FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

November 1, 2022
For the three and nine months ended September 30, 2022

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

Legal Notice – Forward-Looking Information

*This Management Discussion and Analysis ("**MD&A**") is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying Interim Condensed Consolidated Financial Statements and related notes for the three and nine months ended September 30, 2022 and 2021 ("**Interim Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and its Annual Information Form (**"AIF"**), have been filed with Canadian securities regulatory authorities and are available on SEDAR at www.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 18.*

*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; the Russia-Ukraine conflict; uncertainties associated with estimating and establishing oil and natural gas reserves and resources; liabilities inherent with the exploration, development, exploitation and reclamation of oil and natural gas; uncertainty of estimates of capital and operating costs, production estimates and estimated economic return; increases or changes to transportation costs; expectations regarding the Company's ability to raise capital and to continually add reserves through acquisition and development; the Company's ability to access additional financing; the ability of the Company to maintain its credit ratings; the ability of the Company to: meet its financial obligations and minimum commitments, fund capital expenditures and comply with covenants contained in the agreements that govern indebtedness; political developments in the countries where the Company operates; the uncertainties involved in interpreting drilling results and other geological data; geological, technical, drilling and processing problems; 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. 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

		Q3 2022	Q2 2022	Q3 2021	Nine months ended September 30 2022	Nine months ended September 30 2021
Operational Results						
Heavy crude oil production [(1)]	(bbl/d)	20,945	21,455	18,168	21,203	18,791
Light and medium crude oil production [(1)]	(bbl/d)	17,428	17,348	17,160	17,342	17,528
Total crude oil production	(bbl/d)	38,373	38,803	35,328	38,545	36,319
Conventional natural gas production [(1)]	(mcf/d)	9,969	10,374	5,033	9,958	5,141
Natural gas liquids [(1)]	(boe/d)	911	963	211	946	331
Total production [(2)]	(boe/d) [(3)]	41,033	41,586	36,422	41,238	37,552
Total inventory balance	(bbl)	1,137,913	1,423,695	1,423,321	1,137,913	1,423,321
Oil and gas sales, net of purchases [(4)]	($/boe)	90.53	103.34	67.13	94.84	63.00
Realized loss on risk management contracts [(5)]	($/boe)	(1.30)	(1.15)	(2.68)	(1.18)	(4.89)
Royalties [(5)]	($/boe)	(7.23)	(10.57)	(4.83)	(8.46)	(2.26)
Dilution costs [(5)]	($/boe)	(0.07)	(0.12)	(0.15)	(0.10)	(0.97)
Net sales realized price [(4)]	($/boe)	81.93	91.50	59.47	85.10	54.88
Production costs [(5)]	($/boe)	(11.45)	(12.65)	(11.44)	(12.52)	(11.03)
Transportation costs [(5)]	($/boe)	(10.70)	(10.84)	(10.24)	(10.42)	(10.91)
Operating netback per boe [(4)]	($/boe)	59.78	68.01	37.79	62.16	32.94
Financial Results						
Oil & gas sales, net of purchases [(6)]	($M)	305,338	312,910	164,731	847,817	546,268
Realized loss on risk management contracts	($M)	(4,393)	(3,476)	(6,570)	(10,551)	(42,427)
Royalties	($M)	(24,371)	(32,018)	(11,848)	(75,633)	(19,598)
Dilution costs	($M)	(223)	(376)	(366)	(897)	(8,405)
Net sales [(6)]	($M)	276,351	277,040	145,947	760,736	475,838
Net (loss) income [(7)]	($M)	(26,893)	13,484	38,531	88,819	(1,243)
Per share – basic	($)	(0.30)	0.14	0.40	0.96	(0.01)
Per share – diluted	($)	(0.30)	0.14	0.39	0.94	(0.01)
General and administrative	($M)	12,549	15,097	12,656	42,302	39,990
Operating EBITDA [(6)]	($M)	173,207	190,678	77,304	496,883	229,534
Cash provided by operating activities	($M)	120,804	246,615	79,114	482,167	213,898
Capital expenditures [(6)]	($M)	76,018	93,835	103,220	283,398	178,799
Cash and cash equivalents – unrestricted	($M)	253,550	295,098	318,791	253,550	318,791
Restricted cash short and long-term [(8)]	($M)	55,552	57,975	100,692	55,552	100,692
Total cash [(8)]	($M)	309,102	353,073	419,483	309,102	419,483
Total debt and lease liabilities [(8)]	($M)	533,077	535,454	563,173	533,077	563,173
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [(9)]	($M)	412,926	409,694	401,148	412,926	401,148
Net debt (excluding Unrestricted Subsidiaries) [(9)]	($M)	205,625	168,512	130,680	205,625	130,680

1. References 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 30.
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 30.
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 18.
5. Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
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 18.
7. Net (loss) income attributable to equity holders of the Company.
8. Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
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 22.

Performance Highlights

Third Quarter of 2022

During the quarter, the Company generated EBITDA of $173.2 million and, for the nine months ended September 30, 2022, has generated almost $500 million of EBITDA.

Frontera delivered solid operational and financial results during the third quarter. The Company produced 41,033 boe/d in the third quarter of 2022 (consisting of 20,945 bbl/d of heavy crude oil, 17,428 bbl/d of light and medium crude oil, 9,969 mcf/d of conventional natural gas and 911 boe/d of natural gas liquids). For the nine months ended September 30, 2022, the Company has averaged 41,238 boe/d (consisting of 21,203 bbl/d of heavy crude oil, 17,342 bbl/d of light and medium crude oil, 9,958 mcf/d of conventional natural gas and 946 boe/d of natural gas liquids). The Company remains on track to deliver its 2022 production guidance of 41,000 to 43,000 boe/d as production ramps up in the fourth quarter due to additional water disposal capacity in Quifa via the new Battery 4 facility (which came on-line in October) and increased pumping capacity at the CMA water treatment facility in November, as development drilling grows record production at CPE-6, and as liquids recovery increases at VIM-1.

Frontera's third quarter results underscore the Company's continued focus on operational excellence and returning value to shareholders. The Company reduced production costs by 9.5%, transportation costs by 1.3% and G&A costs by 16.9% despite industry-wide inflationary pressures while also repurchasing 6,250,366 million common shares for cancellation through its NCIB (defined below) and SIB (defined below) programs at an approximate cost of $57.9 million.

Operationally, the Company drilled 50 development wells and completed 78 workovers and well services in its Colombian operations during the nine months ended September 30, 2022.

At the VIM-1 (Frontera 50% W.I., and non-operator) block in the Lower Magdalena Valley, the La Belleza-2 horizontal development well was drilled to its total depth with encouraging results. The well is expected to be completed in the fourth quarter of 2022. Once the horizontal well is completed, La Belleza-1 well will be used for gas reinjection. The operator intends to grow long-term liquids recovery by reinjecting gas for enhanced oil recovery. The operator estimates that there is potential to double the liquids recovery factor.

On the exploration front, at the Espejo block in Ecuador, the Pashuri-1 well identified hydrocarbons with logging information and other relevant data. And the Company, through its joint venture with CGX, looks forward to building on the light oil and condensate discovery at Kawa-1 with the spudding of the Wei-1 well, offshore Guyana, which is anticipated between December 2022 and late January 2023.

During the quarter, Frontera increased its indirect interest in the ODL Pipeline in Colombia to 35%. Also, S&P Global Ratings upgraded its outlook for Frontera from 'stable' to 'positive' and affirmed its B+ issuer credit and issue-level ratings.

Finally, the Company continues to deliver on its ESG goals. Through September 2022, Frontera achieved a Total Recordable Incident Rate (TRIR) of 1.01, the best safety performance in Company history and below its 2022 TRIR objective of 1.40. Frontera has also neutralized 52% of its 2022 Colombian emissions through the purchase of carbon credits and has protected 458 hectares of important biodiverse ecosystems.

The Company is focused on bridging diversity, inclusion and gender equity gaps and is advancing training of community women in its oil and gas technical programme - Crece con Frontera. To date, Frontera has invested $2.3 million in 105 social projects, benefiting more than 21,000 people in Colombia, Ecuador and Peru. The Company purchased $32.3 million from local suppliers and will accomplish its goal of purchasing $41 million locally in 2022.

In October 2022, Frontera was recognized by the Society of Petroleum Engineers Win Awards for its commitment to sustainability. The awards highlight leading corporate and individual practices in the hydrocarbons sector. Frontera was recognized in the 'Equity, Diversity and Inclusion' and 'Sustainability' categories and two Frontera women were also recognized in the 'Leadership' category.

