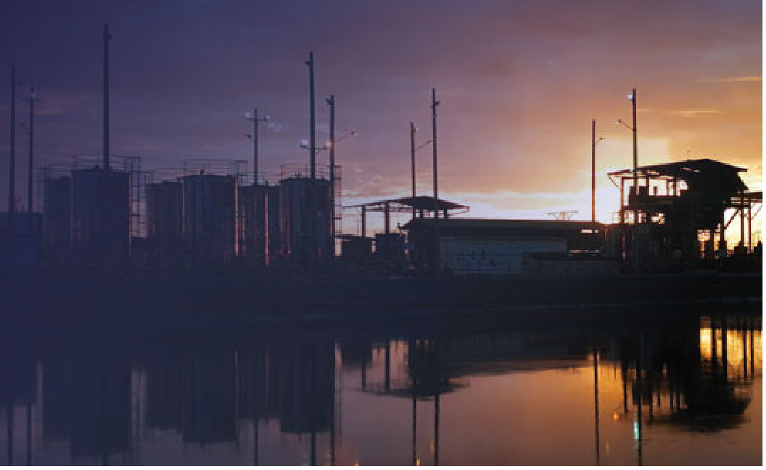
FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

March 10, 2025
For the year ended December 31, 2024



*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 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 Annual Consolidated Financial Statements and related notes for the years ended December 31, 2024 and 2023 (the "**2024 Annual Consolidated Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and its Annual Information Form for the year ended December 31, 2024 ("**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 28.*

*This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to activities, events or developments that the Company believes, expects or anticipates will or may occur in the future. Forward-looking information in this MD&A includes, without limitation, statements regarding estimates and/or assumptions in respect of the oil price environment, potential health risks, the impact of the Russia-Ukraine conflict, the conflict in the Middle East and trade tension between the U.S. and Colombia, 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 strategic alternatives review process for its Colombian Infrastructure business, the Company's goal of enhancing shareholder value and shareholder returns, expectations regarding the 2025 production guidance, the operational timing of the connection project between Puerto Bahia and Reficar, and Puerto Bahia's new LPG project, the water handling capacity at SAARA, expectations regarding the Company's ability to manage its liquidity and capital structure and generate sufficient cash to support operations, capital expenditures and financial commitments, the timing of release of restricted cash, the impact of fluctuations in the price of, and supply and demand for oil and conventional natural gas products, production levels, cash levels, reserves, capital expenditures (including plans and projects related to drilling, exploration activities, and infrastructure and the timing 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 is often identified by words or phrases such as "may", "could", "would", "might", "will", "expects," "anticipates," "plans," "estimates," "projects," "forecasts," "believes," "intends," "possible," "probable," "scheduled," "goal", "objective", or similar words or phrases. All information in this MD&A other than historical fact is forward-looking information.*

Forward-looking information reflects the current expectations, assumptions and beliefs of the Company based on information currently available to it and considers the Company's experience and its perception of historical trends, including expectations and assumptions relating to commodity prices and interest and foreign exchange rates; any health security situation; the performance of assets and equipment; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour, services and infrastructure; and the development and execution of projects.

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

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. MESSAGE TO THE SHAREHOLDERS

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

- **Colombian and Ecuador Upstream Onshore**: cash flow-focused production and reserves management from large, long-life onshore Colombia and Ecuador 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 and 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.

Operations and Business Overview

2024 was another strong year for Frontera as the Company achieved all its key guidance targets while returning over $83 million to its shareholders from 2024 thru today.

The Company generated full year Operating EBITDA of $424 million, and closed the year with a strong balance sheet, including a $223 million cash position. Additionally, the Company reduced its total consolidated debt and lease liabilities by more than $30 million, including repurchasing $5 million of its 2028 Senior Unsecured Notes. Both S&P and Fitch reaffirmed Frontera's B+ and B credit rating, respectively, and stable outlook, highlighting the Company's sound credit quality, strong financial position, and industry-low leverage levels.

In 2024 Frontera successfully executed its strategy generating positive results. Driven by successful drilling campaigns in the CPE-6 block, where it was reached another record daily production level of almost 9,000 boe/d in the fourth quarter, and Sabanero, which saw production increase to 2,384 boe/d in the fourth quarter, Frontera delivered its production targets for the year. For the full year 2024, water processing volumes in SAARA average approximately 44,000 bwpd, and during the fourth quarter, SAARA water processing volumes reached an average of 79,000 bwpd. On the cost side, despite inflationary pressures, the Company achieved all its cost guidance targets, including production cost per boe, which averaged $9.34/boe due to strong cost controls.

Frontera's strategy of value over volumes in its upstream Colombia and Ecuador business supported delivery of 100.6 million boe 1P and 151.3 million boe 2P gross reserves at year end 2024. The net present value of the Company's 2P reserves discounted at 10% before tax ("**NPV10**") was $3.4 billion or $22.4/boe at December 31, 2024 and Frontera's NPV10 per boe grew by 4% year over year driven by its focus on operational efficiencies, optimization of development plans and reduced future development costs. The Company's 1P Reserves Replacement Ratio for 2024 is 45%.

During the year, the Company's Infrastructure business generated $107 million of Adjusted Infrastructure EBITDA, and achieved several key milestones, including the announcement of a new LPG joint venture with Industrias Gasco and the construction of the Reficar connection, which is expected to be operational by the second quarter 2025. In addition, ODL transported over 243,000 bbl/day while generating $274 million in full year EBITDA. Proportional to our 35% equity interest in the pipeline, the Company received over $60 million in capital distributions and its Adjusted Infrastructure EBITDA benefited from $96 million associated with ODL's EBITDA. Puerto Bahia generated approximately $15 million in operating EBITDA, supported by effective port operations. On March 5, 2025, ODL declared $152 million in dividends ($53.3 million, net to Frontera), a 100% 2024 payout ratio, payable in 2025.

The Company's strategic alternatives review for its Infrastructure business is reaching its final stages. Since its launch in May 2024, the Company has prepared a virtual data room, held management presentations and engaged in discussions with several interested third parties. The Company is working diligently to conclude its review process analyzing various options and will communicate its outcome when appropriate. Frontera has retained Goldman Sachs & Co. LLC as financial advisor in connection with the strategic alternatives review. There can be no guarantee that this strategic alternative review process will result in a transaction.

On June 26, 2024, the Company and CGX announced that they submitted a notice of potential commercial interest for the Wei-1 discovery to the Government of Guyana, which preserves their interests in the Petroleum Prospecting License ("**PPL**") for the Corentyne block. On December 12, 2024, the Joint Venture announced that it had sent the Government of Guyana a letter activating a 60-day period for the parties to the Corentyne block PPL to make all reasonable efforts to amicably resolve all disputes via negotiation, as provided for in the Corentyne block PPL, which 60-day period expired on February 10, 2025. On February 11, 2025, the Joint Venture announced that it received a communication from the Government of Guyana 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 announced that the Joint Venture had provided a response in which the Joint Venture advised the Government that, among other things, despite the Government's contradictory positions, the PPL remains valid and in force and that the Joint Venture has contested the Government's purported termination of the PPL. The Joint Venture remains firmly of the view that its interest in, and the PPL for, the Corentyne block remain in place and in good standing.

Frontera's Sustainability Strategy

Importantly, Frontera continues to sustainably achieve its operating objectives, achieving 100% of its 2024 sustainability goals, including restoring and preserving 769 hectares of land, achieving its best Total Recordable Incident Rate performance ever and being recognized for the fourth time as one of the world's most ethical companies by Ethisphere.

Enhancing Investors Returns

Since 2022, the Company has returned over $180 million to its shareholders through normal course issuer bids, substantial issuer bids and dividends. During 2024, the Company returned $15.1 million in declared dividends, $7.8 million in repurchases of its common shares through its normal course issuer bid, and $31 million in repurchases of its common shares through its substantial issuer bid completed in October. In January 2025, the Company repurchased an additional $30 million in common shares via another substantial issuer bid. Both substantial issuer bids saw a high level of shareholder engagement and participation, over 90% combined participation rate, validating the Company's efficient capital distribution strategy.

Pursuant to Frontera's dividend policy, Frontera's Board of Directors has declared a dividend of C$0.0625 per common share to be paid on or around April 16, 2025, to shareholders of record at the close of business on April 2, 2025.

Frontera also announces that the Company intends to file with the TSX a notice of intention to commence a normal course issuer bid for its Common Shares (the "**NCIB**"). Subject to the acceptance of the TSX, the Company would be permitted under the NCIB to purchase, for cancellation, up to that number of Common Shares equal to the greater of (a) 5% of the Company's issued and outstanding Common Shares, and (b) 10% of the Company's "public float" (as such term is defined in the TSX Company Manual), during the 12-month period following commencement of the NCIB.

Frontera will continue to consider future investor initiatives in 2025, including potential additional dividends, distributions, or bond buybacks, based on the overall results of our businesses, oil prices, cash flow generation and the Company's strategic goals.

2025 Operational Update

Year-to-date 2025 production is approximately 40,400 barrels per day. The decrease from fourth quarter 2024 volumes is due to unexpected well failures within our Light and Medium assets occurring near the end of 2024. These issues are being addressed, and we remain confident in meeting our 2025 production guidance.

On the exploration side, The Greta Norte-1 well was drilled on January 18, 2025, and reached a total depth of 12,174 feet MD on February 5, 2025. Integration of drilling data and petrophysical interpretation identified 12.5 feet of net pay, and the well is currently in evaluation phase.

In 2025, Frontera's focus remains on executing its recently announced plan, delivering sustainable production, solid operational and financial results and enhancing shareholder investor returns.

"Orlando Cabrales Segovia" (signed)
Chief Executive Officer

2. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q4 2024	Q3 2024	Q4 2023	Year ended December 31 2024	Year ended December 31 2023
Operational Results						
Heavy crude oil production [(1)]	(bbl/d)	27,740	25,312	23,002	25,329	23,359
Light and medium crude oil combined production [(1)]	(bbl/d)	12,234	12,794	13,795	12,547	14,856
Total crude oil production	(bbl/d)	39,974	38,106	36,797	37,876	38,215
Conventional natural gas production [(1)]	(mcf/d)	2,633	3,192	4,760	3,278	6,042
Natural gas liquids production [(1)]	(boe/d) [(3)]	1,970	1,950	1,635	1,837	1,644
Total production [(2)]	(boe/d) [(3)]	42,406	40,616	39,267	40,288	40,919
Total inventory balance	(bbl)	1,029,466	1,315,384	1,076,394	1,029,466	1,076,394
Brent price reference	($/bbl)	74.01	78.71	82.85	79.86	82.17
Produced crude oil and gas sales [(4)]	($/boe)	67.18	71.11	77.98	72.84	75.16
Purchased crude net margin [(4)]	($/boe)	(3.22)	(3.05)	(2.22)	(2.73)	(2.23)
Oil and gas sales, net of purchases [(4)]	($/boe)	63.96	68.06	75.76	70.11	72.93
Gain (loss) on oil price risk management contracts [(5)(6)]	($/boe)	0.07	(0.45)	(0.69)	(0.70)	(0.80)
Royalties [(5)]	($/boe)	(0.88)	(0.91)	(1.79)	(1.33)	(2.98)
Net sales realized price [(4)]	($/boe)	63.15	66.70	73.28	68.08	69.15
Production costs (excluding energy costs), net of realized FX hedge impact [(4)]	($/boe)	(7.66)	(8.88)	(9.69)	(9.34)	(8.76)
Energy costs, net of realized FX hedge impact [(4)]	($/boe)	(5.29)	(5.11)	(5.06)	(5.11)	(4.49)
Transportation costs, net of realized FX hedge impact [(4)]	($/boe)	(11.20)	(12.12)	(11.02)	(11.39)	(11.21)
Operating netback per boe [(4)]	($/boe)	39.00	40.59	47.51	42.24	44.69
Financial Results						
Oil & gas sales, net of purchases [(7)]	($M)	216,370	214,084	240,105	851,451	905,249
Gain (loss) on oil price risk management contracts [(6)]	($M)	253	(1,425)	(2,198)	(8,457)	(9,903)
Royalties	($M)	(2,971)	(2,853)	(5,683)	(16,104)	(36,949)
Net sales [(7)]	($M)	213,652	209,806	232,224	826,890	858,397
Net (loss) income [(8)]	($M)	(29,401)	16,588	92,038	(24,162)	193,497
Per share – basic	($)	(0.36)	0.20	1.08	(0.29)	2.27
Per share – diluted	($)	(0.36)	0.19	1.04	(0.29)	2.19
General and administrative	($M)	13,170	12,719	16,891	52,373	53,907
Outstanding Common Shares	Number of Shares	80,793,387	84,167,856	85,151,216	80,793,387	85,151,216
Operating EBITDA [(7)]	($M)	113,479	103,184	121,036	424,232	467,219
Cash provided by operating activities	($M)	168,691	124,610	73,432	510,032	411,794
Capital expenditures [(7)]	($M)	85,866	82,411	82,292	317,856	442,734
Cash and cash equivalents – unrestricted	($M)	192,577	205,572	159,673	192,577	159,673
Restricted cash short and long-term [(9)]	($M)	30,249	34,752	30,300	30,249	30,300
Total cash [(9)]	($M)	222,826	240,324	189,973	222,826	189,973
Total debt and lease liabilities [(9)]	($M)	506,037	531,235	536,822	506,037	536,822
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [(10)]	($M)	414,481	415,387	430,170	414,481	430,170
Net debt (excluding Unrestricted Subsidiaries) [(10)]	($M)	277,298	267,043	318,092	277,298	318,092

(1) References to heavy crude oil, light and medium crude oil combined, conventional natural gas and natural gas liquids in the above table and elsewhere in this MD&A refer to the heavy crude oil, light crude oil and medium crude oil combined, conventional natural gas and natural gas liquids, respectively, product types as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities.*
(2) Represents W.I. production before royalties. Refer to the "Further Disclosures" section on page 44.
(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 44.
(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 28.
(5) Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 28.
(6) Includes the net of the put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Please refer to the "Loss (gain) on risk management contracts" section on page 19 for further details.
(7) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 28.
(8) Net (loss) income attributable to equity holders of the Company.
(9) Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 28.
(10) "**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 (formerly named Pipeline Investment Ltd, "**PIL**"), Frontera BIC Holding Ltd. and Frontera Bahía Holding Ltd. ("**Frontera Bahia**"), including Sociedad Portuaria Puerto Bahia S.A ("**Puerto Bahia**"). On April 11, 2023, Frontera Energy Guyana Holding Ltd. and Frontera Energy Guyana Corp. were designated as unrestricted subsidiaries. Refer to the "Liquidity and Capital Resources" section on page 35.

Performance Highlights

Full Year 2024

- Production averaged 40,288 boe/d in 2024 (consisting of 25,329 bbl/d of heavy crude oil, 12,547 bbl/d of light and medium crude oil combined, 3,278 mcf/d of conventional natural gas and 1,837 boe/d of natural gas liquids), compared with 40,919 boe/d in 2023 (consisting of 23,359 bbl/d of heavy crude oil, 14,856 bbl/d of light and medium crude oil combined, 6,042 mcf/d of conventional natural gas and 1,644 boe/d of natural gas liquids).

- Cash provided by operating activities was $510.0 million in 2024, compared with $411.8 million in 2023, contributing to a total cash position as at December 31, 2024, of $222.8 million, compared with $190.0 million as at December 31, 2023. Total cash includes $30.2 million of restricted cash, compared with $30.3 million as at December 31, 2023.

- Net loss [1] was $24.2 million ($0.29/share[2]) in 2024, compared with a net income of $193.5 million ($2.19/share[2]) in 2023.

- Capital expenditures were $317.9 million in 2024, compared with $442.7 million in 2023.

- Operating EBITDA was $424.2 million in 2024, compared with $467.2 million in 2023.

- Operating netback was $42.24/boe in 2024, compared with $44.69/boe in 2023.

- Infrastructure Colombia Segment (as defined below) income was $55.5 million in the 2024, compared with $58.6 million in 2023.

- Adjusted Infrastructure EBITDA was $107.2 million in 2024, compared with $110.1 million in 2023.

- Puerto Bahia liquids volumes handled during the year 2024 were 56,020 bbl/d compared to 60,718 bbl/d in 2023.

- ODL volumes transported were 243,669 bbl/d in 2024, compared to 243,617 in 2023.

Fourth Quarter 2024

- Production averaged 42,406 boe/d in the fourth quarter of 2024 (consisting of 27,740 bbl/d of heavy crude oil, 12,234 bbl/d of light and medium crude oil combined, 2,633 mcf/d of conventional natural gas and 1,970 boe/d of natural gas liquids), compared to 40,616 boe/d in the prior quarter (consisting of 25,312 bbl/d of heavy crude oil, 12,794 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), and compared to 39,267 boe/d in the fourth quarter of 2023 (consisting of 23,002 bbl/d of heavy crude oil, 13,795 bbl/d of light and medium crude oil combined, 4,760 mcf/d of conventional natural gas and 1,635 boe/d of natural gas liquids).

