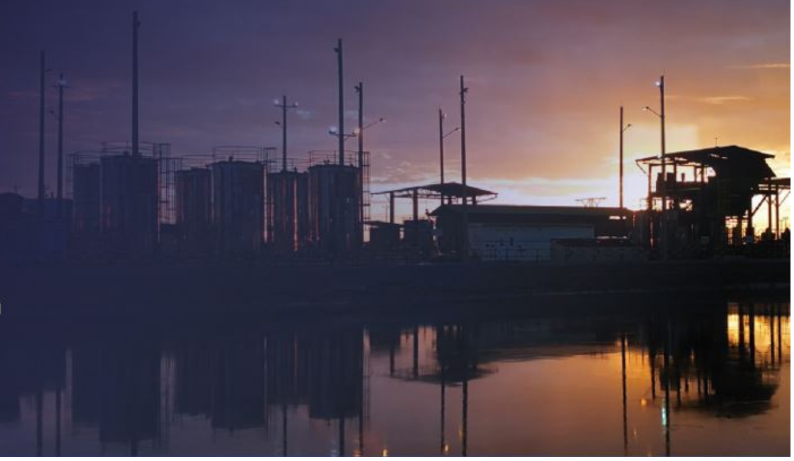
FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

March 7, 2024
For the year ended December 31, 2023



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*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 2000, 222 – 3rd Avenue SW, Calgary, Alberta, Canada, T2P 0B4.*

Legal Notice – Forward-Looking Information

*This Management Discussion and Analysis ("**MD&A**") is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying Annual Consolidated Financial Statements and related notes for the years ended December 31, 2023 and 2022 (the"**2023 Annual Consolidated Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and its Annual Information Form ("**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 27.*

*This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to activities, events or developments that the Company believes, expects or anticipates will or may occur in the future. Forward-looking information in this MD&A includes, without limitation, statements regarding estimates and/or assumptions in respect of the oil price environment, current and expected impacts of the COVID-19 pandemic, actions of the Organization of Petroleum Exporting Countries ("**OPEC+**"), the impact of the Russia-Ukraine conflict and the Israel-Hamas conflict, the expected impact of measures that the Company has taken and continues to take in response to these events, expectations regarding the Company's ability to manage its liquidity and capital structure and generate sufficient cash to support operations, capital expenditures and financial commitments, the timing of release of restricted cash, the impact of fluctuations in the price of, and supply and demand for oil and conventional natural gas products, production levels, cash levels, reserves, capital expenditures (including plans and projects related to drilling, exploration activities, and infrastructure and the timing thereof), operating EBITDA, production costs, transportation costs, the restructuring plan, cost savings, including General and Administrative ("**G&A**") expense savings, and the impact thereof and obtaining regulatory approvals. Forward-looking information is often identified by words or phrases such as "may", "could", "would", "might", "will", "expects," "anticipates," "plans," "estimates," "projects," "forecasts," "believes," "intends," "possible," "probable," "scheduled," "goal", "objective", or similar words or phrases. All information in this MD&A other than historical fact is forward-looking information.*

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

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

All forward-looking information speaks only as of the date on which it is made and the Company disclaims any intent or obligation to update any forward-looking information, whether as a result of new information, future events or otherwise, unless required pursuant to applicable laws. Risks, uncertainties, assumptions and other factors that could cause actual results to differ materially from those anticipated in the forward-looking information are described under the headings "Forward-Looking Information" and "Risk Factors" in the Company's AIF and under the heading "Risks and Uncertainties" in this MD&A. Although the Company has attempted to consider important factors that could cause actual costs or operating results to differ materially, there may be other unforeseen factors and therefore results may not be as anticipated, estimated or intended.

*Certain information included or incorporated by reference in this MD&A may constitute future oriented financial information and financial outlook information (collectively, "**FOFI**") within the meaning of applicable Canadian securities laws. FOFI has been prepared by management to provide an outlook of the Company's activities and results and may not be appropriate for other purposes. Management believes that the FOFI has been prepared on a reasonable basis, reflecting management's reasonable estimates and judgments; however, actual results of the Company's operations and the resulting financial outcome may vary from the amounts set forth herein. Any FOFI speaks only as of the date on which it was made, and the Company disclaims any intent or obligation to update any FOFI, whether as a result of new information, future events or otherwise, unless required by applicable laws.*

1. MESSAGE TO THE SHAREHOLDERS

Frontera's corporate strategy remains focused on maximizing and realizing value through its strategic portfolio of energy and infrastructure related assets as captured by its 3 core businesses:

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

For 2023, we have substantially met our operational and financial objectives, all while maintaining an unwavering commitment to the safe and responsible operation of our business. Frontera successfully delivered results in-line with guidance including production of 40,919 boe/d and Operating EBITDA at the higher end of the guidance range of $467.2 million. Frontera announced positive drilling results from its second well off-shore Guyana and believes that approximately 514-628 mmboe PMean unrisked gross prospective resources are present in multiple Maastrichtian horizons in the northern portion of the Corentyne block. The Company continues to advance its Infrastructure Colombia (formerly Midstream Colombia) business with the signing of the agreement between Puerto Bahia and Refineria de Cartagena S.A.S. ("**Reficar**") connecting Puerto Bahia's liquids port facility and Reficar via bi-directional hydrocarbon flow line which will be capable of handling imported and domestically produced crude, closing the associated financing, and breaking ground on the construction in the first quarter of 2024.

Building A Sustainable Future

At Frontera, we are committed to conduct our business safely and in a socially, environmentally and ethically responsible manner. Frontera recognizes the importance of creating environmental, social and economic value for the short, medium and long term, while following a strong governance framework to manage associated risks in a timely manner.

In 2023, Frontera not only met but exceeded its sustainability goals, achieving 108% of its objectives for the year. Notably, we i) offset 50% of our emissions through carbon credits, demonstrating our commitment to reducing our carbon footprint, ii) accumulated 5,737 hectares of protected land to preserve and conserve, adding in 2023, 1,681 new hectares in strategic biological connectivity corridors. The Company handed over 1,000 hectares to the national park association for the establishment of the Serranía of Manacacías National Park in Meta, Colombia, iii) recycled 45% of our operating water (separate from our SAARA project) and 12% of our solid waste, and v) started up its first solar farm in the CPE-6 block.

We invested approximately $5.5 million on education, inclusive of economic development and quality of life initiatives, benefiting 94,875 people through 256 social projects in Ecuador, Peru and Colombia. The Company also purchased $73.3 million worth of goods and services from local suppliers exceeding our 2023 goal of local purchasing by $55 million.

Our employees also recorded a total recordable injury rate of 0.47 in 2023, the lowest in our Company's history. As a recognition for these key sustainability efforts, the Company was included in the Bloomberg Gender-Equality Index.

Frontera was recognized for the fourth consecutive year as one of the World's Most Ethical Companies by Ethisphere Institute.

Colombia and Ecuador Operation

In 2023, Frontera executed $285.4 million in total capital spending in support of its Colombia and Ecuador upstream business to deliver average daily production of 40,919 boe/d (consisting of 23,359 bbl/d of heavy crude oil, 14,856 bbl/d of light and medium crude oil, 6,042 mcf/d of conventional natural gas and 1,644 boe/d of natural gas liquids). Despite natural declines in our light and medium crude oil production and conventional natural gas production, the expiration of the Neiva block production contract, and the relinquishment of the La Creciente block, our overall production remained steady year-over-year from targeted growth in key heavy assets. This growth was resulted from successful development drilling, enhanced water handling capacity through the SAARA project in the Quifa block, and the installation of new facilities in the CPE-6 block which doubled water-handling capacity there from 120,000 bwpd to 240,000 bwpd. Frontera also increased natural gas liquids production from the VIM-1 block as new development facilities came online. In addition, we successfully completed three exploration wells in the Perico block, in Ecuador, adding reserves and growing production.

Guyana

In December 2023, we announced positive drilling results at Wei-1 and shared updated interpretations of Kawa-1 well results. Based on evaluations by two independent, third-party resource valuators. Frontera and CGX Energy Inc. ("**CGX**"), through its joint venture (the "**Joint Venture**"), believes that approximately 514-628 mmboe PMean unrisked gross prospective resources are present in multiple Maastrichtian horizons in the northern portion of the Corentyne block supporting a potential stand-alone development. The Company also believes there is potential for additional prospective resources from the deeper Campanian and Santonian horizons.

The Joint Venture, with support from Houlihan Lokey, is actively pursuing strategic options, including a potential farm down, to unlock the potential of the Corentyne block.

Infrastructure Colombia (formerly Midstream Colombia)

In 2023, our Infrastructure Colombia business generated an Adjusted Infrastructure EBITDA of $119.8 million, income of $69 million and cash flows from operating activities of $55 million. The Company invested $11.4 million in its subsidiary Sociedad Portuaria S.A. ("**Puerto Bahia**") and $2.5 million at SAARA.

In August 2023, Frontera announced the agreement between Puerto Bahia and Reficar to connect Puerto Bahia's port facility and Reficar via bi-directional hydrocarbon flow line which will be capable of handling imported and domestically produced crude. Work on the connection started during the fourth quarter of 2023 with an investment of $1.1 million mainly related to technical, environmental and social matters. Frontera anticipates breaking ground on the connection construction during the first quarter of 2024 and connection start-up by the end of 2024. Frontera has secured an additional $30 million in committed funding, subject to certain conditions precedent, in connection with this project from its existing group of lenders led by Macquarie Group.

In 2023, Frontera successfully completed the pilot phase of its reverse osmosis water treatment facility, called SAARA, with Ecopetrol. The first phase of the project expects to reach a minimum of 250,000 bwpd available for the Quifa block. The Company's current water handling capacity in Quifa is approximately 1.6 million bwpd. During 2023, the plant processed 20.6 million barrels of water as part of its recommissioning program, providing irrigation source water to the Company's nearby ProAgrollanos palm oil plantation. The Company is actively engaged in discussions with Ecopetrol to permanently bring the SAARA facility online under terms mutually acceptable to both parties.

Reserves

The Company delivered 2P gross reserves of 164 MMboe with a net present value at 10% before taxes of $3.5 billion. The Hamaca field in the CPE-6 block has been growing in 2P gross reserves by 42 MMboe, contributing 25% of the Company's total gross 2P reserves, and drawing near, by approximately 96%, of the total 2P reserve volumes in Quifa SW field. Additionally, as part of the successful exploratory drilling campaign in Ecuador, the Company grew 2P reserves to 4.7 MMboe. Over the last three years, Frontera has averaged 11.2 MMboe gross 2P reserves additions, and delivered a 11 year reserve life index.

Financials

Frontera delivered strong financial results in 2023. We successfully met our 2023 annual guidance metrics, reaching $467 million in operating EBITDA with an operating netback of $44.69 per boe.

Additionally, during 2023, we successfully refinanced Puerto Bahía's existing legacy project finance debt, via a new $120 million loan facility and then in early 2024 secured an additional $30 million in committed funding for the Reficar connection with a group of lenders led by Macquarie Capital.

Moreover, we have rebuilt trust and credibility within the financial sector, leading to securing borrowing agreements totaling $38 million over the course of 2023. During the year, Fitch reaffirmed Frontera's credit at 'B' with a stable outlook and S&P rated Frontera's credit at 'B+' with a stable outlook, underscoring our continued financial stability and resilience.

Shareholder Value Creation

Frontera has returned more than $306 million to shareholders, since 2018, through dividends and share buybacks while maintaining a strong credit profile.

In 2023, Frontera launched a new Normal Course Issuer Bid ("**NCIB**"). Under the Company's current NCIB, which commenced on November 21, 2023, and will expire on November 20, 2024, Frontera is authorized to repurchase for cancellation up to 3,949,454 of the Company's common shares ("**Common Shares**"). As at March 7, 2024, the Company has repurchased approximately 0.6 million Common Shares for cancellation for approximately $3.7 million.

Looking Ahead

In 2024, aligned with the strategy of prioritizing value over volume and its proven track record of enhancing capital efficiency, Frontera plans to invest between $272 million and $335 million in total capital in 2024. This represents a 32% decrease from the midpoint of our 2023 guidance, aiming to generate $400 to $450 million in consolidated Operating EBITDA at an average Brent price of $80 per barrel, while maintaining a full-year production estimate of 40,000 to 42,000 boe/d.

Frontera's capital expenditure and production plan for 2024 is fully financed and safeguarded by a prudent hedging strategy. It focuses on the most productive and profitable assets in its portfolio, taking advantage of exceptional near-field opportunities in our Quifa, CPE-6, and VIM-1 production blocks. This strategy ensures the delivery of our fastest payback barrels, promising sustained growth potential. We anticipate that our development efforts, combined with our exploration investments, particularly the high-potential Hydra-1 well in the VIM-1 block in Colombia, will secure continuous production and robust cash flows in 2024 and for years to follow.

Frontera remains committed to unlocking value and enhancing shareholder returns and will continue to consider future shareholder value enhancement initiatives in 2024, including its intention to pay a dividend of CAD $0.0625 per Common Share payable on or around April 16, 2024, distributions, or bond buybacks, based on the overall results of our businesses and the Company's strategic goals.

We extend our gratitude, on behalf of Frontera's Board, Management team, and all employees, for your ongoing interest in and support of our Company. We eagerly anticipate achieving our 2024 operational and financial objectives with our total commitment to safety and responsibility.

"Orlando Cabrales Segovia" (signed)
Chief Executive Officer

2. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q4 2023	Q3 2023	Q4 2022	Year ended December 31 2023	Year ended December 31 2022
Operational Results						
Heavy crude oil production [1]	(bbl/d)	23,002	24,097	22,144	23,359	21,441
Light and medium crude oil combined production [1]	(bbl/d)	13,795	13,964	17,073	14,856	17,274
Total crude oil production	(bbl/d)	36,797	38,061	39,217	38,215	38,715
Conventional natural gas production [1]	(mcf/d)	4,760	5,250	9,097	6,042	9,741
Natural gas liquids production [1]	(boe/d)	1,635	1,820	993	1,644	958
Total production [2]	(boe/d) [3]	39,267	40,802	41,806	40,919	41,382
Total inventory balance	(bbl)	1,076,394	1,330,418	1,238,780	1,076,394	1,238,780
Brent price reference	($/bbl)	82.85	85.92	88.63	82.17	99.04
Oil and gas sales, net of purchases [4] [5]	($/boe)	75.76	78.48	82.60	72.93	91.39
Premiums paid on oil price risk management contracts [6]	($/boe)	(0.69)	(0.59)	(1.32)	(0.80)	(1.22)
Royalties [6]	($/boe)	(1.79)	(3.76)	(6.04)	(2.98)	(7.83)
Net sales realized price [4] [5]	($/boe)	73.28	74.13	75.24	69.15	82.34
Production costs (excluding energy cost), net of realized FX hedge impact [4][5]	($/boe)	(9.69)	(8.82)	(8.48)	(8.76)	(8.79)
Energy costs, net of realized FX hedge impact [4][5]	($/boe)	(5.06)	(5.04)	(3.08)	(4.49)	(3.35)
Transportation costs, net of realized FX hedge impact [4][5]	($/boe)	(11.02)	(11.73)	(10.55)	(11.21)	(10.44)
Operating netback per boe [4][5]	($/boe)	47.51	48.54	53.13	44.69	59.76
Financial Results						
Oil & gas sales, net of purchases [7]	($M)	240,105	254,805	260,824	905,249	1,105,503
Premiums paid on oil price risk management contracts	($M)	(2,198)	(1,930)	(4,182)	(9,903)	(14,733)
Royalties	($M)	(5,683)	(12,216)	(19,076)	(36,949)	(94,709)
Net sales [7]	($M)	232,224	240,659	237,566	858,397	996,061
Net income [8]	($M)	92,038	32,582	197,796	193,497	286,615
Per share – basic	($)	1.08	0.38	2.29	2.27	3.16
Per share – diluted	($)	1.04	0.37	2.25	2.19	3.08
General and administrative	($M)	16,891	11,925	12,761	53,907	55,063
Outstanding Common Shares	Number of Shares	85,151,216	85,431,716	85,592,075	85,151,216	85,592,075
Operating EBITDA [7]	($M)	121,036	137,800	144,994	467,219	641,877
Cash provided by operating activities	($M)	73,432	153,957	138,312	411,794	620,479
Capital expenditures [7]	($M)	82,292	74,130	134,165	442,734	417,563
Cash and cash equivalents – unrestricted	($M)	159,673	189,190	289,845	159,673	289,845
Restricted cash short and long-term [9]	($M)	30,300	32,048	23,202	30,300	23,202
Total cash [9]	($M)	189,973	221,238	313,047	189,973	313,047
Total debt and lease liabilities [9]	($M)	536,822	525,517	511,552	536,822	511,552
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [10]	($M)	430,170	409,853	407,808	430,170	407,808
Net debt (excluding Unrestricted Subsidiaries) [10]	($M)	318,092	271,508	178,534	318,092	178,534

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

[2] Represents W.I. production before royalties. Refer to the "Further Disclosures" section on page 44.

[3] Boe has been expressed using the 5.7 to 1 Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy. Refer to the "Further Disclosures - Boe Conversion" section on page 44.

[4] Non-IFRS ratio (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 27.

[5] 2022 prior period figures are different compared with those previously reported as a result of the exclusion of Promotora Agricola de los Llanos S.A. ("**ProAgrollanos**") revenues and production and transportation costs.