Financial and Operational Results

- Production averaged 41,033 boe/d in the third quarter of 2022 (consisting of 20,945 bbl/d of heavy crude oil, 17,428 bbl/d of light and medium crude oil, 9,969 mcf/d of conventional natural gas and 911 boe/d of natural gas liquids), a decrease in the third quarter of 2022 compared with 41,586 boe/d in the prior quarter (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), and an increase compared to 36,422 boe/d in the third quarter of 2021 (consisting of 18,168 bbl/d of heavy crude oil, 17,160 bbl/d of light and medium crude oil, 5,033 mcf/d of conventional natural gas and 211 boe/d of natural gas liquids).
- Cash provided by operating activities was $120.8 million in the third quarter of 2022, compared with $246.6 million in the prior quarter, and $79.1 million in the third quarter of 2021. The Company reported a total cash position of $309.1 million, including $55.6 million of restricted cash, as at September 30, 2022, compared with a total cash position of $419.5 million, including $100.7 million of restricted cash, as at September 30, 2021.

- The Company recorded a net loss of $26.9 million ($0.30/share) in the third quarter of 2022, compared with net income of $13.5 million ($0.14/share) in the prior quarter and net income of $38.5 million ($0.40/share) in the third quarter of 2021.
- Capital expenditures were $76.0 million in the third quarter of 2022, compared with $93.8 million in the prior quarter and $103.2 million in the third quarter of 2021.
- Operating EBITDA was $173.2 million in the third quarter of 2022, compared with $190.7 million in the prior quarter and $77.3 million in the third quarter of 2021.
- Operating netback was $59.78/boe in the third quarter of 2022, compared with $68.01/boe in the prior quarter and $37.79/boe in the third quarter of 2021.

2. GUIDANCE

The Company has re-affirmed its guidance as updated on August 9, 2022. The following table reports the Company's actual results for the nine months ended September 30, 2022, against guidance.

		Actual 2022 YTD	2022 Guidance
Average production	boe/d	41,238	41,000 - 43,000
Production costs	$/boe	12.52	11.00 - 12.00
Transportation costs	$/boe	10.42	10.00 - 11.00
Operating EBITDA at $90/bbl [1]	$MM	496.9	575 - 625
Operating EBITDA at $100/bbl [1]	$MM		675 - 700
Development Drilling	$MM	120.1	170 - 180
Development Facilities	$MM	27.3	50 - 60
Colombia and Ecuador Exploration	$MM	28.0	55 - 65
Other [2]	$MM	22.0	5
Total Colombia and Ecuador Upstream Capital Expenditures	$MM	197.4	280 - 310
Guyana Kawa Well	$MM	51.0	51
Guyana Wei Well [3]	$MM	31.7	100 - 130
Guyana Port Project	$MM	3.2	5
Capital Expenditures [1] [4]	$MM	283.4	435 - 495

1. Non-IFRS financial measure Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
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, or the payment $9.0 million related to the acquisition of a 50% interest in the CPE-6 block. (For further information refer to the "Capital Expenditures and Acquisitions" section on page 14).
3. 2022 Guidance - Estimated Wei-1 well costs for 2022. Total Wei-1 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 30 for details of the Company's net production.

		Production				
					Nine months ended September 30	
Producing blocks in Colombia		**Q3 2022**	**Q2 2022**	**Q3 2021**	**2022**	**2021**
Heavy crude oil	(bbl/d)	20,945	21,455	18,168	21,203	18,791
Light and medium crude oil	(bbl/d)	16,224	16,738	17,160	16,641	17,528
Conventional natural gas	(mcf/d)	9,969	10,374	5,033	9,958	5,141
Natural gas liquids	(boe/d)	911	963	211	946	331
Total production Colombia	**(boe/d)**	**39,829**	**40,976**	**36,422**	**40,537**	**37,552**
Producing blocks in Ecuador						
Light and medium crude oil	(bbl/d)	1,204	610	—	701	—
Total production Ecuador	**(bbl/d)**	**1,204**	**610**	**—**	**701**	**—**
Total production	**(boe/d)**	**41,033**	**41,586**	**36,422**	**41,238**	**37,552**

Colombia

Production in Colombia for the three months ended September 30, 2022, decreased by 1,147 bbl/d compared to the prior quarter. Lower production was mainly due to a delay in the initiation of new Battery 4 water disposal facility at the Quifa block which came on-line in October 2022, and operational challenges in the conventional natural gas and light and medium crude oil fields. This was partially offset by record quarterly CPE-6 production of 5,070 bbl/d of heavy crude oil due to development drilling and the reactivation of the Sabanero block on July 1, 2022.

Compared to the three and nine months ended September 30, 2021, production increased by 9% and 8%, respectively, mainly due to (i) heavy oil increases in the Quifa and CPE-6 blocks from development drilling, including reaching record production in CPE-6 of 5,070 bbl/d in the third quarter of 2022 (5,220 bbl/d in October 2022), and the reactivation of the Sabanero block, (ii) increases in the VIM-1 block as a result of the development of the facilities in the block, (iii) the acquisition of Petroleos Sud Americanos S.A. ("**PetroSud**") on December 30, 2021, and the subsequent acquisition of an additional 35% W.I. in the El Dificil block on April 27, 2022, which resulted in the addition of 1,417 boe/d and 1,372 boe/d during the three and nine months ended September 30, 2021, respectively (consisting of 6,028 mcf/d and 5,682 mcf/d of conventional natural gas, 289 bbl/d and 315 bbl/d of light and medium crude oil, and 70 bbl/d and 61 bbl/d of natural gas liquids, respectively). 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 nine months ended September 30, 2022, was 1,204 bbl/d and 701 bbl/d, respectively, of light and medium crude oil. 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, at the Perico block, the three wells have been producing light and medium crude oil since the end of the second quarter of 2022. Production for the three months ended September 30, 2022 increased by 594 bbl/d compared to the previous quarter, due to stimulation in the Jandaya well and the stabilization of the Yin-1 well.

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.

					Nine months ended September 30	
		Q3 2022	**Q2 2022**	**Q3 2021**	**2022**	**2021**
Production	(boe/d)	**41,033**	**41,586**	**36,422**	**41,238**	**37,552**
Royalties in-kind Colombia	(boe/d)	(5,236)	(5,646)	(3,435)	(5,074)	(3,036)
Royalties in-kind Ecuador (1)	(boe/d)	(485)	(262)	—	(283)	—
Net production	(boe/d)	**35,312**	**35,678**	**32,987**	**35,881**	**34,516**
Oil inventory draw (build)	(boe/d)	3,207	115	(4,938)	(1,178)	(1,128)
Overlift (settlement)	(boe/d)	17	14	(3)	7	(207)
Volumes purchased	(boe/d)	6,841	4,084	3,500	4,982	2,534
Other inventory movements (2)	(boe/d)	(2,082)	(1,835)	(1,867)	(1,876)	(1,856)
Sales volumes	(boe/d)	**43,295**	**38,056**	**29,679**	**37,816**	**33,859**
Sale of volumes purchased	(boe/d)	(6,635)	(4,783)	(3,007)	(5,072)	(2,095)
Sales volumes, net of purchases	(boe/d)	**36,660**	**33,273**	**26,672**	**32,744**	**31,764**
Oil sales volumes	(bbl/d)	34,838	31,461	25,773	30,964	30,864
Conventional natural gas sales volumes	(mcf/d)	10,385	10,328	5,124	10,157	5,130
Total oil and conventional natural gas sales volumes, net of purchases	(boe/d)	**36,660**	**33,273**	**26,672**	**32,746**	**31,764**
Inventory balance						
Colombia	(bbl)	590,984	922,719	943,121	590,984	943,121
Peru	(bbl)	480,200	480,200	480,200	480,200	480,200
Ecuador	(bbl)	66,729	20,776	—	66,729	—
Inventory ending balance	**(bbl)**	**1,137,913**	**1,423,695**	**1,423,321**	**1,137,913**	**1,423,321**

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 September 30, 2022, increased by 10% compared with the prior quarter, mainly due to one additional cargo sold in Coveñas. Since the second quarter of 2022, the Company has exported production from Ecuador, which resulted in 227 bbl/d and 180 bbl/d for three and nine months ended September 30, 2022, respectively. For the three and nine months ended September 30, 2022, total sales volumes, net of purchases, increased by 37% and 3%, respectively, compared with same periods of 2021, due to higher net production and drawdown of inventory in Colombia during 2022.

