Exhibit 99.2

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the period ended March 31, 2022

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated April 26, 2022 should be read in conjunction with our March 31, 2022 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2021 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2021 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of April 26, 2022 unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The interim MD&As and the annual MD&A are reviewed by the Audit Committee and recommended for approval by the Cenovus Board of Directors ("the Board"). Additional information about Cenovus, including our annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, (which includes references to "dollar" or "$"), except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board. Production volumes are presented on a before royalties basis. Refer to the Abbreviations section for commonly used oil and gas terms.

OVERVIEW OF CENOVUS

We are a Canadian-based integrated energy company headquartered in Calgary, Alberta. Our common shares and common share purchase warrants (“Cenovus Warrants”) are listed on the Toronto Stock Exchange (“TSX”) and New York Stock Exchange. Our cumulative redeemable preferred shares series 1, 2, 3, 5 and 7 are listed on the TSX. We are the second largest Canadian-based crude oil and natural gas producer, with upstream operations in Canada and the Asia Pacific region, and the second largest Canadian-based refiner and upgrader, with downstream operations in Canada and the United States (“U.S.”). On January 1, 2021, Cenovus and Husky Energy Inc. (“Husky”) closed a transaction to combine the two companies through a plan of arrangement (the“Arrangement”).

Our upstream operations include oil sands projects in northern Alberta, thermal and conventional crude oil, natural gas and natural gas liquids (“NGLs”) projects across Western Canada, crude oil production offshore Newfoundland and Labrador and natural gas and NGLs production offshore China and Indonesia. Our downstream operations include upgrading and refining operations in Canada and the U.S., and retail operations across Canada.

Our operations involve activities across the full value chain to develop, produce, transport and market crude oil and natural gas in Canada and internationally. Our physically integrated upstream and downstream operations help us mitigate the impact of volatility in light-heavy crude oil differentials and contribute to our net earnings by capturing value from crude oil and natural gas production through to the sale of finished products such as transportation fuels.

During the three months ended March 31, 2022, crude oil production from our Oil Sands assets averaged 595.0 thousand barrels per day and total upstream production averaged 798.6 thousand barrels of oil equivalent (“BOE”) per day. Downstream crude oil throughput was 501.8 thousand barrels per day. Refer to the Operating and Financial Results section of this MD&A for a summary of production by product type.

Our Strategy

Our strategy is focused on delivering value over the long-term through sustainable, low-cost, diversified and integrated energy leadership. We aim to maximize shareholder value through competitive cost structures and optimizing margins, while delivering top-tier safety performance and Environment, Social and Governance (“ESG”) leadership. The Company prioritizes Free Funds Flow generation that enables debt reduction, shareholder returns through a combination of base dividend growth and flexible return mechanisms, reinvestment in the business and diversification.

On December 8, 2021, we announced our 2022 budget focused on our operational strength, capital discipline and ESG leadership. Free Funds Flow generation will be used to grow shareholder returns and further reduce debt. Our 2022 guidance, as updated on April 26, 2022, is available on our website at cenovus.com. For more details see the Operating and Financial Results section of this MD&A.

Updates to our Shareholder Return and Capital Allocation Frameworks

Maintaining a strong balance sheet with the resilience to withstand price volatility and capitalize on opportunities throughout the commodity cycle is a key element of Cenovus’s capital allocation framework. We have further defined our capital allocation framework to ensure we continue to strengthen our balance sheet, enable flexibility in both high and low commodity price environments and improve our shareholder value proposition.

We have set an ultimate Net Debt Target(1) of $4 billion, which will serve as a floor on Net Debt. When Net Debt is less than $9 billion and above $4 billion, we will target to allocate 50 percent of Excess Free Funds Flow to shareholder returns, while still continuing to deleverage the balance sheet until we reach the Net Debt Target of $4 billion. When Net Debt is above $9 billion, we would plan to allocate all Excess Free Funds Flow to deleveraging the balance sheet. When Net Debt is at the $4 billion floor, we will target to return 100 percent of Excess Free Funds Flow to shareholders through share buybacks and/or variable dividends.

Excess Free Funds Flow is defined as Free Funds Flow:

- Minus base dividends paid on common shares in the quarter.
- Minus dividends paid on preferred shares in the quarter.
- Minus other uses of cash, including decommissioning liabilities and principal repayment of leases, in the quarter.
- Minus any acquisition costs from acquisition activities closing in the quarter.
- Plus any proceeds from divestiture activities closing in the quarter.

The Company’s capital allocation framework will enable a shift to paying out a higher percentage of Excess Free Funds Flow to shareholders, with lower leverage and a lower risk profile. Our $4 billion Net Debt Target represents a Net Debt to Adjusted Funds Flow Ratio Target(1) of approximately 1.0 times at the bottom of the cycle.

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Based on the capital allocation framework described above, we plan to return incremental capital to shareholders beyond the base dividend as follows:

- When quarter-end Net Debt is less than $9 billion, we will target to deliver to shareholders 50 percent of that quarter's Excess Free Funds Flow, in the form of share buybacks and/or variable dividends.
- When quarter-end Net Debt is at the $4 billion floor, we will target to deliver to shareholders 100 percent of that quarter's Excess Free Funds Flow in the form of share buybacks and/or variable dividends.

Share buybacks will be our preferred mechanism, and will continue to be executed opportunistically, driven by return thresholds. Where the value of share buybacks in a quarter is less than the targeted value of returns, the remainder will be delivered through variable dividends paid in the following quarter. Where the value of share buybacks in a quarter is greater than the targeted value of returns, no variable dividend will be paid for that quarter.

Aligned with this, we have increased the annual base dividend to $0.42 per share and have plans to sustainably grow the base dividend over time.

Key Priorities for 2022

We aim to deliver on our strategy through five key strategic objectives:

Top Tier Safety Performance and ESG Leadership

Underpinning everything we do is the safety of our people and communities, and the integrity of our assets. We've identified safety and asset integrity, and corporate governance as foundational to our business, providing the backbone for all our operations. We will continue to promote a safety culture in all aspects of our work and use a variety of programs to always keep safety top of mind.

A path and program for achieving our targets representing our five ESG focus areas has been established, including identifying the levers and resources that will be required. Additional information on management's efforts and performance across ESG topics, including our ESG targets and plans to achieve them, are available in Cenovus's 2020 ESG report at cenovus.com.

Competitive Cost Structures and Optimizing Margins

We continue to target additional cost savings and margin enhancements through further physical integration of upstream assets with downstream assets, which is expected to shorten the value chain and reduce condensate costs associated with heavy oil transportation. We continue to look for ways to improve efficiencies across Cenovus to drive incremental capital, operating and general and administrative cost reductions.

Maintaining and Further Reducing Debt Levels

As at March 31, 2022, our long-term debt was $11.7 billion and our Net Debt(1) position was $8.4 billion. Our Net Debt to Adjusted EBITDA Ratio(1) was 0.8 times at March 31, 2022. Our Net Debt to Adjusted Funds Flow Ratio(1) was 1.0 times at March 31, 2022. Maintaining a strong balance sheet provides financial flexibility to manage the business through commodity price volatility.

Returns-focused Capital Allocation

The Company's capital program and increased base dividend are sustainable at US$45 WTI per barrel, and provide opportunities to sustainably grow shareholder returns. On April 26, 2022, our second quarter dividend tripled. The Company's Board of Directors declared a second quarter dividend of $0.105 per common share, payable on June 30, 2022, for common shareholders of record as at June 15, 2022.

In 2022, we anticipate our total capital expenditures to be between $2.9 billion and $3.3 billion, including $500 million to $550 million (excluding insurance proceeds) for the Superior Refinery rebuild. We will continue to be disciplined with our capital.

Growing Free Funds Flow Through Pricing Cycles

Our top-tier assets and low cost structure position us to grow Free Funds Flow through pricing cycles. Cenovus's diversified asset and product mix generates predictable and stable Free Funds Flow, and reduces risk and cash flow volatility by leveraging pipelines, logistics and marketing to optimize the value chain. We are able to generate strong margins with modest capital investment.

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Cenovus has a track record of operational reliability. We expect our annual upstream production to average between 760 thousand BOE per day and 800 thousand BOE per day and total downstream crude throughput to average between 530 thousand barrels per day to 580 thousand barrels per day in 2022. We continue to monitor the overall market dynamics to assess how we manage our upstream production levels. Our assets can respond to market signals and ramp production up or down accordingly. Our decisions around production levels and refinery crude run rates will be focused on maximizing the value we receive for our products.

Our Operations

The Company operates through the following reportable segments:

Upstream Segments

- **Oil Sands,** includes the development and production of bitumen and heavy oil in northern Alberta and Saskatchewan. Cenovus's oil sands assets include Foster Creek, Christina Lake, Sunrise (jointly owned with BP Canada Energy Group ULC ("BP Canada") and operated by Cenovus), as well as the Lloydminster thermal and Lloydminster conventional heavy oil assets. Cenovus jointly owns and operates pipeline gathering systems and terminals through the equity-accounted investment in Husky Midstream Limited Partnership ("HMLP"). The sale and transportation of Cenovus's production and third-party commodity trading volumes are managed and marketed through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S. to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Conventional,** includes assets rich in NGLs and natural gas within the Elmworth-Wapiti, Kaybob-Edson, Clearwater and Rainbow Lake operating areas in Alberta and British Columbia and interests in numerous natural gas processing facilities. Cenovus's NGLs and natural gas production is marketed and transported with additional third-party commodity trading volumes through access to capacity on third-party pipelines, export terminals and storage facilities, which provides flexibility for market access to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Offshore,** includes offshore operations, exploration and development activities in China and the east coast of Canada, as well as the equity-accounted investment in the Husky-CNOOC Madura Ltd. ("HCML") joint venture in Indonesia.

Downstream Segments

- **Canadian Manufacturing,** includes the owned and operated Lloydminster upgrading and asphalt refining complex which upgrades heavy oil and bitumen into synthetic crude oil, diesel fuel, asphalt and other ancillary products. Cenovus seeks to maximize the value per barrel from its heavy oil and bitumen production through its integrated network of assets. In addition, Cenovus owns and operates the Bruderheim crude-by-rail terminal and two ethanol plants. Cenovus also markets its production and third-party commodity trading volumes of synthetic crude oil, asphalt and ancillary products.
- **U.S. Manufacturing,** includes the refining of crude oil to produce gasoline, diesel, jet fuel, asphalt and other products at the wholly-owned Lima Refinery and Superior Refinery, the jointly-owned Wood River and Borger refineries (jointly owned with operator Phillips 66) and the jointly-owned Toledo Refinery (jointly owned with operator BP Products North America Inc. ("BP")). Cenovus also markets some of its own and third-party volumes of refined petroleum products including gasoline, diesel and jet fuel.
- **Retail,** includes the sale of Cenovus's own and third-party volumes of refined petroleum products, including gasoline and diesel, through retail, commercial and bulk petroleum outlets, as well as wholesale channels in Canada.

Corporate and Eliminations

Corporate and Eliminations primarily includes Cenovus-wide costs for general and administrative, financing activities, gains and losses on risk management for corporate related derivative instruments and foreign exchange. Eliminations include adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Company's crude-by-rail terminal, crude oil production used as feedstock by the Canadian Manufacturing and U.S. Manufacturing segments, and diesel production in the Canadian Manufacturing segment sold to the Retail segment. Eliminations are recorded based on current market prices.

QUARTERLY RESULTS OVERVIEW

During the first quarter of 2022, commodity prices reached the highest levels since 2014. Strong operational performance of our integrated asset base, combined with our continued focus on health and safety and competitive cost structures, drove solid financial results. Our total upstream production was nearly 800 thousand BOE per day and Adjusted Funds Flow increased 33 percent compared with the fourth quarter of 2021. We reduced our Net Debt from December 31, 2021 by $1.2 billion, paid our common share dividend and continued purchasing shares through our normal course issuer bid ("NCIB"). In addition, we closed previously announced asset dispositions resulting in net proceeds of approximately $950 million.

Summary of Quarterly Results

	2022	2021				2020			
($ millions, except where indicated)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production Volumes [1] (MBOE/d)	**798.6**	825.3	804.8	765.9	769.3	467.2	471.8	465.4	482.6
Crude Throughput [2] (Mbbls/d)	**501.8**	469.9	554.1	539.0	469.1	169.0	191.1	162.3	221.1
Revenues [3]	**16,198**	13,726	12,701	10,637	9,293	3,543	3,737	2,311	3,952
Operating Margin [4]	**3,464**	2,600	2,710	2,184	1,879	625	594	291	(589)
Cash From (Used in) Operating Activities	**1,365**	2,184	2,138	1,369	228	250	732	(834)	125
Adjusted Funds Flow [4]	**2,583**	1,948	2,342	1,817	1,141	333	407	(469)	(154)
Capital Investment	**746**	835	647	534	547	242	148	147	304
Free Funds Flow [4]	**1,837**	1,113	1,695	1,283	594	91	259	(616)	(458)
Net Earnings (Loss) [5]	**1,625**	(408)	551	224	220	(153)	(194)	(235)	(1,797)
Per Share - basic ($)	**0.81**	(0.21)	0.27	0.11	0.10	(0.12)	(0.16)	(0.19)	(1.46)
Per Share - diluted ($)	**0.79**	(0.21)	0.27	0.11	0.10	(0.12)	(0.16)	(0.19)	(1.46)
Total Assets	**55,655**	54,104	54,594	53,384	53,378	32,770	32,857	33,919	33,396
Total Long-Term Liabilities [4]	**21,889**	23,191	22,929	22,972	24,266	13,704	13,889	14,448	13,327
Long-Term Debt, Including Current Portion [6]	**11,744**	12,385	12,986	13,380	13,947	7,441	7,797	8,085	6,979
Net Debt [7]	**8,407**	9,591	11,024	12,390	13,340	7,184	7,530	8,232	7,421
Cash Dividends									
Common Shares	**69**	70	35	36	35	—	—	—	77
Per Common Share ($)	**0.0350**	0.0350	0.0175	0.0175	—	—	—	—	0.0625
Preferred Shares	**9**	8	9	8	9	—	—	—	—

(1) Refer to the Operating and Financial Results section of this MD&A for a summary of total upstream production by product type.
(2) Represents Cenovus's net interest in refining operations.
(3) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.
(4) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(5) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.
(6) Includes current portion of long-term debt of $nil as at March 31, 2022, $545 million as at September 30, 2021 and $632 million as at June 30, 2021 (December 31, 2021, March 31, 2021, December 31, 2020, September 30, 2020, June 30, 2020 and March 31, 2020 – $nil).
(7) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operationally, many items under Management's control performed very well:

- We delivered safe operations.
- Upstream production averaged 798.6 thousand BOE per day in the first quarter, an increase of 29.3 thousand BOE per day compared with the first quarter of 2021. See the Operating and Financial Results section of this MD&A for a summary of upstream production by product type.
- We achieved record high single-day natural gas production in China.

Despite operational challenges in our U.S. Manufacturing segment, downstream crude throughput averaged 501.8 thousand barrels per day in the first quarter, an increase of 32.7 thousand barrels per day compared with the first quarter of 2021.

We generated revenue of $16.2 billion and cash from operating activities of $1.4 billion. Adjusted Funds Flow was $2.6 billion and capital investment was $746 million, resulting in Free Funds Flow of $1.8 billion. Operating Margin was $3.5 billion in the first quarter of 2022 compared with $1.9 billion in the first quarter of 2021, primarily due to increased revenue from higher average realized crude oil, NGLs and natural gas sales prices, higher market crack spreads and higher sales volumes.

We continued to strengthen our balance sheet:

- On February 9, 2022, we completed additional deleveraging by purchasing the remaining US$384 million in principal of outstanding notes due in 2023 and 2024.
- Our long-term debt decreased by $641 million as a result of the purchase discussed above, combined with the appreciation of the Canadian dollar in relation to the US dollar.
- Our Net Debt decreased by $1.2 billion as compared to December 31, 2021.

On April 4, 2022, we announced the suspension of our crude oil sales price risk management activities related to WTI. Given the strength of our balance sheet and liquidity position, we determined that these programs are no longer required to support financial resilience. The WTI contracts impacted by this announcement will be closed by June 30, 2022. For further details, see Notes 26 and 27 to the interim Consolidated Financial Statements.

We closed previously announced asset sales:

- On January 31, 2022, we sold our Tucker asset in the Oil Sands segment for net proceeds of $730 million.
- On February 28, 2022, we sold our Wembley assets in the Conventional segment for net proceeds of $220 million.

In the first quarter of 2022, we incurred $26 million of Total Integration Costs[(1)] (2021 – $245 million), of the $100 million to $150 million expected as integration work continues throughout the year.

We demonstrated our commitment to returning cash to shareholders:

- On April 26, 2022, our Board of Directors declared a second quarter dividend of $0.105 per common share, payable on June 30, 2022 to common shareholders of record as at June 15, 2022. This is an increase of $0.07 per common share compared with our dividends declared and paid in the first quarter of 2022.
- On April 27, 2022, we announced a revised framework to return incremental cash to shareholders through continued share repurchases and/or the use of a variable dividend mechanism.
- In November 2021, we commenced a NCIB for the purchase of up to 146.5 million of the Company's common shares until November 8, 2022. In the first quarter of 2022, Cenovus purchased and cancelled 25 million common shares for $466 million. From April 1, 2022 to April 26, 2022, Cenovus purchased an additional 16 million common shares for $354 million. Cenovus has purchased 58 million common shares for $1.1 billion since the commencement of the NCIB to April 26, 2022.
- We paid our dividend of $0.035 per common share for the first quarter.

