainly driven by the optimization of the transportation routes and pipeline agreements including the termination of the long-term Ocensa P-135 Take or Pay agreement. For the nine months ended September 30, 2025, transportation costs increased by 7% compared with the same period of 2024, primarily due to higher volumes produced and transported, and the regular annual increase in transportation tariffs.
- Production costs (excluding energy costs) for the three and nine months ended September 30, 2025, decreased by 4% and 11%, respectively, compared with the same periods of 2024, due to new field production technologies, continuous optimization, cost reduction in O&M contracts and digital process implementation.
- Energy costs for the three and nine months ended September 30, 2025, increased by 10% and 3%, respectively, compared with the same periods of 2024, mainly due to higher energy use and fuel consumption associated with increased heavy crude oil production levels.
- Trunkline costs related to repairs and other activities undertaken in response to unexpected failures in a trunkline in the Quifa block, which have since been resolved. The Company expects to recover a portion of these costs through claims under its material damages and third-party liability insurance policies. In addition, expenses for the three and nine months ended September 30, 2025, includes external road maintenance expenses associated with damage caused by the heavy rainy season.
- Inventory valuation for the three months ended September 30, 2025, increased by $0.1 million compared to the same period of 2024, primarily due to inventory drawdown. For the nine months ended September 30, 2025, inventory valuation changed by $0.4 million, mainly as a result of higher inventory levels relative to the same period of 2024.
- Post-termination obligations for the three and nine months ended September 30, 2025, resulted in expenses of $2.7 million and $2.6 million, respectively, were primarily related to the relinquishment of production areas within the Cubiro block, and the Rio Ariari block in Colombia, which were partially offset by cost efficiencies in executing activities associated with returned blocks.

### Cost of Diluent and Oil Purchased

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Cost of diluent and oil purchased [1] | 52,250 | 57,557 | 179,719 | 170,569 |

[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 25 for further details.

Cost of diluent and oil purchased represents the cost of third-party hydrocarbon volumes purchased primarily for dilution and refining purposes as part of the Company's oil operations, as well as its marketing and transportation strategy. For the three months ended September 30, 2025, the cost of diluent and oil purchases decreased by $5.3 million compared with the same period of 2024, primarily due to lower Brent benchmark oil prices, and new refining and dilution strategies, partially offset by an increase in heavy oil production volumes, which increased the demand for diluent and fuel used for energy. For the nine months ended September 30, 2025, the cost of diluent and oil purchases increased by $9.2 million, compared to the same period of 2024, mainly driven by higher heavy crude oil production, increasing the demand for diluent and fuel used for energy. Additionally, a decrease in light and medium crude oil production used in refining operations resulted in increased purchase requirements.

### Royalties *

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Royalties (all Colombia) | 2,454 | 2,412 | 7,207 | 12,105 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

Royalties include cash payments for PAP (as defined below), royalty payments, and payments to previous owners of certain blocks in Colombia. For the three months ended September 30, 2025, royalties were in line with the same period of 2024, even though WTI prices is lower in 2025, royalties expense from third quarter of 2024 was offset by a recovery, resulting from a change in the payment method, from cash to in-kind, in the VIM-1 block. For the nine months ended September 30, 2025, royalties decreased by $4.9 million, compared with the same period of 2024, mainly due to a lower WTI oil benchmark price.

## 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, Casimena, and CPE-6 blocks. The ANH requires in-kind PAP payments for all blocks, except for the Guatiquia (Yatay field), Cubiro (Copa A field), and Casimena (Mantis field) blocks.

| | | | | | Nine months ended September 30 | |
|---|---|---|---|---|---|---|
| | | Q3 2025 | Q2 2025 | Q3 2024 | 2025 | 2024 |
| PAP in kind | (bbl/d) | 330 | 379 | 1,658 | 467 | 1,678 |
| PAP in cash | (bbl/d) | 212 | 204 | 338 | 226 | 372 |
| **PAP** | **(bbl/d)** | **542** | **583** | **1,996** | **693** | **2,050** |
| **% Production** | | **1.4 %** | **1.4 %** | **4.9 %** | **1.7 %** | **5.2 %** |

## Depletion, Depreciation and Amortization *

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Depletion, depreciation and amortization | 75,472 | 65,581 | 200,304 | 192,054 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

For the three and nine months ended September 30, 2025, depletion, depreciation, and amortization expense ("**DD&A**") increased by 15% and 4%, respectively, compared to the same periods of 2024, primarily due to higher heavy crude oil production levels and additional depreciation resulting from the additions to SAARA project water treatment facilities.

## Impairment Expense, Exploration Expenses and Others *

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Impairment expense of: | | | | |
| Properties, plant and equipment | 8,369 | — | 8,369 | — |
| Exploration and evaluation assets | 465 | — | 433,049 | — |
| Other | 872 | 361 | 1,315 | 1,780 |
| Total impairment expense | 9,706 | 361 | 442,733 | 1,780 |
| Exploration expenses of: | | | | |
| Geological and geophysical costs, and other | 469 | 384 | 1,407 | 1,198 |
| Total exploration expenses | 469 | 384 | 1,407 | 1,198 |
| Expense of asset retirement obligations | 3,283 | 5,546 | 3,809 | 4,549 |
| **Impairment expense, exploration expenses and other** | **13,458** | **6,291** | **447,949** | **7,527** |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

### Properties, plant and equipment

During the three and nine months ended September 30, 2025, the Company recorded an impairment charge of $8.4 million and $8.4 million, respectively (2024: $Nil and $Nil), as a result, of the relinquishment of certain fields or areas from the Cubiro and Corcel blocks.

### Exploration and Evaluation Assets

During the three and nine months ended September 30, 2025, the Company recorded an impairment charge of $0.5 million and $433.0 million, respectively (2024: $Nil and $Nil), mainly related to the impairment of the Corentyne block (for further information, please refer to "Critical Judgments in Applying Accounting Policies" section of Note 2 the Interim Financial Statements).

### Other

During the three and nine months ended September 30, 2025, the Company recognized an impairment expense of $0.9 million, and $1.3 million, respectively, mainly related to obsolete inventory materials and certain account receivables (2024: Other impairment expenses of $0.4 million and $1.8 million respectively).

### Expense of asset retirement obligations

During the three and nine months ended September 30, 2025, the Company recognized an asset retirement obligations expense of $3.3 million and $3.8 million, respectively. During the three and nine months ended September 30, 2024, the Company recognized an asset retirement obligations expense of $5.5 million and $4.5 million, respectively.

## Other Operating Costs

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| General and administrative | 14,877 | 12,473 | 42,276 | 38,472 |
| Special projects and other costs | 4,245 | 2,907 | 12,562 | 6,841 |
| Share-based compensation | (5) | 686 | 2,457 | 1,687 |
| Restructuring, severance, and other costs | 8,278 | 361 | 18,805 | 3,216 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

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

For the three and nine months ended September 30, 2025, G&A expenses increased by 19% and 10%, respectively, compared to the same periods of 2024, mainly due to Colombian temporary taxes of $2.4 million and $5.3 million for the three and nine months ended September 30, 2025, respectively.

### Special projects and other costs

For the three and nine months ended September 30, 2025, special projects and other costs increased by 46% and 84%, respectively, compared with the same periods of 2024, primarily due to SAARA's operating costs under the agreement with Ecopetrol, which was signed in June 2024.

### Share-Based Compensation

For the three and nine months ended September 30, 2025, share-based compensation decreased by $0.7 million and increased by $0.8 million, respectively, compared to the same periods of 2024. Regarding the third quarter of 2025, the decrease was primarily due to a lower number of share units, resulting from the settlement of units granted in 2022 and the cancellation of units pursuant to the Restructuring Plan (as defined below). In contrast, for the nine-month period ended September 30, 2025, the increase was due to a higher number of share units granted in 2025, partially offset by a lower stock price. Share-based compensation reflects cash and non-cash charges related to the vesting of restricted share units ("**RSUs**") and the granting of deferred share units ("**DSUs**") under the Company's security-based compensation plan, which are subject to variability due to movements in the trading price of the Company's Common Shares.

### Restructuring, Severance and Other Costs

For the three and nine months ended September 30, 2025, restructuring, severance and other costs increased by $7.9 million and $15.6 million, respectively, compared to the same periods of 2024. For the third quarter of 2025, this amount includes the simplification of its corporate structure, through targeted reorganization initiatives that are designed to improve organizational and operational efficiencies, in line with the Restructuring Plan (as defined below). Additionally, for the nine month period ended September 30, 2025, these costs include employee incentive payments, fees and expenses related to the recapitalization of the Company's interest in the ODL pipeline.

## Non-Operating Costs *

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Finance income | 1,745 | 3,123 | 5,285 | 6,512 |
| Finance expenses | (18,899) | (17,570) | (52,445) | (51,779) |
| Foreign exchange gain (loss) | 2,076 | (631) | 1,762 | (9,246) |
| Other income (loss) | 12,013 | (4,203) | 13,367 | (7,368) |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page 17 for further details.

### Finance Income

For the three and nine months ended September 30, 2025, finance income decreased by $1.4 million and $1.2 million, respectively, compared with the same periods of 2024, mainly due to changes in interest rates on investment trust accounts related to abandonment requirements and average of cash balances during the period.

### Finance Expenses

For the three and nine months ended September 30, 2025, finance expenses increased by $1.3 million and $0.7 million, respectively, compared with the same periods of 2024, mainly due to additional interest resulting from the FPI Recapitalization Loan (as defined below), partially offset by lower letters of credit fees and other bank charges.

### Foreign Exchange Gain (Loss)

For the three and nine months ended September 30, 2025, the Company recognized foreign exchange gains of $2.1 million and $1.8 million, respectively, compared to losses of $0.6 million and $9.2 million for the same periods of 2024. The foreign exchange gains were primarily due to the appreciation of the COP against the USD during 2025, compared to a depreciation of the COP against the USD during 2024. These exchange rate movements impacted the Company’s net working capital balances denominated in COP. Foreign exchange rates (COP:USD) as at September 30, 2025, and September 30, 2024, were 3,901.29:1 and 4,164.21:1, respectively.

### Other Income (Loss)

For the three and nine months ended September 30, 2025, the Company recognized other income of $12.0 million and $13.4 million, respectively, mainly related to insurance recoveries for the Sabanero block by $14.7 million, partially offset by losses related to the recognition of contingencies. During the same periods of 2024, the Company recognized other loss of $4.2 million and $7.4 million, respectively, mainly attributable to contingencies, partially offset by income related to insurance recoveries from the Sabanero block.

## (Loss) Gain on Risk Management Contracts

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Loss on oil price risk management contracts (1) | (3,784) | (1,425) | (7,494) | (8,710) |
| Realized gain (loss) on foreign exchange risk hedge (2) | 1,977 | (417) | 2,020 | 6,030 |
| Realized loss on risk management contracts | (1,807) | (1,842) | (5,474) | (2,680) |
| Unrealized (loss) gain on risk management contracts | (3,130) | 7,644 | 5,212 | (3,941) |
| Total (loss) gain on risk management contracts | (4,937) | 5,802 | (262) | (6,621) |

(1) Includes the net amount of put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period.

(2) For determination of operating netback from continuing operations, during the three and nine months ended September 30, 2025, the Company estimates an attribution of $1.2 million and $1.2 million, respectively, of the total realized FX hedge to production cost (excluding energy cost) (2024: $0.2 million and $3.4 million respectively), estimates an attribution of $0.7 million and $0.7 million, respectively, of the total realized FX hedge to energy (2024: $0.1 million and $1.3 million, respectively), and estimates an attribution of $0.9 million and $0.9 million, respectively, of the total realized FX hedge to transportation (2024: $0.1 million and $1.0 million), respectively. Refer to the “Non-IFRS and Other Financial Measures” section on page 25.

For the three and nine months ended September 30, 2025, the realized loss of $1.8 million and $5.5 million, respectively, on risk management contracts was mainly due to: (i) a loss of $3.8 million and $7.5 million, respectively, on oil price risk management contracts, resulting from a net amount of the put premiums paid for expired positions of $6.8 million and $14.6 million, respectively, mitigated in part by the positive cash settlement of $3.0 million and $7.1 million, respectively; and partially offset by (ii) a gain of $2.0 million and $2.0 million, respectively, on the cash settlement of risk management contracts of foreign exchange currency. In comparison, for the three months ended September 30, 2024, the realized loss on risk management contracts was $1.8 million, resulting from $1.4 million in premiums paid on oil price risk management contracts and $0.4 million negative cash settlement on foreign exchange risk management contracts. During the nine months ended September 30, 2024, the realized loss on risk management contracts was $2.7 million, resulting from $8.7 million, in premiums paid on oil price risk management contracts, partially offset by a gain of $6.0 million, from the cash settlement of foreign exchange risk management contracts.