- Cash provided by operating activities was $168.7 million in the fourth quarter of 2024, compared with $124.6 million in the prior quarter, and $73.4 million in the fourth quarter of 2023. The Company reported a total cash position of $222.8 million, including $30.2 million of restricted cash, as at December 31, 2024, compared with a total cash position of $240.3 million, including $34.8 million of restricted cash, as at September 30, 2024, and $190.0 million, including $30.3 million of restricted cash, as at December 31, 2023.

- The Company recorded a net loss[1] of $29.4 million ($0.36/share[2]) in the fourth quarter of 2024, compared with net income[1] of $16.6 million ($0.19/share[2]) in the prior quarter and net income[1] of $92.0 million ($1.04/share[2]) in the fourth quarter of 2023.

- Capital expenditures were $85.9 million in the fourth quarter of 2024, compared with $82.4 million in the prior quarter and $82.3 million in the fourth quarter of 2023.

- Operating EBITDA was $113.5 million in the fourth quarter of 2024, compared with $103.2 million in the prior quarter and $121.0 million in the fourth quarter of 2023.

- Operating netback was $39.00/boe in the fourth quarter of 2024, compared with $40.59/boe in the prior quarter and $47.51/boe in the fourth quarter of 2023.

- Infrastructure Colombia Segment (as defined below) income was $15.2 million in the fourth quarter of 2024, compared with $13.1 million in the prior quarter and $13.2 million in the fourth quarter of 2023.

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

[2] Per Common Share on a diluted basis.

- Adjusted Infrastructure EBITDA in the fourth quarter of 2024 was $27.5 million, compared with $26.2 million in the prior quarter and $27.3 million during the fourth quarter of 2023.

- Puerto Bahia liquids volumes handled during the fourth quarter of 2024 were 61,990 bbl/d compared to 46,964 bbl/d in the prior quarter and 52,754 bbl/d in the fourth quarter of 2023. Puerto Bahia revenues were $11.5 million during the fourth quarter of 2024, compared to $9.7 million in the prior quarter and $10.1 million during the fourth quarter of 2023.

- ODL volumes transported were 235,528 bbl/d during the fourth quarter of 2024, compared to 243,997 bbl/d in the prior quarter of 2024, mainly due to lower production from Llanos 34 transported through the pipeline.

Oil and Gas Reserves

- Frontera added 2.0 MMboe of 2P gross reserves, for total Company 2P gross reserves of 151.3 MMboe and a reserve life index to 10.3 years at year end 2024.

- Frontera's 2024 year-end gross 2P reserves include total additions of **2.0** MMboe by technical revisions, mainly in Sabanero (Sabanero field), Quifa (Cajua and Quifa SW fields), Cubiro (Copa trend fields) and VIM1 blocks (La Belleza field); offset by production of 14.7 MMboe. Proved gross reserves of 100.6 MMboe represent 66% of the total 2P reserves similar to 66% of the total 2P reserves in 2023.

3. GUIDANCE

The Company's 2024 financial and operational results were in-line with all 2024 annual guidance metrics (the "**2024 Guidance**").

In 2024, production averaged 40,288 boe/d, in-line with the Company's 2024 Guidance of 40,000 to 42,000 boe/d. Production costs (excluding energy costs), net of realized foreign exchange ("FX") hedge impact, of $9.34/boe was in-line with the 2024 Guidance range of $8.50/boe to $9.50/boe, and energy costs, net of realized FX hedge impact, of $5.11/boe were below the 2024 Guidance range of $5.75/boe to $6.25/boe mainly due to fixed-price contracts signed during 2024. Transportation costs of $11.39/boe were below the middle point of the 2024 Guidance of $11.00/boe to $12.00/boe.

Operating EBITDA in 2024 totaled $424 million within the 2024 Guidance range at $80/bbl.

Capital expenditures of $318 million in 2024 was consistent with the 2024 Guidance of $272-335 million.

		2024	
		Guidance	**Actual**
Average Daily Production[1]	boe/d	40,000 - 42,000	40,288
Production Costs (excluding energy cost) [2][4]	$/boe	8.50 - 9.50	9.34
Energy Costs [2][4]	$/boe	5.75 - 6.25	5.11
Transportation Costs[3][4]	$/boe	11.00 - 12.00	11.39
Operating EBITDA[5] at $80/bbl [6]	$MM	400 - 450	424.2
Adjusted Infrastructure EBITDA[7]	$MM	95 - 115	107.2
Development Drilling	$MM	85 - 95	108.8
Development Facilities [8]	$MM	95 - 115	105.0
Colombia and Ecuador Development	$MM	180 - 210	213.8
Colombia and Ecuador Exploration	$MM	35 - 45	26.9
Other [9]	$MM	15 - 25	25.9
Total Colombia & Ecuador Upstream Capex	$MM	230 - 280	266.6
Colombia Infrastructure[10]	$MM	40 - 50	47.9
Guyana Exploration	$MM	2 - 5	3.3
Total Capital Expenditures[11]	$MM	272 - 335	317.8

[1] The Company's 2024 average production guidance range does not include in-kind royalties, operational consumption, quality volumetric compensation or potential production from successful exploration activities planned in 2024.
[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 National Instrument 52-112 - Non-GAAP and Other Financial Measures ("NI 52-112")). Refer to the "Non-IFRS and Other Financial Measures".
[5] Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). "Operating EBITDA" represents the operating results of the Company's business, excluding the following items: restructuring, severance and other costs, certain non-cash items and gains or losses arising from the disposal of capital assets. Refer to "Non-IFRS and Other Financial Measures".
[6] Current Guidance Operating EBITDA calculated at Brent $80/bbl and COP/USD exchange rate of 4,100:1.
[7] Reported Adjusted Infrastructure EBITDA is a non-IFRS financial measure used to assist in measuring the operating results of the infrastructure business, including the proportional consolidation of the 35% equity investment in the ODL pipeline.
[8] Investments related to the replacement and repairs of the affected assets in the Quifa block due to unexpected failures in a trunkline, are not included in either the actual results or the Guidance.
[9] Other includes Sabanero Insurance, HSEQ activities and New Technologies.
[10] Colombia Infrastructure includes investments related to the connection of Puerto Bahia's port facility and the Cartagena refinery (the "**Reficar Connection Project**") operated by Reficar, the SAARA reverse osmosis water treatment facility, and safety, maintenance activities and operational optimizations in the port.
[11] Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to "Non-IFRS and Other Financial Measures". Capital expenditures excludes decommissioning.

2025 Guidance

The Company's 2025 financial and operating guidance aims to build off the Company's strategy of value over volumes and its track record of improving capital efficiency. The Company's 2025 capital and production guidance is based on an average Brent price of $75-$80/bbl, an average sales price oil differential of $4.50/bbl, and an exchange rate of 4,250 Colombian Pesos per U.S. dollar in 2025.

In the Company's core Colombia and Ecuador Upstream business, Frontera plans to produce 41,000-43,000 boe/d while reducing capital investment by 13% to $200-$245 million compared to 2024. The Company anticipates delivering between $350 to $380 million and $400 to $430 million in Operating EBITDA in 2025 from its Upstream operations at $75/bbl and $80/bbl average Brent prices, respectively, to generate an anticipated $420 - $465 million in consolidated Operating EBITDA at $80/bbl average Brent prices. The Company estimates 2025 production costs to remain flat compared to 2024 levels and to average $8.75 - $9.25 per boe, excluding energy costs reflecting the positive impact of implemented cost savings initiatives partially offset by incremental costs associated with additional water handling and treatment volumes (primarily associated to SAARA) and continued inflationary pressures. Energy costs, which include electricity consumption and the costs of in-situ power generation, are expected to average $5.25 - $5.75 per boe, driven by higher energy use associated with increasing heavy crude oil production. Transportation costs for 2025 are forecasted to average $12.50 - $13.00 per boe reflecting primarily increases in trucking tariffs resulting from changes to Colombian diesel subsidies starting in 2024 and stepping up in 2025 as well as inflation-related pipeline tariffs increases. The Company's anticipates its total 2025 Colombia and Ecuador Upstream capital expenditures will be $200-$245 million which represents an approximately 13% decrease at the midpoint compared to the Company's 2024 capital budget, and in 2025, the Company anticipates investing $30-$40 million on various exploration activities.

In the Company's Colombia infrastructure business, the Company expects to generate between $20-$35 million in segment Operating EBITDA and between $115-$130 million in Adjusted Infrastructure EBITDA. The expected year over year increase is driven by additional EBITDA generated from the Reficar connection start up and additional revenues from SAARA. Frontera anticipates investing $15-$20 million primarily for Commissioning and completion works related to the Reficar connection and maintenance activities for the port and investments related to palm oil plantation biological asset maintenance, water handling infrastructure and the SAARA facility.

Summary of Frontera's 2025 Capital and Production Guidance

Guidance Metrics	Unit	Guidance
Average Daily Production[1]	boe/d	41,000 - 43,000
Production Costs[2][4]	$/boe	8.75 - 9.25
Energy Costs [2][4]	$/boe	5.25 - 5.75
Transportation Costs[3][4]	$/boe	12.50 - 13.00
Operating EBITDA[5] at $75/bbl[6]	$MM	370 - 415
Upstream Operating EBITDA	$MM	350 - 380
Infrastructure Operating EBITDA [7]	$MM	20 - 35
Operating EBITDA[5] at $80/bbl[6]	$MM	420 - 465
Upstream Operating EBITDA	$MM	400 - 430
Infrastructure Operating EBITDA [7]	$MM	20 - 35
Adjusted Infrastructure EBITDA [8]	$MM	115 - 130
Development Drilling	$MM	100 - 110
Development Facilities	$MM	60 - 80
Colombia and Ecuador Development	$MM	160 - 190
Colombia and Ecuador Exploration	$MM	30 - 40
Other[9]	$MM	10 - 15
Total Colombia & Ecuador Capex	$MM	200 - 245
Guyana Exploration	$MM	1 - 3
Colombia Infrastructure	$MM	15 - 20
Total Capital Expenditures [10]	$MM	216 - 268

(1) The Company's 2025 average production guidance range 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 National Instrument 52-112 - Non-GAAP and Other Financial Measures ("NI 52-112")). See "Advisories – Non-IFRS Financial and Other Measures".
(5) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). "Operating EBITDA" represents the operating results of the Company's Upstream business, excluding the following items: restructuring, severance and other costs, certain non-cash items and gains or losses arising from the disposal of capital assets. See "Advisories – Non-IFRS Financial and Other Measures".
(6) Current Guidance Operating EBITDA calculated at Brent between $75/bbl and $80/bbl, and COP/USD exchange rate of 4,250:1.
(7) Includes Puerto Bahia, SAARA and Promotora Agricola de los Llanos S.A. ("**ProAgrollanos**").
(8) Reported Adjusted Infrastructure EBITDA (previously referred to as Adjusted Midstream EBITDA) is a non-IFRS financial measure used to assist in measuring the operating results of the Infrastructure business, including the proportional consolidation of the 35% equity investment in the ODL pipeline.
(9) Other includes HSEQ activities and new field production technologies
(10) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). See "Advisories – Non-IFRS Financial and Other Measures". Capital expenditures excludes decommissioning.

4. PROVED AND PROBABLE OIL AND GAS RESERVES

For the year ended December 31, 2024, the Company received an independent certified reserves evaluation report ("**Reserves Report**") from DeGolyer and MacNaughton for all of its assets, with total gross 2P reserves of 151.3 MMboe compared with 164.1 MMboe in 2023. All of the Company's reserves are located in Colombia and Ecuador.

Frontera's 2024 year-end gross 2P reserves include total additions of 2.0 MMboe by technical revisions, mainly in Sabanero (Sabanero field), Quifa (Cajua and Quifa SW fields), Cubiro (Copa trend fields) and VIM1 blocks (La Belleza field); offset by production of 14.7 MMboe. Proved gross reserves of 100.6 MMboe represent 66% of the total 2P reserves similar to 66% of the total 2P reserves in 2023.

The Reserves Report was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook, NI 51-101 and CSA Staff Notice 51-324– *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities.*

Concurrently with the filing of this MD&A, the Company has filed the following: (i) the Statement of Reserves Data and Other Oil and Gas Information on Form 51-101F1, (ii) the Report on Reserves Data by Independent Qualified Reserves Evaluator on Form 51-101F2 by DeGolyer and MacNaughton, and (iii) the Report of Management and Directors on Oil and Gas Disclosure on Form 51-101F3. These reports have been filed on SEDAR+ at www.sedarplus.ca.

Reserves at December 31, 2024 (MMboe[1])								
Country	**Field**	**Proved (P1)**		**Probable (P2)**		**Proved + Probable (2P)**		**Hydrocarbon Type**
		Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Colombia	Quifa SW block	32.3	29.2	6.6	5.9	38.9	35.1	Heavy Crude Oil
	CPE-6 block	24.1	21.9	14.8	13.4	39.0	35.2	Heavy Crude Oil
	Other heavy oil blocks [2]	18.7	17.6	4.5	4.3	23.1	21.9	Heavy Crude Oil
	Light/medium oil blocks [3]	13.2	11.9	14.9	13.7	28.1	25.5	Light and Medium Crude Oil Combined
	Natural gas blocks [4]	8.5	8.5	5.0	5.0	13.5	13.5	Conventional Natural Gas
	Natural gas blocks [4]	2.4	2.1	2.2	1.8	4.6	3.9	Natural Gas Liquids
	Sub total	**99.1**	**91.2**	**48.1**	**44.1**	**147.2**	**135.2**	**Oil, Conventional Natural Gas and Natural Gas Liquids**
Ecuador	Light/medium oil blocks[5]	1.4	1.0	2.6	1.8	4.0	2.8	Light and Medium Crude Oil Combined
	Heavy oil blocks[6]	0.1	0.1	0.1	—	0.1	0.1	Heavy Crude Oil
	Sub total	**1.5**	**1.1**	**2.7**	**1.8**	**4.1**	**2.9**	**Oil**
	Total at Dec. 31, 2024	**100.6**	**92.3**	**50.7**	**45.9**	**151.3**	**138.1**	**Oil, Conventional Natural Gas and Natural Gas Liquids**
	Total at Dec. 31, 2023	108.7	99.2	55.4	50.7	164.1	149.9	
	Difference	(8.1)	(6.9)	(4.7)	(4.9)	(12.8)	(11.8)	
	2024 Production [7]	14.7	12.9	**Total reserves incorporated**		2.0	1.2	

(1) See the "Further Disclosures - Boe Conversion" section on page 44.
(2) Includes the Cajua and Jaspe fields in the Quifa block, and the Sabanero block.
(3) Includes the Cubiro, Cravoviejo, Canaguaro, Guatiquia, Casimena, Corcel, Cachicamo and other producing blocks.
(4) Includes the VIM 1 and El Dificil blocks.
(5) Includes the Perico block, which is currently in evaluation period to better quantify resources.
(6) Includes the Espejo block, which is currently in early evaluation period to better quantify resources.
(7) Gross production distribution: light & medium crude oil combined 4.6 MMboe, heavy crude oil 9.3 MMboe, conventional natural gas 0.2 MMboe, natural gas liquids 0.6 MMboe.
(8) In the table above, "Gross" refers to W.I. before royalties, and "Net" refers to W.I. after royalties. Numbers in the table may not add due to rounding differences.

5. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company's operations in Colombia and Ecuador. Refer to the "Further Disclosures" section on page 44 for details of the Company's net production:

		Production				
					Year ended December 31	
Producing blocks in Colombia		**Q4 2024**	**Q3 2024**	**Q4 2023**	**2024**	**2023**
Heavy crude oil	(bbl/d)	27,740	25,312	23,002	25,329	23,359
Light and medium crude oil combined	(bbl/d)	10,484	11,018	12,342	10,882	13,925
Conventional natural gas	(mcf/d)	2,633	3,192	4,760	3,278	6,042
Natural gas liquids	(boe/d)	1,970	1,950	1,635	1,837	1,644
Total production Colombia	**(boe/d)**	**40,656**	**38,840**	**37,814**	**38,623**	**39,988**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	1,750	1,776	1,453	1,665	931
Total production Ecuador	**(bbl/d)**	**1,750**	**1,776**	**1,453**	**1,665**	**931**
Total production	**(boe/d)**	**42,406**	**40,616**	**39,267**	**40,288**	**40,919**

Colombia

For the three months ended December 31, 2024, production in Colombia increased by 1,816 boe/d, compared to the prior quarter. Heavy crude oil production increased by 10%, supported by successful drilling campaigns in the CPE-6 and Sabanero blocks, and increased water disposal capacity in the CPE-6 block. Light and medium crude oil combined production and conventional natural gas production decreased primarily as a result of natural decline and well failures, and the relinquishment of the Abanico production contract on October 10, 2024. Natural gas liquids production was in line with the previous quarter's production.

Production in Colombia for the three months and the year ended December 31, 2024 compared to the same periods of 2023, increased by 2,842 boe/d, and decreased by 1,365 boe/d, respectively, as a result of the following: (i) heavy crude oil increases of 4,738 bbl/d and 1,970 bbl/d, respectively as a result of the successful development drilling campaigns in the CPE-6 and Sabanero blocks, the new water facilities in the CPE-6 block, the reactivation of wells in the Sabanero block, and the increased processing capacity at SAARA, with a water treated daily record 185 Mbbl, which support production levels from the Quifa block; (ii) natural gas liquids production increased by 20% and 12%, respectively, due to the increased production of the VIM-1 block as a result of the development of facilities for surface gas compression and handling systems; (iii) light and medium crude oil combined production decreased by 15% and 22%, respectively, primarily as a result of natural field declines, certain well failures, the termination of the Abanico production contract on October 10, 2024, and the finalization of the Neiva production contract in June 2023; and (iv) conventional natural gas production decreased by 45% and 46%, respectively, attributed to natural declines in the El Dificil block.