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results — Upstream

	Three Months Ended March 31,		
	2022	Percent Change	2021
Upstream Production Volumes by Segment [1] (MBOE/d)			
Oil Sands	**597.0**	**7**	555.6
Conventional	**125.2**	**(8)**	135.9
Offshore	**76.4**	**(2)**	77.8
Total Production Volumes	**798.6**	**4**	769.3
Upstream Production Volumes by Product			
Bitumen (Mbbls/d)	**578.8**	**9**	532.9
Heavy Crude Oil (Mbbls/d)	**16.2**	**(21)**	20.5
Light Crude Oil (Mbbls/d)	**21.9**	**(14)**	25.6
NGLs (Mbbls/d)	**37.6**	**(9)**	41.1
Conventional Natural Gas (MMcf/d)	**865.3**	**(3)**	894.9
Total Production Volumes (MBOE/d)	**798.6**	**4**	769.3
Total Upstream Sales Volumes [2] (MBOE/d)	**724.5**	**6**	685.9
Netback [3] ($/BOE)	**58.74**	**87**	31.36

(1) Refer to the Oil Sands, Conventional or Offshore Operating Results section of this MD&A for a summary of production by product type.
(2) Total upstream sales volumes exclude natural gas volumes used for internal consumption by the Oil Sands segment of 527 MMcf per day for the three months ended March 31, 2022 (519 MMcf per day for the three months ended March 31, 2021).
(3) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

In the first quarter, our upstream assets performed well. Total production increased 29.3 thousand barrels per day compared with 2021, primarily due to new wells coming online in the second half of 2021 at Foster Creek and Christina Lake. The increase was partially offset by the dispositions of the Tucker asset on January 31, 2022 and the Wembley asset on February 28, 2022, as well as divestitures of other assets in the Conventional segment in the second half of 2021.

Selected Operating Results — Downstream

	Three Months Ended March 31,		
	2022	Percent Change	2021
Downstream Manufacturing Crude Throughput (Mbbls/d)			
Canadian Manufacturing	**98.1**	**(8)**	106.2
U.S. Manufacturing	**403.7**	**11**	362.9
Total Throughput	**501.8**	**7**	469.1
Retail [1] (millions of litres/d)			
Fuel sales, including wholesale	**6.6**	**2**	6.5

(1) On November 30, 2021, Cenovus announced agreements to sell 337 gas stations within our retail fuels network for total cash proceeds of $420 million before closing adjustments. The sales are expected to close in mid-2022. We are retaining our commercial fuels business, which includes 167 cardlock, bulkplant and travel centre locations.

In the Canadian Manufacturing segment, crude throughput decreased 8.1 thousand barrels per day. At the Lloydminster Upgrader, we had temporary unplanned maintenance outages during the quarter, and we reduced rates at the end of March as we prepared for planned maintenance, which started in early April, 2022. The Lloydminster Refinery ran at or near capacity throughout the first quarter of 2022.

In the U.S. Manufacturing segment, crude throughput increased 40.8 thousand barrels per day compared with 2021, primarily due to improved market conditions, partially offset by unplanned outages and planned turnarounds in the first quarter of 2022 having a greater negative impact on crude throughput than those in the first quarter of 2021.

In March, we commenced turnarounds at the Wood River and Borger refineries. Early in the quarter, we operated the Lima and Wood River refineries at reduced rates to optimize margins when market crack spreads were low. At the Lima Refinery, we encountered an unplanned equipment outage after completing a turnaround in the fourth quarter of 2021 that was resolved towards the end of January, as well as other temporary unplanned outages during the quarter. In addition, we had temporary unplanned outages at the Toledo Refinery during the quarter.

Selected Consolidated Financial Results

Operating Margin

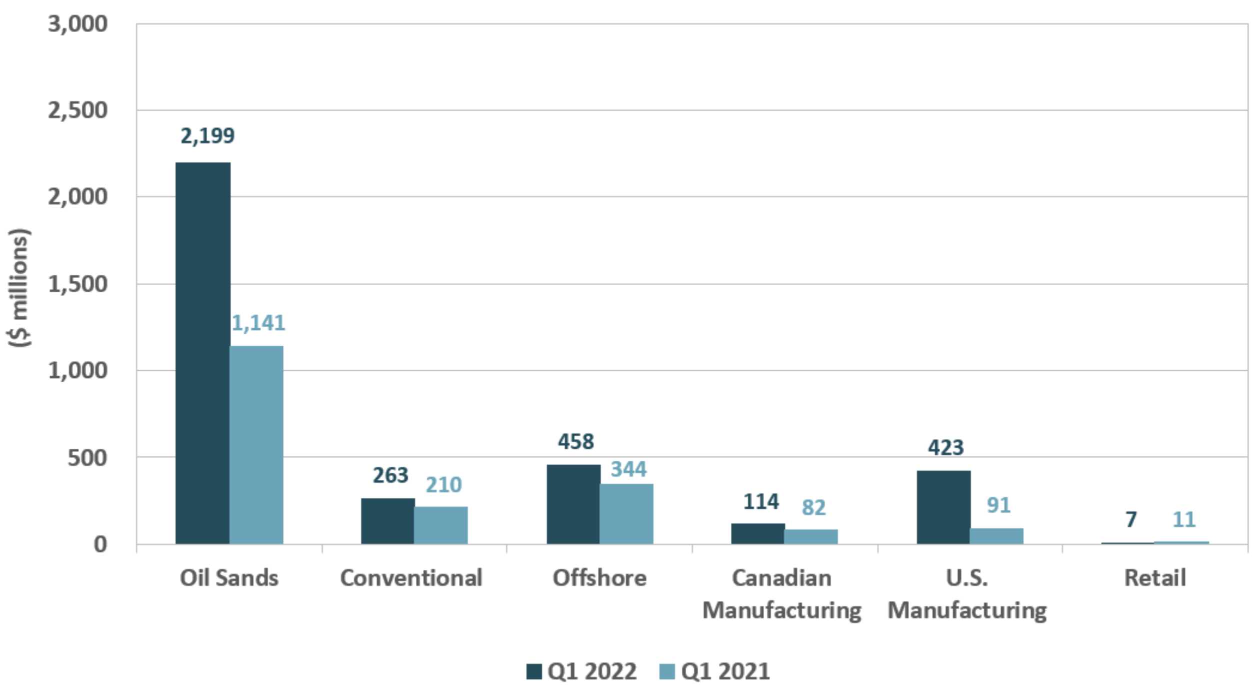
Operating Margin is a non-GAAP financial measure and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods.

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Gross Sales [(1)]	**19,144**	10,815
Less: Royalties	**1,185**	373
Revenues	**17,959**	10,442
Expenses		
Purchased Product [(1)]	**9,035**	5,210
Transportation and Blending	**2,925**	1,800
Operating Expenses	**1,554**	1,302
Realized (Gain) Loss on Risk Management Activities	**981**	251
Operating Margin [(2)]	**3,464**	1,879

(1) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.
(2) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operating Margin by Segment

Three Months Ended March 31, 2022



Operating Margin increased in 2022, primarily due to:

- Higher average crude oil, NGLs and natural gas sales prices resulting from higher benchmark pricing.
- Increased upstream and refined products sales volumes.
- Higher refining margins from our downstream business.

These increases in Operating Margin were partially offset by:

- Increased blending costs due to higher condensate prices and volumes.
- Increased royalties and fuel costs, both impacted by significantly higher benchmark pricing.
- Higher realized risk management losses on the settlement of benchmark prices relative to our risk management contract prices.
- Planned and unplanned outages in our downstream operations.
- Increased Renewable Identification Numbers ("RINs") costs impacting our U.S. Manufacturing segment.

Cash From (Used in) Operating Activities and Adjusted Funds Flow

Adjusted Funds Flow is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations.

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Cash From (Used in) Operating Activities	**1,365**	228
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(19)**	(11)
Net Change in Non-Cash Working Capital	**(1,199)**	(902)
Adjusted Funds Flow [(1)]	**2,583**	1,141

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Cash From Operating Activities and Adjusted Funds Flow were higher in 2022 due to increased Operating Margin, as discussed above. In addition, we incurred integration costs of $24 million, compared with $223 million in 2021. The increases were partially offset by the quarterly settlement of the contingent payment of $160 million.

The change in non-cash working capital in 2022 was primarily due to an increase in inventories and accounts receivable, partially offset by an increase in accounts payable on March 31, 2022, compared with December 31, 2021 primarily due to higher crude oil and refined product pricing. In March 2022, WTI averaged US$108.26 per barrel, compared with the December 2021 average of US$71.69 per barrel. Chicago regular unleaded gasoline ("RUL") averaged US$129.92 per barrel in March 2022, compared with US$83.78 per barrel in December 2021.

Net Earnings (Loss)

($ millions)	
Net Earnings (Loss) for the Three Months Ended March 31, 2021	**220**
Increase (Decrease) due to:	
Operating Margin	**1,585**
Corporate and Eliminations:	
Re-measurement of Contingent Payment	**(49)**
Integration Costs	**199**
General and Administrative	**(36)**
Finance Costs	**15**
Gain (loss) on divestiture of assets	**230**
Other income (loss), net	**298**
Other [(1)]	**52**
Unrealized Risk Management Gain (Loss) [(2)]	**(425)**
Depreciation, Depletion and Amortization	**15**
Exploration Expense	**(10)**
Income Tax Recovery (Expense)	**(469)**
Net Earnings (Loss) for the Three Months Ended March 31, 2022	**1,625**

(1) Includes interest income, realized foreign exchange (gains) losses, share of income (loss) from equity-accounted affiliates, and Corporate and Eliminations revenues, purchased product, transportation and blending, operating expenses and (gain) loss on risk management.

(2) On April 4, 2022, Cenovus announced the suspension of its crude oil sales price risk management activities related to WTI. For the three months ended March 31, 2022, the unrealized risk management loss related to the WTI contracts impacted by this announcement was $370 million.

Net earnings in 2022 improved compared with 2021 due to:

- Increased Operating Margin, as discussed above.
- Gains on divestiture of assets of $242 million in 2022, primarily related to the Tucker and Wembley dispositions.
- Higher other income due to insurance proceeds related to the Superior Refinery and a 2018 incident in the Atlantic region.
- Integration costs of $24 million, compared with $223 million in 2021.

The increase was partially offset by:

- Unrealized risk management losses of $293 million, compared with gains of $132 million in 2021.
- Higher income tax expense.
- A loss on re-measurement of contingent payment of $236 million (2021 – $187 million).

Net Debt

As at ($ millions)	**March 31, 2022**	December 31, 2021
Short-Term Borrowings	**62**	79
Current Portion of Long-Term Debt	**—**	—
Long-Term Debt	**11,744**	12,385
Total Debt (1)	**11,806**	12,464
Less: Cash and Cash Equivalents	**(3,399)**	(2,873)
Net Debt (2)	**8,407**	9,591

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

In the first quarter of 2022, long-term debt decreased by $641 million and Net Debt decreased by $1.2 billion. The reduction in long-term debt was due to the purchase of the remaining US$384 million in principal of outstanding notes due in 2023 and 2024, combined with the appreciation of the Canadian dollar in relation to the US dollar.

Capital Investment (1)

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Upstream		
Oil Sands	**375**	218
Conventional	**88**	66
Offshore	**53**	26
	516	310
Downstream		
Canadian Manufacturing	**14**	4
U.S. Manufacturing	**207**	205
Retail	**1**	1
	222	210
Corporate and Eliminations	**8**	27
Capital Investment	**746**	547

(1) Includes expenditures on PP&E and E&E assets.

Oil Sands capital investment in the first quarter of 2022 was primarily focused on sustaining activities at Christina Lake, Foster Creek and the Lloydminster thermal assets, and the drilling of stratigraphic test wells as part of our integrated winter program.

Conventional capital investment focused on sustaining drilling, completion and tie-in programs.

Offshore capital investment in 2021 was primarily for the Terra Nova asset life extension (“ALE”) project and preservation capital for the West White Rose project in the Atlantic region. Major construction on the West White Rose project was suspended in March of 2020 and the project remains under review while we evaluate options with our partners.

U.S. Manufacturing capital investment focused primarily on the Superior Refinery rebuild, combined with refining reliability and maintenance at the Wood River, Borger and Toledo refineries.

Drilling Activity

(net wells, unless otherwise stated)	Stratigraphic Test Wells and Observation Wells — Three Month Ended March 31, 2022	2021	Production Wells (1) — 2022	2021
Foster Creek	**52**	17	**5**	—
Christina Lake (2)	**—**	25	**8**	8
Sunrise	**15**	—	**2**	—
Lloydminster Thermal	**1**	—	**19**	13
Tucker	**6**	—	**—**	—
Lloydminster Conventional Heavy Oil	**—**	—	**—**	2
Other (3)	**16**	15	**—**	—
	90	57	**34**	23

(1) *Steam-assisted gravity drainage ("SAGD") well pairs in the Oil Sands segment are counted as a single producing well.*
(2) *Includes Narrows Lake.*
(3) *Includes new resource plays.*

Stratigraphic test wells were drilled to help identify well pad locations for sustaining wells and to further progress the evaluation of other assets. Observation wells were drilled to gather information and monitor reservoir conditions.

	Three Months Ended March 31, 2022			Three Months Ended March 31, 2021		
(net wells, unless otherwise stated)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional	**13**	**20**	**20**	9	8	9

In the Offshore segment, we drilled and completed two (0.8 net) planned development wells in Indonesia in the first quarter of 2022 (2021 — no wells drilled, completed or tied-in).

Future Capital Investment

Future Capital Investment is a specified financial measure. See the Specified Financial Measures Advisory of this MD&A. Our 2022 guidance as updated on April 26, 2022, is available on our website at cenovus.com.

Our updated guidance reflects:

- Increased capital investment for the Superior Refinery rebuild project.
- Decreased Oil Sands production to reflect closing the sale of the Tucker asset on January 31, 2022.
- Increased unit operating expenses largely due to higher natural gas prices.

The following table shows guidance for 2022:

	Future Capital Investment ($ millions)	**Production** (MBOE/d)	**Throughput** (Mbbls/d)
Upstream			
Oil Sands	**1,350 - 1,550**	**552 - 609**	
Conventional	**150 - 200**	**118 - 134**	
Offshore	**200 - 250**	**64 - 76**	
Downstream (1)	**1,150 - 1,250**		**530 - 580**
Corporate and Eliminations	**50 - 70**		

(1) *Future Capital Investment includes between $500 million and $550 million for the Superior Refinery rebuild project.*

In 2022, we plan to focus our Future Capital Investment on:

- Sustaining production in the Oil Sands segment.
- Sustaining drilling programs in the Conventional segment.
- The Superior Refinery rebuild project.
- The Terra Nova ALE project and preservation capital for the West White Rose project in the Offshore segment.
- Refining operations and reliability in our downstream segments and a debottlenecking project at the Lloydminster Refinery to increase throughput capacity.

Further information on the changes in our financial and operating results can be found in the Reportable Segments section of this MD&A. Information on our risk management activities can be found in the Risk Management and Risk Factors section of this MD&A and in the notes to the interim Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Key performance drivers for our financial results include commodity prices, quality and location price differentials, refining crack spreads as well as the U.S./Canadian dollar and Chinese Yuan ("RMB")/Canadian dollar exchange rates. The following table shows selected market benchmark prices and average exchange rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates (1)

(Average US$/bbl, unless otherwise indicated)	Q1 2022	Percent Change	Q1 2021	Q4 2021
Dated Brent	**101.41**	**67**	60.90	79.73
WTI	**94.29**	**63**	57.84	77.19
Differential Brent-WTI	**7.12**	**133**	3.06	2.54
WCS at Hardisty	**79.76**	**76**	45.37	62.55
Differential WTI-WCS	**14.53**	**17**	12.47	14.64
WCS (C$/bbl)	**101.01**	**76**	57.44	78.71
WCS at Nederland	**89.19**	**59**	55.93	71.62
Differential WTI-WCS at Nederland	**5.10**	**167**	1.91	5.57
Condensate (C5 @ Edmonton)	**96.09**	**66**	58.04	79.13
Differential WTI-Condensate (Premium)/Discount	**(1.80)**	**(800)**	(0.20)	(1.94)
Differential WCS-Condensate (Premium)/Discount	**(16.33)**	**(29)**	(12.67)	(16.58)
Average (C$/bbl)	**121.69**	**66**	73.49	99.64
Synthetic @ Edmonton	**93.05**	**71**	54.32	75.40
WTI-Synthetic (Premium)/Discount Differential	**1.24**	**(65)**	3.52	1.79
Refined Product Prices				
Chicago Regular Unleaded Gasoline ("RUL")	**109.16**	**57**	69.51	91.84
Chicago Ultra-low Sulphur Diesel ("ULSD")	**119.60**	**63**	73.28	96.53
Refining Benchmarks				
Chicago 3-2-1 Crack Spread (2)	**18.35**	**42**	12.93	16.06
Group 3 3-2-1 Crack Spread (2)	**19.94**	**27**	15.67	15.82
RINs	**6.44**	**17**	5.49	6.11
Natural Gas Prices				
AECO (C$/Mcf)	**4.59**	**57**	2.92	4.94
NYMEX (US$/Mcf)	**4.95**	**84**	2.69	5.83
Foreign Exchange Rate				
US$ per C$1 - Average	**0.790**	**—**	0.790	0.794
US$ per C$1 - End of Period	**0.800**	**1**	0.795	0.789
RMB per C$1 - Average	**5.014**	**(2)**	5.120	5.073

(1) These benchmark prices are not our realized sales prices and represent approximate values. For our average realized sales prices and realized risk management results, refer to the Netback tables in the Reportable Segments section of this MD&A.
(2) The average 3-2-1 crack spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.

