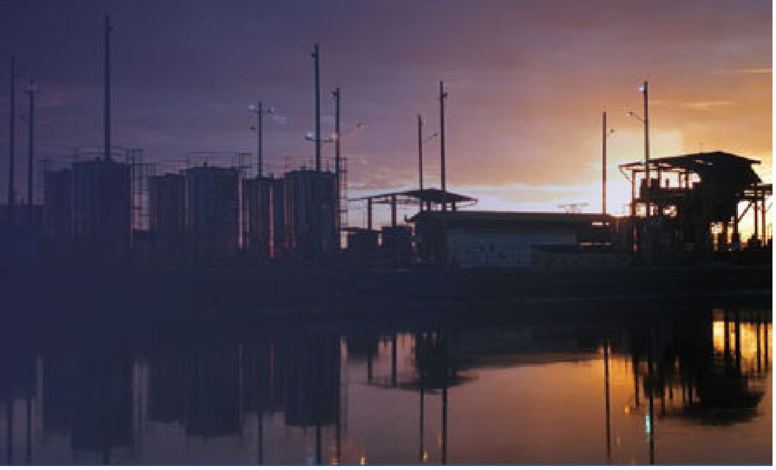
FRONTERA
ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

Aug 7, 2024
For the three and six months ended June 30, 2024



*Frontera Energy Corporation ("**Frontera**" , "**FEC**" or the "**Company**") is an oil and gas company formed and existing under the laws of British Columbia, Canada, that is engaged in the exploration, development, production, transportation, storage and sale of crude oil and conventional natural gas in South America, including strategic investments in both upstream and infrastructure facilities, and is committed to working hand-in-hand with all its stakeholders to conduct business in a socially and environmentally responsible manner. The Company's common shares ("**Common Shares**") are listed and publicly traded on the Toronto Stock Exchange ("**TSX**") under the trading symbol "FEC". The Company's head office is located at 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 Interim Consolidated Financial Statements and related notes for the three and six months ended June 30, 2024 and 2023 (the "**Interim Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and its Annual Information Form ("**AIF**"), have been filed with Canadian securities regulatory authorities and are available on SEDAR+ at www.sedarplus.ca and on the Company's website at www.fronteraenergy.ca. Information contained in or otherwise accessible through the Company's website does not form a part of this MD&A and is not incorporated by reference into this MD&A.*

*The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board, unless otherwise noted. This MD&A contains certain financial terms that are not considered in IFRS. These non-IFRS financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These non-IFRS financial measures are described in greater detail under the heading "Non-IFRS and Other Financial Measures" section on page 23.*

*This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to activities, events or developments that the Company believes, expects or anticipates will or may occur in the future. Forward-looking information in this MD&A includes, without limitation, statements regarding estimates and/or assumptions in respect of the oil price environment, potential health risks, including Covid-19 or any other pandemic, actions of the Organization of Petroleum Exporting Countries ("**OPEC+**"), expectations regarding increased water handling capacity at the Quifa block, the Company's Intention to commence a substantial issuer bid and the funding thereof, the outcome of the Company's ongoing strategic alternatives review processes, reductions in CO2 levels per year, the impact of the Russia-Ukraine conflict and the conflict in the Middle East, the expected impact of measures that the Company has taken and continues to take 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 plan, cost savings, including General and Administrative ("**G&A**") expense savings, and thereof), operating EBITDA, production costs, transportation costs, the restructuring and the impact thereof and obtaining regulatory approvals. Forward-looking information is often identified by words or phrases such as "may", "could", "would", "might", "will", "expects," "anticipates," "plans," "estimates," "projects," "forecasts," "believes," "intends," "possible," "probable," "scheduled," "goal", "objective", or similar words or phrases. All information in this MD&A other than historical fact is forward-looking information.*

Forward-looking information reflects the current expectations, assumptions and beliefs of the Company based on information currently available to it and considers the Company's experience and its perception of historical trends, including expectations and assumptions relating to commodity prices and interest and foreign exchange rates; any health security situation, including Covid-19 or any other pandemic; 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. In addition, no assurance can be given that such an agreement will be reached or the extent of the property covered by the Notice of Potential Commercial Interest outside of the area around the Wei-1 well.

The SIB (as defined below) referred to in this MD&A has not yet commenced. This is for informational purposes only and does not constitute an offer to buy or the solicitation of an offer to sell Common Shares. The solicitation and the offer to buy Common Shares will only be made pursuant to a formal offer to purchase and issuer bid circular, a letter of transmittal, a notice of guaranteed delivery and other related documents to be filed with the applicable Canadian securities regulatory authorities. The offer to purchase pursuant to the SIB (as defined below) will not be made to, nor will tenders be accepted from or on behalf of, holders of Common Shares in any jurisdiction in which the making or acceptance of offers to sell Common Shares would not be in compliance with the laws of that jurisdiction.

Although the Company believes that the assumptions inherent in the forward-looking information are reasonable, forward-looking information is not a guarantee of future performance and accordingly undue reliance should not be placed on such information. Forward-looking information is subject to a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to the Company. The actual results of the Company may differ materially from those expressed or implied by the forward-looking information, and even if such actual results are realized or substantially realized, there can be no assurance that they will have the expected consequences to, or effects on, the Company. Factors that could cause actual results or events to differ materially from current expectations include, among other things: volatility in market prices for oil and natural gas; measures the Company has taken and continues to take or may take in response to pandemics; the Russia-Ukraine conflict and the conflict in the Middle East; 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. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

					Six months ended June 30	
		Q2 2024	Q1 2024	Q2 2023	2024	2023
Operational Results						
Heavy crude oil production [(1)]	(bbl/d)	24,839	23,398	24,051	24,119	23,165
Light and medium crude oil combined production [(1)]	(bbl/d)	12,583	12,580	15,188	12,582	15,849
Total crude oil production	(bbl/d)	37,422	35,978	39,239	36,701	39,014
Conventional natural gas production [(1)]	(mcf/d)	4,019	3,283	5,626	3,654	7,102
Natural gas liquids production [(1)]	(boe/d)	1,785	1,639	1,823	1,711	1,558
Total production [(2)]	(boe/d) [(3)]	39,912	38,193	42,049	39,053	41,818
Total inventory balance	(bbl)	1,319,189	1,278,763	1,434,508	1,319,189	1,434,508
Brent price reference	($/bbl)	85.03	81.76	77.73	83.42	79.91
Produced crude oil and gas sales [(4)]	($/boe)	78.31	76.10	69.96	77.23	70.88
Purchased crude net margin [(4)]	($/boe)	(2.13)	(2.39)	(2.05)	(2.26)	(2.45)
Oil and gas sales, net of purchases [(4)]	($/boe)	76.18	73.71	67.91	74.97	68.43
Premiums paid on oil price risk management contracts [(5)]	($/boe)	(1.32)	(1.27)	(0.80)	(1.30)	(0.96)
Royalties [(5)]	($/boe)	(2.01)	(1.64)	(3.02)	(1.83)	(3.18)
Net sales realized price [(4)]	($/boe)	72.85	70.80	64.09	71.84	64.29
Production costs (excluding energy cost), net of realized FX hedge impact [(4)]	($/boe)	(10.79)	(10.21)	(8.45)	(10.51)	(8.29)
Energy costs, net of realized FX hedge impact [(4)]	($/boe)	(4.74)	(5.29)	(3.94)	(5.01)	(3.94)
Transportation costs, net of realized FX hedge impact [(4)]	($/boe)	(10.92)	(11.33)	(10.89)	(11.12)	(11.04)
Operating netback per boe [(4)]	($/boe)	46.40	43.97	40.81	45.20	41.02
Financial Results						
Oil & gas sales, net of purchases [(6)]	($M)	218,528	202,469	221,218	420,997	410,338
Premiums paid on oil price risk management contracts	($M)	(3,796)	(3,489)	(2,600)	(7,285)	(5,775)
Royalties	($M)	(5,774)	(4,506)	(9,837)	(10,280)	(19,050)
Net sales [(6)]	($M)	208,958	194,474	208,781	403,432	385,513
Net (loss) income [(7)]	($M)	(2,846)	(8,503)	80,207	(11,349)	68,877
Per share – basic	($)	(0.03)	(0.10)	0.94	(0.13)	0.81
Per share – diluted	($)	(0.03)	(0.10)	0.92	(0.13)	0.79
General and administrative	($M)	12,928	13,556	12,422	26,484	25,091
Outstanding Common Shares	Number of Shares	84,253,816	84,693,416	85,188,573	84,253,816	85,188,573
Operating EBITDA [(6)]	($M)	110,321	97,248	116,461	207,569	208,383
Cash provided by operating activities	($M)	149,787	65,616	183,560	215,403	184,405
Capital expenditures [(6)]	($M)	80,198	69,381	154,860	149,579	286,312
Cash and cash equivalents – unrestricted	($M)	180,659	154,907	180,294	180,659	180,294
Restricted cash short and long-term [(8)]	($M)	34,419	27,058	33,485	34,419	33,485
Total cash [(8)]	($M)	215,078	181,965	213,779	215,078	213,779
Total debt and lease liabilities [(8)]	($M)	523,994	537,151	532,273	523,994	532,273
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [(9)]	($M)	426,004	429,556	415,395	426,004	415,395
Net debt (excluding Unrestricted Subsidiaries) [(9)]	($M)	283,651	305,821	286,675	283,651	286,675

[(1)] References to heavy crude oil, light and medium crude oil combined, conventional natural gas and natural gas liquids in the above table and elsewhere in this MD&A refer to the heavy crude oil, light crude oil and medium crude oil combined, conventional natural gas and natural gas liquids, respectively, product types as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*.
[(2)] Represents W.I. production before royalties. Refer to the "Further Disclosures" section on page 36.
[(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 36.
[(4)] Non-IFRS ratio is equivalent to a "non-GAAP ratio", as defined in National Instrument 52-112 - *Non-GAAP and Other Financial Measures Disclosure ("***NI 52-112***")*. Refer to the "Non-IFRS and Other Financial Measures" section on page 23.
[(5)]Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 23.
[(6)] 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 23.
[(7)] Net (loss) income attributable to equity holders of the Company.
[(8)] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 23.
[(9)] "**Unrestricted Subsidiaries**" include CGX Energy Inc. ("**CGX**"), listed on the TSX Venture Exchange under the trading symbol "OYL", Frontera ODL Holding Corp., including its subsidiary Pipeline Investment Ltd. ("**PIL**"), Frontera BIC Holding Ltd. and Frontera Bahía Holding Ltd. ("**Frontera Bahia**"), including Sociedad Portuaria Puerto Bahia S.A ("**Puerto Bahia**"). On April 11, 2023, Frontera Energy Guyana Holding Ltd. and Frontera Energy Guyana Corp. were designated as unrestricted subsidiaries. Refer to the "Liquidity and Capital Resources" section on page 29.

Performance Highlights

Frontera's corporate strategy focuses on maximizing and realizing value through its portfolio of energy and infrastructure related assets via by its three 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**: profitable and significant Colombian infrastructure footprint uniquely positioned to capture growth from emerging opportunities across the value chain providing stable and long-term revenue streams; and
- **Guyana Exploration**: potentially transformational offshore Guyana opportunity for a Maastrichtian-based, stand-alone commercial development, with upside and future opportunities in the deeper zones.

Second Quarter of 2024

Frontera delivered average daily production of 39,912 boe/d (consisting of 24,839 bbl/d of heavy crude oil, 12,583 bbl/d of light and medium crude oil combined, 4,019 mcf/d of conventional natural gas and 1,785 boe/d of natural gas liquids). The Company invested $80.2 million in capital expenditures, including $37.9 million on development drilling in the Quifa, CPE-6, Cajua and Perico blocks, and generated strong operating EBITDA of $110.3 million and cash provided by operating activities of $149.8 million.

The Company's increased production by approximately 5% quarter over quarter, primarily driven by increased water disposal capacity in Quifa block, increased water handling capacity at the CPE-6 block to 240 Mbwpd, where the Company delivered another quarterly production record of 6,947 bbl/d. Additionally, supplementary activities in the Sabanero block and the completion of two wells at the Perico block in Ecuador, partially affected by light & medium oil natural decline.

During the quarter, Frontera and Ecopetrol entered into a two-year contract to treat and dispose water from the Quifa Block at Frontera's reverse osmosis water treatment facility ("**SAARA**"). This agreement is set to significantly improve water disposal operations and drive crude oil production capacity at the Quifa Block. Following the deal with Ecopetrol, Frontera restarted operations at the SAARA facility, currently processing approximately 50,000 barrels of water per day. By the end of 2024, the company aims to increase processing capacity at SAARA to 250,000 barrels per day, which support higher production levels from the Quifa block. During the month of June, the plant realized its first gross revenues associated to the water treatment collaboration agreement with the Quifa Block. In connection with this agreement, SAARA is committed to enhancing the infrastructure necessary to provide additional irrigation source water for the Promotora Agricola de los Llanos S.A. ("**ProAgrollanos**") palm oil plantation.

Second quarter production costs (excluding energy cost), net of realized FX hedge impact, averaged $10.79/boe versus $10.21/boe in the prior quarter mainly driven by higher well services activity. The Company's energy costs, net of realized FX hedge impact, averaged $4.74/boe versus $5.29/boe in the prior quarter due to improved electricity prices in Colombia benefiting from the end of the dry season, partially offset by higher energy use during the quarter. In addition, transportation costs, net of realized FX hedge impact, decreased mainly due to an increase in local sales volumes, and more efficient transportation economics and routing for some of our heavy crude production.