Ecuador

Total production in Ecuador for the three months and the year ended December 31, 2024, increased by 20% and 79%, respectively, for light and medium crude oil combined, compared to the same periods of 2023. This increase was attributed to the drilling and completion of three wells in the Perico block during the second half of 2023 and an additional three wells in 2024, in addition to two exploration wells drilled in the Espejo block in June 2024.

The production in the fourth quarter was in line with the previous quarter.

Production Reconciled to Sales Volumes

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

					Year ended December 31	
		Q4 2024	**Q3 2024**	**Q4 2023**	**2024**	**2023**
Production	(boe/d)	**42,406**	**40,616**	**39,267**	**40,288**	**40,919**
Royalties in-kind Colombia	(boe/d)	(3,948)	(4,788)	(5,257)	(4,404)	(4,436)
Royalties in-kind Ecuador (1)	(boe/d)	(489)	(561)	(485)	(506)	(289)
Net production	(boe/d)	**37,969**	**35,267**	**33,525**	**35,378**	**36,194**
Oil inventory draw	(boe/d)	3,108	42	2,762	129	445
Overlift (Settlement)	(boe/d)	(27)	—	—	(7)	—
Volumes purchased	(boe/d)	6,420	8,161	6,708	7,440	7,152
Other inventory movements (2)	(boe/d)	(2,102)	(2,250)	(2,278)	(2,401)	(2,356)
Sales volumes	(boe/d)	**45,368**	**41,220**	**40,717**	**40,539**	**41,435**
Sale of volumes purchased	(boe/d)	(8,595)	(7,028)	(6,268)	(7,358)	(7,430)
Sales volumes, net of purchases	(boe/d)	**36,773**	**34,192**	**34,449**	**33,181**	**34,005**
Oil sales volumes	(bbl/d)	36,326	33,651	33,896	32,614	32,992
Conventional natural gas sales volumes	(mcf/d)	2,548	3,084	3,152	3,232	5,774
Total oil and conventional natural gas sales volumes, net of purchases	**(boe/d)**	**36,773**	**34,192**	**34,449**	**33,181**	**34,005**
Inventory balance						
Colombia (3)	(bbl)	501,778	777,158	551,715	501,778	551,715
Peru	(bbl)	480,200	480,200	480,200	480,200	480,200
Ecuador	(bbl)	47,488	58,026	44,479	47,488	44,479
Inventory ending balance	**(bbl)**	**1,029,466**	**1,315,384**	**1,076,394**	**1,029,466**	**1,076,394**

(1) The Company reports the share of production retained by the government of Ecuador as royalties paid in-kind.
(2) Mainly corresponds to operational consumption and quality volumetric compensation.
(3) Includes 0.25 MMbbl of oil produced and 0.25 MMbbl of diluent in the fourth quarter of 2024, 0.33 MMbbl of oil produced and 0.45 MMbbl of diluent in the third quarter of 2024, and 0.32 MMbbl of oil produced and 0.23 MMbbl of diluent the fourth quarter of 2023.

Sales volumes, net of purchases, for the three months ended December 31, 2024, increased by 8% and 7%, compared with the prior quarter and the same quarter of 2023, respectively, due to higher volumes of heavy crude oil produced and inventory draw. For the year ended December 31, 2024, sales decreased by 2%, compared with the same period of 2023, mainly due to lower volumes of light and medium oil production partially offset by higher volumes of heavy crude oil produced.

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. In February 2023, the ANH changed the payment method for PAP payments, requiring in-kind payments for all blocks, except for the CPE-6, Guatiquia (Yatay field), and Cubiro (Copa A field) blocks. In October 2023, the ANH made an additional change in the payment method for PAP payments, by requiring in-kind payments for the CPE-6 block.

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

					Year ended December 31	
		Q4 2024	**Q3 2024**	**Q4 2023**	**2024**	**2023**
PAP in kind	(bbl/d)	668	1,658	2,664	1,424	2,057
PAP in cash	(bbl/d)	362	338	402	369	678
PAP	**(bbl/d)**	**1,030**	**1,996**	**3,066**	**1,793**	**2,735**
% Production		**2.4 %**	**4.9 %**	**7.8 %**	**4.5 %**	**6.7 %**

For the three months and the year ended December 31, 2024, the total PAP decreased compared with the prior quarter and the same periods of 2023, mainly due to lower WTI oil benchmark price.

For the three months and the year ended December 31, 2024, PAP in kind decreased compared with the same periods of 2023, primarily due to lower WTI oil benchmark price and lower light and medium crude oil production.

For the three months and the year ended December 31, 2024, PAP in cash decreased compared with same periods of 2023, mainly due to the change in the payment method required by ANH, as mentioned above, and lower light and medium crude oil production.

Realized and Reference Prices

					Year ended December 31	
		Q4 2024	Q3 2024	Q4 2023	2024	2023
Reference price						
Brent [1]	($/bbl)	74.01	78.71	82.85	79.86	82.17
Average realized prices						
Realized oil price, net of purchases	($/bbl)	64.27	68.53	76.35	70.70	74.23
Realized conventional natural gas price	($/mcf)	6.79	6.77	6.93	6.37	5.41
Net sales realized price						
Produced crude oil and gas sales [2]	($/boe)	67.18	71.11	77.98	72.84	75.16
Purchased crude net margin [2]	($/boe)	(3.22)	(3.05)	(2.22)	(2.73)	(2.23)
Oil and gas sales, net of purchases [2]	($/boe)	63.96	68.06	75.76	70.11	72.93
Gain (loss) on oil price risk management contracts[3] [4]	($/boe)	0.07	(0.45)	(0.69)	(0.70)	(0.80)
Royalties [3]	($/boe)	(0.88)	(0.91)	(1.79)	(1.33)	(2.98)
Net sales realized price [2]	**($/boe)**	**63.15**	**66.70**	**73.28**	**68.08**	**69.15**

[1] Frontera's weighted average Brent price for the three months and the year ended December 31, 2024, was $74.30/bbl and $79.33/bbl, respectively.
[2] Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 28. 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.
[3] Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 28.
[4] Includes the net of the put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Please refer to the "Loss (gain) on risk management contracts" section on page 18 for further details.

The average Brent benchmark oil price during the three months and the year ended December 31, 2024, decreased by 11% and 3%, respectively, compared to the same periods of 2023. In comparison to the third quarter of 2024, the average Brent benchmark oil price decreased by 6%. The decrease in crude oil prices during 2024 compared with the same period of 2023, was mainly due to: (i) weak demand in China (ii) high inflation in the USA, which has kept interest rates unchanged, and iii) the excess of supply perceived by the market in USA, Canadian crude going through the TMX to Asia, Brazil offshore, Vaca Muerta field in Argentina among others as the risk war premium was already discounted by the market.

For the three months and the year ended December 31, 2024, the Company's net sales realized price decreased, compared to the same periods of 2023, $10.13/boe and $1.07/boe, respectively. The decrease in the Company's net sales realized price was mainly driven by lower Brent benchmark oil price, weaker oil price differentials quarter-over-quarter. However, oil price differentials remained comparable between the year 2024 and 2023. This was partially offset by lower royalties paid in cash and lower realized losses from oil price risk management contracts, due to a positive cash settlement received during the last quarter of 2024, which was partially offset by the premiums paid on these contracts. Compared to the prior quarter, the Company's net sale realized price, decreased 5%. The decrease was primarily driven by a lower Brent benchmark oil price and weaker oil price differentials, and was partially offset by lower royalties paid in cash and the realized gain from oil price risk management contracts.

Operating Netback

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

	Q4 2024		Q3 2024		Q4 2023	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	213,652	63.15	209,806	66.70	232,224	73.28
Production costs (excluding energy cost), net of realized FX hedge impact (1)(2)(3)	(29,874)	(7.66)	(33,164)	(8.88)	(35,021)	(9.69)
Energy costs, net of realized FX hedge impact (1)(2)(4)	(20,647)	(5.29)	(19,103)	(5.11)	(18,267)	(5.06)
Transportation costs, net of realized FX hedge impact (1)(2)(5)	(39,128)	(11.20)	(39,334)	(12.12)	(33,997)	(11.02)
Operating Netback (1) (2)	**124,003**	**39.00**	**118,205**	**40.59**	**144,939**	**47.51**
		(boe/d)		(boe/d)		(boe/d)
Sales volumes, net of purchases (6)		36,773		34,192		34,449
Production (7)		42,406		40,616		39,267
Net production (8)		37,969		35,267		33,525

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 28.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 28.
(3) Includes $Nil, a loss of $0.2 million, and a gain of $2.1 million from realized FX hedge attributable to production costs for the fourth quarter of 2024, third quarter of 2024, and the fourth quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 18.
(4) Includes $Nil, a loss of $0.1 million, and a gain of $0.7 million from realized FX hedge attributable to energy costs for the fourth quarter of 2024, third quarter of 2024, and the fourth quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 18.
(5) Includes $Nil, a loss of $0.1 million, a gain of $0.8 million from realized FX hedge attributable to transportation costs for the fourth quarter of 2024, third quarter of 2024, and the fourth quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 18.
(6) Sales volumes, net of purchases, excluding sales of third-party volumes.
(7) Refer to the "Production" section on page 10.
(8) Refer to the "Further Disclosures" section on page 44.

The Company's operating netback for the fourth quarter of 2024 was $39.00/boe, compared to $47.51/boe in the same quarter of 2023. In comparison to the third quarter of 2024, the Company's operating netback decreased 4%, from $40.59/boe to $39.00/boe, was a result of lower net sales realized prices and higher energy costs, net of the realized FX hedge impact, related to greater heavy crude oil production levels and increases in electricity prices, partially offset by fixed-price contracts signed during the year 2024. It was reduce by lower transportation costs, net of the realized FX hedge impact, as of result of lower volumes transported primarily attributed to improved domestic wellhead sales, and (ii) lower production costs (excluding energy costs), net of the realized FX hedge impact, driven by strong cost controls, higher production and reduced well intervention activities during the quarter.

The following table provides a summary of the Company's netbacks for the year ended December 31, 2024, and 2023:

	Year ended December 31			
	2024		2023	
	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	826,890	68.08	858,397	69.15
Production costs (excluding energy costs), net of realized FX hedge impact (1)(2)(3)	(137,738)	(9.34)	(130,842)	(8.76)
Energy costs, net of realized FX hedge impact (1)(2)(4)	(75,364)	(5.11)	(67,024)	(4.49)
Transportation costs, net of realized FX hedge impact (1)(2)(5)	(147,531)	(11.39)	(148,152)	(11.21)
Operating Netback (1) (2)	**466,257**	**42.24**	**512,379**	**44.69**
		(boe/d)		(boe/d)
Sales volumes, net of purchases (6)		33,181		34,005
Production (7)		40,288		40,919
Net production (8)		35,378		36,194

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 28.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 28.
(3) Includes $3.4 million and $9.1 million of realized FX hedge gain attributable to production costs for the year ended December 31, 2024, and 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 18.
(4) Includes $1.3 million and $2.9 million of realized FX hedge gain attributable to energy costs for the year ended December 31, 2024, and 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 18.
(5) Includes $1.0 million and $3.3 million of realized FX hedge gain attributable to transportation costs for the year ended December 31, 2024, and 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 18.
(6) Sales volumes, net of purchases, excluding sales of third-party volumes.
(7) Refer to the "Production" section on page 10.
(8) Refer to the "Further Disclosures" section on page 44.

Operating netback for the year ended December 31, 2024, was $42.24/boe compared to $44.69/boe in the same period of 2023. The changes were primarily due to (i) lower net sales realized prices, (ii) an increase in production costs (excluding energy costs), net of realized FX hedge impact, mainly as a result of higher well services activity, inflationary pressures on services and wages indexation, (iii) higher energy costs, net of realized FX hedge impact, related to greater heavy crude oil production levels and increase in electricity prices, and (iv) transportation costs as of result of annual increased tariffs partially offset by lower volumes transported primarily attributed to improved domestic wellhead sales.

Sales

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Produced crude oil sales	225,685	245,123	877,106	921,573
Purchased crude net margin [1]	(10,906)	(7,029)	(33,192)	(27,728)
Conventional natural gas sales	1,591	2,011	7,537	11,404
Oil and gas sales, net of purchases [2]	216,370	240,105	851,451	905,249
Gain (loss) on oil price risk management contracts [3]	253	(2,198)	(8,457)	(9,903)
Royalties	(2,971)	(5,683)	(16,104)	(36,949)
Net sales [1]	**213,652**	**232,224**	**826,890**	**858,397**
Net sales realized price ($/boe) [4]	63.15	73.28	68.08	69.15

[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] Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 28.
[3] Includes the net of the put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Please refer to the "Loss (gain) on risk management contracts" section on page 19 for further details.
[4] Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 28.

Oil and gas sales, net of purchases, decreased by $23.7 million for the three months ended December 31, 2024, compared to the same period of 2023, mainly due to lower Brent benchmark oil price (Refer to the "Realized and Reference Prices" section on page 12 for further details on changes in prices), higher oil price differentials and higher purchased crude net margin. For the year ended December 31, 2024, oil and gas sales, net of purchases, decreased by $53.8 million compared to the same period of 2023, mainly due to a lower Brent benchmark oil price, lower volumes sold and higher purchased crude net margin.

Net sales for the three months and the year ended December 31, 2024, decreased by $18.6 million and $31.5 million, respectively, compared with the same periods of 2023. The following table describes the various factors that impacted net sales:

	Three months ended December 31	Year ended December 31
($M)	**2024-2023**	**2024-2023**
Net sales for the period ended December 31, 2023	232,224	858,397
Decrease due to 16% lower oil and gas price (YTD 4% lower)	(37,422)	(35,009)
Increase (decrease) due to variance of total produced volumes sold	13,687	(18,789)
Decrease in royalties	2,712	20,845
Decrease in oil price risk management contracts, net [1]	2,451	1,446
Net sales for the period ended December 31, 2024	**213,652**	**826,890**

[1] Includes put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Please refer to the "Loss (gain) on risk management contracts" section on page 19 for further details.

Oil and Gas Operating Costs

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Production costs (excluding energy costs)	29,091	37,122	139,726	139,917
Energy costs	20,647	19,005	76,631	69,924
Transportation costs	39,128	34,750	148,513	151,416
Post-termination cost	705	11,160	577	18,814
Inventory valuation	1,446	8,072	360	633
Trunkline costs	1,485	—	5,314	—
Total oil and gas operating costs	**92,502**	**110,109**	**371,121**	**380,704**

During the three months and the year ended December 31, 2024, total oil and gas operating costs decreased by $17.6 million and $9.6 million, respectively, compared to the same periods of 2023. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs (excluding energy costs) for the three months ended December 31, 2024, decreased 22% compared with the same period of 2023, primarily due to reduced well intervention activities during the quarter 2024. For the year ended December 31, 2024 production costs (excluding energy costs) was in line with the same period of 2023.
- Energy costs for the three months and the year ended December 31, 2024, increased 9% and 10%, respectively, compared with the same periods of 2023, mainly due to higher energy use related to greater heavy crude oil production levels and increase in electricity prices, partially offset by fixed-price contracts signed during the year 2024.
- For the three months ended December 31, 2024, transportation costs increased 13% compared with the same period of 2023, primarily due to higher volumes produced and transported during fourth quarter 2024. For the year ended December 31, 2024, transportation costs decreased 2% compared with the same period of 2023, as of result of lower volumes produced and transported primarily attributed to improved domestic wellhead sales.
- Post-termination obligations for the three months and the year ended December 31, 2024, decreased by $10.5 million and $18.2 million, respectively. In the periods of 2023, included post-termination obligations related to the relinquished Lote 192 Block, in Peru. Additionally, there are cost efficiencies in the execution of activities from returned blocks during 2024.
- Inventory valuation for the three months and the year ended December 31, 2024, decreased by $6.6 million and $0.3 million respectively compared with the same periods of 2023, mainly as a result of inventory draw.
- Trunkline costs corresponds to repairs and other activities resulting from unexpected failures in a trunkline in the Quifa block, which has already been resolved. The Company expects to recover a portion of these costs from the proceeds of claims on its material damages and third-party liability insurance policies.

Cost of Diluent and Oil Purchased

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Cost of diluent and oil purchased [1]	65,375	55,353	235,944	235,797

[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 28.

Cost of diluent and oil purchased correspond to the cost of third-party hydrocarbon volumes purchased primarily for dilution and refining usage as part of the Company’s oil operations, and marketing and transportation strategy. For the three months ended December 31, 2024, the cost of diluent and oil purchased, including the transportation and processing fees for volumes sold, increased by $10.0 million, compared with the same period of 2023, primarily due to an increase in heavy crude oil production, which demands higher volumes of diluent and fuel used for energy, and a reduction in light and medium crude oil production. For the year ended December 31, 2024, the cost of diluent and oil purchased was comparable.