For the three and nine months ended September 30, 2025, risk management contracts had an unrealized loss of $3.1 million and a gain of $5.2 million, respectively, primarily due to mark to market variances from foreign exchange risk management contracts and changes in the benchmark forward prices of Brent. Compared to the same periods of 2024, with a gain of $7.6 million and a loss of $3.9 million, respectively, in the same period of 2024, primarily due to the reclassification of amounts to realized losses from instruments settled and variance 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% of estimated production with a tactical approach, using derivative commodity instruments to protect the Company's revenue generation and cash position, while maximizing the upside.

| | | | | Avg. Strike Prices | Carrying Amount | |
|---|---|---|---|---|---|---|
| **Type of Instrument** | **Term** | **Benchmark** | **Volume (bbl)** | **Put $/bbl** | **Assets** | **Liabilities** |
| Put Spread | October 2025 to March 2026 | Brent | 2,477,000 | 65/55 | — | 1,072 |
| Total as at September 30, 2025 | | | | | — | 1,072 |

Following the end of the quarter, the Company entered into the following new hedges:

| | | | | Avg. Strike Prices |
|---|---|---|---|---|
| **Type of Instrument** | **Term** | **Benchmark** | **Volume (bbl)** | **Put $/bbl** |
| Put Spread | March 2026 to June 2026 | Brent | 1,529,200 | 62.7/55 |

### Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. This exposure arises primarily due to expenditures incurred in COP and the fluctuation of this currency against the USD. In addition, during 2025, the Company entered into new derivative contracts associated with the collection of dividends from ODL, as required under the FPI Recapitalization Loan (as defined below).

As at September 30, 2025, the Company has the following foreign currency derivatives contracts:

| | | | | Avg. Put/Call | Carrying Amount | |
|---|---|---|---|---|---|---|
| **Type of Instrument** | **Term** | **Benchmark** | **Notional Amount/ Volume in USD** | **Par forward (COP$)** | **Assets** | **Liabilities** |
| Zero-cost collars | October 2025 to December 2025 | USD/COP | 30,000,000 | 4,250/4,787 | 2,373 | — |
| Forward [1] | October 2025 | USD/COP | 7,741,875 | 4,247 | — | 620 |
| Forward [1] | December 2025 | USD/COP | 4,782,973 | 4,181.5 | — | 263 |
| Total as at September 30, 2025 | | | 42,524,848 | | 2,373 | 883 |

[1] Contracts related to the FPI Recapitalization Loan (as defined below).

Subsequent to the end of the quarter, the Company has not entered into any new hedges.

### Income Tax

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Current income tax expense | (280) | (2,803) | (6,731) | (7,850) |
| Deferred income tax recovery (expense) | 20,880 | (3,526) | 50,810 | (55,880) |
| **Total income tax recovery (expense) from continuing operations** | 20,600 | (6,329) | 44,079 | (63,730) |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

For the three and nine months ended September 30, 2025, the Company recognized a current income tax expense of $0.3 million and $6.7 million, respectively, compared to a current income tax expense of $2.8 million and $7.9 million, respectively, in the same periods of 2024. Additionally, the Company recognized a deferred income tax recovery of $20.9 million and $50.8

million, compared with a deferred income tax expense of $3.5 million and $55.9 million, respectively, in the same periods of 2024. The variance in the deferred tax was mainly due to foreign exchange rate fluctuations.

### Discontinued Operations

On July 31, 2025, the Company entered into an agreement to sell its 50% working interest in the Perico and Espejo blocks in Ecuador to Gran Tierra Energy Inc., for a total cash consideration of $7.8 million, subject to working capital and other customary adjustments as of the effective date of January 1, 2025. The agreement includes an additional contingent consideration of $0.8 million, payable to Frontera upon the Perico block achieving cumulative gross production of two million barrels as from January 1, 2025. Closing of the transaction is subject to satisfaction of customary closing conditions, including the receipt of regulatory approvals for closing and operations takeover from the Ministry of Energy of Ecuador, and is expected to occur by by the end of December 2025. As at September 30, 2025, the Company classified this transaction as asset held for sale and as a discontinued operation, as a result the Company recognize a loss related to remeasurement to fair value less costs to sell of $8.5 million.

The results of the discontinued operations during the three and nine months ended September 30, 2025 and 2024 are presented below:

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| *(In thousands of U.S.$, except per share information)* | **2025** | **2024** | **2025** | **2024** |
| Revenue | 4,521 | 9,439 | 16,475 | 21,298 |
| Operating costs | 2,092 | 2,503 | 6,600 | 5,312 |
| General and administrative | 124 | 246 | 576 | 731 |
| Share-based compensation | (22) | (6) | 2 | 33 |
| Impairment, and depletion, depreciation and amortization | 1,400 | 2,688 | 49,628 | 5,215 |
| Income (loss) from operations from discontinued operations | 927 | 4,008 | (40,331) | 10,007 |
| Finance expense, net | (57) | (123) | (210) | (594) |
| Other income (loss) | 588 | (89) | 424 | (57) |
| Net income (loss) before income tax from discontinued operations | 1,458 | 3,796 | (40,117) | 9,356 |
| Income tax expense (recovery) | 4,205 | (4,131) | 3,334 | (5,974) |
| Related to remeasurement to fair value less costs to sell | (8,481) | — | (8,481) | — |
| Net (loss) income for the period from discontinued operations | $ (2,818) | (335) | $ (45,264) | $ 3,382 |

For more detailed information, including the assets and liabilities classified as held for sale and the cash flows from discontinued operations as at September 30, 2025, refer to Note 7 of the Interim Financial Statements.

### Net Income (Loss) from Continuing Operations and Discontinued Operations

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Net income (loss) for the period from continuing operations [1] | 28,235 | 16,923 | (357,007) | 1,857 |
| Net (loss) income for the period from discontinued operations | (2,818) | (335) | (45,264) | 3,382 |
| Net income (loss) for the period | 25,417 | 16,588 | (402,271) | 5,239 |
| Per share – basic from continuing operations ($) | 0.40 | 0.20 | (4.73) | 0.02 |
| Per share – diluted from continuing operations ($) | 0.38 | 0.19 | (4.73) | 0.02 |
| Per share – basic from discontinued operations ($) | (0.04) | — | (0.60) | 0.04 |
| Per share – from discontinued operations diluted ($) | (0.04) | — | (0.60) | 0.04 |

[1] Income (loss) attributable to equity holders of the Company.

During the third quarter of 2025, the Company reported net income from continuing operations, attributable to equity holders of the Company, of $28.2 million, mainly resulting from a loss from operations of $13.9 million (net of a non-cash impairment expense of $9.7 million), finance expenses of $18.9 million and $4.9 million related to loss on risk management contracts, partially offset by an income tax recovery of $20.6 million (including $20.9 million of deferred income tax recovery), $15.9 million from share of income from associates, other income by $12.0 million mainly related to insurance recoveries for the Sabanero block by $14.7 million, and foreign exchange income of $2.1 million. This compares with net income from continuing operations, attributable to equity holders of the Company, in the third quarter of 2024, of $16.9 million, which included income from operations $22.8 million, $13.4 million from share of income from associates, and $5.8 million related to income on risk management contracts, partially offset by finance expenses of $17.6 million and an income tax expense of $6.3 million (including $3.5 million of deferred income tax expenses).

For the nine months ended September 30, 2025, the Company reported a net loss from continuing operations, attributable to equity holders of the Company, of $357.0 million, mainly resulting from a loss from operations of $433.8 million (net of a non-cash impairment expense of $442.7 million) and finance expenses of $52.4 million, partially offset by an income tax recovery of $44.1 million (including $50.8 million of deferred income tax recovery), $45.1 million from share of income from associates, other income by $13.4 million mainly related to insurance recoveries for the Sabanero block by $14.7 million, $11.9 million of gain on the repurchase of the 2028 Senior Unsecured Notes net of the consent solicitation and finance income of $5.3 million. This compared to a net income from continuing operations, attributable to equity holders of the Company, in the third quarter of 2024, of $1.9 million, mainly resulting from operating income of $91.7 million and $40.7 million from share of income from associates, partially offset by income tax expense of $63.7 million (including $55.9 million of deferred income tax expenses), finance expenses of $51.8 million, $9.2 million of foreign exchange losses and $6.6 million related to loss on risk management contracts.

## Capital Expenditures and Acquisitions *

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Development drilling | 22,742 | 29,089 | 83,672 | 92,826 |
| Development facilities | 19,512 | 23,129 | 42,469 | 63,143 |
| Colombia exploration | 2,567 | 1,598 | 14,599 | 11,096 |
| Other | 694 | 6,641 | 1,892 | 14,496 |
| **Total Colombia upstream capital expenditures** | **45,515** | **60,457** | **142,632** | **181,561** |
| Colombia infrastructure | 5,344 | 13,860 | 12,878 | 21,883 |
| Guyana exploration | — | 555 | 436 | 2,696 |
| **Total capital expenditures from continuing operations (1)** | **50,859** | **74,872** | **155,946** | **206,140** |
| Exploration and development in Ecuador | 578 | 7,539 | 1,604 | 25,850 |
| **Total capital expenditures from discontinued operations (2)** | **578** | **7,539** | **1,604** | **25,850** |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador.

(1) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25 for further details.

(2) Refer to the "Discontinued Operations" section on page 17 for further details.

Capital expenditures for the three and nine months ended September 30, 2025, were $50.9 million and $155.9 million respectively, compared with $74.9 million and $206.1 million respectively, in the same periods of 2024, as follows:

**Development drilling.** During the three and nine months ended September 30, 2025, development drilling expenditures were $22.7 million and $83.7 million, respectively, compared with $29.1 million and $92.8 million respectively, for the same periods of 2024. During the third quarter of 2025, 16 development wells were drilled primarily in the Quifa and CPE-6 blocks, in Colombia. In the same period of 2024, 15 development wells were drilled in the CPE-6, Quifa and Sabanero blocks. During the nine months ended September 30, 2025, 55 development wells were drilled mainly in the Quifa and CPE-6 blocks, in Colombia, while in the same period of 2024 a total of 63 development wells were drilled in the Quifa, CPE-6 and Sabanero blocks.

**Development facilities.** During the three and nine months ended September 30, 2025, development facility expenditures were $19.5 million and $42.5 million, respectively, primarily related to facility expansion and the installation of new and improved flow lines in the Cajua field, within the Quifa block, to support new well production and the SAARA connection. Additionally, expenditures were made to expand crude oil storage capacity and improve roads in the CPE-6 block. For the same periods of 2024, development facility expenditures were $23.1 million and $63.1 million, respectively, mainly related to the increase of water-handling capacity at the CPE-6 block, new and improved flow lines in the Quifa Block supporting new well production and the SAARA connection and the expansion of the Sabanero block facilities.

**Colombia Exploration.** During the three and nine months ended September 30, 2025, expenditures related to exploration activities were $2.6 million and $14.6 million, respectively, compared with $1.6 million and $11.1 million, respectively, in the same periods of 2024. During the third quarter of 2025, the Company's exploration focus remained on the Lower Magdalena Valley and Llanos Basins in Colombia. At the VIM-1 block, activities related to the Guapo-1 exploration well are ongoing. Civil works have been completed, and the well was spudded on October 16, 2025. At the Llanos-119 block, the ANH approved the request to transfer commitments to VIM-46 block in order to acquire a 3D seismic survey. In addition, the Company is engaged in pre-seismic and pre-drilling activities related to social and environmental studies in the Llanos-99 and VIM-46 blocks.

**Other.** Other capital expenditures for the three and nine months ended September 30, 2025, were $0.7 million and $1.9 million, respectively. These expenditures were primarily related to the implementation of new field production technologies at the Quifa and CPE-6 blocks. The expenditures for the same periods of 2024, were mainly related to generation energy facilities funded primarily through the reimbursement of insurance claim related to the Sabanero block.

**Colombia infrastructure.** Capital expenditures for the three and nine months ended September 30, 2025, were $5.3 million and $12.9 million, respectively, compared with $13.9 million and $21.9 million, respectively, for the same periods of 2024. During the third quarter of 2025, investments totaling $4.8 million were made in Puerto Bahia, including: (i) $4.6 million in investment towards the connection project between Puerto Bahia's port facility and the Cartagena refinery, effectively completed, pursuant to the connection agreement between Puerto Bahia and Refinería de Cartagena S.A.S. ("**Reficar**"), (ii) tank maintenance, and (iii) general cargo terminal facilities. In addition, the third quarter of 2025 also included investment in the SAARA project. During the same periods of 2024, capital expenditures included investments in the Puerto Bahia and SAARA project.

**Guyana exploration.** During the three and nine months ended September 30, 2025, Guyana exploration expenditures were $Nil and $0.4 million, respectively, compared to $0.6 million and $2.7 million, respectively during the same periods of 2024. These expenditures were associated with other capitalized costs.

