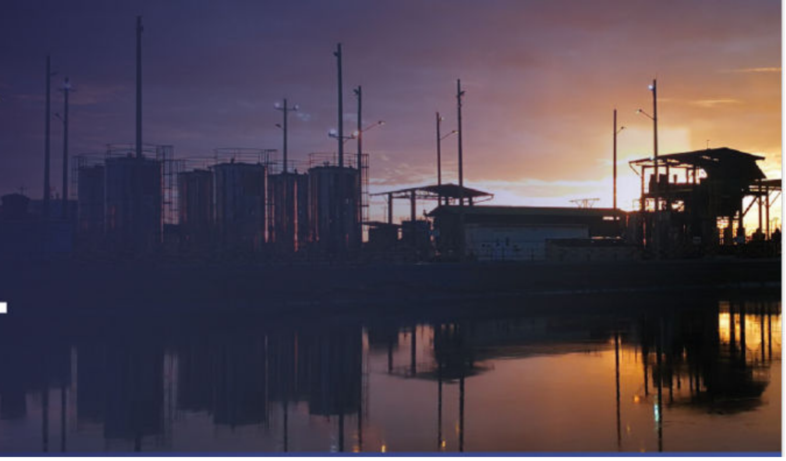

FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

May 8, 2025
For the three months ended March 31, 2025

*Frontera Energy Corporation ("**Frontera**" , "**FEC**" or the "**Company**") is an oil and gas company formed and existing under the laws of British Columbia, Canada, that is engaged in the exploration, development, production, transportation, storage and sale of crude oil and conventional natural gas in South America, including strategic investments in both upstream and infrastructure facilities, and is committed to working hand-in-hand with all its stakeholders to conduct business in a socially and environmentally responsible manner. The Company's common shares ("**Common Shares**") are listed and publicly traded on the Toronto Stock Exchange ("**TSX**") under the trading symbol "FEC". The Company's head office is located at 1030, 140 – 4 Avenue SW, Calgary, Alberta, Canada, T2P 3N3.*

*This Management Discussion and Analysis ("**MD&A**") is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying Interim Condensed Consolidated Financial Statements and related notes for the three months ended March 31, 2025 and 2024 (the **"Interim Financial Statements"**). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and its Annual Information Form ("AIF"), have been filed with Canadian securities regulatory authorities and are available on SEDAR+ at www.sedarplus.ca and on the Company's website at www.fronteraenergy.ca. Information contained in or otherwise accessible through the Company's website does not form a part of this MD&A and is not incorporated by reference into this MD&A.*

*The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board, unless otherwise noted. This MD&A contains certain financial terms that are not considered in IFRS. These non-IFRS financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These non-IFRS financial measures are described in greater detail under the heading "Non-IFRS and Other Financial Measures" section on page 21.*

*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, the Company entering into definitive agreements with respect to the ODL recapitalization and the closing of the financing related thereto, statements regarding estimates and/or assumptions in respect of the oil price environment, potential health risks, the newly imposed U.S. trade tariffs affecting over fifty countries and escalating tensions with China, the impact of the Russia-Ukraine conflict and the conflict in the Middle East, the expected impact of measures that the Company has taken and continues to take or may take in response to these events, the Company's goal of enhancing the value of its Common Shares in the short term and consideration forms of strategic initiatives and transactions in connection therewith, the commencement of a substantial issuer bid and the terms and timing thereof, the commencement of the tender offer and consent solicitation solicitation for the 2028 Senior Unsecured Notes and the terms and timing thereof, the commencement of the NCIB and the terms and timing thereof, the timing of the payment of the dividend, expectations regarding the 2025 production guidance, the operational timing of the connection project between Puerto Bahia (as defined below) and Reficar (as defined below), 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: the failure to enter into definitive agreements with respect to the ODL recapitalization and close such transaction, which could prevent or delay the SIB or could significantly hinder the Company's ability to complete the tender offer and solicitation in respect of the 2028 Senior Unsecured Notes; 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 newly imposed U.S. trade tariffs affecting over fifty countries and escalating tensions with China; the impact of the Russia-Ukraine conflict and the conflict in the Middle East; actions of the Organization of Petroleum Exporting Countries ("OPEC+"); uncertainties associated with estimating and establishing oil and natural gas reserves and resources; liabilities inherent with the exploration, development, exploitation and reclamation of oil and natural gas; uncertainty of estimates of capital and operating costs, production estimates and estimated economic return; increases or changes to transportation costs; expectations regarding the Company's ability to raise capital and to continually add reserves through acquisition and development; the Company's ability to complete strategic initiatives or transactions to enhance the value of its Common Shares and the timing thereof; the Company's 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. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q1 2025	Q4 2024	Q1 2024
Operational Results				
Heavy crude oil production [(1)]	(bbl/d)	27,167	27,740	23,398
Light and medium crude oil combined production [(1)]	(bbl/d)	10,998	12,234	12,580
Total crude oil production	(bbl/d)	38,165	39,974	35,978
Conventional natural gas production [(1)]	(mcf/d)	2,274	2,633	3,283
Natural gas liquids production [(1)]	(boe/d) [(3)]	1,913	1,970	1,639
Total production [(2)]	(boe/d) [(3)]	40,477	42,406	38,193
Total inventory balance	(bbl)	911,886	1,029,466	1,278,763
Brent price reference	($/bbl)	74.98	74.01	81.76
Produced crude oil and gas sales [(4)]	($/boe)	68.42	67.18	76.10
Purchased crude net margin [(4)(5)]	($/boe)	(3.81)	(3.42)	(3.01)
Oil and gas sales, net of purchases [(4)(5)]	($/boe)	64.61	63.76	73.09
(Loss) gain on oil price risk management contracts [(6)(7)]	($/boe)	(1.35)	0.07	(1.27)
Royalties [(6)]	($/boe)	(1.00)	(0.88)	(1.64)
Net sales realized price [(4)(5)]	($/boe)	62.26	62.95	70.18
Production costs (excluding energy costs), net of realized FX hedge impact [(4)]	($/boe)	(10.04)	(7.66)	(10.21)
Energy costs, net of realized FX hedge impact [(4)]	($/boe)	(5.38)	(5.29)	(5.29)
Transportation costs, net of realized FX hedge impact [(4)(5)]	($/boe)	(12.32)	(11.35)	(11.47)
Operating netback per boe [(4)(5)]	($/boe)	34.52	38.65	43.21
Financial Results				
Oil & gas sales, net of purchases [(8)]	($M)	197,975	215,724	200,774
(Loss) gain on oil price risk management contracts [(7)]	($M)	(4,141)	253	(3,489)
Royalties	($M)	(3,060)	(2,971)	(4,506)
Net sales [(8)]	($M)	190,774	213,006	192,779
Net income (loss) [(9)]	($M)	27,524	(29,401)	(8,503)
Per share – basic	($)	0.35	(0.36)	(0.10)
Per share – diluted	($)	0.34	(0.36)	(0.10)
General and administrative	($M)	13,571	13,170	13,556
Outstanding Common Shares	Number of Shares	77,294,460	80,793,387	84,693,416
Operating EBITDA [(8)]	($M)	83,458	113,479	97,248
Cash provided by operating activities	($M)	70,137	168,691	65,616
Capital expenditures [(8)]	($M)	46,711	85,866	69,381
Cash and cash equivalents – unrestricted	($M)	170,094	192,577	154,907
Restricted cash short and long-term [(10)]	($M)	29,738	30,249	27,058
Total cash [(10)]	($M)	199,832	222,826	181,965
Total debt and lease liabilities [(10)]	($M)	505,486	506,037	537,151
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [(11)]	($M)	409,675	414,481	429,556
Net debt (excluding Unrestricted Subsidiaries) [(11)]	($M)	290,732	302,403	309,038

(1) References to heavy crude oil, light and medium crude oil combined, conventional natural gas, and natural gas liquids in the above table and elsewhere in this MD&A refer to heavy crude oil, light crude oil and medium crude oil combined, conventional natural gas, and natural gas liquids, respectively, product types as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*.
(2) Represents W.I. production before royalties. Refer to the "Further Disclosures" section on page 35 for further details.
(3) Boe has been expressed using the 5.7 to 1 Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy. Refer to the "Further Disclosures - Boe Conversion" section on page 35 for further details.
(4) Non-IFRS ratio is equivalent to a "non-GAAP ratio", as defined in National Instrument 52-112 - *Non-GAAP and Other Financial Measures Disclosure ("***NI 52-112***")*. Refer to the "Non-IFRS and Other Financial Measures'' section on page 21 for further details.
(5) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.
(6) Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 21 for further details.
(7) Includes the net effect of put premiums paid for expired positions and positive cash settlements received from oil price contracts during the period. Refer to the "Gain (Loss) on Risk Management Contracts" section on page 13 for further details.
(8) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 21 for further details.
(9) Net income (loss) attributable to equity holders of the Company.
(10) Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 21 for further details.
(11) "**Unrestricted Subsidiaries**" include CGX Energy Inc. ("**CGX**"), listed on the TSX Venture Exchange under the trading symbol "OYL"; FEC ODL Holdings Corp., including its subsidiary Frontera Pipeline Investment AG ("**FPI**", formerly named Pipeline Investment Ltd); Frontera BIC Holding Ltd.; Frontera Energy Guyana Holding Ltd.; Frontera Energy Guyana Corp.; and Frontera Bahía Holding Ltd., including Sociedad Portuaria Puerto Bahia S.A ("**Puerto Bahia**"). Refer to the "Liquidity and Capital Resources" section on page 28 for further details.

Performance Highlights

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

- **Colombian 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, 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.

First Quarter of 2025

The Company remains focused on the delivery of its strategic objectives and generating value for its shareholders. In the first quarter of 2025, the Company generated $83.5 million in Operating EBITDA, and maintained a strong balance sheet, finishing the quarter with a total cash balance of $199.8 million. In addition, the Company's financial results in its Colombia and Ecuador upstream onshore business are in-line with expectations despite some unforeseen challenges, including lower than expected quarterly production levels.

First quarter production was lower on a quarter over quarter basis, mainly due to delays in the heavy oil assets' drilling campaign, lower water handling on SAARA than expected, the impact of the natural decline as well as a greater need for well interventions in the light and medium blocks, that have since been resolved. Despite these challenges, the Company is gaining momentum into the second quarter, with production increasing to an estimated average daily production for May to approximately 42,400 boe/d and increasing water handling in our SAARA water treatment plant to 130,000 barrels per day. The Company remains confident it will meet its full year average production guidance of 41,000 - 43,000 boe/d.

On the cost side, the Company's transportation and energy cost per barrel metrics were within the 2025 Guidance, however production costs rose this quarter mainly due to the impact of higher well intervention activity in the light and medium blocks. Given the current oil price environment and the challenges facing the Oil & Gas industry in Colombia and globally, Frontera's focus remains on taking actions by identifying additional operational improvements, reduction in capital spend and greater cost and processes efficiencies in the business supporting a strong production profile and optimizing cash flow generation.

In the standalone and growing Colombia Infrastructure business, which includes the Company's interest in the Oleoducto de los Llanos Orientales S.A. ("**ODL**"), the segment generated an Adjusted Infrastructure EBITDA of $28.6 million. During the first quarter of 2025, ODL transported over 236,000 barrels of oil. ODL also declared a $151 million dividend ($52.9 million, net to Frontera), paying 50% of this amount in March 2025, highlighting the strong cash generation capacity of this strategic infrastructure investment. For Puerto Bahia, the Company's focus remains on starting up the connection project between Puerto Bahia's port facility and the Cartagena refinery (the "**Reficar Connection Project**"). With construction effectively complete, the Company aims to transport the first volume in the third quarter of 2025. Ongoing strategic investments in the port, including the LPG JV with Empresas Gasco, are progressing as planned. Additionally, the port is also reviewing new investment opportunities that leverage its facilities and infrastructure for profitable long-term growth.