Crude Oil and Condensate Benchmarks

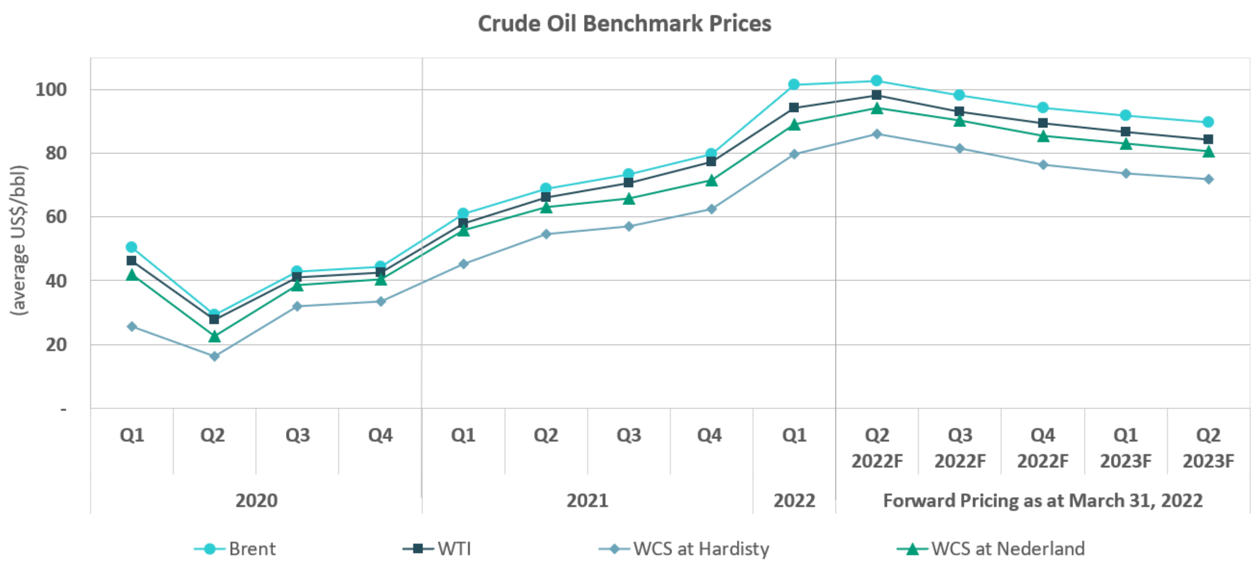
In the first quarter of 2022, Brent and WTI crude oil benchmarks increased significantly compared with both the first and fourth quarters of 2021, generally due to very tight global supply and demand balance. Benchmarks were volatile during the quarter, with WTI ranging from a low of approximately US$76 per barrel and reaching a high of US$124 per barrel following the Russian invasion of Ukraine. The market's reaction is driven primarily by concern about a potential material disruption in Russian exports related to sanctions, which exacerbated previous tight global supply and demand balance, low crude oil spare capacity and other unplanned global supply outages in the first quarter. Further, the Organization of Petroleum Exporting Countries ("OPEC") and a group of 10 non-OPEC members (collectively, "OPEC+") continue to only gradually increase production quotas that began in the second quarter of 2021.

The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent. WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and the Canadian dollar equivalent is the basis for determining royalty rates for a number of our crude oil properties. In the first quarter of 2022, the Brent-WTI differential widened compared with 2021 due to higher fuel costs and supply disruptions as a result of the Russian invasion of Ukraine.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. In the first three months of 2022, the average WTI-WCS differential remained narrow compared to the fourth quarter of 2021 and widened slightly compared to the first quarter of 2021. Startup of the Enbridge Line 3 Replacement in the fourth quarter of 2021 provided incremental takeaway capacity from the Western Canadian Sedimentary Basin ("WCSB"). Unplanned outages in the WCSB and low storage levels also benefitted the WCS differential in the first quarter of 2022.

WCS at Nederland is a heavy oil benchmark at the U.S. Gulf Coast ("USGC") which is representative of pricing for our sales in the USGC. WCS at Nederland prices were strong in the first quarter of 2022 compared to 2021 consistent with increasing crude oil prices globally, as refiners increased crude runs to adjust to increased demand for products. The WTI-WCS at Nederland differential widened in the first quarter of 2022 compared with the first quarter of 2021, mainly attributed to high coking utilization in the USGC, planned and unplanned refinery maintenance, and the gradual return of some OPEC+ medium and heavy oil barrels into the market.

We upgrade heavy crude oil and bitumen into a sweet synthetic crude oil, the Husky Synthetic Blend ("HSB"), at the Lloydminster Upgrader. The price realized for HSB is primarily driven by the price of WTI and by the supply and demand of sweet synthetic crude oil from Western Canada, which influences the WTI-Synthetic differential.



Blending condensate with bitumen enables our production to be transported through pipelines. Our blending ratios, calculated as diluent volumes as a percentage of total blended volumes, range from approximately 25 percent to 35 percent. The WCS-Condensate differential is an important benchmark as a wider differential generally results in a decrease in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by USGC condensate prices plus the cost to transport the condensate to Edmonton. Our blending costs are also impacted by the timing of purchases and deliveries of condensate into inventory to be available for use in blending as well as timing of sales of blended product.

Average Edmonton condensate benchmark prices were at a slight premium relative to WTI in the first quarter of 2022. The differential remained narrow as a result of continued high oil sands production leading to increased blending requirements.

Refining Benchmarks

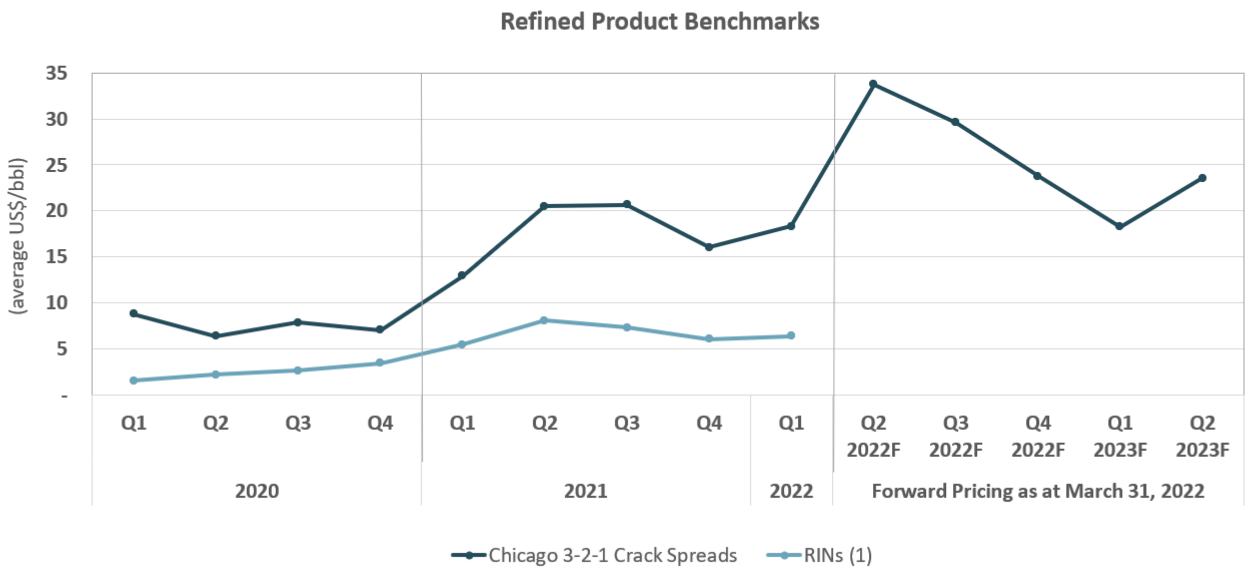
RUL and ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI-based crude oil feedstock prices and valued on a last in, first out accounting basis.

The Chicago 3-2-1 market crack spread reflects the market for our Toledo, Lima and Wood River refineries. The Group 3, 3-2-1 market crack spread, reflects the market for our Borger Refinery.

Average Chicago refined product prices increased in the first quarter of 2022 compared with both the fourth and first quarters of 2021. The strength in crack spreads and refined product prices is driven by a tight distillate market and healthy gasoline and jet fuel demand as restrictions are lifted. Russian sanctions came at a time when the market is already strained because of refinery rationalization. In March 2022, Chicago 3-2-1 market crack spreads averaged almost US$27 per barrel, compared with the quarterly average of US$18.35 per barrel. Global distillate stocks are at critically low levels and reduced clean product supplies from Russia prompted crack spreads to spike in the near term. RINs remain high as a result of a tight biofuel market, rising feedstock prices and uncertainty around policies that drive RINs demand.

As North American refining crack spreads are expressed on a WTI basis, while refined products are generally set by global prices, the strength of refining market crack spreads in the U.S. Midwest and Midcontinent will reflect the differential between Brent and WTI benchmark prices.

Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock; refinery configuration and product output; the time lag between the purchase and delivery of crude oil feedstock; and the cost of feedstock, which is valued on a first in, first out ("FIFO") accounting basis.



(1) There are no forward prices for RINs.

Natural Gas Benchmarks

Average NYMEX natural gas prices increased significantly in the first quarter of 2022, compared to the first quarter of 2021, due to a rebound in U.S. domestic demand and record high liquified natural gas exports, coupled with a muted supply response and strong global pricing. Average AECO prices improved alongside the NYMEX benchmark. The differential between AECO and NYMEX widened compared with the first quarter of 2021 due to increased supply in Western Canada. The price received for our Asia Pacific natural gas production is largely based on long-term contracts.

Foreign Exchange Benchmarks

A substantial amount of our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, NGLs, natural gas and refined products are determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar compared with the U.S. dollar has a negative impact on our reported revenue. In addition to our revenues being denominated in U.S. dollars, a significant portion of our long-term debt is also U.S. dollar denominated. As the Canadian dollar weakens, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars. In addition, changes in foreign exchange rates impact the translation of U.S. and Asia Pacific operations.

In the first quarter of 2022, the Canadian dollar on average was flat relative to the U.S. dollar compared with 2021, resulting in minimal impact on our revenues quarter-over-quarter. The Canadian dollar strengthened relative to the U.S. dollar as at March 31, 2022 compared with December 31, 2021, resulting in unrealized foreign exchange gains on the translation of U.S. dollar debt.

A portion of our long-term sales contracts in Asia Pacific are priced in RMB. An increase in the value of the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region. In the first quarter of 2022, the Canadian dollar on average was relatively flat compared with RMB, resulting in minimal impact on our revenues quarter-over-quarter.

COMMODITY PRICE OUTLOOK

Energy markets remain volatile, starting the year quite strong and significantly improved compared with 2021. Successful global COVID-19 vaccine rollouts, loosening of restrictions and solid economic growth have resulted in demand growth for crude oil and refined products, while generally the supply response has lagged due to a combination of producer discipline, OPEC+ policy and unplanned outages. The market is pricing in potential disruption in Russian supply which could result in continued demand surplus and will necessitate rebalancing of trade flows.

The market faces a highly uncertain future as the Russia-Ukraine conflict develops. We expect the general outlook for crude oil and refined product prices will be volatile and impacted by the duration and severity of the conflict, the extent to which Russian exports are reduced by sanctions, the timing and ability of producers and governments to replace reduced supply, and OPEC+ policy. Potential incremental COVID-19 outbreaks and variants remain a risk to the pace of demand growth.

In addition to the above, our commodity pricing outlook for the next 12 months is influenced by the following:

- We expect that the WTI-WCS differential in Alberta will remain largely tied to the extent supply stays within export capacity, the completion of the Trans Mountain Expansion project and the level of crude-by-rail activity. Upcoming planned oil sands maintenance in the WCSB is expected to keep supply within export capacity into the summer months of 2022.
- The ability and willingness of OPEC and OPEC+ to greatly increase production remains uncertain.
- Crack spreads will remain volatile as Russia is a significant exporter of refined products. Sanctions will reduce supply and result in redirection of global trade flows. Economic effects of the conflict could impact demand. Refining market crack spreads are likely to continue to fluctuate, adjusting for seasonal trends and refinery utilization in North America.
- We expect both Henry Hub and AECO prices to remain strong. Current fundamentals suggest a tight market will persist, but this could be offset by increased associated gas production as well as fuel switching amid high prices. Prices will continue to be impacted by weather.
- We expect the Canadian dollar to continue to be impacted by crude oil prices, the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise or lower benchmark lending rates relative to each other and emerging macro-economic factors.

Our upstream crude oil production and most of our downstream refined products are exposed to movements in the WTI crude oil price. Natural gas and NGLs production associated with our Conventional assets provide improved upstream integration for the fuel, solvent and blending requirements at our Oil Sands operations.

Our refining capacity is focused in the U.S. Midwest along with smaller exposures in the USGC and Alberta, exposing Cenovus to the market crack spread in all of these markets. We will continue to monitor market fundamentals and optimize run rates at our refineries accordingly.

Our WTI exposure to crude differentials includes light-heavy and light-medium price differentials. Light-medium price differential exposure is focused on light-medium crudes in the U.S. Midwest market region where we have refining capacity, and to a lesser degree in the USGC and Alberta. Our exposure to light-heavy crude oil price differentials is composed of a global light-heavy component, a regional component in markets we transport barrels to, as well as the Alberta differentials, which are subject to transportation constraints. While we expect to see volatility in crude oil prices, we have the ability to partially mitigate the impact of crude oil and refined product prices and differentials through the following:

- Transportation commitments and arrangements – using our existing firm service commitments for takeaway capacity and supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets.
- Integration – having heavy oil refining capacity capable of processing Canadian heavy oil. From a value perspective, our refining business positions us to capture value from both the WTI-WCS differential for Canadian crude oil as well as from spreads on refined products.
- Dynamic storage – our ability to use the significant storage capacity in our oil sands reservoirs provides us flexibility on timing of production and sales of our inventory. We will continue to manage our production rates in response to pipeline capacity constraints, voluntary and mandated production curtailments and crude oil price differentials.
- Traditional crude oil storage tanks in various geographic locations.

On April 4, 2022, we announced the suspension of our crude oil sales price risk management activities related to WTI. Given the strength of our balance sheet and liquidity position, we determined that these programs are no longer required to support financial resilience. The WTI contracts impacted by this announcement will be closed by June 30, 2022. We intend to continue to use financial instruments to mitigate our exposure to the prices of various commodities, including some WTI for exposure management unrelated to crude oil sales price risk management; and products, including associated price differentials and refining margins. For further details, see Notes 26 and 27 to the interim Consolidated Financial Statements).

REPORTABLE SEGMENTS

UPSTREAM

OIL SANDS

In the first quarter of 2022, we:

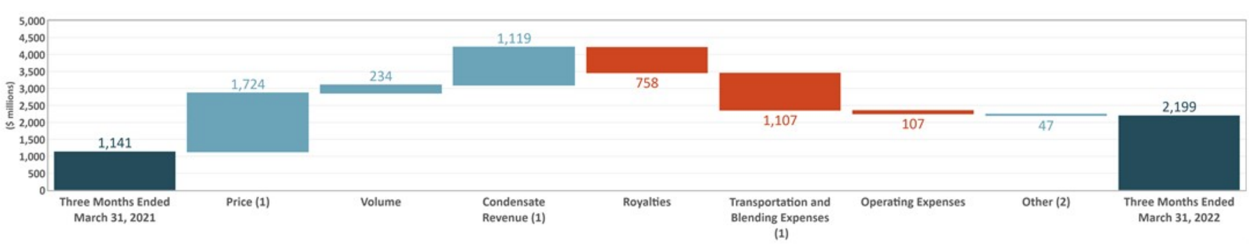
- Delivered safe and reliable operations.
- Sold our Tucker asset for net proceeds of $730 million on January 31, 2022.
- Produced 595.0 thousand barrels per day, compared with 553.4 thousand barrels per day in the first quarter of 2021.
- Generated Operating Margin of $2.2 billion, an increase of $1.1 billion compared with the first quarter of 2021 primarily due to higher average realized sales prices and higher sales volumes.
- Invested capital of $375 million primarily focused on sustaining activities at Christina Lake, Foster Creek and the Lloydminster thermal assets, and the drilling of stratigraphic test wells as part of our integrated winter program.
- Achieved a Netback of $56.44 per BOE.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Gross Sales [(1)]	**9,218**	4,918
Less: Royalties	**1,082**	324
Revenues	**8,136**	4,594
Expenses		
Purchased Product [(1)]	**1,483**	861
Transportation and Blending	**2,885**	1,778
Operating	**702**	585
Realized (Gain) Loss on Risk Management	**867**	229
Operating Margin	**2,199**	1,141
Unrealized (Gain) Loss on Risk Management	**266**	(141)
Depreciation, Depletion and Amortization	**635**	612
Exploration Expense	**1**	11
Segment Income (Loss)	**1,297**	659

(1) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Operating Margin Variance



(1) Reported revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

(2) Other includes third-party sourced volumes, construction and other activities not attributable to the production of crude oil, NGLs or natural gas.

Operating Results

	Three Months Ended March 31, 2022	2021
Total Sales Volumes (MBOE/d)	**609.9**	560.8
Total Realized Price [(1)] ($/BOE)	**95.90**	52.86
Crude Oil Production by Asset (Mbbls/d)		
Foster Creek	**197.9**	163.1
Christina Lake	**254.1**	222.9
Sunrise [(2)]	**24.1**	27.8
Lloydminster Thermal	**96.3**	96.0
Tucker [(3)]	**6.4**	23.1
Lloydminster Conventional Heavy Oil	**16.2**	20.5
Total Daily Crude Oil Production [(4)] (Mbbls/d)	**595.0**	553.4
Oil Sands Natural Gas [(5)] (MMcf/d)	**12.8**	13.0
Total Daily Production (MBOE/d)	**597.0**	555.6
Effective Royalty Rate (percent)	**22.3**	14.4
Transportation and Blending Cost [(1)] ($/BOE)	**7.23**	8.06
Operating Cost [(1)] ($/BOE)	**12.51**	11.49

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Represents Cenovus's 50 percent interest in Sunrise operations.
(3) Sale of the Tucker asset closed on January 31, 2022.
(4) Oil Sands production is primarily bitumen, except for Lloydminster conventional heavy oil, which is heavy crude oil.
(5) Conventional natural gas product type.

