Cenovus Energy Inc.

Management's Discussion and Analysis (unaudited)

For the Periods Ended June 30, 2022

(Canadian Dollars)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the periods ended June 30, 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 July 27, 2022 should be read in conjunction with our June 30, 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 July 27, 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 six months ended June 30, 2022, crude oil production from our Oil Sands assets averaged 575.8 thousand barrels per day and total upstream production averaged 779.9 thousand BOE per day. Downstream crude oil throughput was 479.4 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 maximizing shareholder value through competitive cost structures and optimizing margins, while delivering top-tier safety performance and environmental, 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 released our 2022 budget. Our 2022 guidance was updated on July 27, 2022 and is available on our website at cenovus.com. For further details see the Operating and Financial Results section of this MD&A.

Shareholder Returns and Capital Allocation Framework

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. On April 27, 2022, we announced our updated capital allocation framework to 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 of $4 billion, which serves as a floor on Net Debt. When Net Debt is less than $9 billion and above $4 billion at quarter-end, we will target to allocate 50 percent of the Excess Free Funds Flow achieved in the following quarter 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 at quarter-end, we plan to allocate all of the following quarter’s Excess Free Funds Flow to deleveraging the balance sheet. When Net Debt is at the $4 billion floor at quarter-end, we will target to return 100 percent of the following quarter’s Excess Free Funds Flow to shareholders through share buybacks and/or variable dividends.

Excess Free Funds Flow is defined as Free Funds Flow[(1)]:

- 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 or less any payments related to divestiture activities closing in the quarter.

The Company’s capital allocation framework enables a shift to paying out a higher percentage of Excess Free Funds Flow to common 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 of approximately 1.0 times at the bottom of the cycle.

(1) See the Liquidity and Capital Resources section of this MD&A for the calculation of Free Funds Flow.

Based on the capital allocation framework described above, we plan to return incremental value 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 the following 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 the following quarter's Excess Free Funds Flow in the form of share buybacks and/or variable dividends.

Share buybacks will be our preferred mechanism for shareholder returns, 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 payable for that 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.

On March 31, 2022, our Net Debt position was $8.4 billion and as a result, in accordance with our capital allocation framework, our returns to shareholders target for the three months ended June 30, 2022 was 50 percent of that quarter's Excess Free Funds Flow. During the three months ended June 30, 2022, we generated cash from operating activities of $3.0 billion, Excess Free Funds Flow of $2.0 billion and returned $1.0 billion to our shareholders through share buybacks. As such, we met our return to shareholders target for the quarter exclusively through share buybacks.

($ millions)	Three Months Ended June 30, 2022
Excess Free Funds Flow [1]	**2,020**
Target Return [2]	**1,010**
Less: Purchase of Common Shares Under our Normal Course Issuer Bid ("NCIB")	**(1,018)**
Excess Returns to Shareholders Over Target	**(8)**

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Based on our capital allocation framework, as a result of Net Debt as at March 31, 2022 being less than $9 billion and greater than $4 billion, Target Return was determined to be 50 percent of Excess Free Funds Flow for the three months ended June 30, 2022.

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 have identified safety and asset integrity, and corporate governance as foundational to our business, providing the backbone for all our operations. We 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 in each of 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 2021 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 June 30, 2022, our long-term debt, including current portion, was $11.2 billion (December 31, 2021 – $12.4 billion) and our Net Debt position was $7.5 billion (December 31, 2021 – $9.6 billion). Our Net Debt to Adjusted EBITDA Ratio was 0.6 times and our Net Debt to Adjusted Funds Flow Ratio was 0.8 times at June 30, 2022. Maintaining a strong balance sheet provides financial flexibility to manage our business through commodity price volatility.

Returns-focused Capital Allocation

The Company's sustaining capital program and base dividend are sustainable at US$45 WTI per barrel, and provide opportunities to sustainably grow shareholder returns. On July 27, 2022, the Company's Board of Directors declared a third quarter base dividend of $0.105 per common share payable on September 29, 2022, to common shareholders of record as at September 15, 2022. In addition, during the three and six months ended June 30, 2022, we returned $1.0 billion and $1.5 billion, respectively, to our shareholders through share buybacks.

On June 13, 2022, Cenovus announced it reached an agreement with BP Canada Energy Group ULC ("BP Canada") to acquire BP Canada's 50 percent interest in the Sunrise oil sands project in northern Alberta. This will increase Cenovus's interest in Sunrise to 100 percent and further enhance Cenovus's core strength in the oil sands. The sale is expected to close in the third quarter of 2022. Gross production from the assets is currently approximately 50,000 barrels per day and we expect to achieve nameplate capacity of 60,000 barrels per day through a multi-year development program. The acquisition is expected to be immediately accretive to adjusted funds flow and cash from operating activities.

In 2022, we anticipate our total capital expenditures will be between $3.3 billion and $3.7 billion, including $500 million to $550 million (excluding insurance proceeds) for the Superior Refinery rebuild. We will continue to be disciplined with our capital allocation.

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.

Cenovus has a track record of operational reliability. We expect our annual upstream production to average between 780 thousand BOE per day and 810 thousand BOE per day and total downstream crude oil 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 2022 guidance as updated on July 27, 2022, is available on our website at cenovus.com.

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 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, the sale of condensate extracted from blended crude oil production at our Canadian Manufacturing operations and sold back to the Oil Sands segment, and diesel production in the Canadian Manufacturing segment sold to the Retail segment and unrealized profits in inventory. Eliminations are recorded based on current market prices.

QUARTERLY RESULTS OVERVIEW

During the second quarter of 2022, we continued to deliver solid operating and financial performance while completing significant planned turnarounds and maintenance in our upstream and downstream operations. Commodity prices remained very strong with WTI averaging US$108.41, an increase of 15 percent from the first quarter of 2022, and 64 percent from the second quarter of 2021. Market crack spreads more than doubled compared with the first quarter of 2022. Overall, our continued focus on health and safety and competitive cost structures, combined with high commodity prices, drove solid financial results. We reduced Net Debt by $872 million from March 31, 2022, and returned $1.2 billion to shareholders through share buybacks and dividends.

Summary of Quarterly Results

($ millions, except where indicated)	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021	2022 Q2	2022 Q1	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4	2020 Q3	2020 Q2
Production Volumes [1] (MBOE/d)	**779.9**	767.6	**761.5**	798.6	825.3	804.8	765.9	769.3	467.2	471.8	465.4
Crude Oil Throughput [2] (Mbbls/d)	**479.4**	504.2	**457.3**	501.8	469.9	554.1	539.0	469.1	169.0	191.1	162.3
Revenues [3]	**35,363**	19,930	**19,165**	16,198	13,726	12,701	10,637	9,293	3,543	3,737	2,311
Operating Margin [4]	**8,142**	4,063	**4,678**	3,464	2,600	2,710	2,184	1,879	625	594	291
Cash From (Used in) Operating Activities	**4,344**	1,597	**2,979**	1,365	2,184	2,138	1,369	228	250	732	(834)
Adjusted Funds Flow [4]	**5,681**	2,958	**3,098**	2,583	1,948	2,342	1,817	1,141	333	407	(469)
Capital Investment	**1,568**	1,081	**822**	746	835	647	534	547	242	148	147
Free Funds Flow [4]	**4,113**	1,877	**2,276**	1,837	1,113	1,695	1,283	594	91	259	(616)
Excess Free Funds Flow [4][5]	**4,635**	1,706	**2,020**	2,615	1,169	1,626	1,244	462	N/A	N/A	N/A
Net Earnings (Loss) [6]	**4,057**	444	**2,432**	1,625	(408)	551	224	220	(153)	(194)	(235)
Per Share - Basic ($)	**2.04**	0.21	**1.23**	0.81	(0.21)	0.27	0.11	0.10	(0.12)	(0.16)	(0.19)
Per Share - Diluted ($)	**1.98**	0.21	**1.19**	0.79	(0.21)	0.27	0.11	0.10	(0.12)	(0.16)	(0.19)
Total Assets	**55,894**	53,384	**55,894**	55,655	54,104	54,594	53,384	53,378	32,770	32,857	33,919
Total Long-Term Liabilities	**20,742**	22,972	**20,742**	21,889	23,191	22,929	22,972	24,266	13,704	13,889	14,448
Long-Term Debt, Including Current Portion [7]	**11,228**	13,380	**11,228**	11,744	12,385	12,986	13,380	13,947	7,441	7,797	8,085
Net Debt	**7,535**	12,390	**7,535**	8,407	9,591	11,024	12,390	13,340	7,184	7,530	8,232
Cash Returns to Shareholders											
Common Shares – Base Dividends	**276**	71	**207**	69	70	35	36	35	—	—	—
Base Dividends Per Common Share ($)	**0.1400**	0.0350	**0.1050**	0.0350	0.0350	0.0175	0.0175	0.0175	—	—	—
Purchase of Common Shares Under NCIB	**1,484**	—	**1,018**	466	265	—	—	—	—	—	—
Preferred Share Dividends	**17**	17	**8**	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, and to more appropriately reflect the cost of blending. 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) New metric as of June 30, 2022, used to determine returns to shareholders.
(6) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.
(7) Includes current portion of long-term debt of $nil as at June 30, 2022, March 31, 2022, and December 31, 2021, $545 million as at September 30, 2021, $632 million as at June 30, 2021, and $nil as at March 31, 2021, December 31, 2020, September 30, 2020, and June 30, 2020.

Operations performed well in the second quarter, impacted by planned maintenance and turnaround activity in our upstream and downstream businesses.

- We delivered safe and reliable operations at our operated assets.
- We completed planned turnarounds in our upstream operations at Christina Lake and at the Lloydminster Upgrader and Refinery, and the Wood River and Borger refineries in our downstream operations. We commenced a planned turnaround at the Toledo Refinery in the second quarter, which was substantially completed in July.
- Generated first steam at our Spruce Lake North thermal plant. Production is expected in the third quarter of this year.
- Upstream production averaged 761.5 thousand BOE per day in the second quarter, compared with 798.6 thousand BOE per day in the first quarter of 2022 and 765.9 thousand BOE per day in the second quarter of 2021. See the Operating and Financial Results section of this MD&A for a summary of upstream production by product type.
- Downstream crude oil throughput averaged 457.3 thousand barrels per day in the second quarter, a decrease of 44.5 thousand barrels per day and 81.7 thousand barrels per day compared with the first quarter of 2022 and second quarter of 2021, respectively.

Revenue increased 80 percent to $19.2 billion and cash from operating activities increased 118 percent to $3.0 billion, compared with the second quarter of 2021, primarily due to higher commodity pricing. Higher market crack spreads also contributed to the increase in cash from operating activities. Adjusted Funds Flow was $3.1 billion, compared with $1.8 billion in the second quarter of 2021, and capital investment was $822 million, compared with $534 million in the second quarter of 2021, resulting in Free Funds Flow of $2.3 billion, compared with $1.3 billion in the second quarter of 2021. Operating Margin was $4.7 billion in the second quarter of 2022 compared with $2.2 billion in the second quarter of 2021, primarily due to higher average realized crude oil, NGLs and natural gas sales prices, and higher market crack spreads.

We continued to strengthen our balance sheet and focus on our top-tier asset portfolio.

- During the quarter, we purchased the full $750 million in principal of our outstanding 3.55 percent notes due in 2025. Our Net Debt decreased by $872 million as compared with March 31, 2022.
- On May 31, 2022, Cenovus and our partners announced the restart of the West White Rose project offshore Newfoundland and Labrador. The project is expected to restart in 2023. First oil from the platform is anticipated in the first half of 2026, with peak production anticipated to reach approximately 80 thousand barrels per day, 45 thousand barrels per day net to Cenovus, by 2029.
- On June 8, 2022, we sold our investment in Headwater Exploration Inc. for proceeds of $110 million.
- On June 13, 2022, we announced an agreement to purchase the remaining 50 percent interest in Sunrise from BP Canada giving Cenovus full ownership and further enhancing our core strength in the oil sands. The transaction has an effective date of May 1, 2022, and is anticipated to close in the third quarter of this year.

We demonstrated our commitment to returning cash to shareholders.

- Cenovus purchased and cancelled 43 million common shares for $1.0 billion through our NCIB in the second quarter (68 million common shares for $1.5 billion in the first six months of 2022).
- We met our returns to shareholders target as outlined by our capital allocation and shareholder returns framework.
- On July 27, 2022, the Board declared a third quarter base dividend of $0.105 per common share payable on September 29, 2022, to common shareholders of record as at September 15, 2022.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results — Upstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	**Percent Change**	2021	**2022**	**Percent Change**	2021
Upstream Production Volumes by Segment [1] (MBOE/d)						
Oil Sands	**558.8**	**1**	551.6	**577.9**	**4**	553.6
Conventional	**132.6**	**(6)**	141.3	**128.8**	**(7)**	138.6
Offshore	**70.1**	**(4)**	73.0	**73.2**	**(3)**	75.4
Total Production Volumes	**761.5**	**(1)**	765.9	**779.9**	**2**	767.6
Upstream Production Volumes by Product						
Bitumen (Mbbls/d)	**540.3**	**2**	528.6	**559.5**	**5**	530.8
Heavy Crude Oil (Mbbls/d)	**16.4**	**(21)**	20.8	**16.3**	**(21)**	20.7
Light Crude Oil (Mbbls/d)	**20.8**	**(15)**	24.4	**21.4**	**(14)**	25.0
NGLs (Mbbls/d)	**36.7**	**(11)**	41.1	**37.2**	**(9)**	41.1
Conventional Natural Gas (MMcf/d)	**882.2**	**(3)**	905.6	**873.9**	**(3)**	900.3
Total Production Volumes (MBOE/d)	**761.5**	**(1)**	765.9	**779.9**	**2**	767.6
Total Upstream Sales Volumes [2] (MBOE/d)	**684.5**	**2**	669.2	**704.2**	**4**	677.5
Netback [3][4] ($/BOE)	**71.09**	**106**	34.58	**64.78**	**97**	32.96

(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 506 MMcf per day and 516 MMcf per day for the three months and six months ended June 30, 2022, respectively (510 MMcf per day and 515 MMcf per day for the three and six months ended June 30, 2021, respectively).
(3) Upstream revenue as found in Note 1 of the interim Consolidated Financial Statements was $10.1 billion and $19.8 billion in the three and six months ended June 30, 2022, respectively (three and six months ended June 30, 2021 – $5.6 billion and $11.3 billion, respectively).
(4) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

In the three and six months ended June 30, 2022, total production was relatively flat compared with 2021, even with a planned turnaround at Christina Lake, the disposition of the Tucker asset on January 31, 2022, and the Wembley asset on February 28, 2022, as well as divestitures in the Conventional segment in the second half of 2021. The production impact of the 2022 divestitures and turnarounds were offset as we brought new wells online at Foster Creek and Christina Lake in 2022 and in the second half of 2021. In the second quarter of 2021, we completed a turnaround at Foster Creek.

Selected Operating Results — Downstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	**Percent Change**	2021	**2022**	**Percent Change**	2021
Downstream Manufacturing Crude Oil Throughput (Mbbls/d)						
Canadian Manufacturing	**80.9**	**(22)**	103.5	**89.4**	**(15)**	104.8
U.S. Manufacturing	**376.4**	**(14)**	435.5	**390.0**	**(2)**	399.4
Total Throughput	**457.3**	**(15)**	539.0	**479.4**	**(5)**	504.2
Retail [1] (millions of litres/d)						
Fuel Sales, Including Wholesale	**6.4**	**(4)**	6.7	**6.5**	**(2)**	6.6

(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 sale is currently expected to close in the third quarter of 2022. We are retaining our commercial fuels business, which includes 167 cardlock, bulkplant and travel centre locations.

In the Canadian Manufacturing segment, we completed planned turnarounds at both the Lloydminster Upgrader and Lloydminster Refinery in the second quarter, resulting in lower throughput compared with 2021.

In the U.S. Manufacturing segment, crude oil throughput decreased in the second quarter of 2022 as we completed planned turnarounds in our non-operated facilities at the Wood River and Borger refineries, and commenced a planned turnaround at the non-operated Toledo Refinery which was substantially completed in July. At the Lima Refinery, crude oil throughput was 159.4 thousand barrels per day in the second quarter, relatively flat compared with the second quarter of 2021. Crude utilization at the Lima Refinery was 91 percent in the second quarter. Year-to-date, market conditions were favourable compared with 2021, and partially offset the impacts of the planned turnarounds in the second quarter.

