Frontera Energy Corp. Announces Second Quarter 2025 Results

14.08.2025 | CNW

- Recorded $455.2 million in Net Loss Mainly due to Non-Cash Impairment Charges Related to its Interest in the Corentyne License and Ecuadorian Assets

- Increased Total Production 1% Quarter over Quarter

- Generated Quarterly Operating EBITDA of $76.1 Million

- Generated Adjusted Infrastructure EBITDA of $27.1 million and $14.3 million Segment Income

- Executed C$91 million Substantial Issuer Bid, its Largest to Date, with Over 92.6% Shareholder Participation

- Successfully Completed $80 million Capped Tender Offer and Consent Solicitation of Outstanding 2028 Senior Unsecured Notes

- Declared Quarterly Dividend of C$0.0625 Per Share, or $3.5 Million in Aggregate, Payable on or around October 16, 2025

Frontera Energy Corp. (TSX: FEC) ("Frontera" or the "Company") today reported financial and operational results for the second quarter ended June 30, 2025. All financial amounts in this news release and in the Company's financial disclosures are in United States dollars, unless otherwise stated.

Gabriel de Alba, Chairman of the Board of Directors, commented:

"Despite a volatile global macro-economic and oil market backdrop, Frontera continued to execute on its strategic goals and priorities across its businesses in the second quarter delivering strong operating results and completing significant value-generating initiatives for its shareholders and bondholders. The Company generated $76.1 million in Operating EBITDA, produced $27.1 million of Adjusted Infrastructure EBITDA, and maintained a strong balance sheet, finishing the quarter with a total cash balance of $197.5 million while reducing its upstream net debt by 30%.

Following the expiry of the 90‑day consultation and negotiation period arising from the Notice of Intent -and in view of the uncertainty introduced by the Government of Guyana-we have recognized an impairment of over $430 million related to our investment in the Corentyne block, in accordance with prudent accounting standards. The Joint Venture remains firmly of the view that its interests in, and the license for, the Corentyne block remain in place and in good standing and that the Petroleum Agreement has not been terminated. We remain committed to working with the Government of Guyana to resolve these issues amicably, while preparing to assert and protect our legal and contractual rights through all available legal remedies, as necessary.

The Company prioritized returning capital to all investors via its successful $80 million tender offer and consent solicitation of its senior unsecured notes due in 2028 and, subsequent to the quarter, the completion of a C$91 million substantial issuer bid, the largest in the Company's history.

The Company also declared a quarterly dividend of C$0.0625 per share, or approximately $3.5 million in aggregate, and initiated a non-course issuer bid program.

Over the last twelve-months, Frontera has returned over $144 million to shareholders via dividends and share repurchases while also reducing the outstanding aggregate principal amount of its senior unsecured notes by over 20%. These efforts underscore the success of the Company's return of capital focus to its stakeholders.

The Company will continue to consider similar investor-focused initiatives in 2025 and beyond, including additional dividends, distributions, and share or bond buybacks, based on the overall results of the businesses, oil prices and cash flow generation. Additionally, the Company will consider all options to enhance the value of its common shares, and in so doing may consider other strategic initiatives or transactions. "

Orlando Cabrales, Chief Executive Officer (CEO), Frontera, commented:

"Frontera's second quarter financial and operating results demonstrate the decisive steps we are taking to deliver stakeholder value, maintain financial and operational flexibility, and reduce leverage over the long-term. We increased our total production quarter over quarter driven by increased processing capacity at SAARA, investments in new flow lines in our heavy oil fields, a successful well intervention program within our light and medium blocks and new commercialized volumes of natural gas production from the VIM-1 block.

During the quarter, we continued to prioritize operational improvements, reducing capital spending and cost and process efficiencies across our business, delivering a 10.3% decrease in production costs quarter-over-quarter driven by fewer well interventions and the implementation of new production technologies. We also reduced our transportation costs by 5.7% quarter-over-quarter driven by higher domestic wellhead sales.

Our standalone and growing Colombia infrastructure business, which includes the Company's interest in ODL, generated an Adjusted Infrastructure EBITDA of $27.1 million. At Puerto Bahia, the Reficar connection was completed by the end of the quarter and now the efforts shift to the first transported volumes which are expected during the third quarter of 2025. Strategic investments in the port, including the LPG JV with Empresas Gasco, are progressing on schedule. The port is also pursuing additional investment opportunities that leverage its facilities and infrastructure for sustainable long-term growth.

Consistent with our strategy, following the end of the quarter, the Company announced it had reached an agreement to divest its interest in the Company's non-core Perico and Espejo fields in Ecuador. This transaction is consistent with our strategy of maximizing value over volumes and supports a stronger focus on our higher-impact Colombian upstream operations.

As a result, we are adjusting our 2025 production guidance to account for the impact of Ecuador sale to 39,500 to 41,000 boed. In light of the current oil price environment, we are also adjusting our capital expenditures guidance downwards, by approximately $20 million, reducing development facilities capex to $45 - 65 million and exploration capex to $25 - 35 million, reflecting our disciplined approach to capital spending and ability to identify ongoing operational efficiencies. Additionally, we are providing Operating EBITDA Guidance at a $70/bbl Brent Price with a target of between $320 - $360 million and revising our Adjusted Infrastructure EBITDA Guidance to between $110 - 125 million."