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).

					Nine months ended September 30	
		Q3 2022	Q2 2022	Q3 2021	2022	2021
PAP in cash	(bbl/d)	2,238	2,622	1,318	2,265	1,169
PAP in kind	(bbl/d)	3,150	3,363	1,143	2,851	529
PAP	**(bbl/d)**	**5,388**	**5,985**	**2,461**	**5,116**	**1,698**
% Production		**13.1 %**	**14.4 %**	**6.8 %**	**12.4 %**	**4.5 %**

For the three and nine months ended September 30, 2022, PAP increased compared with the same periods of 2021, 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. For the three months ended September 30, 2022, PAP decreased compared with the prior quarter, mainly due to a lower WTI benchmark price.

Realized and Reference Prices

					Nine months ended September 30	
		Q3 2022	Q2 2022	Q3 2021	2022	2021
Reference price						
Brent	($/bbl)	97.70	111.98	73.23	102.48	67.97
Average realized prices						
Realized oil price, net of purchases	($/bbl)	93.89	107.87	68.70	98.84	64.18
Realized conventional natural gas price	($/mcf)	4.61	4.55	3.88	4.50	3.94
Net sales realized price						
Oil and gas sales, net of purchases [1]	($/boe)	90.53	103.34	67.13	94.84	63.00
Realized loss on risk management contracts[2] [3]	($/boe)	(1.30)	(1.15)	(2.68)	(1.18)	(4.89)
Royalties [2]	($/boe)	(7.23)	(10.57)	(4.83)	(8.46)	(2.26)
Dilution costs [2] [4]	($/boe)	(0.07)	(0.12)	(0.15)	(0.10)	(0.97)
Net sales realized price [1]	**($/boe)**	**81.93**	**91.50**	**59.47**	**85.10**	**54.88**

1. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
2. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
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 at the 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 nine months ended September 30, 2022, increased by 33% and 51%, respectively, compared to the same periods of 2021. In comparison to the second quarter of 2022, the average Brent benchmark oil price decreased by 13%. The decrease in crude oil prices in the third quarter is mainly due to three factors: (i) U.S. dollar strength as a result of worldwide recession sentiment caused by higher inflation causing interest rate increases, especially in the United States; (ii) decreased demand in China resulting from Covid-19 lockdowns; and (iii) a possible agreement between Iran and the United States permitting Iranian crude oil production to enter global markets.

For the three and nine months ended September 30, 2022, the Company's net sales realized price was $81.93/boe and $85.10/boe, respectively, an increase of 38% and 55%, respectively, compared to the same periods of 2021. The increase is mainly a result of higher Brent benchmark oil prices, lower loss on risk management contracts, reduction in dilution costs due to replacement of the dilution service by oil volumes purchased, and better differential prices during the third quarter of 2022, partially offset by higher cash royalties resulting from the Brent benchmark oil price increases. In comparison to the second quarter of 2022, the net sales realized price decreased by 10%, or $9.57/boe, primarily driven by the decrease in Brent benchmark oil price partially offset by better differential prices compared with the previous quarter and lower royalties resulting from Brent benchmark oil price decreases.

Operating Netback

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

	Q3 2022		Q2 2022		Q3 2021	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	276,351	81.93	277,040	91.50	145,947	59.47
Production costs (2) (3)	(43,234)	(11.45)	(47,882)	(12.65)	(38,317)	(11.44)
Transportation costs (2) (3)	(34,772)	(10.70)	(35,178)	(10.84)	(31,072)	(10.24)
Operating Netback (1) (4)	**198,345**	**59.78**	**193,980**	**68.01**	**76,558**	**37.79**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases (5)		36,660		33,273		26,672
Production (6)		41,033		41,586		36,422
Net production (7)		35,312		35,678		32,987

1. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
2. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
3. 2021 period figures are different compared with those previously reported as a result of a reclassification from production costs to transportation costs. Refer to the "Selected Quarterly Information" section on page 16 for further details.
4. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
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 30.

Operating netback for the third quarter of 2022 was $59.78/boe, compared to $37.79/boe in the same quarter of 2021. The increase was as a result of higher net sales realized price, partially offset by higher transportation costs mainly due to the initiation of a pipeline take-or-pay commitment as part of the Conciliation Agreement (as defined below) with Bicentenario de Colombia S.A.S. ("**Bicentenario**") (for further information regarding the Conciliation Agreement, 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 "**Annual Financial Statements**")), and volumes transported in Ecuador during the third quarter of 2022.

In comparison to the second quarter of 2022, the Company's operating netback for the third quarter of 2022 decreased from $68.01/boe to $59.78/boe, primarily due to lower net sales realized price. This effect was partially offset by a decrease in production costs mainly due to lower internal field transportation, personnel expenses and energy costs, as well as a decrease in transportation costs.

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

	Nine months ended September 30			
	2022		2021	
	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	760,736	85.10	475,838	54.88
Production costs (2) (3)	(140,977)	(12.52)	(113,115)	(11.03)
Transportation costs (2) (3)	(102,103)	(10.42)	(102,804)	(10.91)
Operating Netback (1) (4)	**517,656**	**62.16**	**259,919**	**32.94**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases (5)		32,744		31,764
Production (6)		41,238		37,552
Net production (7)		35,881		34,516

1. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
2. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
3. 2021 period figures are different compared with those previously reported as a result of a reclassification from production costs to transportation costs. Refer to the "Selected Quarterly Information" section on page 16 for further details.
4. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.
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 30.

Operating netback for the nine months ended September 30, 2022, increased by 89% to $62.16/boe from $32.94/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 volumes 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, such as well services, internal field transportation, maintenance, personnel expenses and energy.

Sales

	Three months ended September 30		Nine months ended September 30	
($M)	**2022**	**2021**	**2022**	**2021**
Oil and gas sales, net of purchases (1)	305,338	164,731	847,817	546,268
Realized loss on risk management contracts (2)	(4,393)	(6,570)	(10,551)	(42,427)
Royalties	(24,371)	(11,848)	(75,633)	(19,598)
Dilution cost	(223)	(366)	(897)	(8,405)
Net sales (1)	**276,351**	**145,947**	**760,736**	**475,838**
Net sales realized price ($/boe) (3)	81.93	59.47	85.10	54.88

1. Non-IFRS financial measure. Refer to the “Non-IFRS and Other Financial Measures" section on page 18.
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 18.

Oil and gas sales, net of purchases, increased by $140.6 million and $301.5 million for the three and nine months ended September 30, 2022, respectively, compared to the same periods of 2021, mainly due to higher Brent benchmark oil prices and better differential 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 nine months ended September 30, 2022, increased by $130.4 million and $284.9 million, respectively, compared with the same periods of 2021. The following table describes the various factors that impacted net sales:

	Three months ended September 30	Nine months ended September 30
($M)	**2022-2021**	**2022-2021**
Net sales for the period ended September 30, 2021	145,947	475,838
Increase due to 35% higher oil and gas price (YTD 51% higher)	57,416	276,176
Increase due to higher volumes sold of 9,988 boe/d or 37% (YTD 980 boe/d or 3%)	83,191	25,373
Decrease in realized loss on risk management contracts	2,177	31,876
Decrease in dilution costs	143	7,508
Increase in royalties	(12,523)	(56,035)
Net sales for the period ended September 30, 2022	**276,351**	**760,736**

Oil and Gas Operating Costs

	Three months ended September 30		Nine months ended September 30	
($M)	**2022**	**2021**	**2022**	**2021**
Production costs	43,234	38,317	140,977	113,115
Transportation costs	34,772	31,072	102,103	102,804
Cost of purchases (1)	63,255	23,109	151,497	45,549
Dilution costs	223	366	897	8,405
Post-termination obligation	—	4,658	7,070	4,658
Overlift (Settlement)	(28)	23	(15)	(2,638)
Inventory valuation	15,682	(12,247)	(10,509)	(3,782)
Total oil and gas operating costs	**157,138**	**85,298**	**392,020**	**268,111**

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 18.

For the three and nine months ended September 30, 2022, total oil and gas operating costs increased by 84% and 46%, 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 nine months ended September 30, 2022, increased by 13% and 25%, respectively, compared with the same periods of 2021, primarily due to an increase in tariffs and barrels produced affecting variable costs, such as well services, internal field transportation, maintenance, personnel expenses and energy.