Selected Consolidated Financial Results

Operating Margin

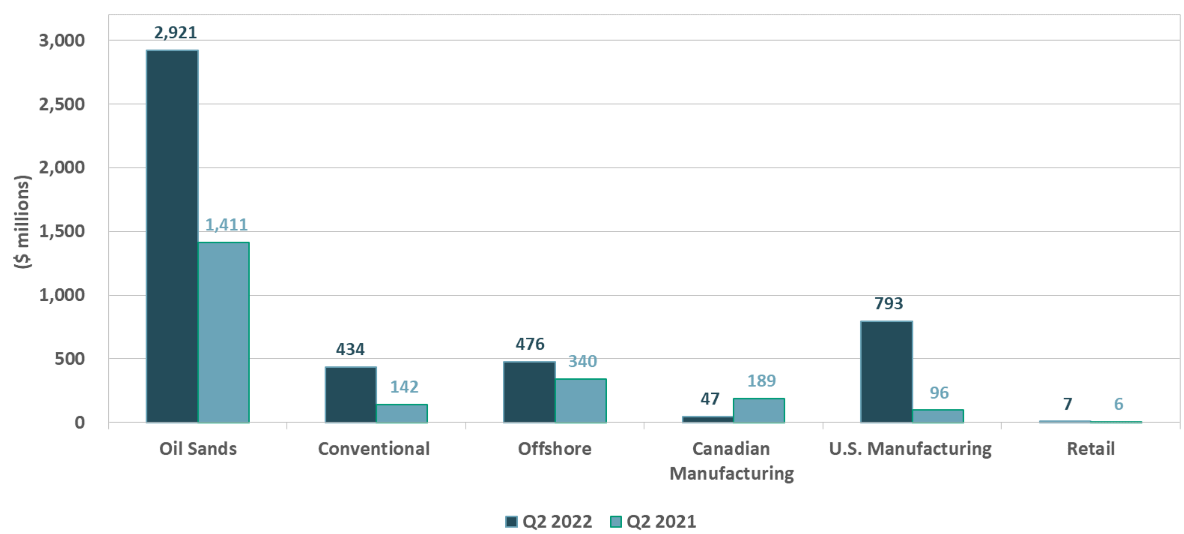
Operating Margin is a specified financial measure and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2022**	2021	**2022**	2021
Gross Sales [(1)]	**22,529**	12,446	**41,673**	23,261
Less: Royalties	**1,582**	533	**2,767**	906
Revenues	**20,947**	11,913	**38,906**	22,355
Expenses				
Purchased Product [(1)]	**10,507**	6,219	**19,271**	11,257
Transportation and Blending [(1)]	**3,236**	2,006	**6,432**	3,978
Operating Expenses	**1,876**	1,306	**3,430**	2,608
Realized (Gain) Loss on Risk Management Activities	**650**	198	**1,631**	449
Operating Margin	**4,678**	2,184	**8,142**	4,063

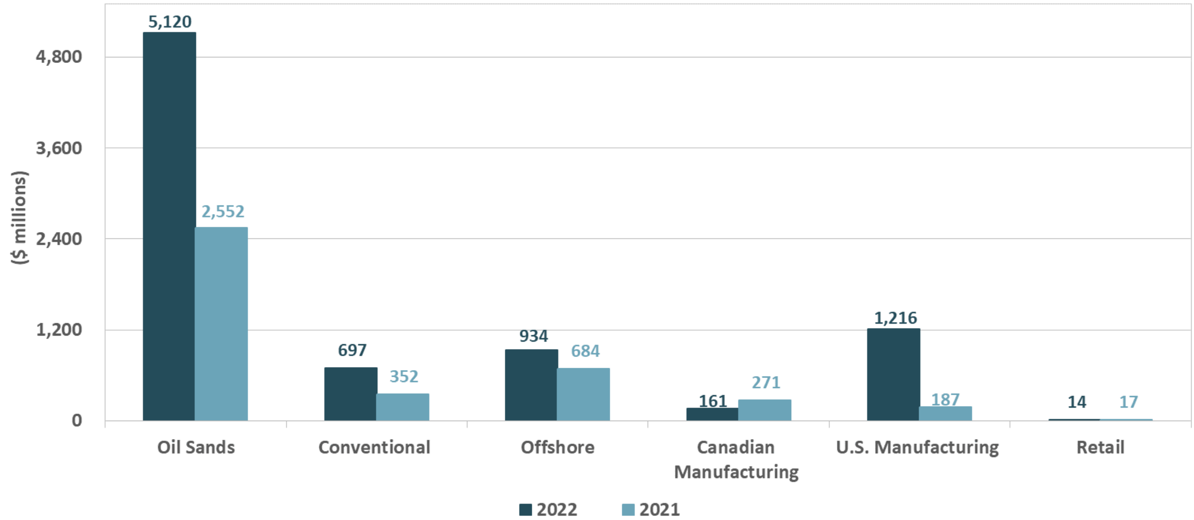
(1) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated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

Operating Margin by Segment

Three Months Ended June 30



Six Months Ended June 30



Operating Margin increased in the three and six months ended June 30, 2022, primarily due to:

- Higher average crude oil, NGLs and natural gas sales prices resulting from higher benchmark pricing.
- Increased refining margins from our downstream business. Market crack spreads more than doubled from 2021.
- Higher sales volumes from our upstream business.

These increases in Operating Margin were partially offset by:

- Increased royalties and fuel costs, both impacted by significantly higher commodity pricing.
- Planned turnarounds in our downstream operations, which impacted sales volumes and operating expenses.
- Increased blending costs due to higher condensate prices.
- Higher realized risk management losses on the settlement of benchmark prices relative to our risk management contract prices. By June 30, 2022, all WTI risk management contracts related to our crude oil sales price risk management were closed.

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 June 30,		Six Months Ended June 30,	
($ millions)	**2022**	2021	**2022**	2021
Cash From (Used in) Operating Activities	**2,979**	1,369	**4,344**	1,597
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(27)**	(18)	**(46)**	(29)
Net Change in Non-Cash Working Capital	**(92)**	(430)	**(1,291)**	(1,332)
Adjusted Funds Flow	**3,098**	1,817	**5,681**	2,958

Cash From Operating Activities and Adjusted Funds Flow were higher in the three months ended June 30, 2022, compared with 2021 due to increased Operating Margin, as discussed above. The increases were partially offset by a higher quarterly contingent payment in 2022.

The change in non-cash working capital in the second quarter of 2022 was relatively small as higher commodity prices resulted in increases to accounts receivable, inventory and accounts payable on June 30, 2022, compared with March 31, 2022, offset by timing of settlements.

Cash From Operating Activities and Adjusted Funds Flow were higher in the six months ended June 30, 2022, compared with 2021 due to increased Operating Margin, as discussed above, combined with lower integration costs. The increases were partially offset by higher quarterly contingent payments in the first half of 2022.

The change in non-cash working capital in 2022 was mainly due to an increase in inventories and accounts receivable, partially offset by an increase in accounts payable on June 30, 2022, compared with December 31, 2021, due to higher crude oil and refined product pricing. In June 2022, WTI averaged US$114.34 per barrel, compared with the December 2021 average of US$71.69 per barrel. Chicago regular unleaded gasoline ("RUL") averaged US$167.61 per barrel in June 2022, compared with US$83.78 per barrel in December 2021.

Net Earnings (Loss)

($ millions)	Three Months Ended	Six Months Ended
Net Earnings (Loss) for the Periods Ended June 30, 2021	**224**	**444**
Increase (Decrease) due to:		
Operating Margin	**2,494**	**4,079**
Corporate and Eliminations:		
General and Administrative	**(48)**	**(84)**
Finance Costs	**37**	**52**
Integration Costs	**6**	**205**
Unrealized Foreign Exchange Gain (Loss)	**(452)**	**(452)**
Re-measurement of Contingent Payment	**234**	**185**
Gain (Loss) on Divestiture of Assets	**2**	**232**
Other Income (Loss), net	**9**	**307**
Other [1]	**(7)**	**45**
Unrealized Risk Management Gain (Loss) [2]	**764**	**339**
Depreciation, Depletion and Amortization	**(96)**	**(81)**
Exploration Expense	**(6)**	**(16)**
Income Tax Recovery (Expense)	**(729)**	**(1,198)**
Net Earnings (Loss) for the Periods Ended June 30, 2022	**2,432**	**4,057**

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

(2) All WTI positions related to crude oil sales price risk management were closed by June 30, 2022.

Net earnings in the second quarter of 2022 improved compared with 2021 due to:

- Increased Operating Margin, as discussed above.
- Unrealized risk management gains of $365 million, compared with losses of $399 million in 2021. Unrealized risk management gains were mainly due to the realization of settled positions as we liquidated our WTI positions related to crude oil sales price risk management in the quarter.
- A loss on the re-measurement of the contingent payment of $15 million compared with $249 million in 2021. On May 17, 2022, the contingent payment obligations associated with the acquisition from ConocoPhillips Company and certain of its subsidiaries ended. The final payment will be made in July 2022.

Net earnings in the first half of 2022 improved compared with 2021 due to:

- Increased Operating Margin, as discussed above.
- Higher other income primarily due to insurance proceeds related to the Superior Refinery.
- Unrealized risk management gains of $72 million, compared with losses of $267 million in 2021.
- Gains on the divestiture of assets of $304 million in 2022, largely related to the Tucker and Wembley dispositions and the divestiture of 12.5 percent of our interest in the White Rose field and satellite extensions.
- A loss on the re-measurement of the contingent payment of $251 million compared with $436 million in 2021.
- Integration costs of $52 million, compared with $257 million in 2021.

The increase to net earnings for the three and six months ended June 30, 2022, discussed above was partially offset by:

- Higher income tax expense.
- Unrealized foreign exchange losses in 2022 as the Canadian dollar at June 30, 2022, weakened relative to the U.S. dollar.
- Increased general and administrative expenses mainly due to higher long-term incentive costs related to our share price appreciation.

Net Debt

As at ($ millions)	June 30, 2022	December 31, 2021
Short-Term Borrowings	**—**	79
Current Portion of Long-Term Debt	**—**	—
Long-Term Debt	**11,228**	12,385
Total Debt	**11,228**	12,464
Less: Cash and Cash Equivalents	**(3,693)**	(2,873)
Net Debt	**7,535**	9,591

Long-term debt decreased by $1.2 billion and Net Debt decreased by $2.1 billion from December 31, 2021. During the second quarter, long-term debt decreased by $516 million and Net Debt decreased by $872 million. In the first quarter of 2022, we purchased the remaining US$384 million in principal of outstanding notes due in 2023 and 2024. In the second quarter, we purchased the full $750 million in principal of the outstanding 3.55 percent notes due in 2025. The decrease in long-term debt was partially offset as the Canadian dollar weakened relative to the U.S. dollar on June 30, 2022 compared with December 31, 2021, impacting our U.S. dollar debt.

Capital Investment (1)

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2022**	2021	**2022**	2021
Upstream				
Oil Sands	**376**	201	**751**	419
Conventional	**33**	28	**121**	94
Offshore	**91**	35	**144**	61
	500	264	**1,016**	574
Downstream				
Canadian Manufacturing	**36**	10	**50**	14
U.S. Manufacturing	**267**	237	**474**	442
Retail	**2**	5	**3**	6
	305	252	**527**	462
Corporate and Eliminations	**17**	18	**25**	45
Capital Investment	**822**	534	**1,568**	1,081

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

Oil Sands capital investment in the first six months 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 in the first six months of 2022 focused on sustaining drilling, completion and tie-in programs.

Offshore capital investment in the first six months of 2022 was primarily for the Terra Nova asset life extension ("ALE") project and capital for the West White Rose project in the Atlantic region. On May 31, 2022, Cenovus and our partners announced the restart of the West White Rose project offshore Newfoundland and Labrador.

U.S. Manufacturing capital investment in the first six months of 2022 focused primarily on the Superior Refinery rebuild, refining reliability initiatives at the Wood River, Borger and Toledo refineries, and yield optimization projects at the Wood River Refinery.

Drilling Activity

Six Months Ended June 30,	Net Stratigraphic Test Wells and Observation Wells 2022	2021	Net Production Wells (1) 2022	2021
Foster Creek	**52**	17	**11**	—
Christina Lake (2)	**—**	25	**20**	9
Sunrise	**15**	—	**2**	—
Lloydminster Thermal	**1**	—	**22**	15
Tucker	**6**	—	**—**	—
Lloydminster Conventional Heavy Oil	**—**	—	**—**	2
Other (3)	**16**	17	**—**	—
	90	59	**55**	26

(1) 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.

	Six Months Ended June 30, 2022			Six Months Ended June 30, 2021		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional	**13**	**28**	**22**	11	13	12

In the Offshore segment, we drilled and completed four (1.6 net) planned development wells in Indonesia in the first six months of 2022 (2021 — no wells drilled, completed or tied-in).

Future Capital Investment

Our 2022 guidance as updated on July 27, 2022, is available on our website at cenovus.com.

Our updated guidance reflects:

- Expected increased production and capital investment due to the announcement of the acquisition of the remaining 50 percent interest in Sunrise.
- Increased capital investment at Foster Creek, Christina Lake and Lloydminster thermal assets to support continued optimization of the assets, including adding shorter-cycle production opportunities and increased delineation drilling to speed well pad development, combined with rising costs due to inflation.
- Higher capital investment related to the announced restart of the West White Rose project.
- Increased investment in the Conventional business to reflect our plans to increase the scope of drilling activity, and asset integrity and emissions reductions initiatives, combined with rising costs due to inflation.
- Increased operating costs in our downstream operations reflecting turnaround activity, higher natural gas prices and inflation.

The following table shows updated guidance for 2022:

	Capital Investment ($ millions)	**Production** (MBOE/d)	**Throughput** (Mbbls/d)
Upstream			
Oil Sands	**1,550 - 1,750**	**574 - 620**	
Conventional	**250 - 300**	**124 - 135**	
Offshore	**300 - 350**	**64 - 76**	
Downstream (1)	**1,150 - 1,250**		**530 - 580**
Corporate and Eliminations	**50 - 70**		

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

For the remainder of 2022, we plan to focus our Capital Investment on:

- Growing production in the Oil Sands segment.
- Sustaining drilling programs in the Conventional segment.
- The Superior Refinery rebuild project.
- The Terra Nova ALE project and 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]

	Six Months Ended June 30,					
(Average US$/bbl, unless otherwise indicated)	**2022**	**Percent Change**	2021	**Q2 2022**	Q1 2022	Q2 2021
Dated Brent	**107.59**	**66**	64.86	**113.78**	101.41	68.83
WTI	**101.35**	**64**	61.96	**108.41**	94.29	66.07
Differential Brent-WTI	**6.24**	**115**	2.90	**5.37**	7.12	2.76
WCS at Hardisty	**87.68**	**75**	49.98	**95.61**	79.76	54.58
Differential WTI-WCS	**13.67**	**14**	11.98	**12.80**	14.53	11.49
WCS (C$/bbl)	**111.54**	**79**	62.21	**122.07**	101.01	66.99
WCS at Nederland	**96.26**	**62**	59.48	**103.34**	89.19	63.03
Differential WTI-WCS at Nederland	**5.09**	**105**	2.48	**5.07**	5.10	3.04
Condensate (C5 @ Edmonton)	**102.21**	**64**	62.22	**108.34**	96.09	66.40
Differential WTI-Condensate (Premium)/Discount	**(0.86)**	**(231)**	(0.26)	**0.07**	(1.80)	(0.33)
Differential WCS-Condensate (Premium)/Discount	**(14.53)**	**(19)**	(12.24)	**(12.73)**	(16.33)	(11.82)
Average (C$/bbl)	**129.99**	**68**	77.50	**138.30**	121.69	81.51
Synthetic @ Edmonton	**103.75**	**72**	60.37	**114.46**	93.05	66.41
WTI-Synthetic (Premium)/Discount Differential	**(2.40)**	**(251)**	1.59	**(6.05)**	1.24	(0.34)
Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**129.11**	**65**	78.27	**149.05**	109.16	87.03
Chicago Ultra-low Sulphur Diesel ("ULSD")	**143.11**	**80**	79.50	**166.62**	119.60	85.73
Refining Benchmarks						
Chicago 3-2-1 Crack Spread [2]	**32.43**	**94**	16.72	**46.50**	18.35	20.50
Group 3 3-2-1 Crack Spread [2]	**32.15**	**83**	17.55	**44.35**	19.94	19.44
Renewable Identification Numbers ("RINs")	**7.12**	**5**	6.80	**7.80**	6.44	8.12
Natural Gas Prices						
AECO (C$/Mcf)	**5.43**	**88**	2.89	**6.28**	4.59	2.85
NYMEX (US$/Mcf)	**6.06**	**120**	2.76	**7.17**	4.95	2.83
Foreign Exchange Rate						
US$ per C$1 - Average	**0.787**	**(2)**	0.802	**0.783**	0.790	0.814
US$ per C$1 - End of Period	**0.776**	**(4)**	0.807	**0.776**	0.800	0.807
RMB per C$1 - Average	**5.098**	**(2)**	5.190	**5.180**	5.014	5.259

(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 second quarter of 2022, Brent and WTI crude oil benchmarks continued to increase resulting from the very tight global crude oil supply and demand balance. Supply has grown this year, although less than expected, and further incremental sources are limited. Russia's invasion of Ukraine has resulted in reshuffling of global trade flows, heightened volatility and increased geopolitical risk. 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, which began in the second quarter of 2021. Global demand remains strong amid roll out efforts of COVID-19 vaccines, economic recovery and easing of restrictions.