Second Quarter 2025 Operational and Financial Summary:

		Q2 2025	Q1 2025	Q2 202
Operational Results				
Heavy crude oil production [1]	(bbl/d)	27,535	27,167	24,839
Light and medium crude oil production [1]	(bbl/d)	11,127	10,998	12,583
Total crude oil production	(bbl/d)	38,662	38,165	37,422
Conventional natural gas production [1]	(mcf/d)	3,118	2,274	4,019
Natural gas liquids production [1]	(boe/d)	1,846	1,913	1,785
Total production [2]	(boe/d) [3]	41,055	40,477	39,912
Inventory Balance				
Colombia	(bbl)	629,147	392,821	758,79
Peru	(bbl)	480,200	480,200	480,20
Ecuador	(bbl)	33,189	38,865	80,195
Total Inventory	(bbl)	1,142,536	911,886	1,319,1
Brent price Reference	($/bbl)	66.71	74.98	85.03
Produced crude oil and gas sales [4]	($/boe)	63.04	68.42	78.31
Purchase crude net margin [4][5]	($/boe)	(3.53)	(3.81)	(2.62)
Oil and gas sales, net of purchases [4][5]	($/boe)	59.51	64.61	75.69
Gain (loss) on oil price risk management contracts [6][7]	($/boe)	0.15	(1.35)	(1.32)
Royalties [6]	($/boe)	(0.80)	(1.00)	(2.01)
Net sales realized price [4][5]	($/boe)	58.86	62.26	72.36
Production costs (excluding energy cost), net of realized FX hedge impact [4]	($/boe)	(9.01)	(10.04)	(10.79)
Energy costs, net of realized FX hedge impact [4]	($/boe)	(4.71)	(5.38)	(4.74)
Transportation costs, net of realized FX hedge impact [4][5]	($/boe)	(11.62)	(12.32)	(11.07)
Operating netback per boe [4][5]	($/boe)	33.52	34.52	45.76
Financial Results				
Oil & gas sales, net of purchases [8]	($M)	170,943	197,975	217,13

Gain (loss) on oil price risk management contracts [7]	($M)	431	(4,141)	(3,796)
Royalties	($M)	(2,304)	(3,060)	(5,774)
Net sales [8]	($M)	169,070	190,774	207,56
Net (loss) income [9]	($M)	(455,212)	27,524	(2,846)
Per share - basic	($)	(5.89)	0.35	(0.03)
Per share - diluted	($)	(5.89)	0.34	(0.03)
General and administrative	($M)	14,279	13,571	12,928
Outstanding Common Shares	Number of shares	77,295,478	77,294,460	84,253,
Operating EBITDA [8]	($M)	76,073	83,458	110,32
Cash provided by operating activities	($M)	41,786	70,137	149,78
Capital expenditures [8]	($M)	59,402	46,711	80,198
Cash and cash equivalents - unrestricted	($M)	184,860	170,094	180,65
Restricted cash short and long-term [10]	($M)	12,679	29,738	34,419
Total cash [10]	($M)	197,539	199,832	215,07
Total debt and lease liabilities [10]	($M)	535,346	505,486	523,99
Consolidated total indebtedness (Excl. Unrestricted Subsidiaries) [11]	($M)	353,764	409,675	426,00
Net Debt (Excluding Unrestricted Subsidiaries) [11]	($M)	204,671	290,732	283,65

(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 news release 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 40 of the Company's management's discussion and analysis for the three months ended on March 31, 2025 (the "MD&A").

(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 40 of the MD&A.

(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 24 of the MD&A.

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

(6) Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 24 of the MD&A.

(7) Includes the net of the put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Please refer to the "Gain (loss) on oil price risk management contracts" section on page 15 of the MD&A for further details.

(8) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 24 of the MD&A.

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

(10) Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 24 of the MD&A.

(11) "Unrestricted Subsidiaries" include CGX Energy Inc., listed on the TSX Venture Exchange under the trading symbol "OYL"; FEC ODL Holdings Corp., including its subsidiary Frontera Pipeline Investment AG ("FPI", formerly named Pipeline Investment Ltd); Frontera BIC Holding Ltd.; Frontera Energy Guyana Holding Ltd.; Frontera Energy Guyana Corp.; and Frontera Bahía Holding Ltd. ("Frontera Bahia"), including Sociedad Portuaria Puerto Bahía S.A. ("Puerto Bahia"). Refer to the "Liquidity and Capital Resources" section on page 31 of the MD&A.

Second Quarter 2025 Operational and Financial Results:

- The Company recorded a net loss of $455.2 million or $5.89/share in the second quarter of 2025, compared with a net income of $27.5 million or $0.35/share in the prior quarter and net loss of $2.8 million or $0.03/share in the second quarter of 2024. Net loss from operations for the second quarter included a loss from operations of $474.8 million (net of non-cash impairment expenses of $477.0 million), finance expenses of $18.3 million and foreign exchange expenses of $2.6 million, partially offset by $14.1 million from share of income from associates, an income tax recovery of $13.0 million (including $14.3 million of deferred income tax recovery), $11.7 million of gain on the repurchase of its outstanding 7.875% Senior Unsecured Notes due in 2028 (the "2028 Senior Unsecured Notes") net of the consent solicitation, and $4.0 million related to a gain on risk management contracts. This compares with 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 a loss on risk management contracts, partially offset by an income from operations of $45.2 million and $13.4 million from the share of income from associates.

- Production averaged 41,055 boe/d in the second quarter of 2025, up 1% compared to 40,477 boe/d in the prior quarter and up 3% against 39,912 boe/d in the second quarter of 2024. Compared to the first quarter 2025, heavy crude oil production, increased by 1%, mainly due to increased processing capacity at SAARA and investments in new flow lines in the Cajua field; light and medium crude oil production, increased by 3% driven by a successful well intervention program; and conventional natural gas production increase by 37%, as a result of new commercialized volumes of natural gas from the VIM-1 Block. Natural gas liquids production decreased 4%, compared to the prior quarter, primarily as a result of natural decline.

				Six months ended June 30	
	Q2 2025	Q1 2025	Q2 2024	2025	2024
Heavy crude oil production (bbl/d)	27,535	27,167	24,839	27,352	24,119
Light and medium crude oil production (bbl/d)	11,127	10,998	12,583	11,062	12,582
Conventional natural gas production (mcf/d)	3,118	2,274	4,019	2,696	3,654
Natural gas liquids production(boe/d)	1,846	1,913	1,785	1,879	1,711
Total production	41,055	40,477	39,912	40,766	39,053