[6] Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 27.

[7] Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 27.

[8] Net income attributable to equity holders of the Company.

[9] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 27.

[10] "**Unrestricted Subsidiaries**" include CGX, listed on the TSX Venture Exchange under the trading symbol "OYL", Frontera ODL Holding Corp., including its subsidiary Pipeline Investment Ltd. ("**PIL**"), Frontera BIC Holding Ltd. and Frontera Bahía Holding Ltd. ("**Frontera Bahia**"), including Puerto Bahia. On April 11, 2023, Frontera Energy Guyana Holding Ltd. and Frontera Energy Guyana Corp. were designated as unrestricted subsidiaries. Refer to the "Liquidity and Capital Resources" section on page 33.

Performance Highlights

Full Year 2023

- Production averaged 40,919 boe/d in 2023 (consisting of 23,359 bbl/d of heavy crude oil, 14,856 bbl/d of light and medium crude oil combined, 6,042 mcf/d of conventional natural gas and 1,644 boe/d of natural gas liquids), compared with 41,382 boe/d in 2022 (consisting of 21,441 bbl/d of heavy crude oil, 17,274 bbl/d of light and medium crude oil combined, 9,741 mcf/d of conventional natural gas and 958 boe/d of natural gas liquids).
- Cash provided by operating activities was $411.8 million in 2023, compared with $620.5 million in 2022, contributing to a total cash position as at December 31, 2023, of $190.0 million, compared with $313.0 million as at December 31, 2022. Total cash includes $30.3 million of restricted cash, compared with $23.2 million as at December 31, 2022.
- Net income(1) was $193.5 million ($2.19/share(2)) in 2023, compared with $286.6 million ($3.08/share(2)) in 2022.
- Capital expenditures were $442.7 million in 2023, compared with $417.6 million in 2022.
- Operating EBITDA was $467.2 million in 2023, compared with $641.9 million in 2022.
- Operating netback was $44.69/boe in 2023, compared with $59.76/boe in 2022.

Fourth Quarter 2023

- Production averaged 39,267 boe/d in the fourth quarter of 2023 (consisting of 23,002 bbl/d of heavy crude oil, 13,795 bbl/d of light and medium crude oil combined, 4,760 mcf/d of conventional natural gas and 1,635 boe/d of natural gas liquids), compared to 40,802 boe/d in the prior quarter (consisting of 24,097 bbl/d of heavy crude oil, 13,964 bbl/d of light and medium crude oil combined, 5,250 mcf/d of conventional natural gas and 1,820 boe/d of natural gas liquids), and compared to 41,806 boe/d in the fourth quarter of 2022 (consisting of 22,144 bbl/d of heavy crude oil, 17,073 bbl/d of light and medium crude oil combined, 9,097 mcf/d of conventional natural gas and 993 boe/d of natural gas liquids).
- Cash provided by operating activities was $73.4 million in the fourth quarter of 2023, compared with $154.0 million in the prior quarter, and $138.3 million in the fourth quarter of 2022. The Company reported a total cash position of $190.0 million, including $30.3 million of restricted cash, as at December 31, 2023, compared with a total cash position of $313.0 million, including $23.2 million of restricted cash, as at December 31, 2022.
- The Company recorded a net income(1) of $92.0 million ($1.04/share(2)) in the fourth quarter of 2023, compared with net income of $32.6 million ($0.37/share(2)) in the prior quarter and net income(1) of $197.8 million ($2.25/share(2)) in the fourth quarter of 2022.
- Capital expenditures were $82.3 million in the fourth quarter of 2023, compared with $74.1 million in the prior quarter and $134.2 million in the fourth quarter of 2022.
- Operating EBITDA was $121.0 million in the fourth quarter of 2023, compared with $137.8 million in the prior quarter and $145.0 million in the fourth quarter of 2022.
- Operating netback was $47.51/boe in the fourth quarter of 2023, compared with $48.54/boe in the prior quarter and $53.13/boe in the fourth quarter of 2022.

Oil and Gas Reserves

- Frontera added 4.2 MMboe of 2P gross reserves, for total Company 2P gross reserves of 164.1 MMboe and a reserve life index to 11.4 years at year end 2023.
- Fontera's 2023 year-end gross 2P reserves include a total additions of 4.2 MMboe by technical revisions, mainly in Hamaca 2.6 MMboe and other blocks (1.8 MMboe). Discoveries and technical revisions in the Perico block in Ecuador added 4.1 MMboe, offset by production of 14.9 MMboe. Proved gross reserves of 108.7 MMboe now represent 66% of the total 2P reserves compared with 64% of the total 2P reserves in 2022.

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

3. GUIDANCE

The Company's 2023 financial and operational results were in-line with all 2023 annual guidance metrics (the "**2023 Guidance**"). On November 9, 2023, the Company updated its guidance for capital expenditures with respect to Guyana Exploration to be within the range of $155-160 million (with the guidance prior to this update being capital expenditures within the range of $185-190 million).

In 2023, production averaged 40,919 boe/d, in-line with the Company's 2023 Guidance of 40,000 to 43,000 boe/d.

Production costs (excluding energy cost), net of realized foreign exchange ("**FX**") hedge impact, of $8.76/boe added with Energy costs, net of realized FX hedge impact, of $4.49, was consistent with the 2023 Guidance range of $12.50/boe to $13.50/boe, despite the higher electricity costs due to an increase in market prices during the year 2023. Transportation costs of $11.21/boe were within the bounds of the 2023 Guidance of $10.50/boe to $11.50/boe.

Operating EBITDA in 2023 totaled $467.2 million within the 2023 Guidance range at $80/bbl.

Capital expenditures of $442.7 million in 2023 were close to the midpoint of the 2023 Guidance of $420-475 million.

		2023	
		Guidance	Actual
Average Daily Production[(1)]	boe/d	40,000 - 43,000	40,919
Production Costs (excluding energy cost), net of realized FX hedge impact [(2)]	$/boe	12.50 - 13.50	8.76
Energy costs, net of realized FX hedge impact [(2)]			4.49
Transportation Costs, net of realized FX hedge impact[(3)]	$/boe	10.50 - 11.50	11.21
Operating EBITDA[(4)] at $80/bbl[(5)]	$MM	425 - 475	467.2
Development Drilling	$MM	110 - 130	122.4
Development Facilities	$MM	75 - 85	78.9
Colombia and Ecuador Exploration	$MM	50 - 60	44.8
Colombia Infrastructure[(6)]	$MM	5 - 10	11.4
Other[(7)]	$MM	25 - 30	27.9
Total Colombia and Ecuador Capital Expenditures	$MM	265 - 315	285.4
Guyana Exploration and Infrastructure	$MM	155 - 160	157.3
Total Capital Expenditure[(8)]	$MM	420 - 475	442.7

(1) The Company's 2023 average production guidance range does not include in-kind royalties, operational consumption, quality volumetric compensation or potential production from successful exploration activities planned in 2023.

(2) Non-IFRS ratio (equivalent to a "non-GAAP ratio" as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures". Per-barrel metric on a share before royalties basis; excludes costs related to ProAgrollanos.

(3) Non-IFRS ratio (equivalent to a "non-GAAP ratio" as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures". Calculated using net production after royalties.

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

(5) Current Guidance Operating EBITDA calculated at Brent $80/bbl, and COP/USD exchange rate of 4600:1. Foreign exchange changes impacted actual results. See "Risk and Uncertainties"

(6) Colombian Infrastructure refers to Puerto Bahia capital expenditures.

(7) Other includes the CPE-6 solar plant project, investment in equipment covered by insurance proceeds, investment in new technologies and HSEQ.

(8) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). See "Non-IFRS Financial and Other Measures." Capital expenditures excludes decommissioning expenses (approximately $14 million).

2024 Guidance

The Company's 2024 financial and operating guidance aims to build off the Company's strategy of value over volumes and its track record of improving capital efficiency. The Company's 2024 capital and production plan is fully funded, capitalizing on outstanding near field opportunities at our Quifa, CPE-6, VIM-1 and Perico producing blocks, while delivering our quickest payback barrels with sustained future growth potential. Frontera expects that its development program, together with its exploration investments, will deliver sustainable production and strong cash flows in 2024 and beyond.

In the Company's core Colombia and Ecuador upstream business, the Company aims to deliver production of 40,000 - 42,000 boe/d, in-line with production in 2023. Investing $272 - $335 million in total capital expenditures, a 32% decrease at the midpoint compared to 2023, to generate an anticipated $400 - $450 million in consolidated Operating EBITDA at $80/bbl average Brent prices. The Company will focus capital investing of $230 - $280 million on its inventory of near-field development drilling opportunities at its Quifa, CPE-6, VIM-1 and Perico producing blocks, invest in development facilities to enhance its water-handling capacity at CPE-6 and increase its gas processing capacity at VIM-1. Frontera's capital program also includes $35 - $45 million in exploration opportunities including drilling Hydra-1 well, in the VIM-1 block and two wells in Ecuador. Frontera anticipates investing $40-$50 million, in its standalone and growing Colombia infrastructure business, primarily to build the pipeline connection between Frontera's liquids terminal at Puerto Bahia and the Cartagena Refinery

Estimating total production costs, including both production and energy costs for 2024, are forecasted to average $14.25 – $15.75, primarily driven by El Niño-related higher energy costs. Transportation costs for 2024 are forecasted to average $11.00 - $12.00 per boe.

Summary of Frontera's 2024 Capital and Production Guidance

		2024 Full Year Guidance Frontera Consolidated
Average Daily Production(1)	boe/d	40,000 - 42,000
Production Costs (excluding energy cost) (2)(3)	$/boe	8.50 - 9.50
Energy Costs (3)	$/boe	5.75 - 6.25
Transportation Costs(3)(4)	$/boe	11.00 - 12.00
Operating EBITDA(5) at $80/bbl (6)	$MM	400 - 450
Upstream Operating EBITDA	$MM	400 - 430
Infrastructure Operating EBITDA(7)	$MM	15 - 25
Adjusted Infrastructure EBITDA(8)	$MM	95 - 115
Development Drilling	$MM	85 - 95
Development Facilities	$MM	95 - 115
Colombia and Ecuador Development	$MM	180 - 210
Colombia and Ecuador Exploration	$MM	35 - 45
Other (9)	$MM	15 - 25
Total Colombia & Ecuador Upstream Capex	$MM	230 - 280
Colombia Infrastructure(10)	$MM	40 -50
Guyana Exploration	$MM	2 - 5
Total Capital Expenditures(11)	$MM	272 - 335

(1) The Company's 2024 average production guidance range does not include in-kind royalties, operational consumption, quality volumetric compensation or potential production from successful exploration activities planned in 2024.
(2) Per-bbl/boe metric on a share before royalties' basis.
(3) Calculated using net production after royalties.
(4) Supplementary financial measure (as defined in National Instrument 52-112 - Non-GAAP and Other Financial Measures ("NI 52-112")). Refer to the "Non-IFRS and Other Financial Measures".
(5) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). "Operating EBITDA" represents the operating results of the Company's business, excluding the following items: restructuring, severance and other costs, certain non-cash items and gains or losses arising from the disposal of capital assets. Refer to the "Non-IFRS and Other Financial Measures".
(6) Current Guidance Operating EBITDA calculated at Brent $80/bbl and COP/USD exchange rate of 4,100:1.
(7) Includes Puerto Bahia (including FEC-related revenues) and, starting in 2024, SAARA and Proagrollanos.
(8) Reported Adjusted Infrastructure EBITDA (previously referred to as Adjusted Midstream (EBITDA) is a non-IFRS financial measure used to assist in measuring the operating results of the Infrastructure business, including the proportional consolidation of the 35% equity investment in the ODL pipeline.
(9) Other includes Sabanero Insurance, HSEQ activities and New Technologies.
(10) Colombia Infrastructure includes investments related to the Reficar connection, the SAARA Reverse Osmosis Water Treatment Facility and safety, maintenance activities and operational optimizations in the port..
(11) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures". Capital expenditures excludes decommissioning.

4. PROVED AND PROBABLE OIL AND GAS RESERVES

For the year ended December 31, 2023, the Company received an independent certified reserves evaluation report ("**Reserves Report**") from DeGolyer and MacNaughton for all of its assets, with total gross 2P reserves of 164.1 MMboe compared with 174.8 MMboe in 2022. All of the Company's reserves are located in Colombia and Ecuador.

Fontera's 2023 year-end gross 2P reserves include total additions of 4.2 MMboe by technical revisions, mainly in Hamaca (2.6 MMboe) and other blocks (1.8 MMboe). Discoveries and technical revisions in the Perico block, in Ecuador, added 4.1 MMboe, offset by production of 14.9 MMboe. Proved gross reserves of 108.7 MMboe now represent 66% of the total 2P reserves compared with 64% of the total 2P reserves in 2022.

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

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

Reserves at December 31, 2023 (MMboe[1])								
Country	**Field**	**Proved (P1)**		**Probable (P2)**		**Proved + Probable (2P)**		**Hydrocarbon Type**
		Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Colombia	Quifa SW block	37.9	34.1	5.4	4.8	43.3	38.9	Heavy Crude Oil
	CPE-6 block	26.9	24.3	14.8	13.3	41.7	37.6	Heavy Crude Oil
	Other heavy oil blocks [2]	15.6	14.5	4.7	4.5	20.2	19.0	Heavy Crude Oil
	Light/medium oil blocks [3]	15.8	14.1	18.2	16.3	34.0	30.4	Light and Medium Crude Oil Combined
	Natural gas blocks [4]	8.0	8.0	5.4	5.4	13.5	13.5	Conventional Natural Gas
	Natural gas blocks [4]	2.4	2.4	4.3	4.3	6.7	6.7	Natural Gas Liquids
	Sub total	**106.6**	**97.4**	**52.7**	**48.6**	**159.4**	**146.0**	**Oil, Conventional Natural Gas and Natural Gas Liquids**
Ecuador	Light/medium oil blocks[5]	2.1	1.7	2.6	2.1	4.7	3.9	Light and Medium Crude Oil Combined
	Sub total	**2.1**	**1.7**	**2.6**	**2.1**	**4.7**	**3.9**	**Oil**
	Total at Dec. 31, 2023	**108.7**	**99.2**	**55.4**	**50.7**	**164.1**	**149.9**	**Oil, Conventional Natural Gas and Natural Gas Liquids**
	Total at Dec. 31, 2022	111.0	98.6	63.8	58.3	174.8	156.8	
	Difference	(2.3)	0.6	(8.4)	(7.5)	(10.7)	(6.9)	
	2023 Production [6]	14.9	13.2	**Total reserves incorporated**		4.2	6.2	

(1) See the "Further Disclosures - Boe Conversion" section on page 44.
(2) Includes the Cajua and Jaspe fields in the Quifa block, and the Sabanero block.
(3) Includes the Cubiro, Cravoviejo, Canaguaro, Guatiquia, Casimena, Corcel, Cachicamo and other producing blocks.
(4) Includes the VIM 1 and El Dificil blocks.
(5) Includes the Perico block, which are currently in early evaluation period to better quantify resources.
(6) Gross production distribution: light & medium crude oil combined 5.4 MMboe, heavy crude oil 8.5 MMboe, conventional natural gas 0.4 MMboe, natural gas liquids 0.6 MMboe.
(7) In the table above, "Gross" refers to W.I. before royalties, and "Net" refers to W.I. after royalties. Numbers in the table may not add due to rounding differences.

5. FINANCIAL AND OPERATIONAL RESULTS

Production

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

		Production				
					Year ended December 31	
Producing blocks in Colombia		**Q4 2023**	**Q3 2023**	**Q4 2022**	**2023**	**2022**
Heavy crude oil	(bbl/d)	23,002	24,097	22,144	23,359	21,441
Light and medium crude oil combined	(bbl/d)	12,342	13,312	15,827	13,925	16,436
Conventional natural gas	(mcf/d)	4,760	5,250	9,097	6,042	9,741
Natural gas liquids	(boe/d)	1,635	1,820	993	1,644	958
Total production Colombia	**(boe/d)**	**37,814**	**40,150**	**40,560**	**39,988**	**40,544**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	1,453	652	1,246	931	838
Total production Ecuador	**(bbl/d)**	**1,453**	**652**	**1,246**	**931**	**838**
Total production	**(boe/d)**	**39,267**	**40,802**	**41,806**	**40,919**	**41,382**

Colombia

For the three months ended December 31, 2023, production in Colombia decreased by 2,336 boe/d, compared to the prior quarter, as a result of lower planned well drilling and workovers activity in the fourth quarter, natural decline, and unplanned maintenance on an injector well in Quifa.

Compared to the three months and year ended December 31, 2022, production decreased by 2,746 boe/d and 556 boe/d, respectively, mainly due to lower production in light and medium crude oil combined of 22% and 15%, respectively, and conventional natural gas of 48% and 38%, respectively, due to the finalization of the Neiva block production contract, the relinquishment of the La Creciente block, and the natural decline. This decrease was partially offset by (i) heavy crude oil increases of 4% and 9%, respectively, due to production increases in the Cajua, CPE-6 and Sabanero blocks as a result of the successful development drilling campaign, increases in water handling capacity through the SAARA project in the Quifa block, new facilities in the CPE-6 block, and the reactivation of the Sabanero block on July 1, 2022, and (ii) increased production of natural gas liquids by 65% and 72%, respectively, in the VIM-1 block as a result of the development of the facilities in the block.