Second quarter 2024 Adjusted Infrastructure EBITDA was $27.8 million, up 8% from $25.7 million during the first quarter of 2024. Volumes pumped at the Oleoducto de los Llanos Orientales S.A. ("**ODL**") oil pipeline facility were 249,196 bbl/d, increased to 246,042 bbl/d, in the prior quarter due to in crude oil volumes received and transported from the Caño Sur and Llanos 34 blocks. Puerto Bahia liquids volumes remained strong at 61,798 bbl/d, up 16% from 53,360 bbl/d in the prior quarter. The general cargo segment also generated higher roll-on/ roll-off ("**RORO**") and break bulk volumes. During the second quarter, ODL paid dividends and return of capital of $89.4 million ($31.3 million, net for PIL).

ESG

As of June 30, 2024, Frontera has achieved 48% of its sustainability goals for the year. During the second quarter, Frontera expanded its protection and preservation coverage activities to 168 hectares.

The Company invested $498 thousands in projects in communities near its operations in Colombia, Ecuador and Guyana and the Company purchased 10.7% of its total goods and services from local suppliers.

Working from a strong and established human rights base, the Company continues to improve its human rights due diligence planning to promote and respect of human rights across its value chain.

Enhancing Shareholder Returns

Frontera also continues to take actions to unlock the value for its stakeholders and remains committed to these efforts for the remainder of 2024 and beyond, including the ongoing strategic alternatives processes.

The Company announced the intention to commence a Substantial Issuer Bid ("**SIB**") to purchase $30 million of the Company's outstanding shares. The Company intends to fund the SIB from current cash resources, highlighting the strong financial results of the first half of 2024. So far this year, considering the proposed SIB, the Company is poised to return over $51 million of capital to our stakeholders, including $11.7 million in declared dividends (including declared quarterly dividend of C$0.0625 per share, or $3.9 million in aggregate, payable on or around October 16, 2024), $6.7 million of common share repurchases and $3.5 million in buybacks of its 2028 unsecured notes.

Unlocking Value from the Sum of Its Parts

The Company continues to execute on its strategic priorities supporting the long-term growth and sustainability of its businesses.

In May 2024, the Company launched a strategic alternatives review for its standalone and growing Infrastructure Colombia Segment (as defined below), which could result in a potential spin-off to Frontera shareholders, a total or partial sale or other business combination of Frontera's infrastructure business, and/or a strategic investment, therein by a third party. Frontera has retained Goldman Sachs & Co. as financial advisor and may retain other advisors to assist the Board in evaluating the various strategic, business, and financial alternatives.

Subsequent to the quarter, Puerto Bahia began construction of its strategic Reficar Connection Project (as defined below), which it expects will become operational in December 2024.

On July 22, 2024, Frontera also announced that its subsidiary, Puerto Bahia and Gasco Soluciones Logísticas y Energéticas S.A.S. ("**GASCO**") had entered into a Framework Collaboration Agreement (the "**Agreement**") to jointly pursue a liquified petroleum gas ("**LPG**") project at Puerto Bahia's state-of-the-art liquids and dry cargo port terminal strategically located in the Bay of Cartagena, Colombia. The estimated cost of the project is expected to be approximately $50 to $60 million, which will be shared between Puerto Bahia and GASCO. Puerto Bahia's contributions are expected to be largely in-kind. The Agreement covers the construction and operation of the LPG project and is expected to be in service by 2027.

In our Guyana exploration business, Frontera and CGX, joint venture partners (the "**Joint Venture**"), and the Government of Guyana have engaged in regular, constructive and collaborative conversations throughout the Joint Venture's tenure on the Corentyne block, including discussions regarding timing and conditions under which further activities could be performed by the Joint Venture in the Corentyne block. The Joint Venture, with support from investment bank and capital markets experts Houlihan Lokey, continues to actively pursue strategic options to unlock the potential of the Corentyne block.

These processes are central to the Company's efforts to streamline the business and unlock the value from the sum of its parts. Frontera believes the value of its assets is not reflected in the current stock price and these processes aim to drive value for shareholders. There can be no guarantee that these strategic review processes will result in a transaction.

Financial and Operational Results

- Production averaged 39,912 boe/d in the second quarter of 2024 (consisting of 24,839 bbl/d of heavy crude oil, 12,583 bbl/d of light and medium crude oil combined, 4,019 mcf/d of conventional natural gas and 1,785 boe/d of natural gas liquids), compared to 38,193 boe/d in the prior quarter (consisting of 23,398 bbl/d of heavy crude oil, 12,580 bbl/d of light and medium crude oil combined, 3,283 mcf/d of conventional natural gas and 1,639 boe/d of natural gas liquids), and compared to 42,049 boe/d in the second quarter of 2023 (consisting of 24,051 bbl/d of heavy crude oil, 15,188 bbl/d of light and medium crude oil combined, 5,626 mcf/d of conventional natural gas and 1,823 boe/d of natural gas liquids).

- Cash provided by operating activities was $149.8 million in the second quarter of 2024, compared with $65.6 million in the prior quarter, and $183.6 million in the second quarter of 2023. The Company reported a total cash position of $215.1 million, including $34.4 million of restricted cash, as at June 30, 2024, compared with a total cash position of $182.0 million, including $27.1 million of restricted cash, as at March 31, 2024, and $213.8 million, including $33.5 million of restricted cash, as at June 30, 2023.

- The Company recorded a net loss(1) of $2.8 million ($0.03/share(2)) in the second quarter of 2024, compared with net loss(1) of $8.5 million ($0.10/share(2)) in the prior quarter and net income(1) of $80.2 million ($0.92/share(2)) in the second quarter of 2023.

- Capital expenditures were $80.2 million in the second quarter of 2024, compared with $69.4 million in the prior quarter and $154.9 million in the second quarter of 2023.

- Operating EBITDA was $110.3 million in the second quarter of 2024, compared with $97.2 million in the prior quarter and $116.5 million in the second quarter of 2023.

- Operating netback was $46.40/boe in the second quarter of 2024, compared with $43.97/boe in the prior quarter and $40.81/boe in the second quarter of 2023.

- Infrastructure Colombia Segment (as defined below) income was $14.6 million in the second quarter of 2024, compared with $12.6 million in the prior quarter and $15.4 million in the second quarter of 2023.

- Adjusted Infrastructure EBITDA in the second quarter of 2024 was $27.8 million, compared with $25.7 million in the prior quarter and $28.5 million during the second quarter of 2023.

- Puerto Bahia liquids volumes handled during the second quarter of 2024 were 61,798 bbl/d compared to 53,360 bbl/d in the prior quarter and 73,714 bbl/d in second quarter of 2023. Puerto Bahia revenues were $11.2 million during the second quarter of 2024, compared to $9.7 million in the prior quarter and $12.2 million during the second quarter of 2023.

- Total ODL volumes transported during the second quarter of 2024 were 249,196 bbl/d compared to 246,042 bbl/d in the prior quarter and 243,490 bbl/d in the second quarter of 2023. During the six months ended June 30, 2024, the Company recognized gross dividends of $54.9 million and recognized a return of capital of $7.9 million, compared with $37.0 million of gross dividends and $5.2 million of return of capital during the same period of 2023.

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

2. GUIDANCE

The following table reports the Company's actual results for the six months ended June 30, 2024, against the full year 2024 guidance metrics as released on February 15, 2024.

Despite some inflationary pressure on our costs, we remain on track to achieve our 2024 capital, production and EBITDA guidance. We have increased production during the quarter, and in June and July, averaged production was approximately 40,600 barrels per day.

		2024	
		Guidance	Actual
Average Daily Production(1)	boe/d	40,000 - 42,000	39,053
Production Costs (excluding energy cost) (2)(4)	$/boe	8.50 - 9.50	10.51
Energy Costs (2)(4)	$/boe	5.75 - 6.25	5.01
Transportation Costs(3)(4)	$/boe	11.00 - 12.00	11.12
Operating EBITDA(5) at $80/bbl (6)	$MM	400 - 450	207.6
Adjusted Infrastructure EBITDA(7)	$MM	95 - 115	53.5
Development Drilling	$MM	85 - 95	72.9
Development Facilities	$MM	95 - 115	45.2
Colombia and Ecuador Development	$MM	180 - 210	118.1
Colombia and Ecuador Exploration	$MM	35 - 45	13.4
Other (8)	$MM	15 - 25	7.9
Total Colombia & Ecuador Upstream Capex	$MM	230 - 280	139.4
Colombia Infrastructure(9)	$MM	40 - 50	8.0
Guyana Exploration	$MM	2 - 5	2.1
Total Capital Expenditures(10)	$MM	272 - 335	149.5

(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) Reported Adjusted Infrastructure EBITDA is a non-IFRS financial measure used to assist in measuring the operating results of the infrastructure business, including the proportional consolidation of the 35% equity investment in the ODL pipeline.
(8) Other includes Sabanero Insurance, HSEQ activities and New Technologies.
(9) Colombia Infrastructure includes investments related to the connection of Puerto Bahia's port facility and the Cartagena refinery (the "**Reficar Connection Project**") operated by Refineria de Cartagena S.A.S. ("**Reficar**"), the SAARA reverse osmosis water treatment facility, and safety, maintenance activities and operational optimizations in the port.
(10) 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.

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company's operations in Colombia and Ecuador. Refer to the "Further Disclosures" section on page 36 for details of the Company's net production:

		Production				
					Six months ended June 30	
Producing blocks in Colombia		**Q2 2024**	**Q1 2024**	**Q2 2023**	**2024**	**2023**
Heavy crude oil	(bbl/d)	24,839	23,398	24,051	24,119	23,165
Light and medium crude oil combined	(bbl/d)	10,928	11,102	14,575	11,015	15,041
Conventional natural gas	(mcf/d)	4,019	3,283	5,626	3,654	7,102
Natural gas liquids	(boe/d)	1,785	1,639	1,823	1,711	1,558
Total production Colombia	**(boe/d)**	**38,257**	**36,715**	**41,436**	**37,486**	**41,010**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	1,655	1,478	613	1,567	808
Total production Ecuador	**(bbl/d)**	**1,655**	**1,478**	**613**	**1,567**	**808**
Total production	**(boe/d)**	**39,912**	**38,193**	**42,049**	**39,053**	**41,818**

Colombia

For the three months ended June 30, 2024, production in Colombia increased by 1,542 boe/d, compared to the prior quarter. Heavy crude oil production increased 6% primarily due to increased water disposal capacity from a new injector well in the Quifa block, the start-up of the SAARA plant during the month of May, increased water handling capacity at the CPE-6 block to 240 Mbwpd and additional activities in the Sabanero block. Conventional natural gas and natural gas liquids increased 22% and 9%, respectively, mainly due to increased production at the La Belleza field in connection with the compression facilities expansion and gas reinjection project. In contrast, light and medium crude oil combined decreased 2%, compared to the prior quarter, mainly due to the natural decline.

Compared to the three and six months ended June 30, 2023, total production in Colombia decreased by 3,179 boe/d and 3,524 boe/d, respectively, as explained as follows: (i) Heavy crude oil production increased by 788 bbl/d and 954 bbl/d, respectively, as a result of the successful development drilling campaign in the CPE-6 and the Quifa blocks, and new water facilities in the CPE-6 block. (ii) Natural gas liquids production decrease by 2%, compared to the second quarter of 2023, due to natural decline, and increased by 10%, compared to the six months ended June 30, 2023, due to the increased production of VIM-1 block as a result of the development of the facilities, partially offset by natural decline. (iii) Compared to the three and six months ended June 30, 2023, light and medium crude oil combined decreased by 25% and 27%, respectively, and conventional natural gas production decreased by 29% and 49%, respectively. These declines in production were primarily attributed to significant declines in the El Dificil block and the Neiva block production contract concluded in June of 2023, which contributed 628 boe/d.

Ecuador

Total production in Ecuador for the three and six months ended June 30, 2024, increased by 170% and 94%, respectively, in light and medium crude oil combined, compared to the same periods of 2023. The increase is benefited by the completion of the Perico Norte A-3, the Perico Centro 1, and the Perico Norte A-4 wells during the second half of 2023, as well as the Perico Norte A-5 in February 2024, Perico Norte 6 in April 2024 and Perico Centro 2 in May 2024. Compared to the prior quarter, production increased due to the completion of Perico Norte 6 and Perico Centro 2 wells.