- Operating EBITDA was $76.1 million in the second quarter of 2025 compared to $83.5 million in the prior quarter and $110.3 million in the second quarter of 2024. The decrease in operating EBITDA compared to the prior quarter was mainly due to lower Brent prices during the quarter, partially offset by lower production and transportation costs during the quarter.
- Cash provided by operating activities in the second quarter of 2025 was $41.8 million, compared to $70.1 million in the prior quarter and $149.8 million in the second quarter of 2024.
- The Company reported a total cash position of $197.5 million at June 30, 2025, compared to $199.8 million at March 31, 2025 and $215.1 million at June 30, 2024. During the quarter, the Company closed and funded the recapitalization of its interest in Oleoducto de los Llanos Orientales S.A. ("ODL") through a $220 million non-recourse, secured loan and received $115 million in net proceeds. In addition, the Company repurchased $80 million in aggregate principal amount of its outstanding 2028 Senior Unsecured Notes. Subsequent to the quarter, the Company paid $66.5 million to shareholders through its substantial issuer bid (as described further below).
- As at June 30, 2025, the Company had a total crude oil inventory balance of 1,142,536 barrels compared to 911,886 barrels at March 31, 2025. The Company had a total inventory balance in Colombia of 629,147 barrels, including 493,510 crude oil barrels and 135,637 bbls of diluent and others. This compared to 392,821 barrels as at March 31, 2025, and 758,794 barrels as at June 30, 2024. The Increase in inventory levels was associated with higher quarter over quarter production levels.
- Capital expenditures were approximately $59.4 million in the second quarter of 2025, compared with $46.7 million in the prior quarter and $80.2 million in the second quarter of 2024. During the second quarter, the Company drilled 26 development wells mainly at the Quifa and CPE-6 blocks.
- The Company's net sales realized price was $58.86/boe in the second quarter of 2025, compared to $62.26/boe in the prior quarter and $72.36/boe in the second quarter of 2024. The decrease was primarily driven by a lower Brent benchmark oil price, which was partially offset by stronger oil price differentials, the realized gain from oil price risk management contracts and lower royalties paid in cash.
- The Company's operating netback was $33.52/boe in the second quarter of 2025, compared with $34.52/boe in the prior quarter and $45.76/boe in the second quarter of 2024. Despite a $8.27/bbl decrease in the Brent benchmark oil price, the Company partially offset the lower netback through: (i) stronger oil price differentials, (ii) a reduction in production costs (excluding energy costs), net of realized FX hedge impact, mainly as a result of a reduction of well intervention activities and the adoption of new field production technologies, (iii) lower energy costs, net of realized FX hedge impact, driven by lower market prices, and (iv) lower transportation costs, due to reduced transported volumes, primarily resulting from improved domestic wellhead sales.
- Production costs (excluding energy cost), net of realized FX hedge impact, averaged $9.01/boe in the second quarter of 2025, compared with $10.04/boe in the prior quarter and $10.79/boe in the second quarter of 2024. The decrease in production cost primarily due to lower well services activities and the implementation of new field production technologies.

- Energy costs, net of realized FX hedging impacts, averaged $4.71/boe in the second quarter of 2025, compared to $5.38/boe in the prior quarter and up from $4.74/boe in the second quarter of 2024. The decrease quarter over quarter was mainly due to lower market prices.
- Transportation costs, net of realized FX hedging impacts averaged $11.62/boe in the second quarter of 2025, compared with $12.32/boe in the prior quarter and $11.07/boe in the second quarter of 2024. The decrease during the quarter was mainly due to reduced transported volumes, primarily resulting from improved domestic wellhead sales.
- ODL volumes transported were 235,804 bbl/d during the second quarter of 2025, volumes transported were in line with Q1 2025, which saw 236,387 bbl/d in volumes transported.
- Total Puerto Bahia liquids volumes were 53,280 bbl/d during the second quarter 2025 compared to 51,579 bbl/d the first quarter of 2025.
- Adjusted Infrastructure EBITDA in the second quarter of 2025 was $27.1 million, compared to $28.6 million in the first quarter of 2025. The decrease was mainly due to higher operating costs in SAARA, offset by positive results in the ODL segment driven by the pipeline tariff increase and lower costs during the quarter.

Frontera's Sustainability Strategy

The Company is advancing towards its 2028 sustainability goals as well as on the 2025 plan, with progress in almost every goal during the second quarter.

On the sustainability front, and in alignment with our supply chain strategy, we launched the Business Network for Responsible Business Conduct to promote best practices in human rights due diligence.

In the second quarter of 2025, local suppliers accounted for 11.37% of total purchases, reflecting the Company's ongoing commitment to support local economic development. Additionally, Frontera maintained strong performance in health and safety indicators, reporting achieved a Total Recordable Incident Rate ("TRIR") of 0.71. The Company also attained a water reuse rate of 37.6% within its operational activities.

Enhancing Shareholder Returns

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

NCIB: Subsequent to the quarter, on July 15,2025, the Company announced the initiation of a Normal Course Issuer Bid, commencing July 18, 2025 and ending July 17, 2026, through which the Company may purchase up to 3,502,962 shares for cancellation, representing approximately 5% of the issued and outstanding shares as at July 15, 2025.

As at August 12, 2024, the Company has repurchased approximately 78,400 common shares for cancellation for approximately $0.4 million.

SIB: On July 15, 2025, the Company announced that, it had taken up and paid for 7,583,333 common shares (approximately 9.77% of the total number of Frontera's issued and outstanding common shares as at July 10, 2025) at a price of CAD$12.00 per common share, representing an aggregate purchase price of approximately CAD $91.0 million pursuant to a substantial issuer bid. The July 2025 substantial issuer bid had a 92.6% participation and the tendered shares were purchased on a pro rata basis, shareholders who tendered to the substantial issuer bid had approximately 10.54% of their tendered shares purchased by the Company. With an over 90% consistent participation rate in the SIBs, the Company's capital distribution strategy has proven effective and well received by the shareholders.

After the cancellation of the common shares taken up and paid for by the Company, approximately 70.06 million common shares remained issued and outstanding.

Bond Capped Cash Tender Offer & Consent Solicitation: On June 10, 2025, the Company announced the results of the cash tender and consent solicitation of its outstanding 2028 Senior Unsecured Notes. The Company received the requisite consents to implement the proposed amendments to the indenture governing the notes with a 50.38% approval, and validly delivered tenders in excess of the maximum tender amount set forth in the offer, Bondholders who participated in the tender offer had their notes repurchased pursuant to a proration factor of 55.63%. The transaction reduced the amount of the Company's outstanding notes by $80 million three years before maturity, for a total cash consideration of $57.6 million and recognizing a gain after fees and expenses associated with transaction of $11.7 million.