The Board is advancing on the strategic path for maximizing shareholder value in Frontera's Infrastructure assets. The next step is the strategic recapitalization of its investment in the ODL pipeline and the development of key growth projects in Puerto Bahia. Frontera's Board will remain open to and consider all opportunities to enhance shareholder value, including a potential future separation and other strategic transactions involving the Infrastructure business, which could include a potential LNG import facility in Puerto Bahia.

Following the close of the first quarter, the Company signed a commitment letter for a $220 million non-recourse secured financing supported by Frontera's indirect interest in ODL. The Company expects to enter into definitive agreements shortly, pursuant to which the Company expects to receive approximately $115 million in net proceeds, after the refinancing of existing indebtedness. The recapitalization would allow Frontera to distribute significant value to its investors, while maintaining the future upside of this key transportation asset in Colombia. Furthermore, the financing is expected to exclude Puerto Bahía from the security package, which would provide Puerto Bahía greater flexibility to secure independent financing for new strategic growth projects.

Although there can be no assurance that the financing will be completed, the Company expects to enter into definitive agreements and close the financing shortly. As a result, the Company is launching a $65 million capped tender and consent solicitation of the 2028 Senior Unsecured Notes (which is subject to a financing and other conditions) and subject to conditional upon closing the ODL recapitalization, the Company plans to commence a substantial issuer bid to purchase up to $65 million of its outstanding shares.

As mentioned above, the Company is launching a capped cash tender and consent solicitation in connection with its 2028 Senior Unsecured Notes, pursuant to which the Company will offer to purchase up to $65 million of its 2028 Senior Unsecured Notes. Simultaneously with the tender offer, Frontera is launching a solicitation of consents from holders of the 2028 Senior Unsecured Notes to effect certain proposed amendments to the indenture governing the 2028 Senior Unsecured Notes dated as of June 21, 2021 (as amended and/or supplemented from time to time, the "**Notes Indenture**"). The tender offer and consent solicitation will be subject to various conditions, including, without limitation, the condition that the Company shall have obtained debt financing on terms and conditions and yielding net cash proceeds reasonably satisfactory to the Company.

The Company is also declaring its quarterly dividend of C$0.0625 per share, or $3.5 million in aggregate. In addition Frontera expects to commence a normal course issuer bid for its common shares (the "**NCIB**") following the completion of the SIB. Subject to the acceptance of the TSX, the Company will seek 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.

These efforts are consistent with the Company's strategy of returning capital to its shareholders. The Company will continue to consider similar investor-focused initiatives in 2025 and beyond, including potential additional dividends, distributions, share or bond buybacks, based on the overall results of the businesses, oil prices and cash flow generation. Additionally, the Company will consider all options to enhance the value of its common shares in the short term, and in so doing may consider other strategic initiatives or transactions.

The Company is very pleased to announce that on March 11 2025, Frontera was once again recognized by Ethisphere as one of the World's Most Ethical Companies. This marks the fifth consecutive year that the Company has received this distinction from Ethisphere, a global leader in defining and advancing the standards of ethical business practices.

Frontera successfully achieved 100% of its 2024 sustainability goals, marking the first milestone towards its 2028 Sustainability Strategy.

Additionally, the Company released its 2024 Sustainability Report which highlights the progress made over the last year against its sustainability goals, as the Company works towards a culture of corporate consciousness that allows to state its commitment to developing a sustainability strategy throughout our business to drive operational efficiency.

Financial and Operational Results

- Production averaged 40,477 boe/d in the first quarter of 2025 (consisting of 27,167 bbl/d of heavy crude oil, 10,998 bbl/d of light and medium crude oil combined, 2,274 mcf/d of conventional natural gas and 1,913 boe/d of natural gas liquids), compared with 42,406 boe/d in the prior quarter (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), and compared with 38,193 boe/d in the first quarter of 2024 (consisting of 23,398 bbl/d of heavy crude oil, 12,580 bbl/d of light and medium crude oil combined, 3,283 mcf/d of conventional natural gas and 1,639 boe/d of natural gas liquids).

- Cash provided by operating activities was $70.1 million in the first quarter of 2025, compared with $168.7 million in the prior quarter, and $65.6 million in the first quarter of 2024. The Company reported a total cash position of $199.8 million, including $29.7 million of restricted cash, as at March 31, 2025, compared with a total cash position of $222.8 million, including $30.2 million of restricted cash, as at December 31, 2024, and $182.0 million, including $27.1 million of restricted cash, as at March 31, 2024.

- The Company recorded a net income(1) of $27.5 million ($0.34/share(2)) in the first quarter of 2025, compared with a net loss(1) of $29.4 million ($0.36/share(2)) in the prior quarter and a net loss(1) of $8.5 million ($0.10/share(2)) in the first quarter of 2024.

- Capital expenditures were $46.7 million in the first quarter of 2025, compared with $85.9 million in the prior quarter and $69.4 million in the first quarter of 2024.

- Operating EBITDA was $83.5 million in the first quarter of 2025, compared with $113.5 million in the prior quarter and $97.2 million in the first quarter of 2024.

- Operating netback was $34.52/boe in the first quarter of 2025, compared with $38.65/boe in the prior quarter and $43.21/boe in the first quarter of 2024.

- Infrastructure Colombia Segment (as defined below) income was $15.3 million in the first quarter of 2025, compared with $15.2 million in the prior quarter and $12.6 million in the first quarter of 2024.
- Adjusted Infrastructure EBITDA in the first quarter of 2025 was $28.6 million, compared with $27.5 million in the prior quarter and $25.7 million in the first quarter of 2024.

- Puerto Bahia liquid volumes handled during the first quarter of 2025 were 51,579 bbl/d, compared with 61,990 bbl/d in the prior quarter and 53,360 bbl/d in the first quarter of 2024. Puerto Bahia revenues were $9.9 million in the first quarter of 2025, compared with $11.5 million in the prior quarter and $9.7 million in the first quarter of 2024.

- ODL volumes transported were 236,387 bbl/d in the first quarter of 2025, compared with 235,528 bbl/d in the prior quarter of 2024, and 246,042 bbl/d in the first quarter of 2024.

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

(2) Per Common Share on a diluted basis.

2. GUIDANCE

The Company remains confident it meets its full 2025 Capital and Production guidance, as released on December 12, 2024. The Company's 2025 drilling campaign continues to progress well and we expect improved production and profitability throughout the rest of the year as the Company advances its development portfolio in Colombia and continue to increase Quifa and CPE-6 water-handling infrastructure and facilities.

2025 Additional Estimates Sensitives

Brent Crude Oil Price ($/bbl)	Unit	$65	$75	$85
Consolidated Operating EBITDA	$MM	270 - 315	370 - 415	460 - 505

The following table reports the Company's actual results for the three months ended March 31, 2025, against the 2025 full year guidance metrics.

Guidance Metrics	Unit	Guidance	Actual
Average Daily Production (1)	boe/d	41,000 - 43,000	40,477
Production Costs (2)(4)	$/boe	8.75 - 9.25	10.04
Energy Costs (2)(4)	$/boe	5.25 - 5.75	5.38
Transportation Costs (3)(4)	$/boe	12.50 - 13.00	12.32
Operating EBITDA (5) at $75/bbl (6)	$MM	370 - 415	83.5
Adjusted Infrastructure EBITDA (5)	$MM	115 - 130	28.6
Development Drilling	$MM	100 - 110	25.5
Development Facilities	$MM	60 - 80	7.2
Colombia and Ecuador Development	$MM	160 - 190	32.7
Colombia and Ecuador Exploration	$MM	30 - 40	10.0
Other (7)	$MM	10 - 15	1.0
Total Colombia & Ecuador Capex	$MM	200 - 245	43.7
Guyana Exploration	$MM	1 - 3	0.3
Colombia Infrastructure	$MM	15 - 20	2.7
Total Capital Expenditures (5)	$MM	216 - 268	46.7

(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 NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 21 for further details.
(5) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 21 for further details.
(6) Current Guidance Operating EBITDA calculated at Brent between $75/bbl and COP/USD exchange rate of 4,250:1.
(7) Other includes HSEQ activities and new field production technologies.

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company's operations in Colombia and Ecuador. Refer to the "Further Disclosures" section on page 35 for details of the Company's net production:

		Production		
Producing blocks in Colombia		**Q1 2025**	**Q4 2024**	**Q1 2024**
Heavy crude oil	(bbl/d)	27,167	27,740	23,398
Light and medium crude oil combined	(bbl/d)	9,531	10,484	11,102
Conventional natural gas	(mcf/d)	2,274	2,633	3,283
Natural gas liquids	(boe/d)	1,913	1,970	1,639
Total production Colombia	**(boe/d)**	**39,010**	**40,656**	**36,715**
Producing blocks in Ecuador				
Light and medium crude oil combined	(bbl/d)	1,467	1,750	1,478
Total production Ecuador	**(bbl/d)**	**1,467**	**1,750**	**1,478**
Total production	**(boe/d)**	**40,477**	**42,406**	**38,193**

Colombia

Production in Colombia for the three months ended March 31, 2025 increased by 2,295 boe/d up 6%, compared with the same period of 2024, mainly due to the following: (i) heavy crude oil increases of 3,769 bbl/d resulting from the increase in water handling capacity in the CPE-6 block, the increased processing capacity at SAARA, which supports production levels from the Quifa block, the new and improved flow lines in the Cajua field, in the Quifa Block, the successful development drilling campaigns in the CPE-6 and Sabanero blocks, the reactivation of wells in the Sabanero block; (ii) natural gas liquids production increased by 17%, coming primarily from 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 14%, primarily due to natural field declines; and (iv) decreased by 31% of conventional natural gas production.

In the first quarter of 2025, production in Colombia decreased by 1,646 boe/d compared with the fourth quarter of 2024. Heavy crude oil production decreased by 2%, mainly due to delays in the heavy oil assets' 2025 drilling campaigns during the first quarter of 2025 and lower water handling on SAARA than expected. Light and medium crude oil combined production and conventional natural gas production decreased primarily due to natural decline of the blocks and a greater need of well interventions activities during the quarter. Natural gas liquids production decreased by 3%.

Ecuador

Production of light and medium crude oil combined in the first quarter of 2025 decreased by 16%, compared with the previous quarter, primarily due to natural reservoir decline, and was consistent with the same quarter of 2024.

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 sales volumes, net of purchases, and summarizes other factors that impacted total sales volumes.