Production Reconciled to Sales Volumes

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

					Six months ended June 30	
		Q2 2024	**Q1 2024**	**Q2 2023**	**2024**	**2023**
Production	(boe/d)	**39,912**	**38,193**	**42,049**	**39,053**	**41,818**
Royalties in-kind Colombia [1]	(boe/d)	(4,871)	(4,011)	(4,163)	(4,441)	(4,190)
Royalties in-kind Ecuador [2]	(boe/d)	(536)	(439)	(180)	(488)	(239)
Net production	(boe/d)	**34,505**	**33,743**	**37,706**	**34,124**	**37,389**
Oil inventory (build) draw	(boe/d)	(444)	(2,223)	1,941	(1,334)	(1,082)
Overlift (settlement)	(boe/d)	—	—	2	—	(1)
Volumes purchased	(boe/d)	6,830	8,354	7,691	7,592	7,838
Other inventory movements [3]	(boe/d)	(2,797)	(2,461)	(2,471)	(2,629)	(2,658)
Sales volumes	(boe/d)	**38,094**	**37,413**	**44,869**	**37,753**	**41,486**
Sale of volumes purchased	(boe/d)	(6,571)	(7,228)	(9,070)	(6,900)	(8,358)
Sales volumes, net of purchases	(boe/d)	**31,523**	**30,185**	**35,799**	**30,853**	**33,128**
Oil sales volumes	(bbl/d)	30,816	29,610	34,827	30,212	31,916
Conventional natural gas sales volumes	(mcf/d)	4,030	3,278	5,540	3,654	6,908
Total oil and conventional natural gas sales volumes, net of purchases	**(boe/d)**	**31,523**	**30,185**	**35,799**	**30,853**	**33,128**
Inventory balance						
Colombia [4]	(bbl)	758,794	683,335	881,758	758,794	881,758
Peru	(bbl)	480,200	480,200	480,200	480,200	480,200
Ecuador	(bbl)	80,195	115,228	72,550	80,195	72,550
Inventory ending balance	**(bbl)**	**1,319,189**	**1,278,763**	**1,434,508**	**1,319,189**	**1,434,508**

(1) Royalties for the 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.
(4) Includes 0.41 MMbbl of oil produced and 0.35 MMbbl oil for dilution in the second quarter of 2024, 0.35 MMbbl of oil produced and 0.33 MMbbl oil volumes for dilution in the first quarter of 2024, and 0.65 MMbbl of oil produced and 0.24 MMbbl volumes for dilution in the second quarter of 2023.

Sales volumes, net of purchases, for the three months ended June 30, 2024, increased by 4% compared with the prior quarter, due to additional oil and gas production and lower inventory build, and compared with the same quarter of 2023, decreased by 12%, mainly due to lower light and medium oil production and inventory build in 2024. For the six months ended June 30, 2024, decreased by 7%, compared with the same period of 2023, due to lower light and medium oil production.

Colombia Royalties PAP

The Company makes high price clause participation ("**PAP**") payments to Ecopetrol and the Agencia Nacional de Hidrocarburos ("**ANH**") on production from the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo, Arrendajo and CPE-6 blocks. In February 2023, the ANH changed the payment method for PAP payments, requiring in-kind payments for all blocks, except for the CPE-6, Guatiquia (Yatay field) and Cubiro (Copa A field) blocks. In October 2023, the ANH made an additional change in the payment method for PAP payments, requiring in-kind payments for the CPE-6 block.

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

					Six months ended June 30	
		Q2 2024	**Q1 2024**	**Q2 2023**	**2024**	**2023**
PAP in kind	(bbl/d)	2,050	1,325	2,303	1,688	1,884
PAP in cash	(bbl/d)	402	376	733	389	763
PAP	**(bbl/d)**	**2,452**	**1,701**	**3,036**	**2,077**	**2,647**
% Production		**6.1 %**	**4.5 %**	**7.2 %**	**5.3 %**	**6.3 %**

For the three and six months ended June 30, 2024, the total PAP decreased compared with the same periods of 2023, mainly due to lower light and medium crude oil production.

During the second quarter of 2024, PAP in kind decreased compared to the same period of 2023, mainly due to the lower light and medium crude oil production. Compared to the prior period, PAP in kind increased due to higher production and a higher WTI oil benchmark price. For the three and six months ended June 30, 2024, PAP in cash decreased compared with the same periods of 2023, mainly due to the change in the payment method required by ANH, as mentioned above, and compared with the prior quarter, PAP in cash increased mainly due to a higher WTI oil benchmark price.

Realized and Reference Prices

					Six months ended June 30	
		Q2 2024	Q1 2024	Q2 2023	2024	2023
Reference price						
Brent [1]	($/bbl)	85.03	81.76	77.73	83.42	79.91
Average realized prices						
Realized oil price, net of purchases	($/bbl)	77.16	74.45	68.90	75.83	69.90
Realized conventional natural gas price	($/mcf)	5.88	6.26	5.65	6.05	5.29
Net sales realized price						
Produced crude oil and gas sales [2]	($/boe)	78.31	76.10	69.96	77.23	70.88
Purchased crude net margin [2]	($/boe)	(2.13)	(2.39)	(2.05)	(2.26)	(2.45)
Oil and gas sales, net of purchases [2]	($/boe)	76.18	73.71	67.91	74.97	68.43
Premiums paid on oil price risk management contracts[3] [4]	($/boe)	(1.32)	(1.27)	(0.80)	(1.30)	(0.96)
Royalties [3]	($/boe)	(2.01)	(1.64)	(3.02)	(1.83)	(3.18)
Net sales realized price [2]	**($/boe)**	**72.85**	**70.80**	**64.09**	**71.84**	**64.29**

(1) Frontera's weighted average Brent price for the three and six months ended June 30, 2024, was $84.06/bbl and $83.34/bbl, respectively.
(2) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 23.
(3) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 23.
(4) Includes put premiums paid for the position expired during the period.

The average Brent benchmark oil price during the three and six months ended June 30, 2024, increased by 9% and 4%, respectively, compared to the same periods of 2023. In comparison to the first quarter of 2024, the average Brent benchmark oil price increased by 4%. The increase in crude oil prices during 2024, compared with the same period of 2023, was mainly due to: (i) the worldwide economy being more resilient to inflation than market expectations, (ii) interest rate increases starting to ease giving relief to the markets, and (iii) geopolitical risk due to the Russia-Ukraine conflict and Middle East conflict and their potential impact on market supply.

For the three months ended June 30, 2024, the Company's net sales realized price was $72.85/boe. There was an increase of 3% compared to the prior quarter, driven by higher Brent benchmark oil price and better oil differential prices, partially offset by premiums paid on oil price risk management contracts and royalties. For the three and six months ended June 30, 2024, the Company's net sales realized price increased by $8.76/boe and $7.55/boe, respectively, compared to the same periods of 2023, driven by higher Brent benchmark oil price, better oil differential prices and lower royalties, partially offset by premiums paid on oil price risk management contracts.

Operating Netback

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

	Q2 2024		Q1 2024		Q2 2023	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price [1]	208,958	72.85	194,474	70.80	208,781	64.09
Production costs (excluding energy cost), net of realized FX hedge impact [1][2][3]	(39,198)	(10.79)	(35,502)	(10.21)	(32,331)	(8.45)
Energy costs, net of realized FX hedge impact [1][2][4]	(17,227)	(4.74)	(18,387)	(5.29)	(15,075)	(3.94)
Transportation costs, net of realized FX hedge impact [1][2][5]	(34,283)	(10.92)	(34,786)	(11.33)	(37,363)	(10.89)
Operating Netback [1] [2]	**118,250**	**46.40**	**105,799**	**43.97**	**124,012**	**40.81**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases [6]		31,523		30,185		35,799
Production [7]		39,912		38,193		42,049
Net production [8]		34,505		33,743		37,706

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 23.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 23.
(3) Includes $2.2 million, $1.3 million and $4.8 million of realized FX hedge gain attributable to production costs for the second quarter of 2024, first quarter of 2024, and the second quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(4) Includes $0.8 million, $0.6 million and $1.4 million of realized FX hedge gain attributable to energy costs for the second quarter of 2024, first quarter of 2024, and the second quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(5) Includes $0.6 million, $0.4 million and $1.8 million of realized FX hedge gain attributable to transportation costs for the second quarter of 2024, first quarter of 2024, and the second quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(6) Sales volumes, net of purchases, excluding sales of third-party volumes.
(7) Refer to the "Production" section on page 6.
(8) Refer to the "Further Disclosures" section on page 36.

The Company's operating netback for the second quarter of 2024 was $46.40/boe, compared to $40.81/boe in the same quarter of 2023. The increase was a result of higher net sales realized prices, partially offset by production costs (excluding energy cost), net of realized FX hedge impact, explained mainly by higher well services activity, inflationary pressures on services and wages indexation, and higher energy costs, net of realized FX hedge impact, due to an El Niño-related increase in market prices.

In comparison to the first quarter of 2024, the Company's operating netback increased 6%, from $43.97/boe to $46.40/boe, mainly due to a higher net sales realized price; lower transportation costs, net of realized FX hedge primarily attributed to an increase in local sales volumes, and more efficient transportation economics and routing for some of our heavy crude production; and lower energy costs, net of realized FX hedge impact, due to better electricity prices in Colombia benefiting from the end of the dry season, partially offset by higher energy use during the quarter; and an increase in production costs (excluding energy cost), net of realized FX hedge impact, driven by higher well services activity.

The following table provides a summary of the Company's netbacks for the six months ended June 30, 2024, and 2023:

	Six months ended June 30			
	2024		2023	
	$M	($/boe)	$M	($/boe)
Net sales realized price [1]	403,432	71.84	385,513	64.29
Production costs (excluding energy cost), net of realized FX hedge impact [1][2][3]	(74,700)	(10.51)	(62,718)	(8.29)
Energy costs, net of realized FX hedge impact [1][2][4]	(35,614)	(5.01)	(29,845)	(3.94)
Transportation costs, net of realized FX hedge impact [1][2][5]	(69,069)	(11.12)	(74,733)	(11.04)
Operating Netback [1] [2]	**224,049**	**45.20**	**218,217**	**41.02**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases [6]		30,853		33,128
Production [7]		39,053		41,818
Net production [8]		34,124		37,389

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 23.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 23.
(3) Includes $3.5 million and $4.8 million of realized FX hedge gain attributable to production costs for the six months ended June 30, 2024, and 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(4) Includes $1.4 million and $1.4 million of realized FX hedge gain attributable to energy costs for the six months ended June 30, 2024, and 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(5) Includes $1.0 million and $1.8 million of realized FX hedge gain attributable to transportation costs for the six months ended June 30, 2024, and 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(6) Sales volumes, net of purchases, excluding sales of third-party volumes.
(7) Refer to the "Production" section on page 6.
(8) Refer to the "Further Disclosures" section on page 36.

Operating netback for the six months ended June 30, 2024, increased from $41.02/boe to $45.20/boe, representing a 10% increase compared in the same period of 2023. The increase was primarily due to higher net sales realized price, partially offset by higher energy costs, net of realized FX hedge impact, due to an increase in market prices related to El Niño-related events, and an increase in production costs (excluding energy cost), net of realized FX hedge impact, mainly as a result of higher well services activity, inflationary pressures on services and wages indexation.

Sales

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Produced crude oil sales	222,487	225,074	429,664	418,408
Purchased crude net margin	(6,118)	(6,705)	(12,692)	(14,676)
Conventional natural gas sales	2,159	2,849	4,025	6,606
Oil and gas sales, net of purchases (1)	218,528	221,218	420,997	410,338
Premiums paid on oil price risk management contracts (2)	(3,796)	(2,600)	(7,285)	(5,775)
Royalties	(5,774)	(9,837)	(10,280)	(19,050)
Net sales (1)	**208,958**	**208,781**	**403,432**	**385,513**
Net sales realized price ($/boe) (3)	72.85	64.09	71.85	64.29

(1) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 23.
(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 23.

Oil and gas sales, net of purchases, decreased by $2.7 million for the three months ended June 30, 2024, compared to the same period of 2023, mainly due to lower volumes sold, but partially offset by higher Brent benchmark oil price (Refer to the "Realized and Reference Prices" section on page 8 for further details on changes in prices) and better oil differential prices. For the six months ended June 30, 2024, oil and gas sales, net of purchases, increased by $10.7 million compared to the same period of 2023, primarily due to higher Brent benchmark oil price and better oil differential prices partially offset by lower volumes sold.

Net sales for the three and six months ended June 30, 2024, increased by $0.2 million and $17.9 million, respectively, compared with the same periods of 2023. The following table describes the various factors that impacted net sales:

	Three months ended June 30	Six months ended June 30
($M)	**2024-2023**	**2024-2023**
Net sales for the period ended June 30, 2023	208,781	385,513
Increase due to 12% higher oil and gas price (YTD 10% higher)	26,944	39,223
Decrease in royalties	4,063	8,770
Decrease due to variance of total produced volumes sold	(29,634)	(28,564)
Increase in premiums paid on oil price risk management contracts	(1,196)	(1,510)
Net sales for the period ended June 30, 2024	**208,958**	**403,432**

Oil and Gas Operating Costs

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Production costs (excluding energy cost)	41,401	37,171	78,240	67,558
Energy cost	17,997	16,444	36,965	31,214
Transportation costs	34,917	39,130	70,112	76,500
Post-termination obligation	(364)	6,120	186	6,277
Inventory valuation	(1,019)	(561)	(4,942)	(8,614)
Total oil and gas operating costs	**92,932**	**98,304**	**180,561**	**172,935**

During the three and six months ended June 30, 2024, total oil and gas operating costs decreased by 5% and increased 4% respectively, compared to the same periods of 2023. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs (excluding energy cost) for the three and six months ended June 30, 2024, were 11% and 16% higher, respectively, compared with the same periods of 2023, driven by higher well services activity, inflationary pressures on services and wages indexation.