Royalties

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Royalties Colombia	2,599	5,314	14,704	36,004
Royalties Ecuador	372	369	1,400	945
Royalties	**2,971**	**5,683**	**16,104**	**36,949**

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia and Ecuador. For the three months and the year ended December 31, 2024, royalties decreased by $2.7 million and $20.8 million, respectively, compared to the same periods of 2023, due to the change in the royalties payment method from in-cash to in-kind as per the ANH’s request, and a lower WTI oil benchmark price. Refer to the “Production Reconciled to Sales Volumes” section on page 11 for further details of royalties PAP paid in-cash and in-kind.

Depletion, Depreciation and Amortization

($M)	Three months ended December 31		Year ended December 31	
	2024	2023	2024	2023
Depletion, depreciation and amortization	65,249	68,411	262,518	278,269

For the three months and the year ended December 31, 2024, depletion, depreciation, and amortization expense ("**DD&A**") decreased by 5% and 6% respectively, compared to the same periods of 2023, due to lower production in light and medium crude oil assets and the end of the Neiva block production contract in June 2023, partially offset by the transfer of the Perico block to Oil & Gas properties at the end of 2023, the expansion of the development facilities on the Sabanero block, and the increase in water-handling capacity facilities on the CPE-6 block.

Impairment Expense, Exploration Expenses and Others

($M)	Three months ended December 31		Year ended December 31	
	2024	2023	2024	2023
Impairment expense of:				
Properties, plant and equipment	9,759	—	9,759	—
Exploration and evaluation assets	19,938	1,090	19,938	20,593
Other	450	327	2,230	4,643
Total impairment expense	30,147	1,417	31,927	25,236
Exploration expenses of:				
Geological and geophysical costs, and other	415	459	1,613	1,673
Minimum work commitment paid	—	358	—	358
Total exploration expenses	415	817	1,613	2,031
(Recovery) expense of asset retirement obligations	(2,214)	(1,621)	2,335	(25,622)
Impairment expense, exploration expenses and other	**28,348**	**613**	**35,875**	**1,645**

Properties, plant and equipment

As of December 31, 2024, the Company recognized impairment charges in properties, plant and equipment of $9.8 million, including $8.8 million in Central CGU due to return of the Entrerrios block to the ANH, and $1.0 million in North CGU related to the Creciente block.

As at December 31, 2023, the Company did not identify impairment indicators in properties, plant, and equipment.

Exploration and Evaluation Assets

During the year ended December 31, 2024, the Company recorded an impairment charge of $19.9 million (2023: $20.6 million) on exploration and evaluation ("**E&E**") assets , as follows: i) $11.9 million associated to Espejo block from Ecuador; and ii) $8.0 million in Colombia as a consequence of the preliminary results from the seismic activities related to the Llanos-119 block, which were below the Company's expectations. Frontera has requested the transfer of its exploration commitments in the block and subsequent relinquishment. During the year ended December 31, 2023, the Company recorded an impairment charge on E&E of assets in Colombia, mainly as a result of the Company's decision to proceed with steps to relinquish the VIM-22 block.

Other

During the year ended December 31, 2024, the Company recognized other impairment expenses of $2.2 million (2023: $4.6 million), mainly related to obsolete material inventories and impairment of crude oil inventories from Peru.

(Recovery) expense of asset retirement obligations

During the year ended December 31, 2024, the Company recognized an expense of asset retirement obligations of $2.3 million. During the year ended December 31, 2023, the Company recognized a recovery of asset retirement obligations of $25.6 million, mainly as a result of the sale of Frontera Energy OffShore Perú S.R.L, the wholly owned subsidiary that held a 100% W.I. in the Z1 Block, for a payment of $7.5 million to a third party. As a result of this transaction, the Company derecognized the asset retirement obligation related to the Z1 Block and recognized a $37.4 million asset retirement obligation recovery.

Other Operating Costs

($M)	Three months ended December 31		Year ended December 31	
	2024	2023	2024	2023
General and administrative	13,170	16,891	52,373	53,907
Special projects and other cost [1]	3,029	2,938	9,870	11,286
Share-based compensation	835	(745)	2,555	1,148
Restructuring, severance and other costs	2,096	3,744	5,312	8,548

[1] Mainly includes costs related to SAARA, including the commissioning period during 2023, and Peru.

General and Administrative ("G&A")

For the three months and the year ended December 31, 2024, G&A expenses decreased by 22% and 3%, respectively, compared with the same periods of 2023, mainly due to higher overhead recovery, partially offset by higher professional fees.

Special projects and other costs

For the three months ended December 31, 2024, special projects and other costs increased by 3% compared with the same period of 2023, mainly due to ProAgrollanos costs. For the year ended December 31, 2024, decreased by 13%, primarily due to a reduction in costs related to the SAARA project and the Z1 Block, following the sale of Frontera Energy Off Shore Perú S.R.L. in 2023.

Share-Based Compensation

For the three months and the year ended December 31, 2024, share-based compensation increased by $1.6 million and $1.4 million, respectively, compared with the same periods of 2023. The increase was primarily due to a higher share units in 2024, in addition, the 2023 expense was impacted by the cancellation of certain restricted share units. Share-based compensation reflects cash and non-cash charges relating to the vesting of restricted share units ("**RSUs**") and grants of deferred share units ("**DSUs**") under the Company's security-based compensation plan, which are subject to variability from movements in the underlying Common Share trading price, and the consolidation of stock option expenses from the Company's indirect majority-held subsidiary, CGX.

Restructuring, Severance and Other Costs

For the three months and the year ended December 31, 2024, restructuring, severance and other costs decreased by $1.6 million and $3.2 million, respectively, compared with the same periods of 2023, primarily due to the restructuring plan executed during 2023.

Non-Operating Costs

($M)	Three months ended December 31		Year ended December 31	
	2024	2023	2024	2023
Finance income	1,852	2,270	8,386	9,984
Finance expenses	(21,810)	(16,865)	(74,205)	(64,185)
Foreign exchange (loss) income	(1,795)	2,724	(11,041)	12,275
Other income (loss)	6,526	4,554	(899)	8,936

Finance Income

For the three months and the year ended December 31, 2024, finance income decreased by $0.4 million and $1.6 million, respectively, compared to the same periods of 2023, mainly due to a variation of interest rates on the investment trust accounts for abandonment requirements.

Finance Expenses

For the three months and the year ended December 31, 2024, finance expenses increased by $4.9 million and $10.0 million, respectively, compared to the same periods of 2023, mainly due to higher accretion expenses related to the maturity of certain liabilities, and additional interest resulting from the Bancolombia Working Capital Loan (as defined below) and additional interest resulting from lease liabilities.

Foreign Exchange (Loss) Income

For the three months and the year ended December 31, 2024, foreign exchange loss was of $1.8 million and $11.0 million, respectively, as a result of the depreciation of the COP against the USD during the fourth quarter of 2024, in addition the year end was impacted by the transfer from the cumulative translation adjustment of the Other Comprehensive (Loss) Income ("**OCI**") to Consolidated Statement of Income of a return of capital and dividends of ODL. In the same period of 2023, the foreign exchange income was $2.7 million and $12.3 million, respectively, as a result of the COP's depreciation against the USD on the translation of the debt consolidated from Puerto Bahia during the first quarter 2023, offset by the transfer from the cumulative translation adjustment of the OCI to Consolidated Statement of Income of a return of capital of ODL for $6.8 million. Foreign exchange rates (COP:USD) as of December 31, 2024, and 2023, were 4,409.15:1 and 3,822.05:1, respectively.

Other Income (Loss)

For the three months ended December 31, 2024, the Company recognized other income of $6.5 million were mainly attributable to the net of reversal and new contingencies and for the same period of 2023, the Company recognized other income of $4.6 million primarily attributable to insurance compensation for the Sabanero block. For the year ended December 31, 2024, the Company recognized other loss of $0.9 million primarily due to contingencies partially offset by income related to insurance compensation for the Sabanero block during the first quarter of 2024, and during the same period of 2023, the Company recognized other income of $8.9 million,was mainly related to the reversal of the legal claim from the late delivery of production from the Quifa block prior to 2014.

(Loss) gain on Risk Management Contracts

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Gain (loss) on oil price risk management contracts	253	(2,198)	(8,457)	(9,903)
Realized gain on foreign exchange risk hedge [(1)(2)]	921	4,187	6,951	17,257
Realized gain (loss) on risk management contracts	1,174	1,989	(1,506)	7,354
Unrealized (loss) gain on risk management contracts	(10,035)	7,000	(13,976)	11,880
Total (loss) gain on risk management contracts	(8,861)	8,989	(15,482)	19,234

(1) For determination of operating netback, during the three months and the year ended December 31, 2024, the Company estimates an attribution of $Nil and $3.4 million, respectively, of the total realized FX hedge to production cost (excluding energy costs) (2023: $2.1 million and $9.1 million respectively), estimates an attribution of $Nil and $1.3 million, respectively, of the total realized FX hedge to energy (2023: $0.7 million and $2.9 million, respectively), and estimates an attribution of $Nil and $1.0 million, respectively, of the total realized FX hedge to transportation (2023: $0.8 million and $3.3 million, respectively). Refer to the "Non-IFRS and Other Financial Measures'' section on page 28.

(2) Realized gain for derivatives resulting from the PIL Loan Facility (as defined below) are not included in the netback.

For the three months ended December 31, 2024, the realized gain on risk management contracts was $1.2 million, resulting from (i) $0.3 million net of the positive cash settlement of $4.0 million from oil price contracts during the period partially offset by the put premiums paid for expired positions of $3.7 million and (ii) $0.9 million positive cash settlement on derivatives resulting from the PIL Loan Facility (as defined below). In the same period of 2023, the Company realized a gain on risk management contracts of $2.0 million, resulting from a gain on cash settlement of risk management contracts of foreign exchange currency of $4.2 million, partially offset by $2.2 million, related to premiums paid on oil price risk management contracts.

During the year ended December 31, 2024, the realized loss on risk management contracts was $1.5 million, resulting from; (i) a loss of $8.5 million, due to the net of the put premiums paid for expired positions by $14.5 million and the positive cash settlement received by $6.1 million from oil price contracts during the period, and partially offset by (ii) a gain of $7.0 million from the cash settlement of foreign exchange risk management contracts. In the same period of 2023, the realized gain on risk management contracts was $7.4 million, resulting from; (i) a gain on cash settlement of risk management contracts of foreign exchange currency of $8.3 million during the year ended December 31, 2023 and the unwinding of risk management contracts of foreign exchange currency of $9.0 million during the second quarter of 2023, and partially offset by (ii) $9.9 million related to premiums paid on oil price risk management contracts.

For the three months and the year ended December 31, 2024, risk management contracts had an unrealized loss of $10.0 million and $14.0 million, respectively, compared to a gain of $7.0 million and $11.9 million, respectively, in the same periods of 2023, primarily due to mark to market variances from foreign exchange risk management contracts and 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 is designed to protect a minimum of 40% of the estimated production with a tactical approach, using derivative commodity instruments to protect the revenue generation and cash position of the Company, while maximizing the upside.

				Avg. Strike Prices	Carrying Amount	
Type of Instrument	Term	Benchmark	Volume (bbl)	Put $/bbl	Assets	Liabilities
Put	January to April 2025	Brent	1,502,000	70	—	2,669
Total as at December 31, 2024			1,502,000		—	2,669

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

				Avg. Strike Prices
Type of Instrument	Term	Benchmark	Volume (bbl)	Put $/bbl
Put	April to June 2025	Brent	766,000	70
Put Spread	May to June 2025	Brent	400,000	55 - 70
		Total volume (bbl)	1,166,000	

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. In addition to the standard hedging program, Puerto Bahia entered into a selling forward in order to hedge the foreign exchange risk related to the Reficar Connection Project payments.

As of December 31, 2024, 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	April to June 2025	USD / COP	60,000,000	4,200/4,626	—	810
Zero-cost collars	July to September 2025	USD / COP	60,000,000	4,200/4,795	—	593
Forward [(1)]	February 2025	USD / COP	7,000,000	4,303	—	219
Zero-cost collars	January to March 2025	USD / COP	60,000,000	4,150/4,618	—	277
Total as at December 31, 2024					—	1,899

[(1)] Contracts related to the Reficar Connection Project.

Subsequently of the end of the quarter, the Company has not entered into new hedges.

Income Tax Expense

	Three months ended December 31		Year ended December 31	
($M)	2024	2023	2024	2023
Current income tax recovery (expense)	3,096	(5,879)	(9,979)	(33,020)
Deferred income tax (expense) recovery	(36,497)	44,886	(93,126)	28,890
Total income tax (expense) recovery	(33,401)	39,007	(103,105)	(4,130)

For the three months and the year ended December 31, 2024, the Company recognized a current income tax recovery of $3.1 million and expense of $10.0 million, respectively, compared to a current income expense of $5.9 million and $33.0 million, respectively, in the same periods of 2023. Additionally, the Company recognized a deferred income tax expense of $36.5 million and $93.1 million, respectively, compared to a deferred income tax recovery of $44.9 million and $28.9 million, respectively, in the same periods of 2023.

The income tax recovery during the fourth quarter of 2024 was due to the recording of the current tax provision for 2024. And the income tax expense generated in the year 2024 was mainly due to the reversals of tax contingencies.

The deferred tax expense for the three months and the year ended December 31, 2024 was mainly due to foreign exchange rate fluctuations and the offsetting of tax losses.

CRA 2016 Settlement

The Company entered into Minutes of Settlement dated July 12, 2024, with the Canadian Minister of National Revenue to resolve a dispute in connection with the Company's 2016 restructuring process and relating to, among other things, the fair market value of the Company's Common Shares as at November 2, 2016, the computation of the net capital losses and the computation of non-capital losses of the Company in respect of its taxation year ending December 31, 2016 (the "**CRA Settlement**").

The Company has assessed the impact of the CRA Settlement on the computation of the historical paid-up capital in respect of the Common Shares. This assessment has resulted in a decrease in the net capital losses of the Company, as last reported in the 2023 Annual Financial Statements, and an increase in the computed amount of the historical paid-up capital in respect of the Common Shares. The resulting increase in the computed amount of the historical paid-up capital in respect of the Common Shares may reduce the amount of the dividends deemed to have been received by certain shareholders in connection with the repurchase of Common Shares under the Company's substantial issuer bid, completed on August 11, 2022.

International Tax Reform – OECD Pillar Two Model Rules

Certain jurisdictions in which the Company operates have enacted global minimum tax legislation generally consistent with the Pillar Two model rules released by the Organization for Economic Co-operation and Development ("OECD"). The Pillar Two model rules are designed to ensure large multinational enterprises pay a minimum level of tax in each jurisdiction where they operate by imposing a top-up tax in jurisdictions where the Pillar Two effective tax rate is below 15%.

Canada's Pillar Two global minimum tax legislation is effective January 1, 2024 for the Company. Based on assessments of the most recent country-by-country reporting data and available financial information of the Company's constituent entities, virtually all jurisdictions in which the Company operates should benefit from transitional safe harbor relief. Consequently, the Company does not estimate a significant impact derived from this new tax legislation.

The IASB issued amendments to IAS 12 Income Taxes on May 23, 2023 to clarify that the accounting standard applies to income taxes arising from implementing the Pillar Two model rules, and to introduce a mandatory temporary exception to recognizing and disclosing Pillar Two deferred taxes and add certain disclosure requirements. The Company has adopted the IAS 12 amendments; however, the application of such amendments has minimal impact on the Company's consolidated financial statements.

Net (Loss) Income

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Net (loss) income [1]	(29,401)	92,038	(24,162)	193,497
Per share – basic ($)	(0.36)	1.08	(0.29)	2.27
Per share – diluted ($)	(0.36)	1.04	(0.29)	2.19

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

During the fourth quarter of 2024, the Company reported a net loss, attributable to equity holders of the Company, of $29.4 million, which included an income tax expense of $33.4 million (including $36.5 million of deferred income tax expenses), finance expenses of $21.8 million, $8.9 million related to loss on risk management contracts, and foreign exchange loss of $1.8 million, partially offset by income from operations of $14.9 million (net of a non cash impairment expense of $30.1 million) and $13.2 million from share of income from associates. This compared to net income, attributable to equity holders of the Company, of $92.0 million for the fourth quarter of 2023, which included operating income of $36.3 million, income tax recovery of $39.0 million, $14.8 million of share of income from associates, $9.0 million related to income on risk management contracts, foreign exchange gain of $2.7 million and finance income of $2.3 million, partially offset by finance expenses of $16.9 million.

For the year ended December 31, 2024, the Company reported a net loss, attributable to equity holders of the Company, of $24.2 million, which included an income tax expense of $103.1 million (including $93.1 million of deferred income tax expenses), finance expenses of $74.2 million, $15.5 million related to loss on risk management contracts and $11.0 million of foreign exchange loss, partially offset by operating income of $116.7 million (net of a non cash impairment expense of $31.9 million) and $53.9 million from share of income from associates. This compared to net income, attributable to equity holders of the Company, of $193.5 million, which included operating income of $154.2 million, a share of income from associates amounting to $56.5 million, a gain of $19.2 million from risk management contracts, foreign exchange gains of $12.3 million, finance income by $10.0

million and other income of $8.9 million, partially offset by finance expenses of $64.2 million and income tax expense of $4.1 million.