The tender offer and consent solicitation provided the Company with increased financial flexibility, while also reducing its outstanding debt obligations. The amendments to the indenture aim to modernize Frontera's indenture in line with that of its peers and also provides targeted operational flexibility to deliver long-term business and reserve growth, including as a result of inorganic transactions.

The carrying value for the 2028 Senior Unsecured Notes, as of June 30, 2025, is $310.3 million.

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

This dividend payment to shareholders is designated as an "eligible dividend" for purposes of the Income Tax Act (Canada). This dividend is eligible for the Company's Dividend Reinvestment Plan which provides Canadian resident shareholders of Frontera the option to automatically reinvest the cash dividends on their common shares into additional common shares, without paying brokerage commissions or services charges.

Frontera's Three Core Businesses

Frontera's three core businesses include: (1) its Colombia and Ecuador Upstream Onshore business, (2) its standalone and growing Colombian Infrastructure business, and (3) its potentially transformational Guyana Exploration business offshore Guyana.

2025 Guidance Update

Frontera is adjusting its 2025 production guidance to reflect its Colombian operations only, now targeting 39,500 to 41,000 boed, following the divestment of its non-core assets in Ecuador. The Company is also revising its capital expenditures guidance downwards by approximately $20 million, reducing its development facilities capex to $45 - 65 million and exploration capex to $25 - 35 million. These changes reflect on the Company's disciplined approach to capital spending and ability to identify ongoing operational efficiencies. Additionally, the Company is providing Operating EBITDA Guidance at a $70/bbl Brent Price targeting between $320 - $360 million and revising our Adjusted Infrastructure EBITDA Guidance targeting between $110 - 125 million.

Guidance Metrics	Unit	2025 Original Guidance	2025 Updated Guidance (excluding Ecuador)
Average Daily Production [1]	boe/d	41,000 - 43,000	39,500 - 41,000
Production Costs [2][4]	$/boe	8.75 - 9.25	8.75 - 9.25
Energy Costs [2][4]	$/boe	5.25 - 5.75	5.25 - 5.75
Transportation Costs [3][4]	$/boe	12.50 - 13.00	12.50 - 13.00
Operating EBITDA [5] at $75/bbl [6]	$MM	370 - 415	
Operating EBITDA [5] at $70/bbl [7]			320 - 360
Adjusted Infrastructure EBITDA [6]	$MM	115 - 130	110 - 125
Development Drilling	$MM	100 - 110	100 - 110
Development Facilities	$MM	60 - 80	45 - 65
Colombia and Ecuador Development	$MM	160 - 190	145 - 175
Colombia and Ecuador Exploration	$MM	30 - 40	25 - 35
Other [8]	$MM	10 - 15	10 - 15
Total Colombia & Ecuador Capex	$MM	200 - 245	180 - 225
Guyana Exploration	$MM	1 - 3	1 - 3
Colombia Infrastructure	$MM	15 - 20	15 - 20
Total Capital Expenditures [5]	$MM	216 - 268	196 - 248

(1) The Company's 2025 original and updated average production guidance range does not include in-kind royalties, operational consumption, quality volumetric compensation or potential production from successful exploration activities planned in 2025.

(2) Per-bbl/boe metric on a share before royalties' basis.

(3) Calculated using net production after royalties.

(4) Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 24 of the MD&A for further details.

(5) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 24 of the MD&A for further details

(6) 2025 Original Guidance Operating EBITDA calculated at Brent between $75/bbl and COP/USD exchange rate of 4,250:1.

(7) 2025 Updated Guidance Operating EBITDA calculated at Brent between $70/bbl and COP/USD exchange rate of 4,150:1..

Colombia & Ecuador Upstream Onshore

(8) Other includes HSEQ activities and new field production technologies.

Colombia

During the second quarter of 2025, Frontera produced 39,778 boe/d from its Colombian operations (consisting of 27,535 bbl/d of heavy crude oil, 9,850 bbl/d of light and medium crude oil, 3,118 mcf/d of conventional natural gas and 1,846 boe/d of natural gas liquids).

In the second quarter of 2025, the Company drilled 26 development wells mainly at the Quifa and CPE-6 blocks and completed well interventions at 22 others.

Currently, the Company has 1 drilling rig and 2 well intervention rigs active at its Quifa and CPE-6 blocks in Colombia.

Quifa Block: Quifa SW and Cajua

At Quifa, second quarter 2025 production averaged 17,576 bbl/d of heavy crude oil (including both Quifa and Cajua). The Company invested in facility expansion and the installation of new flow lines in the Cajua field, in the Quifa block to support new well production and the SAARA connection.

In the second quarter 2025, the Company handled an average of approximately 1.78 million barrels of water per day in Quifa including SAARA.

CPE-6

At CPE-6, second quarter 2025 production averaged approximately 7,771 bbl/d of heavy crude oil, decreasing from 8,056 bbl/d during the first quarter of 2025.

During the second quarter 2025, the Company invested in the expansion of crude oil storage capacity and the implementation of new field production technologies.

The Company handled an average of approximately 327 thousand barrels of water per day in CPE-6 in the second quarter of 2025. The Company's current water handling capacity in CPE-6 is approximately 370 thousand barrels of water per day.

Other Colombia Developments

At Guatiquia, production during the second quarter 2025 averaged 5,385 bbl/d of light and medium crude compared with 5,119 bbl/d in the first quarter 2025. During the quarter the Company performed a sidetrack in its Coralillo 3 well.

In the Cubiro block production averaged 1,057 bbl/d of light and medium crude oil in the second quarter of 2025 compared with 1,213 bbl/d in the first quarter 2025.

At VIM-1 (Frontera 50% W.I., non-operator), production averaged 1,960 boe/d of light and medium crude oil in the second quarter of 2025 compared to 1,840 boe/d of light and medium crude oil in the first quarter 2025.

At the Sabanero block, production averaged 2,189 boe/d of heavy oil crude production in the second quarter of 2025 compared to 2,346 boe/d in the first quarter 2025.