- Energy cost for the three and six months ended June 30, 2024, increased by 9% and 18%, respectively, compared with the same periods of 2023, mainly due to an El Niño-related increase in market prices.
- For the three and six months ended June 30, 2024, transportation costs decreased 11% and 8%, respectively, compared with the same periods of 2023, primarily due to lower volumes produced and transported.
- Post-termination obligations for the three months ended June 30, 2024, was negative by $0.4 million as a result of cost efficiencies in the execution of activities from returned blocks. Post-termination obligations for the six months ended June 30, 2024, was $0.2 million mainly due to the accrual of costs for relinquished Colombia blocks and Block 192 in Peru.
- Inventory valuation for the three months ended June 30, 2024, decreased by $0.5 million compared with the same period of 2023, mainly due to inventory buildup. For the six months ended June 30, 2024, inventory valuation increased $3.7 million, compared with the same period of 2023, mainly due to variance in inventory cost.

Cost of Purchases

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Cost of purchases [1]	55,153	66,602	113,012	125,889

[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 23.

Cost of purchases correspond to the cost of third-party hydrocarbon volumes purchased primarily for dilution and refining usage as part of the Company's oil operations and marketing and transportation strategy. For the three and six months ended June 30, 2024, the cost of purchases, including the transportation and processing fees for purchased volumes sold, decreased by $11.4 million and $12.9 million, respectively, compared with the same periods of 2023, mainly due to lower volumes used as a result of higher quality diluent acquired.

Royalties

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Royalties Colombia	5,299	9,594	9,693	18,657
Royalties Ecuador	475	243	587	393
Royalties	**5,774**	**9,837**	**10,280**	**19,050**

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia and Ecuador. For the three and six months ended June 30, 2024, royalties decreased by $4.1 million and $8.8 million, respectively, compared to the same periods of 2023, due to the change in the royalties payment method from in-cash to in-kind as per the ANH's request, partially offset by a higher WTI oil benchmark price. Refer to the "Production Reconciled to Sales Volumes" section on page 7 for further details of royalties PAP paid in-cash and in-kind.

Depletion, Depreciation and Amortization

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Depletion, depreciation and amortization	63,188	81,389	129,000	148,102

For the three and six months ended June 30, 2024, depletion, depreciation, and amortization expense ("**DD&A**") decreased by 22%, and 13%, respectively, compared to the same periods of 2023, mainly due to lower production during 2024 and the end of the Neiva block production contract in June of 2023.

Impairment Expense, Exploration Expenses and Others

	Three months ended June 30		Six months ended June 30	
($M)	2024	2023	2024	2023
Impairment expense of:				
Exploration and evaluation assets	—	4,339	—	19,503
Other	392	323	1,419	1,974
Total impairment expense	392	4,662	1,419	21,477
Exploration expenses of:				
Geological and geophysical costs, and other	404	392	814	779
Total exploration expenses	404	392	814	779
Expense (recovery) of asset retirement obligations	45	(40,562)	(997)	(27,481)
Impairment expense, exploration expenses and other	**841**	**(35,508)**	**1,236**	**(5,225)**

Total impairment expenses

During the three and six months ended June 30, 2024, the total impairment expenses was $0.4 million and $1.4 million, respectively, mainly related to obsolete material inventories and impairment of crude oil inventories from Peru, compared to $4.7 million and $21.5 million, respectively, during same periods of 2023, which includes mainly an impairment charge on exploration and evaluation of assets in Colombia, as a result of the relinquishment of the VIM-22 block.

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 and six months ended June 30, 2024, the Company recognized an expense of asset retirement obligations of $45 thousand and a recovery of asset retirement obligations of $1.0 million, respectively. During the three and six months ended June 30, 2023, the Company recognized a recovery of asset retirement obligations of $40.6 million and $27.5 million, respectively, mainly as a result of the sale of Frontera Energy OffShore Perú, wholly owned subsidiary that held a 100% W.I. in Block Z1, for a payment of $7.5 million.

Other Operating Costs

	Three months ended June 30		Six months ended June 30	
($M)	2024	2023	2024	2023
General and administrative	12,928	12,422	26,484	25,091
Special projects and other cost [1]	1,853	2,433	3,933	5,429
Share-based compensation	754	1,035	1,040	875
Restructuring, severance and other costs	1,052	1,825	2,855	3,397

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

General and Administrative ("G&A")

For the three and six months ended June 30, 2024, G&A expenses increased by 4% and 6%, respectively, compared with the same periods of 2023, mainly due to higher professional fees and taxes.

Special projects and other costs

For the three and six months ended June 30, 2024, special projects and other costs decreased by 24% and 27%, respectively, compared with the same periods of 2023, mainly due a reduction in costs related to Block Z1, due to the sale of Frontera Energy OffShore Perú, in 2023.

Share-Based Compensation

For the three and six months ended June 30, 2024, share-based compensation decreased by $0.3 million and increased $0.2 million, respectively, compared with the same periods of 2023. The decrease for the three months ended June 30, 2024, was mainly due to the strengthening of the U.S. dollar and the cancellation of certain share-based compensation. During the second quarter of 2024, the increase was mainly due to the recognition of a new grant under the share-based compensation plan at the beginning of second quarter of 2024. Share-based compensation reflects cash and non-cash charges relating to the vesting of restricted share units ("**RSUs**") and grants of deferred share units ("**DSUs**") under the Company's security-based compensation plan, which are subject to variability from movements in the underlying Common Share trading price, and the consolidation of stock option expenses from the Company's majority-held subsidiary, CGX.

Restructuring, Severance and Other Costs

For the three and six months ended June 30, 2024, restructuring, severance and other costs decreased by $0.8 million and $0.5 million, respectively, compared with the same periods of 2023, mainly due to a decrease in professional fees associated with restructuring initiatives.

Non-Operating Costs

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Finance income	1,816	1,472	3,408	5,773
Finance expenses	(17,429)	(15,688)	(34,699)	(30,909)
Foreign exchange (loss) income	(7,518)	17,006	(8,615)	5,246
Other (loss) income	(2,774)	(716)	(3,133)	5,589

Finance Income

For the three and six months ended June 30, 2024, finance income increased by $0.3 million and decreased by $2.4 million, respectively, compared to the same periods of 2023, due to variation of interest rates on the investment trust accounts for abandonment requirements and average of cash balances during the period.

Finance Expenses

For the three and six months ended June 30, 2024, finance expenses increased by $1.7 million and $3.8 million, respectively, compared to the same periods of 2023, mainly due to higher interest resulting from the Bancolombia Working Capital Loan (as defined below) and additional interest resulting from lease liabilities.

Foreign Exchange (Loss) Income

For the three and six months ended June 30, 2024, foreign exchange loss was $7.5 million and $8.6 million, respectively, as a result of the transfer from the cumulative translation adjustment of the Other Comprehensive (Loss) Income ("**OCI**") to Consolidated Statement of Income of a return of capital and dividends of ODL during the first half of 2024. During the same period of 2023, the foreign exchange income was $17.0 million and $5.2 million, respectively, as a result of the COP's depreciation against the USD on the translation of the debt consolidated from Puerto Bahia during the first quarter 2023, offset by the transfer from the cumulative translation adjustment of the OCI to Consolidated Statement of Income of a return of capital of ODL for $6.8 million, during the second quarter 2023. Foreign exchange rates (COP:USD) as of June 30, 2024, and 2023, were 4,148.04:1 and 4,191.28:1, respectively.

Other (Loss) Income

For the three and six months ended June 30, 2024, the Company recognized other loss of $2.8 million and $3.1 million respectively. These expenses were mainly attributable to contingencies, partially offset by income related to insurance compensation for the Sabanero block. During the same periods of 2023, the Company recognized other loss of $0.7 million and an income $5.6 million, respectively. During the second quarter of 2023, the loss was mainly due to recognition of write down of assets, and for the six months ended June 30, 2023, the amount includes the net of the contingencies in the reversal of the legal claim from the late delivery of production from Quifa block prior to 2014.

(Loss) Gain on Risk Management Contracts

($M)	Three months ended June 30		Six months ended June 30	
	2024	2023	2024	2023
Premiums paid on oil price risk management contracts, net	(3,796)	(2,600)	(7,285)	(5,775)
Realized gain on foreign exchange risk hedge [1]	3,832	8,958	6,447	8,958
Realized gain (loss) on risk management contracts	36	6,358	(838)	3,183
Unrealized (loss) gain on risk management contracts	(3,646)	4,057	(11,585)	8,882
Total (loss) gain on risk management contracts	(3,610)	10,415	(12,423)	12,065

[1] For determination of operating netback, during the three and six months ended June 30, 2024, the Company estimates an attribution of $2.2 million and $3.5 million, respectively, of the total realized FX hedge to production cost (excluding energy cost) (2023: $4.8 million and $4.8 million respectively), estimates an attribution of $0.8 million and $1.4 million, respectively, of the total realized FX hedge to energy (2023:$1.4 million and $1.4 million, respectively), and estimates an attribution of $0.6 million and $1.0 million, respectively, of the total realized FX hedge to transportation (2023: $1.8 million and $1.8 million), respectively. Refer to the "Non-IFRS and Other Financial Measures'' section on page 23.

For the three and six months ended June 30, 2024, the realized gain on risk management contracts was $36 thousand and a loss of $0.8 million, respectively, resulting from $3.8 million and $7.3 million, respectively, in premiums paid on oil price risk management contracts, partially offset by a gain of $3.8 million and $6.4 million, respectively, on the cash settlement of risk management contracts of foreign exchange currency. In the same periods of 2023, the Company realized a gain on risk management contracts of $6.4 million and $3.2 million, respectively, resulting from the early termination of some zero-cost collars foreign exchange risk management contracts, and partially offset by the premiums paid on oil price risk management contracts.

For the three and six months ended June 30, 2024, risk management contracts had an unrealized loss of $3.6 million and $11.6 million, respectively, compared to a gain of $4.1 million and $8.9 million, respectively, in the same periods of 2023, 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. Following the end of quarter, the Company successfully achieved a 40% hedging target ratio through November 2024.

Type of Instrument	Term	Benchmark	Notional Amount / Volume in USD	Avg. Put / Call Par forward (COP$)	Carrying Amount Assets	Carrying Amount Liabilities
Put	July 2024	Brent	452,000	75	—	1,258
Put	August 2024	Brent	430,000	76.50	—	939
Put	September 2024 to November 2024	Brent	810,000	78	—	554
Total as at June 30, 2024			1,692,000		—	2,751

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

Type of Instrument	Term	Benchmark	Notional Amount / Volume (bbl)	Avg. Strike Prices Put $/bbl
Put	October 2024 to November 2024	Brent	444,000	78
		Total volume (bbl)	444,000	

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. In addition, during the second quarter 2024, the Company entered new derivatives to hedge its currency risk exposure related to the collection of the dividends from ODL, as required by the PIL Loan Facility (as defined below).

As of June 30, 2024, the Company has the following foreign currency derivatives contracts:

				Avg. Put / Call	Carrying Amount	
Type of Instrument	Term	Benchmark	Notional Amount / Volume in USD	Par forward (COP$)	Assets	Liabilities
Zero-cost collars	July to December 2024	USD / COP	66,000,000	4,010/4,504	—	1,087
Forward	October 2024	USD / COP	17,099,200	4,386	648	—
Forward [(1)]	August 2024 to December 2024	USD / COP	29,908,421	4,044/4,115	995	—
Total as at June 30, 2024					1,643	1,087

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

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

					Avg. Strike Prices
Type of Instrument	Term	Benchmark	Currency Hedged	Notional Amount / Volume in USD	Par forward (COP$)
Zero Cost Collars	October 2024 to December 2024	USD / COP	USD	24,000,000	4,100 / 4,483
		Total volume		24,000,000	

Income Tax Expense

	Three months ended June 30		Six months ended June 30	
($M)	2024	2023	2024	2023
Current income tax expense	(1,273)	(10,801)	(6,283)	(11,808)
Deferred income tax (expense) recovery	(31,386)	8,196	(52,961)	1,683
Total income tax expense	(32,659)	(2,605)	(59,244)	(10,125)

For the three and six months ended June 30, 2024, the Company recognized a current income tax expense of $1.3 million and $6.3 million, respectively, compared to $10.8 million and $11.8 million, respectively, in the same periods of 2023, and a deferred income tax expense of $31.4 million and $53.0 million, respectively, compared to a recovery of $8.2 million and $1.7 million, respectively, in the same periods of 2023.

The decrease in the current income tax expense is mainly due to a reduction in withholding taxes on dividends from investments in associates, and the recognition of the reversal of prior years' tax contingencies. The increase in the deferred income tax expense was caused by foreign currency fluctuations, which were offset by the use of tax losses in both periods and changes in the income tax rate projections on which deferred tax will be recovered.

CRA 2016 Settlement

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

The Settlement may result in a decrease in the net capital losses of the Company, as last reported in the 2023 Annual Consolidated Financial Statements, and an increase in the computed amount of the historical paid-up capital in respect of the Common Shares, which could impact the quantum of dividends deemed to have been received by certain shareholders of Frontera in respect of the repurchase of Common Shares pursuant to the Company's substantial issuer bid that was completed on August 11, 2022. The Company is currently assessing the impact of the Settlement on the computation of the historical paid-up capital in respect of the Common Shares and will provide an update to affected shareholders once such assessment has been completed.