## Selected Quarterly Information *

| | | 2025 | | | 2024 | | | | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| **Operational and financial results from Continuing Operations** | | **Q3** | **Q2** | **Q1** | **Q4** | **Q3** | **Q2** | **Q1** | **Q4** |
| Heavy crude oil production | (bbl/d) | 27,078 | 27,535 | 27,167 | 27,740 | 25,312 | 24,839 | 23,398 | 23,002 |
| Light and medium crude oil combined production | (bbl/d) | 9,235 | 9,850 | 9,531 | 10,484 | 11,018 | 10,928 | 11,102 | 13,795 |
| Total crude oil production | (bbl/d) | 36,313 | 37,385 | 36,698 | 38,224 | 36,330 | 35,767 | 34,500 | 36,797 |
| Conventional natural gas production | (mcf/d) | 4,406 | 3,118 | 2,274 | 2,633 | 3,192 | 4,019 | 3,283 | 4,760 |
| Natural gas liquids production | (boe/d) | 1,848 | 1,846 | 1,913 | 1,970 | 1,950 | 1,785 | 1,639 | 1,635 |
| Total production Colombia | (boe/d) | 38,934 | 39,778 | 39,010 | 40,656 | 38,840 | 38,257 | 36,715 | 39,267 |
| Sales volumes, net of purchases | (boe/d) | 34,205 | 30,537 | 32,873 | 35,376 | 32,670 | 29,953 | 29,910 | 34,449 |
| Brent price reference | ($/bbl) | 68.17 | 66.71 | 74.98 | 74.01 | 78.71 | 85.03 | 81.76 | 82.85 |
| Oil and gas sales, net of purchases (1)(2) | ($/boe) | 61.70 | 59.53 | 64.53 | 63.76 | 67.54 | 75.75 | 73.10 | 75.25 |
| Gain (loss) on oil price risk management contracts (3)(4) | ($/boe) | (1.20) | 0.16 | (1.40) | 0.08 | (0.47) | (1.39) | (1.28) | (0.69) |
| Royalties (3) | ($/boe) | (0.78) | (0.71) | (0.94) | (0.80) | (0.80) | (1.94) | (1.61) | (1.79) |
| Net sales realized price (1)(2) | ($/boe) | 59.72 | 58.98 | 62.19 | 63.04 | 66.27 | 72.42 | 70.21 | 72.77 |
| Production costs (excluding energy costs), net of realized FX hedge impact (2)(3) | ($/boe) | (8.46) | (8.89) | (9.96) | (7.60) | (8.89) | (10.93) | (10.31) | (9.69) |
| Energy costs, net of realized FX hedge impact (3) | ($/boe) | (5.56) | (4.75) | (5.46) | (5.46) | (5.25) | (4.88) | (5.45) | (5.06) |
| Transportation costs, net of realized FX hedge impact (2)(3) | ($/boe) | (11.72) | (11.81) | (12.55) | (11.59) | (12.59) | (11.30) | (11.71) | (11.06) |
| Operating netback from continuing operations per boe (1)(2) | ($/boe) | 33.98 | 33.53 | 34.22 | 38.39 | 39.54 | 45.31 | 42.74 | 46.96 |
| Revenue | ($M) | 257,252 | 234,722 | 268,272 | 282,780 | 269,036 | 269,352 | 263,487 | 299,501 |
| Net income (loss) for the period from continuing operations | ($M) | 28,235 | (410,857) | 25,615 | (21,601) | 16,923 | (6,310) | (8,756) | 92,038 |
| Per share – basic from continuing operations ($) | ($) | 0.40 | (5.32) | 0.33 | (0.26) | 0.20 | (0.07) | (0.10) | 1.08 |
| Per share – diluted from continuing operations ($) | ($) | 0.38 | (5.32) | 0.31 | (0.26) | 0.19 | (0.07) | (0.10) | 1.04 |
| General and administrative | ($M) | 14,877 | 14,021 | 13,378 | 12,936 | 12,473 | 12,682 | 13,317 | 16,891 |
| Operating EBITDA from Continuing Operations (5) | ($M) | 86,585 | 73,489 | 79,048 | 108,505 | 96,494 | 102,776 | 96,228 | 121,036 |
| Capital expenditures (5) | ($M) | 50,859 | 58,967 | 46,120 | 84,544 | 74,872 | 72,671 | 58,597 | 82,292 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador, with the exception of figures from Q4-2023 which have not been adjusted and include the results of operations for the non-core Ecuador assets. Refer to the "Discontinued Operations" section on page 17 for further details.

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details.

(2) 2024 and 2023 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(3) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details.

(4) Includes the net effect of put premiums paid for expired positions and positive cash settlements received from oil price contracts during the period. Refer to the "(Loss) Gain on Risk Management Contracts" section on page 16 for further details.

(5) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25 for further details.

Over the past eight quarters, the Company's sales have experienced fluctuations driven by variations in production levels, movements in Brent oil benchmark prices, the timing of cargo shipments, and changes in crude oil price differentials. Since 2024, production has been increased mainly due to: (i) an increase in heavy crude oil production, driven by successful development drilling campaigns in the Quifa, CPE-6, and Sabanero blocks, the new water-handling facilities in the CPE-6 block, the reactivation of wells in the Sabanero block, and increased processing capacity at SAARA, (ii) Natural gas liquids production fluctuated due to natural decline and increased in the last two quarters as a result of facility development in the VIM-1 block; and (iii) increased in conventional natural gas production during the last two quarters primarily from the VIM-1 block, as a result of the development of facilities for surface gas compression and handling systems. These increases were partially offset by a decrease in light and medium crude oil combined production mainly due to natural decline.

Production costs (excluding energy costs) fluctuated, with reduction in the last two quarters primarily due to new field production technologies and continuous optimization cost reduction in O&M contracts and digital process implementation partially offset by inflationary pressures on services, wage indexation, well services and maintenance activities.Transportation costs have also fluctuated mainly due to the regular annual increase in transportation tariffs, as well as changes in barrels produced and transported, and occasional changes in wellhead sales. In addition, energy costs fluctuated in line with market prices and increase in heavy oil production.

Trends in the Company's net income (loss) from continuing operations, attributable to equity holders of the Company, are primarily impacted by the recognition and derecognition of deferred income taxes, the recognition of impairment charges related to oil and gas and exploration and evaluation assets, DD&A, foreign exchange gains or losses, and gains or losses from risk management contracts, which fluctuate mainly with changes in hedging strategies, crude oil benchmark forward prices and appreciation or devaluation of the COP against the USD. 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.

### Infrastructure Colombia

Frontera has investments in certain infrastructure, midstream, and other assets, including storage facilities, a port, a reverse osmosis water treatment facility, a palm oil plantation, other facilities in Colombia, and the Company's investment in pipelines (together referred to as the "**Infrastructure Colombia Segment**").

The Company's Infrastructure Colombia Segment includes the following:

| Asset | Description | Interest [1] | Accounting Method |
|---|---|---|---|
| Puerto Bahia | Bulk liquids storage and import-export terminal, and bidirectional hydrocarbon flow line connecting port facility and the Cartagena refinery. | 99.97% interest in Puerto Bahia | Consolidation |
| ODL Pipeline | Crude oil pipeline with capacity of 300,000 bbl/d | 100% interest in FPI (formerly PIL) (which holds a 35% interest in the ODL Pipeline) | Equity method [2] |
| SAARA [3] | Reverse osmosis water treatment facility with nameplate capacity of 1,000,000 bwpd | 100% interest in Agro Cascada | Consolidation |
| ProAgrollanos | Palm oil plantation with production capacity 20,000-27,000 tons per year of fresh fruit bunches | 100% interest in ProAgrollanos | Consolidation |

[1] Interests include both direct and indirect holdings.

[2] Equity method accounting requires that the carrying value of the investment be increased to reflect the Company's proportionate share of net income, or reduced to reflect its share of net losses and dividends declared.

[3] SAARA is a project implemented by Agro Cascada S.A.S. ("**Agro Cascada**").

## Performance Highlights

| | | Q3 2025 | Q2 2025 | Q3 2024 | Nine months ended September 30 2025 | Nine months ended September 30 2024 |
|---|---|---|---|---|---|---|
| **Operational and IFRS Results** | | | | | | |
| Volumes pumped at oil pipeline facility | (bbl/d) | 241,958 | 235,804 | 243,997 | 238,070 | 246,403 |
| Volume throughput at port liquids facility | (bbl/d) | 39,560 | 53,280 | 46,964 | 48,096 | 54,015 |
| Volumes handled at RORO port general cargo facility | (Units) | 36,303 | 28,283 | 20,914 | 82,809 | 52,749 |
| Break Bulk Volumes at port | (Tons/m3) | 9,426 | 7,538 | 15,067 | 58,162 | 34,804 |
| Volumes of water received in SAARA from production fields | (bwpd) | 156,767 | 119,409 | 49,589 | 119,495 | 32,505 |
| Production of fresh fruit bunches | (Tons) | 6,214 | 7,039 | 5,184 | 20,937 | 19,174 |
| Infrastructure Colombia segment income | ($M) | 15,544 | 14,278 | 13,122 | 45,118 | 40,294 |
| Infrastructure Colombia segment cash flow from operating activities | ($M) | 22,062 | 1,594 | 12,679 | 49,236 | 43,244 |
| **Non IFRS Results [1]** | | | | | | |
| Adjusted Infrastructure Revenues | ($M) | 49,172 | 44,969 | 42,152 | 139,053 | 126,114 |
| Adjusted Infrastructure EBITDA | ($M) | 30,444 | 27,057 | 26,181 | 86,104 | 79,691 |
| Adjusted Infrastructure Cash | ($M) | 67,811 | 43,346 | 75,625 | 67,811 | 75,625 |
| Adjusted Infrastructure Debt | ($M) | 223,216 | 224,262 | 123,902 | 223,216 | 123,902 |
| Capital Expenditures Infrastructure Colombia Segment | ($M) | 5,344 | 4,834 | 13,860 | 12,878 | 21,883 |

[1] Non-IFRS financial measures (equivalent to "non-GAAP financial measures", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 25 for further details.

## Infrastructure Colombia Segment Results

The Interim Financial Statements include the following amounts related to the Infrastructure Colombia Segment:

| ($M) | Three months ended September 30 2025 | Three months ended September 30 2024 | Nine months ended September 30 2025 | Nine months ended September 30 2024 |
|---|---|---|---|---|
| Revenue | 15,647 | 11,247 | 42,990 | 34,669 |
| Costs | (11,244) | (7,592) | (30,667) | (23,339) |
| General and administrative expenses | (1,429) | (1,528) | (4,116) | (4,396) |
| Depletion, depreciation and amortization | (2,815) | (1,921) | (6,941) | (5,699) |
| Other operating costs | (472) | (495) | (1,238) | (1,653) |
| **Infrastructure Colombia (loss) income from operations** | **(313)** | **(289)** | **28** | **(418)** |
| Share of income from associates - ODL | 15,857 | 13,411 | 45,090 | 40,712 |
| **Infrastructure Colombia segment income** | **15,544** | **13,122** | **45,118** | **40,294** |
| Infrastructure Colombia segment cash flow from operating activities | 22,062 | 12,679 | 49,236 | 43,246 |
| Capital Expenditures Infrastructure Colombia Segment [1] | 5,344 | 13,860 | 12,878 | 21,883 |

[1] Non-IFRS financial measures (equivalent to a "non-GAAP financial measures", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 25 for further details.

The Company's Infrastructure Colombia Segment income for the three months ended September 30, 2025, increased by 18%, compared with the same period of 2024. For the nine months ended September 30, 2025, the Company's Infrastructure Colombia Segment increased $4.8 million, compared to the same period of 2024, mainly due to a higher share of income from ODL, primarily driven by higher revenues resulting from a 7.8% increase in pipeline transportation tariffs implemented in September 2024, and higher general cargo revenue at Puerto Bahia's port, partially offset by higher operating costs.

Segment capital expenditures for the three and nine months ended September 30, 2025, were $5.3 million and $12.9 million, respectively, compared with $13.9 million and $21.9 million, respectively, for the same periods of 2024. During the third quarter of 2025, investments totaling $4.8 million were made in Puerto Bahia, including: (i) $4.6 million towards the connection project between Puerto Bahia's port facility and the Cartagena refinery, (ii) tank maintenance, and (iii) general cargo terminal facilities.

The third quarter also includes investment in the SAARA project and palm oil plantation. During the same periods of 2024, capital expenditures included SAARA project and Puerto Bahia investments.

### ODL Pipeline

The Company, through its 100%-owned subsidiary FPI (formerly PIL), has a 35% equity investment in the ODL pipeline, which connects Rubiales, Quifa, Caño Sur, Llanos-34, and other blocks to the Monterrey and Cusiana Stations in the department of Casanare.

For the three and nine months ended September 30, 2025, ODL generated an EBITDA of $78.5 million and $222.6 million, respectively, and net income of $45.3 million and $128.8 million, respectively. The ODL results are consolidated through the equity method in the Interim Financial Statements as “Share of income from associates”.

The income statement and key balance sheet information for 100% of ODL is as follows:

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Revenue | 95,786 | 88,301 | 274,466 | 261,272 |
| FEC revenue (billed units) | 8,310 | 7,061 | 23,064 | 22,035 |
| Third party revenues | 87,476 | 81,240 | 251,402 | 239,237 |
| Costs | (13,017) | (13,782) | (37,931) | (37,750) |
| General administrative expenses | (4,284) | (5,792) | (13,974) | (15,643) |
| Depletion, depreciation and amortization | (8,268) | (8,152) | (22,316) | (24,011) |
| Other non-operating expense | (933) | (1,626) | (3,060) | (4,913) |
| Income tax | (23,981) | (20,632) | (68,358) | (62,634) |
| **ODL Net Income** | **45,303** | **38,317** | **128,827** | **116,321** |

| **($M)** | **September 30 2025** | **December 31 2024** |
|---|---|---|
| ODL debt | 39,106 | 36,954 |
| ODL cash and cash equivalents | 50,089 | 76,979 |

The following table shows the volumes pumped per injection point:

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **(bbl/d)** | **2025** | **2024** | **2025** | **2024** |
| At Rubiales Station | 131,536 | 172,745 | 145,752 | 170,768 |
| At Caño Sur Station | 50,484 | — | 31,743 | — |
| At Jagüey and Palmeras Stations | 59,938 | 71,252 | 60,575 | 75,634 |
| **Total** | **241,958** | **243,997** | **238,070** | **246,402** |

The following table shows the volumes received per block:

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **(bbl/d)** | **2025** | **2024** | **2025** | **2024** |
| Rubiales | 94,768 | 106,821 | 96,326 | 103,529 |
| Caño Sur | 50,736 | 29,561 | 43,830 | 28,963 |
| Quifa | 30,228 | 28,521 | 29,576 | 28,939 |
| CPE-6 and Sabanero | 1,383 | 1,508 | 1,112 | 2,709 |
| Other blocks | 60,172 | 61,296 | 60,818 | 67,212 |
| **Total** | **237,287** | **227,707** | **231,662** | **231,352** |

For the three and nine months ended September 30, 2025, the Company recognized $15.9 million and $45.1 million, respectively, as its share of income from ODL, which was higher than the same periods of 2024 by $2.4 million and $4.4 million respectively. This result was driven by higher revenues, primarily due to a 7.8% increase in pipeline transportation tariffs implemented in September 2024, partially offset by lower volumes pumped. For third quarter 2025 received volume increase, led by additional production associated with Ecopetrol’s Caño Sur block.