Ecuador

Production in Ecuador for the three months ended December 31, 2023, increased to 1,453 bbl/d of light and medium crude oil combined, compared to 652 bbl/d in the prior quarter. The increase is primarily attributed to the completion of Perico Norte A-3 (formerly Yin 2) in August 2023, Perico Centro-1 in September 2023 and Perico Norte A-4 in November 2023. The three wells previously drilled within the U Sand formation has successfully responded in production and opened key additional opportunities in the Block.

Compared to the three months and year ended December 31, 2022, production in Ecuador increased to 1,453 bbl/d and 931 bbl/d, of light and medium crude oil combined, compared to 1,246 bbl/d and 838 bbl/d respectively, in the same periods of 2022. The increase is primarily attributed to the completion of two exploration wells, Perico Norte A-3 (formerly Yin 2) and Perico Centro 1 (formerly Jandiayacu-1) and the successful Perico Norte 1 (formerly Jandaya-1) well stimulation, at the Perico block. In November of 2023, the Company completed a third exploration well, Perico Norte A-4. All of these, partially offset by the interruption of production in the Espejo block (Frontera holds a 50% W.I., and is a non-operator).

Production Reconciled to Sales Volumes

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

					Year ended December 31	
		Q4 2023	Q3 2023	Q4 2022	2023	2022
Production	(boe/d)	**39,267**	**40,802**	**41,806**	**40,919**	**41,382**
Royalties in-kind Colombia (1)	(boe/d)	(5,257)	(4,093)	(4,630)	(4,436)	(4,964)
Royalties in-kind Ecuador (2)	(boe/d)	(485)	(192)	(427)	(289)	(319)
Net production	(boe/d)	**33,525**	**36,517**	**36,749**	**36,194**	**36,099**
Oil inventory draw (build)	(boe/d)	2,762	1,131	(1,199)	445	(1,183)
Overlift (settlement)	(boe/d)	—	—	(12)	—	2
Volumes purchased	(boe/d)	6,708	6,246	9,587	7,152	6,143
Other inventory movements (3)	(boe/d)	(2,278)	(1,841)	(2,894)	(2,356)	(2,133)
Sales volumes	(boe/d)	**40,717**	**42,053**	**42,231**	**41,435**	**38,928**
Sale of volumes purchased	(boe/d)	(6,268)	(6,764)	(7,908)	(7,430)	(5,787)
Sales volumes, net of purchases	(boe/d)	**34,449**	**35,289**	**34,323**	**34,005**	**33,141**
Oil sales volumes	(bbl/d)	33,896	34,206	32,642	32,992	31,384
Conventional natural gas sales volumes	(mcf/d)	3,152	6,173	9,582	5,774	10,015
Total oil and conventional natural gas sales volumes, net of purchases	**(boe/d)**	**34,449**	**35,289**	**34,323**	**34,005**	**33,141**
Inventory balance						
Colombia	(bbl)	551,715	812,797	683,416	551,715	683,416
Peru	(bbl)	480,200	480,200	480,200	480,200	480,200
Ecuador	(bbl)	44,479	37,421	75,164	44,479	75,164
Inventory ending balance	**(bbl)**	**1,076,394**	**1,330,418**	**1,238,780**	**1,076,394**	**1,238,780**

(1) Royalties for CPE-6 block are paid in-kind, since October 2023.
(2) The Company reports the share of production retained by the government of Ecuador as royalties paid in-kind.
(3) Mainly corresponds to operational consumption and quality volumetric compensation.

Sales volumes, net of purchases, for the three months ended December 31, 2023, decreased by 2% compared with the prior quarter, mainly due to lower volumes of oil and natural gas produced on a net basis, and was comparable with the same period in 2022. For the year ended December 31, 2023, sales volumes, net of purchases, increased by 3%, compared with the same period of 2022, due to higher volumes sold in Colombia and Ecuador as a consequence of a drawdown by 13% of inventory balance built in the prior year.

Colombia Royalties PAP

The Company makes high price clause participation ("**PAP**") payments to Ecopetrol S.A. ("**Ecopetrol**") and the Agencia Nacional de Hidrocarburos ("**ANH**") on production from the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo, Arrendajo and CPE-6 blocks. Until last year (2022), the PAP was paid in cash for all blocks except for those relating to the Quifa block, which were paid using in-kind volumes from production. In February, 2023, the ANH changed the payment method for PAP, requiring in-kind payments for all blocks, except for the CPE-6, Guatiquia (Yatay field) and Cubiro (Copa A) blocks. During the fourth quarter of 2023, the ANH made an additional change in the payment method for PAP, by requiring in-kind payments for the CPE-6 block as of October 2023.

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

					Year ended December 31	
		Q4 2023	Q3 2023	Q4 2022	2023	2022
PAP in cash	(bbl/d)	402	788	1,928	678	2,180
PAP in kind	(bbl/d)	2,664	1,791	2,459	2,057	2,752
PAP	**(bbl/d)**	**3,066**	**2,579**	**4,387**	**2,735**	**4,932**
% Production		**7.8 %**	**6.3 %**	**10.5 %**	**6.7 %**	**11.9 %**

For the three months and year ended December 31, 2023, the total PAP decreased compared with the same periods of 2022, mainly due to a lower WTI oil benchmark price. For the three months and year ended December 31, 2023, PAP in cash decreased compared with the same periods of 2022, mainly due to a change in the payment method required by ANH as mentioned above and a lower WTI oil benchmark price, and compared with the prior quarter, PAP in cash decreased mainly due to a lower WTI oil benchmark price and the change in the payment method required by ANH for CPE-6 since October, 2023. For the three months ended December 31, 2023, PAP in kind increased, compared to the same period of 2022, mainly due to the change in the payment method required by the ANH partially offset by a lower WTI oil benchmark price, and for the year ended December 31, 2023, PAP in kind decreased, compared to the year ended December 31, 2022, mainly due to lower production and a lower WTI oil benchmark price. Compared with the prior quarter PAP in kind increased mainly due to higher volumes delivered from the Quifa block and the change in the payment method required by ANH for CPE-6 since October, 2023.

Realized and Reference Prices

					Year ended December 31	
		Q4 2023	**Q3 2023**	**Q4 2022**	**2023**	**2022**
Reference price						
Brent	($/bbl)	82.85	85.92	88.63	82.17[1]	99.04
Average realized prices						
Realized oil price, net of purchases	($/bbl)	76.35	80.08	85.50	74.23	95.06
Realized conventional natural gas price	($/mcf)	6.93	4.91	4.61	5.41	4.52
Net sales realized price						
Oil and gas sales, net of purchases [2]	($/boe)	75.76	78.48	82.60	72.93	91.39
Premiums paid on oil price risk management contracts[3] [4]	($/boe)	(0.69)	(0.59)	(1.32)	(0.80)	(1.22)
Royalties [3]	($/boe)	(1.79)	(3.76)	(6.04)	(2.98)	(7.83)
Net sales realized price [2]	**($/boe)**	**73.28**	**74.13**	**75.24**	**69.15**	**82.34**

(1) Frontera's weighted average Brent price was $81.88/bbl in 2023.
(2) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.
(3) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.
(4) Includes put premiums paid for the position expired during the period.

The average Brent benchmark oil price during the three months and year ended December 31, 2023, decreased by 7% and 17%, respectively, compared to the same periods of 2022. In comparison to the third quarter of 2023, the average Brent benchmark oil price decreased by 4%. The decrease in crude oil prices during 2023, compared with the same period of 2022, was mainly due to: (i) worldwide economic deceleration creating a lack of demand, (ii) increase in market supplies in countries such as Guyana, Brazil, Venezuela and the USA, that could not be offset by the OPEC+ cuts, and (iii) the rate interest increase cycles that have not come to an end yet, especially those occurring in the USA.

For the three months and year ended December 31, 2023, the Company's net sales realized price decreased 3% and 16%, compared to the same periods of 2022, respectively. The decrease in the Company's net sales realized price was driven by the decrease in the Brent benchmark oil price and higher oil differential prices, partially offset by lower royalties. In comparison to the previous quarter, the Company's net sales realized price decreased from $74.13/boe to $73.28/boe, mainly due to the decrease in the Brent benchmark oil price, partially offset by better oil differential prices and lower royalties.

Operating Netback

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

	Q4 2023		Q3 2023		Q4 2022	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price [1]	232,224	73.28	240,659	74.13	237,566	75.24
Production costs (excluding energy cost), net of realized FX hedge impact [1][2][3]	(35,021)	(9.69)	(33,103)	(8.82)	(32,628)	(8.48)
Energy costs, net of realized FX hedge impact [1][2][4]	(18,267)	(5.06)	(18,912)	(5.04)	(11,837)	(3.08)
Transportation costs, net of realized FX hedge impact [1][2][5]	(33,997)	(11.02)	(39,422)	(11.73)	(35,660)	(10.55)
Operating Netback [1] [2]	**144,939**	**47.51**	**149,222**	**48.54**	**157,441**	**53.13**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases [6]		34,449		35,289		34,323
Production [7]		39,267		40,802		41,806
Net production [8]		33,525		36,517		36,749

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.
(3) Includes $2.1 million, $2.1 million and $Nil of realized FX hedge gain attributable to production costs for the fourth quarter of 2023, third quarter of 2023, and the fourth quarter of 2022, respectively. See "Gain (Loss) on Risk Management Contracts" on page 19.
(4) Includes $0.7 million, $0.8 million and $Nil of realized FX hedge gain attributable to energy costs for the fourth quarter of 2023, third quarter of 2023, and the fourth quarter of 2022, respectively. See "Gain (Loss) on Risk Management Contracts" on page 19.
(5)Includes$0.8 million, $0.7 million and $Nil of realized FX hedge gain attributable to transportation costs for the fourth quarter of 2023, third quarter of 2023, and the fourth quarter of 2022, respectively. See "Gain (Loss) on Risk Management Contracts" on page 19.
(6)Sales volumes, net of purchases, exclude sales of third-party volumes.
(7)Refer to the "Production" section on page 10.
(8)Refer to the "Further Disclosures" section on page 44.

The Company's operating netback for the fourth quarter of 2023 was $47.51/boe, compared to $53.13/boe in the same quarter of 2022. The decrease was a result of lower net sales realized prices, higher energy costs, net of realized FX hedge impact, due to an El Niño-related increase in market prices, additional production costs (excluding energy cost), net of realized FX hedge impact, due to an increase of technical assistance costs. In addition, transportation costs, net of realized FX hedge impact, per boe increase primarily due to the annual transportation tariffs increase.

In comparison to the third quarter of 2023, the Company's operating netback decreased from $48.54/boe to $47.51/boe, representing a slight decrease of 2%, mainly due to a lower net sales realized price and higher production costs (excluding energy cost), net of realized FX hedge impact, resulting from higher well services activity costs. In addition, transportation costs, net of realized FX hedge impact, decreased mainly due to an increase in local thermal market sales volumes.

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

	Year ended December 31			
	2023		2022	
	$M	**($/boe)**	**$M**	**($/boe)**
Net sales realized price [1]	858,397	69.15	996,061	82.34
Production costs (excluding energy cost), net of realized FX hedge impact [1][2][3]	(130,842)	(8.76)	(132,758)	(8.79)
Energy costs, net of realized FX hedge impact [1][2][4]	(67,024)	(4.49)	(50,644)	(3.35)
Transportation costs, net of realized FX hedge impact [1][2][5]	(148,152)	(11.21)	(137,554)	(10.44)
Operating Netback [1] [2]	**512,379**	**44.69**	**675,105**	**59.76**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases [7]		34,005		33,141
Production [6]		40,919		41,382
Net production [8]		36,194		36,098

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.
(3) Includes $9.1 million and $Nil of realized FX hedge gain attributable to production costs for the year ended December 31, 2023 and 2022, respectively. See "Gain (Loss) on Risk Management Contracts" on page 19.
(4) Includes $2.9 million and $Nil of realized FX hedge gain attributable to energy costs for the year ended December 31, 2023 and 2022, respectively. See "Gain (Loss) on Risk Management Contracts" on page 19.
(5) Includes $3.3 million and $Nil of realized FX hedge gain attributable to transportation costs for the year ended December 31, 2023 and 2022, respectively.
(6) Sales volumes, net of purchases, exclude sales of third-party volumes. See "Gain (Loss) on Risk Management Contracts" on page 19.
(7) Refer to the "Production" section on page 10.
(8) Refer to the "Further Disclosures" section on page 44.

Operating netback for the year ended December 31, 2023, decreased by 25% from $59.76/boe to $44.69/boe, compared to the same period of 2022. The decrease was due to a lower net sales realized prices, higher energy costs, net of realized FX hedge impact, due to an El Niño-related increase in market prices and higher fuel consumption. In addition, higher transportation costs, net of realized FX hedge impact, mainly due to the annual transportation tariffs increase and the starting of the new Bicentenario pipeline take-or-pay contract since May, 2022.

Sales

	Three months ended December 31		Year ended December 31	
($M)	**2023**	**2022**	**2023**	**2022**
Oil and gas sales, net of purchases [(1)]	240,105	260,824	905,249	1,105,503
Premiums paid on oil price risk management contracts [(2)]	(2,198)	(4,182)	(9,903)	(14,733)
Royalties	(5,683)	(19,076)	(36,949)	(94,709)
Net sales [(1)]	**232,224**	**237,566**	**858,397**	**996,061**
Net sales realized price ($/boe) [(3)]	73.28	75.24	69.15	82.34

(1) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.
(2) Includes put premiums paid for the position expired during the period.
(3) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.

Oil and gas sales, net of purchases, decreased by $20.7 million and $200.3 million for the three months and year ended December 31, 2023, respectively, compared to the same periods of 2022, mainly due to lower Brent benchmark oil prices and higher price differentials (Refer to the "Realized and Reference Prices" section on page 12 for further details on changes in prices).

Net sales for the three months and year ended December 31, 2023, decreased by $5.3 million and $137.7 million, respectively, compared with the same periods of 2022. The following table describes the various factors that impacted net sales:

	Three months ended December 31	Year ended December 31
($M)	**2023-2022**	**2023-2022**
Net sales for the period ended December 31, 2022	237,566	996,061
Decrease due to 8% lower oil and gas price (full year 20% lower)	(21,552)	(223,300)
Increase due to 0.4% higher produced volumes sold (full year 3% higher)	833	23,046
Decrease in premiums paid on oil price risk management contracts	1,984	4,830
Decrease in royalties	13,393	57,760
Net sales for the period ended December 31, 2023	**232,224**	**858,397**

Oil and Gas Operating Costs

	Three months ended December 31		Year ended December 31	
($M)	**2023**	**2022**	**2023**	**2022**
Production costs (excluding energy cost)	37,122	32,628	139,917	132,758
Energy cost	19,005	11,837	69,924	50,644
Transportation costs	34,750	35,660	151,416	137,554
Post-termination obligation	11,160	5,229	18,814	12,299
Inventory valuation	8,069	3,632	633	(6,877)
Total oil and gas operating costs	**110,106**	**88,986**	**380,704**	**326,378**

Total oil and gas operating costs increased by 24% and 17%, respectively, for the three months and year ended December 31, 2023, compared to the same periods of 2022. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs (excluding energy cost) for the three months and year ended December 31, 2023, increased by 14% and 5%, respectively, compared with the same periods of 2022, due to higher technical assistance and maintenance costs, partially offset by lower costs associated to well services activities.
- Energy cost for the three months and year ended December 31, 2023, increased by 61% and 38%, due to an El Niño-related increase in market prices and higher fuel consumption.
- For the three months ended December 31, 2023, transportation costs decreased 3% compared with the same period of 2022, mainly due to an increase of local sales to the thermal generation market. For the year ended December 31, 2023,

transportation costs increased 10%, compared with the same period of 2022, primarily due to the annual transportation tariffs increase, higher volumes transported and the Bicentenario pipeline take-or-pay, which started in May 2022.

- Post-termination obligations for the three months and year ended December 31, 2023, include post-termination obligations related to Block 192, in Peru, of $10.7 million and $11.1 million, respectively. Also included environmental commitments and operational costs related to the relinquishment of the Rio Ariari, Mapache, Guaduas, Guama, Rio Meta, and La Creciente blocks, and the Arauco field in Colombia. During the same periods in 2022, the post-termination obligations were mainly related to non-recurring cleaning activities to be executed in Block 192 in Peru.
- Inventory valuation for the three months and year ended December 31, 2023, increased by $4.4 million and $7.5 million, respectively, compared with the same periods of 2022, mainly as a result of inventory draw-down in 2023.

Cost of Purchases

	Three months ended December 31		Year ended December 31	
($M)	**2023**	**2022**	**2023**	**2022**
Cost of purchases [1]	55,353	64,981	235,797	217,375

[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 27.

Cost of purchases corresponds to the cost of third-party hydrocarbon volumes purchased primarily for use in dilution and refining as part of the Company's oil operations, and marketing and transportation strategy. For the three months ended December 31, 2023, the cost of purchases, including the transportation and processing fees for purchased volumes sold, decreased $9.6 million compared with the same period of 2022, mainly due to lower Brent benchmark oil prices fourth quarter of 2023.