Revenues

Price

In the first quarter of 2022, our realized sales price was $95.90 per BOE compared with $52.86 per BOE in the first quarter of 2021. The increase in realized sales price was primarily due to higher WTI benchmark prices, partially offset by slightly wider WTI-WCS differentials. In the first quarter of 2022, we sold approximately 25 percent (2021 – 20 percent) of our production to U.S. destinations to improve our realized sales price.

In the first quarter of 2022, gross sales included $1,415 million (2021 – $815 million) from third-party sourced volumes which are not included in our realized price or our Netbacks. Refer to "Netback Reconciliations – Oil Sands" in this MD&A for more detail.

In the first quarter of 2022, gross sales included other amounts of $52 million (2021 – $66 million) relating to construction, transportation and blending activities. These amounts are not included in our realized price or our Netbacks. Refer to "Netback Reconciliations – Oil Sands" in this MD&A for more detail.

The heavy oil and bitumen produced by Cenovus must be blended with condensate to reduce its viscosity to transport it to market through pipelines. Our realized bitumen sales price does not include the sale of condensate, however, it is influenced by the price of condensate. As the cost of condensate increases relative to the price of blended crude oil, our realized heavy oil and bitumen sales price decreases. Up to three months may lapse from when we purchase condensate to when we sell our blended production.

Cenovus makes storage and transportation decisions about our marketing and transportation infrastructure, including storage and pipeline assets, to optimize product mix, delivery points, transportation commitments and customer diversification, and to inventory physical positions. In order to price protect our inventories associated with storage or transport decisions, Cenovus employs various price alignment and volatility management strategies, including risk management contracts, to reduce volatility in future cash flows and improve cash flow stability. As announced on April 4, 2022, we have suspended our crude oil sales price risk management activities related to WTI. Given the strength of our balance sheet and liquidity position, we have determined these programs are no longer required to support financial resilience. The WTI contracts impacted by this announcement will be closed by June 30, 2022.

In the first quarter of 2022, we incurred a realized risk management loss due to the settlement of benchmark prices rising above our risk management contract prices, as physical inventory was sold we recognized an offsetting gain due to rising benchmark prices. In the first quarter of 2022, we recorded unrealized losses on our crude oil financial instruments primarily due to forward benchmark pricing rising above our risk management contract prices that related to future periods and the realization of settled positions.

Production Volumes

Oil Sands crude oil production was 595.0 thousand barrels per day in the first quarter of 2022, an increase of 41.6 thousand barrels per day compared with the first quarter of 2021.

Production at Tucker decreased 16.7 thousand barrels per day quarter-over-quarter as we closed the sale of the asset on January 31, 2022.

Production at Foster Creek increased 34.8 thousand barrels per day quarter-over-quarter due to new wells coming online during the last six months of 2021, partially offset by natural declines.

Production at Christina Lake increased 31.2 thousand barrels per day quarter-over-quarter due to new wells coming online during the quarter and the last nine months of 2021.

Lloydminster thermal continued its strong performance from 2021. Sunrise production decreased 3.7 thousand barrels per day quarter-over-quarter primarily due to natural declines. This is being mitigated with a redevelopment program with production from the program expected in the second quarter of 2022. Lloydminster conventional heavy oil production decreased marginally quarter-over-quarter as wells were shut-in to meet new emissions regulations in Alberta.

Royalties

Royalty calculations for our Oil Sands segment are based on government prescribed royalty regimes in Alberta and Saskatchewan.

Our Alberta oil sands royalty projects (Foster Creek, Christina Lake, and Sunrise) are based on government prescribed pre- and post-payout royalty rates, which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price.

Royalties for a pre-payout project are based on a monthly calculation that applies a royalty rate (ranging from one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Royalties for a post-payout project are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net revenues of the project multiplied by the applicable royalty rate (25 percent to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales revenues less diluent costs and transportation costs. Net revenues are a function of sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

Foster Creek and Christina Lake are post-payout projects and Sunrise is a pre-payout project.

For our Saskatchewan assets, Lloydminster thermal and Lloydminster conventional heavy oil, royalty calculations are based on an annual rate that is applied to each project, as well as each project's Crown and freehold split. For Crown royalties, the pre-payout calculation is based on a one percent rate and the post-payout calculation is based on a 20 percent rate. The freehold calculation is limited to post-payout projects and is based on an eight percent rate.

Effective royalty rates increased primarily due to higher realized pricing and higher Alberta oil sands sliding scale royalty rates.

Royalties increased by $758 million, to $1.1 billion, compared with the first quarter of 2021, mainly due to higher net revenue as a result of higher realized pricing combined with increased production.

Expenses

Transportation and Blending

Blending costs increased $1.1 billion to $2.5 billion quarter-over-quarter. The increase was primarily due to higher condensate benchmark prices (US$96.09 per barrel compared with US$58.04 per barrel in the first quarter of 2021), combined with higher volumes.

Transportation costs decreased $13 million to $397 million in the first quarter of 2022 compared with 2021, primarily due to reduced volumes shipped by rail, partially offset by higher volumes.

Per-unit Transportation Expenses

Transportations costs were $7.23 per BOE in the first quarter of 2022 (2021 – $8.06 per BOE).

At Foster Creek, transportation costs were $9.90 per barrel compared with $10.98 per barrel in the first quarter of 2021 as we reduced our reliance on shipping to the U.S. via rail while increasing our total volumes delivered to the U.S. via our pipeline capacity. We shipped 40 percent (2021 – 25 percent) of our volumes to U.S. destinations, of which five percent (2021 – 35 percent) were via rail.

At Christina Lake, transportation costs were $6.37 per barrel in the first quarter of 2022 (2021 – $6.65 per barrel) as we shipped less volumes to the USGC.

At Sunrise, per unit transportation costs increased $2.13 per barrel compared with 2021 to $13.15 per barrel as we shipped 70 percent (2021 – 40 percent) of our volumes to U.S. destinations.

At our Lloydminster thermal, Tucker and Lloydminster conventional heavy oil assets, per unit transportation costs decreased $2.82 per barrel compared with 2021 to $3.51 per barrel. We stopped shipping these barrels to US destinations after the first quarter of 2021 as we optimized our pipeline capacity after the Arrangement.

Operating

Primary drivers of our operating expenses in the first quarter of 2022 were fuel, chemical costs, workforce, and repairs and maintenance. Total and per-unit operating costs increased primarily due to higher fuel costs as a result of higher natural gas prices. Per-unit non-fuel costs decreased at Foster Creek and Christina Lake primarily due to higher sales volumes, partially offset by increased chemical costs at Foster Creek. Per-unit non-fuel costs at our other Oil Sands assets increased primarily due to higher chemical costs and workover activity at Sunrise and our Lloydminster thermal assets.

	Three Months Ended March 31,		
($/BOE) (1)	**2022**	**Percent Change**	2021
Foster Creek			
Fuel	**4.71**	**30**	3.62
Non-Fuel	**6.48**	**(9)**	7.11
Total	**11.19**	**4**	10.73
Christina Lake			
Fuel	**4.51**	**47**	3.07
Non-Fuel	**4.71**	**(11)**	5.31
Total	**9.22**	**10**	8.38
Other Oil Sands (2)			
Fuel	**6.85**	**55**	4.41
Non-Fuel	**12.93**	**13**	11.45
Total	**19.78**	**25**	15.86
Total	**12.51**	**9**	11.49

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Includes Sunrise, Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets. Sale of the Tucker asset closed on January 31, 2022.

Netbacks

	Three Months Ended March 31,	
($/BOE)	**2022**	2021
Sales Price (1)	**95.90**	52.86
Royalties (1)	**19.72**	6.41
Transportation (1)	**7.23**	8.06
Operating Expenses (1)	**12.51**	11.49
Netback (2)	**56.44**	26.90

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

DD&A

In the first quarter of 2022, DD&A increased $23 million compared with 2021 primarily due to increased production. The average depletion rate for the quarter ended March 31, 2022 was $11.80 per BOE (2021 – $11.13 per BOE).

CONVENTIONAL

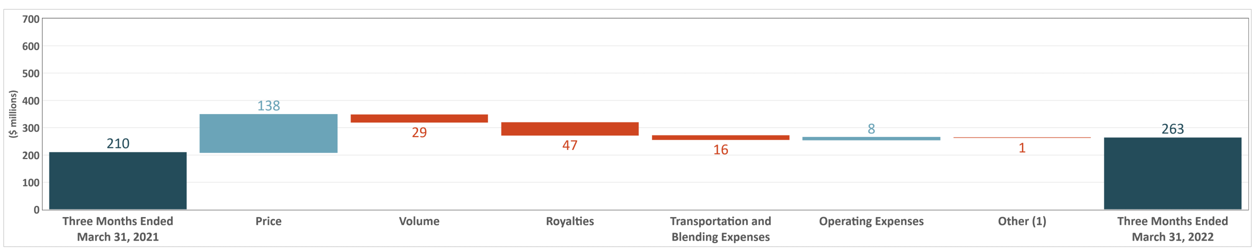
In the first quarter of 2022, we:

- Delivered safe and reliable operations.
- Closed the sale of our assets in the Wembley area for net proceeds of $220 million on February 28, 2022.
- Generated Operating Margin of $263 million, an increase of $53 million compared with the first quarter of 2021, primarily due to higher average realized sales prices.
- Invested capital of $88 million focused on sustaining drilling, completion and tie-in programs.
- Achieved a Netback of $22.04 per BOE.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Gross Sales	**1,112**	776
Less: Royalties	**71**	24
Revenues	**1,041**	752
Expenses		
Purchased Product	**606**	381
Transportation and Blending	**34**	18
Operating	**134**	142
Realized (Gain) Loss on Risk Management	**4**	1
Operating Margin	**263**	210
Unrealized (Gain) Loss on Risk Management	**—**	(1)
Depreciation, Depletion and Amortization	**80**	108
Exploration Expense	**—**	(4)
Segment Income (Loss)	**183**	107

Operating Margin Variance



(1) Reflects operating margin from processing facility.

Revenues

In the first quarter of 2022, gross sales included $606 million (2021 – $381 million) relating to third-party sourced volumes, which are not included in our per-unit pricing metrics or our Netbacks.

In the first quarter of 2022, revenues included amounts relating to processing and transportation activities for third parties of $24 million, (2021 – $24 million), which are not included in our per-unit pricing metrics or our Netbacks.

Operating Results

	Three Months Ended March 31,	
	2022	2021
Total Sales Volumes (MBOE/d)	**125.2**	135.9
Total Realized Price [(1)] ($/BOE)	**42.84**	30.32
Light Crude Oil ($/bbl)	**112.67**	61.59
NGLs ($/bbl)	**55.39**	38.02
Conventional Natural Gas ($/Mcf)	**5.55**	4.23
Production by Product		
Light Crude Oil (Mbbls/d)	**8.2**	8.7
NGLs (Mbbls/d)	**24.5**	28.2
Conventional Natural Gas (MMcf/d)	**555.0**	594.5
Total Daily Production (MBOE/d)	**125.2**	135.9
Conventional Natural Gas Production (percentage of total)	**74**	73
Crude Oil and NGLs Production (percentage of total)	**26**	27
Effective Royalty Rate (percent)	**15.9**	6.9
Transportation Costs [(1)] ($/BOE)	**3.18**	1.43
Operating Costs [(1)] ($/BOE)	**11.33**	11.09
Per Unit DD&A [(1)] ($/BOE)	**8.16**	8.64

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

Price

Our total realized sales price increased quarter-over-quarter primarily due to higher crude oil and natural gas benchmark prices.

Production Volumes

Production volumes decreased 10.7 thousand BOE per day quarter-over-quarter primarily due asset sales in the second half of 2021. The production decrease is partially offset by 20 new net wells brought on production during the quarter.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Total royalties and effective royalty rates increased quarter-over-quarter primarily due to higher realized pricing and lower gas cost allowance credits.

Expenses

Transportation

Our transportation costs reflect charges for the movement of crude oil, NGLs and natural gas from the point of production to where the product is sold. Transportation costs increased by $16 million in 2022 compared with 2021. Per-unit transportation costs averaged $3.18 per BOE in the first quarter of 2022 (2021 – $1.43 per BOE).

Operating

Primary drivers of our operating expenses in the first quarter of 2022 were repairs and maintenance, workforce, and property tax and lease costs. Per-unit operating costs increased marginally quarter-over-quarter. Total operating costs decreased compared with the first quarter of 2021 due to lower sales volumes.

Netbacks

($/BOE)	Three Months Ended March 31, 2022	2021
Sales Price [(1)]	**42.84**	30.32
Royalties [(1)]	**6.29**	2.00
Transportation and Blending [(1)]	**3.18**	1.43
Operating Expenses [(1)]	**11.33**	11.09
Netback [(2)]	**22.04**	15.80

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

DD&A

The average depletion rate for the first three months of 2022 was $8.16 per BOE (2021 – $8.64 per BOE).

In the first quarter of 2022, total Conventional DD&A was $80 million (2021 – $108 million). The decrease was due to asset dispositions in the first quarter of 2022 and the second half of 2021.

OFFSHORE

In the first quarter of 2022, we:

- Delivered safe and reliable operations.
- Generated Operating Margin of $458 million, an increase of $114 million compared with the first quarter of 2021, primarily due to higher average realized sales prices.
- Earned a Netback of $69.57 per BOE.
- Achieved record high single-day natural gas production in China.
- Invested capital of $53 million primarily for the Terra Nova ALE project and preservation capital for the West White Rose project in the Atlantic region.

In the Atlantic region, the West White Rose project remains deferred while we continue to evaluate options with our partners. The decision whether to restart the West White Rose project is expected to be made by mid-2022. The Terra Nova ALE project remains underway in Spain for the dry dock portion of the project. Production is expected to resume before the end of 2022.

In Indonesia, we drilled and completed two planned development wells in the MBH field. In April, we commenced drilling the first of five planned development wells in the MDA field. The MBH and MDA fields are expected to start producing later this year. At the MAC field, production facilities are under construction and three development wells are expected to be drilled later this year.

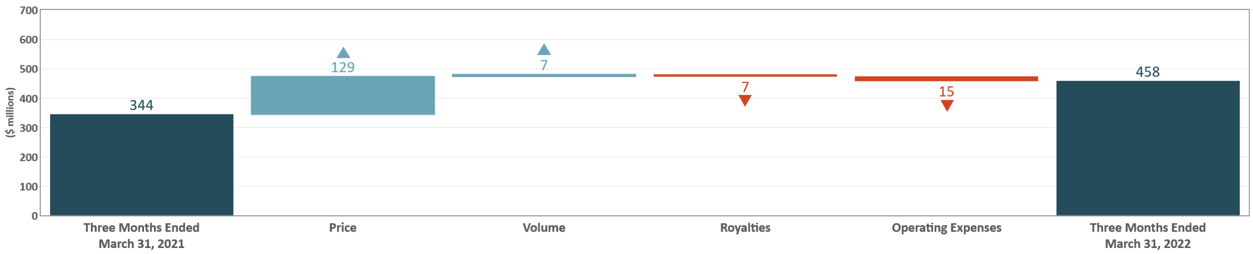
In China, we relinquished Block 23/07. The 23/07 block was in the exploration phase, and never produced or had drilling activity.

Financial Results

	Three Months Ended March 31, 2022			2021		
($ millions)	**Asia Pacific**	**Atlantic**	**Offshore**	Asia Pacific	Atlantic	Offshore
Revenues						
Gross Sales	**395**	**172**	**567**	321	110	431
Less: Royalties	**22**	**10**	**32**	17	8	25
	373	**162**	**535**	304	102	406
Expenses						
Transportation and Blending	**—**	**4**	**4**	—	4	4
Operating	**27**	**46**	**73**	22	36	58
Operating Margin [(1)]	**346**	**112**	**458**	282	62	344
Depreciation, Depletion and Amortization			**150**			125
Exploration Expense			**15**			(1)
Share of (Income) Loss from Equity-Accounted Affiliates			**(4)**			(12)
Segment Income (Loss)			**297**			232

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operating Margin Variance



Operating Results

	Three Months Ended March 31,	
	2022	2021
Total Sales Volumes (MBOE/d)	**77.3**	75.7
Atlantic	**14.6**	14.9
Asia Pacific (1)	**62.7**	60.8
Total Realized Price (2) ($/BOE)	**90.44**	70.70
Atlantic - Light Crude Oil ($/bbl)	**130.87**	81.37
Asia Pacific (1) ($/BOE)	**81.04**	68.08
NGLs ($/bbl)	**110.30**	69.66
Conventional Natural Gas ($/Mcf)	**12.22**	11.28
Production by Product		
Atlantic - Light Crude Oil (Mbbls/d)	**13.7**	16.9
Asia Pacific (1)		
NGLs (Mbbls/d)	**13.1**	12.9
Conventional Natural Gas (MMcf/d)	**297.5**	287.4
Asia Pacific Total (MBOE/d)	**62.7**	60.8
Total Daily Production (MBOE/d)	**76.4**	77.8
Effective Royalty Rate (percent)		
Atlantic	**6.1**	7.0
Asia Pacific (1)	**10.8**	6.5
Operating Expense (2) ($/BOE)	**11.63**	9.37
Atlantic	**36.06**	26.56
Asia Pacific (1)	**5.95**	5.14
Per Unit DD&A (2) ($/BOE)	**29.86**	25.87

(1) Reported sales volumes, associated per unit values and royalty rates reflect Cenovus's 40 percent interest in the Madura-BD gas project. Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

Price

The price we receive for natural gas in Asia is set under long-term contracts. Our realized sales price on light crude oil and NGLs increased quarter-over-quarter primarily due to higher Brent benchmark pricing.

Production and Sales Volumes

Asia Pacific production increased marginally compared with the first quarter of 2021, primarily due to higher demand in China, partially offset by a planned floating production, storage and offloading unit ("FPSO") shutdown in Indonesia.

Atlantic production decreased slightly compared with the first quarter of 2021 due to natural declines. Light oil from production at the White Rose field is offloaded from the SeaRose FPSO to tankers and stored at an onshore terminal before shipment to buyers. The result is a timing difference between production and sales.

