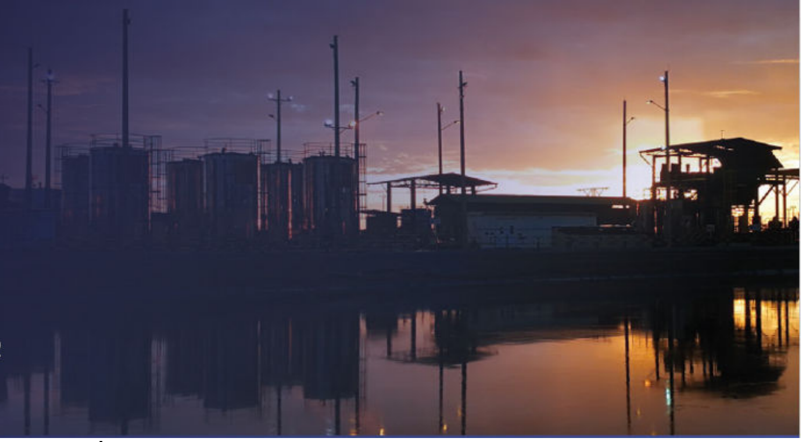
FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

August 9, 2022
For the three and six months ended June 30, 2022



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*Frontera Energy Corporation (“**Frontera**” 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 related investments in both upstream and midstream 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 1610, 222 - 3rd Avenue S.W., 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 Condensed Consolidated Financial Statements and related notes for the three and six months ended June 30, 2022 and 2021 (“**Interim Financial Statements**”). Additional information with respect to the Company, including the Company’s quarterly and annual financial statements and the Annual Information Form (**“AIF”**), have been filed with Canadian securities regulatory authorities and is available on SEDAR at www.sedar.com 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 16.*

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

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

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

		Q2 2022	Q1 2022	Q2 2021	Six months ended June 30 2022	Six months ended June 30 2021
Operational Results						
Heavy crude oil production (1)	(bbl/d)	21,455	21,214	17,241	21,335	19,108
Light and medium crude oil production (1)	(bbl/d)	17,348	17,248	17,142	17,298	17,715
Total crude oil production	(bbl/d)	38,803	38,462	34,383	38,633	36,823
Conventional natural gas production (1)	(mcf/d)	10,374	9,530	5,164	9,952	5,193
Natural gas liquids (1)	(boe/d)	963	966	393	965	392
Total production (2)	(boe/d) (3)	41,586	41,100	35,682	41,343	38,126
Total inventory balance	(bbl)	1,423,695	1,434,111	969,028	1,423,695	807,061
Oil and gas sales, net of purchases (4)	($/boe)	103.34	90.42	64.54	97.45	61.35
Realized loss on risk management contracts (5)	($/boe)	(1.15)	(1.06)	(8.00)	(1.11)	(5.77)
Royalties (5)	($/boe)	(10.57)	(7.58)	(0.53)	(9.21)	(1.25)
Dilution costs (5)	($/boe)	(0.12)	(0.12)	(0.34)	(0.12)	(1.29)
Net sales realized price (4)	($/boe)	91.50	81.66	55.67	87.01	53.04
Production costs (5)	($/boe)	(12.65)	(13.48)	(11.72)	(13.06)	(10.84)
Transportation costs (5)	($/boe)	(10.84)	(9.74)	(11.15)	(10.28)	(11.23)
Operating netback per boe (4)	($/boe)	68.01	58.44	32.80	63.67	30.97
Financial Results						
Oil & gas sales, net of purchases (6)	($M)	312,910	229,569	200,581	542,479	381,537
Realized loss on risk management contracts	($M)	(3,476)	(2,682)	(24,877)	(6,158)	(35,857)
Royalties	($M)	(32,018)	(19,244)	(1,640)	(51,262)	(7,750)
Dilution costs	($M)	(376)	(298)	(1,056)	(674)	(8,039)
Net sales (6)	($M)	277,040	207,345	173,008	484,385	329,891
Net income (loss) (7)	($M)	13,484	102,228	(25,648)	115,712	(39,774)
Per share – basic	($)	0.14	1.08	(0.26)	1.23	(0.41)
Per share – diluted	($)	0.14	1.05	(0.26)	1.20	(0.41)
General and administrative	($M)	15,097	14,656	14,132	29,753	27,334
Operating EBITDA (6)	($M)	190,678	132,998	83,072	323,676	152,230
Cash provided by operating activities	($M)	246,615	114,980	87,391	361,595	134,784
Capital expenditures (6)	($M)	93,835	113,545	61,214	207,380	75,579
Cash and cash equivalents – unrestricted	($M)	295,098	257,373	358,325	295,098	358,325
Restricted cash short and long-term (8)	($M)	57,975	66,146	128,283	57,975	128,283
Total cash (8)	($M)	353,073	323,519	486,608	353,073	486,608
Total debt and lease liabilities (8)	($M)	535,454	558,281	565,238	535,454	565,238
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) (9)	($M)	409,694	410,161	468,424	409,694	468,424
Net debt (excluding Unrestricted Subsidiaries) (9)	($M)	168,512	199,303	138,701	168,512	138,701

1. Reference to heavy crude oil, light and medium crude oil combined, natural gas liquids, or conventional natural gas production in the above table and elsewhere in this MD&A refer to the heavy crude oil, light and medium crude oil combined, natural gas liquids, and conventional natural gas, respectively, product types as defined in National Instrument ("**NI**") 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 27.
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 27.
4. Non-IFRS ratio (equivalent to a "non-GAAP ratio", as defined in NI 52-112 - *Non-GAAP and Other Financial Measures Disclosure "**NI 52-112**"*). Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
5. Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
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 16.
7. Net income (loss) 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 16.
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 Bahía**"), including its subsidiary Sociedad Portuaria Puerto Bahía S.A. ("**Puerto Bahia**"). Refer to the "Liquidity and Capital Resources" section on page 20.

Performance Highlights

Second Quarter of 2022

Frontera continued to build on the positive momentum that began in 2021, substantially delivering on its financial and operating objectives in the first six months of 2022. In the second quarter, the Company generated EBITDA of $190.7 million, generated production of 41,586 boe/d (consisting of 21,455 bbl/d of heavy crude oil, 17,348 bbl/d of light and medium crude oil, 10,374 mcf/d of conventional natural gas and 963 boe/d of natural gas liquids) including record production at the CPE-6 block, improved its operating netback by 16% to $68.01/boe, increased its net sales realized price by 12% to $91.50/boe and grew its cash provided by operating activities by 114% to $246.6 million. This is the fourth consecutive quarter of growth in these metrics. Frontera also recorded net income of $13.5 million.

The Company also significantly enhanced shareholder returns during the quarter through its previously launched NCIB (as defined below) and a recently closed C$65 million (equivalent to $50.0 million) Substantial Issuer Bid (as defined below).

Operationally, the Company also unlocked opportunities within its portfolio with drilling successes during the quarter in Guyana at Kawa-1 and in Ecuador at Yin-1.

Subsequent to the quarter, Frontera and CGX jointly announced that the companies have entered into a JOA Amendment (as defined below), effectively farming into the Corentyne block, offshore Guyana, and securing funding for the Joint Venture’s second exploration well, Wei-1 expected to be spud in October 2022. The JOA Amendment will increase the Company's working interest in the Corentyne block to 68%. The JOA Amendment remains subject to certain conditions precedent.

On May 18, 2022 the Company released its 2021 Sustainability Report (the "**Sustainability Report**"), announced its 2022 environmental, social and governance ("**ESG**") targets and reaffirmed its commitment to continue to develop and implement meaningful actions to strengthen its ESG performance across its business. In 2021, Frontera achieved 98% of its 2021 ESG goals. Frontera's 2021 Sustainability Report details Frontera's ESG initiatives and track record, benchmarks the Company's 2021 ESG performance against its goals and establishes Frontera's 2022 ESG goals. Frontera's 2021 Sustainability Report can be accessed on the Company's website at: https://www.fronteraenergy.ca/sustainability-reports/

During the second quarter of 2022, the Company achieved a neutralization of 52% of its total emissions in Colombia, exceeding its 2022 neutralization ESG goal. Additionally, following an October 2021 decision to migrate its Quifa Field energy demand from the Termopetróleo thermal generation plant to the National Electric System in order to reduce its emission intensity, the Company reduced its CO_2 emissions in the second quarter by 31,000 tons and 69,160 tons in the first half of 2022. Frontera’s CO_2 decrease in the first half of 2022 is a reduction of approximately 12% of Frontera’s total 2021 CO_2 emissions.

Effective June 3, 2022, Mr. René Burgos Díaz, was appointed as Chief Financial Officer (“**CFO**”) of the Company replacing Mr. Alejandro Piñeros. Mr. Burgos is a financial markets executive with over 20 years of experience in investment management, leveraged finance, restructuring and financial advisory expertise across multiple industries and geographies, specifically Latin America. Prior to his appointment as CFO, René served on Frontera’s Board of Directors since December 2019.

Financial and Operational Results

- Production averaged 41,586 boe/d (consisting of 21,455 bbl/d of heavy crude oil, 17,348 bbl/d of light and medium crude oil, 10,374 mcf/d of conventional natural gas and 963 boe/d of natural gas liquids), an increase in the second quarter of 2022 compared with 41,100 boe/d in the prior quarter (consisting of 21,214 bbl/d of heavy crude oil, 17,248 bbl/d of light and medium crude oil, 9,530 mcf/d of conventional natural gas and 966 boe/d of natural gas liquids), and 35,682 boe/d in the second quarter of 2021 (consisting of 17,241 bbl/d of heavy crude oil, 17,142 bbl/d of light and medium crude oil, 5,164 mcf/d of conventional natural gas and 393 boe/d of natural gas liquids).
- Cash provided by operating activities increased to $246.6 million in the second quarter of 2022, compared with $115.0 million in the prior quarter and $87.4 million in the second quarter of 2021. The Company reported a total cash position of $353.1 million, including $58.0 million of restricted cash, as at June 30, 2022, compared with a total cash position of $486.6 million, including $128.3 million of restricted cash, as at June 30, 2021.
- Net income was $13.5 million ($0.14/share) in the second quarter of 2022, compared with net income of $102.2 million ($1.08/share) in the prior quarter and net loss of $25.6 million ($0.26/share) in the second quarter of 2021.
- Capital expenditures were $93.8 million in the second quarter of 2022, compared with $113.5 million in the prior quarter and $61.2 million in the second quarter of 2021.
- Operating EBITDA increased to $190.7 million in the second quarter of 2022, compared with $133.0 million in the prior quarter and $83.1 million in the second quarter of 2021.
- Operating netback increased to $68.01/boe in the second quarter of 2022, compared with $58.44/boe in the prior quarter and $32.80/boe in the second quarter of 2021.

2. GUIDANCE

Frontera is tightening its 2022 production guidance to 41,000-43,000 boe/d and increasing its operating EBITDA guidance to $675-$700 million at $100/bbl average Brent for the year. The Company reiterates its cost guidance including production costs of $11.0-$12.0/boe and transportation costs of $10.0-$11.0/boe. Frontera also increased its total capital expenditures guidance for the year to $435-$495 million, primarily as a result of Frontera's increased working interest in the Corentyne block in Guyana, as previously announced on July 22, 2022, and reflective of the Company's spending commitment at the Wei-1 exploration well.