During the three and nine months ended September 30, 2025, ODL declared net dividends to FPI of $4.4 million and $57.3 million, respectively (2024: $Nil and $54.9 million respectively), and a return of capital of $Nil and $Nil, respectively (2024: $Nil and $7.9 million, respectively). During the three and nine months ended September 30, 2025, FPI received cash of

$18.5 million and $44.7 million, respectively, in dividends from ODL (2024: $12.2 million and $43.5 million, respectively in dividends and return of capital from ODL). On October 16, 2025, the Company received $8.4 million cash dividends payment from ODL, the remaining declared amount is expected to be received during the fourth quarter of 2025.

### 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 in the Cartagena Bay. It is strategically located near the Cartagena refinery operated by Reficar. The port facility has a total area of 150 hectares. Puerto Bahia's income from operations is mainly generated from service contracts in the liquids terminal, which has a nominal capacity of 2,672,000 barrels, and from roll-on/roll-off (RORO) and break bulk services in the general cargo terminal.

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Revenue | 11,961 | 9,712 | 32,992 | 30,660 |
| Liquids port facility | 5,791 | 6,577 | 18,959 | 21,699 |
| FEC liquids port facility | 1,412 | 1,800 | 3,563 | 5,820 |
| Third party liquids port facility | 4,379 | 4,777 | 15,396 | 15,879 |
| General cargo | 6,170 | 3,135 | 14,033 | 8,961 |
| Costs | (6,999) | (4,797) | (18,104) | (16,470) |
| General and administrative expenses | (1,252) | (1,363) | (3,663) | (4,037) |
| Depletion, depreciation and amortization | (1,725) | (1,743) | (5,151) | (5,147) |
| Other operating costs | (472) | (495) | (1,238) | (1,653) |
| **Puerto Bahia Operating Income** | 1,513 | 1,314 | 4,836 | 3,353 |
| **Puerto Bahia EBITDA** | **3,710** | **3,552** | **11,225** | **10,153** |

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

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **(bbl/d)** | **2025** | **2024** | **2025** | **2024** |
| FEC volumes | 10,286 | 12,459 | 9,870 | 14,147 |
| Third party volumes | 29,274 | 34,505 | 28,361 | 39,868 |
| **Total** | **39,560** | **46,964** | **38,231** | **54,015** |

The following table shows the RORO units, their dwell times, and the break bulk volumes, for the general cargo port facility at Puerto Bahia:

| | | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|---|
| | | **2025** | **2024** | **2025** | **2024** |
| RORO | Units [(1)] | 36,303 | 20,914 | 82,809 | 52,749 |
| | Dwell time in days [(2)] | 27 | 47 | 30 | 48 |
| Containers | TEUs [(3)] | 6,205 | — | 11,454 | 306 |
| Break Bulk Volumes | Tons/$m^3$ [(4)] | 9,426 | 15,067 | 58,162 | 34,804 |

[(1)] Wheeled cargo, primarily cars imported to Colombia.

[(2)] Dwell time refers to the time spent by the units within the general cargo port facility. The variance in dwell time associated with Break Bulk Volumes could depend on the characteristics of the cargo, especially in situations where the cargo is received and dispatched within a single day.

[(3)] Twenty-foot Equivalent Unit.

[(4)] Other types of cargo other than wheeled cargo and containers.

For the three and nine months ended September 30, 2025, Puerto Bahia had an operating income of $1.5 million and $4.8 million, respectively (2024: $1.3 million and $3.4 million, respectively). For the three and nine months ended September 30, 2025, Puerto Bahia's general cargo revenues increased by 97% and 57%, respectively, mainly due to a strong performance from general cargo operations, which saw strong growth in container volumes, that surpassed 3,000 TEUs in September 2025 and higher volumes handled, particularly livestock during the first quarter of 2025. In contrast, revenues from the liquids terminal declined compared with the same periods in 2024, mainly due to lower volumes associated to a third-party trader's exit from the country. The Company is actively seeking to replace the lost volumes.

Frontera together with its partner GASCO, announced that the partners had reached a final investment decision on its planned LPG project. The initial phase of the project is being fast-tracked and expected to be operational in the first half of 2026 supporting the challenges in Colombia's domestic LPG market. The LPG project will generate between $10 and $15 million in yearly project EBITDA once it reaches its target capacity. The Company continues to pursue strategic investment opportunities to maximize the port's infrastructure and drive long-term value creation.

The Reficar connection's construction was completed, and the Port's efforts have shifted to working together with Ecopetrol to start utilizing the connection establish Puerto Bahia as a strategic partner for the Reficar Refinery.

### Water Treatment Facility and Palm Oil Plantation

In 2021, Frontera launched a feasibility analysis of the agricultural water reuse system SAARA, which of a reverse osmosis water treatment facility built in 2016 that the Company began recommissioning in 2023. The plant makes use of the availability of production water from the Quifa and Rubiales blocks. It was designed to remove salts from the treated water to make it suitable for irrigating industrial crops.

Through its wholly-owned subsidiary ProAgrollanos, the Company operates a palm oil business located in the municipality of Puerto Gaitan, in the department of Meta, Colombia. With approximately 2,900 hectares currently planted, its oil palm plantation yielded 27,120 tons of fresh fruit bunches in the last 12 months. These crops have an estimated productive lifespan of 30 years.

Most of the water treated by SAARA is reused in agricultural activities carried out by ProAgrollanos with the aim of improving palm crop productivity over the next 24 months. For the nine months ended September 30, 2025, SAARA processed approximately 32 million barrels of water, that irrigated approximately 800 hectares of palm oil crops in ProAgrollanos.

The income statement and key balance sheet information from SAARA and ProAgrollanos, are as follows:

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** | **2025** | **2024** | **2025** | **2024** |
| Revenue | 3,686 | 1,535 | 9,998 | 4,009 |
| Fresh fruit bunches for palm oil | 1,293 | 896 | 4,411 | 3,170 |
| SAARA | 2,393 | 639 | 5,587 | 839 |
| Costs | (4,245) | (2,795) | (12,563) | (6,869) |
| Fresh fruit bunches for palm oil | (1,099) | (1,105) | (3,456) | (2,864) |
| SAARA | (3,146) | (1,690) | (9,107) | (4,005) |
| General and administrative expenses | (177) | (165) | (453) | (359) |
| Depletion, depreciation and amortization | (1,090) | (178) | (1,790) | (552) |
| **SAARA and palm oil plantation operating loss** | **(1,826)** | **(1,603)** | **(4,808)** | **(3,771)** |

The following table shows the key performance measures from SAARA and ProAgrollanos:

| | | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|---|
| **($M)** | | **2025** | **2024** | **2025** | **2024** |
| Fresh fruit bunches for palm oil (produced - sold) | (Tons) | 6,214 | 5,184 | 20,937 | 19,174 |
| Production per hectare per year [(1)] | (Tons/ha/year) | 9.35 | 7.71 | 9.35 | 7.71 |
| Palm oil fruit price | ($/Ton) | 198 | 172 | 200 | 165 |
| Volumes of reverse osmosis water treated | (bwpd) | 156,767 | 49,589 | 119,495 | 32,505 |
| Volumes of water irrigated for palm oil cultivation [(2)] | (bwpd) | 150,125 | 44,585 | 117,106 | 27,594 |

[(1)] Tons per hectare per year for the three months ended September 30, are calculated using the total production for the last 12 months ended September 30.
[(2)] Differences between the water received and water irrigated are due to the water undergoing treatment or being temporarily stored within the plant's facilities.

For the three and nine months ended September 30, 2025, sales from fresh fruit bunches of oil palm totaled $1.3 million and $4.4 million, respectively, (2024: $0.9 million and $3.2 million, respectively). For the three and nine months ended September 30, 2025, sales from fresh fruit bunches increased by 44% and 39%, respectively, mainly due to higher fresh fruit bunches available for palm oil production and market prices. Fluctuations in fruit production volumes are part of normal crop production cycles, as well as the result of other factors, including climate conditions, workforce availability, community blockades near the crop area, and agricultural practices (e.g. fertilization).

During the three and nine months ended September 30, 2025, the volumes of water received and used to irrigate palm oil plantations were higher, compared with the same periods of 2024, mainly due to the temporary suspension of plant operations following the conclusion of the project's pilot program on January 31, 2024. Operations resumed in June 2024 after the signing of an agreement with Ecopetrol to start the first phase of the SAARA project.

For the three months ended September 30, 2025, volumes reached an average of 156,767 bwpd for the quarter, The Company achieved maximum throughput capacity of 230,000 bwpd of water, gaining momentum towards its goal of 250,000 bwpd.

Agro Cascada, a wholly owned subsidiary of the Company, borrowed COP$41,927 million (approximately $9.5 million) from Citibank Colombia under a one-year facility pursuant to the Agro Cascada Working Capital Loan (as defined below) to support development of the Company's water treatment facilities. Subsequently to the end of the quarter, the Company fully repaid the loan. Please refer to Liquidity and Capital Resources section on page 32.

## 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 the Company's 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 from Continuing Operations **

EBITDA is a commonly used non-IFRS financial measure that adjusts net income (loss) as reported under IFRS to exclude the effects of income taxes, finance income and expenses, and DD&A. Operating EBITDA from continuing operations 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, trunkline costs, temporal taxes, payments of minimum work commitments and, certain non-cash items (such as impairments, foreign exchange, unrealized risk management contracts, share-based compensation and debt extinguishment cost) and gains or losses arising from the disposal of capital assets. In addition, other unusual or non-recurring items are excluded from operating EBITDA from continuing operations, as they are not indicative of the underlying core operating performance of the Company.

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

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| ($M) | 2025 | 2024 | 2025 | 2024 |
| Net income (loss) for the period from continuing operations [1] | 28,235 | 16,923 | (357,007) | 1,857 |
| Finance income | (1,745) | (3,123) | (5,285) | (6,512) |
| Finance expenses | 18,899 | 17,570 | 52,445 | 51,779 |
| Income tax (recovery) expense | (20,600) | 6,329 | (44,079) | 63,730 |
| Depletion, depreciation and amortization | 75,472 | 65,581 | 200,304 | 192,054 |
| Colombian temporary taxes [2] | 2,392 | — | 5,250 | — |
| Expense of asset retirement obligation | 3,283 | 5,546 | 3,809 | 4,549 |
| Impairment expense | 9,706 | 361 | 442,733 | 1,780 |
| Trunkline costs [3] | — | 3,829 | 2,000 | 3,829 |
| Post-termination obligation | 2,708 | (314) | 2,599 | (128) |
| Share-based compensation | (779) | (143) | 1,683 | 858 |
| Restructuring, severance and other costs | 8,278 | 361 | 18,805 | 3,216 |
| Share of income from associates | (15,857) | (13,411) | (45,090) | (40,712) |
| Foreign exchange (income) loss | (2,076) | 631 | (1,762) | 9,246 |
| Other (income) loss | (12,013) | 4,203 | (13,367) | 7,368 |
| Unrealized loss (gain) on risk management contracts | 3,130 | (7,644) | (5,212) | 3,941 |
| Realized gain on risk management contract for ODL dividends received | 1,221 | 288 | 1,221 | 288 |
| Non-controlling interests | (13,669) | (201) | (13,964) | (644) |
| Gain on repurchase of senior unsecured notes net of consent solicitation | — | (292) | (11,925) | (1,001) |
| Debt extinguishment cost | — | — | 5,964 | — |
| **Operating EBITDA from continuing operations** | **86,585** | **96,494** | **239,122** | **295,498** |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.
[1] Refers to net income (loss) attributable to equity holders of the Company.
[2] These temporary taxes include a 1% contribution on the export of hydrocarbons in Colombia (Catatumbo Tax) resulting from the state of internal commotion declared by the Government of Colombia.
[3] Other cost related to external road maintenance expenses associated with damage caused by the heavy rainy season of $0.3 million and $0.8 million, for the three and nine months ended September 30, 2025, respectively, were not included.