Net (Loss) Income

	Three months ended June 30		Six months ended June 30	
($M)	2024	2023	2024	2023
Net (loss) income [(1)]	(2,846)	80,207	(11,349)	68,877
Per share – basic ($)	(0.03)	0.94	(0.13)	0.81
Per share – diluted ($)	(0.03)	0.92	(0.13)	0.79

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

During the second quarter of 2024, the Company reported a net loss, attributable to equity holders of the Company, of $2.8 million, mainly resulting from an income tax expense of $32.7 million (including $31.4 million of deferred income tax expenses), finance expenses of $17.4 million, foreign exchange losses of $7.5 million and $3.6 million related to loss on risk management contracts, partially offset by an income from operations of $45.2 million, and $13.4 million from share of income from associates. This compared to net income, attributable to equity holders of the Company, of $80.2 million for the second quarter of 2023, which included income from operations of $55.6 million (including $35.5 million, net of recovery of asset retirement obligations and impairment expenses), $14.3 million of share of income from associates, foreign exchange gain of $17.0 million and finance income of $1.5 million, partially offset by finance expenses of $15.7 million and income tax expenses of $2.6 million.

For the six months ended June 30, 2024, the Company reported a net loss, attributable to equity holders of the Company, of $11.3 million, mainly resulting from income tax expense of $59.2 million (including $53.0 million of deferred income tax expenses), finance expenses of $34.7 million, $12.4 million related to loss on risk management contracts and $8.6 million of foreign exchange losses, partially offset by income from operations of $74.9 million, and $27.3 million from share of income from associates. This compared to a net income, attributable to equity holders of the Company, of $68.9 million, which included income from operations of $52.9 million, $27.9 million of share of income from associates, gain on risk management contracts of $12.1 million and foreign exchange gain of $5.2 million, partially offset by income tax expenses of $10.1 million and finance expenses of $30.9 million.

Capital Expenditures and Acquisitions

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Development drilling	37,868	39,207	72,906	70,705
Development facilities	25,566	27,384	45,244	36,550
Colombia and Ecuador exploration	11,173	11,446	13,410	23,818
Other	1,521	2,401	7,855	3,938
Total Colombia and Ecuador upstream capital expenditures	**76,128**	**80,438**	**139,415**	**135,011**
Colombia infrastructure	3,467	1,456	8,023	2,633
Guyana exploration	603	72,966	2,141	148,668
Total capital expenditures (1)	**80,198**	**154,860**	**149,579**	**286,312**

(1) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 23.

Capital expenditures for the three and six months ended June 30, 2024, were $80.2 million and $149.6 million, respectively, compared with $154.9 million and $286.3 million, respectively, in the same periods of 2023, as follows:

Development drilling. During the three and six months ended June 30, 2024, development drilling expenditures were $37.9 million and $72.9 million, respectively, compared to $39.2 million and $70.7 million, respectively, in the same periods of 2023. During second quarter of 2024, 28 development wells were drilled in the Quifa and CPE-6, in Colombia, and 2 development wells were drilled in the Perico blocks, in Ecuador, while 19 development wells were drilled in the same period of 2023 in the Quifa, CPE-6 and Cubiro blocks and one injector well was drilled at the CPE-6 block. During the six months ended June 30, 2024, 48 development wells were drilled in the Quifa, Cajua and CPE-6 blocks, in Colombia, and 3 development wells were drilled in the Perico block, in Ecuador, while in the same period of 2023 a total of 37 development wells, including 1 injector well, were drilled in the Quifa, CPE-6, Cajua and Cubiro blocks.

Development facilities. During the three and six months ended June 30, 2024, development facilities expenditures were $25.6 million and $45.2 million, respectively, mainly related to the increase of water-handling capacity from 240 Mbpd to 300 Mbpd at CPE-6 block, the expansion of gas compression facilities to 30 MMcf/d production capacity in the VIM-1 block, injector well facilities in Quifa block, the expansion of Sabanero block facilities, and the purchase of facilities related to surface equipment in the Perico block. For the same periods of 2023, development facilities expenditures were $27.4 million and $36.6 million, respectively, mainly related to the expansion and improvement of the development facilities in the CPE-6 block.

Colombia and Ecuador Exploration. During the three and six months ended June 30, 2024, expenditures related to exploration activities were $11.2 million and $13.4 million, respectively, compared $11.4 million and $23.8 million, respectively, in the same periods of 2023. During the three months ended June 30, 2024, the exploration activities executed correspond to the acquisition of 3D seismic with respect to the Llanos-119 block, in Colombia, and the completion of one exploration well, the Espejo Sur-B3 well, at the Espejo Block, in Ecuador. During the same period of 2023, two exploration wells were completed in the VIM-22 block and the Company acquired 3D seismic with respect to the Llanos-99 block. Details relating to exploration activities in Colombia and Ecuador are as follows:

Colombia. The Company's exploration focus remains on the Lower Magdalena Valley and Llanos Basins. During the first half of 2024, in the VIM-1 block, all pre-drill activities were completed for the Hidra-1 exploratory well, now the spud is expected in the third quarter 2024. In the Llanos-119 block, the acquisition of 80 sqkm of 3D seismic was finished and processing is currently underway. The Company is also engaged in pre-seismic and pre-drilling activities related to social and environmental studies in the Llanos-99.

Ecuador. At the Espejo block (Frontera holds a 50% W.I. and is a non-operator), as agreed by the Company's partner, two pending committed exploratory wells are being drilled. The Espejo Sur-B3 well, was drilled during the second quarter of 2024, reaching a total depth 10,090 ft MD, integration of core, and logging while drilling (LWD) and pressure data interpreted 17 ft of net pay in Lower U Sand, currently producing approx. 500 bopd gross. On July 28, 2024, the Company's partner spud the Espejo Norte A-1 (before Espejo Centro-1) exploration well and drilling operations are on-ongoing; the main target is M1 Sand and the secondary target Lower is U Sand.

Other

Other capital expenditures for the three and six months ended June 30, 2024, were $1.5 million and $7.9 million, respectively. The expenditures were mainly related to generation facilities funded primarily through the reimbursement of insurance claim related to the Sabanero block.

Colombia infrastructure

Capital expenditures for the three and six months ended June 30, 2024, was $3.5 million and $8.0 million, respectively, mainly related to investments in the SAARA project and investments at Puerto Bahia including (i) general cargo terminal equipment purchases and terminal upgrading, (ii) tanks major maintenance, and (iii) right of way and engineering expenditure associated to the Reficar Connection Project. During the same periods of 2023 capital expenditures was $1.5 million and $2.6 million, respectively, which includes SAARA project and port facilities investments.

Guyana exploration. During the three and six months ended June 30, 2024, Guyana exploration expenditures were $0.6 million and $2.1 million, respectively, mainly related to post-well studies, compared to $73.0 million and $148.7 million, respectively, during the same periods of 2023, which were related to Wei-1 exploration well.

Selected Quarterly Information

		2024		2023				2022	
Operational and financial results		Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Heavy crude oil production	(bbl/d)	24,839	23,398	23,002	24,097	24,051	22,270	22,144	20,945
Light and medium crude oil combined production	(bbl/d)	12,583	12,580	13,795	13,964	15,188	16,518	17,073	17,428
Total crude oil production	(bbl/d)	37,422	35,978	36,797	38,061	39,239	38,788	39,217	38,373
Conventional natural gas production	(mcf/d)	4,019	3,283	4,760	5,250	5,626	8,590	9,097	9,969
Natural gas liquids production	(boe/d)	1,785	1,639	1,635	1,820	1,823	1,291	993	911
Total production	(boe/d)	39,912	38,193	39,267	40,802	42,049	41,586	41,806	41,033
Sales volumes, net of purchases	(boe/d)	31,523	30,185	34,449	35,289	35,799	30,424	34,323	36,660
Brent price reference	($/bbl)	85.03	81.76	82.85	85.92	77.73	82.10	88.63	97.70
Oil and gas sales, net of purchases [1]	($/boe)	76.18	73.71	75.76	78.48	67.91	69.07	82.60	90.40
Premiums paid on oil price risk management contracts [2]	($/boe)	(1.32)	(1.27)	(0.69)	(0.59)	(0.80)	(1.16)	(1.32)	(1.30)
Royalties [2]	($/boe)	(2.01)	(1.64)	(1.79)	(3.76)	(3.02)	(3.36)	(6.04)	(7.23)
Net sales realized price [1]	($/boe)	72.85	70.80	73.28	74.13	64.09	64.55	75.24	81.87
Production costs (excluding energy cost), net of realized FX hedge impact [2]	($/boe)	(10.79)	(10.21)	(9.69)	(8.82)	(8.45)	(8.12)	(8.48)	(8.30)
Energy costs, net of realized FX hedge impact [2]	($/boe)	(4.74)	(5.29)	(5.06)	(5.04)	(3.94)	(3.95)	(3.08)	(2.90)
Transportation costs, net of realized FX hedge impact[2]	($/boe)	(10.92)	(11.33)	(11.02)	(11.73)	(10.89)	(11.20)	(10.55)	(10.70)
Operating netback per boe [1]	($/boe)	46.40	43.97	47.51	48.54	40.81	41.28	53.13	59.97
Revenue	($M)	279,523	265,175	299,501	308,867	289,869	250,366	317,568	354,548
Net (loss) income [3]	($M)	(2,846)	(8,503)	92,038	32,582	80,207	(11,330)	197,796	(26,893)
Per share – basic ($)	($)	(0.03)	(0.10)	1.08	0.38	0.94	(0.13)	2.29	(0.30)
Per share – diluted ($)	($)	(0.03)	(0.10)	1.04	0.37	0.92	(0.13)	2.25	(0.30)
General and administrative	($M)	12,928	13,556	16,891	11,925	12,422	12,669	12,761	12,549
Operating EBITDA [4]	($M)	110,321	97,248	121,036	137,800	116,461	91,922	144,994	173,207
Capital expenditures [4]	($M)	80,198	69,381	82,292	74,130	154,860	131,452	134,165	76,018

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 23.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 23.
(3) Refers to net (loss) income attributable to equity holders of the Company.
(4) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 23 for further details.

Over the past eight quarters, the Company's sales have fluctuated due to changes in production, movement in Brent benchmark prices, timing of cargo shipments, and fluctuations in crude oil price differentials. Since the second quarter of 2023 until the first quarter of 2024, production had decreased mainly due to: (i) natural decline and well failures in light and medium crude oil combined, and conventional natural gas, (ii) the return of the Neiva block following the completion of the production contract, and (iii) the relinquishment of the La Creciente block. However, this decrease had been offset, and even, during the second quarter of 2024, production increased, attributable to: (i) successful drilling campaign in and investment in water-handling facilities in the Quifa and CPE-6 blocks, (ii) development of facilities in the VIM-I block, and (iii) the development of the Perico block in Ecuador. During the last year, transportation costs had increased, mainly due to the regular annual increase of transportation tariffs, however, during second quarter of 2024, decrease due to higher local sales volumes, and more efficient transportation economics and routing for some of our heavy crude production. Energy costs increased primarily as a result of an El Niño-related increase in market prices, however, during second quarter of 2024 was lower as a result of the finalization of El Niño-related event and stabilization of energy prices. In addition, production costs (excluding energy cost) have also fluctuated mainly due to the inflationary pressures on services, wages indexation, well services and maintenance activities, and changes in barrels produced affecting variable costs.

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

Infrastructure Colombia

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

The Company's Infrastructure Colombia Segment includes the following:

Asset	Description	Interest (1)	Accounting Method
Puerto Bahia	Bulk liquids storage and import-export terminal	99.97% interest in Puerto Bahía	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/day	100% interest in PIL (which holds a 35% interest in the ODL Pipeline)	Equity Method (2)
SAARA (3)	Reverse osmosis water treatment, name plate capacity of 1,000,000 bwpd	100% interest in Agro Cascada	Consolidation
ProAgrollanos	Palm oil plantation, 20,000-27,000 tons per year of fresh fruit bunch	100% interest in Promotora Agricola de los Llanos	Consolidation

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

Performance Highlights

		Q2 2024	Q1 2024	Q2 2023	Six months ended June 30 2024	Six months ended June 30 2023
Operational and IFRS Results						
Volumes pumped at oil pipeline facility	(bbl/d)	249,196	246,042	243,490	247,619	234,690
Volumes throughput at port liquids facility	(bbl/d)	61,798	53,360	73,714	57,579	68,390
Volumes RORO at port general cargo facility	(Units)	18,986	12,849	30,084	31,835	60,299
Volumes at port Break Bulk Volumes	(Tons/m3)	11,256	8,481	4,782	19,737	15,816
Volumes of water received from production fields	(bwpd)	22,097	33,272	43,375	55,369	65,679
Production of fresh fruit bunch	(Tons)	8,895	5,095	7,582	13,990	13,243
Infrastructure Colombia segment income	($M)	14,620	12,552	15,439	27,172	31,428
Infrastructure Colombia segment cash flow from operating activities	($M)	29,922	643	20,129	30,565	25,764
Non IFRS Results [(1)]						
Adjusted Infrastructure Revenues	($M)	43,055	40,907	42,989	83,962	82,539
Adjusted Infrastructure EBITDA	($M)	27,823	25,687	28,512	53,510	55,875
Adjusted Infrastructure Cash	($M)	48,831	78,813	45,821	48,831	45,821
Adjusted Infrastructure Debt	($M)	113,763	120,024	123,459	113,763	123,459
Capital Expenditures Infrastructure Colombia Segment	($M)	3,467	4,556	1,456	8,023	2,633

(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 23.