The Company developed its updated 2022 capital and production guidance using an exchange rate of 4,200 COP per $1 USD. Frontera does not anticipate paying any material cash income taxes in Colombia in 2022, as a result of the Company's existing tax pool position.

The following table reports the Company´s actual results for the six months ending June 30, 2022, against the revised and previous guidance.

			2022 Guidance	
		Actual 2022 YTD	**Revised**	**Previous**
Average production	boe/d	41,343	41,000 - 43,000	40,000 - 43,000
Production costs	$/boe	13.06	11.00 - 12.00	11.00 - 12.00
Transportation costs	$/boe	10.28	10.00 - 11.00	10.00 - 11.00
Operating EBITDA at $90/bbl [(1)]	$MM	323.7	575 - 625	575 - 625
Operating EBITDA at $100/bbl [(1)]	$MM		675 - 700	N/A
Development Drilling	$MM	76.0	170 - 180	130 - 140
Development Facilities	$MM	17.4	50 - 60	40 - 50
Colombia and Ecuador Exploration	$MM	20.9	55 - 65	50 - 60
Other [(2)]	$MM	19.2	5	5
Total Colombia and Ecuador Upstream Capital Expenditures	$MM	133.5	280 - 310	225 - 255
Guyana Kawa Well	$MM	51.0	51	110 - 130
Guyana Wei Well [(3)]	$MM	20.0	100-130	
Guyana Port Project	$MM	2.9	5	5 - 10
Capital Expenditures [(1)] [(4)]	$MM	207.4	435 - 495	340 - 395

1. Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
2. 2022 Guidance - Other does not include $12.0 million related to the acquisition of an additional 35% W.I. in the El Dificil Block nor the payment of $7.0 million related to the acquisition of 50% of the CPE-6 block. (For further information refer to the "Capital Expenditures and Acquisitions" section on page 13).
3. 2022 Guidance - Estimated Wei-1 exploration well costs for 2022. Total Wei-1 exploration well costs are estimated at approximately $130-$140 million (including pre-drill and other costs).
4. Capital Expenditures excludes decommissioning costs of $10.0 million.

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 27 for details of the Company's net production.

		Production				
					Six months ended June 30	
Producing blocks in Colombia		**Q2 2022**	**Q1 2022**	**Q2 2021**	**2022**	**2021**
Heavy crude oil	(bbl/d)	21,455	21,214	17,241	21,335	19,108
Light and medium crude oil	(bbl/d)	16,738	16,969	17,142	16,853	17,715
Conventional natural gas	(mcf/d)	10,374	9,530	5,164	9,952	5,193
Natural gas liquids	(boe/d)	963	966	393	964	392
Total production Colombia	**(boe/d)**	**40,976**	**40,821**	**35,682**	**40,898**	**38,126**
Producing blocks in Ecuador						
Light and medium crude oil	(bbl/d)	610	279	—	445	—
Total production Ecuador	**(bbl/d)**	**610**	**279**	**—**	**445**	**—**
Total production	**(boe/d)**	**41,586**	**41,100**	**35,682**	**41,343**	**38,126**

Colombia

Production in Colombia for the three months ended June 30, 2022, increased by 155 bbl/d compared to the prior quarter. Higher production was a result of the growth in production of the heavy crude oil and conventional natural gas blocks, mainly as a result of development drilling in the Quifa block and the acquisition of a 35% W.I. in the El Dificil block, which was completed on April 27, 2022. This was partially offset by a production reduction in the Company’s light and medium crude oil blocks due to natural decline.

Compared to the second quarter of 2021 and first half of 2021, production increased by 15% and 7%, respectively, mainly due to the acquisition of Petroleos Sud Americanos S.A. (“**PetroSud**”) on December 30, 2021 and the subsequent acquisition of the 35% W.I. in the El Dificil block on April 27, 2022, which resulted in the addition of 1,472 boe/d and 1,350 boe/d during the second quarter and first half of 2022, respectively (consisting of 6,132 mcf/d and 5,506 mcf/d of conventional natural gas, 332 bbl/d and 328 bbl/d of light and medium crude oil, and 64 bbl/d and 56 bbl/d of natural gas liquids, respectively). In addition, during the first half of 2022, heavy crude oil production increased, mainly in the CPE-6 block. Increases were partially offset by lower production in light and medium crude oil primarily due to natural decline.

Ecuador

Production in Ecuador for the three and six months ended June 30, 2022, was 610 bbl/d and 445 bbl/d of light and medium crude oil, respectively. Production in Ecuador started during the first quarter of 2022 after discoveries at the Jandaya and Tui-1 wells. Following the completion of the third exploration well, Yin-1, on June 16, 2022, on the Perico block, the three wells were producing light and medium crude oil by the end of the second quarter. Production for the three months ended June 30, 2022 increased by 331 bbl/d compared to the previous quarter, despite an eight-day shutdown in production near the end of the quarter associated with the national strike in Ecuador.

Production Reconciled to Sales Volumes

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

					Six months ended June 30	
		Q2 2022	Q1 2022	Q2 2021	2022	2021
Production	(boe/d)	**41,586**	**41,100**	**35,682**	**41,343**	**38,126**
Royalties in-kind Colombia	(boe/d)	(5,646)	(4,334)	(2,904)	(4,992)	(2,833)
Royalties in-kind Ecuador [1]	(boe/d)	(262)	(98)	—	(180)	—
Net production	(boe/d)	**35,678**	**36,668**	**32,778**	**36,171**	**35,293**
Oil inventory draw (build)	(boe/d)	115	(6,967)	2,352	(3,406)	809
Overlift (settlement)	(boe/d)	14	(10)	16	2	(310)
Volumes purchased	(boe/d)	4,084	3,990	3,492	4,037	2,043
Other inventory movements [2]	(boe/d)	(1,835)	(1,704)	(1,917)	(1,771)	(1,851)
Sales volumes	(boe/d)	**38,056**	**31,977**	**36,721**	**35,033**	**35,984**
Sale of volumes purchased	(boe/d)	(4,783)	(3,766)	(2,570)	(4,277)	(1,632)
Sales volumes, net of purchases	(boe/d)	**33,273**	**28,211**	**34,151**	**30,756**	**34,352**
Oil sales volumes	(bbl/d)	31,461	26,500	33,258	28,994	33,452
Conventional natural gas sales volumes	(mcf/d)	10,328	9,753	5,090	10,043	5,130
Total oil and conventional natural gas sales volumes, net of purchases	(boe/d)	**33,273**	**28,211**	**34,151**	**30,756**	**34,352**
Inventory balance						
Colombia	(bbl)	922,719	937,583	488,828	922,719	488,828
Peru	(bbl)	480,200	480,200	480,200	480,200	480,200
Ecuador	(bbl)	20,776	16,328	—	20,776	—
Inventory ending balance	**(bbl)**	**1,423,695**	**1,434,111**	**969,028**	**1,423,695**	**969,028**

1. The Company reported the share of production retained by the government of Ecuador as royalties paid in-kind.
2. Mainly corresponds to operational consumption and quality volumetric compensation.

Sales volumes, net of purchases for the three months ended June 30, 2022, increased by 18% compared with the prior quarter, mainly due to one additional cargo sold in Colombia. During the second quarter of 2022, the Company exported its first 28,355 barrels of production in Ecuador. For the three and six months ended June 30, 2022, sales volumes, net of purchases, decreased by 3% and 10%, respectively, compared with same periods of 2021, due to volumes sold in Peru during 2021.

Colombia Royalties PAP

The Company makes high price clause participation ("**PAP**") payments to Ecopetrol S.A. and the Agencia Nacional de Hidrocarburos ("**ANH**") on production from the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo, Arrendajo and CPE-6 blocks. The PAP is paid in cash for all blocks except for those relating to the Quifa block, which are paid using in-kind volumes from production. 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 2022	**Q1 2022**	**Q2 2021**	**2022**	**2021**
PAP in cash	(bbl/d)	2,622	1,933	1,186	2,279	1,093
PAP in kind	(bbl/d)	3,363	2,027	413	2,699	217
PAP	**(bbl/d)**	**5,985**	**3,960**	**1,599**	**4,978**	**1,310**
% Production		**14.4 %**	**9.6 %**	**4.5 %**	**12.0 %**	**3.4 %**

For the three and six months ended June 30, 2022, PAP increased compared with the same periods of 2021 and for the second quarter of 2022, PAP increase compared to the prior quarter, primarily due to a higher WTI oil benchmark price and the activation of the PAP clause on the CPE-6 block late in March 2022.

Realized and Reference Prices

					Six months ended June 30	
		Q2 2022	**Q1 2022**	**Q2 2021**	**2022**	**2021**
Reference price						
Brent	($/bbl)	111.98	97.90	69.08	104.94	65.23
Average realized prices						
Realized oil price, net of purchases	($/bbl)	107.80	94.67	65.67	101.83	62.41
Realized conventional natural gas price	($/mcf)	4.55	4.32	3.99	4.44	3.97
Net sales realized price						
Oil and gas sales, net of purchases [1]	($/boe)	103.34	90.42	64.54	97.45	61.35
Realized loss on risk management contracts[2] [3]	($/boe)	(1.15)	(1.06)	(8.00)	(1.11)	(5.77)
Royalties [2]	($/boe)	(10.57)	(7.58)	(0.53)	(9.21)	(1.25)
Dilution costs [2] [4]	($/boe)	(0.12)	(0.12)	(0.34)	(0.12)	(1.29)
Net sales realized price [1]	**($/boe)**	**91.50**	**81.66**	**55.67**	**87.01**	**53.04**

1. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
2. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
3. Includes put premiums paid for the position expired during the period.
4. Beginning in the second quarter of 2021, the Company moved from using a third-party dilution service to buying its own dilution at the corresponding fields (mainly Quifa block), using it for blending to meet pipeline specifications and other services, and then selling the blended oil at the sales point. The dollar difference between the cost of the purchases versus sales is approximately equivalent to how the Company accounted for the dilution costs in the past, or lower, considering the ability of the Company to secure better prices than a third-party dilution service. The decrease in dilution costs reflects decreased usage of the dilution service as the Company adopts this more cost efficient approach.

The average Brent benchmark price during the three and six months ended June 30, 2022, increased by 62% and 61%, respectively, compared to the same periods of 2021. In comparison to the first quarter of 2021, the average Brent benchmark oil price increased by 14%. The increase in crude oil prices was mostly attributable to three factors: (i) the market was undersupplied due to the low levels of the inventories below the five years average, (ii) the reduction in OPEC+'s spare capacity, and (iii) the Russia Ukraine conflict, which is also affecting the global crude oil supply. Despite the above, the demand was affected by the lockdowns in effect in China during the period due to Covid-19 pandemic.