- For the nine months ended September 30, 2022, transportation costs decreased by 1%, primarily due to no volumes being transported in Peru compared with the same period of 2021. Transportation costs increased by 12% for the three months ended September 30, 2022, compared with the same period of 2021, primarily due to higher volumes produced and transported in Colombia and Ecuador, as well as increase in pipeline-regulated tariffs in Colombia since July 2022. Partially offset by the positive impact of foreign exchange fluctuations in COP denominated costs.
- Cost of purchases for the three and nine months ended September 30, 2022, increased by $40.1 million and $105.9 million, respectively, compared with the same periods of 2021, due to additional volumes of 3,628 bbl/d and 2,977 bbl/d, respectively, acquired from third parties to replace the dilution services, and higher Brent benchmark oil prices. The sale of the volumes purchased represents an estimated income for the three and nine months ended September 30, 2022, of $57.8 million and $138.0 million, respectively.
- Dilution costs for the three and nine months ended September 30, 2022, decreased by $0.1 million and $7.5 million, respectively, compared with the same periods of 2021, 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 nine months ended September 30, 2022, was $Nil and $7.1 million, respectively, mainly related to a non-recurring cleaning activities cost provision related to Block 192 in Peru.
- Overlift for the three and nine months ended September 30, 2022, was not significant, compared to the settlement of the overlift balance during the same periods of 2021.
- Inventory valuation for the three months ended September 30, 2022, increased by $27.9 million, compared with the same period of 2021, mainly due to a drawdown of inventory in Colombia. For the nine months ended September 30, 2022, inventory valuation decreased by $6.7 million, due to higher oil inventory costs as a result of an increase in royalties.

Royalties

	Three months ended September 30		Nine months ended September 30	
($M)	**2022**	**2021**	**2022**	**2021**
Royalties Colombia	24,183	11,848	75,320	19,598
Royalties Ecuador	188	—	313	—
Royalties	**24,371**	**11,848**	**75,633**	**19,598**

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia. For the three and nine months ended September 30, 2022, royalties increased by $12.5 million and $56.0 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. 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 September 30		Nine months ended September 30	
($M)	**2022**	**2021**	**2022**	**2021**
Depletion, depreciation and amortization	57,927	33,480	146,221	106,571

For the three and nine months ended September 30, 2022, depletion, depreciation and amortization expense ("**DD&A**") increased by 73% and 37%, 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 of PetroSud on December 30, 2021.

Impairment, exploration expenses and others

($M)	Three months ended September 30 2022	Three months ended September 30 2021	Nine months ended September 30 2022	Nine months ended September 30 2021
Impairment expense of:				
Exploration and evaluation assets	—	—	2,264	—
Other	—	—	3,033	—
Total impairment expense	—	—	5,297	—
Exploration expenses of:				
Geological and geophysical costs, and other	498	76	1,450	247
Minimum work commitment paid	—	—	919	—
Total exploration expenses	498	76	2,369	247
Expense (Recovery) of asset retirement obligation	969	3,846	(5,058)	(3,003)
Impairment, exploration expenses and other	**1,467**	**3,922**	**2,608**	**(2,756)**

During the three and nine months ended September 30, 2022, the Company recorded an impairment of $Nil and $2.3 million, respectively, 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, during the three and nine months ended September 30, 2022, the Company recorded other impairment charges of $Nil and $3.0 million, respectively, mainly related to obsolete inventory of material in Peru.

During the three months ended September 30, 2022, the exploration expense increased by $0.4 million compared with the same quarter of 2021, due to expenses incurred prior to obtaining the legal rights to explore an area. For the nine months ended September 30, 2022, the exploration expense increased by $2.1 million, compared with the same period of 2021, mainly due to execution of the payment of the remaining balance of a minimum work commitment not executed in the CPE-6 block.

During the three months ended September 30, 2022, the Company recognized an expense related to asset retirement obligations of $1.0 million, compared to an expense of $3.8 million in the same period of 2021. For the nine months ended September 30, 2022, the Company recognized a recovery related to asset retirement obligations of $5.1 million, compared to a recovery of $3.0 million in the same period of 2021. 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

($M)	Three months ended September 30 2022	Three months ended September 30 2021	Nine months ended September 30 2022	Nine months ended September 30 2021
General and administrative	12,549	12,656	42,302	39,990
Share-based compensation	1,422	962	5,927	5,421
Restructuring, severance and other costs	453	954	1,839	2,870

General and Administrative

For the three and nine months ended September 30, 2022, G&A expenses decreased by 1% and increased by 6%, respectively, compared with the same periods of 2021. For the three months ended September 30, 2022, G&A was comparable with the same period of 2021, at $12.5 million. For the nine months ended September 30, 2022, G&A increased due to higher professional fees, personnel costs and taxes, compared to the same period of 2021.

Share-Based Compensation

For the three and nine months ended September 30, 2022, share-based compensation increased by $0.5 million and $0.5 million respectively, due to an increase in share price and a strengthening USD, compared with the same periods in 2021. Share-based compensation reflects cash and non-cash charges relating to the vesting of restricted share units and grants of deferred share units (**“DSUs”**) under the Company’s security-based compensation plan, which are subject to variability from movements in the underlying Common Share price, and the consolidation of stock option expenses from the Company’s majority-held subsidiary, CGX.

Restructuring, Severance and Other Costs

For the three months ended September 30, 2022, restructuring, severance and other costs decreased by $0.5 million compared with the same periods of 2021, mainly due to a reduction in severance package and special projects in 2022.

Non-Operating Costs

	Three months ended September 30		Nine months ended September 30	
($M)	**2022**	**2021**	**2022**	**2021**
Finance income	1,699	817	3,182	5,332
Finance expenses	(13,896)	(12,720)	(38,752)	(40,054)
Foreign exchange loss	(38,745)	(5,846)	(48,183)	(24,382)
Other income (loss), net	5,662	(570)	(5,419)	(13,353)

Finance Income

For the three and nine months ended September 30, 2022, finance income increased by $0.9 million, compared to the three months ended September 30, 2022, as a result of higher interest rates on the investment trust accounts for abandonment requirements. Compared with the nine months ended September 30, 2022, finance income decreased by $2.2 million due to interest collected from VAT reimbursement in previous year.

Finance Expenses

For the three months ended September 30, 2022, finance expenses increased by $1.2 million due to higher interest on the 2025 Puerto Bahia Debt (as defined below), and bank guarantees. For the nine months ended September 30, 2022, finance expenses decreased by $1.3 million mainly due to a reduction in the interest rate applicable to the 2028 Unsecured Notes (as defined below).

Foreign Exchange Loss

For the three and nine months ended September 30, 2022, foreign exchange loss was $38.7 million and $48.2 million, respectively, as a result of the recycling of a cumulative translation adjustment relating to the return of capital of Oleoducto de Los Llanos Orientales ("**ODL**") for $19.1 million during the third quarter of 2022. In addition, a loss was recorded as a result the of the depreciation of COP against the USD on the translation of the debt consolidated from Puerto Bahia and a loss of the translation of the Company's net working capital balances. This compared with a loss of $5.8 million and $24.4 million in same periods of 2021.

Other Income (Loss), Net

For the three and nine months ended September 30, 2022, the Company recognized other income of $5.7 million and a loss of $5.4 million, respectively. Other income in 2022 is mainly from the sale of surplus inventory. This compared to other losses of $0.6 million and $13.4 million in the same periods of 2021, related to the reassessment of contingencies from the allegedly late delivery of production from the Quifa block prior to 2014 (for further information refer to Note 27 of the Annual Financial Statements).

Loss on Risk Management Contracts

	Three months ended September 30		Nine months ended September 30	
($M)	**2022**	**2021**	**2022**	**2021**
Premiums paid on risk management contracts settled	(4,393)	(4,709)	(10,551)	(7,816)
Cash settlement on risk management contracts	—	(1,861)	—	(34,611)
Realized loss on risk management contracts	(4,393)	(6,570)	(10,551)	(42,427)
Unrealized (loss) gain on risk management contracts [1]	(1,637)	4,068	(2,290)	2,683
Total loss on risk management contracts	(6,030)	(2,502)	(12,841)	(39,744)

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 nine months ended September 30, 2022, the realized loss on risk management contracts was $4.4 million and $10.6 million, respectively, resulting from cash paid for put options settled during the period, compared to a loss of $6.6 million and $42.4 million, in the same periods of 2021, primarily from the higher cash settlement on three-way collars, puts and put spreads contracts paid during the three and nine months ended September 30, 2021.