Royalties

Royalty rates in China and Indonesia are governed by production sharing contracts in which production is shared with the Chinese and Indonesian governments. The effective royalty rate for the first quarter of 2022 was 10.8 percent (2021 – 6.5 percent), as development costs at the Madura-BD gas project were recovered by the third quarter of 2021 and no longer deducted from the royalty calculation.

Royalties at the White Rose field are based on an agreement between our working interest partners and the Government of Newfoundland and Labrador. We currently pay a basic royalty of 7.5 percent of gross sales from the White Rose field and 5.0 percent of gross sales at the satellite extensions. The effective royalty rate in the first quarter of 2022 was 6.1 percent (2021 – 7.0 percent).

Expenses

Operating

Primary drivers of our Asia Pacific operating expenses in the first quarter of 2022 were workforce, repairs and maintenance, and insurance. Total and per-unit operating expenses were relatively flat compared with the first quarter of 2021.

Primary drivers of our Atlantic operating expenses in the first quarter of 2022 were repairs and maintenance, workforce, vessel costs and helicopter costs. Total and per-unit operating expenses increased quarter-over-quarter primarily due to a higher working interest in Terra Nova and lower production.

Transportation

Transportation in the Atlantic region includes the cost of transporting crude oil from the SeaRose floating production, storage and offloading unit to onshore via tankers, as well as storage costs.

Netbacks

	Three Months Ended March 31, 2022			
($/BOE, except where indicated)	**China**	**Indonesia** [1]	**Atlantic** ($/bbl)	**Total Offshore**
Sales Price [2]	**82.09**	**74.82**	**130.87**	**90.44**
Royalties [2]	**4.43**	**34.23**	**7.81**	**8.58**
Transportation and Blending [2]	**—**	**—**	**3.51**	**0.66**
Operating Expenses [2]	**4.66**	**13.51**	**36.06**	**11.63**
Netback [3]	**73.00**	**27.08**	**83.49**	**69.57**

	Three Months Ended March 31, 2021			
($/BOE, except where indicated)	China	Indonesia [1]	Atlantic ($/bbl)	Total Offshore
Sales Price [2]	69.44	60.68	81.37	70.70
Royalties [2]	3.70	8.26	5.70	4.67
Transportation and Blending [2]	—	—	2.84	0.56
Operating Expenses [2]	4.71	7.51	26.56	9.37
Netback [3]	61.03	44.91	46.27	56.10

(1) Reported sales volumes, associated per unit values and royalty rates reflect Cenovus's 40 percent interest in the Madura-BD gas project. Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

DD&A

In the first quarter of 2022, total Offshore DD&A was $150 million (2021 – $125 million). The increase was due to a higher DD&A rate and higher production. The average depletion rate in the first quarter of 2022 was $29.86 per BOE (2021 – $25.87 per BOE).

DOWNSTREAM

CANADIAN MANUFACTURING

In the first quarter of 2022, we:

- Averaged combined crude utilization of 89 percent at the Lloydminster Upgrader and Lloydminster Refinery.
- Incurred a temporary unplanned maintenance outage at the Lloydminster Upgrader, negatively impacting throughput.
- Slowed crude run rates at the Lloydminster Upgrader toward the end of March in preparation for planned maintenance that started in April.
- Generated Operating Margin of $114 million, an increase of $32 million compared with the first quarter of 2021 due to a higher upgrading differential, partially offset by lower sales volumes.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Revenues	**1,044**	806
Purchased Product	**804**	631
Gross Margin [1]	**240**	175
Expenses		
Transportation and Blending	**2**	—
Operating	**124**	93
Operating Margin	**114**	82
Depreciation, Depletion and Amortization	**42**	43
Segment Income (Loss)	**72**	39

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operating Results

	Three Months Ended March 31,	
	2022	2021
Crude Oil Throughput Capacity (Mbbls/d)	**110.5**	110.5
Lloydminster Upgrader (Mbbls/d)	**81.5**	81.5
Lloydminster Refinery (Mbbls/d)	**29.0**	29.0
Crude Oil Throughput (Mbbls/d)	**98.1**	106.2
Lloydminster Upgrader (Mbbls/d)	**70.7**	78.4
Lloydminster Refinery (Mbbls/d)	**27.4**	27.8
Crude Utilization [1] (percent)	**89**	96
Refined Products Output (Mbbls/d)	**99.4**	107.4
Upgrading Differential [2]	**20.50**	14.01
Refining Margin [3] ($/bbl)	**22.20**	15.54
Lloydminster Upgrader ($/bbl)	**24.37**	16.64
Lloydminster Refinery ($/bbl)	**16.61**	12.43
Unit Operating Expense [4] ($/bbl)	**10.99**	7.22
Crude-by-Rail Operations		
Volumes Loaded [5] (Mbbls/d)	**3.0**	21.6
Ethanol Production (thousands of litres/d)	**773.4**	396.5

(1) Based on crude throughput volumes and results of operations at the Lloydminster Upgrader and Refinery.
(2) Based on benchmark price differential between heavy oil feedstock and synthetic crude.
(3) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(4) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A. Operating costs divided by crude oil throughput.
(5) Volumes transported outside of Alberta, Canada.

Crude oil throughput decreased 8.1 thousand barrels per day quarter-over-quarter to 98.1 thousand barrels per day in the first quarter of 2022 due to temporary unplanned maintenance outages at the Lloydminster Upgrader. In addition, we slowed crude run rates at the Lloydminster Upgrader towards the end of March to prepare for planned maintenance that began in early April.

At the Lloydminster Refinery, crude oil throughput remained steady quarter-over-quarter. We are scheduled to begin a planned turnaround in the second quarter of 2022.

We expect the impact of planned outages on crude throughput to be between approximately 20 thousand barrels per day to 30 thousand barrels per day in the second quarter of 2022.

Revenues and Gross Margin

Upgrading operations process blended heavy crude oil and bitumen into high value synthetic crude oil and low sulphur distillates. Revenues are dependent on the sales price of synthetic crude oil and diesel. Upgrading gross margin is primarily dependent on the differential between the sales price of synthetic crude oil and diesel, and the cost of heavy crude oil feedstock.

Lloydminster Refinery operations process blended heavy crude oil into asphalt and industrial products. Revenues are dependent on market prices for asphalt and other industrial products. The gross margin is primarily dependent on asphalt and industrial products pricing and the cost of heavy crude oil feedstock. Sales from the Lloydminster Refinery increase during paving season, which typically runs from May through October each year.

The Lloydminster Upgrader has the option to source crude oil feedstock from our Lloydminster thermal production. The Lloydminster Refinery sources crude oil feedstock from our Lloydminster thermal and Lloydminster conventional heavy oil production.

Revenues increased $238 million quarter-over-quarter to $1.0 billion in the first quarter of 2022 primarily due to higher synthetic crude benchmark prices and higher asphalt and industrial products prices. The increase was partially offset by lower sales volumes from the Lloydminster Upgrader.

Gross margin increased $65 million quarter-over-quarter to $240 million in the first quarter of 2022 primarily due to a higher upgrading differential, and higher asphalt and industrial product margins. The increase was partially offset by lower sales volumes from the Lloydminster Upgrader.

Revenues and gross margin at our Bruderheim crude-by-rail terminal decreased compared with the first quarter of 2021 due to minimal third-party volumes and Cenovus's reduced reliance on rail.

See the Specified Financial Measures Advisory of this MD&A for revenues and gross margin by asset.

Operating Expense

Primary drivers of operating expenses in the first quarter of 2022, were workforce, repairs and maintenance, and energy costs. Total and per-unit operating costs increased as we prepared for planned maintenance at the Lloydminster Upgrader and a turnaround at the Lloydminster Refinery, and higher energy and workforce costs. In addition, per-unit operating costs increased due to lower crude throughput volumes.

DD&A

For the quarter ended March 31, 2022, Canadian Manufacturing DD&A was $42 million (2021 – $43 million).

U.S. MANUFACTURING

In the first quarter of 2022, we:

- Generated Operating Margin of $423 million, an increase of $332 million compared with 2021 primarily due to higher market crack spreads, feedstock cost advantage and increased sales volumes.
- Achieved crude utilization of 80 percent and crude throughput of 403.7 thousand barrels per day.
- Commenced turnarounds at the Wood River and Borger refineries in March.
- Incurred temporary unplanned outages at the Toledo Refinery, negatively impacting throughput.
- Incurred a temporary unplanned equipment outage at the Lima Refinery subsequent to completing a turnaround in the fourth quarter of 2022. The outage was resolved towards the end of January, and we incurred other unplanned temporary outages during the quarter.
- Invested capital of $207 million focused primarily on the Superior Refinery rebuild, combined with refining reliability and maintenance at the Wood River, Borger and Toledo refineries.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Revenues	**6,509**	3,437
Purchased Product	**5,482**	2,920
Gross Margin (1)	**1,027**	517
Expenses		
Operating	**494**	405
Realized (Gain) Loss on Risk Management	**110**	21
Operating Margin	**423**	91
Unrealized (Gain) Loss on Risk Management	**27**	10
Depreciation, Depletion and Amortization	**85**	114
Segment Income (Loss)	**311**	(33)

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Select Operating Results

	Three Months Ended March 31,	
	2022	2021
Crude Oil Throughput Capacity (Mbbls/d)	**502.5**	502.5
Lima Refinery	**175.0**	175.0
Toledo Refinery (1)	**80.0**	80.0
Wood River and Borger Refineries (1)	**247.5**	247.5
Crude Oil Throughput (Mbbls/d)	**403.7**	362.9
Lima Refinery	**136.1**	124.7
Toledo Refinery (1)	**72.1**	68.1
Wood River and Borger Refineries (1)	**195.5**	170.1
Throughput by Product (Mbbls/d)		
Heavy Crude Oil	**153.8**	119.6
Light and Medium Crude Oil	**249.9**	243.3
Crude Utilization (percent)	**80**	72
Refining Margin (2)(3) ($/bbl)	**28.26**	15.84
Unit Operating Expense (3)(4) ($/bbl)	**13.59**	12.40

(1) Represents Cenovus's 50 percent interest in Wood River, Borger and Toledo refinery operations.
(2) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Based on crude oil throughput volumes and operating results at Wood River, Borger, Lima, Toledo and Superior refineries.
(4) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Crude oil throughput increased 40.8 thousand barrels per day quarter-over-quarter to 403.7 thousand barrels per day in the first quarter of 2022. The increase was primarily due to improved market conditions compared with the first quarter of 2021, partially offset by unplanned outages and planned turnarounds in the first quarter of 2022 having a greater impact on crude throughput than those in the first quarter of 2021.

At the Lima Refinery, we had a temporary unplanned equipment outage subsequent to completing a turnaround in the fourth quarter of 2021, which was resolved by the end of January 2022. Further equipment outages impacted throughput for the remainder of the quarter. We also operated at reduced rates early in the quarter due to low market crack spreads and ramped up production in March as market crack spreads significantly improved.

At the Toledo Refinery, throughput was optimized in line with market demand, and was impacted by temporary unplanned outages. We began a planned turnaround in the second quarter of 2022.

The Wood River and Borger refineries commenced planned turnarounds in March 2022. At the Wood River Refinery, we operated at reduced rates early in the quarter to optimize margins as market conditions dictated. The Borger Refinery performed well during the quarter.

We expect the impact of planned outages on crude throughput to be approximately 60 thousand barrels per day to 70 thousand barrels per day in the second quarter of 2022.

Revenues and Gross Margin

While market crack spreads are an indicator of margin from processing crude oil into refined products, the refining realized crack spread, which is the gross margin on a per-barrel basis, is affected by many factors. These factors include the type of crude oil feedstock processed, refinery configuration and the proportion of gasoline, distillate and secondary product output, the time lag between the purchase of crude oil feedstock and the processing of that crude oil through the refineries, and the cost of feedstock. Processing less expensive crude relative to WTI creates a feedstock cost advantage. Our feedstock costs are valued on a FIFO accounting basis.

Revenues increased $3.1 billion quarter-over-quarter due to higher sales volumes and higher refined product pricing benchmarks.

In the first quarter of 2022, gross margin increased $510 million compared with 2021 driven by improved market crack spreads and higher crude advantage, combined with increased throughput and sales volumes, partially offset by higher RINs costs.

In the first quarter of 2022, RINs costs were $233 million (2021 – $180 million) with the increase due to higher RINs pricing and volume obligations. RINs prices were US$6.44 per barrel in the quarter ended March 31, 2022 (2021 – US$5.49 per barrel).

Operating Expenses

Primary drivers of operating expenses for the quarter ended March 31, 2022, were workforce costs, repairs, maintenance, services and energy costs.

In the first quarter of 2022, per-unit operating expenses increased $1.19 per barrel of crude throughput to $13.59 per barrel of crude throughput. The increase was primarily due to higher workforce costs, increased repairs and maintenance related to the turnaround at the Wood River Refinery, preparation for the turnaround at the Toledo Refinery and higher maintenance costs at the Superior Refinery. The increase was partially offset by lower utility pricing at the Borger Refinery compared with 2021 when winter storm Uri drove utility prices higher.

Operating expenses increased $89 million quarter-over-quarter to $494 million, primarily due to higher crude throughput and the factors discussed above.

DD&A

U.S. Manufacturing DD&A was $85 million in the first quarter of 2022 (2021 – $114 million). The decrease is the result of impairment charges of $1.9 billion in the fourth quarter of 2021 in the Lima, Wood River and Borger cash-generating units reducing the amounts available to deplete.

RETAIL

As of March 31, 2022, there were 515 independently operated Husky and Esso-branded petroleum product outlets.

On November 30, 2021, Cenovus announced agreements to sell 337 gas stations within our retail fuels network for total cash proceeds of $420 million before closing adjustments. The sales are expected to close in mid-2022. We are retaining our commercial fuels business, which includes 167 cardlock, bulkplant and travel centre locations.

Financial Results

($ millions)	Three Months Ended March 31, 2022	2021
Gross Sales	**694**	447
Purchased Product	**660**	417
Gross Margin [(1)]	**34**	30
Expenses		
Operating	**27**	19
Operating Margin	**7**	11
Depreciation, Depletion and Amortization	**8**	12
Segment Income (Loss)	**(1)**	(1)

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operating margin associated with the retail assets held for sale for the three months ended March 31, 2022, was $16 million (March 31, 2021 – $14 million).

Select Operating Results

	Three Months Ended March 31, 2022	2021
Fuel Sales Volume, including wholesale		
Fuel Sales (millions of litres/d)	**6.6**	6.5
Fuel Sales per Retail Outlet (thousands of litres/d)	**12.8**	12.0

Gross Margin

Gross margin is primarily driven by gasoline and diesel prices and retail pricing for motor fuels.

Operating expenses

Primary drivers of our operating expenses for the quarter ended March 31, 2022, were repairs and maintenance, property tax, workforce and utilities.

DD&A

For the quarter ended March 31, 2022, Retail DD&A was $8 million (2021 – $12 million).

CORPORATE AND ELIMINATIONS

In the first quarter of 2022, our corporate risk management activities resulted in:

- Unrealized risk management losses of $18 million (2021 – gains of $16 million) related to power and foreign exchange risk management contracts.
- Realized risk management gains of $7 million (2021 – losses of $91 million). The losses in 2021 were primarily due to the realization of WTI put and call option contracts acquired as part of the Arrangement.

Expenses

	Three Months Ended March 31,	
($ millions)	**2022**	2021
General and Administrative	**199**	163
Finance Costs	**229**	244
Interest Income	**(15)**	(4)
Integration Costs	**24**	223
Foreign Exchange (Gain) Loss, Net	**(102)**	(117)
Re-measurement of Contingent Payment	**236**	187
(Gain) Loss on Divestiture of Assets	**(242)**	(12)
Other (Income) Loss, Net	**(370)**	(72)
	(41)	612

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs, employee long-term incentive costs and information technology costs. For the quarter ended March 31, 2022, general and administrative expenses increased compared with 2021 primarily due to higher long-term incentive costs as a result of share price increases. Our closing common share price increased from $15.51 on December 31, 2021 to $20.84 on March 31, 2022.

Finance Costs

In the quarter ended March 31, 2022, finance costs decreased by $15 million compared with 2021 primarily due to lower average long-term debt quarter-over-quarter.

The weighted average interest rate of outstanding debt for the quarter ended March 31, 2022, was 4.7 percent (2021 – 4.5 percent).

Integration Costs

For the quarter ended March 31, 2022, we incurred $24 million of costs as a result of the Arrangement, not including capital expenditures (2021 – $223 million). Integration costs decreased quarter-over-quarter as we expect to have spent the majority of these costs in 2021, the year following the Arrangement.

Foreign Exchange

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Unrealized Foreign Exchange (Gain) Loss	**(139)**	(139)
Realized Foreign Exchange (Gain) Loss	**37**	22
	(102)	(117)

In the first quarter of 2022, unrealized foreign exchange gains of $139 million were mainly as a result of the translation of our U.S. dollar denominated debt. Realized foreign exchange losses of $37 million were recorded primarily due to the recognition of a $26 million loss on the purchase of U.S. dollar denominated debt.

Re-measurement of Contingent Payment

Cenovus agreed to make quarterly payments to ConocoPhillips Company and certain of its subsidiaries ("ConocoPhillips") subsequent to the closing date of the acquisition from ConocoPhillips of its 50 percent interest in the FCCL Partnership related to Foster Creek and Christina Lake production. The quarterly payment is $6 million for each dollar that the WCS price exceeds $52 per barrel. The agreement ends on May 17, 2022.

The contingent payment is accounted for as a financial option. The fair value of $178 million as at March 31, 2022, was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. For the quarter ended March 31, 2022, non-cash re-measurement losses of $236 million were recorded. As at March 31, 2022, $294 million is payable under this agreement.

As of March 31, 2022, average WCS forward pricing for the remaining term of the contingent payment is approximately $109.19 per barrel.