Infrastructure Colombia Segment Results

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

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Revenue	12,894	12,883	23,422	25,348
Costs	(7,598)	(8,015)	(15,747)	(15,151)
General and administrative expenses	(1,389)	(1,540)	(2,868)	(2,995)
Depletion, depreciation and amortization	(1,962)	(1,534)	(3,778)	(2,888)
Restructuring, severance and other costs	(732)	(700)	(1,158)	(803)
Infrastructure income (loss) from operations	**1,213**	**1,094**	**(129)**	**3,511**
Share of Income from associates - ODL	13,407	14,345	27,301	27,917
Infrastructure Colombia segment income	**14,620**	**15,439**	**27,172**	**31,428**
Infrastructure Colombia segment cash flow from operating activities	29,922	20,129	30,565	25,764
Capital Expenditures Infrastructure Colombia Segment [(1)]	3,467	1,456	8,023	2,633

(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 23.

The Company's Infrastructure Colombia segment income for the three months ended June 30, 2024, decreased by $0.8 million, compared to the same period of 2023, mainly due to lower Share of Income from ODL partially offset by a costs optimizations at the port. For the six months ended June 30, 2024, the Infrastructure Colombia segment income decreased by $4.3 million, compared to the same period of 2023, mainly due to lower general cargo revenues at Puerto Bahia and higher operating costs due to inflationary pressures.

Segment capital expenditures for the three and six months ended June 30, 2024, was $3.5 million and $8.0 million, respectively, mainly related to investments in the SAARA project and investments at Puerto Bahia including: (i) general cargo terminal equipment purchases and terminal upgrading, (ii) tank major maintenance, and (iii) rights of way and engineering expenditures associated to the Reficar Connection Project. During the same periods of 2023, capital expenditures was $1.5 million and $2.6 million, respectively, including the SAARA project and investments in the 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, Caño Sur, Llanos-34, among other blocks to the Monterrey or Cusiana Stations in the Casanare Department.

For the three and six months ended June 30, 2024, ODL generated $68.3 million and $139.2 million, respectively, of EBITDA, and $38.3 million and $78.0 million, respectively, of net income. The ODL results are consolidated through the equity method in the Interim Financial Statements as “Share of income from associates”.

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

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Revenue	86,174	86,017	172,971	163,404
FEC revenue (billed units)	7,522	7,879	14,974	14,789
Third party revenues	78,652	78,138	157,997	148,615
Costs	(12,572)	(10,212)	(23,968)	(17,708)
General administrative expenses	(5,270)	(3,850)	(9,851)	(6,628)
Depletion, depreciation and amortization	(7,933)	(6,850)	(15,859)	(12,631)
Other non-operating expense	(1,465)	(2,042)	(3,287)	(3,720)
Income tax	(20,627)	(22,074)	(42,002)	(42,954)
ODL Net Income	**38,307**	**40,989**	**78,004**	**79,763**

($M)	**June 30 2024**	**December 31 2023**
ODL debt	39,940	45,147
ODL cash and cash equivalents	54,273	131,839

The following table shows the volumes pumped per injection point:

	Three months ended June 30		Six months ended June 30	
(bbl/d)	**2024**	**2023**	**2024**	**2023**
At Rubiales Station	172,163	170,474	169,770	162,689
At Jagüey and Palmeras Station	77,033	73,016	77,849	72,001
Total	**249,196**	**243,490**	**247,619**	**234,690**

The following table shows the volumes received per block:

	Three months ended June 30		Six months ended June 30	
(bbl/d)	**2024**	**2023**	**2024**	**2023**
Rubiales	102,512	107,418	101,865	106,807
Quifa	29,460	31,540	29,151	29,658
CPE-6	3,118	1,958	3,316	2,110
Other blocks	100,048	86,125	98,863	79,448
Total	**235,138**	**227,041**	**233,195**	**218,023**

For the three and six months ended June 30, 2024, the Company recognized $13.4 million and $27.3 million, respectively, as its share of income from ODL, which was lower than the same periods of 2023 by $0.9 million and $0.6 million respectively. This result was primarily due to an increase in operating and G&A expenses resulting from COP variance, partially offset by the increase in crude oil volumes received and transported from the Caño Sur and Llanos 34 blocks.

During the three and six months ended June 30, 2024, ODL declared net dividends to PIL of $Nil and $54.9 million, respectively (2023: $Nil and $37.0 million, respectively), and a return of capital of $Nil and $7.9 million, respectively (2023: $Nil and $5.2 million, respectively). During the three and six months ended June 30, 2024, PIL received cash of $31.3 million and $31.3 million, respectively, in dividends and return of capital from ODL (2023: $25.7 million and $25.7 million, respectively).

Puerto Bahia

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

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Revenue	11,243	12,175	20,948	23,019
Liquids port facility	8,020	8,252	15,122	15,446
FEC liquids port facility	1,868	1,903	4,020	3,567
Third party liquids port facility	6,152	6,349	11,102	11,879
General cargo	3,223	3,923	5,826	7,573
Costs	(5,604)	(5,733)	(11,673)	(10,850)
General and administrative expenses	(1,270)	(1,453)	(2,674)	(2,796)
Depletion, depreciation and amortization	(1,754)	(1,319)	(3,404)	(2,551)
Restructuring, severance and other costs	(732)	(700)	(1,158)	(803)
Puerto Bahia Operating Income	1,883	2,970	2,039	6,019

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

	Three months ended June 30		Six months ended June 30	
(bbl/d)	**2024**	**2023**	**2024**	**2023**
FEC volumes	13,353	14,267	15,000	12,845
Third party volumes	48,445	59,447	42,579	55,545
Total	**61,798**	**73,714**	**57,579**	**68,390**

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 June 30		Six months ended June 30	
		2024	**2023**	**2024**	**2023**
RORO	units [(1)]	18,986	30,084	31,835	60,299
	dwell time in days [(2)]	70	49	87	42
Break Bulk Volumes	Tons/m3 [(3)]	11,256	4,782	19,737	15,816

(1) Carry wheeled cargo, mainly corresponds to cars imported to Colombia.
(2) Dwell time refers to the time spent by the units within the general cargo port facility. The variance in dwell time associated with Break Bulk Volumes could depend on the characteristics of the cargo, especially in situations where the cargo is received and dispatched within a single day, thereby eliminating the necessity for storage, as occurred during second quarter of 2024.
(3) Other types of cargo different from wheeled cargo.

For the three and six months ended June 30, 2024, Puerto Bahia had an operating income of $1.9 million and $2.0 million, respectively, (2023: $3.0 million and $6.0 million, respectively). For the three and six months ended June 30, 2024, the Puerto Bahia's liquids terminal revenues remained stable, with increased tariffs offset by the reduced volumes, compared to the same periods of 2023. Meanwhile, general cargo revenues decreased due to reduced activity and lower volumes of RORO and break bulk. During the three months ended June 30, 2024, costs decreased 2%, primarily resulting from the end of the port operation outsourcing contract, compared to the same period of 2023. Meanwhile, during the six months ended June 30, 2024, costs increased by 8% mainly due to inflationary pressures on services and the impact of COP appreciation during the period.

During the third quarter of 2023, Puerto Bahia and Reficar agreed to connect Puerto Bahia's port facility and the Cartagena refinery with a 6.8-kilometre, 18-inch, bi-directional hydrocarbon flow line. This connection will facilitate the continuous transport of crude oil and other hydrocarbons between the two locations and shall have a capacity of 84,000 barrels per day, capable of handling both, imported and domestically produced crude oil. Subsequent to the quarter, Puerto Bahia began construction of the connection project between Puerto Bahia and Reficar, which the Company expects will become operational in December 2024.

Subsequent to the quarter, on July 22, 2024, Frontera announced that its subsidiary, Puerto Bahia and GASCO had entered into a Framework Collaboration Agreement to jointly pursue a LPG project at the Puerto Bahia port. The estimated cost of the project is expected to be approximately $50 to $60 million, which will be shared between Puerto Bahia and GASCO. Puerto Bahia's contributions are expected to be largely in-kind and the project is expected to be in service by 2027.

Water Treatment Facility and Palm Oil Plantation

In 2021, Frontera launched a feasibility analysis of the agricultural water reuse utilization system, SAARA, consisting of a reverse osmosis plant water treatment facility (built in 2016) that the Company began recommissioning in 2023. The plant will help solve and take advantage of the availability of production water from the Quifa and Rubiales blocks. The plant was designed to remove salts from its treated water to bring it to a state suitable for use in agricultural irrigation of industrial crops.

Through its wholly-owned subsidiary ProAgrollanos, the Company operates an African palm oil business located in the Municipality of Puerto Gaitan, department of Meta. Spanning across approximately 2,960 hectares, its palm oil plantation yielded 21,218 tons of fresh fruit bunches in 2023. These crops typically exhibit an estimated productive lifespan of 30 years.

A portion of the water treated by SAARA is irrigated and reused in ProAgrollanos' agricultural activities, increasing the irrigation and targeting improving palm crop productivity of 20-25 tons per ha/year. During the recommissioning period in 2023, SAARA processed approximately 20.6 million barrels of water, irrigating approximately 400 hectares of palm oil crops in ProAgrollanos.

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

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Revenue	1,651	708	2,474	2,329
Fresh fruit bunch from palm oil	1,451	708	2,274	2,329
SAARA	200	—	200	—
Costs	(1,994)	(2,282)	(4,074)	(4,301)
Fresh fruit bunch from palm oil	(1,050)	(924)	(1,759)	(1,468)
SAARA	(944)	(1,358)	(2,315)	(2,833)
General and administrative expenses	(119)	(87)	(194)	(199)
Depletion, depreciation and amortization	(208)	(215)	(374)	(337)
SAARA and Palm Oil Assets Operating Loss	**(670)**	**(1,876)**	**(2,168)**	**(2,508)**

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

		Three months ended June 30		Six months ended June 30	
($M)		**2024**	**2023**	**2024**	**2023**
Fresh fruit bunch from palm oil (produced - sold)	(Tons)	8,895	7,582	13,990	13,243
Production per hectare per year [(1)]	(Tons/ha/year)	7.42	6.64	—	—
Palm oil fruit price	($/Ton)	166	162	162	167
Volumes of water received from production fields	(bwpd)	22,097	43,375	27,685	32,898
Volumes of water irrigated in palm oil cultivation	(bwpd)	14,398	33,855	19,006	25,057

[(1)] Tons per hectare per year are calculated using the total production for the last twelve months ended June 30.

For the three and six months ended June 30, 2024, sales from fresh fruit bunches of palm oil was $1.5 million and $2.3 million, respectively, an increase of $0.7 million and a decrease $0.1 million, respectively, compared to the same periods of 2023, resulting primarily from an increase in field productivity, and prices volatility in 2024. Fluctuation in fruit production volume is attributed to factors including climate conditions, agricultural practices (i.e. fertilization), workforce availability and community blockades in the area near to the crop.

During the three and six months ended June 30, 2024, volumes of water received and volumes of water irrigated to palm oil plantation were lower than the previous periods, mainly due to the temporary suspension of the plant following the conclusion of the project's pilot program on January 31, 2024. During the second quarter of 2024, Frontera reached an agreement with Ecopetrol to start the first phase of the SAARA project, which processed approximately 2 million barrels of water in June 2024 generating $0.2 million revenue for the first time in SAARA.

The Company expects increasing processing capacity of SAARA to 250,000 barrels of water per day by year-end.

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 (loss) income to Operating EBITDA:

	Three months ended June 30		Six months ended June 30	
($M)	**2024**	**2023**	**2024**	**2023**
Net (loss) income [1]	(2,846)	80,207	(11,349)	68,877
Finance income	(1,816)	(1,472)	(3,408)	(5,773)
Finance expenses	17,429	15,688	34,699	30,909
Income tax expense	32,659	2,605	59,244	10,125
Depletion, depreciation and amortization	63,188	81,389	129,000	148,102
Expense (recovery) of asset retirement obligation	45	(40,562)	(997)	(27,481)
Expenses of impairment	392	4,662	1,419	21,477
Post-termination obligation	(364)	6,120	186	6,277
Share-based compensation	754	1,035	1,040	536
Restructuring, severance and other costs	1,052	1,825	2,855	3,397
Share of income from associates	(13,407)	(14,345)	(27,301)	(27,917)
Foreign exchange loss (gain)	7,518	(17,006)	8,615	(5,246)
Other loss (income)	2,774	716	3,133	(5,589)
Unrealized loss (gain) on risk management contracts	3,646	(4,057)	11,585	(8,882)
Non-controlling interests	(288)	(344)	(443)	(429)
Gain on repurchased 2028 Unsecured Notes	(415)	—	(709)	—
Operating EBITDA	**110,321**	**116,461**	**207,569**	**208,383**

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

Capital expenditures

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

	Three months ended June 30		Six months ended June 30	
	2024	**2023**	**2024**	**2023**
Consolidated Statements of Cash Flows				
Additions to oil and gas properties, infrastructure port, and plant and equipment	87,033	66,166	149,882	109,146
Additions to exploration and evaluation assets	10,467	88,924	12,954	177,870
Total additions in Consolidated Statements of Cash Flows	**97,500**	**155,090**	**162,836**	**287,016**
Non-cash adjustments [(1)]	(17,302)	(230)	(13,257)	(704)
Total Capital Expenditures	**80,198**	**154,860**	**149,579**	**286,312**
Capital Expenditures attributable to Infrastructure Colombia Segment	3,467	1,456	8,023	2,633
Capital Expenditures attributable to other segments different to Infrastructure Colombia Segment	76,731	153,404	141,556	283,679
Total Capital Expenditure	**80,198**	**154,860**	**149,579**	**286,312**