For the three and nine months ended September 30, 2022, the unrealized loss on risk management contracts was $1.6 million and $2.3 million, respectively, compared to a gain of $4.1 million and $2.7 million in the same periods of 2021, primarily from the reclassification of amounts to realized gain or loss from instruments settled and an 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 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 derivative commodity instruments to protect the revenue generation and cash position of the Company, while maximizing the upside. In 2022, the Company is using only put options, which allows the Company to capture the full upside price benefit while offering efficient downside hedging.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $/bbl**	**Assets**	**Liabilities**
Put	October to December 2022	Brent	1,410,000	70.0	2,038	—
Total as at September 30, 2022					**2,038**	**—**

Subsequent to September 30, 2022, the Company entered into new hedges that protect a portion of the Company's expected production for January 2023. The new transactions are as follows:

				Avg. Strike Prices
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $**
Put	January 2023	Brent	230,000	80.0
		Total (bbl)	**230,000**	

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. The Company monitors its exposure to such foreign currency risks. As at September 30, 2022, the Company had entered into new 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	October to June 2023	COP / USD	$ 150,000	3,750 / 5,220	—	5,515
Total as at September 30, 2022					**—**	**5,515**

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 22 for further information. As at September 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	October 2022 to June 2025	LIBOR + 180	93,100	3.9%	62	0
Total as at September 30, 2022					**62**	**—**

Income Tax Expense

	Three months ended September 30		Nine months ended September 30	
($M)	**2022**	**2021**	**2022**	**2021**
Current income tax expense	(8,584)	(174)	(11,162)	(24,390)
Deferred income tax (expense) recovery	(93,778)	14,166	(169,514)	(12,767)
Total income tax (expense) recovery	**(102,362)**	**13,992**	**(180,676)**	**(37,157)**

For the three months ended September 30, 2022, current income tax expense increased to $8.6 million, compared to $0.2 million for the same period of 2021, mainly due to the recognition of a provision for $7.5 million related to changes in withholding taxes for the years 2021 and 2022. For the nine months ended September 30, 2022, current income tax expense decreased to $11.2 million, compared to $24.4 million for the same period of 2021 mainly due to the recognition of an additional provision of $20.9 million in 2021 that was related to changes in tax assessments for prior years.

For the three and nine months ended September 30, 2022, deferred income tax expense was $93.8 million and $169.5 million, respectively, compared to a deferred income tax recovery of $14.2 million and expense of $12.8 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 devaluation during 2022.

Colombia 2022 Tax Fiscal Reform Legislation

Colombia has proposed tax reform legislation that would significantly impact oil and gas companies:

The bill was initially presented to congress on August 8, 2022, and proposed a 10% levy on oil and gas exports, the elimination of free trade zone status for offshore projects, and the removal of royalties from a list of deductible items for income tax purposes. It also proposed to end accelerated amortization for exploration investments and to abolish certain tax refunds programs, which provides exploration and production incentives during times of low prices.

During the legislative process, the proposed tax reform has been adjusted, including the elimination of the proposed 10% levy on oil and gas exports, and the introduction of a special and progressive surcharge on the income tax rate applicable to the sector, as follows: 10% for full year 2023, 7.5% for full year 2024 and 5% for full year 2025 and thereafter. The non-deductibility of royalties has been maintained. Management expects tax reform legislation to be finalized and approved before the end of the year. Furthermore, management does not expect any impact related to this legislation for FY 2022.

Net (Loss) Income

	Three months ended September 30		Nine months ended September 30	
($M)	**2022**	**2021**	**2022**	**2021**
Net (loss) income attributable to equity holders of the Company	(26,893)	38,531	88,819	(1,243)
Per share – basic ($)	(0.30)	0.40	0.96	(0.01)
Per share – diluted ($)	(0.30)	0.39	0.94	(0.01)

The Company reported a net loss of $26.9 million for the third quarter of 2022, which included an expense in deferred income taxes of $93.8 million, foreign exchange loss of $38.7 million and finance expenses of $13.9 million partially offset by operating income of $118.2 million. This compared to net loss of $38.5 million in the third quarter of 2021, which included operating income of $40.0 million and deferred income tax recovery of $14.2 million partially offset by $12.7 million of finance costs expenses, and a loss on risk management contracts of $2.5 million.

For the nine months ended September 30, 2022, the Company reported a net income of $88.8 million, which included operating income of $346.6 million, partially offset by income tax expenses of $180.7 million, foreign exchange losses of $48.2 million and finance expenses of $38.8 million. This compared to a net loss of $1.2 million for the nine months ended September 30, 2021, which included debt extinguishment costs of $29.1 million, total income tax expenses of $37.2 million, a loss on risk management contracts of $39.7 million, finance expenses of $40.1 million, and other loss of $13.4 million, partially offset by $157.1 million in operating income.

Capital Expenditures and Acquisitions

($M)	Three months ended September 30		Nine months ended September 30	
	2022	2021	2022	2021
Development drilling	44,145	27,239	120,146	67,232
Development facilities	9,863	11,088	27,262	16,414
Colombia and Ecuador exploration	7,083	16,137	27,962	26,853
Other	2,803	567	22,028	1,281
Total Colombia, Ecuador and other capital expenditures	**63,894**	**55,031**	**197,398**	**111,780**
Guyana exploration	11,838	46,180	82,770	63,117
Guyana infrastructure	286	2,009	3,230	3,902
Total capital expenditures (1)	**76,018**	**103,220**	**283,398**	**178,799**

1. Non-IFRS financial measure. Refer to the “Non-IFRS and Other Financial Measures" section on page 18.

Capital expenditures for the three and nine months ended September 30, 2022, were $76.0 million and $283.4 million, respectively, a decrease of $27.2 million and an increase of $104.6 million, compared to the same periods of 2021, respectively. The variance in capital expenditures was mainly due to the following:

Development drilling. During the three and nine months ended September 30, 2022, development drilling increased by $16.9 million and $52.9 million, respectively, compared to the same periods of 2021, mainly due to a total of 16 development wells drilled in the Quifa and CPE-6 blocks in the three months ended September 30, 2022 and 50 development wells drilled in the Quifa, CPE-6 and Guatiquia blocks in the nine months ended September 30, 2022. This compares to 15 and 28 development wells drilled in the same blocks and the La Creciente block in the three and nine months ended September 30, 2021, respectively.

Development facilities. During the three and nine months ended September 30, 2022, development facilities decreased to $9.9 million from $11.1 million, and increased to $27.3 million from $16.4 million, respectively, during the same periods of 2021. During the three and nine months ended September 30, 2022 development facilities investment mainly related to road improvements and construction of an oil storage tank at the CPE-6 block, water pump improvement at the Quifa block, flow handling and injector line facilities at the Guatiquia block, and reactivation of facilities in the Sabanero block.

Colombia and Ecuador Exploration. During the three and nine months ended September 30, 2022, exploration activities decreased by $9.1 million and increased by $1.1 million, respectively, compared to the same periods of 2021. During the three and nine months ended September 30, 2022, 3 exploration wells were completed in Perico block in Ecuador during the first half of 2022, 1 exploration well was spudded in Espejo block in Ecuador in September 2022 and pre-drilling activities are ongoing in the Magari-1 well at the exploratory area of La Creciente block in the third quarter of 2022. Details relating to exploration activities in Colombia and Ecuador are as follows:

Colombia. The Company continues to focus on the Lower Magdalena Valley and Llanos Basins in Colombia. During the remainder of 2022, at the VIM-22 block, pre-drilling activities including civil works will begin in the fourth quarter of 2022 in advance of spudding Chimi-1 exploration well in January 2023. In addition, the Company plans to drill the Magari-1 exploration well in the exploratory area of La Creciente block. The Company is undertaking civil works in the northern exploratory area of the CPE-6 block in advance of spudding the Hamaca Norte-1 exploration well and plans to drill the Hamaca-107D appraisal well in the southern portion of the block in November 2022. In addition, on January 18, 2022, the Company entered into the exploration and production agreement for the VIM-46 block, which covers an area of 58,806 hectares located within the Magdalena Valley. The exploratory commitments for the VIM-46 block include one exploration well to be drilled during the first exploration phase. The Company is working on pre-seismic activities related to social and environmental impact studies in the VIM-46, Llanos 119 and Llanos 99 blocks. The Company anticipates starting 3D seismic acquisition at Llanos 99.