Other (Income) Loss, Net

For the quarter ended March 31, 2022, other income increased by $298 million. The increase is primarily due to:

- Rebuild insurance proceeds of $269 million related to the Superior Refinery in the first quarter of 2022, compared with business interruption proceeds of $45 million in 2021.
- Insurance proceeds of $52 million related to a 2018 incident in the Atlantic region (2021 – $nil).
- Other income of $22 million related to an increase in the value of our Headwater Exploration Inc. shares (2021 – $nil).

(Gain) Loss on Divestiture of Assets

For the quarter ended March 31, 2022, we recognized a gain on divestiture of assets of $242 million (2021 – $12 million), primarily due to the closing of the sales of our Tucker and Wembley assets.

DD&A

DD&A for the quarter ended March 31, 2022, was $30 million (2021 – $31 million).

Income Tax

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Current Tax		
Canada	**367**	12
United States	**20**	—
Asia Pacific	**38**	34
Other International	**—**	1
Current Tax Expense (Recovery)	**425**	47
Deferred Tax Expense (Recovery)	**118**	27
Total Tax Expense (Recovery)	**543**	74

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for income taxes is adequate. There are usually a number of tax matters under review and with consideration of the current economic environment, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

For the three months ended March 31, 2022, the Company recorded a current tax expense related to taxable income arising in Canada, the U.S. and Asia Pacific. The increase is due to higher earnings compared to the first quarter of 2021.

Our effective tax rate is a function of the relationship between total tax expense (recovery) and the amount of earnings (loss) before income taxes. The effective tax rate differs from the statutory tax rate as it reflects different tax rates in other jurisdictions, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other tax legislation, adjustments to the tax basis of the refining assets, variations in the estimate of reserves, differences between the provision and the actual amounts subsequently reported on the tax returns, and other permanent differences.

LIQUIDITY AND CAPITAL RESOURCES

We have further defined our capital allocation framework to ensure we continue to strengthen our balance sheet, enable flexibility in both high and low commodity price environments, and improve our shareholder value proposition. The Company's capital allocation framework will enable a shift to paying out a higher percentage of Excess Free Funds Flow to shareholders with lower leverage and a lower risk profile. Our long-term Net Debt to Adjusted Funds Flow Target reflects approximately 1.0 times at the bottom of the cycle. With this revised framework, the Company would have the flexibility in a depressed commodity price environment to manage our balance sheet up to a Net Debt level of $9 billion, or approximately 2.0 times Net Debt to Adjusted Funds Flow at US$45 WTI, and capitalize on opportunities that deliver stronger, risk-adjusted returns for shareholders.

We expect to fund our near-term cash requirements through cash from operating activities and prudent use of our balance sheet capacity including draws on our committed credit facilities and our uncommitted demand facilities and other corporate and financial opportunities that may be available to us. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, Moody's Investor Service, DBRS Limited and Fitch Ratings. The cost and availability of borrowing and access to sources of liquidity and capital is dependent on current credit ratings and market conditions.

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Cash From (Used In)		
Operating Activities	**1,365**	228
Investing Activities	**337**	204
Net Cash Provided (Used) Before Financing Activities	**1,702**	432
Financing Activities	**(1,093)**	39
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(83)**	24
Increase (Decrease) in Cash and Cash Equivalents	**526**	495

($ millions)	**March 31, 2022**	December 31, 2021
Cash and Cash Equivalents	**3,399**	2,873
Total Debt	**11,806**	12,464

Cash From (Used in) Operating Activities

For the quarter ended March 31, 2022, cash generated from operating activities increased due to higher operating margin and lower integration costs. The increases were partially offset by the quarterly settlement of the contingent payment and changes in non-cash working capital.

Excluding the current portion of the contingent payment and assets and liabilities held for sale, our adjusted working capital was $5.2 billion at March 31, 2022, compared with $3.8 billion at December 31, 2021. The increase was primarily due to the improved commodity price environment as discussed in the Operating and Financial Results section of this MD&A. Working capital increased due to increased accounts receivable and inventories, partially offset by increased accounts payable.

We anticipate that we will continue to meet our payment obligations as they come due.

Cash From (Used in) Investing Activities

Cash from investing activities was higher in the first quarter of 2022 compared with 2021 primarily due to proceeds from divestitures and changes in non-cash working capital. The increase was partially offset by higher capital spending and cash acquired in the Arrangement in 2021.

Cash From (Used in) Financing Activities

During the first quarter, we paid US$402 million to purchase a portion of our unsecured notes with principal amounts of US$384 million. In addition, we repaid $16 million in short-term borrowings.

For the quarter ended March 31, 2022, the Company purchased 25 million common shares through the NCIB which allows the Company to purchase up to 146.5 million common shares until November 8, 2022. The shares were purchased at an average price of $18.91 per common share for a total of $466 million. The common shares were subsequently cancelled.

Adjusted Funds Flow and Free Funds Flow

Adjusted Funds Flow is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations and is the starting point for calculating Free Funds Flow. Free Funds Flow is a non-GAAP financial measure used to assist in measuring the available funds the Company has after financing its capital programs.

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Cash From (Used in) Operating Activities	**1,365**	228
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(19)**	(11)
Net Change in Non-Cash Working Capital	**(1,199)**	(902)
Adjusted Funds Flow	**2,583**	1,141
Total Capital Investment	**746**	547
Free Funds Flow	**1,837**	594
Cash Dividends	**78**	44
	1,759	550

Long-Term Debt and Total Debt

Total Debt as at March 31, 2022 was $11.8 billion (December 31, 2021 – $12.5 billion), which includes $11.7 billion of long-term debt (December 31, 2021 – $12.4 billion). The decrease in Total Debt was primarily due to the purchase of US$384 million of our unsecured notes during the quarter.

As at March 31, 2022, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

The following sources of liquidity are available as at March 31, 2022:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**N/A**	**3,399**
Committed Credit Facility (1)		
Revolving Credit Facility – Tranche A	**August 18, 2025**	**4,000**
Revolving Credit Facility – Tranche B	**August 18, 2024**	**2,000**
Uncommitted Demand Facilities		
Cenovus Energy Inc. (2)	**N/A**	**1,007**
WRB Refining LP (3)	**N/A**	**219**
Sunrise Oil Sands Partnership (4)	**N/A**	**5**

(1) *No amounts were drawn on the committed credit facility on March 31, 2022.*
(2) *Our uncommitted demand facilities includes $1,425 million, which may be drawn for general purposes or $1,875 million can be available to issue letters of credit. As of March 31, 2022, there were outstanding letters of credit aggregating to $543 million (December 31, 2021 – $565 million).*
(3) *Represents Cenovus's 50 percent share of US$450 million (our proportionate share – US$225 million) available to cover short-term working capital requirements. As at March 31, 2022, US$100 million was drawn on these facilities, of which US$50 million was our proportionate share.*
(4) *Represents Cenovus's 50 percent share. Available for general purposes. There were no amounts drawn on this demand facility as at March 31, 2022.*

Under the terms of our committed credit facility, we are required to maintain a debt to capitalization ratio, as defined in the debt agreements, not to exceed 65 percent. We are well below this limit.

U.S. Dollar Denominated Unsecured Notes and Canadian Dollar Unsecured Notes

At March 31, 2022, the total outstanding principal amount of U.S. dollar denominated unsecured notes was US$7.0 billion and the total outstanding principal amount of Canadian dollar denominated unsecured notes was $2.8 billion.

	Unsecured Notes	
	U.S. Dollar Denominated (US $ millions)	**Canadian Dollar Denominated** ($ millions)
As at December 31, 2021	7,385	2,750
Purchases	(384)	—
As at March 31, 2022	**7,001**	**2,750**

On February 9, 2022, we paid US$402 million to purchase a portion of our unsecured notes with principal amounts of US$384 million.

Base Shelf Prospectus

We have a base shelf prospectus that allows us to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere, where permitted by law. The base shelf prospectus will expire in November 2023. As at March 31, 2022, $4.7 billion remained available under the base shelf prospectus for permitted offerings (December 31, 2021 – $4.7 billion).

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, specified financial measures consisting of the Net Debt to Capitalization Ratio, Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio. Net Debt to Adjusted Funds Flow is a new metric as at March 31, 2022.

We define Net Debt as short-term borrowings and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. The components of the ratios include Capitalization, Adjusted Funds Flow and Adjusted EBITDA. We define Capitalization as Net Debt plus Equity. We define Adjusted Funds Flow, as used in the Net Debt to Adjusted Funds Flow Ratio, as cash from (used in) operating activities, less settlement of decommissioning liabilities and net change in operating non-cash working capital calculated on a trailing twelve-month basis. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense (recovery), DD&A, exploration expense, goodwill impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, other income (loss), net and share of income (loss) from equity-accounted investees calculated on a trailing twelve-month basis. These ratios are used to steward our overall debt position and as measures of our overall financial strength.

	March 31,2021	December 31, 2021
Net Debt to Capitalization Ratio [(1)] (percent)	**25**	29
Net Debt to Adjusted Funds Flow Ratio [(1)] (times)	**1.0**	1.3
Net Debt to Adjusted EBITDA Ratio [(1)] (times)	**0.8**	1.2

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Our Net Debt to Adjusted EBITDA and our Net Debt to Adjusted Funds Flow Ratio Targets are approximately 1.0 times at the bottom of the commodity price cycle, which we see as approximately US$45 per barrel WTI. This ratio may fluctuate periodically outside the range due to factors such as persistently high or low commodity prices. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure we have sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, we may, among other actions, adjust capital and operating spending, draw down on our credit facilities or repay existing debt, adjust dividends paid to shareholders, purchase our common shares for cancellation, issue new debt, or issue new shares.

As at March 31, 2022, our Net Debt to Capitalization Ratio decreased compared with December 31, 2021 primarily due to ongoing reductions in Net Debt, described in the Cash From (Used In) Financing Activities above, and net earnings of $1.6 billion during the quarter ended March 31, 2022.

Our Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio decreased compared with December 31, 2021 as a result of lower Net Debt and higher Operating Margin in the first quarter of 2022. See the Operating and Financial Results section of this MD&A for more information on Net Debt.

Additional information regarding our financial measures and capital structure can be found in the notes to the Consolidated Financial Statements.

Share Capital and Stock-Based Compensation Plans

As at March 31, 2022, there were approximately 1,982 million common shares outstanding (December 31, 2021 – 2,001 million common shares) and 36 million preferred shares outstanding (December 31, 2021 – 36 million preferred shares). Refer to Note 22 of the interim Consolidated Financial Statements for more details.

As at March 31, 2022, there were approximately 64 million common share warrants outstanding (December 31, 2021 – 65 million common share warrants). Each common share warrant entitles the holder to acquire one common share for a period of five years (from date of issue) at an exercise price of $6.54 per common share. The common share warrants expire on December 31, 2025. Refer to Note 22 of the interim Consolidated Financial Statements for more details.

Refer to Note 24 of the interim Consolidated Financial Statements for more details on our stock option plans and our PSU, RSU and DSU Plans.

Our outstanding share data is as follows:

As at April 25, 2022	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**1,971,975**	**N/A**
Common Share Warrants	**63,684**	**N/A**
Series 1 Preferred Shares	**10,740**	**N/A**
Series 2 Preferred Shares	**1,260**	**N/A**
Series 3 Preferred Shares	**10,000**	**N/A**
Series 5 Preferred Shares	**8,000**	**N/A**
Series 7 Preferred Shares	**6,000**	**N/A**
Stock Options	**28,593**	**18,889**
Other Stock-Based Compensation Plans	**17,231**	**1,604**

Common Share Dividends

In the first quarter of 2022, we paid dividends of $69 million or $0.0350 per common share (2021 – $35 million or $0.0175 per common share). The declaration of dividends is at the sole discretion of Cenovus's Board and is considered quarterly. The Board declared a second quarter dividend of $0.105 per common share, payable on June 30, 2022 to common shareholders of record as of June 15, 2022.

Cumulative Redeemable Preferred Share Dividends

In the first quarter of 2022, dividends of $9 million, were paid on the series 1, 2, 3, 5 and 7 preferred shares. The declaration of preferred share dividends is at the sole discretion of Cenovus's Board and is considered quarterly. The Board declared a second quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares of $9 million, payable on June 30, 2022 to preferred shareholders of record as of June 15, 2022.

Capital Investment Decisions

Our 2022 capital program is forecast to be between $2.9 billion and $3.3 billion. Our Future Capital Investment is focused on maintaining safe and reliable operations, while positioning the Company to drive enhanced shareholder value to deliver upstream production of approximately 780.0 thousand BOE per day and downstream throughput of approximately 555.0 thousand barrels per day.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Commitments are primarily related to transportation agreements and obligations that have original maturities of less than one year are excluded. For further information, see the interim Consolidated Financial Statements.

Our total commitments were $36.3 billion as at March 31, 2022, of which $32.6 billion are for various transportation and storage commitments. Transportation commitments include $9.1 billion that are subject to regulatory approval or have been approved but are not yet in service. Terms are up to 20 years subsequent to the date of commencement and should help align with the Company's future transportation requirements.

Our commitments with HMLP at March 31, 2022, include $2.6 billion related to transportation, storage and other long-term contracts.

As at March 31, 2022, outstanding letters of credit issued as security for performance under certain contracts totaled $543 million (December 31, 2021 – $565 million).

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations. We believe that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on our Consolidated Financial Statements.

Transactions with Related Parties

Transactions with HMLP are related party transactions as we have a 35 percent ownership interest in HMLP. As the operator of the assets held by HMLP, we provide management services for which we recover shared service costs. We are also the contractor for HMLP and construct its assets on a cost recovery basis with certain restrictions. For the three months ended March 31, 2022, we charged HMLP $48 million for construction and management services (2021 – $32 million).

We pay an access fee to HMLP for the use of its pipeline systems that are used by our blending business. We also pay HMLP for transportation and storage services. For the three months ended March 31, 2022, we incurred costs of $68 million for the use of HMLP's pipeline systems, as well as transportation and storage services (2021 – $72 million).

RISK MANAGEMENT AND RISK FACTORS

For a full understanding of the risks that impact us, the following discussion should be read in conjunction with the Risk Management and Risk Factors section of our 2021 annual MD&A.

We are exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the energy industry as a whole and others are unique to our operations. The impact of any risk or a combination of risks may adversely affect, among other things, our business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict our ability to pursue our strategic priorities, meet our targets or outlooks, goals, initiatives and ambitions, respond to changes in our operating environment, pay dividends to our shareholders, continue with share purchases under our NCIB and fulfill our obligations (including debt servicing requirements) and may materially affect the market price of our securities.

The following provides an update on our risks.

Financial Risk

Commodity Prices

Fluctuations in commodity prices, associated price differentials and refining margins impact our financial condition, results of operations, cash flows, growth, access to capital, our level of shareholder returns and cost of borrowing. We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts, market access commitments and generally through our access to committed credit facilities. In certain instances, we use financial instruments to manage our exposure to price volatility on a portion of our refined products, crude oil and natural gas production, and related inventory or volumes in long-distance transit. Previously, we had also used derivative instruments to manage our overall exposure to volatility in cash flow using WTI derivative instruments, however, as announced on April 4, 2022, we have suspended our crude oil sales price risk management activities related to WTI. Accordingly, we may continue to use financial instruments to mitigate our exposure to the prices of various commodities, including WTI, utilized in condensate and price risk management for refining operations; and products, including associated price differentials, refined products or feedstock, condensate, electricity and interest and exchange rates applicable to our business. Fluctuations in the price of WTI may have a larger impact on our financial condition, results of operations, cash flows, growth, access to capital, our level of shareholder returns and our cost of borrowing, compared to the periods prior to the suspension of our crude oil sales price risk management activities relating to WTI. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 26 and 27 to the interim Consolidated Financial Statements.

Risks Associated with Derivative Financial Instruments

Financial instruments expose us to the risk that a counterparty will default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our Board-approved Credit Policy.

Financial instruments also expose us to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. These risks are managed through hedging limits authorized according to our Market Risk Management Policy.

Although we have suspended our crude oil sales price risk management activities related to WTI, certain financial instruments related to our condensate, feedstock and refined product price risk management programs which include WTI, remain outstanding and will continue to be utilized. For further details, see Notes 26 and 27 to the interim Consolidated Financial Statements. The WTI contracts impacted by this announcement will be closed by June 30, 2022. As a result we will remain exposed to the risk of a loss from adverse changes in the market value thereof. In addition, we may continue to use financial instruments to manage our exposure to fluctuations in the prices of various commodities and products, including associated price differentials, refined products or feedstock, condensate, electricity and interest and exchange rates applicable to our business. As such, we will be exposed to the risk of a loss from adverse changes in the market value of any such financial instruments. These financial instruments may also limit the benefit to us if commodity prices, interest or foreign exchange rates change.

Impact of Financial Risk Management Activities

Cenovus makes storage and transportation decisions using our marketing and transportation infrastructure, including storage and pipeline assets to optimize product mix, delivery points, transportation commitments and customer diversification. In order to price protect our inventories associated with storage or transport decisions, Cenovus employs various price alignment and volatility management strategies, including risk management contracts, to reduce volatility in future cash flows and improve cash flow stability. Previously, Cenovus's price alignment and volatility management strategy included the use of crude oil sales price risk management activities related to WTI. Although certain of Cenovus's crude oil sales prices risk management contracts remain outstanding as of March 31, 2022, these contracts will be closed by June 30, 2022. WTI contracts in place to support condensate, feedstock and refined product exposure management were also outstanding as of March 31, 2022, and will continue to be used for those purposes.

Transactions typically span across periods, as such, these transactions reside across both realized and unrealized risk management. As the financial contracts settle, they will flow from unrealized to realized risk management gains and losses.