For the year ended December 31, 2023, the cost of purchases, including the transportation and processing fees for purchased volumes sold, increased $18.4 million, due to additional volumes acquired as a result of higher dilution and energy consumption requirements driven by an increase of heavy crude oil production, partially offset by lower Brent benchmark oil prices. The sale of purchased volumes generated an income of $48.3 million and $208.1 million, for the three months and year ended December 31, 2023, respectively.

Royalties

	Three months ended December 31		Year ended December 31	
($M)	**2023**	**2022**	**2023**	**2022**
Royalties Colombia	5,314	18,816	36,004	94,136
Royalties Ecuador	369	260	945	573
Royalties	**5,683**	**19,076**	**36,949**	**94,709**

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia and Ecuador. For the three months and year ended December 31, 2023, royalties decreased by $13.4 million and $57.8 million, respectively, compared to the same periods of 2022, due to the change in the royalties payment method from in-cash to in-kind as per the ANH’s request and a lower WTI oil benchmark price. Refer to the “Production Reconciled to Sales Volumes” section on page 11 for further details of royalties PAP paid in-cash and in-kind.

Depletion, Depreciation and Amortization

	Three months ended December 31		Year ended December 31	
($M)	**2023**	**2022**	**2023**	**2022**
Depletion, depreciation and amortization	68,411	49,198	278,269	195,419

For the three months and year ended December 31, 2023, depletion, depreciation, and amortization expense (“**DD&A**”) increased by 39% and 42%, respectively, compared to the same period of 2022, mainly due to a higher depletable base as a result of an impairment reversal in fourth quarter 2022 and the acquisition of an additional 35% W.I. in the El Dificil block, on April 27, 2022.

Impairment Expense, Exploration Expenses and Others

($M)	Three months ended December 31 2023	Three months ended December 31 2022	Year ended December 31 2023	Year ended December 31 2022
Impairment expense (recovery) of:				
Properties, plant and equipment	—	(229,774)	—	(229,774)
Exploration and evaluation assets	1,090	18,644	20,593	20,908
Other	327	—	4,643	3,033
Total impairment expense (recovery)	1,417	(211,130)	25,236	(205,833)
Exploration expenses of:				
Geological and geophysical costs, and other	459	—	1,673	1,450
Minimum work commitment paid	358	—	358	919
Total exploration expenses	817	—	2,031	2,369
(Recovery) expense of asset retirement obligations	(1,621)	3,235	(25,622)	(1,823)
Impairment expense (recovery), exploration expenses and other	**613**	**(207,895)**	**1,645**	**(205,287)**

Properties, plant and equipment

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

For the three months and year ended December 31, 2022, the Company recognized a net impairment reversal of $229.8 million. The Reserves Report included higher forecasted oil prices, and as a consequence, a higher net present value than the carrying amount of the Company's oil and gas properties. As a result, the Company performed an impairment reversal test and concluded that the recoverable amount for the Central Cash Generating Units ("**CGUs**") exceeded its carrying amount resulting in a net reversal of previous impairment charges of $229.8 million.

The recoverable amount of each CGU was determined based on the Company's updated projections of future cash flows generated from proved and probable reserves. For further information refer to Note 8 of the 2023 Annual Consolidated Financial Statements.

Exploration and Evaluation Assets

During the three months and year ended December 31, 2023, the Company recorded an impairment charge on exploration and evaluation of assets in Colombia of $1.1 million and $20.6 million, respectively (2022: $18.6 million and $20.9 million, respectively), mainly as a result of the Company's decision to proceed with steps to relinquish the VIM-22 block, which remains subject to approval by the ANH.

Other

During the three months and year ended December 31, 2023, the Company recognized other impairment expenses of $0.3 million and $4.6 million, respectively, related to obsolete inventories and allowance of doubtful account receivables, compared with $Nil and $3.0 million, during the three months and year ended December 31, 2022, respectively.

Expense (Recovery) of asset retirement obligation

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

During the three months ended December 31, 2023, the Company recognized a recovery of asset retirement obligations of $1.6 million (2022: expense $3.2 million) in Colombia and Peru. For the year ended December 31, 2023, the Company recognized a recovery of asset retirement obligations of $25.6 million, (2022: $1.8 million), mainly as a result of the sale of Frontera Energy Off Shore Perú S.R.L, the 100% consolidated entity that owns the 100% W.I. in Block Z1, for a payment of $7.5 million to a third party. As a result of this transaction, the Company derecognized the asset retirement obligation related to Block Z1 and generated a $37.4 million asset retirement obligation recovery.

Other Operating Costs

($M)	Three months ended December 31		Year ended December 31	
	2023	2022	2023	2022
General and administrative	16,891	12,761	53,907	55,063
Special projects and other cost [1]	2,941	1,207	11,286	3,441
Share-based compensation	(745)	3,213	1,148	9,140
Restructuring, severance and other costs	3,744	2,624	8,548	4,463

[1] Mainly includes costs related to Promotora Agricola de los Llanos S.A., the commissioning of the reverse osmosis water treatment facility "**SAARA**" expansion in 2023 and Peru.

General and Administrative ("G&A")

For the three months ending December 31, 2023, G&A expenses increased by 32%, compared with the same quarter of 2022, mainly due to higher professional fees and personnel expenses. For the year ending December 31, 2023, G&A expenses decreased by 2% mainly attributable to lower professional fees partially offset by foreign exchange variances.

Special projects and other costs

For the three months and year ended December 31, 2023, special projects and other costs increased by $1.7 million and $7.8 million, respectively, compared with the same periods of 2022, mainly due to the SAARA project and Promotora Agricola de los Llanos costs.

Share-Based Compensation

For the three months and year ended December 31, 2023, share-based compensation decreased by $4.0 million and $8.0 million, respectively, compared with the same periods of 2022. The decrease was mainly due to the strengthening U.S. dollar, a decrease in the trading price of the Common Shares and the cancellation of certain restricted share units ("**RSUs**"). Share-based compensation reflects cash and non-cash charges relating to the vesting of RSUs and grants of deferred share units ("**DSUs**") under the Company's security-based compensation plan, which are subject to variability from movements in the underlying Common Share trading price, and the consolidation of stock option expenses from the Company's majority-held subsidiary, CGX.

Restructuring, Severance and Other Costs

For the three months and year ended December 31, 2023, restructuring, severance and other costs increased by $1.1 million and $4.1 million, respectively, compared with the same periods of 2022, mainly due to a reduction of the Company's workforce in line with the Restructuring Plan (as defined below).

Non-Operating Costs

($M)	Three months ended December 31		Year ended December 31	
	2023	2022	2023	2022
Finance income	2,270	2,323	9,984	5,505
Finance expenses	(16,865)	(14,239)	(64,185)	(52,991)
Foreign exchange income (loss)	2,724	(28,230)	12,275	(76,413)
Other income (loss)	4,554	(5,381)	8,936	(10,800)

Finance Income

For the three months and year ended December 31, 2023, finance income decreased by $0.1 million and increased by $4.5 million, respectively, compared with the same periods of 2022, as a result of higher interest rates on the investment trust accounts for abandonment requirements.

Finance Expenses

For the three months and year ended December 31, 2023, finance expenses increased by $2.6 million and $11.2 million, respectively, compared with the same periods of 2022, mainly due to higher interest on the PIL Loan Facility (as defined below) compared to the prior 2025 Puerto Bahía Debt (as defined below), additional interest related to working capital loans and leasing, and higher accretion expenses of asset retirement obligations.

Foreign Exchange Income (Loss)

For the three months ended December 31, 2023, foreign exchange income was $2.7 million, as a result of the COP appreciation against the USD, mainly related to the translation of the debt consolidated from the PIL Loan Facility (as defined below). For the year ended December 31, 2023, foreign exchange income was $12.3 million, as a result of the COP appreciation against the USD, mainly related to the translation of the debt consolidated from the PIL Loan Facility offset by the transfer from the cumulative translation adjustment of the Other Comprehensive Income ("**OCI**") to Consolidated Statement of Income of a return of capital of Oleoducto de los Llanos S.A. ("**ODL**") for $10.3 million. This compares with losses of $28.2 million and $76.4 million, respectively, in the same periods of 2022, mainly related of the transfer from the cumulative translation adjustment of the OCI to Consolidated Statement of Income relating to the return of capital of ODL for $19.7 million during the third quarter of 2022. In addition, a loss was recorded as a result the of the depreciation of the COP against the USD on the translation of the 2025 Puerto Bahia Debt and a loss of the translation of the Company's net working capital balances. Foreign exchange rates for the fourth quarter of 2023 and 2022, were COP 3,822.05:1 and COP 4,810.20:1, respectively.

Other income (Loss)

For the three months and year ended December 31, 2023, the Company recognized other income of $4.6 million and $8.9 million, respectively. During the fourth quarter of 2023, the income was mainly attributable to insurance compensation for the Sabanero Block. For the year ended December 31, 2023, the income is mainly related to the reversal of the legal claim from the late delivery of production from Quifa block prior to 2014 and insurance compensation. During the same periods of 2022, the Company recognized other loss of $5.4 million and $10.8 million, respectively, primarily related to the recognition of contingencies.

Gain (Loss) on Risk Management Contracts

	Three months ended December 31		Year ended December 31	
($M)	**2023**	**2022**	**2023**	**2022**
Premiums paid on oil price risk management contracts, net	(2,198)	(4,182)	(9,903)	(14,733)
Realized gain on foreign exchange risk hedge [(1)(2)]	4,187	—	17,257	—
Realized gain (loss) on risk management contracts	1,989	(4,182)	7,354	(14,733)
Unrealized gain on risk management contracts	7,000	6,600	11,880	4,310
Total gain (loss) on risk management contracts	8,989	2,418	19,234	(10,423)

(1) For the three months and year ended December 31, 2023, includes $4.2 million and $8.3 million, respectively, of cash settlement of foreign exchange risk management contracts and the early termination of zero-cost collars foreign exchange risk management contracts by $Nil and $9.0 million, respectively.

(2) For determination of operating netback, during the three months and year ended December 31, 2023, the Company estimates an attribution of 50% and 53% of the total realized FX hedge to production cost ($2.1 million and $9.1 million; 2022: $Nil and $Nil), respectively, also estimates an attribution of 18% and 17% of the total realized FX hedge to energy ($0.7 million and $2.9 million; 2022: $Nil and $Nil), and estimates an attribution of 18% and 19% of the total realized FX hedge to transportation ($0.8 million and $3.3 million; 2022: $Nil and $Nil), respectively. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.

For the three months and year ended December 31, 2023, the realized gain on risk management contracts was $2.0 million and $7.4 million, respectively, resulting from a gain on cash settlement of risk management contracts of foreign exchange currency of $8.3 million during the year ended December 31, 2023 and the unwinding of risk management contracts of foreign exchange currency of $9.0 million during the second quarter of 2023, partially offset by $2.2 million and $9.9 million respectively, related to premiums paid on oil price risk management contracts, compared to losses of $4.2 million and $14.7 million in the same periods of 2022 respectively, resulting from cash paid for premiums related to put options settled.

For the three months and year ended December 31, 2023, risk management contracts had an unrealized gain of $7.0 million and an unrealized gain of $11.9 million, respectively, compared to a gain of $6.6 million and a loss of $4.3 million, in the same periods of 2022, primarily from the reclassification of amounts to realized losses from instruments settled and variance in the benchmark forward prices of Brent.

Risk Management Contracts - Brent Crude Oil

As part of its risk management strategy, the Company uses derivative commodity instruments to manage exposure to price volatility by hedging a portion of its oil production. The Company's strategy is designed to protect a minimum of 40% of the estimated production with a tactical approach, using derivative commodity instruments to protect the revenue generation and cash position of the Company, while maximizing the price upside. During the fourth quarter of 2023, the Company successfully achieved a 40% hedging ratio for the first quarter of 2024, with an average strike price of $74.76 per barrel.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $/bbl**	**Assets**	**Liabilities**
Put	January 2024	Brent	428,500	80.00	552	—
Put	February to March 2024	Brent	812,835	72.00	—	1,275
Total as at December 31, 2023			1,241,335		552	1,275

Subsequent to December 31, 2023, the Company entered into new hedges that protect a portion of the Company's expected production for April and May 2024. The new transactions are as follows:

				Avg. Strike Prices
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $/bbl**
Put	April to May 2024	Brent	893,491	72.00
Put	June 2024	Brent	440,000	72.00
		Total volume (bbl)	1,333,491	

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. In addition to the standard hedging program, the Company entered into a selling forward in order to hedge the foreign exchange risk related to the principal payment of the Bancolombia Working Capital Loan (as defined below).

As of December 31, 2023, the Company had entered new positions of foreign currency derivatives contracts as follows:

				Avg. Put / Call	Carrying Amount	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume in USD**	**Par forward (COP$)**	**Assets**	**Liabilities**
Zero-cost collars	January to March 2024	COP / USD	60,000,000	4,125/4,763.25	4,544	—
Zero-cost collars	April to June 2024	COP / USD	60,000,000	4,125/4,763.25	4,166	—
Forward	October, 2024	COP / USD	17,099,200	4,386.17	1,403	—
Total as at December 31, 2023					10,113	—

Income Tax Recovery (Expense)

	Three months ended December 31		Year ended December 31	
($M)	**2023**	**2022**	**2023**	**2022**
Current income tax expense	(5,879)	(76,021)	(33,020)	(87,183)
Deferred income tax recovery (expense)	44,886	7,422	28,890	(162,092)
Total income tax recovery (expense)	**39,007**	**(68,599)**	**(4,130)**	**(249,275)**

For the three months and year ended December 31, 2023, the Company recognized a current income tax expense of $5.9 million and $33.0 million, respectively, compared to current income tax expense of $76.0 million and $87.2 million for the same periods of 2022. The decrease in current income tax expense in 2023, as compared to the respective period in 2022, is mainly due to the higher use of use of tax losses during the period.

For the three months and year ended December 31, 2023, deferred income tax recovery was $44.9 million and $28.9 million, respectively, and for the same periods of 2022, the deferred income tax income of $7.4 million and expense of $162.1 million, respectively. The variation is mainly due to the changes in the use of tax losses between both periods and the changes in the projected income tax rates to recover the deferred taxes.

Net Income

	Three months ended December 31		Year ended December 31	
($M)	2023	2022	2023	2022
Net income [(1)]	92,038	197,796	193,497	286,615
Per share – basic ($)	1.08	2.29	2.27	3.16
Per share – diluted ($)	1.04	2.25	2.19	3.08

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

In the fourth quarter of 2023, the Company reported a net income, attributable to equity holders of the Company, of $92.0 million which included operating income of $36.3 million, income tax recovery of $39.0 million, $14.8 million from share of income from associates, $9.0 million related to income on risk management contracts, finance income of $2.3 million, $4.6 million of other income and foreign exchange income of $2.7 million, partially offset by finance expenses of $16.9 million. This compared to net income, attributable to equity holders of the Company, of $197.8 million for the fourth quarter of 2022, which included operating income of $296.8 million (including a non-cash reversal of impairment of $229.8 million), partially offset by $68.6 million of income tax expense, foreign exchange loss of $28.2 million and finance expenses of $14.2 million.

For the year ended December 31, 2023, the Company reported a net income, attributable to equity holders of the Company, of $193.5 million, which included operating income of $154.2 million, a share of income from associates amounting to $56.5 million, a gain of $19.2 million from risk management contracts, finance income by $10.0 million, other income of $8.9 million, foreign exchange gains of $12.3 million and income tax recovery of $4.1 million, partially offset by finance expenses of $64.2 million. This compared to a net income, attributable to equity holders of the Company, of $286.6 million, which included operating income of $643.4 million (including a non-cash reversal of impairment of $229.8 million), partially offset by income tax expense of $249.3 million, foreign exchange losses of $76.4 million primarily related to our infrastructure business, and finance expenses of $53.0 million.

Capital Expenditures and Acquisitions

	Three months ended December 31		Year ended December 31	
($M)	2023	2022	2023	2022
Development drilling	23,717	52,769	122,433	172,915
Development facilities	26,674	20,982	78,929	48,244
Colombia and Ecuador exploration	6,764	34,192	44,831	62,154
Other	24,660	8,690	39,224	30,718
Total Colombia, Ecuador and other capital expenditures	**81,815**	**116,633**	**285,417**	**314,031**
Guyana exploration and infrastructure	477	17,532	157,317	103,532
Total capital expenditures [(1)]	**82,292**	**134,165**	**442,734**	**417,563**

(1) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.

Capital expenditures for the three months and year ended December 31, 2023, were $82.3 million and $442.7 million, respectively, with a decrease of $51.9 million and an increase of $25.2 million, compared to the same periods of 2022, respectively, mainly due to the following:

Development drilling. During the three months and year ended December 31, 2023, development drilling expenditures decreased by $29.1 million and $50.5 million, respectively, compared to the same periods of 2022. During the fourth quarter of 2023, 13 development wells were drilled in the Quifa and CPE-6 blocks. In the same period of 2022, a total of 17 development wells were drilled in the Quifa, Cajua, CPE-6, and Cubiro blocks, and one injector well was drilled in the Quifa block. For the year ended December 31, 2023, 65 development wells (including two injector wells) were drilled in the Quifa, CPE-6, Cajua and Cubiro blocks. This compares to a total of 67 development wells drilled in the Quifa, CPE-6, Cubiro, El Dificil, and Guatiquia blocks during 2022. During 2023, development drilling was lower due to a change in the mix of wells drilled, resulting from a higher focus on our heavy oil assets.