Colombia Exploration Assets

At VIM-1, following engagement efforts with authorities and communities, the joint venture operating the VIM-1 block (Frontera 50% W.I., non-operator) has shifted its focus from Hidra-1 to the Guapo-1 exploratory well. By the second quarter 2025, all necessary designs and permits were secured for roadwork and site preparation for Guapo-1, with drilling and completion expected to occur in the second half of 2025.

At Llanos 119, the Company is awaiting the decision of the Agencia Nacional de Hidrocarburos (ANH) on transferring exploration commitments to VIM-46 for a 3D seismic survey. Meanwhile, pre-seismic and pre-drilling social and environmental studies are underway at Llanos-99 and VIM-46.

Ecuador

In Ecuador, second quarter 2025 production averaged approximately 1,277 bbl/d of light and medium crude oil compared to 1,467 bbl/d in the prior quarter.

At the Espejo block (Frontera holds a 50% W.I. and is a non-operator), long-term tests continued at the Espejo Sur-B3 well with production of 330 bbl/d gross and a water cut of 78%.

Subsequent to the quarter, the Company agreed to divest its 50% interest in the Perico and Espejo blocks in Ecuador. The total cash consideration to Frontera for the blocks is $7.8 million, subject to working capital and other customary adjustments as of the effective date of January 1, 2025. The agreement includes an additional contingent consideration of $750,000, payable to Frontera upon the Perico block achieving cumulative gross production of two million barrels as from January 1, 2025.

Closing of the transaction is subject to satisfaction of customary closing conditions, including the receipt of regulatory approvals for closing and operations takeover from the Ministry of Energy of Ecuador, and is expected to occur by the second quarter of 2026.

2. Infrastructure Colombia

Frontera's Infrastructure Colombia Segment includes the Company's 35% equity interest in the ODL pipeline through Frontera's wholly owned subsidiary, FPI and the Company's 99.97% interest in Puerto Bahia. Beginning in 2024, the Infrastructure Colombia Segment also includes the Company's reverse osmosis water treatment facility (SAARA) and its palm oil plantation (ProAgrollanos).

Frontera processed 119,409 barrels of water per day at is SAARA reverse osmosis water-treatment facility during the quarter and remains focused on reaching its goal of processing 250,000 barrels of water per day.

On the Puerto Bahia side, the Reficar connection's construction was completed by the end of the quarter and, the Company's efforts shift to the first transported volumes, which are expected during the third quarter of 2025. The Company is progressing with its growth plans, including the LPG joint venture with Empresas Gasco.

Infrastructure Colombia Segment Results

Adjusted Infrastructure EBITDA in the second quarter of 2025 was $27.1 million, compared with $28.6 million during the first quarter 2025. The decrease was mainly due to higher operating costs in SAARA, offset by positive results in the ODL segment driven by the pipeline tariff increase and lower costs during the quarter.

				Six months ended June 30	
($M)	Q2 2025	Q1 2025	Q2 2024	2025	2024
Adjusted Infrastructure Revenue [(1)]	44,969	44,912	43,055	89,881	83,962
Adjusted Infrastructure Operating Cost [(1)]	(15,027)	(13,116)	(11,998)	(28,143)	(24,136)
Adjusted Infrastructure General and Administrative [(1)]	(2,885)	3,193	(3,234)	(6,078)	(6,316)
Adjusted Infrastructure EBITDA [(1)]	27,057	34,989	27,823	27,823	27,823

[(1)] Non-IFRS financial measure

Segment capital expenditures for the three months ended June 30, 2025, totaled $4.8 million primarily driven by Puerto Bahia investments of $3.9 million, including: (i) $3.4 million in investment towards the Reficar connection, (ii) tank maintenance, and (iii) general cargo terminal facilities with additional investment in the SAARA project.

				Six months ended June 30	
($M)	Q2 2025	Q1 2025	Q2 2024	2025	2024
Revenue	14,479	12,864	12,894	27,343	23,422
Costs	(10,493)	(8,930)	(7,598)	(19,423)	(15,747)
General and administrative expenses	(1,180)	(1,507)	(1,389)	(2,687)	(2,868)
Depletion, depreciation and amortization	(2,100)	(2,026)	(1,962)	(4,126)	(3,778)
Other operating costs	(552)	(214)	(732)	(766)	(1,158)
Infrastructure Colombia income (loss) from operations	154	187	1,213	341	(129)
Share of income from associates - ODL	14,124	15,109	13,407	29,233	27,301
Infrastructure Colombia segment income	14,278	15,296	14,620	29,574	27,172
Infrastructure Colombia segment cash flow from operating activities	1,594	25,580	29,922	27,174	30,567
Capital Expenditures Infrastructure Colombia Segment [(1)]	4,834	2,700	3,467	7,534	8,023

[(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 24 of the MD&A.

The following table shows the volumes pumped per injection point in ODL:

				Six months ended	
				June 30	
(bbl/d)	Q2 2025	Q1 2025	Q2 2024	2025	2024
At Rubiales Station	133,187	172,988	172,163	152,978	169,770
At Jagüey and Palmeras Station	102,617	63,399	77,033	83,116	77,849
Total	235,804	236,387	249,196	236,094	247,619

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

				Six months ended	
				June 30	
(bbl/d)	Q2 2025	Q1 2025	Q2 2024	2025	2024
FEC volumes	10,914	8,388	13,353	9,658	15,000
Third party volumes	42,366	43,191	48,445	42,776	42,579
Total	53,280	51,579	61,798	52,434	57,579

The following table shows the barrels of water per day treated and irrigated in SAARA and field performance indicators for Proagrollanos:

					Six months ended	
					June 30	
		Q2 2025	Q1 2025	Q2 2024	2025	2024
Fresh fruit bunch from palm oil (produced - sold)	(tons)	7,039	7,684	8,895	14,723	13,990
Production per hectare per year [1]	(tons/ ha/year)	8.86	9.44	7.42	8.86	7.42
Palm oil fruit price	($/ton)	189	209	166	200	164
Volumes of reverse osmosis water treated	(bwpd)	119,409	81,481	14,467	100,550	23,870
Volumes of water irrigated in palm oil cultivation	(bwpd)	118,831	81,609	14,398	100,323	19,006

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

3. Guyana Exploration

On March 26, 2025, the Company and its subsidiaries Frontera Petroleum International Holding B.V. and Frontera Energy Guyana Holding Ltd. (the "Investors") sent a Notice of Intent to the Government of Guyana (the "GoG"). In this Notice of Intent, the Investors alleged breaches of the United Kingdom - Guyana Bilateral Investment Treaty and the Guyana Investment Act by the GoG. The communication initiated a 90-day period for consultations and negotiations between the parties to resolve the dispute amicably. After the 90-day period, no mutually, acceptable solution has been produced. As informed in previous quarters, Frontera Energy Guyana Corp. ("Frontera Guyana") and CGX Resources Inc. ("CGX Resources" and together with

Frontera Guyana, the "Joint Venture") and its stakeholders are prepared to assert their legal rights.