Ecuador. Following the first quarter 2022 completion 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 in order to obtain 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 spudded 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. With this well, the Company has drilled three out of four wells required as part of its work commitment on the Perico block. A complete testing program is now being performed. Additional prospects on the Perico block have been identified and are being analyzed for future drilling.

At the Espejo block (Frontera 50% W.I. and non-operator), the operator completed the acquisition of 63 km^2 of 3D seismic during the second quarter of 2022, spud the first exploration well on the block, Pashuri-1, in September and reached total depth in October 2022. Preliminary logging information and other relevant data indicated the presence of hydrocarbons. Testing activities start in November 2022. Based on the preliminary success at Pashuri-1, the operator anticipated spudding the Caracara-1 well in the fourth quarter.

Other

For the three and nine months ended September 30, 2022, the Company has capitalized other investments of $2.8 million and $22.0 million, respectively, mainly related to the acquisition of an additional 35% W.I. in the 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. This was approved by the ANH on April 27, 2022, which 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, $9.0 million related to the purchase agreement signed with Repsol Colombia Oil & Gas Ltd. (“**RCOG**”) to acquire its 50% of the CPE-6 block, as a result of reaching 5MMbbl of production during the first quarter of 2022 and the variable monthly payments made during the nine months ended September 30, 2022 (for further information refer to the “**Commitments and Contractual Obligations**” section on page 25).

Guyana

Guyana exploration. For the three and nine months ended September 30, 2022, the Company invested $11.8 million and $82.8 million, respectively, in the Corentyne block, mainly related to final drilling activities at the Kawa-1 well during the first quarter 2022, and pre-Wei-1 well activities. Details relating to exploration activities in Corentyne block are as follows:

The Company and its majority-owned subsidiary and co-venture partner, CGX (the “**Joint Venture**”), 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. Multiple datasets and analytic methods indicate the presence of gas condensate in the Maastrichtian and Campanian, and light oil in the Santonian and Coniacian. The Joint Venture is planning to drill a second well called Wei-1well, final preparations are complete in advance of spudding the Wei-1 well and follows the discovery of light oil and condensate at the Kawa-1 well. The Wei-1 well will be located approximately 14 kilometres northwest of the Kawa-1 exploration well in the Corentyne block, approximately 200 kilometres offshore from Georgetown, Guyana and will be drilled in water depth of approximately 1,912 feet (583 metres) to an anticipated total depth of 20,500 (6,248 metres). Wei-1 will target Maastrichtian, Campanian and Santonian aged stacked channels in a western channel complex in the northern section of the Corentyne block.

Guyana infrastructure. During the three and nine months ended September 30, 2022, CGX, Frontera’s majority-owned subsidiary, invested $0.3 million and $3.2 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 17.

Selected Quarterly Information

Operational and financial results		2022 Q3	2022 Q2	2022 Q1	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4
Heavy crude oil production	(bbl/d)	20,945	21,455	21,214	20,912	18,168	17,241	20,997	21,074
Light and medium crude oil production	(bbl/d)	17,428	17,348	17,248	16,300	17,160	17,142	18,294	19,502
Total crude oil production	(bbl/d)	38,373	38,803	38,462	37,212	35,328	34,383	39,291	40,576
Conventional natural gas production	(mcf/d)	9,969	10,374	9,530	4,663	5,033	5,164	5,227	6,356
Natural gas liquids	(boe/d)	911	963	966	575	211	393	391	254
Total production	(boe/d)	41,033	41,586	41,100	38,605	36,422	35,682	40,599	41,945
Sales volumes, net of purchases (1)	(boe/d)	36,660	33,273	28,211	39,001	26,672	34,151	34,555	44,551
Brent price	($/bbl)	97.70	111.98	97.90	79.66	73.23	69.08	61.32	45.26
Oil and gas sales, net of purchases (1) (2)	($/boe)	90.53	103.34	90.42	75.12	67.13	64.54	58.18	42.20
Realized loss on risk management contracts (3)	($/boe)	(1.30)	(1.15)	(1.06)	(1.87)	(2.68)	(8.00)	(3.53)	(2.00)
Royalties (3)	($/boe)	(7.23)	(10.57)	(7.58)	(3.62)	(4.83)	(0.53)	(1.96)	(0.47)
Dilution costs (3) (4)	($/boe)	(0.07)	(0.12)	(0.12)	(0.10)	(0.15)	(0.34)	(2.25)	(1.85)
Net sales realized price (2)	($/boe)	81.93	91.50	81.66	69.53	59.47	55.67	50.44	37.88
Production costs (3) (4)	($/boe)	(11.45)	(12.65)	(13.48)	(12.71)	(11.44)	(11.72)	(10.06)	(12.95)
Transportation costs (3) (4)	($/boe)	(10.70)	(10.84)	(9.74)	(9.02)	(10.24)	(11.15)	(11.30)	(11.36)
Operating netback per boe (2)	($/boe)	59.78	68.01	58.44	47.80	37.79	32.80	29.08	13.57
Revenue	($M)	354,548	344,015	254,627	301,969	182,673	224,685	184,734	177,109
Net (loss) income	($M)	(26,893)	13,484	102,228	629,376	38,531	(25,648)	(14,126)	48,636
Per share – basic ($)	($)	(0.30)	0.14	1.08	6.60	0.40	(0.26)	(0.14)	0.50
Per share – diluted ($)	($)	(0.30)	0.14	1.05	6.40	0.39	(0.26)	(0.14)	0.48
General and administrative	($M)	12,549	15,097	14,656	12,144	12,656	14,132	13,202	19,851
Operating EBITDA (5) (6)	($M)	173,207	190,678	132,998	148,645	77,304	83,072	69,158	35,639
Capital expenditures (6)	($M)	76,018	93,835	113,545	135,458	103,220	61,214	14,365	24,871

1. The fourth quarter of 2020 is 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 18 for further details.
2. Non-IFRS ratio. Refer to the “Non-IFRS and Other Financial Measures" section on page 18
3. Supplementary financial measure. Refer to the “Non-IFRS and Other Financial Measures" section on page 18
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 costs to transportation costs and dilution costs 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 costs.
5. 2021 prior period figures are different compared with those previously reported as a result of the exclusion of post-termination costs.
6. Non-IFRS financial measure. Refer to the “Non-IFRS and Other Financial Measures” section on page 18 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. However, during the third quarter of 2022, there was a reduction in production mainly as a result of maintenance in water disposal facilities at the Quifa block. 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. The trend of reduction partially changed during 2022 due to the initiation of the pipeline take-or-pay commitment as part of the settlement agreement with Bicentenario (for further information, refer to Note 27 of the Annual Financial Statements). 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 (loss) income 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 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 Annual 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	100% 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 nine months ended September 30, 2022, Puerto Bahia has generated $9.5 million of segment income from operations which was $20.6 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

On September 15, 2022, the Company acquired the remaining 40.07% interest it did not already own of PIL, increasing its ownership interest to 100%, for an aggregate cash consideration of approximately $47.4 million is payable to the non-controlling shareholders in installments, with an upfront payment of $18.0 million and the remaining installments to be paid until the end of 2023. For further information refer to the Interim Financial Statements in the "**Statements of Changes in Equity**" on page 5.

PIL 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 nine months ended September 30, 2022, the Company recognized $29.9 million as its share of income from ODL, which was $1.6 million higher than the same period of 2021, primarily due to the impact of foreign exchange fluctuations. During the nine months ended September 30, 2022, the Company recognized gross dividends of $40.5 million (2021: $41.6 million) and a return of capital of $19.7 million (2021: $4.2 million). As at September 30, 2022, the Company had accounts receivables of $23.1 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 kilometres 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 nine months ended September 30, 2022, CGX invested $3.2 million in the Guyana Port Project.

Midstream Segment Results

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

	Three months ended September 30		Nine months ended September 30	
($M)	**2022**	**2021**	**2022**	**2021**
Revenue	12,103	17,625	34,674	52,899
Costs	(5,400)	(5,426)	(15,691)	(14,741)
General and administrative expenses	(1,246)	(1,255)	(3,999)	(4,550)
Depletion, depreciation and amortization	(1,345)	(1,205)	(4,384)	(2,911)
Restructuring, severance and other costs	(57)	(578)	(1,113)	(578)
Puerto Bahia income from operations	**4,055**	**9,161**	**9,487**	**30,119**
Share of Income from associates - ODL	11,166	8,691	29,908	28,282
Segment income	**15,221**	**17,852**	**39,395**	**58,401**

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 (loss) income as reported under IFRS to exclude the effects of income taxes, finance income and expenses, and DD&A. Operating EBITDA is a non-IFRS financial measure that represents the operating results of the Company's primary business, excluding the following items: restructuring, severance and other costs, post-termination obligation, payments of minimum work commitments and, certain non-cash items (such as impairments, foreign exchange, unrealized risk management contracts, and share-based compensation) and gains or losses arising from the disposal of capital assets. In addition, other unusual or non-recurring items are excluded from operating EBITDA, as they are not indicative of the underlying core operating performance of the Company.