In a rising commodity price environment, we would expect to realize losses on our risk management activities but recognize gains on the underlying physical inventory sold in the period and the opposite to occur in a falling commodity price environment. In the three months ended March 31, 2022, we incurred a realized loss on our risk management positions due to the settlement of benchmark prices relative to our risk management contract prices, but recognized a gain on the underlying physical inventory sold during such period due to rising benchmark prices. In the three months ended March 31, 2022, unrealized losses were recorded on our crude oil financial instruments primarily due to forward benchmark prices rising above our risk management contract prices that related to future periods and the realization of settled positions.

For the three months ended March 31, 2022, the unrealized risk management loss related to the WTI contracts impacted by this announcement was $370 million. As at March 31, 2022, the risk management liability related to the WTI contracts impacted by this announcement was $380 million.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, as well as use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2021.

Critical Judgments in Applying Accounting Policies and Key Sources of Estimation Uncertainty

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements. A full list of the key sources of estimation uncertainty can be found in our annual Consolidated Financial Statements for the year ended December 31, 2021. There have been no changes to our critical judgments used in applying accounting policies and key sources of measurement uncertainty during the three months ended March 31, 2022.

New Accounting Standards and Interpretations not yet Adopted

A number of new accounting standards, amendments to accounting standards and interpretations were effective for annual periods beginning on or after January 1, 2022, but are not material to Cenovus's operations. There were no new or amended accounting standards or interpretations issued during the three months ended March 31, 2022, that are expected to have a material impact on the Company's interim Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at March 31, 2022. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at March 31, 2022.

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. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ADVISORY

Oil and Gas Information

Barrels of Oil Equivalent – natural gas volumes have been converted to BOE on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Forward-looking Information

This document contains forward-looking statements and other information (collectively "forward-looking information") about the Company's current expectations, estimates and projections, made in light of the Company's experience and perception of historical trends. Although the Company believes that the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

This forward-looking information is identified by words such as "anticipate", "believe", "capacity", "commit", "continue", "could", "estimate", "expect", "focus", "forecast", "future", "may", "opportunities", "option", "plan", "potential", "project", "progress', "schedule", "seek", "strive", "target", "view", and "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: delivering value over the long-term; maximizing, growing or enhancing shareholder value and/or returns; safety performance and culture; ESG leadership; Free Funds Flow generation, allocation and pay out; returning incremental capital to shareholders; allocating and paying out Excess Free Funds Flow; variable dividend distributions based on Net Debt and share buybacks; funding near-term cash requirements and meeting payment obligations; maintaining investment grade credit ratings; Debt and Net Debt targets; operational strength; capital discipline; strengthening and maintaining a strong balance sheet; flexibility in both high and low commodity price environments; improving the shareholder value proposition; returning incremental capital to shareholders beyond the base dividend payment; opportunistic share repurchases; Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio; the Company's five key strategic objectives and five ESG focus areas; cost savings and reductions; cost structure; margin enhancement; improving efficiencies to drive incremental capital, operating and general and administrative cost reductions; shortening and optimizing the value chain; sustaining the dividend at US$45 WTI per barrel; upstream production and downstream throughput; maximizing value received for products; optimizing run rates at the Company's refineries; mitigating the impact of volatility in light-heavy crude oil differentials; mitigating the impact of crude oil and refined product prices and differentials; closing WTI contracts related to the Company's crude oil sales price risk management activities by June 30, 2022 while continuing to use financial instruments to mitigate exposure to various commodities (including WTI, utilized in condensate and price risk management for refining operations) and products, including associated price differentials and refining margins; initial production and exploration of new fields or projects; planned outages and turnaround activity; financial resilience; adjusting capital and operating spending, drawing down on credit facilities or repaying existing debt, adjusting dividends paid to shareholders, purchasing Cenovus common shares for cancellation, issuing new debt, or issuing new shares; future capital investment; capturing value from crude oil and natural gas production through to the sale of finished products such as transportation fuels; reinvestment in the business and diversification; resuming projects; liabilities from legal proceedings; generating strong margins; the Company's outlook for commodities and the Canadian dollar; upstream integration; and ramping production up or down.

Readers are cautioned not to place undue reliance on forward-looking information as the Company's actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to the Company and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include, but are not limited to: forecast oil and natural gas, natural gas liquids, condensate and refined products prices, light-heavy crude oil price differentials; the Company's ability to realize the anticipated benefits and anticipated cost synergies of Arrangement; the Company's ability to successfully integrate the legacy Husky business with its own and any costs associated therewith; the accuracy of any assessments undertaken in connection with the Arrangement; forecast production and throughput volumes; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; the absence of significant adverse changes to government policies, legislation and regulations (including related to climate change), Indigenous relations, interest rates, inflation, foreign exchange rates, competitive conditions and the supply and demand for crude oil and natural gas, NGLs, condensate and refined products; the political, economic and social stability of jurisdictions in which the Company operates; the absence of significant disruption of operations, including as a result of harsh weather, natural disaster, accident, civil unrest or other similar events; the prevailing climatic conditions in the Company's operating locations; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to the Company's share price and market capitalization over the long term; opportunities to purchase shares for cancellation at prices acceptable to the Company; the sufficiency of cash balances, internally generated cash flows, existing credit facilities, management of the Company's asset portfolio and access to capital and insurance coverage to pursue and fund future investments, sustainability and development plans and dividends, including any increase thereto; production from the Company's Conventional segment providing an economic hedge for the natural gas required as a fuel source at both the Company's oil sands and refining operations; realization of expected capacity to store within the Company's oil sands reservoirs barrels not yet produced, including that the Company will be able to time production and sales of our inventory at later dates when demand has increased, pipeline and/or storage capacity has improved and future crude oil differentials have narrowed; the WTI-WCS differential in Alberta remains largely tied to the extent to which voluntary economically driven supply cuts are made, the potential start-up of the Enbridge Inc.'s Line 3 Replacement Program, the completion of Trans Mountain Expansion project, and the level of crude-by-rail activity; the ability of the Company's refining capacity, dynamic storage, existing pipeline commitments, crude-by-rail loading capacity and financial hedge transactions to partially mitigate a portion of the Company's WCS crude oil volumes against wider differentials; the Company's ability to produce from oil sands facilities on an unconstrained basis; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; the accuracy of accounting estimates and judgments; the Company's ability to obtain necessary regulatory and partner approvals; the successful, timely and cost effective implementation of capital projects, development projects or stages thereof; the Company's ability to generate sufficient cash flow to meet current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; the Company's ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; the Company's ability to complete acquisitions and dispositions, including with desired transaction metrics and within expected timelines; the accuracy of climate scenarios and assumptions, including third party data on which the Company relies; ability to access and implement all technology and equipment necessary to achieve expected future results, including in respect of climate and GHG emissions targets and ambitions and the commercial viability and scalability of emission reduction strategies and related technology and products; continuing; collaboration with the government, Oil Sands Pathways to Net Zero and other industry organizations; expected impacts of the contingent payment to ConocoPhillips; alignment of realized WCS and WCS prices used to calculate the contingent payment to ConocoPhillips; market and business conditions; forecast inflation and other assumptions inherent in Cenovus's 2022 guidance available on cenovus.com and as set out below; the availability of Indigenous owned or operated businesses and Cenovus's ability to retain them; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2022 guidance, as updated April 26, 2022 and available on cenovus.com, assumes: Brent prices of US$99.00 per barrel, WTI prices of US$94.00 per barrel; WCS of US$81.00 per barrel; Differential WTI-WCS of US$13.00 per barrel; AECO natural gas prices of $5.20 per thousand cubic feet; Chicago 3-2-1 crack spread of US$26.00 per barrel; and an exchange rate of $0.80 US$/C$.

The risk factors and uncertainties that could cause the Company's actual results to differ materially from the forward-looking information, include, but are not limited to: the effect of the COVID-19 pandemic, including any variants thereof, on the Company's business, including any related restrictions, containment, and treatment measures taken by varying levels of government in the jurisdictions in which the Company operates; the success of the Company's new COVID-19 workplace policies and the return of people to the Company's workplace; the Company's ability to realize the anticipated benefits of the Arrangement in a timely manner or at all; the Company's ability to successfully integrate the legacy Husky business with its own in a timely and cost effective manner; unforeseen or underestimated liabilities associated with the Arrangement; risks associated with acquisitions and dispositions; the Company's ability to access or implement some or all of the technology necessary to efficiently and effectively operate its assets and achieve expected future results including in respect of climate and GHG emissions targets and ambitions and the commercial viability and scalability of emission reduction strategies and related technology and products; the development and execution of implementing strategies to meet climate and GHG emissions targets and ambitions; the effect of new significant shareholders; volatility of and other assumptions regarding commodity prices; the duration of any market downturn; foreign exchange risk, including related to agreements denominated in foreign currencies; the Company's continued liquidity is sufficient to sustain operations through a prolonged market downturn; WTI-WCS differential in Alberta does not remain largely tied to the extent to which voluntary economically driven supply cuts are made, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, the completion of the Trans Mountain Expansion project, and the level of crude-by-rail activity; the Company's ability to achieve lower transportation costs as a result of temporarily suspending the crude-by-rail program; the Company's ability to realize the expected impacts of its capacity to store within its oil sands reservoirs barrels not yet produced, including possible inability to time production and sales at later dates when pipeline and/or storage capacity and crude oil differentials have improved; the effectiveness of the Company's risk management program; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; the accuracy of the Company's share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in the Company's marketing operations, including credit risks, exposure to counterparties and partners, including the ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of the Company's crude-by-rail terminal, including health, safety and environmental risks; the Company's ability to maintain desirable ratios of Net Debt to Adjusted EBITDA and Net Debt to Adjusted Funds Flow; the Company's ability to access various sources of debt and equity capital, generally, and on acceptable terms; the Company's ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to the Company or any of its securities; changes to the Company's dividend plans; the Company's ability to utilize tax losses in the future; the accuracy of the Company's reserves, future production and future net revenue estimates; the accuracy of the Company's accounting estimates and judgements; the Company's ability to replace and expand crude oil and natural gas reserves; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project developments; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of the Company's assets or goodwill from time to time; the Company's ability to maintain its relationships with its partners and to successfully manage and operate its integrated operations and business; reliability of the Company's assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events resulting in operational interruptions, including blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, gaseous leaks, migration of harmful substances, loss of containment, releases or spills, including releases or spills from offshore facilities and shipping vessels at terminals or hubs and as a result of pipeline or other leaks, corrosion, epidemics or pandemics, and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, iceberg incidents, acts of vandalism and terrorism, and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, such as labour, materials, natural gas and other energy sources used in oil sands processes and increased insurance deductibles or premiums; the cost and availability of equipment necessary to the Company's operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and the Company's reputation, social license to operate and litigation related thereto; unexpected cost increases or technical difficulties in operating, constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and equipment and its application to the Company's business, including potential cyberattacks; geo-political and other risks associated with the Company's international operations; risks associated with climate change and the Company's assumptions relating thereto; the timing and the costs of well and pipeline construction; the Company's ability to access markets and to secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system or storage capacity; availability of, and the Company's ability to attract and retain, critical talent; possible failure to obtain and retain qualified leadership and personnel, and equipment in a timely and cost efficient manner; changes in labour demographics and relationships, including with any unionized workforces; unexpected abandonment and reclamation costs; changes in the regulatory frameworks, permits and approvals in any of the locations in which the Company operates or to any of the infrastructure upon which it relies; government actions or regulatory initiatives to curtail energy operations or pursue broader climate change agendas; changes to regulatory approval processes and land use designations, royalty, tax, environmental, GHG, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on the Company's business, its financial results and Consolidated Financial Statements; changes in general economic, market and business conditions; the impact of production agreements among OPEC and non-OPEC members; the political, social and economic conditions in the jurisdictions in which the Company operates or supplies; the status of the Company's relationships with the communities in which it operates, including with Indigenous communities; the occurrence of unexpected events such as protests, pandemics, war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, shareholder proposals and regulatory actions against the Company. In addition, there are risks that the effect of actions taken by us in implementing targets, commitments and ambitions for ESG focus areas may have a negative impact on our existing business, growth plans and future results from operations.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of the Company's material risk factors, see Risk Management and Risk Factors in this MD&A, and to the risk factors described in other documents the Company files from time to time with securities regulatory authorities in Canada, available on SEDAR at sedar.com, and with the U.S. Securities and Exchange Commission on EDGAR at sec.gov, and on the Company's website at cenovus.com.

Information on or connected to the Company's website at cenovus.com does not form part of this MD&A unless expressly incorporated by reference herein.

ABBREVIATIONS

The following abbreviations have been used in this document:

Crude Oil		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
MMbbls	million barrels	MMcf/d	million cubic feet per day
BOE	barrel of oil equivalent	Bcf	billion cubic feet
MBOE	thousand barrels of oil equivalent	MMBtu	million British thermal units
MBOE/d	thousand barrels of oil equivalent per day	GJ	gigajoule
MMBOE	million barrels of oil equivalent	AECO	Alberta Energy Company
WTI	West Texas Intermediate	NYMEX	New York Mercantile Exchange
WCS	Western Canadian Select		
HSB	Husky Synthetic Blend		

SPECIFIED FINANCIAL MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS including Operating Margin, Operating Margin for the Upstream or Downstream segment, Operating Margin by asset, Total Integration Costs, Adjusted Funds Flow, Free Funds Flow, Net Debt, Total Debt, Net Debt to Adjusted EBITDA Ratio, Net Debt to Adjusted Funds Flow Ratio, Net Debt to Capitalization Ratio, Net Debt Target, Net Debt to Adjusted EBITDA Ratio Target, Net Debt to Adjusted Funds Flow Ratio Target, Long-Term Financial Liabilities, Capital Investment by Asset, Gross Margin, Refining Margin, Unit Operating Costs, Forward-looking Operating Costs per Barrel, Forward-looking Capital Investment, Forward-looking Integration Costs, Per Unit DD&A and Netbacks (including the per BOE components of netbacks and total netbacks per BOE).

These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation, if applicable, of each non-GAAP financial measure or specified financial measure is presented in this Advisory and may also be presented in the Operating and Financial Results or Liquidity and Capital Resources sections of this MD&A.

Operating Margin

Operating Margin and Operating Margin by asset are non-GAAP financial measures, and Operating Margin for the Upstream or Downstream segment are specified financial measures. These are used to provide a consistent measure of the cash generating performance of our operations and assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Margin.

	Q1 2022		
($ millions)	Upstream (1)	Downstream (1)	Total
Revenues			
Gross Sales	**10,897**	**8,247**	**19,144**
Less: Royalties	**1,185**	**—**	**1,185**
	9,712	**8,247**	**17,959**
Expenses			
Purchased Product	**2,089**	**6,946**	**9,035**
Transportation and Blending	**2,923**	**2**	**2,925**
Operating	**909**	**645**	**1,554**
Realized (Gain) Loss on Risk Management	**871**	**110**	**981**
Operating Margin	**2,920**	**544**	**3,464**

(1) *Found in Note 1 of the interim Consolidated Financial Statements.*

	2021														
	Upstream					**Downstream**					**Total**				
($ millions)	2021	Q4	Q3	Q2	Q1	2021	Q4	Q3	Q2	Q1	2021	Q4	Q3	Q2	Q1
Revenues															
Gross Sales [1]	27,844	8,237	7,354	6,128	6,125	26,673	8,135	7,530	6,318	4,690	54,517	16,372	14,884	12,446	10,815
Less: Royalties	2,454	815	733	533	373	—	—	—	—	—	2,454	815	733	533	373
	25,390	7,422	6,621	5,595	5,752	26,673	8,135	7,530	6,318	4,690	52,063	15,557	14,151	11,913	10,442
Expenses															
Purchased Product [1]	4,843	1,410	1,270	921	1,242	23,526	7,348	6,708	5,502	3,968	28,369	8,758	7,978	6,423	5,210
Transportation and Blending	7,930	2,387	1,941	1,802	1,800	—	—	—	—	—	7,930	2,387	1,941	1,802	1,800
Operating	3,241	865	800	791	785	2,258	689	537	515	517	5,499	1,554	1,337	1,306	1,302
Realized (Gain) Loss on Risk Management	788	202	168	188	230	104	56	17	10	21	892	258	185	198	251
Operating Margin	8,588	2,558	2,442	1,893	1,695	785	42	268	291	184	9,373	2,600	2,710	2,184	1,879

(1) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Operating Margin by Asset

	Q1 2022		
($ millions)	**Asia Pacific**	**Atlantic**	**Offshore [1]**
Revenues			
Gross Sales	**395**	**172**	**567**
Less: Royalties	**22**	**10**	**32**
	373	**162**	**535**
Expenses			
Transportation and Blending	**—**	**4**	**4**
Operating	**27**	**46**	**73**
Operating Margin	**346**	**112**	**458**

	Q1 2021		
($ millions)	Asia Pacific	Atlantic	Offshore [1]
Revenues			
Gross Sales	321	110	431
Less: Royalties	17	8	25
	304	102	406
Expenses			
Transportation and Blending	—	4	4
Operating	22	36	58
Operating Margin	282	62	344

(1) Found in Note 1 of the interim Consolidated Financial Statements.

Total Integration Costs

Total Integration Costs is a non-GAAP financial measure representing costs incurred as a result of the Arrangement, excluding share issuance costs.

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Integration Costs [1]	**24**	223
Capitalized Integration Costs [2]	**2**	22
Total Integration Costs	**26**	245

(1) Per the interim Consolidated Statements of Earnings (Loss).
(2) Included in capital expenditures on the interim Consolidated Statements of Cash Flows.

Adjusted Funds Flow and Free Funds Flow

Adjusted Funds Flow is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Adjusted Funds Flow is defined as cash from (used in) operating activities excluding settlement of decommissioning liabilities and net change in non-cash working capital. Non-cash working capital is composed of accounts receivable and accrued revenues, inventories (excluding non-cash inventory write-downs and reversals), income tax receivable, accounts payable and accrued liabilities and income tax payable.

Free Funds Flow is a non-GAAP financial measure used to assist in measuring the available funds the Company has after financing its capital programs. Free Funds Flow is defined as cash from (used in) operating activities excluding settlement of decommissioning liabilities and net change in non-cash working capital minus capital investment.