For the three and six months ended June 30, 2022, the Company's net sales realized price was $91.50/boe and $87.01/boe, respectively, an increase of 64% and 64%, respectively, compared to the same periods of 2021. The increase is mainly the result of higher Brent benchmark oil price, lower loss on risk management contracts, reduction in dilution costs due to replacement of the dilution service by oil volumes purchased, partially offset by higher cash royalties resulting from the oil price increase. In comparison to the first quarter of 2022, the net sales realized price increased by 12%, or $9.84/boe, primarily driven by the increase in the benchmark oil price and, better differential compared with previous quarter, partially offset by higher royalties resulting from the oil price increase.

Operating Netback

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

	Q2 2022		Q1 2022		Q2 2021	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price (1)	277,040	91.50	207,345	81.66	173,008	55.67
Production costs (2) (3)	(47,882)	(12.65)	(49,861)	(13.48)	(38,043)	(11.72)
Transportation costs (2) (3)	(35,178)	(10.84)	(32,153)	(9.74)	(33,259)	(11.15)
Operating Netback (1) (4)	**193,980**	**68.01**	**125,331**	**58.44**	**101,706**	**32.80**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases (5)		33,273		28,211		34,151
Production (6)		41,586		41,100		35,682
Net production (7)		35,678		36,668		32,778

1. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
2. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
3. 2021 period figures are different compared with those previously reported as a result of a reclassification from production cost to transportation cost. Refer to the "Selected Quarterly Information" section on page 14 for further details.
4. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
5. Sales volumes, net of purchases, exclude sales of third-party volumes.
6. Refer to the "Production" section on page 4.
7. Refer to the "Further Disclosures" section on page 27.

Operating netback for the second quarter of 2022 was $68.01/boe, compared to $32.80/boe in the same quarter of 2021. The increase was as a result of higher net sales realized price, and lower transportation costs of $0.31/boe, primarily due to no volumes transported in Peru during 2022. This effect was partially offset by higher production costs due to an increase in tariffs and barrels produced affecting variable costs as energy, internal field transportation and personnel expenses.

In comparison to the first quarter of 2022, operating netback for the second quarter of 2022 increased from $58.44/boe to $68.01/boe, primarily due to higher net sales realized price, and a decrease in production costs mainly due to lower well services activity. This effect was partially offset by higher transportation costs, mainly explained by lower costs during the previous quarter due to non-recurrent savings in the Oleoducto Central S.A. ("**Ocensa**") pipeline take or pay, additional volumes transported in Ecuador during the second quarter of 2022 and the initiation of the pipeline take or pay commitment as part of the settlement agreement with Bicentenario de Colombia S.A.S. ("**Bicentenario**") for further information, refer to Note 27 of the Company's Annual Consolidated Financial Statements and related notes for the years ended December 31, 2021 and 2020 (the **"2021 Annual Consolidated Financial Statements"**).

The following table provides a summary of the Company's netbacks for the six months ended June 30, 2022:

	Six months ended June 30			
	2022		2021	
	$M	**($/boe)**	**$M**	**($/boe)**
Net sales realized price (1)	484,385	87.01	329,891	53.04
Production costs (2) (3)	(97,743)	(13.06)	(74,798)	(10.84)
Transportation costs (2)	(67,331)	(10.28)	(71,732)	(11.23)
Operating Netback (1) (4)	**319,311**	**63.67**	**183,361**	**30.97**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases (5)		30,756		34,352
Production (6)		41,343		38,126
Net production (7)		36,171		35,293

1. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
2. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
3. 2021 period figures are different compared with those previously reported as a result of a reclassification from production cost to transportation cost. Refer to the "Selected Quarterly Information" section on page 14 for further details.
4. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
5. Sales volumes, net of purchases, exclude sales of third-party volumes.
6. Refer to the "Production" section on page 4.
7. Refer to the "Further Disclosures" section on page 27.

Operating netback for the six months ended June 30, 2022, increased by 106% to $63.67/boe from $30.97/boe in the same period of 2021. The increase was primarily due to higher net sales realized price and reduction in transportation costs primarily due to no barrels being transported in Peru during 2022 compared to the same period of 2021. This effect was partially offset by, higher production costs due to an increase in tariffs and barrels produced affecting variable costs as energy, internal field transportation, well services, maintenance and personnel expenses.

Sales

($M)	Three months ended June 30 2022	Three months ended June 30 2021	Six months ended June 30 2022	Six months ended June 30 2021
Oil and gas sales, net of purchases [1]	312,910	200,581	542,479	381,537
Realized loss on risk management contracts [2]	(3,476)	(24,877)	(6,158)	(35,857)
Royalties	(32,018)	(1,640)	(51,262)	(7,750)
Dilution cost	(376)	(1,056)	(674)	(8,039)
Net sales [1]	**277,040**	**173,008**	**484,385**	**329,891**
Net sales realized price ($/boe) [3]	91.50	55.67	87.01	53.04

1. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 16.
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 16.

Oil and gas sales, net of purchases, increased by $112.3 million and $160.9 million for the three and six months ended June 30, 2022, respectively, compared to the same periods of 2021, mainly due to higher Brent benchmark oil prices (refer to the "Realized and Reference Prices" section on page 6 for further detail on changes in prices).

Net sales for the three and six months ended June 30, 2022, increased by $104.0 million and $154.5 million, respectively, compared with the same periods of 2021. The following table describes the various factors that impacted net sales:

($M)	Three months ended June 30 2022-2021	Six months ended June 30 2022-2021
Net sales for the period ended June 30, 2021	173,008	329,891
Increase due to 60% higher oil and gas price (YTD 59% higher)	120,587	224,370
Decrease due to lower volumes sold of 878 boe/d or 3% (YTD 3,596 boe/d or 10%)	(8,258)	(63,428)
Decrease in realized loss on risk management contracts	21,401	29,699
Decrease in dilution costs	680	7,365
Increase in royalties	(30,378)	(43,512)
Net sales for the period ended June 30, 2022	**277,040**	**484,385**

Oil and Gas Operating Costs

($M)	Three months ended June 30 2022	Three months ended June 30 2021	Six months ended June 30 2022	Six months ended June 30 2021
Production costs	47,882	38,043	97,743	74,798
Transportation costs	35,178	33,259	67,331	71,732
Cost of purchases [1]	52,820	18,436	88,242	22,440
Dilution costs	376	1,056	674	8,039
Post-termination obligation	6,842	—	7,070	—
Overlift (Settlement)	35	(2)	13	(2,661)
Inventory valuation	(7,619)	5,237	(26,191)	8,465
Total oil and gas operating costs	**135,514**	**96,029**	**234,882**	**182,813**

1. Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining activities. This item is included in the Oil and gas sales, net of purchases. For further detail refer to the "Non-IFRS and Other Financial Measures" section on page 16.

For the three and six months ended June 30, 2022, total oil and gas operating costs increased by 41% and 28%, respectively, compared to the same periods of 2021. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs for the three and six months ended June 30, 2022, increased by 26% and 31%, respectively, compared with the same periods of 2021, primarily due to an increase in tariffs and barrels produced affecting variable costs as energy, internal field transportation and personnel expenses.
- Transportation costs increased by 6% for the three months ended June 30, 2022, compared with the same period of 2021, primarily due to higher volumes produced and transported in Colombia. For the six months ended June 30, 2022, transportation cost decreased by 6%, primarily due to no volumes transported in Peru compared with the same period of 2021.

- Cost of purchases for the three and six months ended June 30, 2022, increased by $34.4 million and $65.8 million respectively, compared with the same periods of 2021, due to additional volumes acquired from third parties to replace the dilution service, and higher market price of those volumes. The sale of the volumes purchased represents an estimated income for the three and six months ended June 30, 2022, of $47.6 million and $80.2 million, respectively.
- Dilution costs for the three and six months ended June 30, 2022, decreased by $0.7 million and $7.4 million, respectively, compared with the same periods of 2021, mainly due to the replacement of the dilution service by volumes purchased, and the optimization of the Company´s dilution strategy by moving CPE-6 oil volumes to Puerto Bahia to sell as Llanos Blend.
- Post-termination obligation for the three and six months ended June 30, 2022, was $6.8 million and $7.1 million, respectively, mainly related to a non-recurring cleaning activities cost provision related to the Block 192 in Peru.
- Overlift for the three and six months ended June 30, 2022, was not significant, compared to the settlement of the overlift balance during the same periods of 2021.
- Inventory valuation for the three and six months ended June 30, 2022, decreased by $12.9 million and $34.7 million, respectively, compared with the same periods of 2021, mainly due to a buildup of inventory, primarily at Puerto Bahia, which was sold in July 2022 and higher oil costs as a result of an increase in royalties.

Royalties

	Three months ended June 30		Six months ended June 30	
($M)	**2022**	**2021**	**2022**	**2021**
Royalties Colombia	31,893	1,640	51,137	7,750
Royalties Ecuador	125	—	125	—
Royalties	**32,018**	**1,640**	**51,262**	**7,750**

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia. For the three and six months ended June 30, 2022, royalties increased by $30.4 million and $43.5 million, respectively, compared to same periods of 2021, primarily due to the increase in the WTI oil benchmark price and the activation of the PAP clause for the CPE-6 block in late March 2022. In addition, royalties costs for 2021 were lower due to reversal of previously recorded provision. Refer to the “Production Reconciled to Sales Volumes” section on page 5 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)	**2022**	**2021**	**2022**	**2021**
Depletion, depreciation and amortization	49,510	40,455	88,294	73,091

For the three and six months ended June 30, 2022, depletion, depreciation and amortization expense (“**DD&A**”) increased by 22% and 21%, respectively, compared to the same periods of 2021, mainly due to a higher depletable base as a result of the reversal of impairment in fourth quarter 2021 and the acquisition Petrosud On December 30, 2021.

Impairment, exploration expenses and others

	Three months ended June 30		Six months ended June 30	
($M)	**2022**	**2021**	**2022**	**2021**
Impairment expense of:				
Exploration and evaluation assets	2,264	—	2,264	—
Other	3,033	—	3,033	—
Total impairment expense	5,297	—	5,297	—
Exploration expenses of:				
Geological and geophysical costs, and other	480	89	952	171
Minimum work commitment paid	919	—	919	—
Total exploration expenses	1,399	89	1,871	171
Recovery of asset retirement obligation	(1,598)	(1,111)	(6,027)	(6,849)
Impairment, exploration expenses and other	**5,098**	**(1,022)**	**1,141**	**(6,678)**

During the three and six months ended June 30, 2022, the Company recorded an impairment of $2.3 million, related to exploration and evaluation assets in Colombia due to non-commercial exploratory test results, and plans to abandon further work on certain exploration projects from Colombia. In addition, $3.0 million of other impairment charges were recognized mainly related to obsolete inventories in Peru.

During the three and six months ended June 30, 2022, the exploration expense increased by $1.3 million and $1.7 million, respectively, compared with the same periods of 2021, mainly due to the payment of the remaining balance of a minimum work commitment not executed in the CPE-6 block.

During the three and six months ended June 30, 2022, the Company recognized a recovery related to an asset retirement obligation of $1.6 million and $6.0 million, respectively, compared to a recovery of $1.1 million and $6.8 million in the same periods of 2021, respectively. 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.