Since the previous quarter the Company changed the composition of its Operating EBITDA calculation to exclude certain unusual or non-recurring items as post-termination obligations and payments of minimum work commitments, which could distort future projections as they are not considered part of the Company's normal course of operations. 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 (loss) income to operating EBITDA:

	Three months ended September 30		Nine months ended September 30	
($M)	**2022**	**2021**	**2022**	**2021**
Net (loss) income	(26,893)	38,531	88,819	(1,243)
Finance income	(1,699)	(817)	(3,182)	(5,332)
Finance expenses	13,896	12,720	38,752	40,054
Income tax expense (recovery)	102,362	(13,992)	180,676	37,157
Depletion, depreciation and amortization	57,927	33,480	146,221	106,571
Impairment, recovery of asset retirement obligation and minimum work commitment paid	969	3,846	1,158	(3,003)
Post-termination obligation	—	4,658	7,070	4,658
Share-based compensation non cash portion	59	962	4,564	3,722
Restructuring, severance and other costs	453	954	1,839	2,870
Share of income from associates	(11,166)	(8,691)	(29,908)	(28,282)
Foreign exchange loss	38,745	5,846	48,183	24,382
Other (income) loss, net	(5,662)	570	5,419	13,353
Unrealized gain (loss) on risk management contracts	1,637	(4,068)	2,290	(2,683)
Non-controlling interests	2,579	3,305	4,982	8,198
Loss on extinguishment of debt	—	—	—	29,112
Operating EBITDA	**173,207**	**77,304**	**496,883**	**229,534**

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 September 30		Nine months ended September 30	
	2022	2021	2022	2021
Oil and gas sales ($M) (1)	368,593	187,840	999,314	591,817
(-) Cost of purchases ($M) (2)	(63,255)	(23,109)	(151,497)	(45,549)
Oil and gas sales, net of purchases ($M)	**305,338**	**164,731**	**847,817**	**546,268**
Sales volumes, net of purchases - (boe)	3,372,753	2,453,824	8,939,112	8,671,572
Oil and gas sales, net of purchases ($/boe)	90.53	67.13	94.84	63.00

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 17.
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 September 30		Nine months ended September 30	
	2022	2021	2022	2021
Oil sales ($M)	300,936	162,901	835,346	540,750
Conventional natural gas sales ($M)	4,402	1,830	12,471	5,518
Oil and gas sales, net of purchases ($M) (1)	**305,338**	**164,731**	**848,001**	**546,268**
Sales volumes, net of purchases - (bbl)	3,205,111	2,371,123	8,453,041	8,425,914
Conventional natural gas sales volumes - (mcf)	955,588	471,550	2,773,700	1,399,989
Realized oil price, net of purchases ($/bbl)	93.89	68.70	98.84	64.18
Realized conventional natural gas price ($/mcf)	4.61	3.88	4.50	3.94

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 September 30		Nine months ended September 30	
	2022	2021	2022	2021
Oil and gas sales, net of purchases ($M) (1)	305,338	164,731	847,817	546,268
(-) Realized loss on risk management contracts ($M)	(4,393)	(6,570)	(10,551)	(42,427)
(-) Royalties ($M)	(24,371)	(11,848)	(75,633)	(19,598)
(-) Dilution costs ($M)	(223)	(366)	(897)	(8,405)
Net sales ($M)	**276,351**	**145,947**	**760,736**	**475,838**
Sales volumes, net of purchases - (boe)	3,372,753	2,453,824	8,939,112	8,671,572
Oil and gas sales, net of purchases ($/boe)	90.53	67.13	94.84	63.00
Realized (loss) gain on risk management contracts (2)	(1.30)	(2.68)	(1.18)	(4.89)
Royalties ($/boe) (2)	(7.23)	(4.83)	(8.46)	(2.26)
Dilution costs ($/boe) (2)	(0.07)	(0.15)	(0.10)	(0.97)
Net sales realized price ($/boe)	**81.93**	**59.47**	**85.10**	**54.88**

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 September 30		Nine months ended September 30	
	2022	**2021**	**2022**	**2021**
Production costs ($M)	43,234	38,317	140,977	113,115
Production (boe)	3,775,067	3,350,824	11,257,974	10,251,696
Production costs ($/boe)	11.45	11.44	12.52	11.03

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 and pipeline. 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 September 30		Nine months ended September 30	
	2022	**2021**	**2022**	**2021**
Transportation costs ($M)	34,772	31,072	102,103	102,804
Net production (boe)	3,248,737	3,034,804	9,795,513	9,422,868
Transportation costs ($/boe)	10.70	10.24	10.42	10.91

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 (as defined below) is a supplementary financial measure that corresponds to the weighted-average price of shares purchased under the NCIB (as defined below) 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 September 30, 2022, the Company had a total cash balance of $309.1 million (including $55.6 million in restricted cash), which is $11.7 million lower than December 31, 2021. For the nine months ended September 30, 2022, the Company generated $482.2 million in operating cash flows, which were used to fund cash outflows of $334.9 million for capital expenditures and other investing activities. For the nine months ended September 30, 2022, financing activities generated net outflows of $142.3 million as a result of $83.6 million of Common Shares purchased under the SIB (as defined below) and the NCIB (as defined below), $24.2 million of 2025 Puerto Bahia Debt payments and PetroSud Debt payments, $22.0 million of interest and other financing charges, $8.3 million of dividends paid to non-controlling interests and $4.3 million in lease payments. As a result, the working capital[(1)] deficit was reduced to $33.4 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 September 30, 2022), which was classified as a current liability (for further information on the 2025 Puerto Bahia Debt, refer to page 24 hereof and Note 19 of the Annual 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 September 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 September 30, 2022, the Company had total restricted cash of $55.6 million, a decrease of $7.8 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 28.

[1] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 18.

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 September 30, 2022, the Company is in compliance with all such covenants.

Pursuant to requirements under the indenture governing the 2028 Unsecured Notes (the "**Indenture**"), the Company reports consolidated total indebtedness of $412,926,000 as of September 30, 2022, and for the twelve months ended as of September 30, 2022, consolidated adjusted EBITDA of $642,977,000 and consolidated interest expense of $33,132,000.

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 (loss) income (as defined in the Indenture) plus: i) consolidated interest expense; ii) consolidated income tax and equity tax; iii) consolidated depletion and depreciation expense; iv) consolidated amortization expense; and v) consolidated impairment charge, exploration expense and abandonment costs; after excluding the impact of the Unrestricted Subsidiaries.
2. Consolidated fixed charge ratio is the consolidated adjusted EBITDA for the most recent period ended of four consecutive fiscal quarters divided by the consolidated interest expense for such period as defined in the Indenture.
3. Consolidated net tangible assets is defined in the Indenture as the net amount of the Company's total assets less intangible assets and current liabilities, after excluding the impact of the Unrestricted Subsidiaries.

Consolidated Total Indebtedness and Net Debt

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

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

($M)	As at September 30 2022
Long-term debt (1)	$ 405,921
Total lease liabilities (2)	3,528
Risk management liabilities, net (3)	3,477
Consolidated Total Indebtedness	**412,926**
(-) Cash and Cash Equivalents (4)	(207,301)
(=) Net Debt	**$ 205,625**

1. Excludes $123.1 million of long-term debt attributable to the Unrestricted Subsidiaries.
2. Excludes $0.5 million of lease liabilities attributable to the Unrestricted Subsidiaries.
3. Excludes $0.1 million of risk management assets attributable to the Unrestricted Subsidiaries.
4. Includes cash and cash equivalents attributable to the guarantors and borrower according to the Indenture. Borrower means Frontera Energy Corporation (British Columbia) and guarantors mean Frontera Energy Guyana Corp. and Frontera Energy Colombia AG.