### *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 September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| **Consolidated Statements of Cash Flows** | | | | |
| Additions to oil and gas properties, infrastructure port, and plant and equipment | 48,031 | 83,258 | 151,090 | 218,685 |
| Additions to exploration and evaluation assets | 1,154 | 1,301 | 3,677 | 10,278 |
| **Total additions in Consolidated Statements of Cash Flows** | **49,185** | **84,559** | **154,767** | **228,963** |
| Non-cash adjustments [1] | 1,674 | (7,206) | 1,222 | (20,342) |
| Cash adjustments [2] | — | (2,481) | (43) | (2,481) |
| **Total Capital Expenditures from Continuing Operations** | **50,859** | **74,872** | **155,946** | **206,140** |
| Capital Expenditures attributable to Infrastructure Colombia Segment | 5,344 | 13,860 | 12,878 | 21,883 |
| Capital Expenditures attributable to other segments different to Infrastructure Colombia Segment | 45,515 | 61,012 | 143,068 | 184,257 |
| **Total Capital Expenditure from Continuing Operations** | **50,859** | **74,872** | **155,946** | **206,140** |

[1] Related to material consumption movements, capitalized non-cash items and other adjustments.
[2] Investments related to the replacement and repairs of the affected assets in the Quifa Block due to unexpected failures in a trunkline.

*Adjusted Infrastructure Colombia Calculations*

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

A reconciliation of each of Adjusted Infrastructure Revenue, Adjusted Infrastructure Operating Costs and Adjusted Infrastructure General and Administrative is provided below.

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| **($M)** [(1)] | **2025** | **2024** | **2025** | **2024** |
| Revenue Infrastructure Colombia Segment | 15,647 | 11,247 | 42,990 | 34,669 |
| Revenue from ODL | 95,786 | 88,301 | 274,466 | 261,272 |
| Direct participation interest in the ODL | 35 % | 35 % | 35 % | 35 % |
| Equity adjustment participation of ODL [(1)] | 33,525 | 30,905 | 96,063 | 91,445 |
| **Adjusted Infrastructure Revenues** | **49,172** | **42,152** | **139,053** | **126,114** |
| Operating cost Infrastructure Colombia Segment | (11,244) | (7,592) | (30,667) | (23,339) |
| Operating Cost from ODL | (13,017) | (13,782) | (37,931) | (37,750) |
| Direct participation interest in the ODL | 35 % | 35 % | 35 % | 35 % |
| Equity adjustment participation of ODL [(1)] | (4,556) | (4,824) | (13,276) | (13,213) |
| **Adjusted Infrastructure Operating Costs** | **(15,800)** | **(12,416)** | **(43,943)** | **(36,552)** |
| General and administrative Infrastructure Colombia Segment | (1,429) | (1,528) | (4,116) | (4,396) |
| General and administrative from ODL | (4,284) | (5,792) | (13,974) | (15,643) |
| Direct participation interest in the ODL | 35 % | 35 % | 35 % | 35 % |
| Equity adjustment participation of ODL [(1)] | (1,499) | (2,027) | (4,890) | (5,475) |
| **Adjusted Infrastructure General and Administrative** | **(2,928)** | **(3,555)** | **(9,006)** | **(9,871)** |

[(1)] Revenues and expenses related to ODL are accounted for using the equity method, as described in Note 12 of the Interim Financial Statements.

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

A reconciliation of each of Adjusted Infrastructure Cash and Adjusted Infrastructure Debt is provided below.

| ($M) [(1)] | September 30 2025 | December 31 2024 |
|---|---|---|
| Cash and cash equivalents - unrestricted | 158,614 | 192,577 |
| Cash and cash equivalents of Non-Infrastructure Colombia Segment | (108,334) | (147,097) |
| Total Cash Infrastructure Colombia Segment | 50,280 | 45,480 |
| Cash and cash equivalent from ODL | 50,089 | 76,979 |
| Direct participating interest in the ODL | 35 % | 35 % |
| Equity adjustment participation of ODL [(1)] | 17,531 | 26,943 |
| **Adjusted Infrastructure Cash** | **67,811** | **72,423** |
| Short-Term and Long-Term Debt | 520,063 | 493,764 |
| Debt of Non-Infrastructure Colombia Segment | (310,534) | (389,803) |
| Total Loans of Infrastructure Colombia Segment | 209,529 | 103,961 |
| Debt from ODL | 39,106 | 36,954 |
| Direct participating interest in the ODL | 35 % | 35 % |
| Equity adjustment participation of ODL [(1)] | 13,687 | 12,934 |
| **Adjusted Infrastructure Debt** | **223,216** | **116,895** |

(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 Infrastructure EBITDA*

The Adjusted Infrastructure EBITDA is a non-IFRS financial measure used to assist in measuring the operating results of the Infrastructure Colombia Segment business, including ODL's EBITDA direct participation interest.

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| ($M) | 2025 | 2024 | 2025 | 2024 |
| Adjusted Infrastructure Revenue | 49,172 | 42,152 | 139,053 | 126,114 |
| Adjusted Infrastructure Operating Costs | (15,800) | (12,416) | (43,943) | (36,552) |
| Adjusted Infrastructure General and Administrative | (2,928) | (3,555) | (9,006) | (9,871) |
| **Adjusted Infrastructure EBITDA** | **30,444** | **26,181** | **86,104** | **79,691** |

### *Net Sales*

Net sales from continuing operations is a non-IFRS financial measure that adjusts revenue to include realized gains and losses from oil risk management contracts while removing 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 oil risk management activities. The deduction of cost of diluent and oil purchased is helpful to understand the Company's sales from continuing operations performance based on the net realized proceeds from its own production, 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 11.

### *Operating Netback from Continuing Operations*

Operating netback from continuing operations is a non-IFRS financial measure and operating netback from continuing operations per boe is a non-IFRS ratio. Operating netback from continuing operations per boe is used to assess the net margin of the Company's production Colombia 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 results of the Infrastructure Colombia Segment from the per barrel metrics and adds the effects attributable to transportation and operating costs of any realized gain or loss on foreign exchange risk management contracts. Refer to the reconciliation in the "Operating Netback from continuing operations" section on page 9.

### *Oil and Gas Sales, Net of Purchases, from Continuing Operations **

Oil and gas sales from continuing operations, net of purchases, is a non IFRS financial measure that is calculated using oil and gas sales less the purchased crude net margin. Produced crude oil and gas sales from continuing operations per boe and Oil and gas sales from continuing operations, net of purchases per boe, are a non IFRS ratio that are calculated using Produced crude oil and gas sales per boe, and the 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 September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | **2025** | **2024** | **2025** | **2024** |
| Produced crude oil and products sales ($M) (1) | 202,667 | 213,798 | 580,810 | 635,041 |
| Purchased crude net margin ($M) (2)(3) | (8,514) | (10,781) | (30,304) | (26,566) |
| **Oil and gas sales, net of purchases ($M) (2)** | **194,153** | **203,017** | **550,506** | **608,475** |
| Sales volumes, net of purchases - (boe) | 3,146,860 | 3,005,640 | 8,884,239 | 8,453,174 |
| Produced crude oil and gas sales ($/boe) | 64.40 | 71.13 | 65.37 | 75.12 |
| Oil and gas sales, net of purchases ($/boe) (2) | 61.70 | 67.54 | 61.96 | 71.98 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

(1) Excludes sales from infrastructure services, as they are not part of the oil and gas segment. Refer to the "Infrastructure Colombia" section on page 20 for further details.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(3) Purchased crude net margin is a non-IFRS financial measure calculated using purchased crude oil and product sales, less the cost of those volumes purchased from third parties including transportation and refining costs. Please see the calculation below.

## 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 September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | **2025** | **2024** | **2025** | **2024** |
| Oil and gas sales, net of purchases ($M) (1)(2) | 194,153 | 203,017 | 550,506 | 608,475 |
| Crude oil sales volumes, net of purchases - (bbl) | 3,073,301 | 2,955,899 | 8,733,579 | 8,286,708 |
| Conventional natural gas sales volumes - (mcf) | 419,241 | 283,837 | 859,626 | 948,850 |
| Realized oil price, net of purchases ($/bbl) (2) | 61.95 | 68.03 | 62.31 | 72.71 |
| Realized conventional natural gas price ($/mcf) | 8.98 | 6.77 | 7.35 | 6.27 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

(1) Non-IFRS financial measure.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

### *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 oil risk management contracts and less royalties). 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 September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | **2025** | **2024** | **2025** | **2024** |
| Oil and gas sales, net of purchases ($M) (1)(2) | 194,153 | 203,017 | 550,506 | 608,475 |
| Loss (gain) on oil price risk management contracts, net ($M) (3) | (3,784) | (1,425) | (7,494) | (8,710) |
| (-) Royalties ($M) | (2,454) | (2,412) | (7,207) | (12,105) |
| Net sales ($M) | 187,915 | 199,180 | 535,805 | 587,660 |
| Sales volumes, net of purchases - (boe) | 3,146,860 | 3,005,640 | 8,884,239 | 8,453,174 |
| Oil and gas sales, net of purchases ($/boe) (2) | 61.70 | 67.54 | 61.96 | 71.98 |
| Premiums received (paid) on oil price risk management contracts (3)(4) | (1.20) | (0.47) | (0.84) | (1.03) |
| Royalties ($/boe) (4) | (0.78) | (0.80) | (0.81) | (1.43) |
| **Net sales realized price ($/boe) (2)** | 59.72 | 66.27 | 60.31 | 69.52 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page17 for further details.

(1) Non-IFRS financial measure.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(3) Includes the net amount of put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Refer to the “Gain (Loss) on Risk Management Contracts” section on page 15 for further details.

(4) Supplementary financial measure.

### *Purchased crude net margin **

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

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | **2025** | **2024** | **2025** | **2024** |
| Purchased crude oil and products sales ($M) | 44,372 | 47,963 | 150,874 | 148,283 |
| (-) Cost of diluent and oil purchased ($M) (1) | (52,250) | (57,557) | (179,719) | (170,569) |
| Puerto Bahía inter-segment costs (2) | (636) | (1,187) | (1,459) | (4,280) |
| **Purchased crude net margin ($M) (2)** | **(8,514)** | **(10,781)** | **(30,304)** | **(26,566)** |
| Sales volumes, net of purchases - (boe) | 3,146,860 | 3,005,640 | 8,884,239 | 8,453,174 |
| **Purchased crude net margin ($/boe) (2)** | **(2.70)** | **(3.59)** | **(3.41)** | **(3.14)** |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page 17 for further details.

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

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

### *Production costs (excluding energy costs), net of realized FX hedge impact, and production cost (excluding energy costs), net of realized FX hedge impact per boe **

Production costs (excluding energy costs), net of realized FX hedge impact is a non-IFRS financial measure that mainly includes lifting costs, activities developed in the blocks, processes to put the crude oil and gas in sales condition and the realized gain or loss on foreign exchange risk management contracts attributable to production costs. Production cost, net of realized FX hedge impact per boe is a non-IFRS ratio that is calculated using production cost (excluding energy costs), net of realized FX hedge impact divided by production (before royalties).

A reconciliation of this calculation is provided below:

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| **Production costs (excluding energy costs) ($M)** | 29,831 | 31,007 | 94,803 | 107,066 |
| (-) Realized (gain) loss on FX hedge attributable to production costs (excluding energy costs) ($M) [(1)] | (1,205) | 182 | (1,248) | (3,358) |
| SAARA inter-segment costs | 1,675 | 587 | 3,911 | 587 |
| **Production costs (excluding energy costs), net of realized FX hedge impact ($M) [(2)]** | 30,301 | 31,776 | 97,466 | 104,295 |
| Production Colombia (boe) | 3,581,928 | 3,573,280 | 10,712,520 | 10,395,834 |
| **Production costs (excluding energy costs), net of realized FX hedge impact ($/boe)** | 8.46 | 8.89 | 9.10 | 10.03 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

(1) See "Gain (Loss) on Risk Management Contracts" on page 15 for further details.

(2) Non-IFRS financial measure.

### *Energy costs, net of realized FX hedge impact, and production cost, net of realized FX hedge impact per boe **

Energy costs, net of realized FX hedge impact is a non-IFRS financial measure that describes the electricity consumption and the costs of localized energy generation and the realized gain or loss on foreign exchange risk management contracts attributable to energy costs. Energy costs, net of realized FX hedge impact per boe is a non-IFRS ratio that is calculated using energy costs, net of realized FX hedge impact divided by production (before royalties). A reconciliation of this calculation is provided below:

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| **Energy costs ($M)** | 20,589 | 18,664 | 56,951 | 55,183 |
| (-) Realized loss (gain) on FX hedge attributable to energy costs ($M) [(1)] | (689) | 84 | (689) | (1,267) |
| Energy costs, net of realized FX hedge impact ($M) [(2)] | 19,900 | 18,748 | 56,262 | 53,916 |
| Production Colombia (boe) | 3,581,928 | 3,573,280 | 10,712,520 | 10,395,834 |
| **Energy costs, net of realized FX hedge impact ($/boe)** | 5.56 | 5.25 | 5.25 | 5.19 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador.

(1) See "Gain (Loss) on Risk Management Contracts" on page 15 for further details.

(2) Non-IFRS financial measure.

### *Transportation costs, net of realized FX hedge impact, and transportation costs, net of realized FX hedge impact per boe **

Transportation costs, net of realized FX hedge impact is a non-IFRS financial measure, that includes all commercial and logistics costs associated with the sale of produced crude oil and gas such as trucking and pipeline, and the realized gain or loss on foreign exchange risk management contracts attributable to transportation costs. Transportation cost, net of realized FX hedge impact per boe is a non-IFRS ratio that is calculated using transportation cost, net of realized FX hedge impact divided by net production after royalties. A reconciliation of this calculation is provided below:

| | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| **Transportation costs ($M)** | 38,407 | 38,779 | 115,882 | 108,096 |
| (-) Realized (gain) loss on FX hedge attributable to transportation costs ($M) [(1)] | (867) | 61 | (867) | (982) |
| Puerto Bahía inter-segment costs [(2)] | 776 | 613 | 2,104 | 1,514 |
| Transportation costs, net of realized FX hedge impact ($M) [(2)(3)] | 38,316 | 39,453 | 117,119 | 108,628 |
| Net production Colombia (boe) | 3,267,932 | 3,132,784 | 9,739,821 | 9,146,942 |
| **Transportation costs, net of realized FX hedge impact ($/boe) [(2)]** | 11.72 | 12.59 | 12.02 | 11.88 |

* Figures from previous reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 17 for further details.