Other Operating Costs

	Three months ended June 30		Six months ended June 30	
($M)	**2022**	**2021**	**2022**	**2021**
General and administrative	15,097	14,132	29,753	27,334
Share-based compensation	(583)	3,142	4,505	4,459
Restructuring, severance and other costs	1,055	1,535	1,386	1,916

General and Administrative

For the three and six months ended June 30, 2022, G&A expenses increased by 7% and 9%, respectively, compared with the same periods of 2021, mainly due to an increase in professional fees during the three months ended June 30, 2022, compared to the same period of 2021 and higher personnel costs and other taxes during the six months ended June 30, 2022, compared to the same period of 2021.

Share-based Compensation

For the three months ended June 30, 2022, share-based compensation was an income of $0.6 million compared to an expense of $3.1 million in the same period of 2021, mainly due to the decrease in the Common Share price during the second quarter of 2022. For the six months ended June 30, 2022, share-based compensation was comparable with the same period of 2021, amounting to $4.5 million. Share-based compensation reflects cash and non-cash charges relating to the vesting of restricted share units and grants of deferred share units under the Company's security-based compensation plan, which are subject to variability from movements in the underlying Common Share 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, 2022, restructuring, severance and other costs were comparable to those for the same period in 2021.

Non-Operating Costs

	Three months ended June 30		Six months ended June 30	
($M)	**2022**	**2021**	**2022**	**2021**
Finance income	876	3,675	1,483	4,515
Finance expenses	(12,621)	(13,747)	(24,856)	(27,334)
Foreign exchange loss	(13,080)	(48)	(9,438)	(18,536)
Other loss, net	(5,062)	(3,182)	(11,081)	(12,783)

Finance Income

For the three and six months ended June 30, 2022, finance income decreased by $2.8 million and $3.0 million, respectively, compared to the same periods of 2021, due to interest collected from VAT reimbursement in previous year.

Finance Expense

For the three and six months ended June 30, 2022, finance expenses decreased by $1.1 million and $2.5 million, respectively, compared with the same periods of 2021, mainly due to a reduction in the interest rate from the new bonds, and lower interest on the 2025 Puerto Bahia Debt (as defined below) and lease liabilities.

Foreign Exchange Loss

For the three and six months ended June 30, 2022, foreign exchange loss was $13.1 million and $9.4 million, respectively, as a result of the COP's depreciation against the USD on the translation of the debt consolidated from Puerto Bahia and the translation of the Company's net working capital balances, compared with a loss of $0.1 million and $18.5 million in the same period of 2021.

Other Loss, net

For the three and six months ended June 30, 2022, the Company recognized other losses of $5.1 million and $11.1 million, respectively, primarily related to the recognition of contingencies, compared to other losses of $3.2 million and $12.8 million in the same period of 2021, related to the reassessment of contingencies from the late delivery of production from the Quifa block prior to 2014 (for further information refer to Note 27 of the 2021 Annual Financial Statements).

Loss on Risk Management Contracts

	Three months ended June 30		Six months ended June 30	
($M)	**2022**	**2021**	**2022**	**2021**
Premiums paid on risk management contracts settled	(3,476)	(987)	(6,158)	(3,107)
Cash settlement on risk management contracts	—	(23,890)	—	(32,750)
Realized loss on risk management contracts	(3,476)	(24,877)	(6,158)	(35,857)
Unrealized (loss) gain on risk management contracts (1)	(1,797)	7,453	(653)	(1,385)
Total loss on risk management contracts	(5,273)	(17,424)	(6,811)	(37,242)

1. Represents the mark-to-market change in the fair value of outstanding contracts and the reversal of prior unrealized amounts on contracts that settled in the period.

For the three and six months ended June 30, 2022, the realized loss on risk management contracts was $3.5 million and $6.2 million respectively, resulting from cash paid for put options settled during the period, compared to a loss of $24.9 million and $35.9 million, in the same period of 2021, primarily from the cash settlement on three-way collars, puts and put spreads contracts paid during the first half of 2021.

The unrealized loss on risk management contracts for the three months ended June 30, 2022, was $1.8 million compared to a $7.5 million gain in the same period of the previous year, primarily related to the reclassification of amounts to realized gain or loss from instruments settled during the period. For the six months ended June 30, 2022, the unrealized loss was lower than the same period of the previous year, due to the increase in the benchmark forward prices of Brent oil.

Risk Management Contracts - Brent Crude Oil

As part of its risk management strategy, the Company uses derivative commodity instruments to manage its exposure to price volatility by hedging a portion of its oil production. The Company's strategy aims to protect a minimum of 40% to 60% of the estimated production with a tactical approach, using a combination of instruments, capped and non-capped, to protect the revenue generation and cash position of the Company, while maximizing the upside. This diversification of instruments allows the Company to take a more dynamic approach to the management of its hedging portfolio and balancing cash costs. In 2022, the Company executed a risk management strategy using a variety of derivatives instruments, including mainly put options to protect against downward oil price movements.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $/bbl**	**Assets**	**Liabilities**
Put	July to December 2022	Brent	2,825,000	70.0	3,786	—
Total as at June 30, 2022					**3,786**	**—**

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. The Company monitors its exposure to such foreign currency risks. As at June 30, 2022, the Company has outstanding positions of foreign currency derivatives contracts, detailed as follows:

				Carrying Amount	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume USD ($M)**	**Put/ Call; Par forward (COP$)**	**Assets**	**Liabilities**
Zero-cost collars	July to December 2022	COP / USD	$ 120,000	3,750 / 4,420	—	1,711
Total as at June 30, 2022					**—**	**1,711**

Risk Management Contracts - Interest Rate Swap (2025 Puerto Bahia Debt)

The Company has a financial derivative to manage exposure to cash flow risks from the fluctuation of the interest rate expressed in LIBOR on the 2025 Puerto Bahia Debt. Refer to the "Liquidity and Capital Resources" section on page 20 for further information. As at June 30, 2022, the Company had the following interest rate swap contract outstanding:

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount $M**	**Floating rate**	**Assets**	**Liabilities**
Swap	July 2022 to June 2025	LIBOR + 180	107,100	3.9%	—	1,267
Total as at June 30, 2022					**—**	**1,267**

Income Tax Expense

	Three months ended June 30		Six months ended June 30	
($M)	**2022**	**2021**	**2022**	**2021**
Current income tax expense	(1,025)	(20,025)	(2,578)	(24,216)
Deferred income tax expense	(90,040)	(17,844)	(75,736)	(26,933)
Total income tax expense	**(91,065)**	**(37,869)**	**(78,314)**	**(51,149)**

For the three and six months ended June 30, 2022, current income tax expense was $1.0 million and $2.6 million, respectively, compared to current income tax expense of $20.0 million and $24.2 million for the same periods of 2021, respectively. The decrease in 2022 is mainly due to the recognition of an additional provision of $20.9 million in 2021 that was related to changes in prior years tax assessments.

For the three and six months ended June 30, 2022, deferred income tax expense was $90.0 million and $75.7 million, respectively, compared to a deferred income tax expense of $17.8 million and $26.9 million for the same periods of 2021, respectively. The variation is mainly due to the utilization of the deferred tax asset as higher profits are accruing in 2022 and a COP depreciation during second quarter of 2022.

Net Income (Loss)

	Three months ended June 30		Six months ended June 30	
($M)	**2022**	**2021**	**2022**	**2021**
Net income (loss) attributable to equity holders of the Company	13,484	(25,648)	115,712	(39,774)
Per share – basic ($)	0.14	(0.26)	1.23	(0.41)
Per share – diluted ($)	0.14	(0.26)	1.20	(0.41)

The Company reported net income of $13.5 million for the second quarter of 2022, which included operating income of $132.7 million, partially offset by income tax expenses of $91.1 million, foreign exchange loss of $13.1 million, finance expense of $12.6 million and loss on risk management contracts of $5.3 million. This compared to net loss of $25.6 million in the second quarter of 2021, which included debt extinguishment costs of $29.1 million, total income tax expense of $37.9 million and a loss on risk management contracts of $17.4 million, which was partially offset by $65.6 million of operating income.

For the six months ended June 30, 2022, the Company reported a net income of $115.7 million, which included operating income of $228.4 million, partially offset by income tax expenses of $78.3 million, foreign exchange losses of $9.4 million and finance expenses of $24.9 million. This compared to a net loss of $39.8 million for the six months ended June 30, 2021, which included a loss on risk management contracts of $37.2 million, debt extinguishment costs of $29.1 million and total income tax expenses of $51.1 million, which was partially offset by $117.2 million of operating income.

Capital Expenditures and Acquisitions

($M)	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Development drilling	39,120	33,566	76,001	39,993
Development facilities	11,405	3,658	17,399	5,326
Colombia and Ecuador exploration	10,684	9,881	20,879	10,716
Other	12,258	454	19,225	714
Total Colombia, Ecuador and other capital expenditures	**73,467**	**47,559**	**133,504**	**56,749**
Guyana exploration	18,982	12,090	70,932	16,937
Guyana infrastructure	1,386	1,565	2,944	1,893
Total capital expenditures (1)	**93,835**	**61,214**	**207,380**	**75,579**

1. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 16.

Capital expenditures for the three and six months ended June 30, 2022, were $93.8 million and $207.4 million, respectively, an increase of $32.6 million and $131.8 million, compared to the same periods of 2021, which was mainly due to the following:

Development drilling. During the three and six months ended June 30, 2022, development drilling increased by $5.6 million and $36.0 million, respectively, compared to the same periods of 2021, mainly due to a total of 20 and 34 development wells drilled respectively in the Quifa, CPE-6 and Guatiquia blocks in the three and six months ended June 30, 2022, respectively, compared, to 12 and 13 development wells drilled in the same blocks in the three and six months ended June 30, 2021, respectively.

Development facilities. During the three and six months ended June 30, 2022, development facilities increased to $11.4 million from $3.7 million, and $17.4 million from $5.3 million, respectively, during the same periods of 2021, mainly related to additional flow handling and injector line facilities at the Guatiquia block, road improvements at the CPE-6 block, increased expenditures related to environmental requirements at the Quifa block and reactivation of facilities in the Sabanero block.

Colombia and Ecuador Exploration. For the three and six months ended June 30, 2022, exploration activities increased by $0.8 million and $10.2 million, respectively, compared to the same periods of 2021, mainly due to the finalization of Jandaya-1 well and the drilling of Tui-1 and Yin-1 wells in Ecuador, compared to no exploration well drilled in the first half of 2021. Details relating to exploration activities in Colombia and Ecuador are as follows:

Colombia. The Company continues to focus on the Lower Magdalena Valley in Colombia. During the remainder of 2022, the Company plans to drill one exploration well in the La Creciente block and is undertaking preliminary activities to secure the drilling of additional exploratory wells in the VIM-1 and VIM-22 blocks in 2023. In addition, on January 18, 2022, the ANH signed with the Company an exploration and production agreement for the VIM-46 block, which includes 58,806 hectares within the Magdalena Valley. The exploratory commitments include one exploration well during the first exploration phase. The Company is working on pre-seismic and pre-drilling activities related to social and environmental impact studies in the VIM-46, Llanos 119 and Llanos 99 blocks and spud La Belleza-2 development well on July 15, 2022.