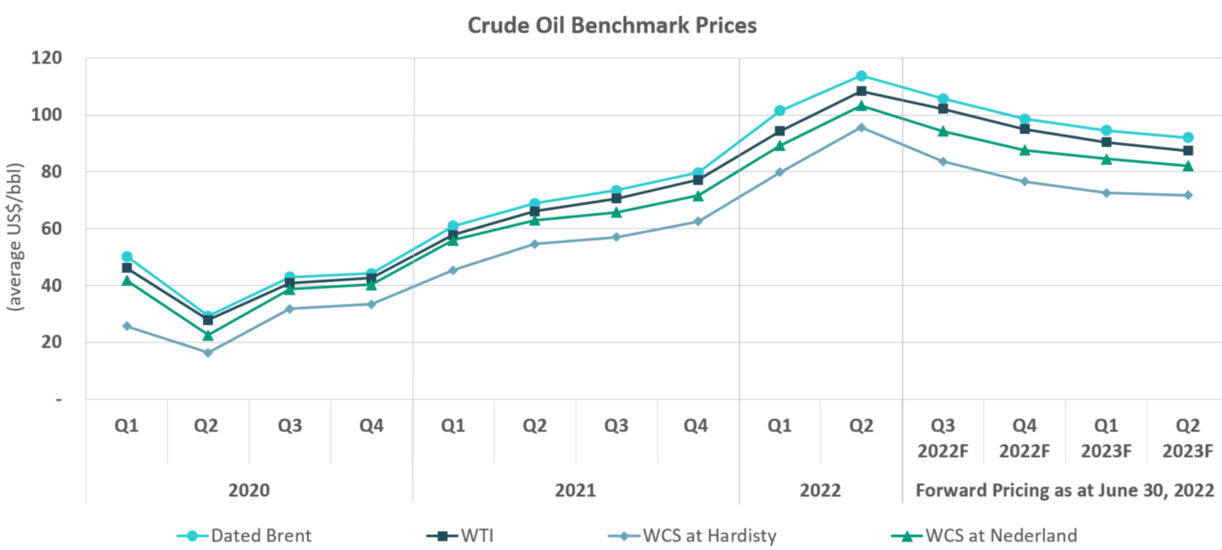
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent. WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and the Canadian dollar equivalent is the basis for determining royalty rates for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

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. In the three months ended June 30, 2022, the average WTI-WCS at Hardisty differential narrowed compared to the first quarter of 2022. Planned maintenance in the Western Canadian Sedimentary Basin ("WCSB"), and low storage levels resulted in incremental spare export pipeline capacity. Startup of the Enbridge Line 3 Replacement in the fourth quarter of 2021, provided incremental takeaway capacity from the WCSB, which has helped keep transport costs consistent. The WTI-WCS at Hardisty differential widened compared to the second quarter of 2021 primarily due to the same factors that caused the WTI-WCS at Nederland differential to widen, as discussed below.

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 second 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 second quarter of 2022 compared with the second quarter of 2021, mainly attributed to planned and unplanned refinery maintenance, and some incremental medium and heavy oil barrels into the market from OPEC+ and from the release of volume from Strategic Petroleum Reserves in the U.S.

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.

Synthetic crude at Edmonton strengthened significantly in the second quarter of 2022 compared with both the first quarter of 2022 and the second quarter of 2021 as a result of widespread upgrader maintenance and strong refinery demand for light crude.



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 22 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 discount relative to WTI in the second quarter of 2022. Pricing was mixed through the quarter as high April pricing, due to higher blending requirements, were offset by weakness in June due to oil sands turnarounds and lower global petrochemical demand.

Refining Benchmarks

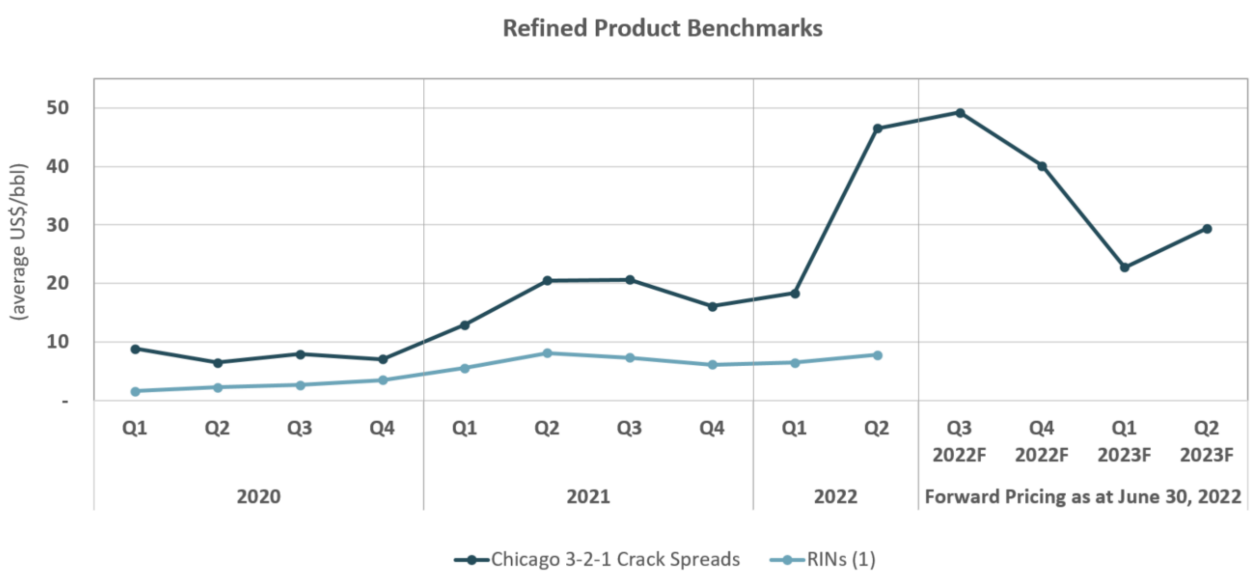
RUL and ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded 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 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 significantly in the second quarter of 2022 compared with both the first quarter of 2022 and the second quarter of 2021. The strength in crack spreads and refined product prices has been driven by refinery rationalization since the beginning of the pandemic, combined with low global inventories of refined products and reduced Russian exports which has led to an undersupply of refined products. 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 generally 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. The market crack spreads do not precisely mirror the configuration and product output of our refineries, however they are used as a general market indicator.



(1) There are no forward prices for RINs.

Natural Gas Benchmarks

Average NYMEX natural gas prices increased further in the second quarter of 2022, compared to the first quarter of 2022, and significantly improved compared to the second 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 2022 and the second quarter of 2021 due to pipeline maintenance in Western Canada, limiting egress from Alberta. 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 half 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 year-over-year. The Canadian dollar weakened relative to the U.S. dollar as at June 30, 2022, compared with December 31, 2021, resulting in unrealized foreign exchange losses 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 six months of 2022, the Canadian dollar on average was relatively flat compared with RMB, resulting in minimal impact on our revenues year-over-year.

Interest Rate Benchmarks

Our short-term borrowings and decommissioning liabilities are impacted by fluctuations in interest rates. An increase in interest rates could increase our net interest expense and affect how certain liabilities are measured, both of which could negatively impact our cash flow and financial results.

As at June 30, 2022, the Bank of Canada's Policy Interest Rate was 1.50 percent, increasing from 0.25 percent on December 31, 2021. On July 13, 2022, the Bank of Canada subsequently increased its policy rate to 2.50 percent due to concerns over inflation.

COMMODITY PRICE OUTLOOK

High crude oil prices persisted through the second quarter of 2022 as oil supply growth lagged demand for crude oil and refined products. Crude oil price trajectory remains uncertain and volatile amid an increasingly fragmented market with unpredictable key drivers. Russian supply risks remain the markets' most significant geopolitical risk. Disruption of Russian exports could result in continued demand surplus and necessitate rebalancing of global trade flows, as incremental supply sources are limited.

We expect the general outlook for crude oil and refined product prices will be volatile and impacted by the duration and severity of the ongoing Russian invasion of Ukraine, 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, weakening economic activity, inflation and rising interest rates, and the potential for a recession 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 will remain largely tied to global supply factors and heavy crude processing capacity as long as supply stays within Canadian crude export capacity.
- The ability, and willingness, of OPEC and OPEC+ to greatly increase production remains uncertain.
- Global economic activity.
- We expect market crack spreads will remain volatile as Russia is a significant exporter of refined products. Sanctions are expected to reduce supply and result in redirection of global trade flows. Economic effects of the conflict and central bank policies 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.

Most of our upstream crude oil production and 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 economic 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 could be 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 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 – heavy oil refining capacity allows 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.

All WTI contracts related to our crude oil sales price risk management activities were close by June 30, 2022. We continue to use financial instruments to mitigate our exposure to the prices of various commodities, including some WTI contracts for exposure management unrelated to crude oil sales price risk management; and products, including associated price differentials and refining margins.

REPORTABLE SEGMENTS

UPSTREAM

OIL SANDS

In the second quarter of 2022, we:

- Delivered another quarter of safe and reliable operations.
- Produced 556.7 thousand barrels per day.
- Generated Operating Margin of $2.9 billion, an increase of $1.5 billion compared with the second quarter of 2021 primarily due to higher average realized sales prices.
- Completed a planned turnaround at Christina Lake and completed routine maintenance at two of our 11 Lloydminster thermal plants.
- Generated first steam at our Spruce Lake North thermal plant. Production is expected in the third quarter of this year.
- Invested capital of $376 million primarily on sustaining activities at Christina Lake, Foster Creek and the Lloydminster thermal assets.
- Achieved a Netback of $67.83 per BOE.

On June 13, 2022, we announced an agreement to purchase the remaining 50 percent interest in Sunrise from BP Canada, giving Cenovus full ownership and further enhancing our core strength in the oil sands. Total consideration includes $600 million in cash, a variable payment with a maximum cumulative value of $600 million expiring after two years, and Cenovus's 35 percent position in the undeveloped Bay du Nord project offshore Newfoundland and Labrador. The transaction is anticipated to close in August 2022. The acquisition will be accounted for using the acquisition method pursuant to IFRS 3, "Business Combinations" ("IFRS 3"). Under the acquisition method, assets and liabilities are recorded at their fair values on the date of acquisition and the total consideration is allocated to the tangible and intangible assets acquired and liabilities assumed. The excess of consideration given over the fair value of the net assets acquired, if any, will be recorded as goodwill. As required by IFRS 3, when an acquirer achieves control, the previously held interest is remeasured to fair value at the acquisition date with any gain or loss recognized in net earnings. At the closing date of the acquisition, Cenovus expects to record a non-cash revaluation gain on the re-measurement to fair value of its existing interest in Sunrise.

Gross production from the assets is approximately 50,000 barrels per day and we expect to achieve nameplate capacity of 60,000 barrels per day through a multi-year development program. The acquisition is expected to be immediately accretive to adjusted funds flow and cash from operating activities.

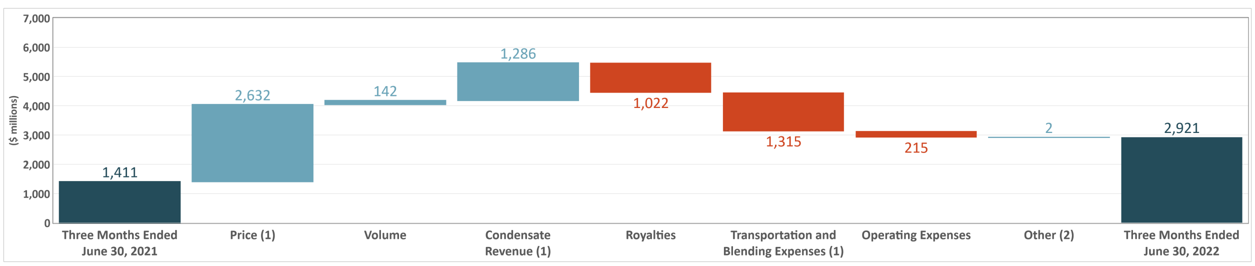
Financial Results

($ millions)	Three Months Ended June 30, 2022	2021	Six Months Ended June 30, 2022	2021
Gross Sales [1]	**10,048**	5,075	**19,266**	9,993
Less: Royalties	**1,491**	469	**2,573**	793
Revenues	**8,557**	4,606	**16,693**	9,200
Expenses				
Purchased Product [1]	**1,071**	430	**2,283**	1,119
Transportation and Blending [1]	**3,200**	1,984	**6,356**	3,934
Operating	**806**	592	**1,508**	1,177
Realized (Gain) Loss on Risk Management	**559**	189	**1,426**	418
Operating Margin	**2,921**	1,411	**5,120**	2,552
Unrealized (Gain) Loss on Risk Management	**(323)**	374	**(57)**	233
Depreciation, Depletion and Amortization	**690**	627	**1,325**	1,239
Exploration Expense	**(1)**	2	**—**	13
Share of (Income) Loss from Equity-Accounted Affiliates	**8**	(5)	**8**	(5)
Segment Income (Loss)	**2,547**	413	**3,844**	1,072

(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, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

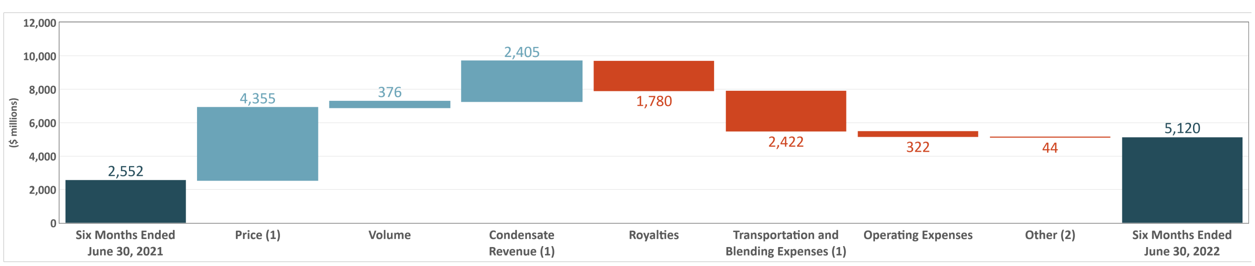
Operating Margin Variance

Three Months Ended June 30, 2022



(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.

Six Months Ended June 30, 2022



(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 June 30,		Six Months Ended June 30,	
	2022	2021	**2022**	2021
Total Sales Volumes (MBOE/d)	**563.9**	539.9	**586.7**	550.3
Total Realized Price [(1)] ($/BOE)	**119.98**	61.16	**107.54**	56.95
Crude Oil Production by Asset (Mbbls/d)				
Foster Creek	**187.8**	156.8	**192.8**	159.9
Christina Lake	**228.8**	230.5	**241.4**	226.7
Sunrise [(2)]	**25.3**	22.4	**24.7**	25.1
Lloydminster Thermal	**98.4**	97.7	**97.4**	96.9
Lloydminster Conventional Heavy Oil	**16.4**	20.8	**16.3**	20.7
Tucker [(3)]	**—**	21.2	**3.2**	22.2
Total Daily Crude Oil Production [(4)] (Mbbls/d)	**556.7**	549.4	**575.8**	551.5
Oil Sands Natural Gas [(5)] (MMcf/d)	**12.0**	13.1	**12.4**	13.1
Total Daily Production (MBOE/d)	**558.8**	551.6	**577.9**	553.6
Effective Royalty Rate (percent)	**25.7**	17.7	**24.1**	16.2
Transportation and Blending Cost [(1)] ($/BOE)	**7.51**	7.08	**7.36**	7.57
Operating Expense [(1)] ($/BOE)	**15.70**	12.00	**14.05**	11.74
Per Unit DD&A [(1)] ($/BOE)	**11.78**	11.55	**11.93**	11.34

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Represents Cenovus's 50 percent interest in Sunrise operations. On June 13, 2022, we announced an agreement to purchase the remaining 50 percent interest from BP Canada. The purchase is expected to close in the third quarter of this year.
(3) The Tucker asset sold 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

WTI benchmark prices increased significantly in both the three and six months ended June 30, 2022, compared with 2021. Our realized sales price for bitumen and heavy crude oil was $119.98 per BOE and $107.54 per BOE in the three and six months ended June 30, 2022, respectively (2021 – $61.16 per BOE and $56.95 per BOE, respectively). In the first half 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 three and six months ended June 30, 2022, gross sales included $975 million and $2.1 billion, respectively (2021 – $364 million and $1.0 billion, respectively), from third-party sourced volumes which are not included in our realized price or our Netbacks. Refer to the Specified Financial Measures Advisory of this MD&A for more detail.

In the three and six months ended June 30, 2022, gross sales included $117 million and $169 million, respectively (2021 – $86 million and $152 million, respectively) relating to construction, transportation and blending activities. These amounts are not included in our realized price or our Netbacks. Refer to the Specified Financial Measures Advisory of 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 suspended our crude oil sales price risk management activities related to WTI. Given the strength of our balance sheet and liquidity position, we determined these programs are no longer required to support financial resilience. All WTI contracts impacted by this decision were closed by June 30, 2022.

In the three and six months ended June 30, 2022, we incurred realized risk management losses of $559 million and $1.4 billion, respectively, of which $431 million relates to the early liquidation of WTI positions in the second quarter. Also contributing to the losses was the settlement of benchmark prices rising above our risk management contract prices. In the three and six months ended June 30, 2022, we recorded unrealized gains of $323 million and $57 million, respectively, on our crude oil financial instruments primarily due to realization of settled positions.

Production Volumes

Oil Sands crude oil production was 556.7 thousand barrels per day and 575.8 thousand barrels per day, respectively, in the three and six months ended June 30, 2022 (2021 – 549.4 thousand barrels per day and 551.5 thousand barrels per day, respectively).

We sold the Tucker asset on January 31, 2022, resulting in decreased production of 19.0 thousand barrels per day in the first six months of 2022 compared with 2021.

Production at Foster Creek increased 31.0 thousand barrels per day and 32.9 thousand barrels per day in the three and six months ended June 30, 2022, respectively, compared with the same periods in 2021. The increases were due to strong performance from new sustaining well pads, partially offset by natural declines. In the second quarter of 2021, we completed a planned turnaround at Foster Creek.

Production at Christina Lake was relatively flat in the three months ended June 30, 2022, compared with 2021. In the six months ended June 30, 2022, production increased 14.7 thousand barrels per day compared with 2021. We completed a planned turnaround during the quarter, however production impacts were offset by redevelopment wells drilled in 2022 and the last half of 2021.

Sunrise production in the first six months of 2022 was consistent with 2021, where we completed a well redevelopment program in the first quarter of 2022, and completed a planned turnaround in the second quarter of 2021.