(1) See "(Loss) Gain on Risk Management Contracts" on page 15 for further details.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to transportation costs.

(3) Non-IFRS financial measure.

### Supplementary Financial Measures

***Realized gain (loss) on oil risk management contracts per boe***

Realized gain (loss) on oil 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 gain (loss) on oil risk management contracts per boe is a supplementary financial measure that is calculated using Realized gain (loss) 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.

***NCIB (as defined below) weighted-average price per share***

Weighted-average price per share under the 2023 NCIB (as defined below) and 2025 NCIB (as defined below) is a supplementary financial measure that corresponds to the weighted-average price of shares purchased under such normal course issuer bids during the periods. 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, comprised of cash and cash equivalents and 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 of the 2028 Unsecured Notes (as defined below), 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, development and infrastructure, including growth plans;
- costs and expenses related to operations, commitments, and existing contingencies;
- debt service requirements related to existing and future debt; and
- shareholder returns through share repurchases and/or dividends payments.

The Company funds its anticipated cash requirements and strategic objectives through 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 are sufficient to meet operational needs and other obligations.

As at September 30, 2025, the Company had a total cash balance of $172.1 million (including $13.4 million in restricted cash), which was $50.8 million lower than cash balances as of December 31, 2024.

For the nine months ended September 30, 2025, the Company generated $227.0 million, of cash from operations, which was used to fund cash outflows of $178.6 million for capital expenditures and other investing activities. During the same period, financing activities generated net outflows of $92.6 million. These included $105.2 million in the full repayment of the PIL Loan

Facility, $66.4 million in repurchases of the 2028 Unsecured Notes, $99.5 million used to repurchase Common Shares under the January 2025 SIB and July 2025 SIB (as defined below), $18.5 million in other financing charges, $14.3 million toward principal payments on the FPI Recapitalization Loan and the Agro Cascada Working Capital Loan, $0.2 million in transaction costs of FPI Recapitalization Loan, $1.0 million used to repurchase Common Shares under the NCIB, $10.4 million in dividends paid to equity holders and $5.5 million in lease payments, partially offset by $212.4 million in net proceeds from the disbursement of the FPI Recapitalization Loan and $16.1 million in the release of the reserve account of the PIL Loan Facility. The Company's net working capital[(1)] was a deficit of $118.9 million as at September 30, 2025, compared to a deficit of $100.6 million as at December 31, 2024.

The Company believes that its net working capital balances, together 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 at September 30, 2025, the main components of restricted cash were long-term abandonment funds, as required by the ANH. Abandonment funds are intended to satisfy abandonment obligations and expected to be released over the long-term as assets are abandoned. Abandonment funding requirements are updated annually. As at September 30, 2025, the Company's restricted cash position was $13.4 million, representing a decrease of $16.8 million from December 31, 2024, primarily due to the cancellation of the reserve account of the PIL Loan Facility.

The measures taken by the Company to manage its liquidity and capital resources are ongoing, and the Company continues to pursue additional opportunities to manage its costs and commitments. Based on the foregoing, including the expected impacts of these measures, the Company expects that unrestricted cash balances together with future cash flows from operations, available credit facilities, and alternative financing arrangements will be sufficient to support its 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 may make additional changes to its business and operations as warranted. See also the "Risks and Uncertainties" section on page 40.

[(1)] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures'' section on page 25 for further details.

### 2028 Unsecured Notes

On June 21, 2021, the Company completed the offering of $400.0 million senior unsecured notes due 2028 ("**2028 Unsecured Notes**"). 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.

On May 9, 2025, the Company announced that it had commenced a cash tender offer (the "**Offer**") for up to $65.0 million in aggregate principal amount of its outstanding 2028 Unsecured Notes and a concurrent consent solicitation (the "**Solicitation**") with respect to certain proposed amendments (the "**Proposed Amendments**") to the indenture governing the 2028 Unsecured Notes (the "**Indenture**"). The Offer and Solicitation were amended on May 26, 2025 to extend the Early Tender Date and Consent Deadline (as defined in the Offer to Purchase and Consent Solicitation Statement dated as of May 9, 2025) to 5:00 p.m., New York City time, on June 9, 2025 (the "**Extended Early Tender Date and Consent Deadline**"). The Offer and Solicitation were further amended on June 2, 2025 to, among other things: (i) increase the maximum tender amount from $65.0 million to $80.0 million; (ii) increase the payment for those consents validly delivered at or prior to the Extended Early Tender Date and Consent Deadline from $15.00 for each $1,000 principal amount of 2028 Unsecured Notes to an aggregate amount of $8 million, to be divided pro rata among all tendering and consenting holders of 2028 Unsecured Notes ("**Holders**") in the Offer and Solicitation in aggregate (the "**Amended Consent Payment**"); and (iii) increase the consideration payment for each $1,000 principal amount of 2028 Unsecured Notes validly tendered at or prior to the Extended Early Tender Date and Consent Deadline, and accepted for purchase pursuant to the Offer, from $700.00 to $720.00. As of the Extended Early Tender Date and Consent Deadline which was also the expiry time of the Offer. The Company received without duplication: (i) validly delivered tenders from Holders representing $134,169,000 in aggregate principal amount 2028 Unsecured Notes and (ii) validly delivered consents from Holders (including consents delivered without tenders) representing $194,448,000 (i.e. 50.38%) in aggregate principal amount of 2028 Unsecured Notes outstanding. Therefore, the Company obtained the requisite consents to the Proposed Amendments under the Indenture and proceeded to execute a supplemental indenture incorporating the Proposed Amendments, paid to consenting Holders the Amended Consent Payment, and repurchased and proceeded to cancel $80.0 million in face value of its 2028 Unsecured Notes. As of the completion of the Offer and Solicitation, the Company has $320.0 million in principal amount of 2028 Unsecured Notes outstanding, including $6.0 million held by the Company.

During the three and nine months ended September 30, 2025, the Company repurchased $Nil and $81.0 million, respectively, of its 2028 Unsecured Notes pursuant to the Offer and Solicitation and in the open market for a cash consideration of $Nil and $58.4 million, respectively. As a result, during the three and nine months ended September 30, 2025, the Company recognized a gain of $Nil and $11.9 million, respectively. These gains are after deducting the Amended Consent Payment of $8.0 million, the proportional deferred financing fees write-offs of $1.0 million, and legal and advisory fees totaling $1.6 million.

The carrying value for the 2028 Unsecured Notes as at September 30, 2025, was $310.5 million (December 31, 2024: $389.8 million).

The purpose of the Offer and the Solicitation was to gain greater financial and operational flexibility while simultaneously reducing the Company's overall debt. Additionally, the Proposed Amendments permitted the Company to take certain actions that were previously restricted under the Indenture. These include, but were not limited to: allowing additional restricted payments (particularly from proceeds of unrestricted subsidiaries); providing greater flexibility in managing working capital to support operational efficiency and financial resilience; increasing the amount of permitted indebtedness and liens; and reducing conditions and requirements that previously limited the Company's ability to pursue strategic transactions aimed at enhancing growth and value.

### 2028 Unsecured Notes Covenants

The 2028 Unsecured Notes are senior, unsecured notes and rank equally in right of payment with all existing and future senior unsecured debt. As at September 30, 2025, the 2028 Unsecured Notes were guaranteed by the Company's subsidiary, Frontera Energy Colombia Corp. On April 11, 2023, the Company designated Frontera Energy Guyana Holding Ltd. and Frontera Guyana as Unrestricted Subsidiaries and released Frontera Guyana as a note guarantor under the Indenture.

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. If 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 greater 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 September 30, 2025, the Company was in compliance with all such covenants.

Pursuant to the requirements under the Indenture, the Company reported consolidated total indebtedness of $357,228,000 as at September 30, 2025, and, for the twelve months ended as of September 30, 2025, a consolidated adjusted EBITDA of $348,731,000 and a consolidated interest expense of $45,904,000 .

(1) Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the Indenture as consolidated total indebtedness as at 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 recently ended period of four consecutive fiscal quarters divided by the consolidated interest expense for such period, as defined in the Indenture.

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

### *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 measures of overall financial strength. Consolidated total indebtedness is defined as long-term debt, plus lease liabilities and the 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 unrestricted cash and cash equivalents. Both measures exclude 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 September 30 2025 |
|---|---|---|
| Short-term and Long-term debt [(1)] | $ | 318,053 |
| Total lease liabilities [(2)] | | 11,284 |
| Customers prepayment [(3)] | | 29,192 |
| Risk management liability net [(4)] | | (1,301) |
| **Consolidated Total Indebtedness** | | **357,228** |
| (-) Cash and Cash Equivalents [(5)] | | (104,588) |
| **(=) Net Debt** | **$** | **252,640** |

(1) Excludes $202.0 million of long-term debt attributable to the Unrestricted Subsidiaries.

(2) Excludes $1.4 million of lease liabilities attributable to the Unrestricted Subsidiaries.

(3) This line includes the customer prepayment relates to one cargo of crude oil to be delivered in the fourth quarter of 2025.

(4) Excludes $0.9 million of net risk management liability attributable to the Unrestricted Subsidiaries.

(5) Includes unrestricted cash and cash equivalents attributable to the guarantors as at September 30, 2025, Frontera Energy Colombia AG and the issuer (i.e., the Company), as defined in the Indenture.

### Frontera Pipeline Investment Loan Facility ("FPI Loan Facility", formerly named PIL Loan Facility) and Frontera Pipeline Investment Recapitalization Loan Facility ("FPI Recapitalization Loan")

On March 27, 2023, FPI entered into a new credit agreement through which lenders provided a $120.0 million loan facility to FPI, secured by substantially all the assets and shares of FPI, Puerto Bahia held by the Company and assets related to Puerto Bahia's liquids terminal. It is guaranteed by Frontera Bahia Holding Ltd. and FEC ODL Holdings Corp. (formerly named Frontera ODL Holding Corp.), the parent company of FPI. The FPI Loan Facility is a five-year credit facility maturing in December 2027, with principal payments made semi-annually. The FPI Loan Facility has two tranches: a $100.0 million amortizing tranche that pays SOFR six-month term plus a margin of 7.25% per annum (with a step down to 6.25% if certain conditions are met) and a $20.0 million bullet maturity tranche that pays a fixed rate of 11.0% per annum. The conditions precedent to the FPI Loan Facility were fully satisfied, and both tranches of the facility were funded on March 31, 2023.

On February 16, 2024, as part of the FPI Loan Facility (Tranche A-2), the Company amended the facility to disburse an accordion tranche of $30.0 million. This tranche secures funding for the connection project between Puerto Bahia's port facility and the Cartagena refinery operated by Refineria de Cartagena S.A.S. On February 23, 2024, August 7, 2024 and December 16, 2024, the lenders disbursed $8.8 million, $10.0 million and $10.0 million, respectively. The accordion tranche was recognized, net of an original issue discount of $1.2 million, primarily related to lender and legal fees, which were discounted at the time of disbursement.

On May 14, 2025, FPI amended and restated its credit agreement through which lenders increased their commitments to $220.0 million. The FPI Recapitalization Loan comprises various tranches, the last of which matures in December 2031, with principal payments made semi-annually. The FPI Recapitalization Loan comprises: a $140.0 million tranche (FPI Recapitalization Loan First Lien - Floating Rate) that pays SOFR six-month term plus a margin of 6% per annum, a $20.0 million tranche (FPI Recapitalization Loan First Lien - Tranche B) that pays a fixed rate of 11% per annum, a $20.0 million tranche (FPI Recapitalization Loan First Lien - Tranche A) that pays a fixed rate of 9.75% per annum and a $40.0 million tranche (FPI Recapitalization Loan Second Lien - Fixed Rate) that pays a fixed rate of 15% per annum.

Apart from extending the term of the $100.8 outstanding amount (for further information, refer to Note 13 of the Interim Condensed Consolidated Financial Statements for the three months ended March 31, 2025), the proceeds of the FPI Recapitalization Loan were used to pay fees and accrued interest. The FPI Recapitalization Loan is guaranteed by FEC ODL Holdings Corp. and is secured exclusively by the cash flows generated from Frontera's interest in ODL, with Puerto Bahia removed from the security package.

As at September 30, 2025, the carrying value of the FPI Loan Facility is $Nil (December 31, 2024: $94.5 million). As at September 30, 2025, the FPI Loan Facility debt service reserve account has a balance of $Nil. (December 31, 2024: $15.9 million). As at September 30, 2025, the carrying value of the FPI Recapitalization Loan is $202.0 million, which includes short-term debt of $41.5 million.