Ecuador. Following the first quarter 2022 completions of the Jandaya-1 and Tui-1 wells in the Perico block (Frontera 50% W.I. and operator) in Ecuador, the Company is under long-term test, and will prepare the environmental impact assessment for obtaining a production environmental license. Additional appraisal activities will be conducted in the near future to confirm size and mid- to long-term production levels. On May 15, 2022, the Company spud its third exploration well, Yin-1, located approximately 0.53 kilometres to the southwest of the Jandaya-1 well in the northeastern portion of the block, reaching a total depth of 11,375 feet. The Yin-1 well was completed on June 16, 2022. A complete testing program is now underway. Additional prospects on the Perico block have been identified and are being matured for future drilling.

In the Espejo block (Frontera 50% W.I. and non-operator), the operator completed the acquisition of 63 km^2 of 3D seismic. Pre-drilling activities are underway ahead of spudding the first exploration well on the block, Pashuri-1, anticipated in September 2022.

Other

For the three and six months ended June 30, 2022, the Company has capitalized other investments for $12.3 million and $19.2 million, respectively, mainly related to the acquisition of an additional 35% W.I. in El Dificil Block previously owned by PCR Investments S.A. (a wholly-owned subsidiary of Petroquímica Comodoro Rivadavia S.A. ("**PCR**")) for total aggregate cash consideration of approximately $12.0 million that was approved by the ANH on April 27, 2022. The transaction has added approximately 500 boe/d of total production (consisting of approximately 2,600 mcf/d of conventional natural gas and 45 bbl/d of natural gas liquids). In addition, $7.0 million related to the purchase agreement signed with Repsol Colombia Oil & Gas Ltd. ("RCOG") to acquire its 50% of the CPE-6 block, as result of reaching 5MMbbl of production during the first quarter of 2022 and the variable monthly payments made during the first half of 2022 (For further information refer to the "Commitments and Contractual Obligations" section on page 23).

Guyana

Guyana exploration. For the three and six months ended June 30, 2022, the Company invested $19.0 million and $70.9 million, respectively, in the Corentyne block, mainly related to preparation activities to spud Wei-1 well during the second quarter 2022 and completion activities at the Kawa-1 well during the first quarter 2022. Details relating to exploration activities in Corentyne block are as follows:

The Company and majority-owned subsidiary and co-venture partner, CGX, completed drilling operations on the Kawa-1 exploration well, located in the northern region of the Corentyne block, in the first quarter of 2022. The Kawa-1 well was drilled to a total depth of 21,578 feet (6,577 metres). Drilling results confirmed the presence of an active hydrocarbon system at the Kawa-1 location. Successful LWD and wireline logging runs confirmed net pay of approximately 228 feet (69 metres) within Maastrichtian, Campanian, Santonian and Coniacian horizons. The joint venture did not get MDT data or sidewall core samples, and engaged an independent third-party to complete further detailed studies and laboratory analysis on drilling cuttings and wellbore fluid samples from the Maastrichtian, Campanian, Santonian and Coniacian intervals in order to characterize in situ hydrocarbons. Multiple datasets and analytic methods indicate the presence of gas condensate in the Maastrichtian and Campanian, and light oil in the Santonian and Coniacian.

Guyana infrastructure. During the three and six months ended June 30, 2022, CGX, Frontera's majority-owned subsidiary, invested $1.4 million and $2.9 million, respectively, mainly related to costs associated with the Guyana Port Project (as defined below). For further information refer to the "Midstream Activities" section on page 15.

Selected Quarterly Information

Operational and financial results		2022 Q2	2022 Q1	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4	2020 Q3
Heavy crude oil production	(bbl/d)	21,455	21,214	20,912	18,168	17,241	20,997	21,074	21,997
Light and medium crude oil production	(bbl/d)	17,348	17,248	16,300	17,160	17,142	18,294	19,502	19,550
Total crude oil production	(bbl/d)	38,803	38,462	37,212	35,328	34,383	39,291	40,576	41,547
Conventional natural gas production	(mcf/d)	10,374	9,530	4,663	5,033	5,164	5,227	6,356	7,895
Natural gas liquids	(boe/d)	963	966	575	211	393	391	254	270
Total production	(boe/d)	41,586	41,100	38,605	36,422	35,682	40,599	41,945	43,202
Sales volumes, net of purchases (1)	(boe/d)	33,273	28,211	39,001	26,672	34,151	34,555	44,551	39,966
Brent price	($/bbl)	111.98	97.90	79.66	73.23	69.08	61.32	45.26	43.34
Oil and gas sales, net of purchases (1) (2)	($/boe)	103.34	90.42	75.12	67.13	64.54	58.18	42.20	40.18
Realized loss on risk management contracts (3)	($/boe)	(1.15)	(1.06)	(1.87)	(2.68)	(8.00)	(3.53)	(2.00)	(1.70)
Royalties (3)	($/boe)	(10.57)	(7.58)	(3.62)	(4.83)	(0.53)	(1.96)	(0.47)	(0.23)
Dilution costs (3) (4)	($/boe)	(0.12)	(0.12)	(0.10)	(0.15)	(0.34)	(2.25)	(1.85)	(1.62)
Net sales realized price (2)	($/boe)	91.50	81.66	69.53	59.47	55.67	50.44	37.88	36.63
Production costs (3) (4)	($/boe)	(12.65)	(13.48)	(12.71)	(11.44)	(11.72)	(10.06)	(12.95)	(8.55)
Transportation costs (3) (4)	($/boe)	(10.84)	(9.74)	(9.02)	(10.24)	(11.15)	(11.30)	(11.36)	(10.24)
Operating netback per boe (2)	($/boe)	68.01	58.44	47.80	37.79	32.80	29.08	13.57	17.84
Revenue	($M)	344,015	254,627	301,969	182,673	224,685	184,734	177,109	152,760
Net income (loss)	($M)	13,484	102,228	629,376	38,531	(25,648)	(14,126)	48,636	(90,473)
Per share – basic ($)	($)	0.14	1.08	6.60	0.40	(0.26)	(0.14)	0.50	(0.93)
Per share – diluted ($)	($)	0.14	1.05	6.40	0.39	(0.26)	(0.14)	0.48	(0.93)
General and administrative	($M)	15,097	14,656	12,144	12,656	14,132	13,202	19,851	10,539
Operating EBITDA (5)	($M)	190,678	132,998	148,645	77,304	83,072	69,158	35,639	52,113
Capital expenditures	($M)	93,835	113,545	135,458	103,220	61,214	14,365	24,871	2,905

1. The fourth quarter of 2020 and prior period figures are different compared with those previously reported as a result of the change in the treatment of purchased volumes and cost of purchases according with the current operating netback approach. Refer to the "Non-IFRS and Other Financial Measures" section on page 16 for further details.
2. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 16
3. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 16
4. The second quarter of 2021 and prior period figures are different compared with those previously reported as a result of a reclassification from production cost to transportation cost and dilution cost by approximately $0.40/boe, $0.30/boe and $0.10/boe per quarter, respectively. The reclassification was related to certain logistic and refining processes fees of own crude oil previously recorded as production cost.
5. 2021 prior period figures are different compared with those previously reported as a result of the exclusion of post-termination cost. Refer to the "Non-IFRS and Other Financial Measures" section on page 16 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 first half of 2021, production volumes have increased due to the reactivation of the drilling activity, removal of COVID-19 related restrictions that were imposed at the peak of the pandemic in Colombia and the starting of oil production in Ecuador. In addition, since 2020, there has been a reduction in transportation costs due to the cessation of payments for unused facilities under the Bicentenario ancillary agreements and Caño Limon Coveñas ancillary agreements that were settled as part of the implementation of the conciliation agreement (the "**Conciliation Agreement**") between the Company, Cenit Transporte y Logistica de Hidrocarburos S.A.S. ("**Cenit**") and Bicentenario (for further information, refer to Note 27 of the 2021 Annual Consolidated Financial Statements) and dilution cost decreased, since the second quarter of 2021, as a result of the replacement of dilution service by volumes purchased. Furthermore, production costs have increased due to higher energy costs and well services.

Trends in the Company's net income (loss) are also impacted most significantly by the recognition and derecognition of deferred income taxes and impairment or reversal of impairment of oil and gas assets, debt extinguishment costs, reclassification of currency translation adjustment on the acquisition of control in Infrastructure Ventures Inc. ("**IVI**") and the disposal of the Company's 43.03% W.I. in Bicentenario, recognition of provisions related to the Conciliation Agreement (refer to Note 27 of the 2021 Annual Consolidated Financial Statements), DD&A, foreign exchange gain or losses and total loss from risk management contracts that fluctuate mainly with changes in hedging strategies and crude oil benchmark forward prices. Refer to the Company's previously issued annual and interim Management´s Discussion and Analysis available on SEDAR at www.sedar.com for further information regarding changes in prior quarters.

Midstream Activities

The Company has investments in certain infrastructure and midstream assets, including storage, port and other facilities relating to the distribution and exportation of crude oil products in Colombia and the Company's investments in pipelines. Also, the Company has an indirect interest in an infrastructure project in Guyana consisting of a port concession which is currently under construction.

The midstream segment principally includes the following assets:

Project [1]	Description	Interest [2]	Accounting Method
Puerto Bahia	Bulk liquid storage and import-export terminal	96.55% interest in Puerto Bahia	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/d	59.93% interest in PIL (which holds a 35% interest in the ODL Pipeline)	Equity Method [3]
Guyana Port Project	Multifunctional port facility	76.98% interest in CGX	Consolidation

1. The midstream segment also includes the Company's interest in three other pipelines in Colombia: the Oleoducto Guaduas-La Dorada pipeline, Oleoducto del Alto Magdalena pipeline, and the Oleoducto de Colombia pipeline. Results of operations from these pipelines are not significant to the Company's consolidated financial results.
2. Interests include both direct and indirect interests.
3. 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.

Puerto Bahia

Puerto Bahia owns and operates a multifunctional port facility located in Cartagena, Colombia, which consists of a hydrocarbon terminal and a dry cargo terminal adjacent to the Bocachica access channel of the Cartagena Bay, and is strategically located near the Cartagena Refinery. On December 23, 2021, the Company increased its ownership in Puerto Bahia from 94.16% to 96.55%, through the conversion of certain debt held by the Company's subsidiaries, Frontera Bahia, IVI, and Frontera Energy Colombia AG into preferred shares with voting rights.

For the six months ended June 30, 2022, Puerto Bahia has generated $5.4 million of segment income from operations which was $15.5 million lower than the same period of 2021, primarily due to the finalization of a take-or-pay contract with Frontera Energy Colombia in December 2021. Puerto Bahia´s segment income from operations is mainly generated from services contracts in the liquid terminal, and roll-on/roll-off services in the general cargo terminal.

ODL Pipeline

The Company holds a 59.93% interest in PIL, which has a 35% equity investment in the Oleoducto de Los Llanos Orientales ("**ODL**") pipeline, which connects the Rubiales, Quifa, and Llanos-34 blocks to the Monterrey Station or Cusiana Station in the Casanare Department.