The Lloydminster thermal assets continued their strong performance from 2021. We completed planned maintenance at two of our 11 producing thermal plants during the quarter, and the downtime had minimal impact on production. Lloydminster conventional heavy oil production decreased marginally in the three and six months ended June 30, 2022, compared with 2021, 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 calculated as 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, which includes 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. In the three and six months ended June 30, 2022, royalties were $1.5 billion and $2.6 billion, respectively (2021 – $469 million and $793 million, respectively). The increases were mainly due to higher net revenue as a result of higher realized pricing combined with increased production.

Expenses

Transportation and Blending

In the second quarter of 2022, blending costs increased $1.2 billion to $2.8 billion compared with 2021. In the first half of 2022, blending costs rose $2.4 billion to $5.6 billion compared with 2021. The increases were largely due to higher condensate benchmark prices of US$108.34 per barrel and US$102.21 per barrel in the three and six months ended June 30, 2022, respectively (2021 – US$66.40 per barrel and US$62.22 per barrel, respectively).

Transportation costs increased $30 million to $394 million in the second quarter of 2022 compared with 2021. In the first six months of 2022, transportation costs rose $17 million to $791 million. The increases were primarily due to higher sales volumes.

Per-unit Transportation Expenses

Transportation costs were $7.51 per BOE and $7.36 per BOE in the three and six months ended June 30, 2022, respectively (2021 – $7.08 per BOE and $7.57 per BOE, respectively).

At Foster Creek, transportation costs decreased 15 percent and 12 percent to $10.37 per barrel and $10.13 per barrel in the three and six months ended June 30, 2022, respectively. The decreases are mainly due to higher sales volumes and reduced reliance on rail, partially offset by increased tariff rates. In the three and six months ended June 30, 2022, we shipped 45 percent and 40 percent, respectively (2021 – 35 percent), of our volumes from Foster Creek to U.S. destinations. Of those, we shipped less than five percent of our volumes by rail in the three and six months ended June 30, 2022 (2021 – less than five percent and 20 percent, respectively).

At Christina Lake, transportation costs increased 11 percent and three percent to $6.75 per barrel and $6.55 per barrel in the three and six months ended June 30, 2022, respectively. The increases are primarily due to increased tariff rates.

At Sunrise, transportation costs in the three and six months ended June 30, 2022, were $12.48 per barrel and $12.82 per barrel, respectively (2021 – $13.66 per barrel and $12.25 per barrel, respectively). In the three and six months ended June 30, 2022 we shipped 50 percent and 60 percent, respectively (2021 – 70 percent and 50 percent, respectively), of our volumes from Sunrise to U.S. destinations.

At our Lloydminster thermal, Tucker and Lloydminster conventional heavy oil assets, transportation costs in the three and six months ended June 30, 2022, were $3.28 per barrel and $3.39 per barrel, respectively (2021 – $2.78 per barrel and $4.51 per barrel, respectively). The Tucker asset was sold on January 31, 2022. Per-unit transportation costs decreased in the first half of 2022 compared with 2021, as we stopped shipping these barrels to U.S. 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 three and six months ended June 30, 2022 were fuel, chemical costs, electricity costs, workforce, and repairs and maintenance. Total and per-unit operating expenses increased largely due to higher fuel costs as a result of higher natural gas prices. AECO benchmark natural gas prices increased 120 percent and 88 percent in the three and six months ended June 30, 2022, respectively, compared with 2021. Chemical costs and electricity costs also increased in the three and six months ended June 30, 2022, as they are influenced by rising crude oil and natural gas benchmark prices.

Foster Creek per-unit non-fuel costs decreased in the three and six months ended June 30, 2022, as higher chemical costs in 2022 were more than offset by higher sales volumes in 2022 and costs associated with the planned turnaround in the second quarter of 2021.

Christina Lake per unit non-fuel costs increased in the three months ended June 30, 2022, mainly due to costs related to the turnaround. Year-to-date, per-unit non-fuel costs were relatively flat as higher sales volumes in 2022 offset the impact of the turnaround in the second quarter of 2022.

Per-unit non-fuel costs at our other Oil Sands assets increased in the quarter and year-to-date primarily due to higher chemical costs and workover activity at Sunrise and our Lloydminster thermal assets, partially offset by costs related to the planned turnaround at Sunrise in the second quarter of 2021.

Unit Operating Expenses [(1)]

($/BOE)	Three Months Ended June 30, 2022	Percent Change	2021	Six Months Ended June 30, 2022	Percent Change	2021
Foster Creek						
Fuel	**6.74**	**71**	3.95	**5.71**	**51**	3.77
Non-Fuel	**7.57**	**(8)**	8.23	**7.02**	**(8)**	7.60
Total	**14.31**	**17**	12.18	**12.73**	**12**	11.37
Christina Lake						
Fuel	**6.13**	**100**	3.06	**5.27**	**72**	3.06
Non-Fuel	**5.64**	**15**	4.89	**5.15**	**1**	5.09
Total	**11.77**	**48**	7.95	**10.42**	**28**	8.15
Other Oil Sands [(2)]						
Fuel	**9.77**	**149**	3.92	**8.31**	**100**	4.16
Non-Fuel	**14.65**	**10**	13.29	**13.85**	**12**	12.36
Total	**24.42**	**42**	17.21	**22.16**	**34**	16.52
Total	**15.70**	**31**	12.00	**14.05**	**20**	11.74

(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. The Tucker asset was sold on January 31, 2022.

Netbacks

($/BOE)	Three Months Ended June 30, 2022	2021	Six Months Ended June 30, 2022	2021
Sales Price [(1)]	**119.98**	61.16	**107.54**	56.95
Royalties [(1)]	**28.94**	9.55	**24.18**	7.96
Transportation [(1)]	**7.51**	7.08	**7.36**	7.57
Operating Expenses [(1)]	**15.70**	12.00	**14.05**	11.74
Netback [(2)]	**67.83**	32.53	**61.95**	29.68

(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 three and six months ended June 30, 2022, DD&A was $690 million and $1.3 billion, respectively (2021 – $627 million and $1.2 billion, respectively). The increase was due to a higher depletion rate. The average depletion rate for the three and six months ended June 30, 2022, was $11.78 per BOE and 11.93 per BOE, respectively (2021 – $11.55 per BOE and $11.34 per BOE, respectively).

CONVENTIONAL

In the second quarter of 2022, we:

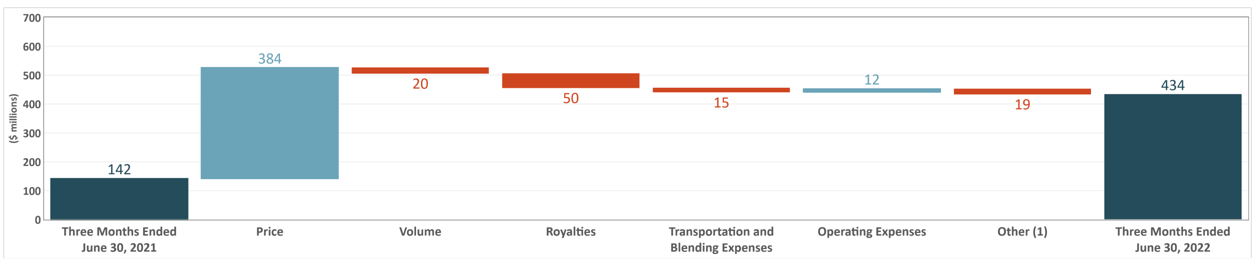
- Delivered another quarter of safe and reliable operations.
- Generated Operating Margin of $434 million, an increase of $292 million compared with the second quarter of 2021, largely due to higher average realized sales prices.
- Invested capital of $33 million focused on completion and tie-in programs, following the winter drilling program.
- Achieved a Netback of $36.78 per BOE.

Financial Results

($ millions)	Three Months Ended June 30, 2022	2021	Six Months Ended June 30, 2022	2021
Gross Sales	**1,079**	626	**2,191**	1,402
Less: Royalties	**89**	39	**160**	63
Revenues	**990**	587	**2,031**	1,339
Expenses				
Purchased Product	**390**	287	**996**	668
Transportation and Blending	**34**	19	**68**	37
Operating	**128**	140	**262**	282
Realized (Gain) Loss on Risk Management	**4**	(1)	**8**	—
Operating Margin	**434**	142	**697**	352
Unrealized (Gain) Loss on Risk Management	**(1)**	2	**(1)**	1
Depreciation, Depletion and Amortization	**99**	102	**179**	210
Exploration Expense	**1**	1	**1**	(3)
Segment Income (Loss)	**335**	37	**518**	144

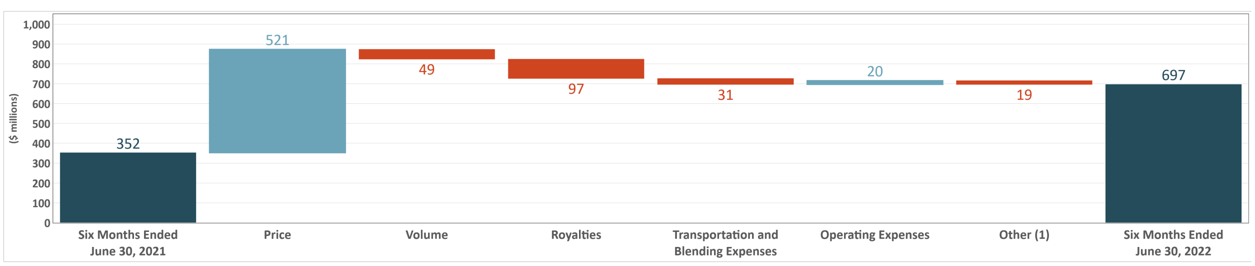
Operating Margin Variance

Three Months Ended June 30, 2022



(1) Reflects Operating Margin from processing facilities.

Six Months Ended June 30, 2022



(1) Reflects Operating Margin from processing facilities.

Operating Results

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	**2022**	2021
Total Sales Volumes (MBOE/d)	**132.6**	141.3	**128.8**	138.6
Total Realized Price [(1)] ($/BOE)	**57.11**	24.90	**50.22**	27.54
Light Crude Oil ($/bbl)	**134.66**	67.91	**123.27**	64.86
NGLs ($/bbl)	**73.47**	35.48	**64.53**	36.73
Conventional Natural Gas ($/Mcf)	**7.87**	3.02	**6.77**	3.61
Production by Product				
Light Crude Oil (Mbbls/d)	**7.5**	9.2	**7.9**	8.9
NGLs (Mbbls/d)	**24.7**	29.0	**24.6**	28.6
Conventional Natural Gas (MMcf/d)	**601.2**	618.4	**578.3**	606.5
Total Daily Production (MBOE/d)	**132.6**	141.3	**128.8**	138.6
Conventional Natural Gas Production (percentage of total)	**76**	73	**75**	73
Crude Oil and NGLs Production (percentage of total)	**24**	27	**25**	27
Effective Royalty Rate (percent)	**13.6**	12.7	**14.5**	9.5
Transportation Costs [(1)] ($/BOE)	**2.97**	1.51	**3.07**	1.49
Operating Expense [(1)] ($/BOE)	**10.02**	10.41	**10.65**	10.65
Per Unit DD&A [(1)] ($/BOE)	**8.21**	7.93	**8.20**	8.28

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

Revenues

Price

Our total realized sales price increased in the three and six months ended June 30, 2022, due to higher crude oil and natural gas benchmark prices.

In the three and six months ended June 30, 2022, gross sales included $390 million and $996 million, respectively (2021 – $287 million and $668 million, respectively), relating to third-party sourced volumes, which are not included in our per-unit pricing metrics or our Netbacks.

In the three and six months ended June 30, 2022, revenues included amounts relating to processing and transportation activities undertaken for third-parties of $14 million and $27 million, respectively (2021 – $19 million and $43 million, respectively), which are not included in our per-unit pricing metrics or our Netbacks.

Production Volumes

Production volumes decreased in the first half of 2022 mainly due to asset sales in the first quarter of 2022 and the second half of 2021. The production decrease is partially offset by 22 new net wells brought on production during the second quarter, combined with production from well reactivations and workovers.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Total royalties and effective royalty rates increased in the three and six months ended June 30, 2022, primarily due to higher realized pricing.

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 $15 million and $31 million in the three and six months ended June 30, 2022, respectively, compared with 2021. Per-unit transportation costs averaged $2.97 per BOE and $3.07 per BOE in the three and six months ended June 30, 2022, respectively (2021 – $1.51 per BOE and $1.49 per BOE, respectively).

Operating

Primary drivers of our operating expenses in the three and six months ended June 30, 2022, were repairs and maintenance, workforce, property taxes and lease costs. Operating expenses per BOE in the three and six months ended June 30, 2022, were relatively flat compared with 2021. Total operating expenses in the three months ended June 30, 2022, decreased due to lower sales volumes.

Netbacks

	Three Months Ended June 30,		Six Months Ended June 30,	
($/BOE)	**2022**	2021	**2022**	2021
Sales Price (1)	**57.11**	24.90	**50.22**	27.54
Royalties (1)	**7.34**	2.98	**6.83**	2.50
Transportation and Blending (1)	**2.97**	1.51	**3.07**	1.49
Operating Expenses (1)	**10.02**	10.41	**10.65**	10.65
Netback (2)	**36.78**	10.00	**29.67**	12.90

(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

The average depletion rate for the three and six months ended June 30, 2022, was $8.21 per BOE and $8.20 per BOE, respectively (2021 – $7.93 per BOE and $8.28 per BOE).

In the three and six months ended June 30, 2022, total Conventional DD&A was $99 million and $179 million, respectively (2021 – $102 million and $210 million, respectively). The decrease was due to asset dispositions in the first quarter of 2022 and the second half of 2021.

OFFSHORE

In the second quarter of 2022, we:

- Delivered another quarter of safe and reliable operations.
- Generated Operating Margin of $476 million, an increase of $136 million compared with the second quarter of 2021, largely due to higher average realized sales prices.
- Earned a Netback of $76.48 per BOE.
- Invested capital of $91 million mainly for the Terra Nova ALE project and capital for the West White Rose project in the Atlantic region.

On May 31, 2022, Cenovus and our partners announced we reached an agreement to restart the West White Rose project in the Atlantic region. The project is expected to restart in 2023. First oil is anticipated in the first half of 2026, with peak production anticipated to reach approximately 80 thousand barrels per day, 45 thousand barrels per day net to Cenovus, by 2029. Contributing to the decision to restart the project is an amended royalty structure with the Government of Newfoundland and Labrador which provides safeguards to the project's economics in periods of low commodity prices. The remaining capital required to achieve first oil is expected to be approximately $2.0 billion to $2.3 billion net to Cenovus, of which we expect to spend an estimated $120 million in 2022. The project is around 65 percent complete. Following our decision to restart the project, we invested approximately $10 million by June 30, 2022.

On June 13, 2022, we announced we are selling our 35 percent interest in the undeveloped Bay du Nord project as part of the consideration to purchase the remaining 50 percent interest in Sunrise from BP Canada. The transaction has an effective date of May 1, 2022, and is anticipated to close in the third quarter of this year.

The Terra Nova ALE project remains underway in Spain, and the FPSO is anticipated to return to the field before the end of 2022.

In Indonesia, we drilled two planned development wells in the MDA field during the quarter, of the five we plan to drill this year. 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 start drilling late in 2022.

In China we finalized an agreement that will increase gas sales at Liuhua 29-1 for the duration of the contract. This will partially offset some of the reduction in contracted natural gas sales from Liwan 3-1, due to the conclusion of an amendment that temporarily increased sales volumes.

Financial Results

($ millions)	Three Months Ended June 30, 2022 Asia Pacific	2022 Atlantic	2022 Offshore	2021 Asia Pacific	2021 Atlantic	2021 Offshore
Revenues						
Gross Sales	**351**	**207**	**558**	308	119	427
Less: Royalties	**18**	**(16)**	**2**	16	9	25
	333	**223**	**556**	292	110	402
Expenses						
Transportation and Blending	**—**	**4**	**4**	—	3	3
Operating	**29**	**47**	**76**	24	35	59
Operating Margin (1)	**304**	**172**	**476**	268	72	340
Depreciation, Depletion and Amortization			**159**			117
Exploration Expense			**10**			1
Share of (Income) Loss from Equity-Accounted Affiliates			**(6)**			(12)
Segment Income (Loss)			**313**			234

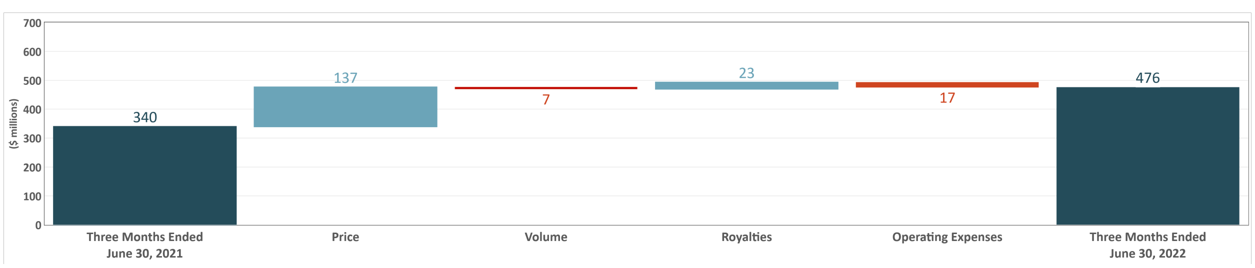
(1) Asia Pacific and Atlantic Operating Margin are Non-GAAP financial measures. See the Specified Financial Measures Advisory of this MD&A.