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

The Joint Venture remains firmly of the view that its interests in, and the license for, the Corentyne block remain in place and in good standing and that the Petroleum Agreement has not been terminated. Although the 90-day consultation and negotiation period derived from the Notice of Intent has now expired, the Joint Venture and its stakeholders continue to invite the GoG to amicably resolve the issues affecting the Joint Venture's investments in the Corentyne block. Should the parties not reach a mutually agreeable solution, the Joint Venture and its stakeholders are prepared to assert their legal rights.

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

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

Hedging Update

As part of its risk management strategy, Frontera uses derivative commodity instruments to manage exposure to price volatility by hedging a portion of its oil production. The Company's strategy aims to protect 40-60% of its estimated net after royalties' production using a combination of instruments, capped and non-capped, to protect the revenue generation and cash position of the Company, while maximizing the upside, thereby allowing the Company to take a more dynamic approach to the management of its hedging portfolio.

The following table summarizes Frontera's hedging position as of August 13, 2025.

Term	Type of Instrument	Positions	Strike Prices
		(bbl/d)	Put/Call
Jul 25	Put Spread	13,097	70/55
Aug 25	Put Spread	16,935	70/55
Sep 25	Put Spread	17,667	70/55
3Q-2025	Total Average	15,880	70/55
Oct 25	Put Spread	15,161	65/55
Nov 25	Put Spread	15,000	65/55
Dec 25	Put Spread	14,516	65/55
4Q-2025	Total Average	14,891	65/55

The Company is exposed to foreign currency fluctuations primarily arising from expenditures that are incurred in COP and its fluctuation against the USD. As of August 13, 2025 the Company had the following foreign currency derivatives contracts:

Term	Type of Instrument	Open Interest	Strike Prices	Hedging Ratio
		(US$ MM)	Put/Call	
3Q-2025	Zero-Cost Collars	60	4,200/4,795	40 %
4Q-2025	Zero-Cost Collars	30	4,295/4,787	20 %

Second Quarter 2025 Financial Results Conference Call Details

A conference call for investors and analysts will be held on Thursday, August 14th, 2025, at 11:00 a.m. Eastern Time. Participants will include Gabriel de Alba, Chairman of the Board of Directors, Orlando Cabrales, Chief Executive Officer, Rene Burgos, Chief Financial Officer, and other members of the senior management team.

Analysts and investors are invited to participate using the following dial-in numbers:

RapidConnect URL:	https://emportal.ink/4m3hn0f
Participant Number (Toll Free North America):	1-888-510-2154
Participant Number (Toll Free Colombia):	+57-601-489-8375
Participant Number (International):	1-437-900-0527
Conference ID:	38526
Webcast URL:	www.fronteraenergy.ca

A replay of the conference call will be available until 11:59 p.m. Eastern Time on August 21st, 2025.

Encore Toll free Dial-in Number:	1-888-660-6345
International Dial-in Number:	1-289-819-1450
Encore ID:	38526

About Frontera:

Frontera Energy Corporation is a Canadian public company involved in the exploration, development, production, transportation, storage and sale of oil and natural gas in South America, including related investments in both upstream and midstream facilities. The Company has a diversified portfolio of assets with interests in 22 exploration and production blocks in Colombia, Ecuador and Guyana, and pipeline and port facilities in Colombia. Frontera is committed to conducting business safely and in a socially, environmentally and ethically responsible manner.

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Advisories:

Cautionary Note Concerning Forward-Looking Statements

This news release contains forward-looking statements. All statements, other than statements of historical fact, that address activities, events or developments that the Company believes, expects or anticipates will or may occur in the future (including, without limitation, the Company's goal of enhancing shareholder value by returning capital to shareholders, the Company's intent to consider future shareholder initiatives including a potential future separation and other strategic transactions involving the Infrastructure business , the expected date for pre-drilling and drilling activity to commence in the Lower Magdalena Valley and Llanos Basins in Colombia, the operational timing of the connection project between Puerto Bahia and Reficar, holding the conference call for investors and the timing thereof, the Company's exploration and development plans and objectives, production levels, profitability, costs, future income generation capacity, cash levels (including the timing and ability to release restricted cash), regulatory approval, and the Company's hedging program and its ability to mitigate the impact of changes in oil prices) are forward-looking statements.

These forward-looking statements reflect the current expectations or beliefs of the Company based on information currently available to the Company. Forward-looking statements are subject to a number of risks and uncertainties that may cause the actual results of the Company to differ materially from those discussed in the forward-looking statements, and even if such actual results are realized or substantially realized, there can be no assurance that they will have the expected consequences to, or effects on, the Company. Factors that could cause actual results or events to differ materially from current expectations include, among other things: volatility in market prices for oil and natural gas; the newly imposed U.S. trade tariffs affecting over fifty countries and escalating tensions with China; the impact of the Russia-Ukraine conflict and the conflict in the Middle East; actions of the Organization of Petroleum Exporting Countries; uncertainties associated with estimating and establishing oil and natural gas reserves and resources; liabilities inherent with the exploration, development, exploitation and reclamation of oil and natural gas; uncertainty of estimates of capital and operating costs, production estimates and estimated economic return; increases or changes to transportation costs; expectations regarding the Company's ability to raise capital and to continually add reserves through acquisition and development; the Company's ability to complete strategic initiatives or transactions to enhance the value of its common shares and the timing thereof; the Company's ability to access additional financing; the ability of the Company to maintain its credit ratings; the ability of the Company to: meet its financial obligations and minimum commitments, fund capital expenditures and comply with covenants contained in the agreements that govern indebtedness; political developments in the countries where the Company operates; the uncertainties involved in interpreting drilling results and other geological data; geological, technical, drilling and processing problems; timing on receipt of government approvals; fluctuations in foreign exchange or interest rates and stock market volatility, the ability of the Joint Venture to reach an agreement with the GoG in respect of the Joint Venture's interest in the PA and PPL for the Corentyne block, and the other risks disclosed under the heading "Risk Factors" and elsewhere in the Company's annual information form dated March 10, 2025 filed on SEDAR+ at www.sedarplus.ca.