For the six months ended June 30, 2022, the Company recognized $18.7 million as its share of income from ODL, which was $0.8 million lower than the same period of 2021, primarily due to the impact of foreign exchange fluctuations. During the six months ended June 30, 2022, the Company recognized gross dividends of $40.5 million (2021: $41.6 million) and a return of capital of $3.9 million (2021: $4.2 million). As at June 30, 2022, the Company has accounts receivables of $18.6 million of dividends and return of capital contributions.

Guyana Port Project

CGX, Frontera's majority-owned subsidiary and joint venture partner in the Corentyne block, off-shore Guyana, plans to build a multifunctional port facility adjacent to Crab Island on the Eastern Bank of the Berbice River in Guyana, 4.8 kilometers from the Atlantic Ocean, called the Berbice Deep Water Port, which is intended to serve as an offshore supply base and a multi-purpose terminal (the "**Guyana Port Project**"). The land for the Guyana Port Project is leased until 2060, and is renewable for an additional term of 50 years. For the six months ended June 30, 2022, CGX invested $2.9 million in the Guyana Port Project and the construction had no impact on the Company's income statement.

Midstream Segment Results

The Interim Financial Statements include the following amounts relating to the midstream segment:

	Three months ended June 30		**Six months ended June 30**	
($M)	**2022**	**2021**	**2022**	**2021**
Revenue	12,239	18,429	22,571	35,274
Costs	(5,612)	(4,787)	(10,291)	(9,315)
General and administrative expenses	(1,082)	(1,819)	(2,753)	(3,295)
Depletion, depreciation and amortization	(1,563)	(913)	(3,039)	(1,706)
Restructuring, severance and other costs	(882)	—	(1,056)	—
Puerto Bahia income from operations	**3,100**	**10,910**	**5,432**	**20,958**
Share of Income from associates - ODL	9,648	9,805	18,742	19,591
Segment income	**12,748**	**20,715**	**24,174**	**40,549**

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 (loss) 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 Company is changing the composition of its Operating EBITDA calculation to exclude certain unusual or non-recurring items as post-termination obligation and payments of minimum work commitments, that could distort future projections as they are not considered part of its normal course of operations. The Operating EBITDA for the full year 2021 was revised to reflect this change, resulting in an increase of $5.0 million from what was previously reported.

The following table provides a reconciliation of net income (loss) to operating EBITDA:

	Three months ended June 30		Six months ended June 30	
($M)	**2022**	**2021**	**2022**	**2021**
Net income (loss)	13,484	(25,648)	115,712	(39,774)
Finance income	(876)	(3,675)	(1,483)	(4,515)
Finance expenses	12,621	13,747	24,856	27,334
Income tax expense	91,065	37,869	78,314	51,149
Depletion, depreciation and amortization	49,510	40,455	88,294	73,091
Impairment, recovery of asset retirement obligation and minimum work commitment paid	4,618	(1,111)	189	(6,849)
Post-termination obligation	6,842	—	7,070	—
Share-based compensation non cash portion	(583)	1,443	4,505	2,760
Restructuring, severance and other costs	1,055	1,535	1,386	1,916
Share of income from associates	(9,648)	(9,805)	(18,742)	(19,591)
Foreign exchange loss	13,080	48	9,438	18,536
Other loss, net	5,062	3,182	11,081	12,783
Unrealized loss (gain) on risk management contracts	1,797	(7,453)	653	1,385
Non-controlling interests	2,651	3,373	2,403	4,893
Loss on extinguishment of debt	—	29,112	—	29,112
Operating EBITDA	**190,678**	**83,072**	**323,676**	**152,230**

Capital expenditures

Capital expenditures is a non-IFRS financial measure that reflects the cash and non cash items used by a company to invest in capital assets. This financial measure considers oil and gas properties, plant and equipment, infrastructure, exploration and evaluation assets.

Net Sales

Net sales is a non-IFRS financial measure that adjusts revenue to include realized gains and losses from risk management contracts while removing the cost of dilution activities, including 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 risk management activities. The deduction for dilution costs and cost of purchases is helpful to understand the Company's sales performance based on the net realized proceeds from its own production net of dilution, 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 8.

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 midstream segment from the per barrel metrics. Refer to the reconciliation in the "Operating Netback" section on page 7.

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 cost. 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 June 30		Six months ended June 30	
	2022	2021	2022	2021
Oil and gas sales ($M) [1]	365,730	219,017	630,721	403,977
(-) Cost of purchases ($M) [2]	(52,820)	(18,436)	(88,242)	(22,440)
Oil and gas sales, net of purchases ($M)	**312,910**	**200,581**	**542,479**	**381,537**
Sales volumes, net of purchases - (boe)	3,027,843	3,107,751	5,566,836	6,217,712
Oil and gas sales, net of purchases ($/boe)	103.34	64.54	97.45	61.35

1. Excludes sales from port services as they are not part of the oil and gas segment. For further information, refer to the "Midstream Activities" section on page 15.
2. Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining costs.

Non-IFRS Ratios

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

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

	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Oil sales ($M)	308,632	198,734	534,410	377,849
Conventional natural gas sales ($M)	4,278	1,847	8,069	3,688
Oil and gas sales, net of purchases ($M) [1]	**312,910**	**200,581**	**542,479**	**381,537**
Sales volumes, net of purchases - (bbl)	2,862,947	3,026,461	5,247,930	6,054,791
Conventional natural gas sales volumes - (mcf)	939,919	462,971	1,818,112	928,439
Realized oil price, net of purchases ($/bbl)	107.80	65.67	101.83	62.40
Realized conventional natural gas price ($/mcf)	4.55	3.99	4.44	3.97

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 risk management contracts less royalties and dilution costs). 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	
	2022	2021	2022	2021
Oil and gas sales, net of purchases ($M) [1]	312,910	200,581	542,479	381,537
(-) Realized loss on risk management contracts ($M)	(3,476)	(24,877)	(6,158)	(35,857)
(-) Royalties ($M)	(32,018)	(1,640)	(51,262)	(7,750)
(-) Dilution costs ($M)	(376)	(1,056)	(674)	(8,039)
Net sales ($M)	**277,040**	**173,008**	**484,385**	**329,891**
Sales volumes, net of purchases - (boe)	3,027,843	3,107,751	5,566,836	6,217,712
Oil and gas sales, net of purchases ($/boe)	103.34	64.54	97.45	61.35
Realized (loss) gain on risk management contracts [2]	(1.15)	(8.00)	(1.11)	(5.77)
Royalties ($/boe) [2]	(10.57)	(0.53)	(9.21)	(1.25)
Dilution costs ($/boe) [2]	(0.12)	(0.34)	(0.12)	(1.29)
Net sales realized price ($/boe)	**91.50**	**55.67**	**87.01**	**53.04**

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

Supplementary Financial Measures

Production cost per boe

Production costs mainly includes lifting costs, activities developed in the blocks, and processes to put the crude oil and gas in sales condition. Production cost per boe is a supplementary financial measure that is calculated using production cost divided by production (before royalties). A reconciliation of this calculation is provided below:

	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Production costs ($M)	47,882	38,043	97,743	74,798
Production (boe)	3,784,235	3,247,062	7,483,264	6,900,806
Production costs ($/boe)	12.65	11.72	13.06	10.84

Transportation cost per boe

Transportation costs includes all commercial and logistics costs associated with the sale of produced crude oil and gas such as trucking, pipeline and refining processing fees. Transportation cost per boe is a supplementary financial measure that is calculated using transportation cost divided by net production after royalties. A reconciliation of this calculation is provided below:

	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Transportation costs ($M)	35,178	33,259	67,331	71,732
Net production (boe)	3,246,607	2,982,798	6,546,770	6,388,033
Transportation costs ($/boe)	10.84	11.15	10.28	11.23

Realized (loss) gain on risk management contracts per boe

Realized (loss) gain on risk management contracts includes the gain or loss during the period, as a result of the Company´s exposure in derivative contracts. Realized (loss) gain on 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.

Dilution costs per boe

Dilution costs includes all costs associated with the dilution services. Dilution costs per boe is a supplementary financial measure that is calculated using the dilution costs divided by total sales volumes, net of purchases.

NCIB weighted-average price per share

Weighted-average price per share under the NCIB is a supplementary financial measure that corresponds to the weighted-average price of shares purchased under the NCIB program 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

Working Capital

Working capital is a capital management measure to describe the liquidity position and ability to meet its short term liabilities. 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 sum the short term portion and long term portion of the cash that the Company has in term deposits that have been escrowed to cover future commitments and future abandonment obligations or insurance collateral for certain contingencies and other matters that are not available for immediate disbursement.

Total cash

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

Total debt and lease liabilities

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

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
- enhancing shareholder returns through share repurchases.

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

As of June 30, 2022, the Company had a total cash balance of $353.1 million (including $58.0 million in restricted cash), which is $32.2 million higher than December 31, 2021. For the six months ended June 30, 2022, the Company generated $361.6 million in operating cash flows, which were used to fund cash outflows of $239.7 million for capital expenditures and other investing activities. For the six months ended June 30, 2022, financing activities generated net outflows of $80.7 million as a result of, $25.6 million of common shares repurchased, $22.6 million of 2025 Puerto Bahia Debt payments and Petrosud Debt payments, $20.9 million of interest and other financing charges, $8.3 million of dividends paid to non-controlling interests and $3.3 million in lease payments. As a result, the working capital(1) deficit was reduced to $7.2 million compared to a deficit of $78.9 million at year-end 2021.

Since 2020, the Company's consolidated working capital position changed to a deficit due to the acquisition of control in IVI, which resulted in the consolidation of the 2025 Puerto Bahia Debt ($123.1 million as of June 30, 2022), which was classified as a current liability (for further information on the 2025 Puerto Bahia Debt, refer to page 22 hereof and Note 19 of the 2021 Annual Consolidated Financial Statements). The Company believes that its 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, 2022, the main components of restricted cash were long-term abandonment funds as required by the ANH, and restricted funds related to the 2025 Puerto Bahia Debt. 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, typically during the third quarter, and can be satisfied through additional allocations of restricted cash, designation of letters of credit, or a combination of both. As of June 30, 2022, the Company had total restricted cash of $58.0 million, a decrease of $5.3 million from December 31, 2021, primarily due to restricted cash being released from insurance activities and foreign exchange fluctuations.

The measures taken by the Company to manage its liquidity and capital resources are ongoing and the Company continues to look for additional opportunities to manage its costs and commitments. Based on the foregoing, including the expected impacts of such measures, the Company expects that unrestricted cash balances in conjunction with future cash flows from operations, available credit facilities, and alternate financing arrangements will be sufficient to support its working capital deficit, operational and capital requirements and other financial commitments. The Company intends to remain flexible and disciplined with respect to capital allocation decisions as the current commodity price environment evolves and can make additional changes to its business and operations as warranted. See also the "Risks and Uncertainties" section on page 25.

[1] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 16.

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 amount of $400.0 million, 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. The net proceeds of the 2028 Unsecured Notes were partially used to repurchase, at a premium and including accrued interest, the total obligation under the Company's previously issued unsecured notes, which were set to mature in 2023. The remaining proceeds were used for general corporate purposes.