		Q1 2025	Q4 2024	Q1 2024
Production	(boe/d)	**40,477**	**42,406**	**38,193**
Royalties in-kind Colombia	(boe/d)	(3,802)	(3,948)	(4,011)
Royalties in-kind Ecuador [1]	(boe/d)	(420)	(489)	(439)
Net production	(boe/d)	**36,255**	**37,969**	**33,743**
Oil inventory draw (build)	(boe/d)	1,307	3,108	(2,223)
Overlift (Settlement)	(boe/d)	(9)	(27)	—
Volumes purchased	(boe/d)	8,088	6,420	8,354
Other inventory movements [2]	(boe/d)	(2,701)	(2,102)	(2,461)
Sales volumes	(boe/d)	**42,940**	**45,368**	**37,413**
Sale of volumes purchased	(boe/d)	(8,896)	(8,595)	(7,228)
Sales volumes, net of purchases	(boe/d)	**34,044**	**36,773**	**30,185**
Oil sales volumes	(bbl/d)	33,697	36,326	29,610
Conventional natural gas sales volumes	(mcf/d)	1,978	2,548	3,278
Total oil and conventional natural gas sales volumes, net of purchases	**(boe/d)**	**34,044**	**36,773**	**30,185**
Inventory balance				
Colombia [3]	(bbl)	392,821	501,778	683,335
Peru	(bbl)	480,200	480,200	480,200
Ecuador	(bbl)	38,865	47,488	115,228
Inventory ending balance	**(bbl)**	**911,886**	**1,029,466**	**1,278,763**

[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 0.22 MMbbl of oil produced and 0.17 MMbbl of diluent in the first quarter of 2025, 0.25 MMbbl of oil produced and 0.25 MMbbl of diluent in the fourth quarter of 2024, and 0.35 MMbbl of oil produced and 0.33 MMbbl of diluent in the first quarter of 2024.

In the first quarter of 2025, sales volumes, net of purchases, increased by 13% compared with the same period in 2024, driven by higher volumes sold, due to higher production in the first quarter of 2025 and inventory build in the first quarter of 2024. For the three months ended March 31, 2025, sales volumes, net of purchases, decreased by 7% compared with the prior quarter, mainly due to lower production.

Realized and Reference Prices

		Q1 2025	Q4 2024	Q1 2024
Reference price				
Brent [1]	($/bbl)	74.98	74.01	81.76
Average realized prices				
Realized oil price, net of purchases	($/bbl)	64.95	64.07	73.82
Realized conventional natural gas price	($/mcf)	5.61	6.78	6.26
Net sales realized price				
Produced crude oil and gas sales [2]	($/boe)	68.42	67.18	76.10
Purchased crude net margin [2][3]	($/boe)	(3.81)	(3.42)	(3.01)
Oil and gas sales, net of purchases [2]	($/boe)	64.61	63.76	73.09
(Loss) gain on oil price risk management contracts [4] [5]	($/boe)	(1.35)	0.07	(1.27)
Royalties [4]	($/boe)	(1.00)	(0.88)	(1.64)
Net sales realized price [2]	**($/boe)**	**62.26**	**62.95**	**70.18**

(1) Frontera's weighted average Brent price for the three months ended March 31, 2025, was 74.35/bbl.
(2) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 21 for further details. Corresponds to the net sales and costs of third-party hydrocarbon volumes purchased primarily for dilution and refining purposes, as part of the Company's oil operations, marketing and transportation strategy.
(3) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.
(4) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 21 for further details.
(5) Includes the net amount of put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Refer to the "Gain (Loss) on Risk Management Contracts" section on page 13 for further details.

The average Brent benchmark oil price during the three months ended March 31, 2025, decreased by 8% compared with the same period in 2024. Compared with the fourth quarter of 2024, the average Brent benchmark oil price increased by 1%. The decrease in crude oil prices in 2025 compared with the same period in 2024 was mainly due to: (i) weak demand in China; (ii) OPEC+ starting to unwind crude oil production costs; (iii) an excess of supply perceived by the market in the US, Brazil offshore, and Vaca Muerta field in Argentina, among others; and (iv) lower war risk premium (Russia-Ukraine and the Middle East).

For the three months ended March 31, 2025, the Company's net sales realized price decreased by $7.92/boe compared with the same period in 2024. The decrease was primarily driven by a lower Brent benchmark oil price and additional purchased crude net margin due to higher dilution cost, partially offset by lower cash royalties paid.

Compared with the prior quarter, the Company's net realized sales price decreased by 1%. The decrease was primarily driven by a positive cash settlement on oil price risk management contracts during the last quarter of 2024. This was partially offset by a higher Brent benchmark oil price and a better oil price differential.

Operating Netback

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

	Q1 2025		Q4 2024		Q1 2024	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price [1]	190,774	62.26	213,006	62.95	192,779	70.18
Production costs (excluding energy costs), net of realized FX hedge impact [1][2][3]	(36,592)	(10.04)	(29,874)	(7.66)	(35,502)	(10.21)
Energy costs, net of realized FX hedge impact [1][2][4]	(19,584)	(5.38)	(20,647)	(5.29)	(18,387)	(5.29)
Transportation costs, net of realized FX hedge impact [1][2][4][5]	(40,185)	(12.32)	(39,635)	(11.35)	(35,217)	(11.47)
Operating Netback [1][2][6]	**94,413**	**34.52**	**122,850**	**38.65**	**103,673**	**43.21**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases [7]		34,044		36,773		30,185
Production [8]		40,477		42,406		38,193
Net production [9]		36,255		37,969		33,743

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 21 for further details.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 21 for further details.
(3) Includes $Nil, $Nil, and a gain of $1.3 million from realized FX hedge attributable to production costs for the first quarter of 2025, the fourth quarter of 2024, and the first quarter of 2024, respectively. See "Gain (loss) on Risk Management Contracts" on page 13 for further details.
(4) Includes $Nil, $Nil, and a gain of $0.6 million from realized FX hedge attributable to energy costs for the first quarter of 2025, the fourth quarter of 2024, and the first quarter of 2024, respectively. See "Gain (loss) on Risk Management Contracts" on page 13 for further details.
(5) Includes $Nil, $Nil, and a gain of $0.4 million from realized FX hedge attributable to transportation costs for the first quarter of 2025, the fourth quarter of 2024, and the first quarter of 2024, respectively. See "Gain (loss) on Risk Management Contracts" on page 13 for further details.
(6) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.
(7) Sales volumes, net of purchases, excluding sales of third-party volumes.
(8) Refer to the "Production" section on page 6 for further details.
(9) Refer to the "Further Disclosures" section on page 35 for further details.

The Company's operating netback for the first quarter of 2025 was $34.52/boe, compared with $43.21/boe in the same quarter of 2024. Compared with the fourth quarter of 2024, the Company's operating netback decreased by 11%, from $38.65/boe to $34.52/boe, mainly due to (i) lower net sales realized prices; (ii) higher production costs (excluding energy costs), net of the realized FX hedge impact, driven by increased well intervention activities during the first quarter of 2025; (iii) higher transportation costs, attributed to tariff increases for the Ocensa pipeline and trucking; and (iv) despite lower production during the quarter, energy costs, net of the realized FX hedge impact per barrel, increased due to carbon credits purchases in the first quarter of 2025 and higher energy price increase.

Sales

	Three months ended March 31	
($M)	**2025**	**2024**
Produced crude oil sales	208,630	207,177
Purchased crude net margin [1][2]	(11,652)	(8,269)
Conventional natural gas sales	997	1,866
Oil and gas sales, net of purchases [3]	197,975	200,774
Loss on oil price risk management contracts [4]	(4,141)	(3,489)
Royalties	(3,060)	(4,506)
Net sales [1]	**190,774**	**192,779**
Net sales realized price ($/boe) [5]	62.26	70.18

(1) Corresponds to the net sales and costs of third-party hydrocarbon volumes purchased primarily for dilution and refining purposes, as part of the Company's oil operations, marketing and transportation strategy.
(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.
(3) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 21 for further details.
(4) Includes put premiums paid for expired positions. Refer to the "Gain (Loss) on Risk Management Contracts" section on page 13 for further details.
(5) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 21 for further details.

Oil and gas sales, net of purchases, decreased by $2.8 million for the three months ended March 31, 2025, compared with the same period of 2024, mainly due to a lower Brent benchmark oil price (refer to the "Realized and Reference Prices" section on page 8 for further details on price changes) and a higher purchased crude net margin. This was partially offset by the additional volumes produced and better oil price differentials.

Net sales for the three months ended March 31, 2025, decreased by $2.0 million, compared with the same period of 2024. The following table describes the various factors that impacted net sales:

	Three months ended March 31
($M)	2025-2024
Net sales for the period ended March 31, 2024	192,779
Decrease due to 12% lower oil and gas price	(23,280)
Increase due to variance of total produced volumes sold	20,481
Decrease in royalties	1,446
Increase in oil price risk management contracts, net [1]	(652)
Net sales for the period ended March 31, 2025	**190,774**

[1] Includes put premiums paid for expired positions. Refer to the "Income (Loss) on Risk Management Contracts" section on page 13 for further details.

Oil and Gas Operating Costs

	Three months ended March 31	
($M)	2025	2024
Transportation costs	39,549	35,195
Production costs (excluding energy costs)	35,679	36,839
Energy costs	19,584	18,968
Trunkline costs	2,000	—
Inventory valuation	1,756	(3,923)
Post-termination costs	297	550
Total oil and gas operating costs	**98,865**	**87,629**

During the three months ended March 31, 2025, total oil and gas operating costs increased by $11.2 million, compared with the same period of 2024. 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 March 31, 2025, decreased by 3% compared with the same period of 2024, primarily due to lower maintenance costs.
- Energy costs for the three months ended March 31, 2025, increased by 3%, mainly due to carbon credits purchases in the first quarter of 2025.
- For the three months ended March 31, 2025, transportation costs increased by 12% compared with the same period of 2024, primarily due to higher volumes produced and transported, and the annual increase in transportation tariffs.
- Post-termination obligations for the three months ended March 31, 2025, decreased by $0.3 million, primarily reflecting the $0.3 million recognized in connection with the relinquishment of the Orito block in the first quarter of 2024.
- Inventory valuation for the three months ended March 31, 2025, increased by $5.7 million compared with the same period of 2024, mainly due to inventory draw.
- Trunkline costs related to repairs and other activities undertaken in response to unexpected failures in a trunkline in the Quifa block, which have since been resolved. The Company expects to recover a portion of these costs through claims under its material damages and third-party liability insurance policies.

Cost of Diluent and Oil Purchased

	Three months ended March 31	
($M)	2025	2024
Cost of diluent and oil purchased [1]	68,860	57,859

[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 21 for further details.

Cost of diluent and oil purchased represents the cost of third-party hydrocarbon volumes purchased primarily for dilution and refining purposes as part of the Company's oil operations, as well as its marketing and transportation strategy. For the three months ended March 31, 2025, the cost of diluent and oil purchases, including the transportation and processing fees for volumes sold, increased by $11.0 million, compared with the same period of 2024, primarily due to increased demand for diluent and fuel used for energy, and a reduction in light and medium crude oil production.

Royalties

($M)	Three months ended March 31 2025	2024
Royalties Colombia	2,788	4,394
Royalties Ecuador	272	112
Royalties	**3,060**	**4,506**

Royalties include cash payments for PAP (as defined below), royalty payments, and payments to previous owners of certain blocks in Colombia and Ecuador. For the three months ended March 31, 2025, royalties decreased by $1.4 million, compared with the same period of 2024, due to a decline in the WTI oil benchmark price.

Colombia Royalties PAP

The Company makes high price clause participation ("**PAP**") payments to Ecopetrol S.A. ("**Ecopetrol**") and the Agencia Nacional de Hidrocarburos ("**ANH**") on production from the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo, Arrendajo, Casimena, and CPE-6 blocks. The ANH requires in-kind PAP payments for all blocks, except for Guatiquia (Yatay field), Cubiro (Copa A field) blocks, and Casimena (Mantis field).