Development facilities. During the three months and year ended December 31, 2023, development facilities increased substantially from $21.0 million to $26.7 million, and from $48.2 million to $78.9 million, respectively, compared to the same periods of 2022. This increase is mainly related to new flow lines, the expansion and improvement of the development facilities in CPE-6 block, which expansion initiative doubled the water-handling capacity from 120,000 to 240,000 bwpd. In addition, the

Company invested in new flow lines in the Quifa block to integrate with SAARA project, and expansion of gas compression facilities in VIM-1 block.

Colombia and Ecuador Exploration. During the three months and year ended December 31, 2023, expenditures related to exploration activities decrease by $27.4 million and $17.3 million, respectively, compared to same periods of 2022. During the three months ended December 31, 2023, one exploration well, Perico Norte-A4, was drilled in Ecuador. For the year ended December 31, 2023, a total of seven exploration wells were drilled in Ecuador (three wells), VIM-22 (three wells) and Cubiro (one well). In addition, 3D seismic data was acquired in the Llanos-99 block. During the year ended December 31, 2022, five exploration wells were drilled in Ecuador (two wells in the Espejo block and three wells in the Perico block), and two exploration wells were drilled in Colombia (one well in the CPE-6 block and one well in the La Creciente block).

Colombia. The Company's exploration focus remains on the Lower Magdalena Valley and Llanos Basins in Colombia. During the fourth quarter of 2023, the Company finished the processing of 163 square kilometers of 3D seismic data, corresponding to the Llanos 99 block, confirmed one of the exploratory opportunities formerly identified with a 2D survey (LLA99 West), and also identified multiple smaller traps to the northeast of the 2D survey. The Company is working on pre-seismic and pre-drilling activities related to social and environmental studies in the Llanos-119, LLA99, CPE-6 and VIM-46 blocks. Additionally, during the year ended December 31, 2023, the Company received approval from the ANH to terminate by mutual agreement the CR-1 and COR-24 block commitments, which reduced exploratory commitments by $11.1 million.

Ecuador. The Perico Norte A-4 well, in the Perico block (Frontera 50% W.I. and operator), was spudded on October 8, 2023 and was completed on November 4, 2023 , and reached a total depth of 11,433 ft measured depth ("**MD**") on October 23, 2023. Petrophysical interpretation identified a net pay in the lower U Sand of 49 ft. The well has an average production of 1,000 bbl/d, approximately (29.4 API), with 0.3% BSW. In addition, during the year 2023, the Perico Centro-1 well (formerly Jandiayacu-1) was spudded on August 22, 2023, finding oil in three intervals, reached total depth of 11,198 ft MD on September 11, 2023. The well was completed, and an initial test showed an average production of 800 bbl/d, approximately, (28 API) with 1% BSW. The Perico Norte A-3 (formerly Yin-2) appraisal well was drilled in July 2023, discovering 48 feet of net pay in the Lower U sand and 24 feet net pay in the Hollin main formation. At the Perico Norte 1 (formerly Jandaya-1), Perico Sur B-1 (formerly Tui-1) and Perico Norte A-2 (formerly Yin-1) exploration wells, the Company is conducting long-term testing and is preparing environmental impact assessments in order to obtain a production environmental license. Currently, the Company has completed the four wells required as part of its exploration commitment on the Perico block.

At the Espejo block (Frontera holds a 50% W.I. and is a non-operator), as agreed by the Company's partner in the Espejo block, the two pending committed exploratory wells will be drilled, targeting one opportunity for Lower U Sand in the southern area and one opportunity for M1 Sand in the central area of the block.

Other

Other capital expenditures for the three months and year ended December 31, 2023, were $24.7 million and $39.2 million, respectively, mainly related to investments in the CPE-6 solar plant project, investments in Puerto Bahia, the Sabanero block policy, and the SAARA project .

Guyana exploration and infrastructure. During the three months and year ended December 31, 2023, Guyana exploration and infrastructure expenditures were $0.5 million and $157.3 million, respectively, compared to $17.5 million and $103.5 million during the same periods of 2022, mainly related to the following:

Exploration. The Company and its majority-owned subsidiary and Joint Venture partner, CGX, in the Petroleum Prospecting License for the Corentyne block offshore Guyana (the "**PPL**"), announced the positive drilling results at Wei-1 and updated interpretation of Kawa-1 well results, based on evaluations by two independent, third-party resource valuators, effective as of October 30, 2023 and November 30, 2023, respectively, and each prepared in compliance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook. Based on such evaluations, the Joint Venture believes that approximately 514-628 mmboe PMean unrisked gross prospective resources are present in multiple Maastrichtian horizons in the northern portion of the Corentyne block, approximately 200 kilometers offshore from Georgetown, Guyana. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. See "Further Disclosures".

The Joint Venture also believes there is potential for additional prospective resources from the horizons of Campanian and Santonian ages.

The Joint Venture is in the process of concluding the exploration phase of the project. Typical deepwater developments can range from four to seven years from discovery to first oil. The total cost of a typical deepwater project varies greatly depending on several factors that challenge each project. Deepwater projects are more complicated developments that require appraisal drilling and conceptual modeling before a final investment decision ("**FID**") can be made. After FID has been made, it takes approximately three years to complete detailed design/construction/commissioning, prior to the well commencing production.

Based on results from the Wei-1 and Kawa-1 wells, the Joint Venture retained Subsea Integration Alliance, a Subsea 7 – Schlumberger joint venture, to complete a conceptual field development plan for the northern portion of the Corentyne block, including subsea architecture, development well planning, production and export facilities and other considerations. As is normal course following discoveries such as those made by the Joint Venture at Wei-1 and Kawa-1 wells, additional appraisal activities will be required before commerciality can be determined. The Joint Venture currently holds a 100% working interest in the Corentyne block.

The Company's investment in the Wei-1 well during the three months and year ended December 31, 2023 was $0.4 million and $155.4 million, respectively.

Infrastructure. CGX, Frontera's majority-owned subsidiary, is building a multifunctional port facility adjacent to Crab Island on the eastern bank of the Berbice River in Guyana, 4.8 kilometres from the Atlantic Ocean, called the Berbice Deep Water Port, which will serve as an offshore supply base and a multi-purpose terminal (the "**Guyana Port Project**"). The land for the Guyana Port Project is leased until 2060 and is renewable for an additional term of 50 years. During the three months and year ended December 31, 2023, the Company invested on infrastructure $Nil and $1.9 million, respectively, related to the Guyana Port Project's trestle.

Selected Quarterly Information

		2023				2022			
Operational and financial results		**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Heavy crude oil production	(bbl/d)	23,002	24,097	24,051	22,270	22,144	20,945	21,455	21,214
Light and medium crude oil combined production	(bbl/d)	13,795	13,964	15,188	16,518	17,073	17,428	17,348	17,248
Total crude oil production	(bbl/d)	36,797	38,061	39,239	38,788	39,217	38,373	38,803	38,462
Conventional natural gas production	(mcf/d)	4,760	5,250	5,626	8,590	9,097	9,969	10,374	9,530
Natural gas liquids production	(boe/d)	1,635	1,820	1,823	1,291	993	911	963	966
Total production	(boe/d)	39,267	40,802	42,049	41,586	41,806	41,033	41,586	41,100
Sales volumes, net of purchases	(boe/d)	34,449	35,289	35,799	30,424	34,323	36,660	33,273	28,211
Brent price reference	($/bbl)	82.85	85.92	77.73	82.10	88.63	97.70	111.98	97.90
Oil and gas sales, net of purchases (1) (3)	($/boe)	75.76	78.48	67.91	69.07	82.60	90.40	102.80	90.01
Premiums paid on oil price risk management contracts (2)	($/boe)	(0.69)	(0.59)	(0.80)	(1.16)	(1.32)	(1.30)	(1.15)	(1.06)
Royalties (2)	($/boe)	(1.79)	(3.76)	(3.02)	(3.36)	(6.04)	(7.23)	(10.57)	(7.58)
Net sales realized price (1) (3)	($/boe)	73.28	74.13	64.09	64.55	75.24	81.87	91.08	81.37
Production costs (excluding energy cost), net of realized FX hedge impact (2) (3)	($/boe)	(9.69)	(8.82)	(8.45)	(8.12)	(8.48)	(8.30)	(9.25)	(9.13)
Energy costs, net of realized FX hedge impact (2) (3)	($/boe)	(5.06)	(5.04)	(3.94)	(3.95)	(3.08)	(2.90)	(3.26)	(4.21)
Transportation costs, net of realized FX hedge impact(2) (3)	($/boe)	(11.02)	(11.73)	(10.89)	(11.20)	(10.55)	(10.70)	(10.80)	(9.72)
Operating netback per boe (1)	($/boe)	47.51	48.54	40.81	41.28	53.13	59.97	67.77	58.31
Revenue	($M)	299,501	308,867	289,869	250,366	317,568	354,548	344,015	254,627
Net income (loss) (5)	($M)	92,038	32,582	80,207	(11,330)	197,796	(26,893)	13,484	102,228
Per share – basic ($)	($)	1.08	0.38	0.94	(0.13)	2.29	(0.30)	0.14	1.08
Per share – diluted ($)	($)	1.04	0.37	0.91	(0.13)	2.25	(0.30)	0.14	1.05
General and administrative	($M)	16,891	11,925	12,422	12,669	12,761	12,549	15,097	14,656
Operating EBITDA (4)	($M)	121,036	137,800	116,461	91,922	144,994	173,207	190,678	132,998
Capital expenditures (4)	($M)	82,292	74,130	154,860	131,452	134,165	76,018	93,835	113,545

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.
(3) 2022 prior period figures are different compared with those previously reported as a result of the exclusion of ProAgrollanos' revenues and, production and transportation costs.
(4) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 27 for further details.
(5) Refers to net income (loss) attributable to equity holders of the Company.

Over the past eight quarters, the Company's sales have fluctuated due to changes in production, movement in Brent benchmark prices, timing of cargo shipments, and fluctuations in crude oil price differentials. Production volumes have increased since the first quarter of 2022 until the second quarter 2023, mainly due to a successful drilling campaign, the investment in water handling facilities in Colombia, specifically in the Quifa and CPE-6 blocks, and the start of oil production in Ecuador. However, during the third quarter of 2023, there was a decrease in production mainly due to maintenance of water disposal facilities at the Quifa block, which was completed during the fourth quarter of 2022. In addition, there was a decreased in production during the last two quarters of 2023, due to the return of the Neiva block following the completion of the block's production contract and the relinquishment of the La Creciente block. During the last year, transportation costs have increased, mainly due to the initiation of the new pipeline take-or-pay contract with Bicentenario that commenced in 2022 and the annual increase of transportation tariffs. Energy costs increased primarily as a result of higher market electricity prices. In addition, production costs (excluding energy cost) have also fluctuated mainly due to 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 also impacted most significantly by the recognition and derecognition of deferred income taxes and expenses or reversal of impairment of oil and gas and exploration and evaluation assets, DD&A, foreign exchange gain or losses and gain or losses from risk management contracts that fluctuate mainly with changes in hedging strategies and crude oil benchmark forward prices. Please refer to the Company's previously filed annual and interim management's discussion and analysis available on SEDAR+ at www.sedarplus.ca for further information regarding changes in prior quarters.

Selected Annual Information

	As at and for the year ended December 31		
($M, except as noted)	**2023**	**2022**	**2021**
Revenue	1,148,603	1,270,758	894,061
Net income[(1)]	193,497	286,615	628,133
Per share – basic ($)	2.27	3.16	6.50
Per share – diluted ($)	2.19	3.08	6.29
Cash and cash equivalents	159,673	289,845	257,504
Total assets	3,016,280	2,737,239	2,611,080
Total non-current liabilities	637,586	530,194	566,144
Total liabilities	1,182,287	1,148,035	1,162,189

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

Revenue decreased to $1.1 billion in 2023 from $1.3 billion in 2022, and increased from $0.9 billion in 2021. The revenue decrease and increase between 2023 and 2021 was mainly due to changes in the Brent benchmark oil prices.

Net income, attributable to equity holders of the Company, for 2023 was $193.5 million, compared to a net income, attributable to equity holders of the Company of $286.6 million in 2022, and a net income of $628.1 million in 2021, mainly as a result of recognition and derecognition of deferred income taxes and impairment or reversal of impairment of oil and gas assets, and variances in operating EBITDA.

Total assets increased to $3.0 billion in 2023 from $2.7 billion in 2022, and increased from $2.6 billion in 2021, mainly as a result of the increase of investment activities during 2023, and reversal of impairment in oil and gas properties in 2022 and 2021.

Cash and cash equivalents decreased to $159.7 million in 2023 from $289.8 million in 2022, and $257.5 million in 2021, as a result of a variances in cash flows from operations mainly due to changes in the Brent benchmark oil price, and high exploration investment activities, particularly in Guyana.

Infrastructure Colombia [(1)]

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

[(1)] According to Guidance 2024, Colombia Infrastructure will also include investments related to SAARA Reverse Osmosis Water Treatment Facility and Proagrollanos.

The Company's Infrastructure Colombia Segment includes the following:

Asset	Description	Interest [(1)]	Accounting Method
Puerto Bahia	Bulk liquid storage and import-export terminal	99.97% interest in Puerto Bahia	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/day	100% interest in PIL (which holds a 35% interest in the ODL Pipeline)	Equity Method [(2)]

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

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

Performance Highlights

		Q4 2023	Q3 2023	Q4 2022	Year ended December 31 2023	Year ended December 31 2022
Operational and IFRS Results						
Volumes pumped at oil pipeline facility	(bbl/d)	252,810	251,988	222,855	243,617	213,059
Volumes throughput at port liquids facility	(bbl/d)	52,754	53,586	66,717	60,718	62,422
Volumes RORO at port general cargo facility	(Units)	15,794	25,346	35,596	101,439	133,736
Volumes at port Break Bulk Volumes	(Tons/m3)	23,230	43,534	17,291	82,580	103,178
Segment income	($M)	16,956	17,251	14,934	69,349	54,329
Segment cash flow from operating activities	($M)	7,639	19,168	12,796	54,516	46,898
Non IFRS Results [1]						
Adjusted Infrastructure Revenues	($M)	43,951	43,774	38,355	169,142	113,583
Adjusted Infrastructure EBITDA	($M)	30,691	29,878	26,558	119,821	74,893
Adjusted Infrastructure Cash	($M)	67,836	54,687	49,165	67,836	49,165
Adjusted Infrastructure Debt	($M)	111,423	123,778	116,173	111,423	116,173
Capital Expenditures Infrastructure Colombia	($M)	7,867	2,341	718	11,407	2,573

[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 27.

Infrastructure Colombia (formerly Midstream Colombia) Segment Results

The 2023 Annual Consolidated Financial Statements include the following amounts relating to the Infrastructure Colombia:

	Three months ended December 31		Year ended December 31	
($M)	**2023**	**2022**	**2023**	**2022**
Revenue	10,954	12,209	48,263	46,883
Liquids port facility	7,591	6,750	32,082	29,550
FEC liquids port facility	1,719	2,096	7,379	7,261
Third party liquids port facility	5,872	4,654	24,703	22,289
General cargo	3,363	5,459	16,181	17,333
Costs	(5,864)	(5,685)	(23,133)	(21,376)
General administrative expenses	(951)	(1,376)	(5,148)	(5,375)
Depletion, depreciation and amortization	(1,570)	(1,233)	(5,562)	(5,617)
Restructuring, severance and other costs	(446)	(1,116)	(1,547)	(2,229)
Puerto Bahia income from operations	**2,123**	**2,799**	**12,873**	**12,286**
Share of Income from associates ODL	14,833	12,135	56,476	42,043
Segment income	**16,956**	**14,934**	**69,349**	**54,329**
Segment cash flow from operating activities	7,639	12,796	54,516	46,898

The Company's Infrastructure Colombia Segment income increased by $2.0 million and $15.0 million for the three months and year ended December 31, 2023, respectively, compared with the same periods of 2022, mainly due to the increase in share of income from associates ODL which increased by $2.7 million and $14.4 million, respectively, driven by stronger crude oil volumes from the Cano Sur and Rubiales blocks. In addition, for the three months ended December 31, 2023, Puerto Bahia revenues decreased $1.3 million, compared with the same period of 2022, mainly due to lower volumes sold of general cargo. For the year ended December 31, 2023, Puerto Bahia revenues increased $1.4 million compared with the same period of 2022, the increase was primarily due to the higher liquids terminal revenues by $2.5 million, and a decrease by $1.2 million in general cargo terminal revenues due to lower volumes of cargo handled.

Cash provided by operating activities of the Infrastructure Colombia Segment for three months ended December 31, 2023 was $7.6 million, compared to $12.8 million, in the same period of 2022. The decrease was mainly due to no payment of dividends during the fourth quarter of 2023, while there was a dividend payments on fourth quarter of 2022. For year ended December 31, 2023, cash provided by operating activities of the Infrastructure Colombia Segment was $54.5 million, compared to $46.9 million, in the same period of 2022, variations was mainly due to fluctuations in working capital.

Non-IFRS Results of Infrastructure Colombia (formerly Midstream Colombia) Segment

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

	Three months ended December 31		Year ended December 31	
($M)	**2023**	**2022**	**2023**	**2022**
Adjusted Infrastructure Revenue[1]	43,951	38,355	169,142	113,583
Adjusted Infrastructure Operating Costs[1]	(10,287)	(8,950)	(38,216)	(29,720)
Adjusted Infrastructure General and Administrative[1]	(2,973)	(2,847)	(11,105)	(8,970)
Adjusted Infrastructure EBITDA[1]	**30,691**	**26,558**	**119,821**	**74,893**

[1] Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 27.