Capital Expenditures and Acquisitions

($M)	Three months ended December 31		Year ended December 31	
	2024	**2023**	**2024**	**2023**
Development drilling	5,996	20,946	108,859	120,122
Development facilities [(1)]	36,021	32,409	105,037	91,877
Colombia and Ecuador exploration	5,883	6,004	26,919	38,257
Other	11,396	12,732	25,892	19,865
Total Colombia and Ecuador upstream capital expenditures	**59,296**	**72,091**	**266,707**	**270,121**
Colombia infrastructure	25,999	9,724	47,882	15,296
Guyana exploration	571	477	3,267	157,317
Total capital expenditures [(2)]	**85,866**	**82,292**	**317,856**	**442,734**

(1) Investments related to the replacement and repairs of the affected assets in the Quifa block due to the trunkline unexpected failures are not included.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 28.

Capital expenditures for the three months and the year ended December 31, 2024, were $85.9 million and $317.9 million, respectively, compared with $82.3 million and $442.7 million, respectively, in the same periods of 2023, as follows:

Development drilling. During the three months and the year ended December 31, 2024, development drilling expenditures were $6.0 million and $108.9 million, respectively, compared to $20.9 million and $120.1 million, respectively, in the same periods of 2023. During the fourth quarter of 2024, 2 development wells were drilled in the Sabanero block, while 13 development wells were drilled in the same period of 2023, in the Quifa and CPE-6 blocks. For the year ended December 31, 2024, 65 development wells (including two injector wells) were drilled in the Quifa, CPE-6 and Sabanero blocks, in Colombia, and 3 development wells were drilled in the Perico block, in Ecuador, while in the same period of 2023 a total of 65 development wells (including two injector wells) were drilled in the Quifa, CPE-6, and Cubiro blocks. During 2024, development drilling was lower due to optimizations during the construction of the wells.

Development facilities. During the three months and the year ended December 31, 2024, development facilities expenditures were $36.0 million and $105.0 million, respectively, mainly related to the expansion of the development facilities that increased water-handling capacity at the CPE-6 block to 360 Mbwpd during the last quarter; new and improved flow lines in the Quifa block supporting new well production and the SAARA connection; and the expansion of the VIM-1 and Sabanero blocks facilities. For the same periods of 2023, development facilities expenditures were $32.4 million and $91.9 million, respectively, mainly related to the expansion of the development facilities in the CPE-6 block increasing water-handling capacity to 240 Mbwpd and new flow lines in the Quifa block to integrate with the SAARA project, and expansion of gas compression facilities in the VIM-1 block.

Colombia and Ecuador Exploration. During the three months and the year ended December 31, 2024, expenditures related to exploration activities were $5.9 million and $26.9 million, respectively, compared $6.0 million and $38.3 million, respectively, in the same periods of 2023. During the three months ended December 31, 2024, the exploration activities executed included one exploration well spud and predrilling activities, related to socialization, for two exploration wells, in Colombia. Details regarding exploration activities in Colombia and Ecuador are as follows:

Colombia. During the fourth quarter of 2024, the Company's exploration focus remained on the Lower Magdalena Valley and Llanos Basins in Colombia. At the Cachicamo block, the Papilio-1 well was spud on December 31, 2024, reaching a total depth of 8,580 feet MD by January 8, 2025. Integration of drilling data and petrophysical interpretation identified 21.5 feet of net pay, and well is currently producing approximately 135 bopd with 97% BSW. The Greta Norte-1 well was drilled on January 18, 2025, and reached a total depth of 12,174 feet MD on February 5, 2025. Integration of drilling data and petrophysical interpretation identified 12.5 feet of net pay, and the well is currently in completion phase. At the VIM-1 block, ongoing discussions with authorities and communities are taking place to drill the Hidra-1 well in 2025. At the Llanos 119 Block, preliminary results from the seismic of 80 square kilometers of 3D seismic data were below the Company's expectations. Frontera has requested the transfer of its exploration commitments in the block and subsequent relinquishment. In addition, the Company is also engaged in pre-seismic and pre-drilling activities related to social and environmental studies in the Llanos-99 and VIM-46 blocks.

Ecuador. At the Espejo block (Frontera holds a 50% W.I. and is a non-operator), the Espejo Sur-B3 well continues its long-term tests with a production of 437 bbl/d gross and a BSW of 71%. The development plan will be assessed during the first quarter of 2025.

Other. Other capital expenditures for the three months and the year ended December 31, 2024, were $11.4 million and $25.9 million, respectively. The expenditures were mainly related to generation facilities partially funded through the reimbursement of insurance claim related to the Sabanero lock.

Colombia infrastructure. Capital expenditures for the three months and the year ended December 31, 2024, was $26.0 million and $47.9 million, respectively, mostly related to Puerto Bahia investments, including: (i) the Reficar Connection Project by $21.1 million and $30.9 million, respectively, including engineering and civil works, costs associated to the project´s rights of way, and others, (ii) tank maintenance, and (iii) general cargo terminal equipment and facilities. In addition, includes investment in the SAARA project. During the same periods of 2023, capital expenditures were $9.7 million and $15.3 million, respectively, for the SAARA project and Puerto Bahia.

Guyana exploration. During the three months and the year ended December 31, 2024, Guyana exploration expenditures were $0.6 million and $3.3 million, respectively, mainly related to post-well studies and other capitalized expenses, compared to $0.5 million and $157.3 million, respectively, during the same periods of 2023, which were related to the Wei-1 exploration well.

Selected Quarterly Information

		2024				2023			
Operational and financial results		**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Heavy crude oil production	(bbl/d)	27,740	25,312	24,839	23,398	23,002	24,097	24,051	22,270
Light and medium crude oil combined production	(bbl/d)	12,234	12,794	12,583	12,580	13,795	13,964	15,188	16,518
Total crude oil production	(bbl/d)	39,974	38,106	37,422	35,978	36,797	38,061	39,239	38,788
Conventional natural gas production	(mcf/d)	2,633	3,192	4,019	3,283	4,760	5,250	5,626	8,590
Natural gas liquids production	(boe/d)	1,970	1,950	1,785	1,639	1,635	1,820	1,823	1,291
Total production	(boe/d)	42,406	40,616	39,912	38,193	39,267	40,802	42,049	41,586
Sales volumes, net of purchases	(boe/d)	36,773	34,192	31,523	30,185	34,449	35,289	35,799	30,424
Brent price reference	($/bbl)	74.01	78.71	85.03	81.76	82.85	85.92	77.73	82.10
Oil and gas sales, net of purchases (1)	($/boe)	63.96	68.06	76.18	73.71	75.76	78.48	67.91	69.07
Gain (loss) on oil price risk management contracts (2) (3)	($/boe)	0.07	(0.45)	(1.32)	(1.27)	(0.69)	(0.59)	(0.80)	(1.16)
Royalties (2)	($/boe)	(0.88)	(0.91)	(2.01)	(1.64)	(1.79)	(3.76)	(3.02)	(3.36)
Net sales realized price (1)	($/boe)	63.15	66.70	72.85	70.80	73.28	74.13	64.09	64.55
Production costs (excluding energy costs), net of realized FX hedge impact (2)	($/boe)	(7.66)	(8.88)	(10.79)	(10.21)	(9.69)	(8.82)	(8.45)	(8.12)
Energy costs, net of realized FX hedge impact (2)	($/boe)	(5.29)	(5.11)	(4.74)	(5.29)	(5.06)	(5.04)	(3.94)	(3.95)
Transportation costs, net of realized FX hedge impact(2)	($/boe)	(11.20)	(12.12)	(10.92)	(11.33)	(11.02)	(11.73)	(10.89)	(11.20)
Operating netback per boe (1)	($/boe)	39.00	40.59	46.40	43.97	47.51	48.54	40.81	41.28
Revenue	($M)	290,614	278,475	279,523	265,175	299,501	308,867	289,869	250,366
Net (loss) income (4)	($M)	(29,401)	16,588	(2,846)	(8,503)	92,038	32,582	80,207	(11,330)
Per share – basic ($)	($)	(0.36)	0.20	(0.03)	(0.10)	1.08	0.38	0.94	(0.13)
Per share – diluted ($)	($)	(0.36)	0.19	(0.03)	(0.10)	1.04	0.37	0.92	(0.13)
General and administrative	($M)	13,170	12,719	12,928	13,556	16,891	11,925	12,422	12,669
Operating EBITDA (5)	($M)	113,479	103,184	110,321	97,248	121,036	137,800	116,461	91,922
Capital expenditures (5)	($M)	85,866	82,411	80,198	69,381	82,292	74,130	154,860	131,452

(1) Non-IFRS ratio. Refer to the “Non-IFRS and Other Financial Measures'' section on page 28.
(2) Supplementary financial measure. Refer to the “Non-IFRS and Other Financial Measures'' section on page 28.
(3) Includes the net of the put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Please refer to the “Loss (gain) on risk management contracts” section on page 19 for further details.
(4) Refers to net (loss) income attributable to equity holders of the Company.
(5) Non-IFRS financial measure. Refer to the “Non-IFRS and Other Financial Measures” section on page 28 for further details.

Over the past eight quarters, the Company’s sales have fluctuated due to changes in production, movement in Brent benchmark prices, timing of cargo shipments, and fluctuations in crude oil price differentials. During the year 2024, production increased mainly due to (i) an increase in heavy crude oil as a result of the successful development drilling campaigns in the CPE-6 and Sabanero blocks, the new water facilities in the CPE-6 block, the reactivation of wells in the Sabanero block, and the increased processing capacity at SAARA and; (ii) natural gas liquids production increased resulting from the VIM-1 block development of the facilities. These were partially offset by light and medium crude oil combined production and conventional natural gas production decrease mainly due to natural decline. During the last year, transportation costs increased, mainly due to the regular annual increase of transportation tariffs. Energy costs increased primarily as a result increase in market prices. In addition, production costs (excluding energy costs) have also fluctuated mainly due to the inflationary pressures on services, wages indexation, well services and maintenance activities, and changes in barrels produced affecting variable costs.

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

Selected Annual Information

	As at and for the year ended December 31		
($M, except as noted)	**2024**	**2023**	**2022**
Revenue	1,113,787	1,148,603	1,270,758
Net (loss) income[1]	(24,162)	193,497	286,615
Per share – basic ($)	(0.29)	2.27	3.16
Per share – diluted ($)	(0.29)	2.19	3.08
Cash and cash equivalents	192,577	159,673	289,845
Total assets	2,900,877	3,016,280	2,737,239
Total non-current liabilities	661,129	637,586	530,194
Total liabilities	1,174,744	1,182,287	1,148,035

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

Revenue decreased to $1.11 billion in 2024 from $1.15 billion in 2023, and from $1.27 billion in 2022. The revenue decrease was primarily due to fluctuations in Brent benchmark oil prices and variance of total produced volumes sold.

Net (loss) income, attributable to equity holders of the Company, for 2024 was $24.2 million, compared to $193.5 million in 2023, and $286.6 million in 2022, mainly as a result of lower income from operations, the recognition and derecognition of deferred income taxes, and the impairment or reversal of impairment of oil and gas assets.

Total assets decreased to $2.90 billion in 2024, compared to $3.02 billion in 2023, primarily due to a reduction in deferred tax assets and income tax receivables, while in 2023 increased from $2.74 billion in 2022 mainly as a result of investments in oil and gas properties and exploration and evaluation assets, particularly in Guyana during the year 2023.

Cash and cash equivalents increased to $192.6 million in 2024 from $159.7 million in 2023, and decreased from $289.8 million in 2022, as a result of variances in cash flows from operations mainly due to changes in the Brent benchmark oil price and high exploration investment activities, particularly in Guyana during the year 2023.

Infrastructure Colombia

Frontera has investments in certain infrastructure, midstream and other assets, including storage, 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 bi-directional hydrocarbon flow line connecting port facility and the Cartagena refinery.	99.97% interest in Puerto Bahia	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/day	100% interest in PIL (which holds a 35% interest in the ODL Pipeline)	Equity Method [2]
SAARA [3]	Reverse osmosis water treatment, name plate capacity of 1,000,000 bwpd	100% interest in Agro Cascada	Consolidation
ProAgrollanos	Palm oil plantation, 20,000-27,000 tons per year of fresh fruit bunch	100% interest in ProAgrollanos	Consolidation

(1) Interests include both direct and indirect interests.
(2) Equity method accounting requires that the carrying value of the investment be increased to reflect the Company's proportionate share of net income, or reduced to reflect its share of net losses and dividends declared.
(3) SAARA is a project implemented by Agro Cascada S.A.S.

Performance Highlights

		Q4 2024	Q3 2024	Q4 2023	Year ended December 31 2024	Year ended December 31 2023
Operational and IFRS Results						
Volumes pumped at oil pipeline facility	(bbl/d)	235,528	243,997	252,810	243,669	243,617
Volumes throughput at port liquids facility	(bbl/d)	61,990	46,964	52,754	56,020	60,718
Volumes RORO at port general cargo facility	(Units)	21,676	20,914	15,794	74,425	101,439
Volumes at port Break Bulk Volumes	(Tons/m3)	34,690	15,067	23,230	69,494	82,580
Volumes of water received from production fields	(bwpd)	78,716	49,589	71,406	44,121	56,441
Production of fresh fruit bunch	(Tons)	6,183	5,184	3,650	25,357	21,218
Infrastructure Colombia segment income	($M)	15,183	13,122	13,221	55,477	58,601
Infrastructure Colombia segment cash flow from operating activities	($M)	14,788	12,679	4,243	58,034	42,579
Non IFRS Results [(1)]						
Adjusted Infrastructure Revenues	($M)	45,278	42,152	43,622	171,392	169,920
Adjusted Infrastructure EBITDA	($M)	27,532	26,181	27,324	107,223	110,057
Adjusted Infrastructure Cash	($M)	72,423	75,625	71,631	72,423	71,631
Adjusted Infrastructure Debt	($M)	116,895	123,902	111,423	116,895	111,423
Capital Expenditures Infrastructure Colombia Segment	($M)	25,999	13,860	9,724	47,882	15,296

(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 28.

Infrastructure Colombia Segment Results

The 2024 Annual Consolidated Financial Statements include the following amounts relating to the Infrastructure Colombia Segment:

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Revenue	13,873	10,625	48,542	49,041
Costs	(8,099)	(8,798)	(31,438)	(33,296)
General and administrative expenses	(1,507)	(1,055)	(5,903)	(5,527)
Depletion, depreciation and amortization	(1,877)	(1,938)	(7,576)	(6,546)
Other operating costs	(407)	(446)	(2,060)	(1,547)
Infrastructure Colombia income (loss) from operations	**1,983**	**(1,612)**	**1,565**	**2,125**
Share of Income from associates - ODL	13,200	14,833	53,912	56,476
Infrastructure Colombia segment income	**15,183**	**13,221**	**55,477**	**58,601**
Infrastructure Colombia segment cash flow from operating activities	14,788	4,243	58,034	42,579
Capital Expenditures Infrastructure Colombia Segment [(1)]	25,999	9,724	47,882	15,296

(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 28.

The Company's Infrastructure Colombia Segment income for the three months and the year ended December 31, 2024 increased $2.0 million and decreased $3.1 million, respectively, compared to the same periods of 2023. The variances were mainly due to fluctuations in revenue from Puerto Bahia, ProAgrollanos, and SAARA, lower operating cost in Puerto Bahia and SAARA, partially offset by a reduced share of income from ODL and higher G&A expenses within the segment.

Segment capital expenditures for the three months and the year ended December 31, 2024, were $26.0 million and $47.9 million, respectively, mostly for Puerto Bahia investments, including: (i) the Reficar Connection Project by $21.1 million and $30.9 million, respectively, including engineering and civil works, costs associated to the project´s rights of way, and others, (ii) tank maintenance, and (iii) general cargo terminal equipment and facilities. In addition, includes investment in the SAARA project. During the same periods of 2023, capital expenditures were $9.7 million and $15.3 million, respectively, for the SAARA project and Puerto Bahia.

ODL Pipeline

The Company, through its 100%-owned subsidiary PIL, has a 35% equity investment in the ODL pipeline, which connects the Rubiales, Quifa, Caño Sur, Llanos-34, among other blocks to the Monterrey or Cusiana Stations in the Casanare Department.

For the three months and the year ended December 31, 2024, ODL generated an EBITDA of $66.5 million and $274.4 million, respectively, and $37.7 million and $154.0 million, respectively, of net income. The ODL results are consolidated through the equity method in the Company's 2024 Annual Consolidated Financial Statements as "Share of income from associates".