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 and are guaranteed by the Company's principal subsidiaries, Frontera Energy Colombia AG and Frontera Energy Guyana Corp. 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, 2022, the Company is in compliance with all such covenants.

Pursuant to requirements under the Indenture, the Company reports as of June 30, 2022, consolidated total indebtedness of $409,694,000, and for the twelve months ended as of June 30, 2022, consolidated adjusted EBITDA of $548,889,000 and consolidated interest expense of $33,859,000.

1. Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the indenture governing the 2028 Unsecured Notes (the "**Indenture**") as the consolidated total indebtedness as of such date divided by consolidated adjusted EBITDA for the most recently ended period of four consecutive fiscal quarters.
   a. Consolidated total indebtedness is defined below.
   b. Consolidated adjusted EBITDA is defined as the consolidated net income (loss) (as defined in the Indenture) plus: i) consolidated interest expense; ii) consolidated income tax and equity tax; iii) consolidated depletion and depreciation expense; iv) consolidated amortization expense; and v) consolidated impairment charge, exploration expense and abandonment costs; after excluding the impact of the Unrestricted Subsidiaries.
2. Consolidated fixed charge ratio is the consolidated adjusted EBITDA for the most recent period ended of four consecutive fiscal quarters divided by the consolidated interest expense for such period as defined in the Indenture.
3. Consolidated net tangible assets is defined in the Indenture as the net amount of the Company's total assets less intangible assets and current liabilities, after excluding the impact of the Unrestricted Subsidiaries.

Consolidated Total Indebtedness and Net Debt

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

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

	As at June 30	
($M)		**2022**
Long-term debt (1)	$	407,367
Total lease liabilities (2)		4,402
Risk management assets, net (3)		(2,075)
Consolidated Total Indebtedness		**409,694**
(-) Cash and Cash Equivalents (4)		(241,182)
(=) Net Debt	**$**	**168,512**

1. Excludes $123.0 million of long-term debt attributable to the Unrestricted Subsidiaries.
2. Excludes $0.6 million of lease liabilities attributable to the Unrestricted Subsidiaries.
3. Excludes $1.3 million of risk management liabilities attributable to the Unrestricted Subsidiaries.
4. Includes cash and cash equivalents attributable to the guarantors and borrower according to the Indenture. Guarantors and borrower mean Frontera Energy Corporation (British Columbia), Frontera Energy Guyana Corp, Frontera Energy Colombia AG, Frontera Energy Colombia (Ecuador Branch), Frontera Energy Colombia Sucursal Colombia.

Puerto Bahia Secured Syndicated Credit Agreement

During the third quarter of 2020, the Company acquired control of IVI which at the time of acquisition held 99.9% of Puerto Bahia (for further information refer to Note 4 of the 2021 Annual Consolidated Financial Statements).

In October 2013, Puerto Bahia entered into a credit agreement with a syndicate of lenders for a $370 million debt facility, which matures in June 2025, for the construction and development of the port (the "**2025 Puerto Bahia Debt**"). During the course of 2018, 2019 and 2020, the lenders gave notices stating that Puerto Bahia is in breach of various loan covenants but did not accelerate the loan. As a result, the total amount outstanding under the 2025 Puerto Bahia Debt is presented as a current liability in accordance with IAS 1 "Presentation of Financial Statements". The 2025 Puerto Bahia Debt bears interest at 6-month LIBOR plus 5% which is payable semi-annually, is secured by substantially all the assets and shares of Puerto Bahia, is non-recourse to the Company (other than as provided for by the equity contribution agreement ("**ECA**") described below), and has no impact on the Company's financial covenants under the 2028 Unsecured Notes. As at June 30, 2022, the 2025 Puerto Bahia Debt outstanding amount is $123.1 million.

As part of the agreements for the banks' loan to fund the construction of Puerto Bahia, the Company entered into the ECA on October 4, 2013. Under the ECA, the Company and IVI agreed jointly and severally to cause contributions (via debt or equity) to Puerto Bahia up to the aggregate amount of $130.0 million whenever Puerto Bahia had a deficiency in the reserve account supporting its bank loan. Amounts disbursed under the ECA are designated to the repayment of principal and interest from that loan. Pursuant to the terms of the ECA, Frontera has from time to time made loans to Puerto Bahia ("**ECA Loans**") that are subordinated to the 2025 Puerto Bahia Debt and bear interest of 14%. The ECA loans give Frontera a direct claim against Puerto Bahia that is in priority to IVI's equity interest in Puerto Bahia, and thus indirectly in priority to the claims of the remaining minority shareholders of IVI.

To date, the Company has fully disbursed the total ECA amount of $130.0 million under the ECA Loans, of which $68.3 million was capitalized into preferred shares and common shares of Puerto Bahia. All intercompany balances and transactions between the Company and IVI are eliminated as part of the consolidation process.

PetroSud Loans

On December 30, 2021, the Company acquired 100% of the issued and outstanding shares of PetroSud (for further information refer to Note 4 of the 2021 Annual Consolidated Financial Statements).

On March 15, 2019 and December 20, 2021, PetroSud entered into two credit agreements with Banco Davivienda S.A. for a principal amount of $22.0 million and $2.8 million, respectively (the "**PetroSud Debt**"), both with a maturity date in December 2023. The PetroSud Debt bears interest at 3-month LIBOR plus 4.95%, which is payable quarterly. The PetroSud Debt is secured by a trust agreement that receives 100% of PetroSud's sales, and contemplates a debt service account for an amount equal to 100% of the next scheduled debt service, and a debt reserve account for an amount of $1.8 million. As at June 30, 2022, the outstanding amount under the Petrosud Debt is $15.4 million. The PetroSud Debt is subject to covenants that require PetroSud to maintain a finance debt to EBITDA ratio that is less than or equal to 3.50:1.0 and a free cash flow debt service ratio that is greater than or equal to 1.20:1.0. In the event that these financial ratios are not met, Banco Davivienda S.A. is entitled to accelerate the PetroSud Debt. As at June 30, 2022, PetroSud is in compliance with all such covenants.

Letters of Credit

The Company has various uncommitted bilateral letters of credit lines. As of June 30, 2022, the Company had issued letters of credit and guarantees for exploration, operational, and transport commitments totaling $85.0 million (total credit lines of $107.8 million), without cash collateral.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at June 30, 2022, undiscounted by calendar year, are presented below:

As at June 30, 2022 ($M)	2022	2023	2024	2025	2026	2027 and Beyond	Total
Financial obligations							
2028 Unsecured Notes, principal and interest	15,750	31,500	31,500	31,500	31,500	447,250	589,000
Lease liabilities	2,137	2,950	173	143	—	—	5,403
2025 Puerto Bahía Debt and interest (1)	24,340	52,261	48,863	13,818	—	—	139,282
PetroSud Debt and interest	2,264	14,258	—	—	—	—	16,522
Total financial obligations	**44,491**	**100,969**	**80,536**	**45,461**	**31,500**	**447,250**	**750,207**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	32,565	65,129	65,129	48,847	—	—	211,670
ODL agreements	6,928	13,207	23,112	—	—	—	43,247
Other transportation and processing commitments	4,505	11,783	11,783	11,783	18,193	—	58,047
Exploration commitments							
Minimum work commitments (2)	60,150	40,450	69,116	12,660	—	5,066	187,442
Other commitments							
Operating purchases, leases and community obligations	65,119	18,374	11,885	17,171	8,923	15,686	137,158
Total Commitments	**169,267**	**148,943**	**181,025**	**90,461**	**27,116**	**20,752**	**637,564**

1. For financial reporting purposes, the 2025 Puerto Bahia Debt is classified as a current liability. Amounts shown in the table are in accordance with the repayment schedule.
2. 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. The Company, through its interests in CGX, has other exploration work commitments in Guyana (not included in the table), described below.

Guyana Commitments

As of June 30, 2022, the Company, through its 76.98% interest in CGX and directly through its 33,33% W.I. in the Corentyne and Demerara blocks, has exploration work commitments under Petroleum Prospecting Licenses ("**PPL**") for certain Guyana blocks, as follows:

- In accordance with the Corentyne PPL, which is currently in phase two of the second renewal period, one exploration well must be drilled by November 26, 2022.

- On February 14, 2022, CGX and Frontera, the majority shareholder of CGX and joint venture partner of CGX in the petroleum prospecting license for the Demerara block, announced that as a result of the initial positive results at the Kawa-1 exploration well on the Corentyne block, the joint venture will focus on the significant exploration opportunities in the Corentyne block and will not engage in drilling activities on the Demerara block in 2022. In addition, Frontera and CGX have, in principle, reached an agreement with the Government of Guyana to allow for the relinquishment of the Demerara block through a mutual termination agreement, the terms of which remain to be defined and documented.

Subsequent to the quarter, on July 22, 2022, Frontera and CGX jointly announced that the companies have entered into an agreement to amend the Joint Operating Agreement originally signed between CGX and a subsidiary of Frontera on January 30, 2019, as amended (the "**JOA Amendment**"), effectively farming into the Corentyne block and securing funding for the Wei-1 exploration well. The Agreement remains subject to certain conditions precedent, including approval of the TSX Venture Exchange and certain confirmations from the Government of Guyana relating to the petroleum agreement for the Corentyne block.

As part of the JOA Amendment, CGX will transfer 29.73% of its participating interest in the Corentyne block to Frontera in exchange for Frontera funding the Joint Venture's costs associated with the Wei-1 exploration well for up to $130.0 million and up to an additional $29 million of certain Kawa-1 exploration well and Wei-1 Pre-Drill and other costs. In addition, CGX shall assign an additional 4.94% of its participating interest in the Corentyne block to Frontera as consideration for the discharge of the outstanding principal amounts under (i) the previously announced $19 million convertible loan to CGX dated May 28, 2021, as amended, and (ii) the previously announced $35 million convertible loan to CGX dated March 10, 2022, as amended, and Frontera making a cash payment to CGX of $3.8 million. The JOA Amendment remains subject to certain condition precedents. As a result of the JOA Amendment, CGX will have a 32.00% participating interest and Frontera will have a 68.00% participating interest in the Corentyne block.

In addition, on July 22, 2022, the Company and CGX jointly announced that in connection with a drilling contract agreement between Maersk Drilling Holdings Singapore Pte. Ltd. ("Maersk") and CGX, operator of the Corentyne block, for the provision of a semi-submersible drilling unit owned by Maersk (the "Maersk Discoverer") and associated services to drill the joint venture's Wei-1 well, Frontera anticipates entering into a deed of guarantee with Maersk for certain obligations, up to a maximum of $30.0 million, subject to a sliding scale mechanism in connection with payments made under the drilling contract.

As of June 30, 2022, the aggregate minimum future obligations outstanding related to agreements with suppliers for the drilling of the Wei-1 well and the Guyana Port Project is $68.0 million, which is expected to be paid in 2022.

Ocensa and Cenit Pledge

In May 2022, a new ship-or-pay contract with Bicentenario and Cenit entered into force, and as a result, the pledged inventory crude oil is stored in Cenit's terminal of Coveñas (TLU-3) instead of Ocensa's terminal. On March 31, 2022, the Company signed a new pledge agreement with Cenit and Ocensa, which guarantees the payment obligations of both contracts, for the period from May 1, 2022, to September 30, 2022, with Ocensa up to $30.0 million, and for the period from May 1, 2022, to October 31, 2022, with Cenit up to $6.0 million.