		Q1 2025	Q1 2024
PAP in kind	(bbl/d)	697	1,325
PAP in cash	(bbl/d)	262	376
PAP	**(bbl/d)**	**959**	**1,701**
% Production		**2.4 %**	**4.5 %**

Depletion, Depreciation and Amortization

($M)	Three months ended March 31 2025	2024
Depletion, depreciation and amortization	67,394	65,812

For the three months ended March 31, 2025, depletion, depreciation, and amortization expense ("**DD&A**") increased by 2% compared to the same period of 2024 mainly due to higher production.

Impairment Expense, Exploration Expenses and Others

($M)	Three months ended March 31 2025	2024
Impairment expense of:		
Exploration and evaluation assets	235	—
Other	899	1,027
Total impairment expense	1,134	1,027
Exploration expenses of:		
Geological and geophysical costs, and other	472	410
Total exploration expenses	472	410
Expense (recovery) of asset retirement obligations	375	(1,042)
Impairment expense, exploration expenses and other	**1,981**	**395**

Exploration and Evaluation Assets

During the three months ended March 31, 2025, the Company recorded an impairment charge of $0.2 million (2024: $Nil) resulting from certain additions to exploration and evaluation ("**E&E**") assets that had previously been impaired.

Other

During the three months ended March 31, 2025, the Company recognized other impairment expenses of $0.9 million (2024: $1.0 million), mainly related to obsolete inventory materials.

Expense (recovery) of asset retirement obligations

During the three months ended March 31, 2025, the Company recognized an asset retirement obligations expense of $0.4 million. During the three months ended March 31, 2024, the Company recognized a recovery of asset retirement obligations of $1.0 million.

Other Operating Costs

	Three months ended March 31	
($M)	**2025**	**2024**
General and administrative	13,571	13,556
Special projects and other costs	3,928	2,080
Share-based compensation	862	286
Restructuring, severance, and other costs	1,001	1,803

General and Administrative ("G&A")

For the three months ended March 31, 2025, G&A expenses were consistent with the same period of 2024.

Special projects and other costs

For the three months ended March 31, 2025, special projects and other costs increased by 89% compared with the same quarter of 2024, mainly due to SAARA operating costs under of the agreement with Ecopetrol signed in June 2024.

Share-Based Compensation

For the three months ended March 31, 2025, share-based compensation increased by $0.6 million, compared with the same quarter of 2024. The increase was primarily due to a higher number of share units granted in 2025 and a higher performance multiplier percentage, partially offset by a lower stock price. Share-based compensation reflects cash and non-cash charges related to the vesting of restricted share units ("**RSUs**") and the granting of deferred share units ("**DSUs**") under the Company's security-based compensation plan, which are subject to variability due to movements in the trading price of the Company's Common Shares, and the consolidation of stock option expenses from the Company's majority-held subsidiary, CGX.

Restructuring, Severance and Other Costs

For the three months ended March 31, 2025, restructuring, severance and other costs decreased by $0.8 million compared with the same period of 2024, primarily due to severance costs incurred during the first quarter of 2024.

Non-Operating Costs

	Three months ended March 31	
($M)	**2025**	**2024**
Finance income	1,483	1,592
Finance expenses	(15,405)	(17,270)
Foreign exchange income (loss)	2,239	(1,097)
Other loss	(112)	(359)

Finance Income

For the three months ended March 31, 2025, finance income decreased by $0.1 million, compared with the same period of 2024, mainly due to changes in interest rates on investment trust accounts related to abandonment requirements and lower cash balances during the period.

Finance Expenses

For the three months ended March 31, 2025, finance expenses decreased by $1.9 million, compared with the same period of 2024, mainly due to lower interest expenses related to the Bancolombia working capital loan, which was fully repaid on October 30, 2024, and the Davivienda loans, which were fully repaid on March 11, 2024 and May 23, 2024.

Foreign Exchange Income (Loss)

For the three months ended March 31, 2025, the Company recognized foreign exchange income was $2.2 million, resulting from of the appreciation of the COP against the USD during the first quarter of 2025, which impacted the Company's net working capital balances denominated in COP. In the same period of 2024, the foreign exchange loss was $1.1 million, due to the transfer from the cumulative translation adjustment within Other Comprehensive Income to the Consolidated Statement of Income of a return of capital and dividends of ODL, partially compensated by income from a tax refund collection. Foreign exchange rates (COP:USD) as at March 31, 2025, and March 31, 2024, were 4,192.57:1 and 3,842.30:1, respectively.

Other Loss

For the three months ended March 31, 2025, the Company recognized an other loss of $0.1 million, net, mainly due to the recognition of contingencies of $3.2 million, partially offset by other income received from the sale of inventory and other assets from relinquished blocks totaling $2.8 million. During the same period of 2024, the Company recognized an other loss of $0.4 million, mainly attributable to contingencies, and partially offset by income from insurance compensation related to for the Sabanero block.

Gain (Loss) on Risk Management Contracts

	Three months ended March 31	
($M)	2025	2024
Loss on oil price risk management contracts [1]	(4,141)	(3,489)
Realized gain on foreign exchange risk hedge [2]	—	2,615
Realized loss on risk management contracts	(4,141)	(874)
Unrealized gain (loss) on risk management contracts	4,786	(7,939)
Total gain (loss) on risk management contracts	645	(8,813)

[1] Corresponds to the put premiums paid for expired position.

[2] For determination of operating netback, during the three months ended March 31, 2025 and 2024, the Company estimates an attribution of $Nil and $1.3 million of the total realized FX hedge to production cost, respectively, estimates an attribution of $Nil and $0.6 million of the total realized FX hedge to energy, respectively, and estimates an attribution of $Nil and $0.4 million of the total realized FX hedge to transportation, respectively. Refer to the "Non-IFRS and Other Financial Measures" section on page 24.

For the three months ended March 31, 2025, the realized loss on risk management contracts was $4.1 million, resulting from premiums paid for expired put positions. In the same period of 2024, the loss on risk management contracts was $0.9 million, resulting in $3.5 million related to premiums paid on oil price risk management contracts, partially offset by a gain of $2.6 million on the cash settlement of foreign exchange risk management contracts.

For the three months ended March 31, 2025, risk management contracts had an unrealized gain of $4.8 million, compared with a loss of $7.9 million, in the same period of 2024, primarily due to mark to market variances from foreign exchange risk management contracts and changes in the benchmark forward prices of Brent.

Risk Management Contracts - Brent Crude Oil

As part of its risk management strategy, the Company uses derivative commodity instruments to manage exposure to price volatility by hedging a portion of its oil production. The Company's strategy aims to protect a minimum of 40% of estimated production with a tactical approach, using derivative commodity instruments to protect the Company's revenue generation and cash position, while maximizing the upside.

				Avg. Strike Prices	Carrying Amount	
Type of Instrument	Term	Benchmark	Volume (bbl)	Put $/bbl	Assets	Liabilities
Put Spread	May 2025 to June 2025	Brent	400,000	55/70	—	548
Put Option	April 2025 to June 2025	Brent	876,000	70	—	1,596
Total as at March 31, 2025			1,276,000		—	2,144

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

				Avg. Strike Prices
Type of Instrument	Term	Benchmark	Volume (bbl)	Put $/bbl
Put Spreads	July 2025 to August 202	Brent	460,000	55/70
		Total volume (bbl)	460,000	

Risk Management Contracts - Foreign Exchange

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

As at March 31, 2025, the Company has the following foreign currency derivatives contracts:

				Avg. Put / Call	Carrying Amount	
Type of Instrument	Term	Benchmark	Notional Amount / Volume in USD	Par forward (COP$)	Assets	Liabilities
Zero-cost collars	April to June 2025	USD / COP	60,000,000	4,200/4,626	801	—
Zero-cost collars	July to September 2025	USD / COP	60,000,000	4,200/4,795	1,095	—
Forward [1]	August 2025	USD / COP	10,423,124	4,206	110	—
Forward [1]	October 2025	USD / COP	7,741,875	4,247	76	—
Forward [1]	December 2025	USD / COP	7,666,063	4,289	60	—
Total as at March 31, 2025			145,831,062		2,142	—

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

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

					Avg. Strike Prices
Type of Instrument	Term	Benchmark	Currency Hedged	Notional Amount / Volume in USD	Par forward (COP$)
Zero-cost Collar	October 2025 to December 2025	USD / COP	USD	30,000,000	4,250/4,787
		Total		30,000,000	

Income Tax Expense

	Three months ended March 31	
($M)	2025	2024
Current income tax expense	(5,795)	(5,010)
Deferred income tax recovery (expense)	15,446	(21,575)
Total income tax recovery (expense)	9,651	(26,585)

For the three months ended March 31, 2025, the Company recognized a current income tax expense of $5.8 million, compared to a current income tax expense of $5.0 million, in the same period of 2024. Additionally, the Company recognized a deferred income tax recovery of $15.4 million, compared with a deferred income tax expense of $21.6 million, in the same period of 2024.

The deferred tax recovery for the three months ended March 31, 2025 was mainly due to foreign exchange rate fluctuations.

Net Income (Loss)

	Three months ended March 31	
($M)	2025	2024
Net income (loss) [1]	27,524	(8,503)
Per share – basic ($)	0.35	(0.10)
Per share – diluted ($)	0.34	(0.10)

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

During the first quarter of 2025, the Company reported a net income, attributable to equity holders of the Company, of $27.5 million, mainly resulting from an income tax recovery of $9.7 million (including $15.4 million of deferred income tax recovery), income from operations of $13.6 million (net of a non cash impairment expense of $1.1 million), $15.1 million from share of income from associates, foreign exchange income of $2.2 million, and $0.6 million related to gain on risk management contracts, partially offset by finance expenses of $15.4 million. This compares with a net loss, attributable to equity holders of the Company, of $8.5 million for the first quarter of 2024, mainly resulting from income tax expense of $26.6 million (including $21.6 million of deferred income tax expenses), finance expenses of $17.3 million and $8.8 million related to loss on risk management contracts, partially offset by operating income of $29.7 million, and $13.9 million in share of income from associates.

Capital Expenditures and Acquisitions

	Three months ended March 31	
($M)	**2025**	**2024**
Development drilling	25,530	35,038
Development facilities	7,179	19,678
Colombia and Ecuador exploration	10,021	2,237
Other	934	6,334
Total Colombia and Ecuador upstream capital expenditures	**43,664**	**63,287**
Colombia infrastructure	2,700	4,556
Guyana exploration	347	1,538
Total capital expenditures [1]	**46,711**	**69,381**

[1] Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 21 for further details.

Capital expenditures for the three months ended March 31, 2025, were $46.7 million, compared with $69.4 million in the same period of 2024, as follows:

Development drilling. During the three months ended March 31, 2025, development drilling expenditures were $25.5 million, compared with $35.0 million for the same period of 2024. During the first quarter of 2025, 13 development wells were drilled in the Quifa and CPE-6 blocks, in Colombia. In the same period of 2024, 20 development wells were drilled in the Quifa, and CPE-6 blocks in Colombia, and one development well was drilled in the Perico block, in Ecuador.

Development facilities. During the three months ended March 31, 2025, development facility expenditures were $7.2 million, and primarily related to the facility expansion and the installation of new and improved flow lines in the Cajua field, in the Quifa block, to support new well production and the SAARA connection. For the same period of 2024, development facility were $19.7 million, mainly related to the Perico block, the increase of water capacity at the CPE-6 block, the expansion of gas compression facilities in the VIM-1 block, and facilities for an injector well in the Quifa block.