The Adjusted Infrastructure EBITDA for the three months ended December 31, 2023 increased by $4.1 million compared with the same period of 2022, mainly due to as a result of higher revenues.

For the year ended December 31, 2023 the Adjusted Infrastructure EBITDA increased by $44.9 million, compared with the same period of 2022, as a result of the increase from 59.93% to 100.00% in PIL at the end of September 2022, partially offset by lower throughput volumes at the liquids port facility.

ODL Pipeline

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

For the three months and year ended December 31, 2023, ODL generated $75.9 million and $285.3 million of EBITDA, respectively, and $42.4 million and $161.4 million of net income, respectively. The ODL results are consolidated through the equity method in the Company's 2023 Annual Consolidated Financial Statements as "Share of income from associates".

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

	Three months ended December 31		Year ended December 31	
($M)	**2023**	**2022**	**2023**	**2022**
Revenue	94,277	74,702	345,370	268,040
FEC revenue (billed units)	7,776	6,977	30,525	23,313
Third party revenues	86,501	67,725	314,845	244,727
Costs	(12,637)	(9,329)	(43,094)	(33,541)
General administrative expenses	(5,776)	(4,204)	(17,019)	(14,330)
Depletion, depreciation and amortization	(8,188)	(6,122)	(28,902)	(29,666)
Other non-operating expense	(2,644)	(1,083)	(8,275)	(5,055)
Income tax	(22,653)	(19,293)	(86,720)	(65,324)
ODL Net Income	**42,379**	**34,671**	**161,360**	**120,124**

	December 31	
($M)	**2023**	**2022**
ODL debt	45,147	37,368
ODL cash and cash equivalents	131,839	65,004

The following table shows the volumes pumped per injection point:

(bbl/d)	Three months ended December 31 2023	Three months ended December 31 2022	Year ended December 31 2023	Year ended December 31 2022
At Rubiales Station	173,888	150,634	169,701	140,393
At Jagüey and Palmeras Station	78,922	72,221	73,916	72,666
Total	**252,810**	**222,855**	**243,617**	**213,059**

The following table shows the volumes received per block:

(bbl/d)	Three months ended December 31 2023	Three months ended December 31 2022	Year ended December 31 2023	Year ended December 31 2022
Rubiales	106,817	104,407	107,755	100,046
Quifa	28,534	27,691	29,392	27,235
CPE-6	4,094	3,188	2,645	1,866
Other blocks	96,897	82,872	87,968	78,633
Total	**236,342**	**218,158**	**227,760**	**207,780**

For the three months and year ended December 31, 2023, the Company recognized $14.8 million and $56.5 million, respectively, as its share of income from ODL, which was $2.7 million and $14.4 million higher than the same periods of 2022, primarily due to the increase in volumes received and transported and the impact of foreign exchange fluctuations. During the three months and year ended December 31, 2023, the Company recognized gross dividends of $Nil and $37.0 million, respectively, (2022: $Nil and $40.5 million, respectively) and recognized a return of capital of $5.1 million and $10.3 million, respectively, (2022: $Nil and $19.7 million, respectively).

On October 31, 2023, ODL's shareholders approved a return of capital to the shareholders of approximately $14.8 million (equivalent to 30% of the outstanding capital contributions) payable on November 2, 2023. As a result, PIL received a $5.1 million cash payment from ODL.

Puerto Bahia

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

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

(bbl/d)	Three months ended December 31 2023	Three months ended December 31 2022	Year ended December 31 2023	Year ended December 31 2022
FEC volumes	11,971	13,575	12,863	13,292
Third party volumes	40,783	53,142	47,855	49,130
Total	**52,754**	**66,717**	**60,718**	**62,422**

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

		Three months ended December 31 2023	Three months ended December 31 2022	Year ended December 31 2023	Year ended December 31 2022
RORO	units [1]	15,794	35,596	101,439	133,736
	dwell time in days [2]	82	32	56	26
Break Bulk Volumes	tons/m3 [3]	23,230	17,291	82,580	103,178
	dwell time in days [2]	145	45	107	45

[1] Carry wheeled cargo, mainly corresponds to cars imported to Colombia.
[2] Dwell time refers to the time spent by the units within the general cargo port facility.
[3] Other types of cargo different from wheeled cargo.

For the three months and year ended December 31, 2023, Puerto Bahia has generated $2.1 million and $12.9 million of segment income from operations, respectively (2022: $2.8 million and $12.3 million, respectively), and $4.1 million and $20.0 million of EBITDA, respectively (2022: $5.1 million and $20.1 million, respectively).

During the third quarter of 2023, Puerto Bahia and Reficar entered into a connection agreement to connect Puerto Bahia's port facility and the Cartagena refinery via a 6.8-kilometre, 18-inch bi-directional hydrocarbon flow line. Once in service, the connection shall enable the continuous transport of crude oil and other hydrocarbons between Puerto Bahía's port facility and the Cartagena Refinery. The connection will be built, operated and maintained by Puerto Bahia and will have a capacity of up to 84,000 barrels per day. The connection will be capable of handling imported and domestically produced crude. The construction phase of the connection started during the fourth quarter of 2023, Frontera anticipates breaking ground on the connection construction during the first quarter of 2024 and connection start-up by the end of 2024. Frontera has secured an additional $30 million in committed funding, subject to certain conditions precedent, in connection with this project from its existing group of lenders led by Macquarie Group.

In addition, capital expenditures for the Infrastructure Colombia for the three months and year ended December 31, 2023, was $7.9 million and $11.4 million, respectively, increasing $7.1 million and $8.8 million, respectively, for the same periods in 2022, mainly due to investments in equipment and locations of the container cargo infrastructure, major maintenance of the tanks, and certain capital expenditures related to the initiation of the Reficar connection.

Non-IFRS and Other Financial Measures

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

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

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

Non-IFRS Financial Measures

Operating EBITDA

EBITDA is a commonly used non-IFRS financial measure that adjusts net income as reported under IFRS to exclude the effects of income taxes, finance income and expenses, and DD&A. Operating EBITDA is a non-IFRS financial measure that represents the operating results of the Company's primary business, excluding the following items: restructuring, severance and other costs, post-termination obligation, 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:

($M)	Three months ended December 31		Year ended December 31	
	2023	2022	2023	2022
Net income [1]	92,038	197,796	193,497	286,615
Finance income	(2,270)	(2,323)	(9,984)	(5,505)
Finance expenses	16,865	14,239	64,185	52,991
Income tax (recovery) expense	(39,007)	68,599	4,130	249,275
Depletion, depreciation and amortization	68,411	49,198	278,269	195,419
Minimum work commitment paid	358	—	358	919
(Recovery) expense of asset retirement obligation	(1,621)	3,235	(25,622)	(1,823)
Expenses (recovery) of impairment	1,417	(211,130)	25,236	(205,833)
Post-termination obligation	11,160	5,229	18,814	12,299
Share-based compensation	(745)	3,213	96	7,777
Restructuring, severance and other costs	3,744	2,624	8,548	4,463
Share of income from associates	(14,833)	(12,135)	(56,476)	(42,043)
Foreign exchange (income) loss	(2,724)	28,230	(12,275)	76,413
Other (income) loss	(4,554)	5,381	(8,936)	10,800
Unrealized gain on risk management contracts	(7,000)	(6,600)	(11,880)	(4,310)
Non-controlling interests	(203)	(562)	(741)	4,420
Operating EBITDA	**121,036**	**144,994**	**467,219**	**641,877**

[1] Refers to net income attributable to equity holders of the Company.

Capital expenditures

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

	Three months ended December 31		Year ended December 31	
	2023	2022	2023	2022
Consolidated Statements of Cash Flows				
Additions to oil and gas properties, infrastructure port, and plant and equipment	70,294	85,074	241,185	261,144
Additions to exploration and evaluation assets	5,171	46,281	195,210	154,516
Total additions in Consolidated Statements of Cash Flows	**75,465**	**131,355**	**436,395**	**415,660**
Non-cash adjustments [1]	6,827	2,810	6,339	1,903
Total Capital Expenditures	**82,292**	**134,165**	**442,734**	**417,563**
Capital Expenditures attributable to Infrastructure Colombia Segment	7,867	718	11,407	2,573
Capital Expenditures attributable to other segments different to Infrastructure Colombia Segment	74,425	133,447	431,327	414,990
Total Capital Expenditure	**82,292**	**134,165**	**442,734**	**417,563**

[1] Related to material inventory movements, capitalized non-cash items and other adjustments. In addition, CPE-6 solar plant project is included as part of the Capital Expenditures, according to Guidance 2023. In the Consolidated Statements of Cash Flows is considered as non-cash adjustment.

Infrastructure Colombia (formerly Midstream Colombia) Calculations

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

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

	Three months ended December 31		Year ended December 31	
($M) [1]	**2023**	**2022**	**2023**	**2022**
Revenue Infrastructure Colombia Segment	10,954	12,209	48,263	46,883
Revenue from ODL	94,277	74,702	345,370	268,040
Direct participation interest in the ODL [1]	35.00 %	35.00 %	35.00 %	35.00 %
Equity adjustment participation of ODL [2]	32,997	26,146	120,879	66,700
Adjusted Infrastructure Revenues	**43,951**	**38,355**	**169,142**	**113,583**
Operating cost Infrastructure Colombia Segment	(5,864)	(5,685)	(23,133)	(21,376)
Operating Cost from ODL	(12,637)	(9,329)	(43,094)	(33,541)
Direct participation interest in the ODL [1]	35.00 %	35.00 %	35.00 %	35.00 %
Equity adjustment participation of ODL [2]	(4,423)	(3,265)	(15,083)	(8,344)
Adjusted Infrastructure Operating Costs	**(10,287)**	**(8,950)**	**(38,216)**	**(29,720)**
General and administrative Infrastructure Colombia Segment	(951)	(1,376)	(5,148)	(5,375)
General and administrative from ODL	(5,776)	(4,204)	(17,019)	(14,330)
Direct participation interest in the ODL [1]	35.00 %	35.00 %	35.00 %	35.00 %
Equity adjustment participation of ODL [2]	(2,022)	(1,471)	(5,957)	(3,595)
Adjusted Infrastructure General and Administrative	**(2,973)**	**(2,847)**	**(11,105)**	**(8,970)**

[1] On September 15, 2022, the Company acquired the remaining 40.07% interest it did not already own of PIL, increasing its ownership interest to 100%, and have a direct participation in ODL by 35%.

[2] Revenues and expenses related to the ODL are accounted for using the equity method described in the Note 15 of the 2023 Annual Consolidated Financial Statements.

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

	December 31	
($M) [1]	**2023**	**2022**
Cash and cash equivalents - unrestricted	159,673	289,845
Cash and cash equivalents of Non-Infrastructure Colombia Segment's	(137,981)	(263,431)
Total Cash Infrastructure Colombia Segment	21,692	26,414
Cash and cash equivalent from ODL	131,839	65,004
Direct participating interest in the ODL	35.00 %	35.00 %
Equity adjustment participation of ODL [1]	46,144	22,751
Adjusted Infrastructure Cash	**67,836**	**49,165**
Long-term debt	517,604	508,457
Debt of Non-Infrastructure Colombia Segment's	(421,982)	(405,363)
Total Debt	95,622	103,094
Debt from ODL	45,147	37,368
Direct participating interest in the ODL	35.00 %	35.00 %
Equity adjustment participation of ODL [1]	15,801	13,079
Adjusted Infrastructure Debt	**111,423**	**116,173**

[1] 35% ODL participation is accounted using the equity method in the 2023 Annual Consolidated Financial Statements, Cash and cash equivalents, and Debt related to the ODL are embedded in the value of the Investment in Associates.

Adjusted Infrastructure EBITDA

The Adjusted Infrastructure EBITDA is a non-IFRS financial measure used to assist in measuring the operating results of the Infrastructure Colombia (formerly Midstream Colombia) Segment business. Refer to the Calculation in "Non-IFRS Results of Infrastructure Segment" section on page 25.

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 purchases is helpful to understand the Company's sales performance based on the net realized proceeds from its own production, the cost of which is partially recovered when the blended product is sold. Net sales also exclude sales from port services, as it is not considered part of the oil and gas segment. Refer to the reconciliation in the "Sales" section on page 14.

Operating Netback and Oil and Gas Sales, Net of Purchases

Operating netback is a non-IFRS financial measure and operating netback per boe is a non-IFRS ratio. Operating netback per boe is used to assess the net margin of the Company's production after subtracting all costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and gas industry to analyze financial and operating performance expressed as profit per barrel and is an indicator of how efficient the Company is at extracting and selling its product. For netback purposes, the Company removes the effects of any trading activities and results from its Infrastructure Colombia segment from the per barrel metrics and adds the effects attributable to transportation and operating costs of any realized gain or loss on foreign exchange risk management contracts. Refer to the reconciliation in the "Operating Netback" section on page 13.

The following is a description of each component of the Company's operating netback and how it is calculated. Oil and gas sales, net of purchases, is a non-IFRS financial measure that is calculated using oil and gas sales less the cost of volumes purchased from third parties including its transportation and refining costs. Oil and gas sales, net of purchases per boe, is a non-IFRS ratio that is calculated using oil and gas sales, net of purchases, divided by the total sales volumes, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2023	2022	2023	2022
Produced crude oil and gas sales ($M) (1)	247,134	262,430	932,977	1,121,344
Purchased crude oil and products sales ($M)	48,324	63,375	208,069	201,534
(-) Cost of purchases ($M) (2)	(55,353)	(64,981)	(235,797)	(217,375)
Oil and gas sales, net of purchases ($M)	**240,105**	**260,824**	**905,249**	**1,105,503**
Sales volumes, net of purchases - (boe)	3,169,346	3,157,716	12,411,825	12,096,465
Oil and gas sales, net of purchases ($/boe)	75.76	82.60	72.93	91.39

(1) Excludes sales from port services as they are not part of the oil and gas segment. For further information, refer to the "Infrastructure Colombia (formerly Midstream Colombia)" section on page 23.
(2) Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining costs.

Non-IFRS Ratios

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

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

	Three months ended December 31		Year ended December 31	
	2023	2022	2023	2022
Produced crude oil sales ($M)	245,123	258,365	921,573	1,104,808
Purchased crude oil and products sales ($M)	48,324	63,375	208,069	201,534
(-) Cost of purchases ($M)	(55,353)	(64,981)	(235,797)	(217,375)
Conventional natural gas sales ($M)	2,011	4,065	11,404	16,536
Oil and gas sales, net of purchases ($M) (1)	**240,105**	**260,824**	**905,249**	**1,105,503**
Sales volumes, net of purchases - (bbl)	3,118,407	3,003,102	12,042,019	11,456,143
Conventional natural gas sales volumes - (mcf)	289,993	881,402	2,107,707	3,655,102
Realized oil price, net of purchases ($/bbl)	76.35	85.50	74.23	95.06
Realized conventional natural gas price ($/mcf)	6.93	4.61	5.41	4.52

(1) Non-IFRS financial measure.

Net sales realized price

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

	Three months ended December 31		Year ended December 31	
	2023	**2022**	**2023**	**2022**
Oil and gas sales, net of purchases ($M) [1]	240,105	260,824	905,249	1,105,503
(-) Premiums paid on oil price risk management contracts ($M)	(2,198)	(4,182)	(9,903)	(14,733)
(-) Royalties ($M)	(5,683)	(19,076)	(36,949)	(94,709)
Net sales ($M)	**232,224**	**237,566**	**858,397**	**996,061**
Sales volumes, net of purchases - (boe)	3,169,346	3,157,716	12,411,825	12,096,465
Oil and gas sales, net of purchases ($/boe)	75.76	82.60	72.93	91.39
Premiums paid on oil price risk management contracts [2]	(0.69)	(1.32)	(0.80)	(1.22)
Royalties ($/boe) [2]	(1.79)	(6.04)	(2.98)	(7.83)
Net sales realized price ($/boe)	**73.28**	**75.24**	**69.15**	**82.34**

[1] Non-IFRS financial measure.
[2] Supplementary financial measure.

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

Production costs (excluding energy cost), 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 cost), net of realized FX hedge impact divided by production (before royalties). A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2023	**2022**	**2023**	**2022**
Production costs (excluding energy cost) ($M)	37,122	32,628	139,917	132,758
(-) Realized gain on FX hedge attributable to production costs (excluding energy cost) ($M) [1]	(2,101)	—	(9,075)	—
Production costs (excluding energy cost), net of realized FX hedge impact ($M) [2]	35,021	32,628	130,842	132,758
Production (boe)	3,612,564	3,846,152	14,935,435	15,104,430
Production costs (excluding energy cost), net of realized FX hedge impact ($/boe)	9.69	8.48	8.76	8.79

[1] See "Gain (Loss) on Risk Management Contracts" on page 19.
[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 described 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 cost, net of realized FX hedge impact per boe is a non-IFRS ratio that is calculated using e cost, net of realized FX hedge impact divided by production (before royalties). A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2023	**2022**	**2023**	**2022**
Energy costs ($M)	19,005	11,837	69,924	50,644
(-) Realized gain on FX hedge attributable to energy costs ($M) [1]	(738)	—	(2,900)	—
Energy costs, net of realized FX hedge impact ($M) [2]	18,267	11,837	67,024	50,644
Production (boe)	3,612,564	3,846,152	14,935,435	15,104,430
Energy costs, net of realized FX hedge impact ($/boe)	5.06	3.08	4.49	3.35

[1] See "Gain (Loss) on Risk Management Contracts" on page 19.
[2] Non-IFRS financial measure.