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

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Revenue	89,728	94,277	351,000	345,370
FEC revenue (billed units)	7,573	7,776	29,608	30,525
Third party revenues	82,155	86,501	321,392	314,845
Costs	(16,270)	(12,637)	(54,020)	(43,094)
General administrative expenses	(6,985)	(5,776)	(22,628)	(17,019)
Depletion, depreciation and amortization	(6,855)	(8,188)	(30,866)	(28,902)
Other non-operating expense	(1,424)	(2,644)	(6,337)	(8,275)
Income tax	(20,479)	(22,653)	(83,113)	(86,720)
ODL Net Income	**37,715**	**42,379**	**154,036**	**161,360**

($M)	**December 31 2024**	**December 31 2023**
ODL debt	36,954	45,147
ODL cash and cash equivalents	76,979	131,839

The following table shows the volumes pumped per injection point:

	Three months ended December 31		Year ended December 31	
(bbl/d)	**2024**	**2023**	**2024**	**2023**
At Rubiales Station	167,272	173,888	169,890	169,701
At Jagüey and Palmeras Stations	68,256	78,922	73,779	73,916
Total	**235,528**	**252,810**	**243,669**	**243,617**

The following table shows the volumes received per block:

	Three months ended December 31		Year ended December 31	
(bbl/d)	**2024**	**2023**	**2024**	**2023**
Rubiales	100,604	106,817	102,794	107,755
Quifa	28,384	28,534	28,800	29,392
CPE-6 and Sabanero	1,501	4,094	2,405	2,645
Other blocks	89,816	96,897	94,576	87,968
Total	**220,305**	**236,342**	**228,575**	**227,760**

For the three months and the year ended December 31, 2024, the Company recognized $13.2 million and $53.9 million, respectively, as its share of income from ODL, which was lower than the same periods of 2023 by $1.6 million and $2.6 million respectively. This result was primarily due to an increase in operating costs and G&A expenses resulting from COP variance, inflationary pressures on services and wages indexation. The fourth quarter 2024 was also affected by lower volumes transported partially offset by a 7.8% increase in pipeline transportation tariffs since September 2024.

During the three months and the year ended December 31, 2024, ODL declared net dividends to PIL of $Nil and $54.9 million, respectively (2023: $Nil and $37.0 million, respectively), and a return of capital of $Nil and $7.9 million, respectively (2023: $5.1 million and $10.3 million, respectively). During the three months and the year ended December 31, 2024, PIL received cash of $16.9 million and $60.3 million, respectively, in dividends and return of capital from ODL (2023: $5.0 million and $42.5 million, respectively).

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 multipurpose 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 with a nominal capacity of 2,672,000 barrels, and RORO and breakbulk services in the general cargo terminal.

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Revenue	11,502	10,134	42,162	45,487
Liquids port facility	7,726	6,771	29,425	30,055
FEC liquids port facility	1,152	1,719	6,972	7,379
Third party liquids port facility	6,574	5,052	22,453	22,676
General cargo	3,776	3,363	12,737	15,432
Costs	(5,088)	(5,860)	(21,558)	(23,130)
General and administrative expenses	(1,390)	(952)	(5,427)	(5,148)
Depletion, depreciation and amortization	(1,657)	(1,569)	(6,804)	(5,562)
Other operating costs	(407)	(446)	(2,060)	(1,547)
Puerto Bahia Operating Income	2,960	1,307	6,313	10,100

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

	Three months ended December 31		Year ended December 31	
(bbl/d)	**2024**	**2023**	**2024**	**2023**
FEC volumes	11,626	11,971	13,513	12,863
Third party volumes	50,364	40,783	42,507	47,855
Total	**61,990**	**52,754**	**56,020**	**60,718**

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

		Three months ended December 31		Year ended December 31	
		2024	**2023**	**2024**	**2023**
RORO	units [(1)]	21,676	15,794	74,425	101,439
	dwell time in days [(2)]	48	82	54	52
Break Bulk Volumes	Tons/m3 [(3)]	34,690	23,230	69,494	82,580

[(1)] Carry wheeled cargo, mainly corresponds to 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)] Other types of cargo different from wheeled cargo.

For the three months and the year ended December 31, 2024, Puerto Bahia had an operating income of $3.0 million and $6.3 million, respectively (2023: $1.3 million and $10.1 million, respectively). During the year 2024, the reduction was mainly due to lower volumes handled at the liquids terminal as a result of lower the navigability levels in the Magdalena River due to weather conditions, and lower volumes in general cargo of RORO and break bulk. During the fourth quarter, compared to the same period of 2023, the volumes at liquids terminal and general cargo increased significantly. In addition, during the year 2024, there was a tariff increase in RORO and a costs reduction of 13% and 7%, respectively, primarily resulting from the end of the port operation outsourcing contract.

The Reficar Connection Project is expected to become operational by the second quarter of 2025. This connection facilitates the continuous transport of crude oil and other hydrocarbons between the two locations and has a capacity of 84,000 barrels per day; capable of handling both, imported and domestically produced crude oil. As for the year ended December 31, 2024, the Company has invested $32.2 million.

On July 22, 2024, Frontera announced that its subsidiary, Puerto Bahia and GASCO had entered into a Framework Collaboration Agreement to jointly pursue a LPG project at the Puerto Bahia port, and currently working groups have been assembled and detailed engineering work is taking place. The estimated cost of the project is expected to range between $50 and $60 million, which will be shared between Puerto Bahia and GASCO. Puerto Bahia's contributions are expected to be largely in-kind and the project is expected to be commissioned by 2027.

Water Treatment Facility and Palm Oil Plantation

In 2021, Frontera launched a feasibility analysis of the agricultural water reuse utilization system, SAARA, consisting of a reverse osmosis plant water treatment facility (built in 2016) that the Company began recommissioning in 2023. The plant will help solve and take advantage of the availability of production water from the Quifa and Rubiales blocks. The plant was designed to remove salts from the treated water to bring it to a state suitable for use in agricultural irrigation for 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. Spanning across approximately 2,960 hectares currently planted, its oil palm plantation yielded 22,823 tons of fresh fruit bunches in the last twelve months. These crops typically exhibit an estimated productive lifespan of 30 years.

A portion of the water treated by SAARA is irrigated and reused in ProAgrollanos agricultural activities, increasing the irrigation and targeting improving palm crop productivity within the next 24 months. During the year 2024, SAARA processed approximately 15 million barrels of water, irrigating approximately 400 hectares of palm oil crops in ProAgrollanos.

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

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Revenue	2,371	491	6,380	3,554
Fresh fruit bunch from palm oil	1,253	491	4,423	3,554
SAARA	1,118	—	1,957	—
Costs	(3,011)	(2,938)	(9,880)	(10,166)
Fresh fruit bunch from palm oil	(1,352)	(1,039)	(4,216)	(3,393)
SAARA	(1,659)	(1,899)	(5,664)	(6,773)
General and administrative expenses	(117)	(103)	(476)	(379)
Depletion, depreciation and amortization	(220)	(369)	(772)	(984)
SAARA and Palm Oil Assets Operating Loss	**(977)**	**(2,919)**	**(4,748)**	**(7,975)**

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

		Three months ended December 31		Year ended December 31	
($M)		**2024**	**2023**	**2024**	**2023**
Fresh fruit bunch from palm oil (produced - sold)	(Tons)	6,183	3,650	25,357	21,218
Production per hectare per year (1)	(Tons/ha/year)	8.40	7.17	8.40	7.17
Palm oil fruit price	($/Ton)	206	156	176	166
Volumes of reverse osmosis water treated	(bwpd)	78,716	71,406	44,121	56,441
Volumes of water irrigated in palm oil cultivation (2)	(bwpd)	80,276	49,201	40,837	41,159

(1) Tons per hectare per year for the three months ended December 31, are calculated using the total production for the last twelve months ended December 31.

(2) Differences between the water received and the water irrigated are due to the water being in the plant undergoing treatment or is temporarily stored within the plant's facilities.

For the three months and the year ended December 31, 2024, sales from fresh fruit bunches of oil palm was $1.3 million and $4.4 million, respectively, an increase of $0.8 million and $0.9 million, respectively, compared to the same periods of 2023, resulting primarily from an increase of market prices during the last quarter of the year 2024, and in field productivity. Fluctuation in fruit production volume is attributed to factors including climate conditions, agricultural practices (i.e. fertilization), workforce availability, changes in the administration operation model and community blockades in the area near to the crop.

During the three months and the year ended December 31, 2024, the volumes of water received and irrigated for palm oil plantations were higher and lower, respectively, compared to the same periods in 2023, mainly due to the temporary suspension of the operation of the plant following the conclusion of the project's pilot program on January 31, 2024, and subsequently reactivated in June 2024 after the signature of the agreement with Ecopetrol to start the first phase of the SAARA project. For the three months ended December 31, 2024, the project processed 78,716 barrels of water per day generating a revenue of $1.1 million. The Company processed an average of 99,366 barrels of water per day in December and peaked a daily record during the fourth quarter at 185,000 bwpd. The Company remains focused on reaching the Company's goal of processing 250,000 bwpd, and made an investment of $8.8 million during the year ended December 31, 2024.

Agro Cascada, a wholly owned subsidiary of the Company, borrowed COP$41,927 million (roughly $9,5 million) from Citibank Colombia under a 1-year facility to support the development of the Company's water treatment facilities. On October 10, 2024 and November 21, 2024, the lender disbursed COP $29,337 million and COP $12,590 million, respectively. Frontera Energy Colombia Corp. Sucursal Colombia acted as a guarantor of the loan.

Non-IFRS and Other Financial Measures

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

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

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

Non-IFRS Financial Measures

Operating EBITDA

EBITDA is a commonly used non-IFRS financial measure that adjusts net income as reported under IFRS to exclude the effects of income taxes, finance income and expenses, and DD&A. Operating EBITDA is a non-IFRS financial measure that represents the operating results of the Company's primary business, excluding the following items: restructuring, severance and other costs, post-termination obligation, trunkline costs, payments of minimum work commitments and, certain non-cash items (such as impairments, foreign exchange, unrealized risk management contracts, and share-based compensation) and gains or losses arising from the disposal of capital assets. In addition, other unusual or non-recurring items are excluded from operating EBITDA, as they are not indicative of the underlying core operating performance of the Company.

The following table provides a reconciliation of net income to Operating EBITDA:

	Three months ended December 31		Year ended December 31	
($M)	**2024**	**2023**	**2024**	**2023**
Net (loss) income [1]	(29,401)	92,038	(24,162)	193,497
Finance income	(1,852)	(2,270)	(8,386)	(9,984)
Finance expenses	21,810	16,865	74,205	64,185
Income tax expense (recovery)	33,401	(39,007)	103,105	4,130
Depletion, depreciation and amortization	65,249	68,411	262,518	278,269
Minimum work commitment paid	—	358	—	358
(Recovery) expense of asset retirement obligation	(2,214)	(1,621)	2,335	(25,622)
Impairment expense	30,147	1,417	31,927	25,236
Trunkline costs	1,485	—	5,314	—
Post-termination obligation	705	11,160	577	18,814
Share-based compensation	835	(745)	1,726	96
Restructuring, severance and other costs	2,096	3,744	5,312	8,548
Share of income from associates	(13,200)	(14,833)	(53,912)	(56,476)
Foreign exchange loss (gain)	1,795	(2,724)	11,041	(12,275)
Other (income) loss	(6,526)	(4,554)	899	(8,936)
Unrealized loss (gain) on risk management contracts	10,035	(7,000)	13,976	(11,880)
Realized gain on risk management contract for ODL dividends received	(921)	—	(633)	—
Non-controlling interests	35	(203)	(609)	(741)
Gain on repurchased 2028 Unsecured Notes	—	—	(1,001)	—
Operating EBITDA	**113,479**	**121,036**	**424,232**	**467,219**

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

Capital expenditures

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

	Three months ended December 31		Year ended December 31	
	2024	**2023**	**2024**	**2023**
Consolidated Statements of Cash Flows				
Additions to oil and gas properties, infrastructure port, and plant and equipment	93,762	70,294	328,177	241,185
Additions to exploration and evaluation assets	2,030	5,171	22,480	195,210
Total additions in Consolidated Statements of Cash Flows	**95,792**	**75,465**	**350,657**	**436,395**
Non-cash adjustments [1]	(8,690)	6,827	(29,084)	6,339
Cash adjustments [2]	(1,236)	—	(3,717)	—
Total Capital Expenditures	**85,866**	**82,292**	**317,856**	**442,734**
Capital Expenditures attributable to Infrastructure Colombia Segment	25,999	9,724	47,882	15,296
Capital Expenditures attributable to other segments different to Infrastructure Colombia Segment	59,867	72,568	269,974	427,438
Total Capital Expenditure	**85,866**	**82,292**	**317,856**	**442,734**

[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 the trunkline incident.

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 December 31		Year ended December 31	
($M) [(1)]	**2024**	**2023**	**2024**	**2023**
Revenue Infrastructure Colombia Segment	13,873	10,625	48,542	49,041
Revenue from ODL	89,728	94,277	351,000	345,370
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [(1)]	31,405	32,997	122,850	120,879
Adjusted Infrastructure Revenues	**45,278**	**43,622**	**171,392**	**169,920**
Operating cost Infrastructure Colombia Segment	(8,099)	(8,798)	(31,438)	(33,296)
Operating Cost from ODL	(16,270)	(12,637)	(54,020)	(43,094)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [(1)]	(5,695)	(4,423)	(18,908)	(15,083)
Adjusted Infrastructure Operating Costs	**(13,794)**	**(13,221)**	**(50,346)**	**(48,379)**
General and administrative Infrastructure Colombia Segment	(1,507)	(1,055)	(5,903)	(5,527)
General and administrative from ODL	(6,985)	(5,776)	(22,628)	(17,019)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [(1)]	(2,445)	(2,022)	(7,920)	(5,957)
Adjusted Infrastructure General and Administrative	**(3,952)**	**(3,077)**	**(13,823)**	**(11,484)**

[(1)] Revenues and expenses related to the ODL are accounted for using the equity method described in the Note 15 of the Annual Consolidated 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]	December 31 2024	December 31 2023
Cash and cash equivalents - unrestricted	192,577	159,673
Cash and cash equivalents of Non-Infrastructure Colombia Segment's	(147,097)	(134,186)
Total Cash Infrastructure Colombia Segment	45,480	25,487
Cash and cash equivalent from ODL	76,979	131,839
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	26,943	46,144
Adjusted Infrastructure Cash	**72,423**	**71,631**
Short-Term and Long-Term Debt	493,764	517,604
Debt of Non-Infrastructure Colombia Segment's	(389,803)	(421,982)
Total Loans	103,961	95,622
Debt from ODL	36,954	45,147
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	12,934	15,801
Adjusted Infrastructure Debt	**116,895**	**111,423**

[1] 35% ODL participation is accounted using the equity method in the 2024 Annual Consolidated 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 December 31		Year ended December 31	
($M)	2024	2023	2024	2023
Adjusted Infrastructure Revenue	45,278	43,622	171,392	169,920
Adjusted Infrastructure Operating Costs	(13,794)	(13,221)	(50,346)	(48,379)
Adjusted Infrastructure General and Administrative	(3,952)	(3,077)	(13,823)	(11,484)
Adjusted Infrastructure EBITDA	**27,532**	**27,324**	**107,223**	**110,057**

Net Sales

Net sales 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 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 14.

Operating Netback

Operating netback is a non-IFRS financial measure and operating netback per boe is a non-IFRS ratio. Operating netback per boe is used to assess the net margin of the Company's production after subtracting all costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and gas industry to analyze financial and operating performance expressed as profit per barrel and is an indicator of how efficient the Company is at extracting and selling its product. For netback purposes, the Company removes the 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" section on page 13.

Oil and Gas Sales, Net of Purchases

Oil and gas sales, 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 per boe and Oil and gas sales, 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 December 31		Year ended December 31	
	2024	2023	2024	2023
Produced crude oil and products sales ($M) [1]	227,276	247,134	884,643	932,977
Purchased crude net margin ($M) [2]	(10,906)	(7,029)	(33,192)	(27,728)
Oil and gas sales, net of purchases ($M)	**216,370**	**240,105**	**851,451**	**905,249**
Sales volumes, net of purchases - (boe)	3,383,116	3,169,346	12,144,246	12,411,825
Produced crude oil and gas sales ($/boe)	67.18	77.98	72.84	75.16
Oil and gas sales, net of purchases ($/boe)	63.96	75.76	70.11	72.93

[1] Excludes sales from infrastructure services as they are not part of the oil and gas segment. For further information, refer to the “Infrastructure Colombia” section on page 23.
[2] 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. 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 December 31		Year ended December 31	
	2024	2023	2024	2023
Oil and gas sales, net of purchases ($M) [1]	216,370	240,105	851,451	905,249
Crude oil sales volumes, net of purchases - (bbl)	3,342,067	3,118,407	11,936,680	12,042,019
Conventional natural gas sales volumes - (mcf)	234,321	289,993	1,183,171	2,107,707
Realized oil price, net of purchases ($/bbl)	64.27	76.35	70.70	74.23
Realized conventional natural gas price ($/mcf)	6.79	6.93	6.37	5.41

[1] Non-IFRS financial measure.