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

Adjusted Infrastructure Colombia Calculations

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

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

	Three months ended June 30		Six months ended June 30	
($M) [(1)]	**2024**	**2023**	**2024**	**2023**
Revenue Infrastructure Colombia Segment	12,894	12,883	23,422	25,348
Revenue from ODL	86,174	86,017	172,971	163,404
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [(1)]	30,161	30,106	60,540	57,191
Adjusted Infrastructure Revenues	**43,055**	**42,989**	**83,962**	**82,539**
Operating cost Infrastructure Colombia Segment	(7,598)	(8,015)	(15,747)	(15,151)
Operating Cost from ODL	(12,572)	(10,212)	(23,968)	(17,708)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [(1)]	(4,400)	(3,574)	(8,389)	(6,198)
Adjusted Infrastructure Operating Costs	**(11,998)**	**(11,589)**	**(24,136)**	**(21,349)**
General and administrative Infrastructure Colombia Segment	(1,389)	(1,540)	(2,868)	(2,995)
General and administrative from ODL	(5,270)	(3,850)	(9,851)	(6,628)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [(1)]	(1,845)	(1,348)	(3,448)	(2,320)
Adjusted Infrastructure General and Administrative	**(3,234)**	**(2,888)**	**(6,316)**	**(5,315)**

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

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

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

($M) [1]	June 30 2024	December 31 2023
Cash and cash equivalents - unrestricted	180,659	159,673
Cash and cash equivalents of Non-Infrastructure Colombia Segment's	(150,824)	(134,186)
Total Cash Infrastructure Colombia Segment	29,835	25,487
Cash and cash equivalent from ODL	54,273	131,839
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	18,996	46,144
Adjusted Infrastructure Cash	**48,831**	**71,631**
Short-Term and Long-Term Debt	508,602	517,604
Debt of Non-Infrastructure Colombia Segment's	(408,818)	(421,982)
Total Debt	99,784	95,622
Debt from ODL	39,940	45,147
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	13,979	15,801
Adjusted Infrastructure Debt	**113,763**	**111,423**

[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 Segment business, including ODL's EBITDA direct participation interest.

	Three months ended June 30		Six months ended June 30	
($M)	2024	2023	2024	2023
Adjusted Infrastructure Revenue	43,055	42,989	83,962	82,539
Adjusted Infrastructure Operating Costs	(11,998)	(11,589)	(24,136)	(21,349)
Adjusted Infrastructure General and Administrative	(3,234)	(2,888)	(6,316)	(5,315)
Adjusted Infrastructure EBITDA	**27,823**	**28,512**	**53,510**	**55,875**

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 10.

Operating Netback

Operating netback is a non-IFRS financial measure and operating netback per boe is a non-IFRS ratio. Operating netback per boe is used to assess the net margin of the Company's production after subtracting all costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and gas industry to analyze financial and operating performance expressed as profit per barrel and is an indicator of how efficient the Company is at extracting and selling its product. For netback purposes, the Company removes the results 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 9.

Oil and Gas Sales, Net of Purchases

Oil and gas sales, net of purchases, is a non IFRS financial measure that is calculated using oil and gas sales less the purchased crude net margin. Produced crude oil and gas sales per boe and Oil and gas sales, net of purchases per boe, are a non IFRS ratio that are calculated using Produced crude oil and gas sales per boe, and the oil and gas sales, net of purchases, divided by the total sales volumes, net of purchases.

A reconciliation of this calculation is provided below:

	Three months ended June 30		Six months ended June 30	
	2024	**2023**	**2024**	**2023**
Purchased crude oil and products sales ($M)[1]	224,646	227,923	433,689	425,014
Purchased crude net margin ($M)	(6,118)	(6,705)	(12,692)	(14,676)
Oil and gas sales, net of purchases ($M)	**218,528**	**221,218**	**420,997**	**410,338**
Sales volumes, net of purchases - (boe)	2,868,593	3,257,709	5,615,246	5,996,168
Produced crude oil and gas sales ($/boe)	78.31	69.96	77.23	70.88
Oil and gas sales, net of purchases ($/boe)	76.18	67.91	74.97	68.43

(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” section on page 18.

Non-IFRS Ratios

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

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

	Three months ended June 30		Six months ended June 30	
	2024	**2023**	**2024**	**2023**
Oil and gas sales, net of purchases ($M) [1]	218,528	221,218	420,997	410,338
Crude oil sales volumes, net of purchases - (bbl)	2,804,205	3,169,231	5,498,687	5,776,594
Conventional natural gas sales volumes - (mcf)	366,869	504,166	665,013	1,249,960
Realized oil price, net of purchases ($/bbl)	77.16	68.90	75.83	69.90
Realized conventional natural gas price ($/mcf)	5.88	5.65	6.05	5.29

(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 June 30		Six months ended June 30	
	2024	**2023**	**2024**	**2023**
Oil and gas sales, net of purchases ($M) [1]	218,528	221,218	420,997	410,338
(-) Premiums paid on oil price risk management contracts ($M)	(3,796)	(2,600)	(7,285)	(5,775)
(-) Royalties ($M)	(5,774)	(9,837)	(10,280)	(19,050)
Net sales ($M)	**208,958**	**208,781**	**403,432**	**385,513**
Sales volumes, net of purchases - (boe)	2,868,593	3,257,709	5,615,246	5,996,168
Oil and gas sales, net of purchases ($/boe)	76.18	67.91	74.97	68.43
Premiums paid on oil price risk management contracts [2]	(1.32)	(0.80)	(1.30)	(0.96)
Royalties ($/boe) [2]	(2.01)	(3.02)	(1.83)	(3.18)
Net sales realized price ($/boe)	**72.85**	**64.09**	**71.84**	**64.29**

(1) Non-IFRS financial measure.
(2) Supplementary financial measure.

Purchased crude net margin

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

	Three months ended June 30		Six months ended June 30	
	2024	**2023**	**2024**	**2023**
Purchased crude oil and products sales ($M)	49,035	59,897	100,320	111,213
(-) Cost of purchases ($M) (1)	(55,153)	(66,602)	(113,012)	(125,889)
Purchased crude net margin ($M)	**(6,118)**	**(6,705)**	**(12,692)**	**(14,676)**
Sales volumes, net of purchases - (boe)	2,868,593	3,257,709	5,615,246	5,996,168
Purchased crude net margin ($/boe)	**(2.13)**	**(2.05)**	**(2.26)**	**(2.45)**

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

Production costs (excluding energy 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 June 30		Six months ended June 30	
	2024	**2023**	**2024**	**2023**
Production costs (excluding energy cost) ($M)	41,401	37,171	78,240	67,558
(-) Realized gain on FX hedge attributable to production costs (excluding energy cost) ($M) (1)	(2,203)	(4,840)	(3,540)	(4,840)
Production costs (excluding energy cost), net of realized FX hedge impact ($M) (2)	39,198	32,331	74,700	62,718
Production (boe)	3,631,992	3,826,459	7,107,646	7,569,058
Production costs (excluding energy cost), net of realized FX hedge impact ($/boe)	10.79	8.45	10.51	8.29

(1) See “(Loss) Gain on Risk Management Contracts” on page 14.

(2) Non-IFRS financial measure.

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

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

	Three months ended June 30		Six months ended June 30	
	2024	**2023**	**2024**	**2023**
Energy costs ($M)	17,997	16,444	36,965	31,214
(-) Realized gain on FX hedge attributable to energy costs ($M) (1)	(770)	(1,369)	(1,351)	(1,369)
Energy costs, net of realized FX hedge impact ($M) (2)	17,227	15,075	35,614	29,845
Production (boe)	3,631,992	3,826,459	7,107,646	7,569,058
Energy costs, net of realized FX hedge impact ($/boe)	4.74	3.94	5.01	3.94

(1) See “(Loss) Gain on Risk Management Contracts” on page 14.

(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 June 30		Six months ended June 30	
	2024	**2023**	**2024**	**2023**
Transportation costs ($M)	34,917	39,130	70,112	76,500
(-) Realized gain on FX hedge attributable to transportation costs ($M) [1]	(634)	(1,767)	(1,043)	(1,767)
Transportation costs, net of realized FX hedge impact ($M) [2]	34,283	37,363	69,069	74,733
Net production (boe)	3,139,955	3,431,246	6,210,568	6,767,409
Transportation costs, net of realized FX hedge impact ($/boe)	10.92	10.89	11.12	11.04

[1] See “(Loss) Gain on Risk Management Contracts” on page 14.
[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 of the 2028 Unsecured Notes, loans and liabilities from leases of various properties, power generation supply, vehicles and other assets.

4. LIQUIDITY AND CAPITAL RESOURCES

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

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

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

As of June 30, 2024, the Company had a total cash balance of $215.1 million (including $34.4 million in restricted cash), which is $25.1 million higher than December 31, 2023.

For the six months ended June 30, 2024, the Company generated $215.4 million, of cash from operations, including approximately $27 million in tax recoveries, which were used to fund cash outflows of $147.2 million for capital expenditures and other investing activities. For the six months ended June 30, 2024, financing activities generated net outflows of $43.6 million, mainly as a result of $22.9 million of interest paid and other charges, $13.7 million used for the repayment in full of the principal amount outstanding with respect to the PetroSud Debt and the PIL Loan Facility (as defined below), $5.5 million in Common Shares purchased under the 2023 NCIB, $3.9 million related to dividends paid to equity holders, $2.8 million in repurchases of the 2028 Unsecured Notes and $3.1 million in lease payments, partially offset by the disbursement of $8.8 million in net proceeds from the accordion tranche as part of the PIL Loan Facility. In addition, the Company's net working capital(1) improved by $46.4 million, reducing the deficit to $15.5 million as at June 30, 2024, compared to a deficit of $61.9 million at year-end 2023.

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

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. As of June 30, 2024, the main components of restricted cash were long-term abandonment funds as required by the ANH, and restricted funds related to the PIL Loan Facility. Abandonment funds will satisfy abandonment obligations and are expected to be released in the long-term as assets are abandoned. Abandonment funding requirements are updated annually. As of June 30, 2024, the Company's restricted cash position was $34.4 million, representing an increase of $4.1 million from December 31, 2023, primarily due to the increase in the debt service reserve account of the PIL Loan Facility, partially compensated by the finalization of the debt service reserve account of the PetroSud Debt, used in full to support the repayment.

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

Unsecured Notes

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

During the six months ended June 30, 2024, the Company repurchased in the open market $3.5 million, of its 2028 Unsecured Notes for a cash consideration of $2.8 million, including interest payable of $0.1 million. As a result, during the six months ended June 30, 2024, the Company recognized a gain of $0.7 million. The carrying value for the 2028 Unsecured Notes as at June 30, 2024, is $390.7 million (December 31, 2023: $393.7 million).

[1] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures'' section on page 23.

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 June 30, 2024, the 2028 Unsecured Notes were guaranteed by the Company's subsidiary, Frontera Energy Colombia Corp. ("**Frontera Colombia**"). On April 11, 2023, the Company designated Frontera Energy Guyana Holding Ltd. and Frontera Guyana as an unrestricted subsidiary and released Frontera Guyana as a note guarantor under the indenture governing the 2028 Unsecured Notes (the "**Indenture**").

Under the terms of the 2028 Unsecured Notes, the Company (excluding the Unrestricted Subsidiaries) may, among other things, incur indebtedness, provided that the consolidated debt to consolidated adjusted EBITDA ratio(1) is less than or equal to 3.25:1.0 and the consolidated fixed charge ratio(2) is greater than or equal to 2.25:1.0. In the event that these financial tests are not met, the Company may still incur indebtedness under certain permitted baskets, including an aggregate amount that does not exceed the higher of $100.0 million and 10% of consolidated net tangible assets(3). The 2028 Unsecured Notes also contain covenants that limit the Company's ability to, among other things, make certain investments or restricted payments, including dividends and share buybacks. As at June 30, 2024, the Company is in compliance with all such covenants.

Pursuant to requirements under the Indenture, the Company reports consolidated total indebtedness of $426,004,000 as of June 30, 2024, and for the last twelve months ended as of June 30, 2024, a consolidated adjusted EBITDA of $462,975,000 and a consolidated interest expense of $45,385,000.

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

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

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

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

Consolidated Total Indebtedness and Net Debt

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

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

($M)		**As at June 30 2024**
Short-term and Long-term debt (1)	$	408,817
Total lease liabilities (2)		13,997
Risk management asset net (3)		3,190
Consolidated Total Indebtedness		**426,004**
(-) Cash and Cash Equivalents (4)		(142,353)
(=) Net Debt	**$**	**283,651**

(1) Excludes $99.8 million of long-term debt attributable to the Unrestricted Subsidiaries.

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

(3) Excludes $1.0 million of risk management asset attributable to the Unrestricted Subsidiaries.

(4) Includes unrestricted cash and cash equivalents attributable to the guarantors as of June 30, 2024, Frontera Energy Colombia AG and the issuer (i.e., the Company) according to the Indenture.