Any forward-looking statement speaks only as of the date on which it is made and, except as may be required by applicable securities laws, the Company disclaims any intent or obligation to update any forward-looking statement, whether as a result of new information, future events or results or otherwise. Although the Company believes that the assumptions inherent in the forward-looking statements are reasonable, forward-looking statements are not guarantees of future performance and accordingly undue reliance should not be put on such statements due to the inherent uncertainty therein.

This news release contains future oriented financial information and financial outlook information (collectively, "FOFI") (including, without limitation, statements regarding expected average production), and are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraph. The FOFI has been prepared by management to provide an outlook of the Company's activities and results, and such information may not be appropriate for other purposes. The Company and management believe that the FOFI has been prepared on a reasonable basis, reflecting management's reasonable estimates and judgments, however, actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein. Any FOFI speaks only as of the date on which it is made, and the Company disclaims any intent or obligation to update any FOFI, whether as a result of new information, future events or results or otherwise, unless required by applicable laws.

Non-IFRS Financial Measures

This press release 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 the MD&A.

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.

A reconciliation of Operating EBITDA to net loss is as follows:

	Three months ended		Six months ended	
	June 30		June 30	
($M)	2025	2024	2025	2024
Net loss	(455,212)	(2,846)	(427,688)	(11,349)
Finance Income	(2,073)	(1,816)	(3,556)	(3,408)
Finance expenses	18,310	17,429	33,715	34,699
Income tax (recovery) expense	(12,957)	32,659	(22,608)	59,244
Depletion, depreciation and amortization	60,600	63,188	127,994	129,000
Expense (recovery) of asset retirement obligation	151	45	526	(997)
Expenses of impairment	476,960	392	478,094	1,419
Trunkline incident costs	-	-	2,000	-
Post-termination obligation	(406)	(364)	(109)	186
Shared-based compensation	1,624	754	2,486	1,040
Restructuring, severance and other cost	9,526	1,052	10,527	2,855
Share of income from associates	(14,124)	(13,407)	(29,233)	(27,301)
Foreign exchange loss	2,553	7,518	314	8,615
Other (income) loss	(1,303)	2,774	(1,191)	3,133
Unrealized (gain) loss on risk management contracts	(3,556)	3,646	(8,342)	11,585
Non-controlling interests	(168)	(288)	(295)	(443)
Gain on repurchased of notes	(11,735)	(415)	(11,925)	(709)
Debt extinguishment cost	5,964	-	5,964	-
Colombian Temporary taxes	1,919	-	2,858	-
Operating EBITDA	76,073	110,321	159,531	207,569

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		Six months ended	
	June 30		June 30	
($M)	2025	2024	2025	2024
Consolidated Statements of Cash Flows				
Additions to oil and gas properties, infrastructure port, and plant and equipment	60,487	87,033	103,069	149,882
Additions to exploration and evaluation assets	1,692	10,467	3,527	12,954
Total additions in Consolidated Statements of Cash Flows	62,179	97,500	106,596	162,836
Non-cash adjustments [1]	(2,768)	(17,302)	(440)	(13,257)
Cash adjustments	(9)	-	(43)	-
Total Capital Expenditures	59,402	80,198	106,113	149,579

[1] Related to materials inventory movements, capitalized non-cash items and other adjustments

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		Six months ended	
	June 30		June 30	
($M)	2025	2024	2025	2024
Revenue Infrastructure Colombia Segment	14,479	12,894	27,343	23,422
Revenue from ODL	87,114	86,174	178,680	172,971
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [1]	30,490	30,161	62,538	60,540
Adjusted Infrastructure Revenues	44,969	43,055	89,881	83,962
Operating Cost Infrastructure Colombia Segment	(10,493)	(7,598)	(19,423)	(15,747)
Operating Cost from ODL	(12,955)	(12,572)	(24,914)	(23,968)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [1]	(4,534)	(4,400)	(8,720)	(8,389)
Adjusted Infrastructure Operating Costs	(15,027)	(11,998)	(28,143)	(24,136)
General and administrative Infrastructure Colombia Segment	(1,180)	(1,389)	(2,687)	(2,868)
General and administrative from ODL	(4,872)	(5,270)	(9,690)	(9,851)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [1]	(1,705)	(1,845)	(3,392)	(3,448)
Adjusted Infrastructure General and Administrative	(2,885)	(3,234)	(6,079)	(6,316)

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

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.

	Three months ended		Six months ended	
	June 30		June 30	
($M)	2025	2024	2025	2024
Adjusted Infrastructure Revenue [1]	44,969	43,055	89,881	83,962
Adjusted Infrastructure Operating Cost [1]	(15,027)	(11,998)	(28,143)	(24,136)
Adjusted Infrastructure General and Administrative [1]	(2,885)	(3,234)	(6,078)	(6,316)
Adjusted Infrastructure EBITDA [1]				

27,057

27,823

55,660

53,510

[1] Non-IFRS financial measure

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 of the MD&A.

Operating Netback and Oil and Gas Sales, Net of Purchases

Operating netback is a non-IFRS financial measure and operating netback per boe is a non-IFRS ratio. Operating netback per boe is used to assess the net margin of the Company's production after subtracting all costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and gas industry to analyze financial and operating performance expressed as profit per barrel and is an indicator of how efficient the Company is at extracting and selling its product. For netback purposes, the Company removes the effects of any trading activities and results from its Infrastructure Colombia Segment from the per barrel metrics and adds the effects attributable to transportation and operating costs of any realized gain or loss on foreign exchange risk management contracts. Refer to the reconciliation in the "Operating Netback" section on page 9.