Colombia and Ecuador Exploration. During the three months ended March 31, 2025, expenditures related to exploration activities were $10.0 million, compared with $2.2 million in the same period of 2024. During the three months ended March 31, 2025, two exploratory wells were drilled, completed and tested in Colombia, and predrilling activities (socialization) were ongoing for the drilling of two new exploration wells in Colombia. Details regarding exploration activities in Colombia and Ecuador are as follows:

Colombia. During the first quarter of 2025, the Company's exploration focus remained on the Lower Magdalena Valley and Llanos Basins in Colombia. In the Cachicamo block, the Papilio-1 well was spud on December 31, 2024, reaching a total measured depth of 8,580 feet by January 8, 2025. Integration of drilling data and petrophysical interpretation identified 21.5 feet of net pay and the well is currently producing approximately 130 boe/d with 97% BSW. The Greta Norte-1 well was drilled on January 18, 2025, and reached a total measured depth of 12,174 feet on February 5, 2025. Integration of drilling data and petrophysical interpretation identified 12.5 feet of net pay, and the well will be plugged and abandoned. At the VIM-1 block, discussions with authorities and communities are ongoing to drill the Hidra-1 well during the second half of 2025. At the Llanos 119 block, the Company has requested the transfer of the remaining exploration commitments to the VIM-46 block and its 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 continued its long-term tests with a production of 380 bbl/d gross and a BSW of 73%. The Company continues to evaluate the development plan.

Other. Other capital expenditures for the three months ended March 31, 2025, were $0.9 million. These expenditures were mainly related to new field production technologies at the CPE-6 block.

Colombia infrastructure. Capital expenditures for the three months ended March 31, 2025, were $2.7 million, mostly related to Puerto Bahia investments of $1.9 million, including: (i) $0.8 million in investment towards the connection project between Puerto Bahia's port facility and the Cartagena refinery via a 6.8-kilometre, 18-inch bi-directional hydrocarbon flow line, pursuant to the connection agreement between Puerto Bahia and Refinería de Cartagena S.A.S. ("**Reficar**"), (ii) tank maintenance, and (iii) general cargo terminal facilities. The total also, this includes investment in the SAARA project. During the same period of 2024, capital expenditures were $4.6 million, for the capital expenditures in connection with SAARA project and Puerto Bahia.

Guyana exploration. During the three months ended March 31, 2025, and March 31, 2024, Guyana exploration expenditures were $0.3 million, and $1.5 million, respectively and mainly related to post-well studies and other capitalized expenses.

Selected Quarterly Information

		2025	2024				2023		
Operational and financial results		**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Heavy crude oil production	(bbl/d)	27,167	27,740	25,312	24,839	23,398	23,002	24,097	24,051
Light and medium crude oil combined production	(bbl/d)	10,998	12,234	12,794	12,583	12,580	13,795	13,964	15,188
Total crude oil production	(bbl/d)	38,165	39,974	38,106	37,422	35,978	36,797	38,061	39,239
Conventional natural gas production	(mcf/d)	2,274	2,633	3,192	4,019	3,283	4,760	5,250	5,626
Natural gas liquids production	(boe/d)	1,913	1,970	1,950	1,785	1,639	1,635	1,820	1,823
Total production	(boe/d)	40,477	42,406	40,616	39,912	38,193	39,267	40,802	42,049
Sales volumes, net of purchases	(boe/d)	34,044	36,773	34,192	31,523	30,185	34,449	35,289	35,799
Brent price reference	($/bbl)	74.98	74.01	78.71	85.03	81.76	82.85	85.92	77.73
Oil and gas sales, net of purchases (1)(2)	($/boe)	64.61	63.76	67.68	75.69	73.09	75.25	78.01	67.46
Gain (loss) on oil price risk management contracts (3)(4)	($/boe)	(1.35)	0.07	(0.45)	(1.32)	(1.27)	(0.69)	(0.59)	(0.80)
Royalties (3)	($/boe)	(1.00)	(0.88)	(0.91)	(2.01)	(1.64)	(1.79)	(3.76)	(3.02)
Net sales realized price (1)(2)	($/boe)	62.26	62.95	66.32	72.36	70.18	72.77	73.66	63.64
Production costs (excluding energy costs), net of realized FX hedge impact (2)(3)	($/boe)	(10.04)	(7.66)	(8.88)	(10.79)	(10.21)	(9.69)	(8.82)	(8.45)
Energy costs, net of realized FX hedge impact (3)	($/boe)	(5.38)	(5.29)	(5.11)	(4.74)	(5.29)	(5.06)	(5.04)	(3.94)
Transportation costs, net of realized FX hedge impact (2)(3)	($/boe)	(12.32)	(11.35)	(12.31)	(11.07)	(11.47)	(11.06)	(11.90)	(11.02)
Operating netback per boe (1)(2)	($/boe)	34.52	38.65	40.02	45.76	43.21	46.96	47.90	40.23
Revenue	($M)	275,061	290,614	278,475	279,523	265,175	299,501	308,867	289,869
Net income (loss) (5)	($M)	27,524	(29,401)	16,588	(2,846)	(8,503)	92,038	32,582	80,207
Per share – basic ($)	($)	0.35	(0.36)	0.20	(0.03)	(0.10)	1.08	0.38	0.94
Per share – diluted ($)	($)	0.34	(0.36)	0.19	(0.03)	(0.10)	1.04	0.37	0.92
General and administrative	($M)	13,571	13,170	12,719	12,928	13,556	16,891	11,925	12,422
Operating EBITDA (6)	($M)	83,458	113,479	103,184	110,321	97,248	121,036	137,800	116,461
Capital expenditures (6)	($M)	46,711	85,866	82,411	80,198	69,381	82,292	74,130	154,860

(1) Non-IFRS ratio. Refer to the “Non-IFRS and Other Financial Measures'' section on page 21 for further details.
(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.
(3) Supplementary financial measure. Refer to the “Non-IFRS and Other Financial Measures'' section on page 21 for further details.
(4) Includes the net effect of put premiums paid for expired positions and positive cash settlements received from oil price contracts during the period. Refer to the “Gain (Loss) on Risk Management Contracts” section on page 13 for further details.
(5) Refers to net income (loss) attributable to equity holders of the Company.
(6) Non-IFRS financial measure. Refer to the “Non-IFRS and Other Financial Measures” section on page 21 for further details.

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

Trends in the Company’s net income (loss), attributable to equity holders of the Company, are primarily impacted by the recognition and derecognition of deferred income taxes, the recognition or reversal of impairment charges related to oil and gas and exploration and evaluation assets, DD&A, foreign exchange gains or losses, and gains or losses from risk management contracts, which fluctuate mainly with changes in hedging strategies 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.

Infrastructure Colombia

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

The Company's Infrastructure Colombia Segment includes the following:

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

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

Performance Highlights

		Q1 2025	Q4 2024	Q1 2024
Operational and IFRS Results				
Volumes pumped at oil pipeline facility	(bbl/d)	236,387	235,528	246,042
Volume throughput at port liquids facility	(bbl/d)	51,579	61,990	53,360
Volumes handled at RORO port general cargo facility	(Units)	18,223	21,676	12,849
Break Bulk Volumes at port	(Tons/m3)	41,198	34,690	8,481
Volumes of water received from production fields	(bwpd)	81,481	78,716	33,272
Production of fresh fruit bunches	(Tons)	7,684	6,183	5,095
Infrastructure Colombia segment income	($M)	15,296	15,183	12,552
Infrastructure Colombia segment cash flow from operating activities	($M)	25,580	14,788	645
Non IFRS Results [(1)]				
Adjusted Infrastructure Revenues	($M)	44,912	45,278	40,907
Adjusted Infrastructure EBITDA	($M)	28,603	27,532	25,687
Adjusted Infrastructure Cash	($M)	57,795	72,423	78,813
Adjusted Infrastructure Debt	($M)	117,935	116,895	120,024
Capital Expenditures Infrastructure Colombia Segment	($M)	2,700	25,999	4,556

[(1)] Non-IFRS financial measures (equivalent to "non-GAAP financial measures", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 21 for further details.

Infrastructure Colombia Segment Results

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

	Three months ended March 31	
($M)	2025	2024
Revenue	12,864	10,528
Costs	(8,930)	(8,149)
General and administrative expenses	(1,507)	(1,479)
Depletion, depreciation and amortization	(2,026)	(1,816)
Other operating costs	(214)	(426)
Infrastructure Colombia income (loss) from operations	**187**	**(1,342)**
Share of income from associates - ODL	15,109	13,894
Infrastructure Colombia segment income	**15,296**	**12,552**
Infrastructure Colombia segment cash flow from operating activities	25,580	645
Capital Expenditures Infrastructure Colombia Segment (1)	2,700	4,556

(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 21 for further details.

The Company's Infrastructure Colombia Segment income for the three months ended March 31, 2025, increased by $2.7 million, compared with the same period of 2024. The variance was mainly due to a higher share of income from ODL, SAARA's revenues under the agreement with Ecopetrol signed in June 2024, and positive fluctuations in revenue from Promotora Agricola de los Llanos S,A ("**ProAgrollanos**"), partially offset by higher operating costs in SAARA.

Segment capital expenditures for the three months ended March 31, 2025, were $2.7 million, mostly for Puerto Bahia investments of $1.9 million, including (i) the Reficar Connection Project at $0.8 million, (ii) tank maintenance, and (iii) general cargo terminal facilities. In addition, the total this includes investment in the SAARA project. During the same period of 2024, capital expenditures were $4.6 million, and were allocated to SAARA project and Puerto Bahia.

ODL Pipeline

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

For the three months ended March 31, 2025, ODL generated an EBITDA of $74.8 million, and $43.2 million, of net income. The ODL results are consolidated through the equity method in the Interim Financial Statements as "Share of income from associates".

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

	Three months ended March 31	
($M)	2025	2024
Revenue	91,566	86,797
FEC revenue (billed units)	7,255	7,452
Third party revenues	84,311	79,345
Costs	(11,959)	(11,396)
General administrative expenses	(4,818)	(4,581)
Depletion, depreciation and amortization	(6,462)	(7,926)
Other non-operating expense	(1,910)	(1,822)
Income tax	(23,249)	(21,375)
ODL Net Income	**43,168**	**39,697**

($M)	March 31 2025	December 31 2024
ODL debt	37,989	36,954
ODL cash and cash equivalents	35,130	76,979

The following table shows the volumes pumped per injection point:

(bbl/d)	Three months ended March 31 2025	Three months ended March 31 2024
At Rubiales Station	172,988	167,378
At Jagüey, Palmeras and Caño Sur Stations	63,399	78,664
Total	**236,387**	**246,042**

The following table shows the volumes received per block:

(bbl/d)	Three months ended March 31 2025	Three months ended March 31 2024
Rubiales	101,152	101,218
Quifa	28,855	28,841
CPE-6 and Sabanero	980	3,513
Other blocks	88,935	97,678
Total	**219,922**	**231,250**

For the three months ended March 31, 2025, the Company recognized $15.1 million from its share of income from ODL, an increase of $1.2 million compared with the same period of 2024. This increase was primarily due to higher revenues, driven by a 7.8% increase in pipeline transportation tariffs since September 2024, and lower depletion, depreciation, and amortization expenses. These positive effects were partially offset by higher income tax expenses.

During the three months ended March 31, 2025, ODL declared net dividends to FPI (formerly PIL) of $52.9 million (2024: $54.9 million). During the first quarter of 2025, FPI received cash dividends $26.2 million from ODL (2024: Nil). The remaining declared amount is expected to be received during 2025.