Net sales realized price

Net sales realized price is a non-IFRS ratio that is calculated using net sales (including oil and gas sales net of purchases, realized gains and losses from 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 December 31		Year ended December 31	
	2024	2023	2024	2023
Oil and gas sales, net of purchases ($M) [1]	216,370	240,105	851,451	905,249
Gain (loss) on oil price risk management contracts, net ($M) [2]	253	(2,198)	(8,457)	(9,903)
(-) Royalties ($M)	(2,971)	(5,683)	(16,104)	(36,949)
Net sales ($M)	**213,652**	**232,224**	**826,890**	**858,397**
Sales volumes, net of purchases - (boe)	3,383,116	3,169,346	12,144,246	12,411,825
Oil and gas sales, net of purchases ($/boe)	63.96	75.76	70.11	72.93
Premiums paid on oil price risk management contracts [3]	0.07	(0.69)	(0.70)	(0.80)
Royalties ($/boe)	(0.88)	(1.79)	(1.33)	(2.98)
Net sales realized price ($/boe)	**63.15**	**73.28**	**68.08**	**69.15**

[1] Non-IFRS financial measure.

[2] Includes the net of the put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Please refer to the “Loss (gain) on risk management contracts” section on page 18 for further details.

[3] 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 December 31		Year ended December 31	
	2024	**2023**	**2024**	**2023**
Purchased crude oil and products sales ($M)	54,469	48,324	202,752	208,069
(-) Cost of diluent and oil purchased ($M) [1]	(65,375)	(55,353)	(235,944)	(235,797)
Purchased crude net margin ($M)	**(10,906)**	**(7,029)**	**(33,192)**	**(27,728)**
Sales volumes, net of purchases - (boe)	3,383,116	3,169,346	12,144,246	12,411,825
Purchased crude net margin ($/boe)	**(3.22)**	**(2.22)**	**(2.73)**	**(2.23)**

[1] Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining 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 December 31		Year ended December 31	
	2024	**2023**	**2024**	**2023**
Production costs (excluding energy costs) ($M)	29,091	37,122	139,726	139,917
(-) Realized loss (gain) on FX hedge attributable to production costs (excluding energy costs) ($M) [1]	—	(2,101)	(3,358)	(9,075)
SAARA inter-segment costs	783	—	1,370	—
Production costs (excluding energy costs), net of realized FX hedge impact ($M) [2]	29,874	35,021	137,738	130,842
Production (boe)	3,901,352	3,612,564	14,745,408	14,935,435
Production costs (excluding energy costs), net of realized FX hedge impact ($/boe)	7.66	9.69	9.34	8.76

[1] See “Gain (Loss) on Risk Management Contracts” on page 18.

[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 December 31		Year ended December 31	
	2024	**2023**	**2024**	**2023**
Energy costs ($M)	20,647	19,005	76,631	69,924
(-) Realized loss (gain) on FX hedge attributable to energy costs ($M) [1]	—	(738)	(1,267)	(2,900)
Energy costs, net of realized FX hedge impact ($M) [2]	20,647	18,267	75,364	67,024
Production (boe)	3,901,352	3,612,564	14,745,408	14,935,435
Energy costs, net of realized FX hedge impact ($/boe)	5.29	5.06	5.11	4.49

[1] See “(Loss) Gain on Risk Management Contracts” on page 18.

[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 December 31		Year ended December 31	
	2024	**2023**	**2024**	**2023**
Transportation costs ($M)	39,128	34,750	148,513	151,416
(-) Realized loss (gain) on FX hedge attributable to transportation costs ($M) (1)	—	(753)	(982)	(3,264)
Transportation costs, net of realized FX hedge impact ($M) (2)	39,128	33,997	147,531	148,152
Net production (boe)	3,493,148	3,084,300	12,948,348	13,210,810
Transportation costs, net of realized FX hedge impact ($/boe)	11.20	11.02	11.39	11.21

(1) See "(Loss) Gain on Risk Management Contracts" on page 18.
(2) Non-IFRS financial measure.

Supplementary Financial Measures

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

Realized (loss) gain 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 (loss) gain on oil risk management contracts per boe is a supplementary financial measure that is calculated using Realized (loss) gain on risk management contracts divided by total sales volumes, net of purchases.

Royalties per boe

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

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

Weighted-average price per share under the 2023 NCIB (as defined below) is a supplementary financial measure that corresponds to the weighted-average price of shares purchased under the 2023 NCIB (as defined below) during the period. It is calculated using the total amount of common shares repurchased in U.S. dollars divided by the number of Common Shares repurchased.

Capital Management Measures

Net working capital

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

Restricted cash short- and long-term

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

Total cash

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

Total debt and lease liabilities

Total debt and lease liabilities are capital management measures to describe the total financial liabilities of the Company, and is comprised of the 2028 Unsecured Notes, loans and liabilities from leases of various properties, power generation supply, vehicles and other assets.

6. LIQUIDITY AND CAPITAL RESOURCES

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

- capital expenditures for exploration, production and development, including growth plans;
- costs and expenses relating to operations, commitments and existing contingencies;
- debt service requirements relating to existing and future debt; and
- shareholder returns through share repurchases and/or dividends payments.

The Company funds its anticipated cash requirements and strategic objectives using current cash and working capital balances, cash flows from operations, and available debt and credit facilities. In accordance with the Company's investment policy, available cash balances are held in interest-bearing savings accounts, term deposits and Colombian mutual funds with high credit ratings and liquidity. The Company regularly reviews its capital structure and liquidity sources with a focus on ensuring that capital resources will be sufficient to meet operational needs and other obligations.

As of December 31, 2024, the Company had a total cash balance of $222.8 million (including $30.2 million in restricted cash), which is $32.9 million higher than December 31, 2023.

For the year ended December 31, 2024, the Company generated $510.0 million, of cash from operations, including approximately $42.0 million of net income tax reimbursed (including $94.5 million in tax refund proceeds associated with the 2023 income tax return), which was used to fund cash outflows of $339.2 million for capital expenditures and other investing activities. For the year ended December 31, 2024, financing activities generated net outflows of $128.9 million, primarily due to $57.5 million in principal payments toward the PIL Loan Facility and the full repayment of the outstanding principal amounts of the PetroSud Debt (as defined below) and Bancolombia Working Capital Loan (as defined below), $48.2 million of interest from unsecured notes, loans and other financing charges, $30.6 million in Common Shares repurchased under the 2024 SIB (as defined below), $11.7 million related to dividends paid to equity holders, $7.8 million in Common Shares purchased under the 2023 NCIB, $6.9 million in lease payments and $4.0 million in repurchases of the 2028 Unsecured Notes, partially offset by the disbursement of $28.8 million in net proceeds from the accordion tranches as part of the PIL Loan Facility and the Agro Cascada Working Capital Loan (as defined below) by $9.5 million. In addition, the Company's net working capital[(1)] decreased by $38.7 million, continuing with a deficit to $100.6 million as at December 31, 2024, compared to a deficit of $61.9 million at year-end 2023.

The Company believes that its net working capital balances in conjunction with future cash flows from operations and available credit facilities are sufficient to support the Company's normal operating requirements, capital expenditures and financial commitments on an ongoing basis.

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. As of December 31, 2024, the main components of restricted cash were long-term abandonment funds as required by the ANH, and restricted funds related to the PIL Loan Facility. Abandonment funds will satisfy abandonment obligations and are expected to be released in the long-term as assets are abandoned. Abandonment funding requirements are updated annually. As of December 31, 2024, the Company's restricted cash position was $30.2 million, representing an increase of $0.1 million from December 31, 2023, primarily due to the increase in the debt service reserve account of the PIL Loan Facility, partially compensated by the release of abandonment funds driven by lower abandonment needs, particularly in the Corcel, Guatiquia, Cubiro, and Cachicamo blocks.

The measures taken by the Company to manage its liquidity and capital resources are ongoing and the Company continues to look for additional opportunities to manage its costs and commitments. Based on the foregoing, including the expected impacts of such measures, the Company expects that unrestricted cash balances in conjunction with future cash flows from operations, available credit facilities, and alternate financing arrangements will be sufficient to support its operational and capital requirements and other financial commitments. The Company intends to remain flexible and disciplined with respect to capital allocation decisions as the current commodity price environment evolves and can make additional changes to its business and operations as warranted. See also the "Risks and Uncertainties" section on page 43.

Unsecured Notes

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

During the year ended December 31, 2024, the Company repurchased in the open market $5.0 million, of its 2028 Unsecured Notes for a cash consideration of $4.0 million, including interests. As a result, during the year ended December 31, 2024, the Company recognized a gain of $1.0 million. The carrying value for the 2028 Unsecured Notes as at December 31, 2024, is $389.8 million (December 31, 2023: $393.7 million).

[1] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures'' section on page 28.

Unsecured Notes Covenants

The 2028 Unsecured Notes are senior, unsecured notes and rank equal in right of payment with all existing and future senior unsecured debt. As at December 31, 2024, the 2028 Unsecured Notes were guaranteed by the Company's subsidiary, Frontera Energy Colombia Corp. ("**Frontera Colombia**"). On April 11, 2023, the Company designated Frontera Energy Guyana Holding Ltd. and Frontera Guyana as an unrestricted subsidiary and released Frontera Guyana as a note guarantor under the indenture governing the 2028 Unsecured Notes (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. In the event that these financial tests are not met, the Company may still incur indebtedness under certain permitted baskets, including an aggregate amount that does not exceed the higher of $100.0 million and 10% of consolidated net tangible assets(3). The 2028 Unsecured Notes also contain covenants that limit the Company's ability to, among other things, make certain investments or restricted payments, including dividends and share buybacks. As at December 31, 2024, the Company is in compliance with all such covenants.

Pursuant to requirements under the Indenture, the Company reports consolidated total indebtedness of $414,481,000 as of December 31, 2024, and for the last twelve months ended as of December 31, 2024, a consolidated adjusted EBITDA of $418,625,000 and a consolidated interest expense of $54,558,000.

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

a. Consolidated total indebtedness is defined below.
b. Consolidated adjusted EBITDA is defined as the consolidated net income (loss) (as defined in the Indenture) plus: i) consolidated interest expense; ii) consolidated income tax and equity tax; iii) consolidated depletion and depreciation expense; iv) consolidated amortization expense; and v) consolidated impairment charge, exploration expense and abandonment costs; after excluding the impact of the Unrestricted Subsidiaries.

(2) Consolidated fixed charge ratio is the consolidated adjusted EBITDA for the most recent period ended of four consecutive fiscal quarters divided by the consolidated interest expense for such period as defined in the Indenture.

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

Consolidated Total Indebtedness and Net Debt

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

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

($M)		As at December 31 2024
Short-term and Long-term debt (1)	$	399,312
Total lease liabilities (2)		10,820
Risk management liability net (3)		4,349
Consolidated Total Indebtedness		**414,481**
(-) Cash and Cash Equivalents (4)		(137,183)
(=) Net Debt	**$**	**277,298**

(1) Excludes $94.5 million of long-term debt attributable to the Unrestricted Subsidiaries.

(2) Excludes $1.5 million of lease liabilities attributable to the Unrestricted Subsidiaries.

(3) Excludes $0.2 thousand of risk management liability attributable to the Unrestricted Subsidiaries.

(4) Includes unrestricted cash and cash equivalents attributable to the guarantors as of December 31, 2024, Frontera Energy Colombia AG and the issuer (i.e., the Company) according to the Indenture.

Pipeline Investment Loan Facility

On March 27, 2023, PIL entered into a credit agreement through which lenders provided a $120.0 million loan facility to PIL, secured by substantially all the assets and shares of PIL, the shares of 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 PIL (the **"PIL Loan Facility"**). The PIL Loan Facility is a five-year credit, to mature in December 2027, paying its principal semi-annually. The PIL Loan Facility has two tranches: a $100.0 million amortizing tranche that pays a SOFR six-month term plus 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 PIL Loan Facility were fully satisfied, and both tranches of the facility were funded on March 31, 2023.

The PIL Loan Facility was recognized net of an original issue discount of $5.1 million, and directly attributable transaction costs of $1.1 million, primarily related to underwriter fees, legal fees, registration fees and other professional fees. In addition, a $10.5 million debt service reserve account for the PIL Loan Facility was constituted.

The proceeds of the PIL Loan Facility were used to repay in full the Puerto Bahia debt facility between Puerto Bahia, Itaú BBA Colombia S.A. and other lenders, maturing in June 2025, which had an outstanding balance plus accrued interest of $106.2 million to pay transaction fees and expenses, and to fund a six-month debt service reserve account (for further information, refer to Note 16 of the 2023 Annual Financial Statements). The PIL Loan Facility has no impact on the Company's financial covenant calculations under the 2028 Unsecured Notes.

On February 16, 2024, as part of the PIL Loan Facility (Tranche A-2), the Company amended the facility to disburse an accordion tranche of $30.0 million. This tranche secured the funding for the Reficar Connection Project. 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 lenders and legal fees discounted at the disbursement.

As at December 31, 2024, the carrying value of the PIL Loan Facility was $94.5 million (December 31, 2023: $95.6 million) which includes short-term debt of $21.0 million. As at December 31, 2024 the PIL Loan Facility debt service reserve account had a balance of $15.9 million. (December 31, 2023: $11.3 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] + 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.

As at December 31, 2024, the carrying value of the Agro Cascada Working Capital Loan was $9.5 million.

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

Bancolombia Working Capital Loan

On October 24, 2023, the Company entered into a one-year working capital loan agreement with Bancolombia S.A. ("**Bancolombia**"), denominated in COP, with a principal amount of COP 75,000 million (equivalent to $18.2 million), maturing on October 30, 2024, with an interest rate of IBR + 4.00%, payable quarterly (the "**Bancolombia Working Capital Loan**"). On October 30, 2023, Bancolombia disbursed the total amount of the loan. The proceeds of the Bancolombia Working Capital Loan were intended for general corporate purposes. In connection to the Bancolombia Working Capital Loan, the Company entered into a FX forward on October 31, 2023, hedging the original loan amount at a forward rate of COP 4,386.17, with a maturity date of October 29, 2024.

On October 30, 2024, the Bancolombia Working Capital Loan was paid in full. As at December 31, 2024, the carrying value of the Bancolombia Working Capital Loan was $Nil (2023: $19.6 million).

PetroSud Loans

On December 30, 2021, the Company acquired 100% of the issued and outstanding shares of Petroleos Sud Americanos S.A. ("**PetroSud**"). For further information, refer to Note 4 of the 2022 Annual Consolidated Financial Statements.

On March 15, 2019, and December 20, 2021, PetroSud entered into two credit agreements with Banco Davivienda S.A. ("**Banco Davivienda**") for a principal amount of $22.0 million and $2.8 million, respectively (the "**PetroSud Debt**").

On March 11, 2024 and May 23, 2024, the Company prepaid the outstanding balance of $5.9 million and $2.8 million, respectively to Banco Davivienda. As of September 30, 2024, the PetroSud Debt was paid in full. PetroSud and Frontera have no obligation under the former PetroSud Debt, and there are no additional restricted funds related to the PetroSud Debt.

Letters of Credit

The Company has various uncommitted bilateral letters of credit. As of December 31, 2024, the Company had issued letters of credit and guarantees for exploration and abandonment funds totalling $108.9 million (total credit lines of $152.5 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, amounting approximately to $5.8 million as at December 31, 2024, and its maturity date is 72 months counted from April 3, 2024. The Solar Plant Debt bears interest equivalent to IBR +5.75%, payable monthly over the outstanding amount. As at December 31, 2024, the outstanding balance was $5.5 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 entered into 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, amounting approximately to $0.9 million as at December 31, 2024, and its maturity date is April 9, 2029. The BESS Project leasing bears interest equivalent to IBR +5.10%, payable monthly. As at December 31, 2024, 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 December 31, 2024, undiscounted by calendar year, are presented below:

As at December 31, 2024 ($M)	2025	2026	2027	2028	2029	2029 and Beyond	Total
Short-term and long-term debt principal and interest	72,779	58,966	82,361	425,512	—	—	639,618
Lease liabilities	5,793	3,583	2,111	2,074	1,542	505	15,608
Total financial obligations	**78,572**	**62,549**	**84,472**	**427,586**	**1,542**	**505**	**655,226**
Transportation							
Ocensa P-135 ship-or-pay agreement	37,011	—	—	—	—	—	37,011
ODL agreements	356	—	—	—	—	—	356
Other transportation and processing commitments	14,204	13,051	—	—	—	—	27,255
Exploration and evaluation							
Minimum work commitments	17,681	9,871	5,066	—	—	—	32,618
Other commitments							
Operating purchases, community obligations and others	50,018	288	268	259	264	2,361	53,458
Commitments energy supply	25,481	14,363	9,091	4,421	1,061	2,209	56,626
Total Commitments	**144,751**	**37,573**	**14,425**	**4,680**	**1,325**	**4,570**	**207,324**

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 January 30, 2025, the term of the pledge agreement was extended to June 30, 2025 with Ocensa and to July 31, 2025 with Cenit.

Overriding Royalty Interest CPE-6

As part of the Company's acquisition of Repsol Colombia Oil & Gas Ltd.'s ("**RCOG**") 50% working interest in the CPE-6 block, the Company granted a pledge to RCOG over the production from the CPE-6 block to guarantee the payments, of up to a maximum of $48.0 million. Under the farm-out agreement, two kinds of payments are set, each contingent on production from this block and each applicable until the maximum payment of $48.0 million is paid: (i) a variable monthly payment, and (ii) three potential production milestone payments of $5.0 million each when 5 million, 10 million and 20 million total barrels production, respectively, are achieved. As at December 31, 2024, the Company has an outstanding payment of $20.7 million.