Other Guarantees and Pledges

As part of the Company's acquisition of RCOG´s 50% W.I. in the CPE-6 block, the Company granted a pledge to RCOG over the production from the CPE-6 block to guarantee the payments, up to a maximum of $48.0 million. Under the farm-out agreement, two kinds of payments are set, each contingent on production from this block and each applicable until the maximum payment of $48.0 million is paid: (i) a variable monthly payment, and (ii) three potential production milestone payments of $5.0 million each when 5 million, 10 million and 20 million total barrels production, respectively, are achieved. As at June 30, 2022, the Company has paid or accrued a total of $12.1 million of such amounts under the agreement.

Sale of Subsidiary Maurel et Prom Colombia B.V. ("M&P")

On October 22, 2021, the Company executed and closed a sale and settlement agreement, transferring to Etablissement Maurel & Prom ("**EMP**") 49.999% of all issued and outstanding shares it held in M&P, which holds 100% interests in the COR-15 and Muisca blocks in Colombia. The Company's cash consideration was $1.8 million. In addition, during the period ended June 30, 2022, the Company made payments of $6.0 million related to outstanding commitments at the COR-15 block.

Contingencies

The Company is involved in various claims and litigation arising in 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 that may arise could have a material impact on the Company's financial position, results of operations or cash flows.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at August 8, 2022:

	Number
Common shares	92,825,541
Deferred share units ("**DSUs**") (1)	806,934
Restricted share units ("**RSUs**") (2)	1,820,980

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

On March 17, 2022, the Company launched a normal course issuer bid (“**NCIB**”), upon the expiry of its previous NCIB (which expired on March 16, 2022) pursuant to which the Company may purchase for cancellation up to 4,787,976 of its Common Shares during the twelve-month period commencing March 17, 2022 and ending March 16, 2023, representing approximately 10% of the Company’s “public float” (as calculated in accordance with TSX rules) as at March 7, 2022. In connection with the Substantial Issuer Bid, and as required under TSX rules, Frontera suspended share repurchases under its NCIB from June 20, 2022 (the date the Substantial Issuer Bid was announced) until August 8, 2022 (the expiry time of the Substantial Issuer Bid). The Company anticipates recommencing share repurchases under its NCIB on August 10, 2022.

Purchases subject to the NCIB were (prior to the suspension of repurchases in connection with the Substantial Issuer Bid) 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, 2022, the Company purchased a total of 1,754,900 and 2,380,300 Common Shares, respectively, under its current and previous NCIBs (1,992,100 under its current NCIB and 388,200 under its previous NCIB). As at August 8, 2022, the Company had repurchased for cancellation a total of 1,992,100 Common Shares under its new NCIB for approximately $22.1 million with an additional 2,795,876 Common Shares remaining available for repurchase under the new NCIB. Under the prior NCIB that expired on March 16, 2022, the Company repurchased for cancellation during the twelve-month term and the three and six months ended June 30, 2022 a total of 4,243,600 and 388,200 Common Shares, for approximately $25.0 million and $3.5 million, respectively.

The following table provides a summary of total share repurchases under the Company’s NCIB programs:

	Six months ended June 30
	2022
Number of common shares repurchased	2,380,300
Total amount of common shares repurchased ($M)	25,644
Weighted-average price per share ($) (1)	10.77

1. Supplementary financial measure. Refer to the “Non-IFRS and Other Financial Measures" section on page 16.

Substantial Issuer Bid

During the quarter, the Company launched a C$65 million substantial issuer bid (the “**SIB**”), which proceeded by way of a “modified Dutch auction” procedure with a tender price range C$11.00 to C$13.00 per share. The SIB expired at 11:59 p.m. on August 8, 2022. On August 9, 2022, Frontera announced that in accordance with the terms and conditions of the SIB and based on the preliminary calculation of Computershare Investor Services Inc., as depositary for the SIB (“the **Depositary**”), Frontera expects to take up and pay for approximately 5.42 million of its common shares (approximately 5.84% of the total number of Frontera's issued and outstanding common shares as of June 30, 2022) at a price of $12.00 per Share (the “**Purchase Price**”), representing an aggregate Purchase Price of approximately C$65 million. After the cancellation of the common shares taken up and paid for by the Company, Frontera anticipates that approximately 87.26 million common shares will be issued and outstanding. Final results will be confirmed by press release on August 11, 2022.

6. RELATED-PARTY TRANSACTIONS

The following tables provide the total balances outstanding, commitments and transactional amounts with related parties, as at June 30, 2022 and December 31, 2021, and for the three and six months ended June 30, 2022 and 2021, respectively:

($M)		Accounts Receivable	Accounts Payable	Commitments	Three Months Ended June 30 Purchases / Services	Six Months Ended June 30 Purchases / Services
ODL	2022	18,633	1,951	43,247	5,178	10,541
	2021	—	112	56,716	7,281	16,353

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, the environment, its assets, regulatory environment and reputation, and seeks to systematically mitigate these risks to an acceptable level. In addition, we continuously monitor our risk profile as well as industry best practices.

For a comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, investors are urged to review the AIF and the 2021 Annual Consolidated Financial Statements, copies of which are available on SEDAR at www.sedar.com.

In addition, the COVID-19 pandemic could have negative impacts on the Company's financial condition, results of operations, and cash flows. Despite successful vaccine rollouts in many jurisdictions, the risk of a resurgence or additional variant strains remains high and could result in continued fluctuations in the price of oil and conventional natural gas products. The extent to which such events impact the Company's business, financial condition and results of operations will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence. Such events could have a material adverse effect on the Company's business, financial condition and results of operations. Even after the COVID-19 pandemic has subsided, the Company may continue to experience materially adverse impacts to its business as a result of the pandemic's global economic impact, long-term implications and risk of resurgences. To the extent that the COVID-19 pandemic adversely affects the Company's business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described herein and in the Company's AIF.

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

See the "Liquidity and Capital Resources" section on page 20 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.

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 2021 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 2 of the Interim 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 COVID-19 pandemic on the world economy, the impact of the Russia Ukraine conflict and the associated volatility in oil prices, could have negative impacts on the Company and has significantly increased economic uncertainty. The Company continues to monitor this rapidly changing environment and the impact on the Company's business, financial conditions and results of operations, however the duration and magnitude of these events remains unknown at this time. There may also be effects that are not currently known, as the full impact of the COVID-19 pandemic and the impact of the Russia Ukraine conflict is still uncertain. As a result, it is difficult to reliably assess the full impact this will have on the Company's business, financial conditions and results of operations which presents uncertainties and risks in 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 significant judgments and estimates made by management in the preparation of its financial information is provided in Note 3c of the 2021 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". This Certification requires certifying officers to certify, among other things, that they are responsible for establishing and maintaining Disclosure Controls and Procedures ("**DC&P**") and Internal Controls over Financial Reporting ("**ICFR**") as those terms are defined in NI 52-109. The control framework used to design the Company's ICFR is based on the framework established in Internal Control - Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company's ICFR are designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's ICFR may not prevent or detect all misstatements because of inherent limitations. Additionally, in the second quarter of 2022, Management continued to monitor the impacts of COVID-19 on the Company's control environment. These impacts include remote and/or hybrid work environment, oil price environment, cyber threats, IT help desk services response time, health and safety. While there were no changes made to the Company's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting, the Company will continue to monitor and mitigate the risks associated with any changes to its control environment in response to COVID-19 pandemic.

There have been no changes in the Company's ICFR during the quarter ended June 30, 2022, that have materially affected, or are reasonably likely to materially affect, its ICFR.

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 interim filings are being prepared, and that information required to be disclosed by the Company in its annual filings, interim filings and other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

On December 30, 2021, the Company closed its acquisition of PetroSud and PetroSud became a wholly-owned subsidiary of the Company. As permitted by and in accordance with NI 52-109, Management has limited the scope on the design of ICFR and DC&P of the Company to exclude the controls, policies and procedures of PetroSud. The scope limitation is in accordance with Section 3.3 of NI 52-109, which allows an issuer to limit its design of ICFR and DC&P of a company acquired not more than 365 days before the end of the financial period to which the certificate relates, and is primarily due to the time required for Management to assess the ICFR and DC&P relating to PetroSud in a manner consistent with the Company's operations.

The integration activities are in process and are expected to be completed before the end of 2022. As of the end of June 2022, some of PetroSud's processes and systems have been aligned with those of the Company. The design and implementation phase of ICFR started at PetroSud during the second quarter, and it is being documented in the risk and process control matrices. Assets attributable to PetroSud as at June 30, 2022 represented approximately 2% of the Company's total assets, and $10.2 million revenues were consolidated for the year ended June 30, 2022 (for further information refer to Note 4 of the 2021 Annual Consolidated Financial Statements). 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.

10. FURTHER DISCLOSURES

Production Reporting

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

The following table includes the average net production:

		Net Production				
					Six months ended June 30	
Producing blocks in Colombia		**Q2 2022**	**Q1 2022**	**Q2 2021**	**2022**	**2021**
Heavy crude oil	(bbl/d)	16,854	17,987	15,802	17,418	17,706
Light and medium crude oil	(bbl/d)	15,689	15,866	15,677	15,777	16,284
Conventional natural gas	(mcf/d)	10,374	9,530	5,164	9,952	5,193
Natural gas liquids	(boe/d)	967	962	393	965	392
Net production Colombia	**(boe/d)**	**35,330**	**36,487**	**32,778**	**35,906**	**35,293**
Producing blocks in Ecuador						
Light and medium crude oil	(bbl/d)	348	181	—	265	—
Net production Ecuador	**(bbl/d)**	**348**	**181**	**—**	**265**	**—**
Total net production	**(boe/d)**	**35,678**	**36,668**	**32,778**	**36,171**	**35,293**

Overlift and Settlement

Overlift and settlement corresponds to a short-term imbalance between the Company’s production and sales volumes. In these instances, the Company lifts barrels from the pipeline system resulting in more volumes sold than produced, which is considered “overlift.” Overlift represents an obligation for the Company to deliver the equivalent future production. Settlement occurs when this production is delivered to settle the overlift liability. During overlift, the Company recognizes the sales and an equivalent cost with no margin or operating EBITDA impact during the quarter. When the overlift is settled, this expense is reversed to recognize the gross margin and operating EBITDA earned on the related sale in the period of production. Refer to the “Oil and Gas Operating Costs” section on page 8.

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.

Abbreviations

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

bbl	Oil barrels	**mcf/d**	Thousand cubic feet per day
bbl/d	Barrels of oil per day	**Q**	Quarter
boe	Barrels of oil equivalent	**USD**	United States dollars
boe/d	Barrels of oil equivalent per day	**WTI**	West Texas Intermediate
COP	Colombian pesos	**W.I.**	Working interest
C$	Canadian dollars	**$**	U.S. dollars
MMbbl	Millions of oil barrels	**$M**	Thousand U.S. dollars
Mcf	Thousand cubic feet	**$MM**	Million U.S. dollars