Puerto Bahia

Puerto Bahia owns and operates a multifunctional port facility located in Cartagena, Colombia, which consists of a hydrocarbons terminal and a general cargo terminal adjacent to the Bocachica access channel in the Cartagena Bay. It is strategically located near the Cartagena refinery operated by Reficar. The port facility has a total area of 150 hectares. Puerto Bahia's income from operations is mainly generated from service contracts in the liquids terminal, which has a nominal capacity of 2,672,000 barrels, and from roll-on/roll-off (RORO) and breakbulk services in the general cargo terminal.

($M)	Three months ended March 31 2025	Three months ended March 31 2024
Revenue	9,867	9,705
Liquids port facility	6,334	7,102
FEC liquids port facility	791	2,152
Third party liquids port facility	5,543	4,950
General cargo	3,533	2,603
Costs	(5,002)	(6,069)
General and administrative expenses	(1,346)	(1,404)
Depletion, depreciation and amortization	(1,715)	(1,650)
Other operating costs	(214)	(426)
Puerto Bahia Operating Income	1,590	156

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

(bbl/d)	Three months ended March 31 2025	Three months ended March 31 2024
FEC volumes	8,388	16,647
Third party volumes	43,191	36,713
Total	**51,579**	**53,360**

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

		Three months ended March 31	
		2025	2024
RORO	Units [1]	18,223	12,849
	Dwell time in days [2]	40	105
Break Bulk Volumes	Tons/m^3 [3]	41,198	8,481

[1] Wheeled cargo, primarily cars imported to Colombia.
[2] Dwell time refers to the time spent by the units within the general cargo port facility. The variance in dwell time associated with Break Bulk Volumes could depend on the characteristics of the cargo, especially in situations where the cargo is received and dispatched within a single day.
[3] Other types of cargo other than wheeled cargo.

For the three months ended March 31, 2025, Puerto Bahia had an operating income of $1.6 million (2024: $0.2 million). This improvement was primarily driven by lower operational costs. For the three months ended March 31, 2025, Puerto Bahia's general cargo revenues increased by 36%, driven by an increase in break bulk volumes and a greater number of vehicles received. In contrast, revenues from the liquids terminal declined compared with the same period in 2024, mainly due to lower volumes of Nafta resulting from lower requirements from third parties.

The Company's focus remains on starting up the Reficar Connection Project in Puerto Bahia. With construction effectively complete, the Company aims to transport the first volume in the third quarter of 2025. Ongoing strategic investments in the port, including the LPG JV with Empresas Gasco, are progressing as planned.

Water Treatment Facility and Palm Oil Plantation

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

Through its wholly-owned subsidiary ProAgrollanos, the Company operates a palm oil business located in the municipality of Puerto Gaitan, in the department of Meta, Colombia. With approximately 2,960 hectares currently planted, its oil palm plantation yielded 27,945 tons of fresh fruit bunches in the last 12 months. These crops have an estimated productive lifespan of 30 years.

A portion of the water treated by SAARA is reused in agricultural activities carried out by ProAgrollanos with the aim of improving palm crop productivity over the next 24 months. In 2024, SAARA processed approximately 15 million barrels of water, that irrigated approximately 400 hectares of palm oil crops in ProAgrollanos.

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

	Three months ended March 31	
($M)	**2025**	**2024**
Revenue	2,997	823
Fresh fruit bunches for palm oil	1,693	823
SAARA	1,304	—
Costs	(3,928)	(2,080)
Fresh fruit bunches for palm oil	(1,099)	(709)
SAARA	(2,829)	(1,371)
General and administrative expenses	(161)	(75)
Depletion, depreciation and amortization	(311)	(166)
SAARA and palm oil plantation operating loss	**(1,403)**	**(1,498)**

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

		Three months ended March 31	
($M)		**2025**	**2024**
Fresh fruit bunches for palm oil (produced - sold)	(Tons)	7,684	5,095
Production per hectare per year [1]	(Tons/ha/year)	9.44	6.98
Palm oil fruit price	($/Ton)	209	158
Volumes of reverse osmosis water treated	(bwpd)	81,481	33,272
Volumes of water irrigated for palm oil cultivation [2]	(bwpd)	81,609	23,613

[1] Tons per hectare per year for the three months ended March 31, are calculated using the total production for the last 12 months ended March 31.
[2] Differences between the water received and water irrigated are due to the water undergoing treatment or being temporarily stored within the plant's facilities.

For the three months ended March 31, 2025, sales from fresh fruit bunches of oil palm were $1.7 million, an increase of $0.9 million, compared with the same period of 2024, resulting primarily from an increase in market prices during the first quarter of 2025 and increased production. Fluctuations in fruit production volumes are part of normal crop production cycles, as well as the result of other factors, including climate conditions, agricultural practices (e.g. fertilization), workforce availability, changes in the operational administration model, and community blockades near the crop area.

During the three months ended March 31, 2025, the volumes of water received and used to irrigate palm oil plantations were higher, compared with the same period in 2024, mainly due to the temporary suspension of plant operations following the conclusion of the project's pilot program on January 31, 2024. Operations resumed in June 2024 after the signing of an agreement with Ecopetrol to start the first phase of the SAARA project. For the three months ended March 31, 2025, the project processed 81,481 barrels of water per day, generating revenue of $1.3 million. The Company remains focused on reaching its goal of processing 250,000 bwpd.

Agro Cascada, a wholly owned subsidiary of the Company, borrowed COP$41,927 million (approximately $9.5 million) from Citibank Colombia under a one-year facility pursuant to the Agro Cascada Working Capital Loan (as defined below) to support development of the Company's water treatment facilities. 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 development of the Company's water treatment facilities, and the loan is guaranteed by Frontera Energy Colombia Corp., Sucursal Colombia.

Non-IFRS and Other Financial Measures

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

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

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

Non-IFRS Financial Measures

Operating EBITDA

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, temporal taxes, 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 March 31	
($M)	**2025**	**2024**
Net income (loss) [1]	27,524	(8,503)
Finance income	(1,483)	(1,592)
Finance expenses	15,405	17,270
Income tax (recovery) expense	(9,651)	26,585
Depletion, depreciation and amortization	67,394	65,812
Colombian Temporary taxes [2]	939	—
Expense (recovery) of asset retirement obligation	375	(1,042)
Impairment expense	1,134	1,027
Trunkline costs	2,000	—
Post-termination obligation	297	550
Share-based compensation	862	286
Restructuring, severance and other costs	1,001	1,803
Share of income from associates	(15,109)	(13,894)
Foreign exchange (gain) loss	(2,239)	1,097
Other loss	112	359
Unrealized (gain) loss on risk management contracts	(4,786)	7,939
Non-controlling interests	(127)	(155)
Gain on repurchased 2028 Unsecured Notes (as defined below)	(190)	(294)
Operating EBITDA	**83,458**	**97,248**

(1) Refers to net income (loss) attributable to equity holders of the Company.
(2) These temporary taxes include a 1% contribution on the export of hydrocarbons in Colombia (Catatumbo Tax) resulting from the state of internal commotion declared by the Government of Colombia.

Capital Expenditures

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

	Three months ended March 31	
	2025	**2024**
Consolidated Statements of Cash Flows		
Additions to oil and gas properties, infrastructure port, and plant and equipment	42,582	62,849
Additions to exploration and evaluation assets	1,835	2,487
Total additions in Consolidated Statements of Cash Flows	**44,417**	**65,336**
Non-cash adjustments [1]	2,328	4,045
Cash adjustments	(34)	—
Total Capital Expenditures	**46,711**	**69,381**
Capital Expenditures attributable to Infrastructure Colombia Segment	2,700	4,556
Capital Expenditures attributable to other segments different to Infrastructure Colombia Segment	44,011	64,825
Total Capital Expenditure	**46,711**	**69,381**

(1) Related to materials consumption movements, capitalized non-cash items and other adjustments.

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.

($M) [1]	Three months ended March 31 2025	Three months ended March 31 2024
Revenue Infrastructure Colombia Segment	12,864	10,528
Revenue from ODL	91,566	86,797
Direct participation interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	32,048	30,379
Adjusted Infrastructure Revenues	**44,912**	**40,907**
Operating cost Infrastructure Colombia Segment	(8,930)	(8,149)
Operating Cost from ODL	(11,959)	(11,396)
Direct participation interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	(4,186)	(3,989)
Adjusted Infrastructure Operating Costs	**(13,116)**	**(12,138)**
General and administrative Infrastructure Colombia Segment	(1,507)	(1,479)
General and administrative from ODL	(4,818)	(4,581)
Direct participation interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	(1,686)	(1,603)
Adjusted Infrastructure General and Administrative	**(3,193)**	**(3,082)**

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

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

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

($M) [1]	March 31 2025	December 31 2024
Cash and cash equivalents - unrestricted	170,094	192,577
Cash and cash equivalents of Non-Infrastructure Colombia Segment's	(124,595)	(147,097)
Total Cash Infrastructure Colombia Segment	45,499	45,480
Cash and cash equivalent from ODL	35,130	76,979
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	12,296	26,943
Adjusted Infrastructure Cash	**57,795**	**72,423**
Short-Term and Long-Term Debt	493,650	493,764
Debt of Non-Infrastructure Colombia Segment's	(389,011)	(389,803)
Total Loans	104,639	103,961
Debt from ODL	37,989	36,954
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	13,296	12,934
Adjusted Infrastructure Debt	**117,935**	**116,895**

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

Adjusted Infrastructure EBITDA

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

	Three months ended March 31	
($M)	**2025**	**2024**
Adjusted Infrastructure Revenue	44,912	40,907
Adjusted Infrastructure Operating Costs	(13,116)	(12,138)
Adjusted Infrastructure General and Administrative	(3,193)	(3,082)
Adjusted Infrastructure EBITDA	**28,603**	**25,687**

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 9.

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 9.

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 March 31	
	2025	**2024**
Produced crude oil and products sales ($M) [(1)]	209,627	209,043
Purchased crude net margin ($M) [(2)(3)]	(11,652)	(8,269)
Oil and gas sales, net of purchases ($M) [(2)]	**197,975**	**200,774**
Sales volumes, net of purchases - (boe)	3,063,960	2,746,835
Produced crude oil and gas sales ($/boe)	68.42	76.10
Oil and gas sales, net of purchases ($/boe) [(2)]	64.61	73.09

[(1)] Excludes sales from infrastructure services, as they are not part of the oil and gas segment. Refer to the "Infrastructure Colombia" section on page 17 for further details.
[(2)] 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.
[(3)] Purchased crude net margin is a non-IFRS financial measure calculated using purchased crude oil and product sales, less the cost of those volumes purchased from third parties including transportation and refining costs. Please see the calculation below.

Non-IFRS Ratios

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

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

	Three months ended March 31	
	2025	**2024**
Oil and gas sales, net of purchases ($M) (1)(2)	197,975	200,774
Crude oil sales volumes, net of purchases - (bbl)	3,032,796	2,694,482
Conventional natural gas sales volumes - (mcf)	177,756	298,144
Realized oil price, net of purchases ($/bbl) (2)	64.95	73.82
Realized conventional natural gas price ($/mcf)	5.61	6.26

(1) Non-IFRS financial measure.