### Agro Cascada Working Capital Loan

On October 10, 2024, the Company entered into a one-year working capital loan agreement with Citibank Colombia S.A., denominated in COP, with a principal amount of COP $41,927 million (equivalent to $9.5 million), maturing on October 10, 2025, with an interest rate of IBR[(1)] plus 2.5%, payable monthly (the "**Agro Cascada Working Capital Loan**"). On October 10, 2024 and November 21, 2024, the lender disbursed COP $29,337 million and COP $12,590 million, respectively. The proceeds of the Agro Cascada Working Capital Loan were intended to support the development of the Company's water treatment facilities, and it is guaranteed by Frontera Energy Colombia Corp., Sucursal Colombia.

The Company prepaid $2.1 million of the Agro Cascada Working Capital Loan during the third quarter. As at September 30, 2025, the carrying value of the Agro Cascada Working Capital Loan was $7.5 million (December 31, 2024: $9.5 million). Subsequent to the end of the quarter, the Company fully repaid the loan on October 10, 2025.

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

### Letters of Credit

The Company has various uncommitted bilateral letters of credit. As at September 30, 2025, the Company had issued letters of credit and guarantees for exploration and abandonment funds totaling $120.4 million (against total credit lines of $172.5 million), without cash collateral.

### CPE-6 Solar Plant Project Leasing Agreement

During the fourth quarter of 2022, the Company executed a leasing agreement with Bancolombia to finance the construction and commissioning of a solar power plant project in the CPE-6 block (the "**Solar Plant Debt**"). The financing is denominated in COP, with an equivalent value of approximately to $6.6 million as at September 30, 2025, and has a maturity date of 72 months from April 3, 2024. The Solar Plant Debt bears interest equivalent to IBR plus 5.75%, payable monthly on the outstanding amount. As at September 30, 2025, the outstanding balance was $5.6 million. The Company recognized this obligation as a lease liability.

### CPE-6 Battery Energy Storage System Leasing Agreement

During the fourth quarter of 2023, the Company executed a leasing agreement with Bancolombia to finance the Battery Energy Storage System at the CPE-6 block (the "**BESS Project**"). The financing is denominated in COP, with an equivalent value of approximately $1.0 million as at September 30, 2025, and has a maturity date of April 9, 2029. The BESS Project leasing bears interest equivalent to IBR plus 5.10%, payable monthly. As at September 30, 2025, the outstanding balance was $0.6 million. The Company recognized this obligation as a lease liability.

### Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at September 30, 2025, undiscounted by calendar year, are presented below:

| As at September 30, 2025 ($M) | 2025 | 2026 | 2027 | 2028 | 2029 | Subsequent to 2030 | Total |
|---|---|---|---|---|---|---|---|
| Short-term and long-term debt principal and interest | 63,547 | 84,981 | 82,816 | 381,037 | 28,465 | 28,441 | 669,287 |
| Lease liabilities | 1,775 | 5,240 | 2,843 | 2,721 | 2,064 | 1,295 | 15,938 |
| **Total financial obligations** | **65,322** | **90,221** | **85,659** | **383,758** | **30,529** | **29,736** | **685,225** |
| **Transportation** | | | | | | | |
| Ocensa P-135 ship-or-pay agreement | 7,675 | — | — | — | — | — | 7,675 |
| Other transportation and processing commitments | 3,662 | 14,560 | 754 | — | — | — | 18,976 |
| **Exploration and evaluation** | | | | | | | |
| Minimum work commitments (1) | — | 15,687 | 6,880 | 5,066 | — | — | 27,633 |
| **Other commitments** | | | | | | | |
| Operating purchases, community obligations and others | 46,000 | 273 | 270 | 268 | 264 | 2,598 | 49,673 |
| Energy supply commitments (2) | 17,362 | 15,590 | 9,898 | 11,572 | 8,249 | 8,496 | 71,167 |
| **Total Commitments** | **74,699** | **46,110** | **17,802** | **16,906** | **8,513** | **11,094** | **175,124** |

(1) The Company has been reducing the value of its exploratory commitments as they are executed. In addition, on August 28, 2025, the Company received a communication from the Agencia Nacional de Hidrocarburos "ANH" confirming the acceptance of the transfer of the investment commitment from Llanos 119 to Vim-46, amounting to $6.8 million. This does not imply any decrease or increase in the minimum exploration commitments.

(2) Includes executed contracts for grid-connected, on-site generation, and solar power sources, ensuring the electricity supply across operational blocks, particularly Quifa and CPE-6.

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

In May 2022, a new ship-or-pay contract with Bicentenario and Cenit became effective, 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 16, 2025, the overall guaranteed amount was reduced to $21.0 million (up to $15.0 million with Ocensa and $6.0 million with Cenit) and the term of the pledge agreement was extended to December 31, 2026, with Ocensa and to January 31, 2027, with Cenit.

## 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.

### Corentyne License

The Joint Venture jointly holds 100% working interest in the Corentyne block, located offshore Guyana. Frontera Guyana and CGX Resources have agreed that their respective participating interests are 72.52% and 27.48%, which includes a 4.52% interest which CGX Resources agreed to assign to Frontera Guyana in 2023. This assignment remains subject to the approval of the Government of Guyana ("**GoG**") but is enforceable between Frontera Guyana and CGX Resources.

On June 26, 2024, the Company and CGX Energy Inc. announced that the Joint Venture submitted a notice of potential commercial interest for the Wei-1 discovery to the GoG, which preserves their interests in the Petroleum Prospecting License ("**PPL**") and the Petroleum Agreement for the Corentyne block. On December 12, 2024, the Company and CGX Energy Inc. announced that the Joint Venture had sent the GoG a letter activating a 60-day period for the parties to the PA to make all reasonable efforts to amicably resolve all disputes via negotiation. On February 11, 2025, the Company and CGX Energy Inc. announced that the Joint Venture received a communication from the GoG in which the Government has taken the position that the PPL has terminated or, alternatively, that the communication served as a 30-day notice of the Government's intention to cancel the PPL, but that the Government invites the Joint Venture to submit representations for the Government to consider in making its final decision as to whether or not to cancel the PPL. On February 24, 2025, CGX Energy Inc. announced that the Joint Venture had provided a response advising the GoG that notwithstanding the Government's contradictory positions, both the PPL and the PA remain valid and in force. On March 13, 2025, the Company and CGX Energy Inc. announced that the Joint Venture received a communication from the GoG indicating that, on the one hand, the Government was of the view that the PPL and PA are at an end but, on the other hand, that the Government was terminating the PA and cancelling the PPL. On March 26, 2025, the Company and its subsidiaries, Frontera Petroleum International Holding B.V. and Frontera Energy Guyana Holding Ltd. (the "**Investors**") delivered a notice of intent to the GoG. In this Notice, the Investors alleged breaches of the United Kingdom–Guyana Bilateral Investment Treaty and the Guyana Investment Act by the GoG. This communication triggered a 90-day consultation and negotiation period intended to resolve the dispute amicably ("**Notice of Intent**"). The parties have been unable to reach a mutual resolution to date.

On July 23, 2025, the GoG, through its legal counsel, responded to the Investors, rejecting their claims regarding the Corentyne block license. The GoG reaffirmed its view that the Joint Venture's interest expired on June 28, 2024, but noted that it may consider a final meeting with the Investors, on a without prejudice basis, in October 2025, and the Joint Venture would be informed as to whether such a meeting will occur in September 2025.

The GoG, through its counsel, communicated its willingness to participate in a final "Without Prejudice" meeting with the Joint Venture to discuss the matters in dispute. The Government proposed November 25 or December 2, 2025, as possible dates for this meeting. The Joint Venture remains open to engaging in good faith discussions with the Government.

The Joint Venture continues to firmly maintain that its interests in, and the license for, the Corentyne block remain valid and in good standing and that the Petroleum Agreement for such block has not been terminated. While the GoG reaffirmed its position that the Joint Venture's interest expired on June 28, 2024, the Joint Venture strongly disagrees and remains committed to asserting its legal rights under applicable treaties and agreements.

The Company evaluated the Corentyne E&E asset's recoverability given the GoG's conduct and communications, and its unwillingness to recognize the joint venture's rights during the consultation periods, which have since expired. Although all contractual requirements of the Company have been met and an external legal assessment determined that the Company's interests in the licenses and agreements for the Corentyne block remain valid, the GoG's positions mentioned above have restricted the Company's ability to develop activities under those licenses and agreements. This situation has led to uncertainty regarding the asset's future development and constituted an impairment indicator under IFRS 6 and IAS 36. Consequently, the Company recognized an impairment of $432.2 million in its income statement during the second quarter of 2025. The Corentyne E&E asset's carrying value as of September 30, 2025 is $Nil (December 31, 2024, $431.9 million).

### High-Price Clause

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

On March 13, 2025, the Company obtained a favorable arbitral award in the Cubiro E&P Contract litigation, confirming its contractual rights under the Cubiro E&P Contract. The Tribunal ruled in the Company's favor, rejecting ANH's actions and recognizing the independence of the Copa and Petirrojo exploitation areas. While the award was favorable to the Company, the arbitral tribunal refrained from ruling on the legality of the administrative acts issued by the ANH. Consequently, both parties have filed annulment appeals against the award, which remain pending adjudication.

## 5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at November 12, 2025:

| | **Number** |
|---|---|
| Common shares | 69,677,149 |
| DSUs [1] | 1,285,139 |
| RSUs [2] | 1,856,749 |

[1] DSUs represent a future right to receive Common Shares (or the cash equivalent) at the time of the holder's retirement, death or other cessation of service to the Company, subject to limited exceptions as agreed to by the holder of the DSU. Each DSU awarded by the Company approximates the fair market value of a Common Share at the time of the award. The value of a DSU increases or decreases as the price of the Common Shares fluctuates, thereby promoting alignment of interests between the DSU holder and shareholders. DSUs are settled in Common Shares, cash, or a combination thereof, as determined by the Compensation and Human Resources Committee of the board of directors of the Company (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, subject to established vesting conditions. RSUs are granted with vesting conditions 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 fluctuates, thereby promoting the alignment of interests between the RSU holder and 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 Bids ("NCIB")

On November 21, 2023, the Company launched an NCIB (the "**2023 NCIB**"), pursuant to which it was permitted to repurchase for cancellation up to 3,949,454 of its Common Shares, representing approximately 10% of the Company's "public float" (as calculated in accordance with TSX rules) as at November 8, 2023, during the 12-month period commencing on November 21, 2023, and ending on November 20, 2024.

Purchases subject to the NCIBs have been or are being 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. The Company repurchased a total of 1,552,100 Common Shares under the 2023 NCIB for approximately $9.5 million prior to its expiration on November 20, 2024.

On July 15, 2025, the Company launched an NCIB (the "**2025 NCIB**"), pursuant to which it was permitted to repurchase for cancellation up to 3,502,962 of its Common Shares, representing approximately 5% of the Company's "public float" (as calculated in accordance with TSX rules) as at July 15, 2025, during the 12-month period commencing July 18, 2025, and ending July 17, 2026.

The average daily trading volume of the Common Shares (as calculated in accordance with the TSX rules) was 48,188 Common Shares over the period between January 1, 2025 and June 30, 2025. Consequently, daily purchases through the facilities of the TSX will be limited to 12,047 Common Shares, other than block purchase exceptions.

As at November 12, 2025, the Company had repurchased for cancellation a total of 385,200 Common Shares under the 2025 NCIB for approximately $1.6 million with an additional 3,117,762 Common Shares remaining available for repurchase under the 2025 NCIB.

### Substantial Issuer Bid

On September 4, 2024, the Company's Board of Directors approved an SIB to repurchase from shareholders up to 3,375,000 Common Shares for cancellation at a purchase price of CAD$12.00 per share, totaling up to CAD$40.5 million (equivalent to $30.0 million) (the "**2024 SIB**"). The bid expired on October 17, 2024.

On October 22, 2024, the Company, in accordance with the terms and conditions of the 2024 SIB, took up and paid for 3,375,000 Common Shares (approximately 4.01% of the total number of Frontera's issued and outstanding Common Shares as at October 17, 2024) at a price of CAD$12.00 per Common Share, with an approximately 92% shareholder participation rate, and representing an aggregate purchase price of approximately CAD$40.5 million. Following the cancellation of the Common Shares repurchased under the 2024 SIB, approximately 80.78 million Common Shares remained issued and outstanding.

On November 6, 2024, the Company announced its intention to commence another SIB to purchase up to $30 million of its Common Shares for cancellation at a fixed price per share.

On December 16, 2024, the Company's Board of Directors approved an SIB to repurchase from shareholders up to 3,500,000 Common Shares for cancellation at a purchase price of CAD$12.00 per share, totaling up to CAD$42.0 million (equivalent to $30.0 million) (the "**January 2025 SIB**"). The January 2025 SIB expired on January 24, 2025.

On January 28, 2025, the Company announced that, in accordance with the terms and conditions of the January 2025 SIB, Frontera had taken up and paid for 3,500,000 Common Shares (approximately 4.33% of the total number of Frontera's issued and outstanding Common Shares as at January 24, 2025) at a price of CAD$12.00 per Common Share, representing an aggregate purchase price of approximately CAD$42.0 million. The January 2025 SIB had over 90% shareholder participation rate. After the cancellation of the Common Shares taken up and paid for by the Company under the January 2025 SIB, approximately 77.29 million Common Shares remained issued and outstanding.

On May 21, 2025, the Company's Board of Directors approved an SIB to repurchase from shareholders up to 7,583,333 Common Shares for cancellation at a purchase price of CAD$12.00 per share, totaling up to CAD$91.0 million (equivalent to $65.0 million) (the "**July 2025 SIB**"). The July 2025 SIB expired on July 10, 2025.