Contingencies

The Company is involved in various claims and litigation arising from its 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

On June 26, 2024, the Company and CGX announced that they submitted a notice of potential commercial interest for the Wei-1 discovery to the Government of Guyana, which preserves their interests in the PPL for the Corentyne block. On December 12, 2024, the Joint Venture announced that it had sent the Government of Guyana a letter activating a 60-day period for the parties to the Corentyne block PPL to make all reasonable efforts to amicably resolve all disputes via negotiation, as provided for in the Corentyne block PPL, which 60-day period expired on February 10, 2025. On February 11, 2025, the Joint Venture announced that it received a communication from the Government of Guyana 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 announced that the Joint Venture had provided a response in which the Joint Venture advised the Government that, among other things, despite the Government's contradictory positions, the PPL remains valid and in force and that the Joint Venture has contested the Government's purported termination of the PPL. The Joint Venture remains firmly of the view that its interest in, and the PPL for, the Corentyne block remain in place and in good standing.

Agencia Nacional de Hidrocarburos Discussion

On December 20, 2022, the Company requested that the ANH terminate the contracts for the CAG-5 and CAG-6 blocks due to social and security restrictions in the contracted areas pursuant to a recent regulation issued by the ANH (Acuerdo 01 of 2022). On July 26, 2024 the Company received a communication from the ANH accepting the termination of the CAG-6 contract by mutual agreement. On October 8, 2024, the Company received a communication from the ANH accepting the termination of the CAG-5 contract by mutual agreement. As at December 31, 2024, the CAG-5 and CAG-6 blocks have exploration commitments for a total of $Nil million (2023: $101.8 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 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.

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

Puerto Bahia –Tank Construction Related Arbitration

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

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

In September, 2023, CITT filed a constitutional action (tutela) against the award rendered on March 1, 2023. However, on September 29, 2023, Colombian Supreme Court issued a first instance ruling dismissing the constitutional action indicating that CITT cannot use it as a replacement of the annulment action which was not timely exercised. On October 4, 2023, CITT filed and appeal against the tutela decision.

In December, 2023, the Colombian Supreme Court confirmed the tutela decision however, it may eventually be selected for review by the Colombian Constitutional Court.

On April 16, 2024, the Colombian Supreme Court admitted an annulment appeal from CITT against the arbitral award from February 28, 2023, and its clarifying Addendum from May 19, 2023. CITT seeks to overturn the ruling, alleging violations of due process, access to justice, and international public order. The Colombian Supreme Court also included Puerto Bahia as a party to the case.

Puerto Bahia has strongly opposed this appeal, arguing that it does not meet the limited legal grounds for annulling an international arbitral award under Colombian law. Furthermore, Puerto Bahia emphasized that the annulment appeal is not a second-instance review, and the Supreme Court should not re-evaluate the arbitral tribunal’s legal interpretations, evidentiary analysis, or substantive conclusions, as CITT intends.

Ecopetrol - Rubiales Field Disagreement

Since 2018, Frontera and Ecopetrol have initiated claims against each other before local courts due to disagreements related to the expiration of the Rubiales and Piriri exploration and production contracts.

To settle certain differences under dispute, on December 13, 2023, Frontera and Ecopetrol entered into an agreement which closed 21 (out of 57) disagreements between the parties. As a result, the Company recorded a reversal of a liability provision of $5.9 million recognized during 2016, 2017, 2020, 2021, 2022, and 2023, a reversal of net liabilities with Ecopetrol of $0.5 million and paid to Ecopetrol $4.2 million pursuant to the settlement agreement. Also, as a result of the settlement, Ecopetrol amended the amount of its first lawsuit from $45.0 million to $32.0 million and Frontera withdrew one of the lawsuits filed against Ecopetrol and amended the amount of another one from $9.0 million to $2.6 million.

In addition, Ecopetrol has filed a new lawsuit claiming approximately $4.3 million against Frontera for post-termination activities in Rubiales. Frontera has challenged the admission of this lawsuit, and a decision is currently pending.

Tax Reviews

The Company operates in various jurisdictions and is subject to assessments by tax authorities in each of those jurisdictions, which can be complex and based on interpretations. The Company is currently in discussions with tax authorities for various assessments with respect to certain income tax deductions relating to exportation expenditures, transportation costs, VAT credits, municipal taxes, and other expenses. As at December 31, 2024, the Company has assessed a possible tax exposure of $90.9 million (2023: $145.8 million) relating to these assessments for taxes, interest, and penalties (the decrease is mainly due to the closure of some of income tax and municipal tax litigation). As at December 31, 2024, the carrying value of the tax liability provisions is $0.7 million (2023: $13.1 million). The decrease is mainly due to the Company's decision to reverse the 2020 self-withholding contingency corresponding to the months of January to November. In a previous analysis with the lawyers, it was concluded that these periods are already closed and there is no possibility of a claim by the Dirección de Impuestos y Aduanas Nacionales.

7. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at March 10, 2025:

	Number
Common shares	77,294,460
DSUs (1)	1,062,179
RSUs (2)	2,076,557

(1) DSUs represent a future right to receive Common Shares (or the cash equivalent) at the time of the holder's retirement, death or the holder otherwise ceasing to provide services to the Company, 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 the DSU is awarded. The value of a DSU increases or decreases as the price of the Common Shares increases or decreases, thereby promoting alignment of interests of a DSU holder with shareholders. DSUs are settled in Common Shares, cash or a combination thereof, as determined by the Compensation and Human Resources Committee of the Board (the "CHRC"), in its sole discretion. Only directors are entitled to receive DSUs.

(2) RSUs represent a right to receive Common Shares (or the cash equivalent) at a future date as determined by the established vesting conditions. RSUs are granted with vesting conditions that are based on continued service and/or the achievement of corporate objectives. The value of an RSU increases or decreases as the price of the Common Shares increases or decreases, thereby promoting alignment of interests of an RSU holder with shareholders. RSUs are settled in Common Shares, cash or a combination thereof, as determined by the CHRC, in its sole discretion. Vesting terms for RSUs are determined by the CHRC, in its sole discretion, and specified in the award agreement pursuant to which the RSU is granted.

Normal Course Issuer Bids ("NCIB")

On November 21, 2023, the Company launched an NCIB (the "**2023 NCIB**"), pursuant to which the Company may 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 twelve-month period commencing November 21, 2023, and ending on November 20, 2024. On September 4, 2024, the Company suspended repurchases under the 2023 NCIB in connection with the 2024 SIB.

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

Purchases subject to both NCIBs were or are 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. Under the 2022 NCIB that expired on March 16, 2023, the Company repurchased for cancellation during the twelve-month term a total of 4,270,100 Common Shares, for approximately $40.9 million.

The following table provides a summary of total share repurchases under the 2023 NCIB program:

	Year Ended December 31
	2024
Number of Common Shares repurchased (1)	1,271,600
Total amount of Common Shares repurchased ($M)	7,823
Weighted-average price per share ($) (2)	6.15

(1) Approximately 1.6% of its common shares.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 28.

In addition, the Company intends to file with the TSX a notice of intention to commence a NCIB for its Common Shares. Subject to the acceptance of the TSX, the Company would be permitted under the NCIB to purchase, for cancellation, up to that number of Common Shares equal to the greater of (a) 5% of the Company's issued and outstanding Common Shares, and (b) 10% of the Company's "public float", during the 12-month period following commencement of the NCIB.

Substantial Issuer Bid

On September 4, 2024, the Company announced that its board of directors has approved the commencement of an SIB pursuant to which the Company offered to purchase from shareholders of Common Shares of the Company up to 3,375,000 Common Shares for cancellation at a purchase price of CAD$12.00 per share, for an aggregate purchase price 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 announced that in accordance with the terms and conditions of the 2024 SIB, Frontera had taken 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 of 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. After the cancellation of the

Common Shares taken up and paid for by the Company under the 2024 SIB, approximately 80.78 million Common Shares were issued and outstanding.

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

On December 16, 2024, the Company announced that its board of directors has approved the commencement of an SIB pursuant to which the Company offered to purchase from shareholders of Common Shares of the Company up to 3,500,000 Common Shares for cancellation at a purchase price of CAD$12.00 per share, for an aggregate purchase price up to CAD$42.0 million (equivalent to $30.0 million) (the "**2025 SIB**"). The 2025 SIB expired on January 24, 2025.

Subsequently to the year end, on January 28, 2025, the Company announced that in accordance with the terms and conditions of the 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 of January 24, 2025) at a price of CAD$12.00 per Common Share, with an over 90% shareholder participation rate and representing an aggregate purchase price of approximately CAD$42.0 million. After the cancellation of the Common Shares taken up and paid for by the Company under the 2025 SIB, approximately 77.29 million Common Shares were issued and outstanding.

Dividends

On March 7, 2024, the Company adopted a dividend policy that includes an initial cash dividend of C$0.0625 per Common Share, or $3.9 million. This dividend payment to shareholders is designated as an "eligible dividend" under the Income Tax Act (Canada). The declaration and payment of any specific quarterly dividend remain at the discretion of the Company's board of directors.

The Company´s dividends paid or declared during the year ended December 31, 2024, 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

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

Pursuant to Frontera's dividend policy, Frontera's Board of Directors has declared a dividend of C$0.0625 per common share to be paid on or around April 16, 2025, to shareholders of record at the close of business on April 2, 2025.

No dividends were declared payable during the years ended December 31, 2022, or 2023.

8. RELATED-PARTY TRANSACTIONS

The following tables provide the total balances outstanding, commitments and transactional amounts with related parties as at December 31, 2024 and December 31, 2023, and for the three months and the year ended December 31, 2024, and 2023, respectively:

		As at December 31			Three Months Ended December 31	Year Ended December 31
($M)		**Receivables from Investment**	**Accounts Payable**	**Commitments**	**Purchases / Services**	
ODL	2024	—	2,901	356	7,573	29,608
	2023	—	3,141	2,380	7,776	30,525

The related-party transactions correspond to the ship-and-pay contract for the transportation of crude oil in Colombia and ship-or-pay for other services for a total commitment of $0.4 million until 2025.

9. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of known and unknown risks in the pursuit of its strategic objectives including, but not limited to: production; liquidity/financial; health, safety and environmental; exploration, new business and reserves growth; information security; and political risk. The impact of any risk may adversely affect, among other things, the Company's business, reputation, financial condition, results of operations and cash flows, which may affect the market price of its securities.

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

See the "Liquidity and Capital Resources" section on page 35 for additional detail on the steps the Company has taken to mitigate or manage some of these risks. However, the situation continues to be dynamic and highly uncertain, and the effectiveness and adequacy of such measures cannot be determined at this time.

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

The information above does not contain all the risks associated with an investment in the securities of the Company. For a more comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, please see the Company's AIF and the 2024 Annual Consolidated Financial Statements, copies of which are available on SEDAR+ at www.sedarplus.ca.

10. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The 2024 Annual Consolidated Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board, and with interpretations of the International Financial Reporting Interpretations Committee, which the Canadian Accounting Standards Board has approved for incorporation into Part 1 of the CPA Canada Handbook Accounting. A summary of significant accounting policies applied is included in Note 3a of the 2024 Annual Consolidated Financial Statements. The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective. Recent accounting pronouncements of significance or potential significance are described in Note 3b of the 2024 Annual Consolidated Financial Statements, including management's evaluation of impact and implementation progress.

The preparation of the 2024 Annual Consolidated Financial Statements in accordance with IFRS requires the Company to make judgments in applying its accounting policies, estimates and assumptions about the future. These judgments, estimates and assumptions affect the reported amounts of assets, liabilities, revenues and other items in net operating earnings or loss and the related disclosure of contingent assets and liabilities included in the 2024 Annual Consolidated Financial Statements. The Company evaluates its estimates on an ongoing basis.

The estimates are based on historical experience and on various other assumptions that the Company believes are reasonable under the circumstances. These estimates form the basis for making judgments about the carrying value of assets and liabilities and the reported amounts of revenues and other items.

The effect of the global economy, including the impact of the Russia-Ukraine conflict, the Middle East conflict, the trade tensions between the U.S. and Colombia, and the associated volatility in oil prices, could have negative impacts on the Company. The uncertainty these events bring has resulted in a challenging economic environment, with more volatile commodity prices, foreign exchange rates, long-term interest rates and changes in international trade policies. The outcome of the conflict in the Middle East continues to be uncertain and has the potential to have wide-ranging consequences on the world economy. Global oil prices have remained highly volatile since the beginning of the Middle East conflict. There is a risk that the conflict could lead to wider regional instability in the Middle East, home to some of the world's biggest oil producers. In addition, In January 2025, the U.S. government threatened to impose tariffs of up to 25% on Colombian imports. Although an agreement was ultimately reached to avert these tariffs, the Company continues to monitor the situation for any new developments. The Company could be adversely affected by the imposition of new tariffs which could disrupt its 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.

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 conflict 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 2024 Annual Consolidated Financial Statements.

The results of the economic downturn and any potential resulting direct and indirect impact to the Company has been considered in management's judgments and estimates as described above for the quarter end; however, there could be further prospective material impacts in future periods. As such, actual results may differ from these estimates under different assumptions or conditions. A summary of the key accounting estimates and judgments made by management in the preparation of its financial information is provided in Note 3c of the 2024 Annual Consolidated Financial Statements.

11. INTERNAL CONTROL

In accordance with National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings* ("**NI 52-109**") of the Canadian Securities Administrators, the Company issues a "Certification of Annual Filings" 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 control and procedures ("**DC&P**") and internal controls over financial reporting ("**ICFR**") as those terms are defined in NI 52-109. The control framework used to design the Company's ICFR is based on the framework established in Internal Control - Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company's ICFR are designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's ICFR may not prevent or detect all misstatements because of inherent limitations.

Management of the Company has evaluated the effectiveness of the Company's ICFR for the period beginning July 2024 and ending December 31, 2024. Based on this assessment, the Company's Chief Executive Officer and its Chief Financial Officer concluded that the Company's ICFR were effective as at December 31, 2024.

There have been no change in the Company's ICFR during the period quarter ending on December 31, 2024, 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 its Chief Financial Officer, concluded that the Company's DC&P were effective as at December 31, 2024.

12. FURTHER DISCLOSURES

Production Reporting by block

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

		Production				
Producing blocks		**Q4 2024**	**Q3 2024**	**Q4 2023**	**2024**	**2023**
Quifa	(bbl/d)	16,890	16,778	16,465	16,973	17,427
CPE-6	(bbl/d)	8,466	7,459	6,162	7,279	5,487
Guatiquia	(bbl/d)	5,690	5,801	6,206	5,660	6,878
Vim1	(boe/d)	1,883	1,934	1,775	1,814	1,740
Perico	(bbl/d)	1,431	1,470	1,453	1,508	861
Cubiro	(bbl/d)	1,310	1,447	1,535	1,427	1,838
Cravoviejo	(bbl/d)	1,263	1,331	1,464	1,314	1,587
Casimena	(bbl/d)	993	1,077	1,254	1,110	1,300
Other blocks	(boe/d)	4,480	3,319	2,953	3,203	3,801
Total production	**(boe/d)**	**42,406**	**40,616**	**39,267**	**40,288**	**40,919**

Production Reporting

Production volumes are reported on a Company's W.I. before royalties basis. In Ecuador, the government has a variable share over the total volumes produced under Perico and Espejo joint venture exploration and extraction contracts. The Company has reported this share of production retained by the government under the contract, as royalties paid in-kind in this MD&A.

The following table includes the average net production:

		Net Production				
					Year ended December 31	
Producing blocks in Colombia		**Q4 2024**	**Q3 2024**	**Q4 2023**	**2024**	**2023**
Heavy crude oil	(bbl/d)	25,513	22,324	19,381	22,563	20,499
Light and medium crude oil combined	(bbl/d)	9,235	9,647	10,833	9,535	12,462
Conventional natural gas	(mcf/d)	2,633	3,192	4,760	3,278	6,042
Natural gas liquids	(boe/d)	1,498	1,521	1,508	1,546	1,531
Net production Colombia	**(boe/d)**	**36,708**	**34,052**	**32,557**	**34,219**	**35,552**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	1,261	1,215	968	1,159	642
Net production Ecuador	**(bbl/d)**	**1,261**	**1,215**	**968**	**1,159**	**642**
Total net production	**(boe/d)**	**37,969**	**35,267**	**33,525**	**35,378**	**36,194**

Boe Conversion

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

Oil and Gas Information Advisories

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

Abbreviations

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

bbl	Oil barrels	**MMcf/d**	Million cubic feet per day
bbl/d	Barrels of oil per day	**m3**	Cubic meter
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	**USD**	United States dollars
COP	Colombian Pesos	**WTI**	West Texas Intermediate
CAD$	Canadian dollars	**W.I.**	Working interest
FX	Foreign exchange	**$**	U.S. dollars
ha	Hectare	**$M**	Thousands U.S. dollars
MMbbl	Millions of oil barrels	**$MM**	Millions U.S. dollars
MMboe	Millions of barrels of oil equivalent	**P1**	Proved reserves
Mbbl	Thousands of oil barrels	**P2**	Probable reserves
Mcf	Thousands cubic feet	**2P**	Proved reserves + Probable reserves
mcf/d	Thousands cubic feet per day		