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

	Three months ended		Six months ended	
	June 30		June 30	
	2025	2024	2025	2024
Produced crude oil and products sales ($M)[1]	181,081	224,646	390,708	433,689
Purchase crude net margin ($M)	(10,138)	(7,516)	(21,790)	(15,785)
Oil and gas sales, net of purchases ($M)	170,943	217,130	368,918	417,904
Sales volumes, net of purchases - (boe)	2,872,688	2,868,593	5,936,619	5,615,246
Produced crude oil and gas sales ($/boe)	63.04	78.31	65.81	77.23
Oil and gas sales, net of purchases ($/boe)	59.51	75.69	62.14	74.42

[1] Excludes sales from infrastructure services, as they are not part of the oil and gas segment. Refer to the "Infrastructure Colombia" section on page 19 for further details.

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		Six months ended	
	June 30		June 30	
	2025	2024	2025	2024
Oil and gas sales, net of purchases ($M) [1]	170,943	217,130	368,918	417,904
Crude oil sales volumes, net of purchases - (bbl)	2,826,599	2,804,205	5,859,395	5,498,687
Conventional natural gas sales volumes - (mcf)	262,629	366,869	440,385	665,013
Realized oil price, net of purchases ($/bbl)	59.93	76.66	62.53	75.27
Realized conventional natural gas price ($/mcf)	5.93	5.88	5.80	6.05

(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		Six months ended	
	June 30		June 30	
($M)	2025	2024	2025	2024
Oil and gas sales, net of purchases ($M) [1][2]	170,943	217,130	368,918	417,904
Gain (loss) on oil price risk management contracts, net ($M) [3]	431	(3,796)	(3,710)	(7,285)
(-) Royalties ($M)	(2,304)	(5,774)	(5,364)	(10,280)
Net Sales ($M)	169,070	207,560	359,844	400,339
Sales volumes, net of purchases (boe)	2,872,688	2,868,593	5,936,619	5,615,246
Oil and gas sales, net of purchases ($/boe)	59.51	75.69	62.14	74.42
Premiums received (paid) on oil price risk management contracts [4]	0.15	(1.32)	(0.62)	(1.30)
Royalties ($/boe)	(0.80)	(2.01)	(0.90)	(1.83)
Net sales realized price ($/boe)	58.86	72.36	60.62	71.29

(1) Non-IFRS financial measure.

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

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

(4) Supplementary financial measure.
Purchase crude net margin
Purchase 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. Purchase crude net margin per boe is a non-IFRS ratio that is calculated using the Purchase crude net margin, divided by the total sales volumes, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended		Six months ended	
	June 30		June 30	
	2025	2024	2025	2024
Purchased crude oil and products sales ($M)	49,139	49,035	106,502	100,320
(-) Cost of diluent and oil purchases ($M) (1)	(58,609)	(55,153)	(127,469)	(113,012)
Puerto Bahía inter-segment costs (2)	(668)	(1,398)	(823)	(3,093)
Purchase crude net margin ($M)	(10,138)	(7,516)	(21,790)	(15,785)
Sales volumes, net of purchases - (boe)	2,872,688	2,868,593	5,936,619	5,615,246
Purchase crude net margin ($/boe)	(3.53)	(2.62)	(3.67)	(2.81)

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

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahía inter-segment costs related to diluent and oil purchases as well as transportation 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		Six
	June 30		Jur
	2025	2024	202
Production costs (excluding energy cost) ($M)	32,367	41,401	68,
(-) Realized gain on FX hedge attributable to production costs (excluding energy cost) ($M) (1)	(43)	(2,203)	(43
SAARA Inter-segment costs	1,323	-	2,2
Production costs (excluding energy cost), net of realized FX hedge impact ($M) (2)	33,647	39,198	70,
Production (boe)	3,736,005	3,631,992	7,3
Production costs (excluding energy cost), net of realized FX hedge impact ($/boe)	9.01	10.79	9.5

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

(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		Six months ended	
	June 30		June 30	
	2025	2024	2025	2024
Energy costs ($M)	17,591	17,997	37,175	36,965
(-) Realized gain on FX hedge attributable to energy costs ($M) (1)	-	(770)	-	(1,351)
Energy costs, net of realized FX hedge impact ($M) (2)	17,591	17,227	37,175	35,614
Production (boe)	3,736,005	3,631,992	7,378,646	7,107,646
Energy costs, net of realized FX hedge impact ($/boe)	4.71	4.74	5.04	5.01

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

(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		Six months ended	
	June 30		June 30	
	2025	2024	2025	2024
Transportation costs ($M)	38,701	34,917	78,250	70,112
(-) Realized gain on FX hedge attributable to transportation costs ($M) (1)	-	(634)	-	(1,043)
Puerto Bahía inter-segment costs (2)	692	470	1,328	901
Transportation costs, net of realized FX hedge impact ($M) (2)(3)	39,393	34,753	79,578	69,970
Net Production (boe)	3,389,204	3,139,955	6,652,293	6,210,568
Transportation costs, net of realized FX hedge impact ($/boe)	11.62	11.07	11.96	11.27

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

(2) 2024 prior period figures are different compared with those previously reported as a result as a result of the inclusion of Puerto Bahia inter-segment costs related to cost of diluent and oil purchased, and transportation cost.

(3) Non-IFRS financial measure.

Supplementary Financial Measures

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

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

Royalties per boe

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

NCIB weighted-average price per share

Weighted-average price per share under the 2023 NCIB is a supplementary financial measure that corresponds to the weighted-average price of common 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

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 debt of the 2028 Unsecured Notes, loans, and liabilities from leases of various properties, power generation supply, vehicles and other assets.

Definitions:

bbl(s)	Barrel(s) of oil
bbl/d	Barrel of oil per day
boe	Refer to "Boe Conversion" disclosure above
boe/d	Barrel of oil equivalent per day
Mcf	Thousand cubic feet
Net Production	Net production represents the Company's working interest volumes, net of royalties and internal consumption

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FOR FURTHER INFORMATION:

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