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

Net sales realized price

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

	Three months ended March 31	
	2025	**2024**
Oil and gas sales, net of purchases ($M) (1)(2)	197,975	200,774
(Loss) gain on oil price risk management contracts, net ($M) (3)	(4,141)	(3,489)
(-) Royalties ($M)	(3,060)	(4,506)
Net sales ($M)	190,774	192,779
Sales volumes, net of purchases - (boe)	3,063,960	2,746,835
Oil and gas sales, net of purchases ($/boe) (2)	64.61	73.09
Premiums paid on oil price risk management contracts (4)	(1.35)	(1.27)
Royalties ($/boe)	(1.00)	(1.64)
Net sales realized price ($/boe) (2)	62.26	70.18

(1) Non-IFRS financial measure.

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

(3) Represents premiums paid for expired put positions. Refer to the “Gain (Loss) on Risk Management Contracts” section on page 13 for further details.

(4) Supplementary financial measure.

Purchased crude net margin

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

	Three months ended March 31	
	2025	**2024**
Purchased crude oil and products sales ($M)	57,363	51,285
(-) Cost of diluent and oil purchased ($M) (1)	(68,860)	(57,859)
Puerto Bahía inter-segment costs (2)	(155)	(1,695)
Purchased crude net margin ($M) (2)	**(11,652)**	**(8,269)**
Sales volumes, net of purchases - (boe)	3,063,960	2,746,835
Purchased crude net margin ($/boe) (2)	**(3.81)**	**(3.01)**

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

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

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

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

A reconciliation of this calculation is provided below:

	Three months ended March 31	
	2025	**2024**
Production costs (excluding energy costs) ($M)	35,679	36,839
(-) Realized gain on FX hedge attributable to production costs (excluding energy costs) ($M) [1]	—	(1,337)
SAARA inter-segment costs	913	—
Production costs (excluding energy costs), net of realized FX hedge impact ($M) [2]	36,592	35,502
Production (boe)	3,642,930	3,475,563
Production costs (excluding energy costs), net of realized FX hedge impact ($/boe)	10.04	10.21

[1] See "Gain (Loss) on Risk Management Contracts" on page 13 for further details.

[2] Non-IFRS financial measure.

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

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

	Three months ended March 31	
	2025	**2024**
Energy costs ($M)	19,584	18,968
(-) Realized gain on FX hedge attributable to energy costs ($M) [1]	—	(581)
Energy costs, net of realized FX hedge impact ($M) [2]	19,584	18,387
Production (boe)	3,642,930	3,475,563
Energy costs, net of realized FX hedge impact ($/boe)	5.38	5.29

[1] See "Gain (Loss) on Risk Management Contracts" on page 13 for further details.

[2] Non-IFRS financial measure.

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

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

	Three months ended March 31	
	2025	**2024**
Transportation costs ($M)	39,549	35,195
(-) Realized gain on FX hedge attributable to transportation costs ($M) [1]	—	(409)
Puerto Bahía inter-segment costs [2]	636	431
Transportation costs, net of realized FX hedge impact ($M) [2][3]	40,185	35,217
Net production (boe)	3,262,950	3,070,613
Transportation costs, net of realized FX hedge impact ($/boe) [2]	12.32	11.47

[1] See "Gain (Loss) on Risk Management Contracts" on page 13 for further details.

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

[3] 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, comprised of cash and cash equivalents and restricted cash short and long-term.

Total debt and lease liabilities

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

4. LIQUIDITY AND CAPITAL RESOURCES

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

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

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

As at March 31, 2025, the Company had a total cash balance of $199.8 million (including $29.7 million in restricted cash), which was $23.0 million lower than at December 31, 2024.

For the three months ended March 31, 2025, the Company generated $70.1 million, of cash from operations, which was used to fund cash outflows of $58.5 million for capital expenditures and other investing activities. During the same period, financing activities resulted in outflows of $36.2 million, including $30.2 million used to repurchase Common Shares under the 2025 SIB (as defined below), $3.5 million in dividends paid to equity holders, $1.4 million in lease payments, $0.8 million in repurchases of the 2028 Unsecured Notes, and $0.3 million in other financing charges. In addition, the Company's net working capital[(1)] improved by $20.4 million, reducing the deficit to $80.1 million as at March 31, 2025, compared with a deficit of $100.6 million at year-end 2024.

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

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. As at March 31, 2025, the main components of restricted cash were long-term abandonment funds, as required by the ANH, and restricted funds related to the FPI Loan Facility (as defined below). Abandonment funds are intended to satisfy abandonment obligations and expected to be released over the long-term as assets are abandoned. Abandonment funding requirements are updated annually. As at March 31, 2025, the Company's restricted cash position was $29.7 million, representing a decrease of $0.5 million from December 31, 2024, primarily due to the release of abandonment funds driven by lower abandonment needs, particularly in the El Dificil and Guatiquía blocks.

The measures taken by the Company to manage its liquidity and capital resources are ongoing, and the Company continues to pursue additional opportunities to manage its costs and commitments. Based on the foregoing, including the expected impacts of these measures, the Company expects that unrestricted cash balances together with future cash flows from operations, available credit facilities, and alternative financing arrangements will be sufficient to support its operational and capital requirements and other financial commitments. The Company intends to remain flexible and disciplined with respect to capital allocation decisions as the current commodity price environment evolves, and may make additional changes to its business and operations as warranted. See also the "Risks and Uncertainties" section on page 34.

(1) Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures'' section on page 21 for further details.

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 they are redeemed or repurchased earlier.

During the three months ended March 31, 2025, the Company repurchased $1.0 million, of its 2028 Unsecured Notes in the open market for a cash consideration of $0.8 million, including interest. As a result, the Company recognized a gain of $0.2 million during the same period. The carrying value of the 2028 Unsecured Notes as at March 31, 2025, was $389.0 million (December 31, 2024: $389.8 million).

Unsecured Notes Covenants

The 2028 Unsecured Notes are senior, unsecured notes and rank equally in right of payment with all existing and future senior unsecured debt. As at March 31, 2025, the 2028 Unsecured Notes were guaranteed by the Company's subsidiary, Frontera Energy Colombia Corp. On April 11, 2023, the Company designated Frontera Energy Guyana Holding Ltd. and Frontera Guyana as Unrestricted Subsidiaries and released Frontera Guyana as a note guarantor under the indenture 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. If these financial tests are not met, the Company may still incur indebtedness under certain permitted baskets, including an aggregate amount that does not exceed the greater of $100.0 million and 10% of consolidated net tangible assets[(3)]. The 2028 Unsecured Notes also contain covenants that limit the Company's ability to, among other things, make certain investments or restricted payments, including dividends and share buybacks. As at March 31, 2025, the Company was in compliance with all such covenants.

Pursuant to the requirements under the Indenture, the Company reported consolidated total indebtedness of $409,675,000 as at March 31, 2025, and, for the twelve months ended as of March 31, 2025, a consolidated adjusted EBITDA of $401,905,000 and a consolidated interest expense of $53,422,000.

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

a. Consolidated total indebtedness is defined below.
b. Consolidated adjusted EBITDA is defined as the consolidated net 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 recently ended period of four consecutive fiscal quarters divided by the consolidated interest expense for such period, as defined in the Indenture.

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

Consolidated Total Indebtedness and Net Debt

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

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

($M)		As at March 31 2025
Short-term and Long-term debt [(1)]	$	399,012
Total lease liabilities [(2)]		10,415
Risk management liability net [(3)]		248
Consolidated Total Indebtedness		**409,675**
(-) Cash and Cash Equivalents [(4)]		(118,943)
(=) Net Debt	**$**	**290,732**

[(1)] Excludes $94.6 million of long-term debt attributable to the Unrestricted Subsidiaries.

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

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

[(4)] Includes unrestricted cash and cash equivalents attributable to the guarantors as at March 31, 2025, Frontera Energy Colombia AG and the issuer (i.e., the Company), as defined in the Indenture.

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

On March 27, 2023, FPI entered into a credit agreement through which lenders provided a $120.0 million loan facility to FPI, secured by substantially all the assets and shares of FPI, 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 FPI. The FPI Loan Facility is a five-year credit facility, maturing in December 2027, with principal payments made semi-annually. The FPI Loan Facility has two tranches: a $100.0 million amortizing tranche that pays SOFR six-month term plus a margin of 7.25% per annum (with a step-down to 6.25% if certain conditions are met), and a $20.0 million bullet maturity tranche that pays a fixed rate of 11.0% per annum. The conditions precedent to the FPI Loan Facility were fully satisfied, and both tranches of the facility were funded on March 31, 2023.

On February 16, 2024, as part of the FPI Loan Facility (Tranche A-2), the Company amended the facility to disburse an accordion tranche of $30.0 million. This tranche secured 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 lender and legal fees, which were discounted at the time of disbursement.

As at March 31, 2025, the carrying value of the FPI Loan Facility was $94.6 million (December 31, 2024: $94.5 million), which includes short-term debt of $34.2 million. As at March 31, 2025, the FPI Loan Facility debt service reserve account had a balance of $16.0 million. (December 31, 2024: $15.9 million).

Agro Cascada Working Capital Loan

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

As at March 31, 2025, the carrying value of the Agro Cascada Working Capital Loan was $10.0 million (December 31, 2024: $9.5 million).

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

Letters of Credit

The Company has various uncommitted bilateral letters of credit. As at March 31, 2025, the Company had issued letters of credit and guarantees for exploration and abandonment funds totalling $113.5 million (against total credit lines of $165.4 million), without cash collateral.

CPE-6 Solar Plant Project Leasing Agreement

During the fourth quarter of 2022, the Company executed a leasing agreement with Bancolombia to finance the construction and commissioning of a solar power plant project in the CPE-6 block (the "**Solar Plant Debt**"). The financing is denominated in COP, with an equivalent value of approximately to $6.1 million as at March 31, 2025, and has a maturity date of 72 months from April 3, 2024. The Solar Plant Debt bears interest equivalent to IBR plus 5.75%, payable monthly on the outstanding amount. As at March 31, 2025, the outstanding balance was $5.6 million. The Company recognized this obligation as a lease liability.

CPE-6 Battery Energy Storage System Leasing Agreement

During the fourth quarter of 2023, the Company executed a leasing agreement with Bancolombia to finance the Battery Energy Storage System at the CPE-6 block (the "**BESS Project**"). The financing is denominated in COP, with an equivalent value of approximately $0.9 million as at March 31, 2025, and has a maturity date of April 9, 2029. The BESS Project leasing bears interest equivalent to IBR plus 5.10%, payable monthly. As at March 31, 2025, the outstanding balance was $0.6 million. The Company recognized this obligation as a lease liability.

Unsecured Notes Capped Cash Tender & Consent Solicitation

As mentioned above, the Company is launching a capped cash tender and consent solicitation in connection with its 2028 Senior Unsecured Notes, pursuant to which the Company will offer to purchase up to $65 million of its 2028 Senior Unsecured Notes. Simultaneously with the tender offer, Frontera is launching a solicitation of consents from holders of the 2028 Senior Unsecured Notes to effect certain proposed amendments to the indenture governing the 2028 Senior Unsecured Notes dated as of June 21, 2021 (as amended and/or supplemented from time to time, the Notes Indenture). The tender offer and consent solicitation will be subject to various conditions, including, without limitation, the condition that the Company shall have obtained debt financing on terms and conditions and yielding net cash proceeds reasonably satisfactory to the Company.