Pipeline Investment Loan Facility

On March 27, 2023, PIL entered into a new credit agreement through which lenders provided a $120.0 million loan facility to PIL, secured by substantially all the assets and shares of PIL, the shares of Puerto Bahia held by the Company and assets related to Puerto Bahia's liquids terminal. It is guaranteed by Frontera Bahia Holding Ltd., and Frontera ODL Holding Corp., the parent company of PIL (the **"PIL Loan Facility"**). The PIL Loan Facility was originally a five-year credit, which matured in December 2027, paying its principal semi-annually. The PIL Loan Facility had two tranches: a $100.0 million amortizing tranche that pays a SOFR six-month term plus margin of 7.25% per annum and a $20.0 million bullet maturity tranche that pays a fixed rate of 11.0%

per annum. The conditions precedent to the PIL Loan Facility were fully satisfied, and both tranches of the facility were funded on March 31, 2023.

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

The proceeds of the PIL Loan Facility were used to repay in full the Puerto Bahia debt facility between Puerto Bahia, Itaú BBA Colombia S.A. and other lenders, maturing in June 2025, which had an outstanding balance plus accrued interest of $106.2 million to pay transaction fees and expenses, and to fund a 6-month debt service reserve account (for further information, refer to Note 13 of the Interim Financial Statements for the three and six months ended June 30, 2023). The PIL Loan Facility has no impact on the Company's financial covenant calculations under the 2028 Unsecured Notes.

On February 16, 2024, as part of the PIL Loan Facility (Tranche A-2), the Company amended the facility to disburse an accordion tranche of $30.0 million. This tranche secures the funding for the Reficar Connection Project. On February 23, 2024, the lenders disbursed $8.8 million, with additional resources expected to be disbursed between the third and the fourth quarters of 2024, each amounting to $10.0 million. The accordion tranche was recognized, net of an original issue discount of $1.2 million, primarily related to lenders and legal fees discounted at the disbursement.

As at June 30, 2024, the carrying value of the PIL Loan Facility was $99.8 million (December 31, 2023: $95.6 million) and the PIL Loan Facility debt service reserve account had a balance of $17.7 million. (December 31, 2023: $11.3 million).

Bancolombia Working Capital Loan

On October 24, 2023, the Company entered 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 proceeds of the Bancolombia Working Capital Loan were destined to general corporate purposes. In connection to the Bancolombia Working Capital Loan, the Company entered a FX forward on October 31, 2023, hedging the original loan amount at a forward rate of COP 4,386.17, maturing on October 29, 2024.

Concurrent with the closing of the Bancolombia Working Capital Loan, the Company repaid in full the existing Citibank working capital loan, which had an outstanding balance of $12.0 million (for further information, refer to Note 13 of the Interim Financial Statements for the three and nine months ended September 30, 2023).

As at June 30, 2024, the carrying value of the Bancolombia Working Capital Loan was $18.1 million (2023: $19.6 million).

(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 December 31, 2023, extending the maturity date to June 2024. On March 11, 2024, the Company prepaid the outstanding balance of $5.9 million to Banco Davivienda.

For the second loan, on December 13, 2023, Banco Davivienda approved an extension for the original $2.8 million loan to June 2024. On May 23, 2024, the Company prepaid the outstanding balance of $2.8 million to Banco Davivienda.

As of June 30, 2024, the PetroSud Debt was paid in full. PetroSud and Frontera have no obligation under the former PetroSud Debt, and there are no additional restricted funds related to the PetroSud Debt.

Letters of Credit

The Company has various uncommitted bilateral letters of credit. As of June 30, 2024, the Company had issued letters of credit and guarantees for exploration and abandonment funds totaling $115.4 million (total credit lines of $152.4 million), without cash collateral.

CPE-6 Solar Plant Project Leasing Agreement

During the fourth quarter of 2022, the Company executed a leasing agreement with Bancolombia to finance the construction and commissioning of a solar power plant project in the CPE-6 block (the "**Solar Plant Debt**"). The financing is denominated in COP, amounting to $6.2 million as at June 30, 2024, and has a maturity date of 72 months from April 3, 2024. The Solar Plant Debt bears interest equivalent to IBR +5.75%, payable monthly over the outstanding amount. As at June 30, 2024, the outstanding balance was $6.2 million. The Company recognized this obligation as a lease liability.

CPE-6 Battery Energy Storage System Leasing Agreement

During the fourth quarter of 2023, the Company entered into a leasing agreement with Bancolombia to finance the Battery Energy Storage System at the CPE-6 block (the "**BESS Project**"). The financing is denominated in COP, amounting to $0.9 million as at June 30, 2024, and has a maturing on April 9, 2029. The BESS Project leasing bears interest equivalent to IBR +5.10%, payable monthly. As at June 30, 2024, the outstanding balance was $0.7 million. The Company recognized this obligation as a lease liability.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at June 30, 2024, undiscounted by calendar year, are presented below:

As at June 30, 2024 ($M)	2024	2025	2026	2027	2028	2029 and Beyond	Total
Short-term and long-term debt principal and interest	64,680	58,161	58,126	77,312	417,205	—	675,484
Lease liabilities	6,045	5,251	3,494	2,263	2,016	1,455	20,524
Total financial obligations	**70,725**	**63,412**	**61,620**	**79,575**	**419,221**	**1,455**	**696,008**
Transportation							
Ocensa P-135 ship-or-pay agreement	36,531	36,531	—	—	—	—	73,062
ODL agreements	381	358	—	—	—	—	739
Other transportation and processing commitments	7,839	12,761	12,697	719	—	—	34,016
Exploration and evaluation							
Minimum work commitments (1) (2)	5,817	27,748	50,236	—	—	5,066	88,867
Other commitments							
Operating purchases, community obligations and others	79,392	428	325	284	259	11,521	92,209
Commitments energy supply	18,756	6,288	8,875	4,986	—	—	38,905
Total Commitments	**148,716**	**84,114**	**72,133**	**5,989**	**259**	**16,587**	**327,798**

(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 26, 2024 the Company received a communication from the ANH accepting the termination of the CAG-6 contract by mutual agreement, as a result the $12.7 million commitment has been removed.

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

In May 2022, a new ship-or-pay contract with Bicentenario and Cenit became effective, and as a result, the pledged inventory crude oil is stored in Cenit's terminal of Coveñas (TLU-3) instead of Ocensa's terminal. On March 31, 2022, the Company signed a new pledge agreement with Ocensa and Cenit, which guarantees the payment obligations of both contracts, up to $30.0 million and $6.0 million, respectively. On February 21, 2024, the term of the pledge agreement was extended to September 30, 2024 with Ocensa and to October 31, 2024 with Cenit.

Contingencies

The Company is involved in various claims and litigation arising from the normal course of business. Since the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company's favour. The outcome of adverse decisions in any pending or threatened proceedings related to these and other matters could have a material impact on the Company's financial position, results of operations or cash flows. No material changes have occurred regarding the matters disclosed in Note 25 - Commitments and Contingencies of the 2023 Annual Consolidated Financial Statements.

5. OUTSTANDING SHARE DATA

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

	Number
Common shares	84,045,242
DSUs [1]	1,001,065
RSUs [2]	2,553,142

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

On March 17, 2022, the Company launched an 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 and six months ended June 30, 2024 the Company repurchased a total of 439,600 Common Shares and 897,400 Common Shares, respectively, pursuant to the 2023 NCIB. As at August 7, 2024, the Company had repurchased for cancellation a total of 1,387,100 Common Shares under 2023 NCIB for approximately $8.4 million with an additional 2,562,354 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 2023 NCIB program:

	Six Months Ended June 30
	2024
Number of Common Shares repurchased	897,400
Total amount of Common Shares repurchased ($M)	5,519
Weighted-average price per share ($) [1]	6.15

[1] Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 23.

SIB

On August 7, 2024, the Company announced its intention to commence the SIB pursuant to which the Company will offer to purchase $30 million of its Common Shares for cancellation at a fixed price per share. The Company intends to fund the SIB from current cash resources.

The Company intends to determine the terms of the SIB, including pricing, in due course, and expects that the SIB will be completed in October 2024. Commencement and/or completion of the SIB is subject to receipt of a satisfactory liquidity opinion from a qualified financial adviser, approval of the Board of Directors, and obtaining any necessary exemptive relief under applicable securities laws in Canada. The SIB will not be conditional upon any minimum number of shares being tendered and will be subject to conditions customary for transactions of this nature.

6. RELATED-PARTY TRANSACTIONS

The following tables provide the total balances outstanding, commitments and transactional amounts with related parties as at June 30, 2024 and December 31, 2023, and for the three and six months ended June 30, 2024, and 2023, respectively:

($M)		As at June 30, 2024 and December 31, 2023			Three Months Ended June 30	Six Months Ended June 30
		Receivables from investment	Accounts Payable	Commitments	Purchases / Services	
ODL	2024	29,426	3,047	739	7,522	14,974
	2023	—	3,141	2,380	7,879	14,789

The related-party transactions correspond to the ship-and-pay contract for the transportation of crude oil in Colombia and ship-or-pay for other services for a total commitment of $0.7 million until 2025.

7. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of known and unknown risks in the pursuit of its strategic objectives including, but not limited to: production; liquidity/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, its assets, operation, regulatory environment, health, safety and environment, liquidity, communities and political landscape, and seeks to systematically mitigate these risks to an acceptable level. In addition, we continuously monitor our risk profile as well as industry best practices.

During the fourth quarter 2023, the Board 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 included 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 29 for additional detail on the steps the Company has taken to mitigate or manage some of these risks. However, the situation continues to be dynamic and highly uncertain, and the effectiveness and adequacy of such measures cannot be determined at this time.

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

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

8. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The Interim Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board, and with interpretations of the International Financial Reporting Interpretations Committee, which the Canadian Accounting Standards Board has approved for incorporation into Part 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 Interim Financial Statements in accordance with IFRS requires the Company to make judgments in applying its accounting policies, estimates and assumptions about the future. These judgments, estimates and assumptions affect the reported amounts of assets, liabilities, revenues and other items in net operating earnings or loss and the related disclosure of contingent assets and liabilities included in the Interim Financial Statements. The Company evaluates its estimates on an ongoing basis.

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

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

The results of the economic downturn and any potential resulting direct and indirect impact to the Company has been considered in management's judgments and estimates as described above for the quarter end; however, there could be further prospective material impacts in future periods. As such, actual results may differ from these estimates under different assumptions or conditions. A summary of the 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.

9. INTERNAL CONTROL

In accordance with National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings* ("**NI 52-109**") of the Canadian Securities Administrators, the Company issues a "Certification of Interim Filings" on Form 52-109F2. This Certification requires that each "certifying officer" (as defined in NI 52-109) certify, among other things, that they, together with the other certifying officer(s), are responsible for establishing and maintaining disclosure control and procedures ("**DC&P**") and internal controls over financial reporting ("**ICFR**") as those terms are defined in NI 52-109. The control framework used to design the Company's ICFR is based on the framework established in Internal Control - Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission.

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

Management of the Company has evaluated the effectiveness of the Company's ICFR as at June 30, 2024. Based on this assessment, the Company's Chief Executive Officer and its Chief Financial Officer concluded that the Company's ICFR were effective as at June 30, 2024.

There has been no change in the Company's ICFR during the period beginning on April 1, 2024 and ended on June 30, 2024, that has materially affected, or is reasonably likely to materially affect, its ICFR.

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

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

Based on management's evaluation, which was carried out to assess the effectiveness of the Company's DC&P, the Company's Chief Executive Officer and its Chief Financial Officer, concluded that the Company's DC&P were effective as at June 30, 2024.

10. FURTHER DISCLOSURES

Production Reporting by block

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

		Production				
					Six months ended June 30	
Producing blocks		**Q2 2024**	**Q1 2024**	**Q2 2023**	**2024**	**2023**
Quifa	(bbl/d)	17,371	16,858	18,467	17,115	17,689
CPE-6	(bbl/d)	6,947	6,228	5,116	6,588	4,984
Guatiquia	(bbl/d)	5,539	5,610	7,239	5,575	7,278
Vim1	(boe/d)	1,856	1,579	1,711	1,718	1,693
Perico	(bbl/d)	1,655	1,478	503	1,567	667
Cubiro	(bbl/d)	1,491	1,461	1,915	1,476	2,047
Cravoviejo	(bbl/d)	1,314	1,348	1,633	1,331	1,661
Casimena	(bbl/d)	1,165	1,208	1,295	1,187	1,339
Other blocks	(boe/d)	2,574	2,423	4,170	2,496	4,460
Total production	**(boe/d)**	**39,912**	**38,193**	**42,049**	**39,053**	**41,818**

Production Reporting

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

The following table includes the average net production:

		Net Production				
					Six months ended June 30	
Producing blocks in Colombia		**Q2 2024**	**Q1 2024**	**Q2 2023**	**2024**	**2023**
Heavy crude oil	(bbl/d)	21,534	20,853	21,455	21,194	20,520
Light and medium crude oil combined	(bbl/d)	9,496	9,763	13,144	9,630	13,589
Conventional natural gas	(mcf/d)	4,019	3,278	5,626	3,648	7,102
Natural gas liquids	(boe/d)	1,651	1,513	1,687	1,581	1,465
Net production Colombia	**(boe/d)**	**33,386**	**32,704**	**37,273**	**33,045**	**36,820**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	1,119	1,039	433	1,079	569
Net production Ecuador	**(bbl/d)**	**1,119**	**1,039**	**433**	**1,079**	**569**
Total net production	**(boe/d)**	**34,505**	**33,743**	**37,706**	**34,124**	**37,389**

Boe Conversion

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

Oil and Gas Information Advisories

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

Abbreviations

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

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