($ millions)	Six Months Ended June 30, 2022 Asia Pacific	2022 Atlantic	2022 Offshore	2021 Asia Pacific	2021 Atlantic	2021 Offshore
Revenues						
Gross Sales	**746**	**379**	**1,125**	629	229	858
Less: Royalties	**40**	**(6)**	**34**	33	17	50
	706	**385**	**1,091**	596	212	808
Expenses						
Transportation and Blending	**—**	**8**	**8**	—	7	7
Operating	**56**	**93**	**149**	46	71	117
Operating Margin (1)	**650**	**284**	**934**	550	134	684
Depreciation, Depletion and Amortization			**309**			242
Exploration Expense			**25**			—
Share of (Income) Loss from Equity-Accounted Affiliates			**(10)**			(24)
Segment Income (Loss)			**610**			466

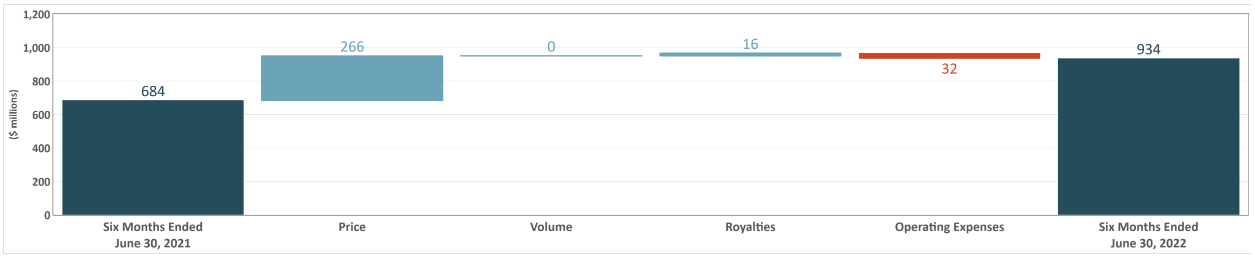
(1) Asia Pacific and Atlantic Operating Margin are Non-GAAP financial measures. See the Specified Financial Measures Advisory of this MD&A.

Operating Margin Variance

Three Months Ended June 30, 2022



Six Months Ended June 30, 2022



Operating Results

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	**2022**	2021
Total Sales Volumes (MBOE/d)	**72.3**	73.0	**74.8**	74.4
Atlantic	**15.5**	15.2	**15.1**	15.1
Asia Pacific (1)	**56.8**	57.8	**59.7**	59.3
Total Realized Price (2) ($/BOE)	**95.16**	71.70	**92.74**	71.20
Atlantic - Light Crude Oil ($/bbl)	**146.38**	86.07	**138.92**	83.75
Asia Pacific (1) ($/BOE)	**81.16**	67.93	**81.09**	68.01
NGLs ($/bbl)	**120.75**	72.55	**115.33**	71.07
Conventional Natural Gas ($/Mcf)	**11.76**	11.12	**12.00**	11.20
Production by Product				
Atlantic - Light Crude Oil (Mbbls/d)	**13.3**	15.2	**13.5**	16.1
Asia Pacific (1)				
NGLs (Mbbls/d)	**12.0**	12.1	**12.6**	12.5
Conventional Natural Gas (MMcf/d)	**269.0**	274.1	**283.2**	280.7
Asia Pacific Total (MBOE/d)	**56.8**	57.8	**59.7**	59.3
Total Daily Production (MBOE/d)	**70.1**	73.0	**73.2**	75.4
Effective Royalty Rate (percent)				
Atlantic	**(8.0)**	7.6	**(1.6)**	7.3
Asia Pacific (1)	**13.1**	5.9	**11.9**	6.2
Operating Expense (2) ($/BOE)	**12.27**	9.64	**11.94**	9.50
Atlantic	**30.57**	25.24	**33.22**	25.89
Asia Pacific (1)	**7.27**	5.56	**6.58**	5.35
Per Unit DD&A (2) ($/BOE)	**30.11**	25.14	**29.98**	25.57

(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 in the consolidated financial statements.

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

Revenues

Price

The price we receive for natural gas sold in Asia is set under long-term contracts. Our realized sales price on light crude oil and NGLs increased in the three and six months ended June 30, 2022, compared with 2021, primarily due to higher Brent benchmark pricing.

Production and Sales Volumes

Asia Pacific production in the second quarter of 2022 was relatively flat compared with 2021, as high demand in China in 2022 and lower production in 2021 due to planned maintenance in China and Indonesia, was offset by planned maintenance at block 29/26 in China in 2022.

Asia Pacific production in the first half of 2022 was relatively flat compared with 2021, for the same factors as discussed above. In addition, we completed planned maintenance at the FPSO in Indonesia in the first quarter of 2022.

Atlantic production decreased slightly in the three and six months ended June 30, 2022, 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 rates for the three and six months ended June 30, 2022 were 13.1 percent and 11.9 percent, respectively (2021 – 5.9 percent and 6.2 percent, respectively). The increases in the effective royalty rates in 2022 are due to the full recovery of development costs at the Madura-BD gas project in the third quarter of 2021.

Royalties at the White Rose field are based on an amended agreement between our working interest partners and the Government of Newfoundland and Labrador. Retroactive to January 1, 2022, we pay a basic royalty of 1.0 percent of gross sales from the White Rose field and 1.0 percent of gross sales from the satellite extensions. The effective royalty rates for the three and six months ended June 30, 2022 were negative 8.0 percent and negative 1.6 percent, respectively (2021 – 7.6 percent and 7.3 percent, respectively). The three months ended June 30, 2022, includes a year-to-date adjustment to reflect the amended royalty regime.

Expenses

Operating

Primary drivers of our Asia Pacific operating expenses in the first half of 2022 were workforce, repairs and maintenance, and insurance. Total and per-unit operating expenses increased largely due to planned maintenance at block 29/26 in China in the second quarter.

Primary drivers of our Atlantic operating expenses in the first half of 2022 were repairs and maintenance, workforce, vessel costs and helicopter costs. Total and per-unit operating expenses increased mainly due to higher fuel prices combined with higher repair and maintenance.

Transportation

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

Netbacks

	Three Months Ended June 30, 2022			
($/BOE, except where indicated)	**China**	**Indonesia** [1]	**Atlantic** ($/bbl)	**Total Offshore**
Sales Price [2]	**82.25**	**76.06**	**146.38**	**95.16**
Royalties [2]	**4.44**	**39.69**	**(11.50)**	**5.89**
Transportation and Blending [2]	**—**	**—**	**2.40**	**0.52**
Operating Expenses [2]	**5.89**	**13.70**	**30.57**	**12.27**
Netback [3]	**71.92**	**22.67**	**124.91**	**76.48**

	Three Months Ended June 30, 2021			
($/BOE, except where indicated)	China	Indonesia [1]	Atlantic ($/bbl)	Total Offshore
Sales Price [2]	69.04	61.79	86.07	71.70
Royalties [2]	3.71	5.81	6.56	4.56
Transportation and Blending [2]	—	—	2.10	0.44
Operating Expenses [2]	4.96	8.87	25.24	9.64
Netback [3]	60.37	47.11	52.17	57.06

(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 in the consolidated financial statements.

(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.

($/BOE, except where indicated)	**Six Months Ended June 30, 2022** China	Indonesia [1]	Atlantic ($/bbl)	Total Offshore
Sales Price [2]	**82.16**	**75.47**	**138.92**	**92.74**
Royalties [2]	**4.44**	**37.10**	**(2.20)**	**7.27**
Transportation and Blending [2]	**—**	**—**	**2.93**	**0.59**
Operating Expenses [2]	**5.24**	**13.61**	**33.22**	**11.94**
Netback [3]	**72.48**	**24.76**	**104.97**	**72.94**

($/BOE, except where indicated)	Six Months Ended June 30, 2021 China	Indonesia [1]	Atlantic ($/bbl)	Total Offshore
Sales Price [2]	69.25	61.22	83.75	71.20
Royalties [2]	3.71	7.07	6.13	4.61
Transportation and Blending [2]	—	—	2.46	0.50
Operating Expenses [2]	4.83	8.17	25.89	9.50
Netback [3]	60.71	45.98	49.27	56.59

(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 in the consolidated financial statements.
(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 three and six months ended June 30, 2022, total Offshore DD&A was $159 million and $309 million, respectively (2021 – $117 million and $242 million). The increase in DD&A was impacted by asset write-downs in the second quarter. The average depletion rate in the three and six months ended June 30, 2022 was $30.11 per BOE and 29.98 per BOE (2021 – $25.14 per BOE and $25.57 per BOE).

DOWNSTREAM

CANADIAN MANUFACTURING

In the second quarter of 2022, we:

- Delivered another quarter of safe and reliable operations.
- Completed planned turnarounds at both the Lloydminster Upgrader and the Lloydminster Refinery.
- Averaged combined crude utilization of 73 percent at the Lloydminster Upgrader and Lloydminster Refinery.
- Generated Operating Margin of $47 million, a decrease of $142 million compared with the second quarter of 2021 due to the impact of maintenance and turnaround activities on sales volumes and operating expenses, partially offset by higher refining margins.

Financial Results

($ millions)	**Three Months Ended June 30,** **2022**	2021	**Six Months Ended June 30,** **2022**	2021
Revenues	**1,521**	1,088	**2,565**	1,894
Purchased Product	**1,296**	807	**2,100**	1,438
Gross Margin [1]	**225**	281	**465**	456
Expenses				
Transportation and Blending	**(2)**	—	**—**	—
Operating	**180**	92	**304**	185
Operating Margin	**47**	189	**161**	271
Depreciation, Depletion and Amortization	**64**	43	**106**	86
Segment Income (Loss)	**(17)**	146	**55**	185

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

Operating Results

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	**2022**	2021
Crude Oil Throughput Capacity (Mbbls/d)	**110.5**	110.5	**110.5**	110.5
Lloydminster Upgrader (Mbbls/d)	**81.5**	81.5	**81.5**	81.5
Lloydminster Refinery (Mbbls/d)	**29.0**	29.0	**29.0**	29.0
Crude Oil Throughput (Mbbls/d)	**80.9**	103.5	**89.4**	104.8
Lloydminster Upgrader (Mbbls/d)	**64.6**	76.1	**67.6**	77.2
Lloydminster Refinery (Mbbls/d)	**16.3**	27.4	**21.8**	27.6
Crude Utilization (1) (percent)	**73**	94	**81**	95
Refined Products Output (Mbbls/d)	**80.0**	104.7	**89.7**	106.1
Sales Volumes (2) (Mbbls/d)	**88.4**	110.4	**93.7**	110.1
Upgrading Differential (3)	**26.47**	16.53	**23.44**	15.22
Refining Margin (4) ($/bbl)	**25.04**	17.19	**23.50**	16.37
Lloydminster Upgrader ($/bbl)	**25.79**	16.90	**25.06**	16.77
Lloydminster Refinery ($/bbl)	**22.08**	18.03	**18.67**	15.22
Unit Operating Expense (5) ($/bbl)	**19.93**	7.57	**15.05**	7.40
Crude-by-Rail Operations				
Volumes Loaded (6) (Mbbls/d)	**—**	3.1	**1.5**	12.3
Ethanol Production (thousands of litres/d)	**728.5**	649.0	**750.8**	523.5

(1) Based on crude oil throughput volumes and results of operations at the Lloydminster Upgrader and Lloydminster Refinery.
(2) From the Lloydminster Upgrader and Lloydminster Refinery.
(3) Based on benchmark price differential between heavy oil feedstock and synthetic crude.
(4) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A. Revenues from the Lloydminster Upgrader for the three and six months ended were $898 million and $1.7 billion, respectively (2021 – $601 million and $1.1 billion, respectively). Revenues from the Lloydminster Refinery for the three and six months ended were $243 million and $427 million, respectively (2021 – $197 million and $333 million, respectively).
(5) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(6) Volumes transported outside of Alberta, Canada.

In the three and six months ended June 30, 2022, crude oil throughput was 80.9 thousand barrels per day and 89.4 thousand barrels per day, respectively (2021 – 103.5 thousand barrels per day and 104.8 thousand barrels per day, respectively). The decrease was due to planned turnarounds at the Lloydminster Upgrader and Lloydminster Refinery completed in the second quarter of 2022. In addition, there were unplanned maintenance outages at the Lloydminster Upgrader in the first quarter of 2022.

Revenues and Gross Margin

Lloydminster Upgrader 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 largely 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 sources crude oil feedstock primarily from our Lloydminster thermal production. The Lloydminster Refinery sources crude oil feedstock from our Lloydminster thermal and Lloydminster conventional heavy oil production.

In the three and six months ended June 30, 2022, revenues increased $433 million and $671 million, respectively, to $1.5 billion and $2.6 billion, respectively, mainly due to higher synthetic crude benchmark prices and higher asphalt and industrial products prices. The increases were partially offset by lower sales volumes from the Lloydminster Upgrader and Lloydminster Refinery due to the planned turnarounds.

Gross margin decreased $56 million quarter-over-quarter to $225 million in the second quarter of 2022 primarily due to the settlement of a take-or-pay contract with a customer of approximately $55 million in the second quarter of 2021 related to Bruderheim crude-by-rail terminal operations, and lower sales volumes from the Lloydminster Upgrader and Lloydminster Refinery. The decrease was partially offset by a higher upgrading differential and higher asphalt and industrial product margins.

Gross margin was relatively consistent in the first half of 2022 compared with 2021, as a higher upgrading differential and higher asphalt and industrial product margins were offset by the settlement of the take-or-pay contract in 2021 and lower sales volumes from the Lloydminster Upgrader and the Lloydminster Refinery.

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 second quarter of 2022 were workforce, repairs and maintenance, and energy costs. Total and per-unit operating expenses in the three and six months ended June 30, 2022, increased due to the planned turnarounds at the Lloydminster Upgrader and Lloydminster Refinery, combined with higher energy and workforce costs. In addition, per-unit operating expenses increased due to lower crude oil throughput volumes.

DD&A

For the three and six months ended June 30, 2022, Canadian Manufacturing DD&A was $64 million and $106 million, respectively (2021 – $43 million and $86 million, respectively). The increase in DD&A was impacted by asset write-downs in the second quarter.

U.S. MANUFACTURING

In the second quarter of 2022, we:

- We delivered safe and reliable operations at our operated assets.
- Continued preparations for the Superior Refinery restart.
- Completed planned turnarounds at the Wood River and Borger refineries.
- Commenced a significant planned turnaround at the Toledo Refinery, which was substantially completed in July.
- Had crude utilization of 75 percent and crude oil throughput of 376.4 thousand barrels per day.
- Generated Operating Margin of $793 million, an increase of $697 million compared with 2021 largely due to significantly higher market crack spreads.
- Invested capital of $267 million focused primarily on the Superior Refinery rebuild, refining reliability initiatives at the Wood River, Borger and Toledo refineries, and yield optimization projects at the Wood River Refinery.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2022**	2021	**2022**	2021 (1)
Revenues	**8,474**	4,729	**14,983**	8,166
Purchased Product	**6,939**	4,229	**12,421**	7,149
Gross Margin (1)	**1,535**	500	**2,562**	1,017
Expenses				
Operating	**655**	394	**1,149**	799
Realized (Gain) Loss on Risk Management	**87**	10	**197**	31
Operating Margin	**793**	96	**1,216**	187
Unrealized (Gain) Loss on Risk Management	**(41)**	23	**(14)**	33
Depreciation, Depletion and Amortization	**83**	103	**168**	217
Segment Income (Loss)	**751**	(30)	**1,062**	(63)

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

Select Operating Results

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	**2022**	2021
Crude Oil Throughput Capacity (Mbbls/d)	**502.5**	502.5	**502.5**	502.5
Lima Refinery	**175.0**	175.0	**175.0**	175.0
Toledo Refinery (1)	**80.0**	80.0	**80.0**	80.0
Wood River and Borger Refineries (1)	**247.5**	247.5	**247.5**	247.5
Crude Oil Throughput (Mbbls/d)	**376.4**	435.5	**390.0**	399.4
Lima Refinery	**159.4**	160.9	**147.8**	142.9
Toledo Refinery (1)	**27.0**	65.7	**49.5**	66.9
Wood River and Borger Refineries (1)	**190.0**	208.9	**192.7**	189.6
Throughput by Product (Mbbls/d)				
Heavy Crude Oil	**106.5**	136.7	**130.1**	127.5
Light and Medium Crude Oil	**269.9**	298.8	**259.9**	271.9
Crude Utilization (percent)	**75**	87	**78**	79
Sales Volumes (Mbbls/d)	**392.4**	419.2	**411.4**	415.8
Refining Margin (2)(3) ($/bbl)	**44.81**	12.59	**36.29**	14.06
Unit Operating Expense (3)(4) ($/bbl)	**19.13**	9.96	**16.28**	11.06

(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.

During the three and six months ended June 30, 2022, crude utilization was 75 percent and 78 percent, respectively (2021 – 87 percent and 79 percent, respectively). The quarter-over-quarter decrease was mainly due to the impact of planned turnarounds at the non-operated Wood River, Borger and Toledo refineries having a greater impact than planned and unplanned outages in the second quarter of 2021. Year-over-year, crude utilization was relatively consistent, as the impact of the turnarounds and unplanned outages in 2022, were offset by higher throughput due to improved market conditions in 2022 and unplanned outages in 2021.

The Lima Refinery performed well during the quarter, achieving crude utilization of 91 percent, even with outages on the pipeline that delivers feedstock to the refinery. In the first quarter of 2022, temporary unplanned equipment outages impacted throughput, and we operated at reduced rates early in the first quarter due to low market crack spreads.