The purpose of the tender offer and consent solicitation is to gain greater financial and operational flexibility while simultaneously reducing the Company's overall debt. Additionally, the proposed amendments shall permit the Company to take certain actions previously limited by certain restrictions in the Notes Indenture, including, but not limited to, allowing for additional restricted payments (including those related to unrestricted subsidiaries), provide additional flexibility in managing working capital to support operational efficiency and financial resilience, increase the amount of permitted indebtedness and liens and reduce conditions and requirements limiting the Company's ability to pursue strategic transactions that may enhance the issuer's growth and value, in each case, without violating the provisions of the Note Indenture.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at March 31, 2025, undiscounted by calendar year, are presented below:

As at March 31, 2025 ($M)	2025	2026	2027	2028	2029	Subsequent to 2030	Total
Short-term and long-term debt principal and interest	86,581	57,674	71,297	420,896	—	—	636,448
Lease liabilities	4,487	3,851	2,304	2,209	1,622	518	14,991
Total financial obligations	**91,068**	**61,525**	**73,601**	**423,105**	**1,622**	**518**	**651,439**
Transportation							
Ocensa P-135 ship-or-pay agreement	18,608	—	—	—	—	—	18,608
ODL agreements	205	—	—	—	—	—	205
Other transportation and processing commitments	10,521	10,583	—	—	—	—	21,104
Exploration and evaluation							
Minimum work commitments [1]	12,396	10,171	5,066	—	—	—	27,633
Other commitments							
Operating purchases, community obligations and others	54,421	871	254	259	264	2,455	58,524
Energy supply commitments	24,430	14,706	9,307	4,421	1,061	2,209	56,134
Total Commitments	**120,581**	**36,331**	**14,627**	**4,680**	**1,325**	**4,664**	**182,208**

[1] The Company has been reducing the value of its exploratory commitments as they are executed. Some of these commitments are still pending accreditation by the ANH; however, the Company does not consider this situation to represent a risk.

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.

Contingencies

The Company is involved in various claims and litigation arising from the normal course of business. Since the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company's favour. The outcome of adverse decisions in any pending or threatened proceedings related to these and other matters could have a material impact on the Company's financial position, results of operations or cash flows.

Corentyne License

On June 26, 2024, the Company and CGX announced that the joint venture composed by Frontera Energy Guyana Corp. and CGX Resources Inc. (the "**Joint Venture**") 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. On March 13, 2025, the Joint Venture announced the receipt of a communication from the Government of Guyana indicating that, on the one hand, the Government was of the view that the PPL and Petroleum Agreement are at an end but, on the other hand, that the Government was terminating the Petroleum Agreement and cancelling the PPL. On March 26, 2025, the Company and its subsidiaries Frontera Petroleum International Holding B.V. and Frontera Energy Guyana Holding Ltd. (the "**Investors**") sent a notice of intent to the Government of Guyana, by which the Investors alleged breaches of the United Kingdom – Guyana Bilateral Investment Treaty (BIT) and the Guyana Investment Act by the Government of Guyana (the "**Notice of Intent**"). The Notice of Intent initiated a three-month period for consultations and negotiations between the parties to resolve the dispute amicably. 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, and continues to invite the Government to amicably resolve the issues affecting the Joint Venture's investments in the Corentyne block. Should the parties not reach a mutually agreeable solution, the Joint Venture and its other stakeholders are prepared to assert their legal rights. The Joint Venture looks forward to expeditiously resolving this matter and continuing its multi-year efforts and investments to realize value for the people of Guyana and its shareholders from the Corentyne block.

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.

On March 13, 2025, the Company obtained a favorable arbitral award in the Cubiro E&P Contract litigation, confirming its contractual rights under the Cubiro E&P Contract. The Tribunal ruled in the Company's favor, rejecting ANH's actions and recognizing the independence of the Copa and Petirrojo exploitation areas. This decision is favorable to the Company. However, the ANH can still pursue remedies against the award, so it is not yet final.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at May 8, 2025:

	Number
Common shares	77,295,478
DSUs [(1)]	1,127,565
RSUs [(2)]	2,833,788

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

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

Normal Course Issuer Bids ("NCIB")

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

Purchases subject to the NCIBs have been or are being carried out pursuant to open market transactions through the facilities of the TSX or alternative trading systems, if eligible, by BMO Nesbitt Burns Inc., on behalf of Frontera, in accordance with an automatic share purchase plan and applicable regulatory requirements. The Company repurchased a total of 1,552,100 Common Shares under the 2023 NCIB for approximately $9.5 million prior to its expiration on November 20, 2024.

Substantial Issuer Bid

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

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

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

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

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 at January 24, 2025) at a price of CAD$12.00 per Common Share, representing an aggregate purchase price of approximately CAD$42.0 million. The 2025 SIB had over 90% shareholder participation rate. After the cancellation of the Common Shares taken up and paid for by the Company under the 2025 SIB, approximately 77.29 million Common Shares remained issued and outstanding.

Dividends

On March 7, 2024, the Company adopted a dividend policy that included an initial cash dividend of CAD$0.0625 per Common Share, 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 subject to the discretion of the Company's Board of Directors.

The Company's dividends declared or paid during the year ended December 31, 2024, and the three months ended March 31, 2025, are presented below:

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

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

Pursuant to the Company's dividend policy, the Company's Board of Directors has declared a dividend of CAD$0.0625 per Common Share to be paid on or around July 17, 2025, to shareholders of record at the close of business on July 3, 2025.

6. RELATED-PARTY TRANSACTIONS

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

		As at March 31, 2025, and December 31, 2024			Three months ended March 31
($M)		Receivables from Investment	Accounts Payable	Commitments	Purchases / Services
ODL	2025	26,141	3,036	205	7,255
	2024	—	2,901	356	7,452

The related-party transactions correspond to dilution services for a total commitment of $0.2 million until 2025.

7. RISKS AND UNCERTAINTIES

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

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

See the "Liquidity and Capital Resources" section on page 28 for further details on the steps the Company has taken to mitigate or manage some of these risks. However, the situation continues to be dynamic and highly uncertain, and the effectiveness and adequacy of such measures cannot be determined at this time.

The Company will continue to consider investor-focused initiatives in 2025 and beyond, including potential additional dividends, distributions, share or bond buybacks, based on the overall results of the businesses, oil prices and cash flow generation. Additionally, the Company also continues to consider all options to enhance the value of its common shares in the short term, and in so doing may consider forms of strategic initiatives or transactions, which may include a further return of capital to shareholders, a merger or a business combination, or the transfer, sale or other disposition of all or a significant portion of the business, assets or securities of the Company or the recapitalization of interests in one or more subsidiaries or in assets of the Company, whether in one or a series of transactions. However, there can be no assurance that any such initiative or transaction will occur or if it occurs, the timing thereof.

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

8. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

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

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

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

The effect of the global economy, including the impact of the newly imposed U.S. trade tariffs affecting over 50 countries, including Colombia, and escalating tensions between the U.S. and China, the Russia-Ukraine conflict, the Middle East conflict, and the associated volatility in oil prices, may negatively impact the Company. The uncertainty these events create has resulted in a challenging economic environment marked by more volatile commodity prices, foreign exchange rates, long-term interest rates, and changes in international trade policies. The outcome of the Middle East conflict remains uncertain and may have wide-ranging global economic consequences. Global oil prices have remained highly volatile since the conflict began, and there is a risk that it could lead to wider regional instability in the Middle East, which is home to some of the world's biggest oil producers. In addition, in early April 2025, the U.S. government enacted trade tariffs on over 50 countries. The global shock triggered by these tariffs is ongoing, and although it was subsequently announced that the tariffs would ultimately be lower than initially stated, and that a 90-day pause would be granted to most affected countries so they can negotiate new agreements with the administration, uncertainty persists. The Company continues to monitor the situation closely. 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 favourably for the Company.

To date, these events have not impacted the Company’s ability to carry on business, and there have been no significant delays or direct security issues affecting the Company’s operations, offices, or personnel. The long-term impacts of the conflicts remain uncertain, and the Company continues to monitor the evolving situation. This presents uncertainty and risk with respect to management’s judgments, estimates, and assumptions used in the preparation of the Interim Financial Statements.

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

9. INTERNAL CONTROL

In accordance with National Instrument 52-109 - *Certification of Disclosure in Issuers’ Annual and Interim Filings* (“**NI 52-109**”) of the Canadian Securities Administrators, the Company issues a “Certification of Interim Filings” on Form 52-109F1. This Certification requires that each “certifying officer” (as defined in NI 52-109) certify, among other things, that they, together with the other certifying officer(s), are responsible for establishing and maintaining disclosure controls and procedures (“**DC&P**”) and internal control over financial reporting (“**ICFR**”), as those terms are defined in NI 52-109. The control framework used to design the Company’s ICFR is based on the framework established in Internal Control - Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission.

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

Management of the Company has evaluated the effectiveness of the Company’s ICFR for the period beginning January 1, 2025, and ending March 31, 2025. Based on this assessment, the Company’s Chief Executive Officer and Chief Financial Officer concluded that the Company’s ICFR was effective as at March 31, 2025.

There has been no change in the Company’s ICFR during the period beginning on January 1, 2025, and ending on March 31, 2025, that has materially affected, or is reasonably likely to materially affect, its ICFR.

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

The Company’s DC&P is designed to provide reasonable assurance that material information relating to the Company is made known to the Company’s certifying officers by others, particularly during the period in which the annual filings are being prepared, and that information required to be disclosed by the Company in its annual filings, interim filings, and other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized, and reported within the time period specified in securities legislation.

Based on management’s evaluation, which was carried out to assess the effectiveness of the Company’s DC&P, the Company’s Chief Executive Officer and Chief Financial Officer concluded that the Company’s DC&P was effective as at March 31, 2025.

10. 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		**Q1 2025**	**Q4 2024**	**Q1 2024**
Quifa	(bbl/d)	16,766	16,890	16,858
CPE-6	(bbl/d)	8,056	8,466	6,228
Guatiquia	(bbl/d)	5,119	5,690	5,610
Vim1	(boe/d)	1,840	1,883	1,579
Perico	(bbl/d)	1,197	1,431	1,478
Cubiro	(bbl/d)	1,213	1,310	1,461
Cravoviejo	(bbl/d)	1,199	1,263	1,348
Casimena	(bbl/d)	899	993	1,208
Other blocks	(boe/d)	4,188	4,480	2,423
Total production	**(boe/d)**	**40,477**	**42,406**	**38,193**

Production Reporting

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

The following table shows the average net production:

		Net Production		
Producing blocks in Colombia		**Q1 2025**	**Q4 2024**	**Q1 2024**
Heavy crude oil	(bbl/d)	24,971	25,513	20,853
Light and medium crude oil combined	(bbl/d)	8,386	9,235	9,763
Conventional natural gas	(mcf/d)	2,269	2,633	3,278
Natural gas liquids	(boe/d)	1,453	1,498	1,513
Net production Colombia	**(boe/d)**	**35,208**	**36,708**	**32,704**
Producing blocks in Ecuador				
Light and medium crude oil combined	(bbl/d)	1,047	1,261	1,039
Net production Ecuador	**(bbl/d)**	**1,047**	**1,261**	**1,039**
Total net production	**(boe/d)**	**36,255**	**37,969**	**33,743**

Boe Conversion

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

Oil and Gas Information Advisories

Reported production levels may not be reflective of sustainable production rates and future production rates may differ materially from those reflected in this MD&A due to, among other factors, difficulties or interruptions encountered during the production of hydrocarbons. Disclosure of well-flow test results included in this MD&A is 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 completed.

Abbreviations

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

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