On July 15, 2025, the Company announced that, in accordance with the terms and conditions of the July 2025 SIB, Frontera had taken up and paid for 7,583,333 Common Shares (approximately 9.77% of the total number of Frontera's issued and outstanding Common Shares as at July 10, 2025) at a price of CAD$12.00 per Common Share, representing an aggregate purchase price of approximately CAD $91.0 million. The July 2025 SIB had a 92.6% participation and the tendered Common Shares were purchased on a pro rata basis. After the cancellation of the Common Shares taken up and paid for by the Company under the July 2025 SIB, approximately 70.06 million Common Shares were issued and outstanding.

### Dividends

On March 7, 2024, the Company adopted a dividend policy that included an initial cash dividend of CAD$0.0625 per Common Share. This dividend payment to shareholders was designated as an "eligible dividend" under the Income Tax Act (Canada). The declaration and payment of any specific quarterly dividend remain subject to the discretion of the Company's Board of Directors.

The Company's dividends declared or paid during the nine months ended September 30, 2025, are presented below:

| Declaration Date | Record Date | Payment Date | Dividend (C$/ Share) | Dividends Amount ($M) | Number of DRIP Shares (1) |
|---|---|---|---|---|---|
| March 7, 2024 | April 2, 2024 | April 16, 2024 | 0.0625 | 3,899 | — |
| May 7, 2024 | July 3, 2024 | July 17, 2024 | 0.0625 | 3,858 | 626 |
| August 6, 2024 | October 2, 2024 | October 16, 2024 | 0.0625 | 3,849 | 531 |
| November 6, 2024 | January 3, 2025 | January 17, 2025 | 0.0625 | 3,502 | 1,073 |
| March 10, 2025 | April 7, 2025 | April 16, 2025 | 0.0625 | 3,373 | 1,018 |
| May 9, 2025 | July 8, 2025 | July 17, 2025 | 0.0625 | 3,543 | 808 |
| August 12, 2025 | October 2, 2025 | October 16, 2025 | 0.0625 | 3,115 | 735 |

(1) In connection with the adoption of the dividend policy, the Company adopted a Dividends Reinvestment Program ("DRIP"), which provides shareholders who are resident in Canada with the option to have cash dividends declared on their Common Shares automatically reinvested into additional Common Shares, without brokerage commissions or service charges.

Pursuant to the Company's dividend policy, following the end of the third quarter, the Company's Board of Directors has declared a dividend of CAD$0.0625 per Common Share to be paid on or around January 19, 2026, to shareholders of record at the close of business on January 5, 2026.

## 6. RELATED-PARTY TRANSACTIONS

The following table provide the total balances outstanding, commitments, and transactional amounts with related parties as at September 30, 2025, and December 31, 2024, and for the three and nine months ended September 30, 2025, and 2024, respectively:

| | | September 30, 2025, and December 31, 2024 | | | Three Months Ended September 30 | Nine Months Ended September 30 |
|---|---|---|---|---|---|---|
| ($M) | | Receivables from ODL Investment | Accounts Payable | Commitments | Purchases/Services | |
| ODL | 2025 | 12,914 | 553 | — | 8,310 | 23,064 |
| | 2024 | — | 2,901 | 356 | 7,061 | 22,035 |

As at September 30, 2025, as part of the second lien of FPI Recapitalization Loan, a $5.0 million balance (December 31, 2024: $Nil) was acquired by funds controlled by GDA Luma Capital Management, LP (which itself is controlled by Gabriel de Alba, the Chair of the Board of Directors of Frontera).

## 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 and 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 identifies, evaluates, prioritizes, monitors, and plans for risk across the organization and supports decision-making. This program identifies critical strategic risks related to people, assets, operations, the regulatory environment, health, safety and environment, liquidity, reputation, communities, and the political landscape, and seeks to systematically mitigate these risks to an acceptable level. In addition, the Company continuously monitors its risk profile as well as industry best practices.

During the third quarter of 2025, the board of directors of the Company approved a restructuring plan (the "**Restructuring Plan**"), as part of Frontera's ongoing focus on cost-savings, designed to simplify its corporate structure, through targeted reorganization initiatives that are designed to improve organizational and operational efficiencies, generating between $10 and $15 million expected savings in overhead going forward. The Company may encounter challenges in the execution of these restructuring efforts that could prevent it from recognizing the intended benefits of the Restructuring Plan or otherwise adversely affect its business, results of operations and financial condition. As a result of the Restructuring Plan, the Company has incurred and may continue to incur additional costs in the short-term, including cash expenditures for employee transition, notice period and severance payments, employee benefits and related costs. These additional expenditures could have the effect of reducing the Company's operating margins. The Restructuring Plan may result in other unintended consequences. If the Company experiences any of these adverse consequences, the Restructuring Plan may not achieve or sustain its intended benefits, or the benefits, even if achieved, may not be adequate to meet the Company's long-term profitability and operational expectations, which could adversely affect the Company's business, results of operations and financial condition.

See the "Liquidity and Capital Resources" section on page 32 for further details 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 will continue to consider investor-focused initiatives for the remainder 2025 and beyond, including potential additional dividends, distributions, share or bond buybacks, based on the overall results of the businesses, oil prices and cash flow generation. Additionally, 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, which may include a further return of capital to shareholders, a merger or a business combination, or the transfer, sale or other disposition of all or a significant portion of the business, assets or securities of the Company or the recapitalization of interests in one or more subsidiaries or in assets of the Company, whether in one or a series of transactions. However, there can be no assurance that any such initiative or transaction will occur or if it occurs, the timing thereof.

See the disclaimer regarding forward-looking information on the front page of this MD&A.

The information above is not intended to describe all of the risks associated with an investment in the securities of the Company. For a more comprehensive discussion of the risks and uncertainties that could affect the business and operations of the Company, please see the Company's AIF and the 2024 Annual Consolidated Financial Statements, copies of 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 I of the CPA Canada Handbook-Accounting. A summary of the significant accounting policies applied is included in Note 3a of the 2024 Annual Consolidated Financial Statements. The Company has not early adopted any standards, interpretations or amendments that have been issued but are not yet effective. Recent accounting pronouncements of significance or potential significance are described in Note 3b of the 2024 Annual Consolidated Financial Statements, including management's evaluation of their 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, and to make 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 as well as 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, as well as the reported amounts of revenues and other items.

Following the February 2022 invasion by Russia of Ukraine, certain countries, including Canada, the United States and many European nations, have imposed numerous and varying levels of financial and trade sanctions against Russia, a major oil and gas producing state. In addition, other international disputes, including the recent conflict and ongoing instability in the Middle East, which is home to many of the world's biggest oil producers, may have wide-ranging consequences on the world economy and in particular the oil and gas industry. These matters have caused and may continue to cause increased volatility in the global supply of oil and natural gas and energy prices. To date, these events have not negatively impacted the Company's operation, and there have been no significant delays or direct security issues affecting the Company's operations, offices or personnel. The long-term impacts of these conflicts and sanctions remain uncertain, the Company continues to monitor these types of situations as they evolve. Recent developments indicate heightened trade tensions between the United States and Colombia and elsewhere. During the year, the U.S. government enacted trade tariffs on numerous countries including Colombia and has more recently entered into trade agreements with certain jurisdictions involving the imposition of broad tariffs. The Company may be adversely affected by the imposition of new tariffs or adverse developments in the diplomatic and commercial relations between the United States and Colombia or the United States and other countries, which may disrupt the Company's financial performance and operational stability. Additionally, given the unpredictable nature of international trade policies, there can be no assurance that future disputes will not arise or that they will be resolved favorably. The long-term implications of these trade tensions remain uncertain, and the Company continues to monitor these matters as they evolve.

To date, these events have not impacted the Company's ability to carry on business, and there have been no significant delays or direct security issues affecting the Company's operations, offices, or personnel. The long-term impacts of the conflicts remain uncertain, and the Company continues to monitor the evolving situation. 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 have 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. Actual results may therefore differ from these estimates under different assumptions or conditions. A summary of the critical accounting estimates and judgments made by management in the preparation of its financial information for the past two financial years is provided in Note 3c of the 2024 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" on Form 52-109F1. This Certification requires that each "certifying officer" (as defined in NI 52-109) certify, among other things, that they, together with the other certifying officer(s), are responsible for establishing and maintaining disclosure controls and procedures ("**DC&P**") and internal control 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 is 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 due to inherent limitations.

Management of the Company has evaluated the effectiveness of the Company's ICFR for the period beginning July 1, 2025, and ending September 30, 2025. Based on this assessment, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company's ICFR was effective as at September 30, 2025.

There has been no change in the Company's ICFR during the period beginning on July 1, 2025, and ending on September 30, 2025, that has materially affected, or is 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 annual filings are being prepared, and that information required to be disclosed by the Company in its annual filings, interim filings, and other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized, and reported within the time period specified in securities legislation.

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 Chief Financial Officer concluded that the Company's DC&P was effective as at September 30, 2025.

## 10. FURTHER DISCLOSURES

### Production Colombia Reporting by Block

The following table summarizes the average production Colombia before royalties from the Company's operations:

| | | Production | | | | |
|---|---|---|---|---|---|---|
| **Producing blocks** | | **Q3 2025** | **Q2 2025** | **Q3 2024** | **2025** | **2024** |
| Quifa | (bbl/d) | 17,586 | 17,576 | 16,778 | 17,312 | 17,002 |
| CPE-6 | (bbl/d) | 7,710 | 7,771 | 7,459 | 7,844 | 6,880 |
| Guatiquia | (bbl/d) | 5,145 | 5,385 | 5,801 | 5,216 | 5,651 |
| Sabanero | (bbl/d) | 1,781 | 2,189 | 1,075 | 2,103 | 637 |
| VIM-1 | (boe/d) | 2,187 | 1,960 | 1,934 | 1,997 | 1,790 |
| Cubiro | (bbl/d) | 981 | 1,057 | 1,447 | 1,083 | 1,466 |
| Cravoviejo | (bbl/d) | 1,295 | 1,242 | 1,331 | 1,246 | 1,331 |
| Other blocks | (boe/d) | 2,249 | 2,598 | 3,015 | 2,439 | 3,184 |
| **Total production** | **(boe/d)** | **38,934** | **39,778** | **38,840** | **39,240** | **37,941** |

### Net Production

Production volumes in this MD&A are reported on a Company's gross W.I. basis before royalties. The Company has reported the share of production retained by the government under the contract, as royalties paid in-kind in this MD&A.

The following table shows the average net production, after deduction of such royalties:

| | | Net Production | | | | |
|---|---|---|---|---|---|---|
| | | | | | **Nine months ended September 30** | |
| **Net Production from Continuing Operations:** | | **Q3 2025** | **Q2 2025** | **Q3 2024** | **2025** | **2024** |
| **Net Producing blocks in Colombia** | | | | | | |
| Heavy crude oil | (bbl/d) | 25,175 | 25,593 | 22,324 | 25,247 | 21,573 |
| Light and medium crude oil combined | (bbl/d) | 8,169 | 8,759 | 9,647 | 8,439 | 9,635 |
| Conventional natural gas | (mcf/d) | 4,406 | 3,118 | 3,192 | 3,272 | 3,494 |
| Natural gas liquids | (boe/d) | 1,404 | 1,395 | 1,521 | 1,417 | 1,562 |
| **Net production Colombia** | **(boe/d)** | **35,521** | **36,294** | **34,052** | **35,677** | **33,383** |
| **Production from Discontinued Operations:** | | | | | | |
| **Producing blocks in Ecuador** | | | | | | |
| Light and medium crude oil combined | (bbl/d) | 698 | 950 | 1,215 | 897 | 1,125 |
| **Net production Ecuador** | **(bbl/d)** | **698** | **950** | **1,215** | **897** | **1,125** |

## Boe Conversion

The term "boe" is used in this MD&A. The use of boe may be misleading, particularly when presented 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 is expressed using the Colombian conversion standard of 5.7 Mcf to 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 those reflected in this MD&A due to, among other factors, difficulties or interruptions encountered during the production of hydrocarbons.

## Abbreviations

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

| | | | |
|---|---|---|---|
| **bbl** | Oil barrels | **MMcf/d** | Millions of cubic feet per day |
| **bbl/d** | Barrels of oil per day | **m3** | Cubic metre |
| **boe** | Barrels of oil equivalent | **Q** | Quarter |
| **boe/d** | Barrels of oil equivalent per day | **sqkm** | Square kilometre |
| **BSW** | Basic sediment and water | **Tons** | Tonnes |
| **bwpd** | Barrels of water per day | **TEU** | Twenty-foot Equivalent Unit |
| **COP** | Colombian pesos | **USD** | United States dollars |
| **CAD$** | Canadian dollars | **WTI** | West Texas Intermediate |
| **FX** | Foreign exchange | **W.I.** | Working interest |
| **ha** | Hectare | **$** | U.S. dollars |
| **MMbbl** | Millions of oil barrels | **$M** | Thousands of U.S. dollars |
| **MMboe** | Millions of barrels of oil equivalent | **$MM** | Millions of U.S. dollars |
| **Mbbl** | Thousands of oil barrels | **P1** | Proved reserves |
| **Mcf** | Thousands cubic feet | **P2** | Probable reserves |
| **mcf/d** | Thousands cubic feet per day | **2P** | Proved reserves + Probable reserves |
| **LPG** | Liquified Petroleum Gas | **2P** | Proved reserves + Probable reserves |