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

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

	Three months ended December 31		Year ended December 31	
	2023	**2022**	**2023**	**2022**
Transportation costs ($M)	34,750	35,660	151,416	137,554
(-) Realized gain on FX hedge attributable to transportation costs ($M) [1]	(753)	—	(3,264)	—
Transportation costs, net of realized FX hedge impact ($M) [2]	33,997	35,660	148,152	137,554
Net production (boe)	3,084,338	3,380,908	13,210,810	13,175,770
Transportation costs, net of realized FX hedge impact ($/boe)	11.02	10.55	11.21	10.44

(1) See “Gain (Loss) on Risk Management Contracts” on page 19.

(2) Non-IFRS financial measure.

Supplementary Financial Measures

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

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

Royalties per boe

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

NCIB 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 during the period. It is calculated using the total amount of common shares repurchased in U.S. dollars divided by the number of Common Shares repurchased.

Capital Management Measures

Net working capital

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

Restricted cash short- and long-term

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

Total cash

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

Total debt and lease liabilities

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

6. LIQUIDITY AND CAPITAL RESOURCES

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

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

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

As of December 31, 2023, the Company had a total cash balance of $190.0 million (including $30.3 million in restricted cash), which is $123.1 million lower than December 31, 2022. For the year ended December 31, 2023, the Company generated $411.8 million of cash from operations, which were used to fund cash outflows of $484.3 million for capital expenditures and other investing activities. For year ended December 31, 2023, financing activities generated net outflows of $62.7 million, respectively, as a result of $114.9 million from net proceeds from the PIL Loan Facility (as defined below), $20.0 million from the Citibank Working Capital Loan (as defined below) and $18.2 million from the Bancolombia Working Capital Loan, $106.2 million toward repayment of the 2025 Puerto Bahia Debt, $8.7 million to constitute a debt services reserve account for the PIL Loan Facility, $46.6 million of interest from borrowings, loans and other financing charges, $42.7 million toward the Citibank Working Capital Loan, PIL Loan Facility and PetroSud Debt principal payments, $5.9 million in Common Shares purchased under the 2022 NCIB, and $4.5 million in lease payments. As a consequence, the Company's net working capital[(1)] was improved by $47.8 million, going from a deficit of $109.6 million at year-end 2022, to a deficit of $61.9 million as at December 2023.

As at December 31, 2023, the net working capital was negative due to lower a cash balance as a result of investments in capital expenditures and because changes to Colombian tax rules, effective since March 1, 2023, increased the self-withholding tax rates related to crude oil extraction and exportation from 4.6% to 9.9%.

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

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. As of December 31, 2023, the main components of restricted cash were long-term abandonment funds as required by the ANH, and restricted funds related to the PIL Loan Facility. Abandonment funds will satisfy abandonment obligations and are expected to be released in the long term as assets are abandoned. Abandonment funding requirements are updated annually. As of December 31, 2023, the Company's restricted cash position was $30.3 million, an increase of $7.1 million from December 31, 2022, primarily due to the constitution of a debt service reserve account of the PIL Loan Facility.

The measures taken by the Company to manage its liquidity and capital resources are ongoing and the Company continues to look for additional opportunities to manage its costs and commitments. Based on the foregoing, including the expected impacts of such measures, the Company expects that unrestricted cash balances in conjunction with future cash flows from operations, available credit facilities, and alternate financing arrangements will be sufficient to support its working capital deficit, operational and capital requirements and other financial commitments. The Company intends to remain flexible and disciplined with respect to capital allocation decisions as the current commodity price environment evolves and can make additional changes to its business and operations as warranted. See also the "Risks and Uncertainties" section on page 41.

Unsecured Notes

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

[1] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 27.

Unsecured Notes Covenants

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

Under the terms of the 2028 Unsecured Notes, the Company (excluding the Unrestricted Subsidiaries) may, among other things, incur indebtedness provided that the consolidated debt to consolidated adjusted EBITDA ratio(1) is less than or equal to 3.25:1.0 and the consolidated fixed charge ratio(2) is greater than or equal to 2.25:1.0. In the event that these financial tests are not met, the Company may still incur indebtedness under certain permitted baskets, including an aggregate amount that does not exceed the higher of $100.0 million and 10% of consolidated net tangible assets(3). The 2028 Unsecured Notes also contain covenants that limit the Company's ability to, among other things, make certain investments or restricted payments, including dividends and share buybacks. As at December 31, 2023, the Company is in compliance with all such covenants.

Pursuant to requirements under the Indenture, the Company reports consolidated total indebtedness of $430,170,000 as of December 31, 2023, and for the twelve months ended as of December 31, 2023, consolidated adjusted EBITDA of $462,338,000 and consolidated interest expense of $39,132,000.

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

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

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

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

Consolidated Total Indebtedness and Net Debt

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

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

($M)		As at December 31 2023
Short-term and Long-term debt (1)	$	421,982
Total lease liabilities (2)		17,578
Risk management asset		(9,390)
Consolidated Total Indebtedness		**430,170**
(-) Cash and Cash Equivalents (3)		(112,078)
(=) Net Debt	**$**	**318,092**

(1) Excludes $95.6 million of long-term debt attributable to the Unrestricted Subsidiaries.

(2) Excludes $1.6 million of lease liabilities attributable to the Unrestricted Subsidiaries.

(3) Includes cash and cash equivalents attributable to the guarantors as of December 31, 2023, Frontera Colombia and the borrower (the Company) according to the Indenture.

Pipeline Investment Loan Facility

On March 27, 2023, PIL entered into a new credit agreement through which the lender provided a $120.0 million loan facility to PIL, secured by substantially all the assets and shares of PIL, the shares of Sociedad Portuaria Puerto Bahia S.A. ("**Puerto Bahía**") held by the Company and assets related to Puerto Bahia's liquids terminal, and is guaranteed by Frontera Bahía Holding Ltd., and Frontera ODL Holding Corp., the parent company of PIL (the **"PIL Loan Facility"**). The PIL Loan Facility is a 5-year credit facility, which matures in December 2027, pays semi-annually and amortizes during the term of the loan with a scheduled $45.0 million payment due upon maturity. The PIL Loan Facility has two tranches: a $100.0 million amortizing tranche that pays a

SOFR 6-month term plus margin of 7.25% per annum and a $20.0 million bullet maturity tranche that pays a fixed rate of 11.00% per annum. The conditions precedent to the PIL Loan Facility were fully satisfied and both tranches of the facility were funded on March 31, 2023. As at December 31, 2023, the carrying value of the PIL Loan Facility was $95.6 million (2022: $Nil).

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

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

Bancolombia Working Capital Loan

On October 24, 2023, the Company entered into a one-year working capital loan agreement with Bancolombia S.A. ("**Bancolombia**"), denominated in COP, with a principal amount of COP 75,000 million (equivalent to $18.2 million), maturing on October 29, 2024, with an interest rate of IBR[(1)] + 4.00%, payable quarterly (the "**Bancolombia Working Capital Loan**"). On October 30, 2023, Bancolombia disbursed the total amount of the loan. The main purpose of the Bancolombia Working Capital Loan is to fund general corporate purposes. In connection to the Bancolombia Working Capital Loan, the Company entered into a FX forward on October 31, 2023, hedging the original loan amount, at a forward rate of COP 4,386.17, and a maturity date on October 29, 2024.

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

PetroSud Loans

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

On March 15, 2019, and December 20, 2021, PetroSud entered into two credit agreements with Banco Davivienda S.A. ("**Banco Davivienda**") for a principal amount of $22.0 million and $2.8 million, respectively (the "**PetroSud Debt**"). Both agreements originally had a maturity date in December 2023. On September 15, 2023, Banco Davivienda approved an extension for the original $22.0 million loan, with an outstanding balance of $5.9 million as of September 30, 2023, extending the maturity date to June 2024. On December 13, 2023, Banco Davivienda approved an extension for the original $2.8 million loan, with an outstanding balance of $2.8 million as of December 31, 2023, extending the maturity date to June 2024. The PetroSud Debt bears interest at 3-month SOFR plus 5.30%, payable quarterly. The PetroSud Debt is secured by a trust agreement that receives 100% of PetroSud's sales and contemplates a debt service account for an amount equal to 100% of the next scheduled debt service, and a debt service reserve account for an amount of $2.9 million. As at December 31, 2023, the outstanding amount under the PetroSud Debt was $8.7 million. The PetroSud Debt is subject to certain covenants that require PetroSud to maintain a financial debt to EBITDA ratio of less than or equal to 3.50:1.0 and an operating free cash flow plus the debt reserve account balance to debt service ratio that is greater than or equal to 1.20:1.0. As of December 31, 2023, PetroSud was in compliance with all such covenants.

Citibank Working Capital Loan

On June 5, 2023, the Company entered into a working capital loan agreement with Citibank NY (the "**Citibank Working Capital Loan**"). The Citibank Working Capital Loan is denominated in USD, for an amount of $20.0 million, and a maturity date of December 7, 2023. The Citibank Working Capital Loan bears interest equivalent to SOFR +4.25%, payable monthly, and amortizes in five equal installments from August to December 2023. Proceeds from this loan were used for general corporate purposes. As of September 30, 2023, the outstanding balance under the Citibank Working Capital Loan was $19.6 million, which was fully repaid in October 2023.

Puerto Bahia Secured Syndicated Credit Agreement

Puerto Bahia entered into a credit agreement with a syndicate of lenders in October 2013 for a $370 million debt facility, maturing in June 2025, for the construction and development of a multipurpose port in the Cartagena Bay (the "**2025 Puerto Bahia Debt**"). The 2025 Puerto Bahia Debt had an interest rate of 6-month LIBOR plus 5% payable semi-annually. The 2025 Puerto Bahia Debt was secured by substantially all the assets and shares of Puerto Bahia. The 2025 Puerto Bahia Debt was non-recourse to the Company. On March 31, 2023, the 2025 Puerto Bahia Debt outstanding amount of $103.1 million plus accrued interest of $3.1 million, was fully repaid with the funds provided by the PIL Loan Facility.

As at December 31, 2023, Puerto Bahía and Frontera have no obligations under the 2025 Puerto Bahia Debt.

Letters of Credit

The Company has various uncommitted bilateral letters of credit. As of December 31, 2023, the Company had issued letters of credit and guarantees for exploration and abandonment funds totaling $135.7 million (total credit lines of $168.6 million), without cash collateral.

CPE-6 Solar Plant Project Leasing Agreement

During the fourth quarter of 2022, the Company entered into a leasing agreement with Bancolombia to finance the construction and commissioning of a solar power plant project at the CPE-6 block (the "**Solar Plant Debt**"). The financing is denominated in COP, for an amount equivalent to $6.7 million as at December 31, 2023, and a maturity date that is 72 months following the date the conditions precedent to the financing are satisfied. The Solar Plant Debt bears interest equivalent to IBR +5.75%, payable monthly over the disbursed amount outstanding. As of December 31, 2023, Bancolombia disbursed $6.7 million to Enel Colombia S.A. ESP, the developer of the CPE-6 solar plant project. In addition, during 2023 the Company paid availability fees of $0.2 million to Bancolombia. As at December 31, 2023, the Company recognized this obligation as a lease liability.

CPE-6 Battery Energy Storage System Leasing Agreement

During the fourth quarter of 2023, the Company entered into a leasing agreement with Bancolombia to finance the Battery Energy Storage System at CPE-6 block (the "**BESS Project**"). The financing is denominated in COP, for an amount equivalent to $1.0 million as at December 31, 2023, and a maturity date that is 60 months following the date conditions precedent to the financing are satisfied. The BESS Project debt bears interest equivalent to IBR +5.10%, payable monthly. As of December 31, 2023, the Company has drawn $Nil million. The Company expects to initiate disbursement in 2024.

Commitments and Contractual Obligations

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

As at December 31, 2023 ($M)	2024	2025	2026	2027	2028	2028 and Beyond	Total
Long term debt principal and interest	99,260	56,510	59,492	78,863	415,750	—	709,875
Lease liabilities	7,438	5,842	5,462	2,526	2,493	1,856	25,617
Total financial obligations	**106,698**	**62,352**	**64,954**	**81,389**	**418,243**	**1,856**	**735,492**
Transportation							
Ocensa P-135 ship-or-pay agreement	72,670	36,235	—	—	—	—	108,905
ODL agreements	2,380	—	—	—	—	—	2,380
Other transportation and processing commitments	13,981	11,512	11,512	3,816	—	—	40,821
Exploration and evaluation							
Minimum work commitments (1) (2)	9,067	87,458	—	—	—	5,066	101,591
Other commitments							
Operating purchases, community obligations and others.	97,719	17,033	14,660	9,891	608	2,904	142,815
Total Commitments	**195,817**	**152,238**	**26,172**	**13,707**	**608**	**7,970**	**396,512**

(1) Includes minimum work commitments relating to exploration activities in Colombia and Ecuador until the contractual phase when the Company will decide whether to continue or relinquish the exploration areas.

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

Guyana Commitments

As at December 31, 2023, the Company, through its 76.05% equity interest in CGX and directly through its working interest, has certain work commitments under the Petroleum Prospecting License ("**PPL**") for the Corentyne block, offshore Guyana (Frontera 72.52% W.I. and non-operator). In accordance with the PPL for the Corentyne block, a second exploration well was required to be spud by January 31, 2023, which was extended from the previous expiry date of November 26, 2022. On January 23, 2023, CGX and Frontera, the majority shareholder of CGX and joint venture (the "**Joint Venture**") partner of CGX, announced that the Joint Venture had spud the Wei-1 well on the Corentyne block, approximately 200 kilometers offshore from Georgetown, Guyana. In addition, the Government of Guyana has approved an appraisal plan for the northern section of the Corentyne block, which commenced with the Wei-1 well. Following completion of Wei-1 drilling operations and upon detailed analysis of the results, the Joint Venture may consider future wells per its appraisal program to evaluate possible development feasibility in the Kawa-1 discovery area and throughout the northern section of the Corentyne block. The Joint Venture has complied with its exploration commitments under the Corentyne PPL.

On June 13, 2023, CGX and Frontera announced that the Joint Venture successfully reached total depth of 20,450 feet on the Wei-1 well. On June 28, 2023, CGX and Frontera announced that the Joint Venture discovered oil at the Wei-1 well, with 210 feet of hydrocarbon bearing sands in the Santonian horizon being encountered. The Joint Venture successfully finished drilling operations without any safety incidents.

On November 9, 2023, CGX and Frontera announced the discovery of a total of 114 feet (35 meters) of net pay at the Wei-1 well on the Corentyne block.

On December 11, 2023, CGX and Frontera presented a virtual informational presentation. Based on such evaluations, the Joint Venture believes that approximately 514 to 628 mmboe PMean unrisked gross prospective resources may be present in the Maastrichtian horizons alone and that additional potential upside may exist in the deeper Campanian and Santonian horizons. The Joint Venture, with support from Houlihan Lokey, is actively pursuing options for a possible farm down, to unlock the potential of the Corentyne block.

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

In accordance with the JOA Amending Agreement, 4.7% of CGX's participating interest in the Corentyne block was initially assigned to Frontera (subject to government approval), in exchange for Frontera funding CGX's additional expected outstanding share of the Joint Venture's costs associated with the Wei-1 well for up to $16.5 million. After reviewing the funding amounts, and due to lower costs associated with the Wei-1 well, CGX and Frontera have agreed to reassign to CGX a portion of such 4.7% interest, resulting in CGX effectively assigning 4.52% of CGX's participating interest in the Corentyne block to Frontera.

In addition, in connection with (i) a drilling contract agreement (the "**Drilling Contract**") between Maersk Drilling Holdings Singapore Pte. Ltd. (now NobleCorp.) and CGX Resources Inc. ("**CGX Resources**"), the operator of the Corentyne block, for the provision of a semi-submersible drilling unit owned by NobleCorp. and associated services to drill the Joint Venture's Wei-1 well, and (ii) a services agreement (the "**Services Agreement**") between Schlumberger Guyana Inc. ("**Schlumberger**") and CGX Resources for the provision of certain oilfield services and the supply of related goods and products for the Corentyne block, Frontera entered into a deed of guarantee with each of NobleCorp. and Schlumberger for certain obligations. Each of the parent company guarantees provided by Frontera to secure payment obligations under the Drilling Contract and the Services Agreement is limited to a maximum amount of $30 million. As of December 31, 2023, (i) there is no outstanding balance under the Services Agreement and the corresponding parent company guarantee; and (ii) there are no outstanding payments under the Drilling Contract or the corresponding parent company guarantee.

As at December 31, 2023, CGX had entered into purchase orders and contracts for the Corentyne block to complete its requirement under the Corentyne PPL. As of December 31, 2023, the outstanding purchase orders and contracts under these agreements amount to $0.8 million for the year 2024.