At the Toledo Refinery, we commenced a significant planned turnaround during the quarter, which was substantially completed in July. In the first quarter of 2022, throughput was optimized in line with market demand, and was reduced as a result of temporary unplanned outages.

The Wood River and Borger refineries commenced planned turnarounds in March 2022 and were completed in the second quarter, which impacted throughput. The turnaround at Wood River was delayed due to cold weather which resulted in labour shortages and cost overruns. At the Wood River Refinery, we operated at reduced rates early in the first quarter to optimize margins as market conditions dictated.

Revenues and Gross Margin

Market crack spreads do not precisely mirror the configuration and product output of our refineries, however they are used as a general market indicator. 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 $3.7 billion and $6.8 billion in the three and six months ended June 30, 2022, respectively, compared with 2021. The increases were primarily due to significantly higher refined product pricing benchmarks, partially offset by lower sales volumes.

Gross margin increased $1.0 billion and $1.5 billion in the three and six months ended June 30, 2022, respectively, compared with 2021. The increases were largely due to significantly improved market crack spreads, partially offset by lower sales volumes.

In the three and six months ended June 30, 2022, RINs costs were $271 million and $504 million, respectively (2021 – $305 million and $485 million, respectively). RINs prices averaged US$7.80 per barrel and US$7.12 per barrel in the three and six months ended June 30, 2022, respectively (2021 – US$8.12 per barrel and US$6.80 per barrel, respectively).

In the three and six months ended June 30, 2022, we incurred realized risk management losses of $87 million and $197 million, respectively, of which $36 million relates to the early liquidation of WTI positions in the second quarter. In the three and six months ended June 30, 2022, we recorded unrealized gains of $41 million and $14 million, respectively, on our crude oil financial instruments primarily due to realization of settled positions.

Operating Expenses

Primary drivers of operating expenses for the three and six months ended June 30, 2022, were repairs and maintenance, workforce and energy costs.

Operating expenses increased $261 million and $350 million in the three and six months ended June 30, 2022, respectively, compared with 2021. The increase was mainly due to the impact of planned turnarounds at the Wood River, Borger and Toledo refineries, combined with higher utility costs, and increased repairs and maintenance costs at the Superior Refinery.

In the three and six months ended June 30, 2022, per-unit operating expenses increased $9.17 per barrel of crude oil throughput and $5.22 per barrel of crude oil throughput, respectively. The increase was primarily due to the same factors as discussed above, combined with lower crude oil throughput.

DD&A

U.S. Manufacturing DD&A was $83 million and $168 million in the three and six months ended June 30, 2022, respectively (2021 – $103 million and $217 million). Depreciation decreased in 2022 due to impairment charges recorded in the fourth quarter of 2021 at the Lima, Wood River and Borger refineries reducing the amounts available to depreciate.

RETAIL

As of June 30, 2022, there were 511 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 sale is currently expected to close in the third quarter of 2022. We will retain our commercial fuels business, which includes 167 cardlock, bulkplant and travel centre locations.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2022**	2021	**2022**	2021
Gross Sales	**849**	501	**1,543**	948
Purchased Product	**811**	466	**1,471**	883
Gross Margin [(1)]	**38**	35	**72**	65
Expenses				
Operating	**31**	29	**58**	48
Operating Margin	**7**	6	**14**	17
Depreciation, Depletion and Amortization	**8**	13	**16**	25
Segment Income (Loss)	**(1)**	(7)	**(2)**	(8)

(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 six months ended June 30, 2022, was $6 million (six months ended June 30, 2021 – $7 million).

Select Operating Results

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	**2022**	2021
Fuel Sales Volume, Including Wholesale				
Fuel Sales (millions of litres/d)	**6.4**	6.7	**6.5**	6.6
Fuel Sales per Retail Outlet (thousands of litres/d)	**12.6**	12.5	**12.7**	12.3

Gross Margin

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

Operating expenses

Primary drivers of our operating expenses for the three and six months ended June 30, 2022, were repairs and maintenance, property tax, workforce and utilities.

DD&A

For the three and six months ended June 30, 2022, Retail DD&A was $8 million and $16 million, respectively (2021 – $13 million and $25 million, respectively). The retail assets held for sale are not subject to depreciation.

CORPORATE AND ELIMINATIONS

In the three and six months ended June 30, 2022, our corporate risk management activities resulted in:

- Unrealized risk management gains of $16 million and losses of $2 million, respectively, related to renewable power contracts and foreign exchange risk management contracts (2021 – losses of $2 million and gains of $14 million, respectively).
- Realized risk management losses of $14 million and $7 million, respectively, relate to foreign exchange risk management contracts (2021 – losses of $1 million and $92 million, respectively). The losses in 2021 were mainly due to the realization of WTI put and call option contracts acquired as part of the Arrangement.

Expenses

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2022**	2021	**2022**	2021
General and Administrative	**218**	170	**417**	333
Finance Costs	**195**	232	**424**	476
Interest Income	**(8)**	(3)	**(23)**	(7)
Integration Costs	**28**	34	**52**	257
Foreign Exchange (Gain) Loss, Net	**192**	(172)	**90**	(289)
Re-measurement of Contingent Payment	**15**	249	**251**	436
(Gain) Loss on Divestiture of Assets	**(62)**	(60)	**(304)**	(72)
Other (Income) Loss, Net	**(38)**	(29)	**(408)**	(101)
	540	421	**499**	1,033

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs, employee long-term incentive costs and information technology costs. In the three and six months ended June 30, 2022, general and administrative expenses increased compared with 2021 primarily due to higher long-term incentive costs as a result of our share price increases. Our closing common share price increased from $15.51 on December 31, 2021, to $20.84 on March 31, 2022, and to $24.49 on June 30, 2022.

Finance Costs

In the three and six months ended June 30, 2022, finance costs decreased by $37 million and $52 million, respectively, compared with 2021 largely due to lower average long-term debt. Refer to the Liquidity and Capital Resources section of this MD&A for further details on long-term debt.

The weighted average interest rate of outstanding debt for the three and six months ended June 30, 2022, was 4.7 percent (three and six months ended June 30, 2021 – 4.6 percent).

Integration Costs

For the three and six months ended June 30, 2022, we incurred $28 million and $52 million, respectively, of integration costs as a result of the Arrangement, not including capital expenditures (2021 – $34 million and $257 million, respectively). Integration costs decreased in 2022 as integration activities wind down.

In the first six months of 2022, we incurred $56 million of Total Integration Costs[1], which include capital expenditures (2021 – $291 million). We expect to incur between $100 million to $150 million expected as integration work continues throughout the year.

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

Foreign Exchange

($ millions)	Three Months Ended June 30, 2022	2021	Six Months Ended June 30, 2022	2021
Unrealized Foreign Exchange (Gain) Loss	**260**	(192)	**121**	(331)
Realized Foreign Exchange (Gain) Loss	**(68)**	20	**(31)**	42
	192	(172)	**90**	(289)

In the second quarter of 2022 and on a year-to-date basis, unrealized foreign exchange losses of $260 million and $121 million, respectively, were mainly as a result of the translation of our U.S. dollar denominated debt. Realized foreign exchange gains of $68 million and $31 million, respectively, were recorded related to the purchase of unsecured notes, and working capital.

Re-measurement of Contingent Payment

The contingent payment associated with the acquisition of a 50 percent interest in the FCCL Partnership from ConocoPhillips Company and certain of its subsidiaries ended on May 17, 2022. The quarterly payment was $6 million for each dollar that the WCS price exceeded $52 per barrel.

As at June 30, 2022, $177 million is payable under this agreement. This is the final payment under this agreement and it will be made in July 2022.

Other (Income) Loss, Net

For the three and six months ended June 30, 2022, other income increased by $9 million and $307 million, respectively. The increases are primarily due to:

- Rebuild insurance proceeds of $269 million related to the Superior Refinery in the first half 2022, compared with business interruption proceeds of $45 million in 2021.
- Insurance proceeds in the first half of 2022, related to a 2018 incident in the Atlantic region.

(Gain) Loss on Divestiture of Assets

For the three and six months ended June 30, 2022, we recognized a gain on divestiture of assets of $62 million and $304 million, respectively (2021 – $60 million and $72 million, respectively), due to the closing of the sales of our Tucker and Wembley assets in the first quarter of 2022, and the divestiture of 12.5 percent of our interest in the White Rose field and satellite extensions in the second quarter of 2022.

DD&A

DD&A for the three and six months ended June 30, 2022, was $29 million and $59 million, respectively (2021 – $31 million and $62 million, respectively).

Income Tax

($ millions)	Three Months Ended June 30, 2022	2021	Six Months Ended June 30, 2022	2021
Current Tax				
Canada	**570**	2	**937**	14
United States	**261**	—	**281**	—
Asia Pacific	**71**	47	**109**	81
Other International	**—**	—	**—**	1
Current Tax Expense (Recovery)	**902**	49	**1,327**	96
Deferred Tax Expense (Recovery)	**(61)**	63	**57**	90
Total Tax Expense (Recovery)	**841**	112	**1,384**	186

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 and six months ended June 30, 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 2021 and the availability of tax deductions to calculate taxable income.

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 for many reasons, including, but not limited to, different tax rates between jurisdictions, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other tax legislation.

LIQUIDITY AND CAPITAL RESOURCES

On April 27, 2022, we 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 is approximately 1.0 times at the bottom of the cycle.

We expect to fund our near-term cash requirements through cash from operating activities and prudent use of our balance sheet capacity. This includes draws on our committed credit facilities, uncommitted demand facilities and other corporate and financial opportunities. 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 are dependent on current credit ratings and market conditions.

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2022**	2021	**2022**	2021
Cash From (Used In)				
Operating Activities	**2,979**	1,369	**4,344**	1,597
Investing Activities	**(791)**	(424)	**(454)**	(220)
Net Cash Provided (Used) Before Financing Activities	**2,188**	945	**3,890**	1,377
Financing Activities	**(2,011)**	(717)	**(3,104)**	(678)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**117**	(46)	**34**	(22)
Increase (Decrease) in Cash and Cash Equivalents	**294**	182	**820**	677

As at ($ millions)	**June 30, 2022**	December 31, 2021
Cash and Cash Equivalents	**3,693**	2,873
Total Debt	**11,228**	12,464

Cash From (Used in) Operating Activities

For the three months ended June 30, 2022, cash generated from operating activities increased compared with 2021 due to a higher Operating Margin. In the first half of 2022, cash generated from operating activities increased compared with 2021 due to a higher Operating Margin, combined with lower integration costs. The increases were partially offset by changes in non-cash working capital.

Excluding the contingent payment and assets and liabilities held for sale, our adjusted working capital was $6.1 billion at June 30, 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 higher inventories and accounts receivable, partially offset by higher accounts payable.

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

Cash From (Used in) Investing Activities

Cash used in investing activities was higher in the second quarter of 2022 compared with 2021 largely due to higher capital spending in 2022 and the payment related to the divestiture of 12.5 percent of our interest in the White Rose field and satellite extensions. The increase was partially offset by changes in non-cash working capital and cash proceeds of $110 million on the sale of our remaining investment in Headwater Exploration Inc. in the second quarter.

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

Cash From (Used in) Financing Activities

In the second quarter, we paid $750 million to purchase the full amount of our 3.55 percent unsecured notes. A net discount on redemption of $32 million was recorded in finance costs. In addition, we repaid $63 million in short-term borrowings.

In the first six months of 2022, we paid US$402 million to purchase the remaining balances of our unsecured notes with principal amounts of US$384 million, and purchased the $750 million unsecured notes as discussed above. In addition, we repaid $79 million in short-term borrowings.

In the six months ended June 30, 2022, the Company purchased 68 million common shares through our NCIB. The shares were purchased at a volume weighted average price of $21.89 per common share for a total of $1.5 billion. The common shares were subsequently cancelled.

Adjusted Funds Flow, Free Funds Flow and Excess 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. 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. Excess Free Funds Flow is a non-GAAP financial measure used by the Company to deliver shareholder returns and allocate capital according to our shareholder returns plan. Excess Free Funds Flow is a new metric as of June 30, 2022.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2022**	2021	**2022**	2021
Cash From (Used in) Operating Activities	**2,979**	1,369	**4,344**	1,597
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(27)**	(18)	**(46)**	(29)
Net Change in Non-Cash Working Capital	**(92)**	(430)	**(1,291)**	(1,332)
Adjusted Funds Flow	**3,098**	1,817	**5,681**	2,958
Capital Investment	**822**	534	**1,568**	1,081
Free Funds Flow	**2,276**	1,283	**4,113**	1,877
Add (Deduct):				
Base Dividends Paid on Common Shares	**(207)**	(36)	**(276)**	(71)
Dividends Paid on Preferred Shares	**(8)**	(8)	**(17)**	(17)
Settlement of Decommissioning Liabilities	**(27)**	(18)	**(46)**	(29)
Principal Repayment of Leases	**(75)**	(77)	**(150)**	(152)
Acquisition Costs	**(1)**	—	**(1)**	(7)
Proceeds From Divestitures, Net	**62**	100	**1,012**	105
Excess Free Funds Flow	**2,020**	1,244	**4,635**	1,706

Long-Term Debt and Total Debt

Total Debt and long-term debt, including current portion, as at June 30, 2022, was $11.2 billion (December 31, 2021 – $12.5 billion and $12.4 billion, respectively). The decrease in Total Debt and long-term debt was due to the purchase of $750 million of our unsecured notes in the second quarter and the purchase of US$384 million of our unsecured notes in the first quarter.

As at June 30, 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 June 30, 2022:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**N/A**	**3,693**
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**	**1,021**
WRB Refining LP [3]	**N/A**	**290**
Sunrise Oil Sands Partnership [4]	**N/A**	**5**

(1) No amounts were drawn on the committed credit facility on June 30, 2022.

(2) Our uncommitted demand facilities includes $1.4 billion, which may be drawn for general purposes or $1.9 billion can be available to issue letters of credit. As of June 30, 2022, there were outstanding letters of credit aggregating to $514 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 June 30, 2022, no amounts were drawn on these facilities.

(4) Represents Cenovus's 50 percent share. Available for general purposes. There were no amounts drawn on this demand facility as at June 30, 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 June 30, 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 $2.0 billion.

	Unsecured Notes	
	U.S. Dollar Denominated (US $ millions)	**Canadian Dollar Denominated** ($ millions)
As at December 31, 2021	7,385	2,750
Purchases	(384)	(750)
As at June 30, 2022	**7,001**	**2,000**

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 June 30, 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 a 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. Refer to Note 18 of the interim Consolidated Financial Statements for further details.

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 write-down, 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.

As at	June 30, 2022	December 31, 2021
Net Debt to Capitalization Ratio (percent)	**22**	29
Net Debt to Adjusted Funds Flow Ratio (times)	**0.8**	1.3
Net Debt to Adjusted EBITDA Ratio (times)	**0.6**	1.2

Our Net Debt to Adjusted Funds Flow Ratio and our Net Debt to Adjusted EBITDA Ratio Targets are approximately 1.0 times at the bottom of the commodity price cycle, which we believe is 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 June 30, 2022, our Net Debt to Capitalization Ratio decreased compared with December 31, 2021, primarily due to ongoing reductions in Net Debt and strong net earnings of $4.1 billion during the six months ended June 30, 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 six months of 2022. See the Operating and Financial Results section of this MD&A for more information on Net Debt.

Share Capital and Stock-Based Compensation Plans

As at June 30, 2022, there were approximately 1,950 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 23 of the interim Consolidated Financial Statements for further details.

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 six months of 2022, Cenovus purchased and cancelled 68 million common shares for $1.5 billion (year ended December 31, 2021 – 17 million common shares for $265 million). The shares were purchased for a weighted average price of $21.89 per common share. From July 1, 2022 to July 27, 2022, Cenovus purchased an additional 19 million common shares for $425 million. Cenovus purchased 104 million common shares for $2.2 billion from the commencement of our NCIB to July 27, 2022.

As at June 30, 2022, there were approximately 59 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 the date of issue) at an exercise price of $6.54 per common share. The common share warrants expire on January 1, 2026. Refer to Note 23 of the interim Consolidated Financial Statements for further details.

Refer to Note 25 of the interim Consolidated Financial Statements for further details on our stock option plans and our performance share unit, restricted share unit and deferred share unit plans.

Our outstanding share data is as follows:

As at July 26, 2022	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**1,931,091**	**N/A**
Common Share Warrants	**58,544**	**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	**20,540**	**11,100**
Other Stock-Based Compensation Plans	**17,038**	**1,605**

Common Share Dividends

In the second quarter of 2022, we paid base dividends of $207 million or $0.1050 per common share (2021 – $36 million or $0.0175 per common share). In the first six months of 2022, we paid base dividends of $276 million or $0.1400 per common share (2021 – $71 million or $0.0350 per common share).

The Board declared a third quarter base dividend of $0.105 per common share, payable on September 29, 2022, to common shareholders of record as at September 15, 2022.

The declaration of common share dividends is at the sole discretion of Cenovus's Board and is considered quarterly.

Cumulative Redeemable Preferred Share Dividends

In the three and six months ended June 30, 2022, dividends of $8 million and $17 million, respectively, 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 third quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares of $9 million, payable on October 3, 2022, to preferred shareholders of record as of September 15, 2022.

Capital Investment Decisions

Our 2022 capital program is forecast to be between $3.3 billion and $3.7 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 795.0 thousand BOE per day and downstream throughput of approximately 555.0 thousand barrels per day, at the midpoint of our guidance.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Commitments are largely related to transportation agreements and obligations that have original maturities of less than one year are excluded. For further information, see Note 30 to the interim Consolidated Financial Statements.