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 Annual 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 September 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 Annual 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 September 30, 2022, the outstanding amount under the PetroSud Debt is $13.7 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 September 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 September 30, 2022, the Company had issued letters of credit and guarantees for exploration, operational, and transport commitments totaling $99.4 million (total credit lines of $113.0 million), without cash collateral.

Commitments and Contractual Obligations

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

As at September 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	669	3,215	294	163	20	—	4,361
2025 Puerto Bahía Debt and interest (1)	24,340	52,261	48,863	13,818	—	—	139,282
PetroSud Debt and interest	1,154	13,608	—	—	—	—	14,762
Total financial obligations	**41,913**	**100,584**	**80,657**	**45,481**	**31,520**	**447,250**	**747,405**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	17,684	70,735	70,735	35,416	—	—	194,570
ODL agreements	4,208	16,322	15,996	1,333	—	—	37,859
Other transportation and processing commitments	3,387	11,678	11,678	11,678	11,678	3,895	53,994
Exploration commitments							
Minimum work commitments (2)	54,860	53,303	25,027	53,025	—	5,066	191,281
Other commitments							
Operating purchases, leases and community obligations	71,557	25,034	14,821	19,572	12,442	20,536	163,962
Total Commitments	**151,696**	**177,072**	**138,257**	**121,024**	**24,120**	**29,497**	**641,666**

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 September 30, 2022, the Company, through its 76.98% interest in CGX and directly through its 33,33% W.I. in the Corentyne block, has exploration work commitments under the Petroleum Prospecting Licenses ("**PPL**") for the Corentyne and Demerara blocks.

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. However, due to unforeseen challenges to the exploration activities of a third-party operator, the release of the NobleCorp Discoverer drilling unit to CGX has been delayed. This situation is beyond the reasonable control of the Joint Venture. Frontera and CGX have communicated the revised spud window for the Wei-1 well to the Government of Guyana; expected to now be between December 2022 and late January 2023, subject to rig release by the third-party operator.

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. On September 20, 2022, the Government of Guyana provided CGX a surrender deed to formalize relinquishment of the Demerara block. Subsequent to September 30, 2022, the Joint Venture signed the surrender of the Demerara PPL. The Joint Venture's relinquishment of the block allows the people of Guyana to benefit from exploration activities under the stewardship of interested parties. As of October 31, 2022, the Deed of Surrender was in the process of being finalized.

On July 22, 2022, Frontera and CGX jointly announced that the companies 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 Joint Venture's Wei-1 exploration well. The JOA Amendment 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 well for up to $130.0 million and up to an additional $29.0 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 $19.0 million convertible loan to CGX dated May 28, 2021, as amended (the "**Loan Agreement**"), and (ii) the previously announced $35.0 million convertible loan to CGX dated March 10, 2022, as amended, and Frontera making a cash payment to CGX of $3.8 million. 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.

On October 3, 2022, Frontera and CGX jointly announced that the companies had agreed to (i) extend the maturity date of the Loan Agreement to November 30, 2022, and (ii) further amend the JOA Amendment to extend the outside date by which the conditions precedent to the JOA Amendment must be fulfilled to November 30, 2022, as the Joint Venture continues to await the satisfaction of all conditions precedent.

In addition, in connection with (i) a drilling contract agreement between Maersk Drilling Holdings Singapore Pte. Ltd. ("**Maersk**", now NobleCorp.) and CGX Resources Inc., operator of the Corentyne block, for the provision of a semi-submersible drilling unit owned by Maersk and associated services to drill the Joint Venture's Wei-1 well, and (ii) a services agreement between Schlumberger Guyana Inc. ("**Schlumberger**") and CGX Resources Inc. for the provision of certain oilfield services and the supply of related goods and products for the Corentyne block, Frontera has entered into a deed of guarantee with each of Maersk and Schlumberger for certain obligations, in each case up to a maximum of $30.0 million, and subject to a sliding scale mechanism in connection with payments made under the drilling contract with Maersk or the services agreement with Schlumberger, as applicable.

As of September 30, 2022, CGX has entered into purchase orders and contracts for the drilling of the Wei-1 well and the Guyana Port Project, pursuant to which the Company has amounts outstanding of $111.6 million, which is expected to be paid in 2022 and 2023.

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, up to $30.0 million, and $6.0 million, respectively. The term of the pledge agreement has been amended and extended for the period from May 1, 2022, to March 31, 2023, with Ocensa, and for the period from May 1, 2022, to April 30, 2023, with Cenit.

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 September 30, 2022, the Company has paid and accrued a total of $14.2 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 of 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 September 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. No material changes have occurred regarding the matters disclosed in Note 27 - Commitments and Contingencies of the 2021 Annual Financial Statements.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at October 31, 2022:

	Number
Common shares	86,233,775
Deferred share units ("**DSUs**") (1)	828,827
Restricted share units ("**RSUs**") (2)	1,886,099

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 Company's C$65 million substantial issuer bid ("**SIB**"), and as required under TSX rules, Frontera suspended share repurchases under its NCIB from June 20, 2022 (the date the SIB was announced) until August 8, 2022 (the expiry time of the SIB).

Purchases subject to the NCIB were 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 nine months ended September 30, 2022, the Company purchased a total of 833,700 and 3,214,000 Common Shares, respectively, under its current and previous NCIBs (2,825,800 under its current NCIB and 388,200 under its previous NCIB). As at October 31, 2022, the Company had repurchased for cancellation a total of 3,167,200 Common Shares under its NCIB for approximately $31.7 million with an additional 1,620,776 Common Shares remaining available for repurchase under the NCIB. Under the prior NCIB that expired on March 16, 2022, the Company repurchased for cancellation during the twelve-month term and the nine months ended September 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:

	Nine months ended September 30
	2022
Number of Common Shares repurchased	3,214,000
Total amount of Common Shares repurchased ($M)	32,441
Weighted-average price per share ($) (1)	10.09

1. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 18.

Substantial Issuer Bid

On June 24, 2022, the Company launched the SIB, pursuant to which the Company offered to purchase from shareholders for cancellation up to C$65.0 million of its outstanding Common Shares. The SIB proceeded by way of a "**modified Dutch auction**" procedure, with a tender price range from C$11.00 to C$13.00 per Common Share. The SIB expired on August 8, 2022.

On August 11, 2022, the Company announced that, in accordance with the terms and conditions of the SIB, the Company took up for cancellation 5,416,666 Common Shares at a price of C$12.00 per Common Share, for a total cost of $51.1 million (funded by cash, representing an aggregate purchase price of C$65 million plus transaction costs). The Common Shares taken up for cancellation under the SIB represented approximately 5.84% of the total number of the Company's issued and outstanding Common Shares as of August 8, 2022.

6. RELATED-PARTY TRANSACTIONS

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

($M)		Accounts Receivable	Accounts Payable	Commitments	Three Months Ended September 30 Purchases / Services	Nine Months Ended September 30 Purchases / Services
ODL	2022	23,297	2,337	37,859	5,795	16,336
	2021	—	112	56,716	5,140	21,493

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 Annual 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 as the COVID-19 pandemic subsides, the Company may continue to experience materially adverse impacts to its business as a result of the pandemic's global economic impact, long-term implications and risk of resurgences. To the extent that the COVID-19 pandemic adversely affects the Company's business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described herein and 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 22 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 Annual 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 Annual 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 third 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 September 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 September 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 September 30, 2022 represented approximately 2% of the Company's total assets, and $15.1 million revenues were consolidated for the year ended September 30, 2022 (for further information refer to Note 4 of the Annual 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				
					Nine months ended September 30	
Producing blocks in Colombia		**Q3 2022**	**Q2 2022**	**Q3 2021**	**2022**	**2021**
Heavy crude oil	(bbl/d)	16,667	16,854	15,986	17,164	17,126
Light and medium crude oil	(bbl/d)	15,267	15,689	15,907	15,605	16,157
Conventional natural gas	(mcf/d)	9,966	10,374	5,033	9,958	5,141
Natural gas liquids	(boe/d)	911	967	211	947	331
Net production Colombia	**(boe/d)**	**34,593**	**35,330**	**32,987**	**35,463**	**34,516**
Producing blocks in Ecuador						
Light and medium crude oil	(bbl/d)	719	348	—	418	—
Net production Ecuador	**(bbl/d)**	**719**	**348**	**—**	**418**	**—**
Total net production	**(boe/d)**	**35,312**	**35,678**	**32,987**	**35,881**	**34,516**

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
Mbbl	Thousand of oil barrels	**$MM**	Million U.S. dollars
Mcf	Thousand cubic feet		