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

In May 2022, a new ship-or-pay contract with Bicentenario and Cenit entered into force, and as a result, the pledged inventory crude oil is stored in Cenit's terminal of Coveñas (TLU-3) instead of Ocensa's terminal. On March 31, 2022, the Company signed a new pledge agreement with Ocensa and Cenit, which guarantees the payment obligations of both contracts, up to $30.0 million and $6.0 million, respectively. On July 5, 2023, the term of the pledge agreement has been extended up to March 31, 2024, with Ocensa, and up to April 30, 2024, with Cenit.

Other Guarantees and Pledges

As part of the Company's acquisition of Repsol Colombia Oil & Gas Ltd.'s ("**RCOG**") 50% working interest in the CPE-6 block, the Company granted a pledge to RCOG over the production from the CPE-6 block to guarantee the payments, of up to a maximum of $48.0 million. Under the farm-out agreement, two kinds of payments are set, each contingent on production from this block and each applicable until the maximum payment of $48.0 million is paid: (i) a variable monthly payment, and (ii) three potential production milestone payments of $5.0 million each when 5 million, 10 million and 20 million total barrels production, respectively, are achieved. As at December 31, 2023, the Company has paid and accrued a total $18.2 million of such amounts under the agreement.

Contingencies

The Company is involved in various claims and litigation arising from the normal course of business. Since the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company's favour. The outcome of adverse decisions in any pending or threatened proceedings related to these and other matters could have a material impact on the Company's financial position, results of operations or cash flows. Other than as disclosed below, no material changes have occurred regarding the matters disclosed in Note 26 - Commitments and Contingencies of the 2022 Annual Consolidated Statements.

Quifa Late Delivery Volumes Claim

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

In March 2021, the Company received notification that the Court had decided in favour of Ecopetrol and awarded $8.5 million, as adjusted by the Consumer Price Index. The Company filed an appeal against the first instance ruling on March 16, 2021.

On March 17, 2023, the Council of State issued a final ruling revoking what was decided by the Court in the first instance ruling and stating that statute of limitations barred Ecopetrol's judicial action. In addition, the Council of State ordered Ecopetrol to pay Frontera Colombia judicial costs which amount to approximately $0.3 million. As a result, the Company recorded a reversal of a liability provision of $9.3 million recognized in 2021.

On August 28, 2023, Ecopetrol filed a constitutional action (*tutela*) in order to revoke the final decision of the Council of State that declared the statute of limitations applied to Ecopetrol's claim of the difference in the value of the barrels of crude oil as a consequence of the late delivery by the Company, in the amount of $8.5 million plus interest. The Company was linked to the proceeding as an interested third party and, on September 7, 2023, filed a statement of defense.

On September 27, 2023, the Council of State issued a first instance ruling in which it declared inadmissible the constitutional action (tutela) filed by Ecopetrol due to its lack of constitutional relevance. Ecopetrol appealed this decision and a final ruling is pending.

Agencia Nacional de Hidrocarburos Discussion ("ANH")

On December 12, 2021, the Company informed the ANH that the outstanding commitments at the LLA-7 and LLA-55 blocks of $26.2 million were going to be executed by means of drilling exploration wells in other blocks, as provided under the recent regulation issued by the ANH (Acuerdo 10 of 2021). The Company proposed some activities to be deducted from these commitments. On October 2023, the Company received a communication from the ANH notifying the investment accreditation for the LLA-7 and LLA-55 blocks.

On December 20, 2022, the Company requested that the ANH terminate the contracts for the CAG-5 and CAG-6 blocks due to social and security restrictions in the contracted areas pursuant to a recent regulation issued by the ANH (Acuerdo 01 of 2022). On October 2023, the Company received a communication from the ANH notifying the Company of the extension of the suspension of phase zero of the CAG-5 and CAG-6 blocks until April 10, 2024. As at December 31, 2023, the CAG-5 and CAG-6 blocks have exploration commitments for a total of $101.8 million (the Company's net share of such commitment is $53.0 million).

High-Price Clause

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

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

Puerto Bahia –Tank Construction Related Arbitration

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

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

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

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

Ecopetrol - Rubiales Field Disagreement

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

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

Tax Reviews

The Company operates in various jurisdictions and is subject to assessments by tax authorities in each of those jurisdictions, which can be complex and based on interpretations. The Company is currently in discussions with tax authorities for various assessments with respect to certain income tax deductions relating to exportation expenditures, transportation costs, VAT credits, municipal taxes, and other expenses. As at December 31, 2023, the Company has assessed a possible tax exposure of $145.8 million, (2022: $85.4 million) relating to these assessments for taxes, interest, and penalties (the increase in the exposure is mainly due to foreign exchange variances and interest adjustment). As at December 31, 2023, the carrying value of the tax liability provisions was $13.1 million (2022: $4.6 million).

7. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at March 7, 2024:

	Number
Common shares	84,807,116
Deferred share units ("**DSUs**") (1)	938,443
Restricted share units ("**RSUs**") (2)	1,796,558

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

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

Normal Course Issuer Bid ("NCIB")

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

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

Purchases subject to both NCIBs were or are carried out pursuant to open market transactions through the facilities of the TSX or alternative trading systems, if eligible, by BMO Nesbitt Burns Inc., on behalf of Frontera in accordance with an automatic share purchase plan and applicable regulatory requirements. During the three months and year ended December 31, 2023, the Company purchased a total of 280,500 and 741,700 Common Shares, respectively (280,500 under its 2023 NCIB and 461,200 under its 2022 NCIB). As at March 7, 2024, the Company had repurchased for cancellation a total of 624,600 Common Shares under 2023 NCIB for approximately $3.7 million with an additional 3,324,854 Common Shares remaining available for repurchase under the 2023 NCIB. Under the 2022 NCIB that expired on March 16, 2023, the Company repurchased for cancellation during the twelve-month term a total of 4,270,100 Common Shares, for approximately $40.9 million.

The following table provides a summary of total share repurchases under the Company's 2022 and 2023 NCIB programs:

	Year ended December 31
	2023
Number of Common Shares repurchased	741,700
Total amount of Common Shares repurchased ($M)	5,866
Weighted-average price per share ($) (1)	7.91

(1) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 27.

Substantial Issuer Bid

On June 24, 2022, the Company launched a substantial issuer bid (the "**SIB**"), pursuant to which the Company offered to purchase from shareholders for cancellation up to C$65.0 million of its outstanding Common Shares. The SIB proceeded by way of a "modified Dutch auction" procedure, with a tender price range from C$11.00 to C$13.00 per Common Share. The SIB expired on August 8, 2022. On August 11, 2022, the Company announced that, in accordance with the terms and conditions of the SIB, the Company took up for cancellation 5,416,666 Common Shares at a price of C$12.00 per Common Share, representing an aggregate purchase price of C$65 million funded by cash, for a total cost of $51.2 million, including transaction costs. The Common Shares taken up for cancellation under the SIB represented approximately 5.84% of the total number of the Company's issued and outstanding Common Shares as of August 8, 2022.

8. RELATED-PARTY TRANSACTIONS

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

		As at December 31		Three Months Ended December 31	Year Ended December 31
($M)		Accounts Payable	Commitments	Purchases / Services	
ODL	2023	3,141	2,380	7,776	30,525
	2022	2,553	31,796	6,977	23,313

The related-party transactions correspond to the ship-or-pay contract for the transportation of crude oil in Colombia for a total commitment of $2.4 million until 2024.

9. RISKS AND UNCERTAINTIES

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

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

Pandemics, epidemics or outbreaks of an infectious disease in Colombia, Canada or worldwide, including the recent COVID-19 pandemic or any other similar illness, and related government responses, could have negative impacts on the Company's financial condition, results of operations, and cash flows. Despite successful vaccine rollouts in many jurisdictions, the risk of a resurgence or additional variant strains continues to exist and could result in continued fluctuations in the price of oil and conventional natural gas products. The extent to which such events impact the Company's business, financial condition and results of operations will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence. Such events could have a material adverse effect on the Company's business, financial condition and results of operations. Even as the COVID-19 pandemic subsides, the Company may continue to experience materially adverse impacts to its business as a result of the pandemic's global economic impact, long-term implications and risk of resurgences. To the extent that the COVID-19 pandemic adversely affects the Company's business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described herein and other risks set forth in the Company's AIF and the 2023 Annual Consolidated Financial Statements, copies of which are available on SEDAR+ at www.sedarplus.ca.

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

On October 7, 2023, Hamas terrorists infiltrated Israel's southern border from the Gaza Strip and conducted a series of attacks on civilian and military targets. Hamas also launched extensive rocket attacks on the Israeli population and industrial centers located along Israel's border with the Gaza Strip and in other areas within the State of Israel. Following the attack, Israel's security cabinet declared war against Hamas and a military campaign against these terrorist organizations and has launched a series of responding attacks in Palestine. The outcome of the conflict continues to be uncertain and has the potential to have wide-ranging consequences on the world economy. Global oil prices have remained highly volatile since the beginning of the Israel-Hamas conflict. While neither Israel nor the Gaza Strip are significant oil producers, there is a risk that the conflict could lead to wider regional instability in the Middle East, home to some of the word's biggest oil producers. To date, these events have not impacted the Company's ability to carry on business, and there have been no significant delays or direct security issues affecting the Company's operations, offices or personnel. The long-term impacts of the conflict remain uncertain and the Company continues to monitor the evolving situation.

During the fourth quarter 2023, the board of directors of the Company approved a restructuring plan (the "**Restructuring Plan**"), designed to drive operational efficiencies, reduce operating costs and better align the Company's workforce with current business needs, top strategic priorities, and key growth opportunities. The Restructuring Plan includes the reduction of the Company's workforce by approximately 16%. The Company may encounter challenges in the execution of these restructuring efforts that could prevent it from recognizing the intended benefits of the Restructuring Plan or otherwise adversely affect its business, results of operations and financial condition. As a result of the Restructuring Plan, the Company has incurred and may continue to incur additional costs in the short-term, including cash expenditures for employee transition, notice period and severance payments, employee benefits and related costs. These additional expenditures could have the effect of reducing the Company's operating margins. The Restructuring Plan may result in other unintended consequences. If the Company experiences any of these adverse consequences, the Restructuring Plan may not achieve or sustain its intended benefits, or the benefits, even if achieved, may not be adequate to meet the Company's long-term profitability and operational expectations, which could adversely affect the Company's business, results of operations and financial condition.

See the "Liquidity and Capital Resources" section on page 33 for additional detail on the steps the Company has taken to mitigate or manage some of these risks. However, the situation continues to be dynamic and highly uncertain, and the effectiveness and adequacy of such measures cannot be determined at this time.

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

The list above does not contain all the risks associated with an investment in the securities of the Company. For a more comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, please see the Company's AIF and the 2023 Annual Consolidated Financial Statements, copies of which are available on SEDAR+ at www.sedarplus.ca.

10. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The 2023 Annual Consolidated Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board, and with interpretations of the International Financial Reporting Interpretations Committee, which the Canadian Accounting Standards Board has approved for incorporation into Part 1 of the CPA Canada Handbook Accounting. A summary of significant accounting policies applied is included in Note 3a of the 2023 Annual Consolidated Financial Statements. The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective. Recent accounting pronouncements of significance or potential significance are described in Note 3b of the 2023 Annual Consolidated Financial Statements, including management's evaluation of impact and implementation progress.

The preparation of the 2023 Annual Consolidated Financial Statements in accordance with IFRS requires the Company to make judgments in applying its accounting policies, estimates and assumptions about the future. These judgments, estimates and assumptions affect the reported amounts of assets, liabilities, revenues and other items in net operating earnings or loss and the related disclosure of contingent assets and liabilities included in the 2023 Annual Consolidated Financial Statements. The Company evaluates its estimates on an ongoing basis.

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

The effect of the global economy, including the impact of Covid-19, the Russia-Ukraine conflict, the Israel-Hamas conflict, and the associated volatility in oil prices, could have negative impacts on the Company. The uncertainty these events bring has resulted in a challenging economic environment, with more volatile commodity prices, foreign exchange rates and long-term interest rates. The current global crude oil price environment is being lifted mainly by the Russia-Ukraine conflict, the intervention by members of OPEC reducing oil and gas supplies and the consequences of these events on the certainty of the supply of hydrocarbons in the world. On one hand, these events are supportive of global oil prices. On the other, these events also undermine economic conditions and exacerbate inflation in several economies, directly impacting the cost of goods and services. This presents uncertainty and risk with respect to management's judgments, estimates and assumptions used in the preparation of the 2023 Annual Consolidated Financial Statements.

The results of the economic downturn and any potential resulting direct and indirect impact to the Company has been considered in management's judgments and estimates as described above for the quarter end; however, there could be further prospective material impacts in future periods. As such, actual results may differ from these estimates under different assumptions or conditions. A summary of the key accounting estimates and judgments made by management in the preparation of its financial information is provided in Note 3c of the 2023 Annual Consolidated Financial Statements.

11. INTERNAL CONTROL

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

The Company's ICFR are designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's ICFR may not prevent or detect all misstatements because of inherent limitations. Additionally, in 2023, management of the Company continued to monitor the impacts of COVID-19 on the Company's control environment. These impacts include remote and/or hybrid work environment, oil price environment, cyber threats, IT help desk services response time, health and safety. While there were no changes made to the Company's ICFR that have materially affected, or are reasonably likely to materially affect, the Company's ICFR, the Company will continue to monitor and mitigate the risks associated with any changes to its control environment in response to the COVID-19 pandemic.

Based on this assessment, the Company's Chief Executive Officer and its Chief Financial Officer concluded that the Company's ICFR were effective as at December 31, 2023.

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

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

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

Based on management's evaluation, which was carried out to assess the effectiveness of the Company's DC&P, the Company's Chief Executive Officer and its Chief Financial Officer, concluded that the Company's DC&P were effective as at December 31, 2023.

12. FURTHER DISCLOSURES

Production Reporting

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

The following table includes the average net production:

		Net Production				
					Year ended December 31	
Producing blocks in Colombia		**Q4 2023**	**Q3 2023**	**Q4 2022**	**2023**	**2022**
Heavy crude oil	(bbl/d)	19,381	21,575	18,466	20,499	17,492
Light and medium crude oil combined	(bbl/d)	10,833	11,875	14,876	12,462	15,420
Conventional natural gas	(mcf/d)	4,760	5,250	9,092	6,042	9,741
Natural gas liquids	(boe/d)	1,508	1,686	993	1,531	958
Net production Colombia	**(boe/d)**	**32,557**	**36,057**	**35,930**	**35,552**	**35,579**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	968	460	819	642	519
Net production Ecuador	**(bbl/d)**	**968**	**460**	**819**	**642**	**519**
Total net production	**(boe/d)**	**33,525**	**36,517**	**36,749**	**36,194**	**36,098**

Boe Conversion

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

Oil and Gas Information Advisories

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

Certain disclosures in this MD&A constitute "anticipated results" for the purposes of NI 51-101 because the disclosure in question may, in the opinion of a reasonable person, indicate the potential value or quantities of resources in respect of Frontera's or the Joint Venture's resources or a portion of its resources. Without limitation, the anticipated results disclosed in this MD&A include "net pay" (and variations thereof) and estimates of volume attributable to the resources of Frontera or the Joint Venture. Such estimates (other than in respect of estimates of volume) have been prepared by Frontera or the Joint Venture, as applicable and have not been prepared or reviewed by an independent qualified reserves evaluator or auditor. Estimates of volume have been prepared by an independent qualified reserved evaluator or auditor. Such terms should not be interpreted to mean there is any level of certainty in regard to the hydrocarbons present, or that hydrocarbons may be produced profitably, in commercial quantities, or at all. Anticipated results are subject to certain risks and uncertainties, including those described herein and various geological, technical, operational, engineering, commercial, and technical risks. In addition, the geotechnical analysis and engineering to be conducted in respect of such resources is not complete. Such risks and uncertainties may cause the anticipated results disclosed herein to be inaccurate. Actual results may vary, perhaps materially.

Prospective Resources

This MD&A discloses estimates of the Joint Venture's prospective resources. Prospective resources are defined as those quantities of petroleum estimated, as of a given date, to be potentially prospective from undiscovered accumulations by application of future development projects. Prospective resources are not, and should not be confused with, reserves or contingent resources.

The prospective resource estimates contained in this MD&A were made based on separate reviews by two independent, third-party qualified reserves evaluators, effective as of October 30, 2023, and November 30, 2023, respectively. Such estimates have been prepared in compliance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook. All estimates of prospective resources presented herein are on an un-risked basis, meaning that they have not been adjusted for risk based on the chance or discovery or the chance of development, and all volumes are presented on a gross basis, meaning the Joint Venture's aggregate working interest before adjustment for royalties. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Estimates of resources always involve uncertainty, and the degree of uncertainty can vary widely between accumulations/projects and over the life of a project. Readers are cautioned that the prospective resource potential disclosed in this news release are not necessarily indicative of ultimate recovery.

The resource estimates presented above are subject to certain risks and uncertainties, including those associated with the drilling and completion of future wells, limited available geological and geophysical data and uncertainties regarding the actual production characteristics of the reservoirs, all of which have been assumed for the preparation of the resource estimates. In addition, significant positive and negative factors related to the prospective resource estimate include the high exploration success rate of, and frequency of development projects by, operators in the Guyana-Suriname Basin, a lack of infrastructure and transportation in the Corentyne area and the capital expenditures and financing required to conduct additional appraisal activities and/or develop resources at an acceptable cost.

Abbreviations

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

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