	2022	2021				2020			
($ millions)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Cash From (Used in) Operating Activities	**1,365**	2,184	2,138	1,369	228	250	732	(834)	125
(Add) Deduct:									
Settlement of Decommissioning Liabilities	**(19)**	(35)	(38)	(18)	(11)	(6)	(3)	(2)	(31)
Net Change in Non-Cash Working Capital	**(1,199)**	271	(166)	(430)	(902)	(77)	328	(363)	310
Adjusted Funds Flow	**2,583**	1,948	2,342	1,817	1,141	333	407	(469)	(154)
Capital Investment	**746**	835	647	534	547	242	148	147	304
Free Funds Flow	**1,837**	1,113	1,695	1,283	594	91	259	(616)	(458)

Debt Measures and Targets

Our Net Debt, Total Debt, Net Debt Target, Net Debt to Capitalization Ratio, Net Debt to Adjusted EBITDA Ratio, Net Debt to Adjusted Funds Flow Ratio, Net Debt to Adjusted EBITDA Ratio Target and Net Debt to Adjusted Funds Flow Ratio Target measures are used to steward our overall debt position and as measures of our overall financial strength.

Net Debt is a specified financial measure used to monitor our capital structure. Our forward-looking Net Debt Target is the desired amount of Net Debt that the Company strives to achieve and maintain. Net Debt is defined as Total Debt net of cash and cash equivalents and short-term investments. Total Debt is defined as short-term borrowings plus the current and long-term portions of long-term debt.

We define Capitalization as Net Debt plus Shareholders' Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense (recovery), DD&A, exploration expense, goodwill impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, other income (loss), net and share of income (loss) from equity-accounted investees calculated on a trailing twelve-month basis.

	2022	2021				2020			
As at ($ millions)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Short-Term Borrowings (1)	**62**	79	48	65	266	121	137	299	602
Current Portion of Long-Term Debt (1)	**—**	—	545	632	—	—	—	—	—
Long-Term Debt (1)	**11,744**	12,385	12,441	12,748	13,947	7,441	7,797	8,085	6,979
Total Debt	**11,806**	12,464	13,034	13,445	14,213	7,562	7,934	8,384	7,581
Less: Cash and Cash Equivalents (1)	**(3,399)**	(2,873)	(2,010)	(1,055)	(873)	(378)	(404)	(152)	(160)
Net Debt	**8,407**	9,591	11,024	12,390	13,340	7,184	7,530	8,232	7,421
Shareholders' Equity (1)	**24,614**	23,596	24,373	23,629	23,618	16,707	17,032	17,311	17,734
Capitalization	**33,021**	33,187	35,397	36,019	36,958	23,891	24,562	25,543	25,155
Net Debt to Capitalization Ratio (percent)	**25**	29	31	34	36	30	31	32	30
Adjusted EBITDA (2)(3)	**9,934**	8,086	6,327	4,369	2,584	606	900	1,360	2,386
Net Debt to Adjusted EBITDA Ratio (times)	**0.8**	1.2	1.7	2.8	5.2	11.9	8.4	6.1	3.1
Adjusted Funds Flow (2)(3)	**8,690**	7,248	—	—	—	—	—	—	—
Net Debt to Adjusted Funds Flow Ratio (4) (times)	**1.0**	1.3	—	—	—	—	—	—	—

(1) Per the interim Consolidated Balance Sheets.
(2) Per Note 17 of the interim Consolidated Financial Statements.
(3) Calculated on a trailing twelve-month basis.
(4) New financial metric for monitoring our capital structure and financing requirements as of March 31, 2022.

Total Long-Term Liabilities

Total Long-Term Liabilities is a non-GAAP financial measure. The measure is disclosed to fulfill the requirements of National Instrument 51-102, "*Continuous Disclosure Obligations*" and is defined as total liabilities less total current liabilities.

	2022	2021				2020			
As at ($ millions)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total Liabilities	**31,029**	30,496	30,053	29,580	29,589	16,063	15,825	16,608	15,662
Less: Total Current Liabilities	**9,140**	7,305	7,124	6,608	5,323	2,359	1,936	2,160	2,335
Total Long-Term Liabilities	**21,889**	23,191	22,929	22,972	24,266	13,704	13,889	14,448	13,327

Gross Margin, Refining Margin and Unit Operating Expense

Gross Margin, Refining Margin and Unit Operating Expense are specified financial measures used to evaluate the performance of our downstream operations. We define Gross Margin as revenues less purchased product. We define Refining Margin as Gross Margin divided by barrels of crude throughput. We define Unit Operating Expense as operating expenses divided by barrels of crude throughput.

Canadian Manufacturing

	Q1 2022				
($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Basis of Refining Margin and Unit Operating Expense Calculation	Other (1)	Per Consolidated Interim Financial Statements
Revenues	802	184	986	58	1,044
Purchased Product	647	143	790	14	804
Gross Margin	155	41	196	44	240
Operating expenses	67	30	97	27	124

	Operating Statistics		
	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Crude Throughput (Mbbls/d)	70.7	27.4	98.1
Refining Margin ($/bbl)	24.37	16.61	22.20
Unit Operating Expense ($/bbl)	10.59	12.01	10.99

(1) Includes ethanol and crude-by-rail operations, and marketing activities.

	2021														
	Lloydminster Upgrader					Lloydminster Refinery					Basis of Refining Margin and Unit Operating Expense Calculation				
($ millions)	2021	Q4	Q3	Q2	Q1	2021	Q4	Q3	Q2	Q1	2021	Q4	Q3	Q2	Q1
Revenues	2,559	748	684	601	526	817	206	278	197	136	3,376	954	962	798	662
Purchased Product	2,041	592	556	484	409	659	172	230	152	105	2,700	764	786	636	514
Gross Margin	518	156	128	117	117	158	34	48	45	31	676	190	176	162	148
Operating Expenses	211	55	54	52	50	84	25	20	20	19	295	80	74	72	69
	Basis of Refining Margin and Unit Operating Expense Calculation					Other (1)					Per Interim Consolidated Financial Statements				
Revenues	3,376	954	962	798	662	1,096	409	253	290	144	4,472	1,363	1,215	1,088	806
Purchased Product	2,700	764	786	636	514	852	364	200	171	117	3,552	1,128	986	807	631
Gross Margin	676	190	176	162	148	244	45	53	119	27	920	235	229	281	175
Operating Expenses	295	80	74	72	69	93	24	25	20	24	388	104	99	92	93

(1) Includes ethanol and crude-by-rail operations, and marketing activities.

	2021														
	Operating Statistics														
	Lloydminster Upgrader					Lloydminster Refinery					Lloydminster Upgrader and Lloydminster Refinery Total				
	2021	Q4	Q3	Q2	Q1	2021	Q4	Q3	Q2	Q1	2021	Q4	Q3	Q2	Q1
Crude Throughput (Mbbls/d)	79.0	80.4	81.2	76.1	78.4	27.5	27.9	27.1	27.4	27.8	106.5	108.3	108.3	103.5	106.2
Refining Margin [1] ($/bbl)	17.99	21.05	16.93	16.90	16.64	15.64	13.25	19.29	18.03	12.43	17.35	18.95	17.57	17.19	15.54
Unit Operating Expense [1] ($/bbl)	7.28	7.44	7.43	7.44	7.53	8.35	9.81	7.86	7.93	7.75	7.55	7.99	7.38	7.57	7.22

(1) Comparative periods have been restated for the total Canadian Manufacturing refining margin and unit operating expense per barrel metrics to exclude ethanol, crude-by-rail operations and marketing activities from the basis of the calculation.

U.S. Manufacturing

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Revenues [1]	**6,509**	3,437
Purchased Product [1]	**5,482**	2,920
Gross Margin	**1,027**	517
Crude Throughput (Mbbls/d)	**403.7**	362.9
Refining Margin ($/bbl)	**28.26**	15.84

(1) Found in Note 1 of the interim consolidated financial statements.

Retail

	Three Months Ended March 31,	
($ millions)	**2022**	2021
Revenues [1]	**694**	447
Purchased Product [1]	**660**	417
Gross Margin	**34**	30

(1) Found in Note 1 of the interim Consolidated Financial Statements.

Per Unit DD&A

Per Unit DD&A is a specified financial measure used to measure DD&A on a per-unit of production basis. We define Per Unit DD&A as DD&A divided by production.

	Q1 2022		
($ millions)	**Per Consolidated Financial Statements** [1]	**Reconciling Items** [2]	**Basis of DD&A per BOE Calculation**
Oil Sands	**635**	**13**	**648**
Conventional	**80**	**12**	**92**
Offshore	**150**	**(6)**	**144**

	Q1 2021		
($ millions)	Per Consolidated Financial Statements [1]	Reconciling Items [2]	Basis of DD&A per BOE Calculation
Oil Sands	612	(49)	563
Conventional	108	(2)	106
Offshore	125	(5)	120

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Includes items depreciated on a straight-line basis, right-of-use assets and asset retirement costs.

Netback Reconciliations

Netback is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. Netbacks reflect our margin on a per-barrel of oil equivalent basis. Netback is defined as gross sales less royalties, transportation and blending and operating expenses divided by sales volumes. Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold. The sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with crude oil to transport it to market.

The following tables provide a reconciliation of the items comprising Netbacks to Operating Margin found in our interim Consolidated Financial Statements.

Total Production

Upstream Financial Results

Three Months Ended March 31, 2022 ($ millions)	Per Interim Consolidated Financial Statements Total Upstream [1]	Adjustments Condensate	Third-Party Sourced	Internal Consumption [2]	Equity Adjustment [3]	Other [4]	Basis of Netback Calculation Total Upstream
Gross Sales	10,897	(2,487)	(2,021)	(239)	61	(76)	6,135
Royalties	1,185	—	—	—	28	—	1,213
Purchased Product	2,089	—	(2,021)	—	—	(68)	—
Transportation and Blending	2,923	(2,487)	—	—	—	1	437
Operating	909	—	—	(239)	7	(21)	656
Netback	3,791	—	—	—	26	12	3,829
Realized (Gain) Loss on Risk Management	871	—	(4)	—	—	—	867
Operating Margin	2,920	—	4	—	26	12	2,962

Three Months Ended March 31, 2021 ($ millions)	Per Interim Consolidated Financial Statements Total Upstream [1]	Adjustments Condensate	Third-Party Sourced	Internal Consumption [2]	Equity Adjustment [3]	Other [4]	Basis of Netback Calculation Total Upstream
Gross Sales [5]	6,125	(1,368)	(1,196)	(149)	52	(90)	3,374
Royalties	373	—	—	—	7	—	380
Purchased Product [5]	1,242	—	(1,196)	—	—	(46)	—
Transportation and Blending	1,800	(1,368)	—	—	—	(3)	429
Operating	785	—	—	(149)	5	(11)	630
Netback	1,925	—	—	—	40	(30)	1,935
Realized (Gain) Loss on Risk Management	230	—	—	—	—	—	230
Operating Margin	1,695	—	—	—	40	(30)	1,705

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.
(3) Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(4) Other includes construction, transportation and blending and third-party processing margin.
(5) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Oil Sands

Three Months Ended March 31, 2022 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands [1]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
	Basis of Netback Calculation						
Gross Sales	**1,820**	**2,232**	**232**	**976**	**5,260**	**4**	**5,264**
Royalties	**388**	**584**	**11**	**99**	**1,082**	**—**	**1,082**
Purchased Product	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Transportation and Blending	**178**	**151**	**30**	**38**	**397**	**—**	**397**
Operating	**202**	**219**	**39**	**221**	**681**	**6**	**687**
Netback	**1,052**	**1,278**	**152**	**618**	**3,100**	**(2)**	**3,098**
Realized (Gain) Loss on Risk Management							**867**
Operating Margin							**2,231**

Three Months Ended March 31, 2022 ($ millions)	Basis of Netback Calculation: Total Oil Sands	Adjustments: Condensate	Adjustments: Third-party Sourced	Adjustments: Other [3]	Per Interim Consolidated Financial Statements [2]: Total Oil Sands
Gross Sales	**5,264**	**2,487**	**1,415**	**52**	**9,218**
Royalties	**1,082**	**—**	**—**	**—**	**1,082**
Purchased Product	**—**	**—**	**1,415**	**68**	**1,483**
Transportation and Blending	**397**	**2,487**	**—**	**1**	**2,885**
Operating	**687**	**—**	**—**	**15**	**702**
Netback	**3,098**	**—**	**—**	**(32)**	**3,066**
Realized (Gain) Loss on Risk Management	**867**	**—**	**—**	**—**	**867**
Operating Margin	**2,231**	**—**	**—**	**(32)**	**2,199**

Three Months Ended March 31, 2021 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands [1]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
	Basis of Netback Calculation						
Gross Sales	852	995	123	696	2,666	3	2,669
Royalties	107	167	3	47	324	—	324
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	173	130	24	80	407	—	407
Operating	169	164	31	211	575	5	580
Netback	403	534	65	358	1,360	(2)	1,358
Realized (Gain) Loss on Risk Management							229
Operating Margin							1,129

Three Months Ended March 31, 2021 ($ millions)	Basis of Netback Calculation: Total Oil Sands	Adjustments: Condensate	Adjustments: Third-party Sourced	Adjustments: Other [3]	Per Interim Consolidated Financial Statements [2]: Total Oil Sands
Gross Sales [4]	2,669	1,368	815	66	4,918
Royalties	324	—	—	—	324
Purchased Product [4]	—	—	815	46	861
Transportation and Blending	407	1,368	—	3	1,778
Operating	580	—	—	5	585
Netback	1,358	—	—	12	1,370
Realized (Gain) Loss on Risk Management	229	—	—	—	229
Operating Margin	1,129	—	—	12	1,141

(1) *Includes Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets. Sale of the Tucker asset closed on January 31, 2022.*
(2) *Found in Note 1 of the interim Consolidated Financial Statements.*
(3) *Other includes construction, transportation and blending margin.*
(4) *Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.*

Conventional

Three Months Ended March 31, 2022 ($ millions)	Basis of Netback Calculation	Adjustments		Per Consolidated Financial Statements [1]
	Conventional	Third-party Sourced	Other [2]	Conventional
Gross Sales	482	606	24	1,112
Royalties	71	—	—	71
Purchased Product	—	606	—	606
Transportation and Blending	36	—	(2)	34
Operating	128	—	6	134
Netback	247	—	20	267
Realized (Gain) Loss on Risk Management	—	4	—	4
Operating Margin	247	(4)	20	263

Three Months Ended March 31, 2021 ($ millions)	Basis of Netback Calculation	Adjustments		Per Consolidated Financial Statements [1]
	Conventional	Third-party Sourced	Other [2]	Conventional
Gross Sales	371	381	24	776
Royalties	24	—	—	24
Purchased Product	—	381	—	381
Transportation and Blending	18	—	—	18
Operating	136	—	6	142
Netback	193	—	18	211
Realized (Gain) Loss on Risk Management	1	—	—	1
Operating Margin	192	—	18	210

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Reflects operating margin from processing facility.

Offshore

Three Months Ended March 31, 2022 ($ millions)	Basis of Netback Calculation					Adjustment	Per Consolidated Financial Statements [2]
	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Total Offshore
Gross Sales	395	61	456	172	628	(61)	567
Royalties	22	28	50	10	60	(28)	32
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	4	4	—	4
Operating	23	11	34	46	80	(7)	73
Netback	350	22	372	112	484	(26)	458
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					484	(26)	458

Three Months Ended September 30, 2021 ($ millions)	Basis of Netback Calculation					Adjustment	Per Consolidated Financial Statements [2]
	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Total Offshore
Gross Sales	336	60	396	68	464	(60)	404
Royalties	20	11	31	4	35	(11)	24
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	3	3	—	3
Operating	27	7	34	21	55	(6)	49
Netback	289	42	331	40	371	(43)	328
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					371	(43)	328

(1) Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(2) Found in Note 1 of the interim Consolidated Financial Statements.

Three Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Adjustment Equity Adjustment [1]	Per Consolidated Financial Statements [2] Total Offshore
Gross Sales	308	50	358	119	477	(50)	427
Royalties	16	5	21	9	30	(5)	25
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	3	3	—	3
Operating	23	8	31	35	66	(7)	59
Netback	269	37	306	72	378	(38)	340
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					378	(38)	340

Three Months Ended March 31, 2021 ($ millions)	Basis of Netback Calculation China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Adjustment Equity Adjustment [1]	Per Consolidated Financial Statements [2] Total Offshore
Gross Sales	321	52	373	110	483	(52)	431
Royalties	17	7	24	8	32	(7)	25
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	4	4	—	4
Operating	21	6	27	36	63	(5)	58
Netback	283	39	322	62	384	(40)	344
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					384	(40)	344

(1) Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(2) Found in Note 1 of the interim Consolidated Financial Statements.

Sales Volumes [(1)]

The following table provides the sales volumes used to calculate Netback:

(MBOE/d)	Three Months Ended March 31, 2022	2021
Oil Sands		
Foster Creek	**200.1**	175.0
Christina Lake	**263.4**	217.5
Sunrise [(2)]	**25.3**	24.2
Other Oil Sands	**121.1**	144.1
Total Oil Sands [(2)]	**609.9**	560.8
Conventional	**125.2**	135.9
Sales before Internal Consumption	**735.1**	696.7
Less: Internal Consumption [(3)]	**(87.9)**	(86.5)
Sales after Internal Consumption	**647.2**	610.2
Offshore		
Asia Pacific - China	**53.6**	51.4
Asia Pacific - Indonesia	**9.1**	9.4
Asia Pacific - Total	**62.7**	60.8
Atlantic	**14.6**	14.9
Total Offshore	**77.3**	75.7
Total Sales	**724.5**	685.9

(1) Presented on dry bitumen basis.
(2) Sunrise sales volumes have been re-presented to reflect a change in classification of marketing activities for the first quarter of 2021.
(3) Less natural gas volumes used for internal consumption by the Oil Sands segment.