Our total commitments were $36.9 billion as at June 30, 2022, of which $33.2 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 June 30, 2022, include $2.3 billion related to transportation, storage and other long-term contracts.

As at June 30, 2022, outstanding letters of credit issued as security for performance under certain contracts totaled $514 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 interim 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 and six months ended June 30, 2022, we charged HMLP $29 million and $77 million, respectively, for construction and management services (2021 – $32 million and $64 million, respectively).

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 six months ended June 30, 2022, we incurred costs of $64 million and $133 million, respectively, for the use of HMLP's pipeline systems, as well as transportation and storage services (2021 – $73 million and $145 million, respectively).

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

Dividend Payments and Purchase of Securities

The payment of dividends, whether base or variable, the continuation of our dividend reinvestment plan and any potential purchase by Cenovus of our securities is at the discretion of our Board, and is dependent upon, among other things, financial performance, debt covenants, satisfying solvency tests, our ability to meet financial obligations as they come due, working capital requirements, future tax obligations, future capital requirements, commodity prices and other business and risk factors set forth in this MD&A and in our 2021 annual MD&A.

Specifically, in connection with Cenovus's updated capital allocation framework, the Company will target returns to shareholders as a percentage of Excess Free Funds Flow, through share buybacks or variable dividends, based on Net Debt at the preceding quarter-end, as described in the Overview of Cenovus section of this MD&A. The frequency and amount of variable dividend payments, if any, may vary significantly over time as a result of our Net Debt, Excess Free Funds Flow, amount of share buybacks and other factors inherent with our capital allocation framework from time to time. As the payment of dividends remains at the discretion of our Board and dependent on, among other things, the factors described above, the Company can provide no assurance that it will continue to pay base or variable dividends or authorize share buybacks at the current rate or at all.

Further, the individual or aggregate amount of base or variable dividends, if any, paid by Cenovus from time to time may result in adjustments to the exercise price and the exchange basis (the number of common shares received for each Cenovus Warrant exercised) of the Cenovus Warrants under the terms of the indenture governing the Cenovus Warrants. Such adjustments may impact the value received by Cenovus upon the exercise of Cenovus Warrants and may result in additional issuances of common shares on the exercise of Cenovus Warrants which may have a further dilutive effect on the ownership interest of shareholders of Cenovus and on Cenovus's earnings per share.

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, renewable power contracts 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 suspended our crude oil sales price risk management activities related to WTI. All WTI positions impacted by this decision were closed by June 30, 2022.

Risks Associated with Derivative Financial Instruments

Derivative 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.

Derivative 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 used, in addition to electricity, 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. 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 related 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 27 and 28 to the interim Consolidated Financial Statements.

Impact of Financial Risk Management Activities

Cenovus makes storage and transportation decisions, considering 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.

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 and six months ended June 30, 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 and six months ended June 30, 2022, unrealized gains were recorded on our crude oil financial instruments mainly due to the realization of settled positions as we liquidated our WTI positions related to crude oil sales price risk management in the quarter.

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 six months ended June 30, 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 six months ended June 30, 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 June 30, 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 June 30, 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", "seek", "target", 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; the Company's capital allocation framework; safety performance and culture; ESG governance and leadership; the Company's targets for each of its five ESG focus areas; Free Funds Flow generation, allocation and pay out; returning incremental capital to shareholders; allocating and paying out Excess Free Funds Flow under the capital allocation framework; opportunistic share repurchases and variable dividend distributions; funding near-term cash requirements and meeting payment obligations; maintaining investment grade credit ratings; Debt reduction and Debt and Net Debt targets; capital discipline; strengthening and maintaining a strong balance sheet; flexibility in both high and low commodity price environments; managing capital structure; improving the shareholder value proposition; returning incremental capital to shareholders beyond the base dividend payment; Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio; cost savings and reductions; cost structure; turnaround costs; interest expense; financial results; margin enhancement; improving efficiencies to drive incremental capital, operating and general and administrative cost reductions; shortening and optimizing the value chain; maintaining the Company's capital program and 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 exposure to various prices for commodities and associated price differentials and refining margins; the final contingent payment in respect of the acquisition of the FCCL Partnership from ConocoPhillips Company; the timing for closing the transaction to acquire 50 percent of the Sunrise oil sands project from BP Canada and benefits of the acquisition; increasing production at Sunrise; timing for closing the sale of gas stations within the Company's retail fuels network; continued use of 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; integration costs; 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, including capital to achieve first oil for the West White Rose project; 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; production at the Spruce Lake North thermal plant; the winter drilling program in the Conventional business; resuming projects, including restarting the West White Rose project and achieving first and peak oil therefrom; the timing for closing the transaction to sell the Company's position in the Bay du Nord project; the return to the field of the floating, production, storage and offloading unit for the Terra Nova ALE project; drilling development wells and construction of production facilities and production therefrom; partially offsetting the reduction of gas sales in China; liabilities from legal proceedings; generating strong margins; and the Company's outlook for commodities and the Canadian dollar and the effects thereof on Cenovus.

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 the Arrangement and other acquisitions; 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 or other acquisitions; 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 global supply factors and heavy crude processing capacity; 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, Pathways Alliance and other industry organizations; 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 the Company's 2022 guidance available on cenovus.com and as set out below; the availability of Indigenous owned or operated businesses and the Company's ability to retain them; and other risks and uncertainties described from time to time in the filings the Company makes with securities regulatory authorities.

2022 guidance, as updated July 27, 2022, and available on cenovus.com, assumes: Brent prices of US$103.00 per barrel, WTI prices of US$100.00 per barrel; WCS of US$84.00 per barrel; Differential WTI-WCS of US$16.00 per barrel; AECO natural gas prices of $5.30 per thousand cubic feet; Chicago 3-2-1 crack spread of US$38.00 per barrel; and an exchange rate of $0.78 US$\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 and other acquisitions in a timely manner or at all; the Company's ability to successfully integrate the legacy Husky business and other acquired businesses with its own in a timely and cost effective manner; unforeseen or underestimated liabilities associated with the Arrangement or other acquisitions; 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 will remain largely

tied to global supply factors and heavy crude processing capacity; 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 recalculate 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 the Company's Annual MD&A, and in this MD&A, and 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	SAGD	steam-assisted gravity drainage
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 operations, Operating Margin by asset, Total Integration Costs, Adjusted Funds Flow, Free Funds Flow, Excess Free Funds Flow, Gross Margin, Refining Margin, Forward-looking Integration Costs, and Netbacks (including the 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 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.

	Three Months Ended June 30, 2022			Three Months Ended March 31, 2022 (1)			**Six Months Ended June 30, 2022**		
($ millions)	**Upstream (2)**	**Downstream (2)**	**Total**	Upstream	Downstream	Total	**Upstream (2)**	**Downstream (2)**	**Total**
Revenues									
Gross Sales	**11,685**	**10,844**	**22,529**	10,897	8,247	19,144	**22,582**	**19,091**	**41,673**
Less: Royalties	**1,582**	**—**	**1,582**	1,185	—	1,185	**2,767**	**—**	**2,767**
	10,103	**10,844**	**20,947**	9,712	8,247	17,959	**19,815**	**19,091**	**38,906**
Expenses									
Purchased Product	**1,461**	**9,046**	**10,507**	1,818	6,946	8,764	**3,279**	**15,992**	**19,271**
Transportation and Blending	**3,238**	**(2)**	**3,236**	3,194	2	3,196	**6,432**	**—**	**6,432**
Operating	**1,010**	**866**	**1,876**	909	645	1,554	**1,919**	**1,511**	**3,430**
Realized (Gain) Loss on Risk Management	**563**	**87**	**650**	871	110	981	**1,434**	**197**	**1,631**
Operating Margin	**3,831**	**847**	**4,678**	2,920	544	3,464	**6,751**	**1,391**	**8,142**

(1) *Prior period results were revised to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.*

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

	2021																	
	Upstream						Downstream						Total					
	Year-to-Date	Three Months Ended					Year-to-Date	Three Months Ended					Year-to-Date	Three Months Ended				
($ millions)	2021	Q2	Q4	Q3	Q2	Q1	2021	Q2	Q4	Q3	Q2	Q1	2021	Q2	Q4	Q3	Q2	Q1
Revenues																		
Gross Sales [1]	27,844	12,253	8,237	7,354	6,128	6,125	26,673	11,008	8,135	7,530	6,318	4,690	54,517	23,261	16,372	14,884	12,446	10,815
Less: Royalties	2,454	906	815	733	533	373	—	—	—	—	—	—	2,454	906	815	733	533	373
	25,390	11,347	7,422	6,621	5,595	5,752	26,673	11,008	8,135	7,530	6,318	4,690	52,063	22,355	15,557	14,151	11,913	10,442
Expenses																		
Purchased Product [1]	4,059	1,787	1,198	1,074	717	1,070	23,526	9,470	7,348	6,708	5,502	3,968	27,585	11,257	8,546	7,782	6,219	5,038
Transportation and Blending [1]	8,714	3,978	2,599	2,137	2,006	1,972	—	—	—	—	—	—	8,714	3,978	2,599	2,137	2,006	1,972
Operating	3,241	1,576	865	800	791	785	2,258	1,032	689	537	515	517	5,499	2,608	1,554	1,337	1,306	1,302
Realized (Gain) Loss on Risk Management	788	418	202	168	188	230	104	31	56	17	10	21	892	449	258	185	198	251
Operating Margin	8,588	3,588	2,558	2,442	1,893	1,695	785	475	42	268	291	184	9,373	4,063	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, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.*

Operating Margin by Asset

	Three Months Ended June 30, 2022			**Six Months Ended June 30, 2022**		
($ millions)	**Asia Pacific**	**Atlantic**	**Offshore [1]**	**Asia Pacific**	**Atlantic**	**Offshore [1]**
Revenues						
Gross Sales	**351**	**207**	**558**	**746**	**379**	**1,125**
Less: Royalties	**18**	**(16)**	**2**	**40**	**(6)**	**34**
	333	**223**	**556**	**706**	**385**	**1,091**
Expenses						
Transportation and Blending	**—**	**4**	**4**	**—**	**8**	**8**
Operating	**29**	**47**	**76**	**56**	**93**	**149**
Operating Margin	**304**	**172**	**476**	**650**	**284**	**934**

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

	Three Months Ended June 30, 2021			Six Months Ended June 30, 2021		
($ millions)	Asia Pacific	Atlantic	Offshore [1]	Asia Pacific	Atlantic	Offshore [1]
Revenues						
Gross Sales	308	119	427	629	229	858
Less: Royalties	16	9	25	33	17	50
	292	110	402	596	212	808
Expenses						
Transportation and Blending	—	3	3	—	7	7
Operating	24	35	59	46	71	117
Operating Margin	268	72	340	550	134	684

(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 June 30,		**Six Months Ended June 30,**	
($ millions)	**2022**	2021	**2022**	2021
Integration Costs [1]	**28**	34	**52**	257
Capitalized Integration Costs [2]	**2**	12	**4**	34
Total Integration Costs	**30**	46	**56**	291

(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, Free Funds Flow and Excess 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.

Excess Free Funds Flow is a non-GAAP financial measure used by the Company to deliver shareholder returns and allocate capital according to our shareholder returns and capital allocation framework. Excess Free Funds Flow is defined as Free Funds Flow minus base dividends paid on common shares, dividends paid on preferred shares, other uses of cash (including settlement of decommissioning liabilities and principal repayment of leases), and acquisition costs, plus proceeds from or payments related to divestitures. Excess Free Funds Flow is a new metric as of June 30, 2022.

	2022		2021				2020		
($ millions)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Cash From (Used in) Operating Activities	**2,979**	1,365	2,184	2,138	1,369	228	250	732	(834)
(Add) Deduct:									
Settlement of Decommissioning Liabilities	**(27)**	(19)	(35)	(38)	(18)	(11)	(6)	(3)	(2)
Net Change in Non-Cash Working Capital	**(92)**	(1,199)	271	(166)	(430)	(902)	(77)	328	(363)
Adjusted Funds Flow	**3,098**	2,583	1,948	2,342	1,817	1,141	333	407	(469)
Capital Investment	**822**	746	835	647	534	547	242	148	147
Free Funds Flow	**2,276**	1,837	1,113	1,695	1,283	594	91	259	(616)
Add (Deduct):									
Base Dividends Paid on Common Shares	**(207)**	(69)	(70)	(35)	(36)	(35)			
Dividends Paid on Preferred Shares	**(8)**	(9)	(8)	(9)	(8)	(9)			
Settlement of Decommissioning Liabilities	**(27)**	(19)	(35)	(38)	(18)	(11)			
Principal Repayment of Leases	**(75)**	(75)	(78)	(70)	(77)	(75)			
Acquisitions Costs	**(1)**	—	—	—	—	(7)			
Proceeds From Divestitures, Net	**62**	950	247	83	100	5			
Excess Free Funds Flow	**2,020**	2,615	1,169	1,626	1,244	462			

	Six Months Ended June 30,		Twelve Months Ended December 31,
($ millions)	**2022**	2021	2021
Cash From (Used in) Operating Activities	**4,344**	1,597	5,919
(Add) Deduct:			
Settlement of Decommissioning Liabilities	**(46)**	(29)	(102)
Net Change in Non-Cash Working Capital	**(1,291)**	(1,332)	(1,227)
Adjusted Funds Flow	**5,681**	2,958	7,248
Capital Investment	**1,568**	1,081	2,563
Free Funds Flow	**4,113**	1,877	4,685
Add (Deduct):			
Base Dividends Paid on Common Shares	**(276)**	(71)	(176)
Dividends Paid on Preferred Shares	**(17)**	(17)	(34)
Settlement of Decommissioning Liabilities	**(46)**	(29)	(102)
Principal Repayment of Leases	**(150)**	(152)	(300)
Acquisition Costs	**(1)**	(7)	(7)
Proceeds From Divestitures, Net	**1,012**	105	435
Excess Free Funds Flow	**4,635**	1,706	4,501

Gross Margin, Refining Margin and Unit Operating Expense

Gross Margin and Refining Margin are non-GAAP financial measures, or contain a non-GAAP financial measure, 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 oil throughput. Unit Operating Expenses are specified financial measures used to evaluate the performance of our upstream and downstream operations. We define Unit Operating Expense as operating expenses divided by barrels of crude oil throughput in our downstream operations.

Canadian Manufacturing

	Three Months Ended June 30, 2022				
($ millions)	**Lloydminster Upgrader**	**Lloydminster Refinery**	**Basis of Refining Margin Calculation**	**Other (1)**	**Total Canadian Manufacturing (2)**
Revenues	**898**	**243**	**1,141**	**380**	**1,521**
Purchased Product	**747**	**210**	**957**	**339**	**1,296**
Gross Margin	**151**	**33**	**184**	**41**	**225**

	Operating Statistics		
	Lloydminster Upgrader	**Lloydminster Refinery**	**Lloydminster Upgrader and Lloydminster Refinery Total**
Crude Oil Throughput (Mbbls/d)	**64.6**	**16.3**	**80.9**
Refining Margin ($/bbl)	**25.79**	**22.08**	**25.04**

(1) Includes ethanol and crude-by-rail operations, and marketing activities.
(2) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.

	Six Months Ended June 30, 2022				
($ millions)	**Lloydminster Upgrader**	**Lloydminster Refinery**	**Basis of Refining Margin Calculation**	**Other (1)**	**Total Canadian Manufacturing (2)**
Revenues	**1,700**	**427**	**2,127**	**438**	**2,565**
Purchased Product	**1,394**	**353**	**1,747**	**353**	**2,100**
Gross Margin	**306**	**74**	**380**	**85**	**465**

	Operating Statistics		
	Lloydminster Upgrader	**Lloydminster Refinery**	**Lloydminster Upgrader and Lloydminster Refinery Total**
Crude Oil Throughput (Mbbls/d)	**67.6**	**21.8**	**89.4**
Refining Margin ($/bbl)	**25.06**	**18.67**	**23.5**

(1) Includes ethanol and crude-by-rail operations, and marketing activities.
(2) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.

	2021																	
	Lloydminster Upgrader						**Lloydminster Refinery**						**Basis of Refining Margin Calculation**					
	Year-to-Date		Three Months Ended				Year-to-Date		Three Months Ended				Year-to-Date		Three Months Ended			
($ millions)	Q4	Q2	Q4	Q3	Q2	Q1	Q4	Q2	Q4	Q3	Q2	Q1	Q4	Q2	Q4	Q3	Q2	Q1
Revenues	2,559	1,127	748	684	601	526	817	333	206	278	197	136	3,376	1,460	954	962	798	662
Purchased Product	2,041	893	592	556	484	409	659	257	172	230	152	105	2,700	1,150	764	786	636	514
Gross Margin	518	234	156	128	117	117	158	76	34	48	45	31	676	310	190	176	162	148
	Basis of Refining Margin Calculation						**Other (1)**						**Total Canadian Manufacturing (2)**					
Revenues	3,376	1,460	954	962	798	662	1,096	434	409	253	290	144	4,472	1,894	1,363	1,215	1,088	806
Purchased Product	2,700	1,150	764	786	636	514	852	288	364	200	171	117	3,552	1,438	1,128	986	807	631
Gross Margin	676	310	190	176	162	148	244	146	45	53	119	27	920	456	235	229	281	175

(1) Includes ethanol and crude-by-rail operations, and marketing activities.
(2) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.

	2021																	
	Operating Statistics																	
	Lloydminster Upgrader						**Lloydminster Refinery**						**Lloydminster Upgrader and Lloydminster Refinery Total**					
	Year-to-Date		Three Months Ended				Year-to-Date		Three Months Ended				Year-to-Date		Three Months Ended			
	Q4	Q2	Q4	Q3	Q2	Q1	Q4	Q2	Q4	Q3	Q2	Q1	Q4	Q2	Q4	Q3	Q2	Q1
Crude Oil Throughput (Mbbls/d)	79.0	77.2	80.4	81.2	76.1	78.4	27.5	27.6	27.9	27.1	27.4	27.8	106.5	104.8	108.3	108.3	103.5	106.2
Refining Margin [(1)] ($/bbl)	17.99	16.77	21.05	16.93	16.90	16.64	15.64	15.22	13.25	19.29	18.03	12.43	17.35	16.37	18.95	17.57	17.19	15.54

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

U.S. Manufacturing

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2022**	2021	2022	2021
Revenues [(1)]	**8,474**	4,729	**14,983**	8,166
Purchased Product [(1)]	**6,939**	4,229	**12,421**	7,149
Gross Margin	**1,535**	500	**2,562**	1,017
Crude Oil Throughput (Mbbls/d)	**376.4**	435.5	**390.0**	399.4
Refining Margin ($/bbl)	**44.81**	12.59	**36.29**	14.06

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

Retail

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2022**	2021	2022	2021
Revenues [(1)]	**849**	501	**1,543**	948
Purchased Product [(1)]	**811**	466	**1,471**	883
Gross Margin	**38**	35	**72**	65

(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 basis. We define Per Unit DD&A as DD&A divided by sales volumes.

Netback Reconciliations

Netback is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring operating performance and is also presented on a per-unit basis. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. Netbacks per BOE 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, and netback per BOE is 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, and Netbacks per BOE to Operating Margin found in our interim Consolidated Financial Statements.

Total Production

Upstream Financial Results

Three Months Ended June 30, 2022 ($ millions)	Total Upstream (1)	Adjustments: Condensate	Adjustments: Third-Party Sourced	Adjustments: Internal Consumption (2)	Adjustments: Equity Adjustment (3)	Adjustments: Other (4)	Basis of Netback Calculation: Total Upstream
Gross Sales	11,685	(2,801)	(1,365)	(347)	70	(117)	7,125
Royalties	1,582	—	—	—	36	(5)	1,613
Purchased Product	1,461	—	(1,365)	—	—	(96)	—
Transportation and Blending	3,238	(2,801)	—	—	—	(12)	425
Operating	1,010	—	—	(347)	8	(10)	661
Netback	4,394	—	—	—	26	6	4,426
Realized (Gain) Loss on Risk Management	563	—	(4)	—	—	—	559
Operating Margin	3,831	—	4	—	26	6	3,867

Three Months Ended June 30, 2021 ($ millions)	Total Upstream (1)	Adjustments: Condensate	Adjustments: Third-Party Sourced	Adjustments: Internal Consumption (2)	Adjustments: Equity Adjustment (3)	Adjustments: Other (4)	Basis of Netback Calculation: Total Upstream
Gross Sales (5)	6,128	(1,620)	(651)	(145)	50	(105)	3,657
Royalties	533	—	—	—	5	—	538
Purchased Product (5)	717	—	(651)	—	—	(66)	—
Transportation and Blending	2,006	(1,620)	—	—	—	(17)	369
Operating	791	—	—	(145)	7	(11)	642
Netback	2,081	—	—	—	38	(11)	2,108
Realized (Gain) Loss on Risk Management	188	—	—	—	—	—	188
Operating Margin	1,893	—	—	—	38	(11)	1,920

(1) These amounts, excluding netback, are found in Note 1 of the interim 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 in the consolidated financial statements.
(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, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Six Months Ended June 30, 2022 ($ millions)	Total Upstream (1)	Adjustments Condensate	Third-Party Sourced	Internal Consumption (2)	Equity Adjustment (3)	Other (4)	Basis of Netback Calculation Total Upstream
Gross Sales	**22,582**	**(5,559)**	**(3,115)**	**(586)**	**131**	**(193)**	**13,260**
Royalties	**2,767**	**—**	**—**	**—**	**64**	**(5)**	**2,826**
Purchased Product	**3,279**	**—**	**(3,115)**	**—**	**—**	**(164)**	**—**
Transportation and Blending	**6,432**	**(5,559)**	**—**	**—**	**—**	**(11)**	**862**
Operating	**1,919**	**—**	**—**	**(586)**	**15**	**(31)**	**1,317**
Netback	**8,185**	**—**	**—**	**—**	**52**	**18**	**8,255**
Realized (Gain) Loss on Risk Management	**1,434**	**—**	**(8)**	**—**	**—**	**—**	**1,426**
Operating Margin	**6,751**	**—**	**8**	**—**	**52**	**18**	**6,829**

Six Months Ended June 30, 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)	12,253	(3,160)	(1,675)	(294)	102	(195)	7,031
Royalties	906	—	—	—	12	—	918
Purchased Product (5)	1,787	—	(1,675)	—	—	(112)	—
Transportation and Blending	3,978	(3,160)	—	—	—	(20)	798
Operating	1,576	—	—	(294)	12	(22)	1,272
Netback	4,006	—	—	—	78	(41)	4,043
Realized (Gain) Loss on Risk Management	418	—	—	—	—	—	418
Operating Margin	3,588	—	—	—	78	(41)	3,625

(1) These amounts, excluding netback, are found in Note 1 of the interim 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 in the consolidated financial statements.
(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, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Oil Sands

Three Months Ended June 30, 2022 ($ millions)	Basis of Netback Calculation						
	Foster Creek	Christina Lake	Sunrise	Other Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	2,135	2,419	278	1,317	6,149	6	6,155
Royalties	625	722	17	121	1,485	1	1,486
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	182	143	27	34	386	—	386
Operating	250	249	45	253	797	7	804
Netback	1,078	1,305	189	909	3,481	(2)	3,479
Realized (Gain) Loss on Risk Management							559
Operating Margin							2,920

Three Months Ended June 30, 2022 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales	6,155	2,801	975	117	10,048
Royalties	1,486	—	—	5	1,491
Purchased Product	—	—	975	96	1,071
Transportation and Blending	386	2,801	—	13	3,200
Operating	804	—	—	2	806
Netback	3,479	—	—	1	3,480
Realized (Gain) Loss on Risk Management	559	—	—	—	559
Operating Margin	2,920	—	—	1	2,921

Three Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation						
	Foster Creek	Christina Lake	Sunrise	Other Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	860	1,274	131	737	3,002	3	3,005
Royalties	142	242	2	83	469	—	469
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	155	131	26	35	347	—	347
Operating	154	171	54	205	584	5	589
Netback	409	730	49	414	1,602	(2)	1,600
Realized (Gain) Loss on Risk Management							189
Operating Margin							1,411

Three Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales (4)	3,005	1,620	364	86	5,075
Royalties	469	—	—	—	469
Purchased Product (4)	—	—	364	66	430
Transportation and Blending	347	1,620	—	17	1,984
Operating	589	—	—	3	592
Netback	1,600	—	—	—	1,600
Realized (Gain) Loss on Risk Management	189	—	—	—	189
Operating Margin	1,411	—	—	—	1,411

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.

(2) Other includes construction, transportation and blending margin.

(3) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.

(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, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Six Months Ended June 30, 2022 ($ millions)	Basis of Netback Calculation						
	Foster Creek	**Christina Lake**	**Sunrise**	**Other Oil Sands** (1)	**Total Bitumen and Heavy Oil**	**Natural Gas**	**Total Oil Sands**
Gross Sales	**3,955**	**4,651**	**510**	**2,293**	**11,409**	**10**	**11,419**
Royalties	**1,013**	**1,306**	**28**	**220**	**2,567**	**1**	**2,568**
Purchased Product	**—**	**—**	**—**		**—**		**—**
Transportation and Blending	**360**	**294**	**57**	**72**	**783**		**783**
Operating	**452**	**468**	**84**	**474**	**1,478**	**13**	**1,491**
Netback	**2,130**	**2,583**	**341**	**1,527**	**6,581**	**(4)**	**6,577**
Realized (Gain) Loss on Risk Management							**1,426**
Operating Margin							**5,151**

Six Months Ended June 30, 2022 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	**Condensate**	**Third-party Sourced**	**Other** (2)	**Total Oil Sands** (3)
Gross Sales	**11,419**	**5,559**	**2,119**	**169**	**19,266**
Royalties	**2,568**	**—**	**—**	**5**	**2,573**
Purchased Product	**—**	**—**	**2,119**	**164**	**2,283**
Transportation and Blending	**783**	**5,559**	**—**	**14**	**6,356**
Operating	**1,491**	**—**	**—**	**17**	**1,508**
Netback	**6,577**	**—**	**—**	**(31)**	**6,546**
Realized (Gain) Loss on Risk Management	**1,426**	**—**	**—**	**—**	**1,426**
Operating Margin	**5,151**	**—**	**—**	**(31)**	**5,120**

Six Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation						
	Foster Creek	**Christina Lake**	**Sunrise**	**Other Oil Sands** (1)	**Total Bitumen and Heavy Oil**	**Natural Gas**	**Total Oil Sands**
Gross Sales	1,712	2,269	254	1,433	5,668	6	5,674
Royalties	249	409	5	130	793	—	793
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	328	261	50	115	754	—	754
Operating	323	335	85	416	1,159	10	1,169
Netback	812	1,264	114	772	2,962	(4)	2,958
Realized (Gain) Loss on Risk Management							418
Operating Margin							2,540

Six Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	**Condensate**	**Third-party Sourced**	**Other** (2)	**Total Oil Sands** (3)
Gross Sales (4)	5,674	3,160	1,007	152	9,993
Royalties	793	—	—	—	793
Purchased Product (4)	—	—	1,007	112	1,119
Transportation and Blending	754	3,160	—	20	3,934
Operating	1,169	—	—	8	1,177
Netback	2,958	—	—	12	2,970
Realized (Gain) Loss on Risk Management	418	—	—	—	418
Operating Margin	2,540	—	—	12	2,552

(1) Includes Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets. The Tucker asset was sold on January 31, 2022.

(2) Other includes construction, transportation and blending margin.

(3) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.

(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, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Conventional

Three Months Ended June 30, 2022 ($ millions)	Basis of Netback Calculation	Adjustments		
	Conventional	Third-party Sourced	Other (1)	Conventional (2)
Gross Sales	689	390	—	1,079
Royalties	89	—	—	89
Purchased Product	—	390	—	390
Transportation and Blending	35	—	(1)	34
Operating	120	—	8	128
Netback	445	—	(7)	438
Realized (Gain) Loss on Risk Management	—	4	—	4
Operating Margin	445	(4)	(7)	434

Three Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation	Adjustments		
	Conventional	Third-party Sourced	Other (1)	Conventional (2)
Gross Sales	320	287	19	626
Royalties	39	—	—	39
Purchased Product	—	287	—	287
Transportation and Blending	19	—	—	19
Operating	132	—	8	140
Netback	130	—	11	141
Realized (Gain) Loss on Risk Management	(1)	—	—	(1)
Operating Margin	131	—	11	142

Six Months Ended June 30, 2022 ($ millions)	Basis of Netback Calculation	Adjustments		
	Conventional	Third-party Sourced	Other (1)	Conventional (2)
Gross Sales	1,171	996	24	2,191
Royalties	160	—	—	160
Purchased Product	—	996	—	996
Transportation and Blending	71	—	(3)	68
Operating	248	—	14	262
Netback	692	—	13	705
Realized (Gain) Loss on Risk Management		8		8
Operating Margin	692	(8)	13	697

Six Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation	Adjustments		
	Conventional	Third-party Sourced	Other (1)	Conventional (2)
Gross Sales	691	668	43	1,402
Royalties	63	—	—	63
Purchased Product	—	668	—	668
Transportation and Blending	37	—	—	37
Operating	268	—	14	282
Netback	323	—	29	352
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	323	—	29	352

(1) Reflects Operating Margin from processing facilities.
(2) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.

Offshore

	Basis of Netback Calculation					Adjustment	
Three Months Ended June 30, 2022 ($ millions)	China	Indonesia (1)	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment (1)	Total Offshore (2)
Gross Sales	351	70	421	207	628	(70)	558
Royalties	18	36	54	(16)	38	(36)	2
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	4	4	—	4
Operating	24	13	37	47	84	(8)	76
Netback	309	21	330	172	502	(26)	476
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					502	(26)	476

	Basis of Netback Calculation					Adjustment	
Three Months Ended September 30, 2021 ($ millions)	China	Indonesia (1)	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment (1)	Total Offshore (2)
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

	Basis of Netback Calculation					Adjustment	
Three Months Ended June 30, 2021 ($ millions)	China	Indonesia (1)	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment (1)	Total Offshore (2)
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

	Basis of Netback Calculation					Adjustment	
Three Months Ended March 31, 2021 ($ millions)	China	Indonesia (1)	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment (1)	Total Offshore (2)
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 in the consolidated financial statements.
(2) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.

Six Months Ended June 30, 2022 ($ millions)	Basis of Netback Calculation					Adjustment	
	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Total Offshore [2]
Gross Sales	**746**	**131**	**877**	**379**	**1,256**	**(131)**	**1,125**
Royalties	**40**	**64**	**104**	**(6)**	**98**	**(64)**	**34**
Purchased Product			**—**		**—**		**—**
Transportation and Blending			**—**	**8**	**8**		**8**
Operating	**47**	**24**	**71**	**93**	**164**	**(15)**	**149**
Netback	**659**	**43**	**702**	**284**	**986**	**(52)**	**934**
Realized (Gain) Loss on Risk Management					**—**		**—**
Operating Margin					**986**	**(52)**	**934**

Six Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation					Adjustment	
	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Total Offshore [2]
Gross Sales	629	102	731	229	960	(102)	858
Royalties	33	12	45	17	62	(12)	50
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	7	7	—	7
Operating	44	14	58	71	129	(12)	117
Netback	552	76	628	134	762	(78)	684
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					762	(78)	684

(1) Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the consolidated financial statements.
(2) These amounts, excluding netback, are 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 June 30, 2022	2021	Six Months Ended June 30, 2022	2021
Oil Sands				
Foster Creek	**192.2**	139.0	**196.1**	156.9
Christina Lake	**233.0**	235.8	**248.1**	226.7
Sunrise [2]	**23.8**	20.9	**24.5**	22.6
Other Oil Sands	**114.9**	144.2	**118.0**	144.1
Total Oil Sands [2]	**563.9**	539.9	**586.7**	550.3
Conventional	**132.6**	141.3	**128.8**	138.6
Sales before Internal Consumption	**696.5**	681.2	**715.5**	688.9
Less: Internal Consumption [3]	**(84.3)**	(85.0)	**(86.1)**	(85.8)
Sales after Internal Consumption	**612.2**	596.2	**629.4**	603.1
Offshore				
Asia Pacific - China	**46.8**	49.0	**50.1**	50.2
Asia Pacific - Indonesia	**10.0**	8.8	**9.6**	9.1
Asia Pacific - Total	**56.8**	57.8	**59.7**	59.3
Atlantic	**15.5**	15.2	**15.1**	15.1
Total Offshore	**72.3**	73.0	**74.8**	74.4
Total Sales	**684.5**	669.2	**704.2**	677.5

(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 and second quarters of 2021.
(3) Less natural gas volumes used for internal consumption by the Oil Sands segment.

The following tables have been re-presented for the first, second, third and fourth quarters of 2021 and the first quarter of 2022 to more appropriately reflect the cost of blending at our Lloydminster Thermal and Lloydminster conventional heavy oil assets, which resulted in a reclassification of costs between purchased products and transportation and blending. In addition, the tables were also re-presented for the first, second and third quarters of 2021 for a change in the presentation of product swaps and certain third-party purchases used in blending and optimization activities and a change in the classification of marketing activities at Sunrise. Sunrise sales volumes, gross sales, royalties, transportation and blending, and operating expenses have been re-presented. See Adjustments to the Interim Consolidated Statements of Earnings (Loss) below for further details.

Upstream Financial Results

		Adjustments					Basis of Netback Calculation
Three Months Ended March 31, 2022 ($ millions)	**Total Upstream**	**Condensate**	**Third-Party Sourced**	**Internal Consumption** [(1)]	**Equity Adjustment** [(2)]	**Other** [(3)]	**Total Upstream**
Gross Sales	**10,897**	(2,758)	(1,750)	(239)	61	(76)	**6,135**
Royalties	**1,185**	—	—	—	28	—	**1,213**
Purchased Product	**1,818**	—	(1,750)	—	—	(68)	**—**
Transportation and Blending	**3,194**	(2,758)	—	—	—	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**

		Adjustments					Basis of Netback Calculation
Year Ended December 31, 2021 ($ millions)	**Total Upstream**	**Condensate**	**Third-party Sourced**	**Internal Consumption** [(1)]	**Equity Adjustment** [(2)]	**Other** [(3)]	**Total Upstream**
Gross Sales	**27,844**	(7,095)	(3,761)	(710)	224	(390)	**16,112**
Royalties	**2,454**	—	—	—	52	—	**2,506**
Purchased Product	**4,059**	—	(3,761)	—	—	(298)	**—**
Transportation and Blending	**8,714**	(7,095)	—	—	—	—	**1,619**
Operating	**3,241**	—	(8)	(710)	25	(36)	**2,512**
Netback	**9,376**	**—**	**8**	**—**	**147**	**(56)**	**9,475**
Realized (Gain) Loss on Risk Management	**788**	—	(2)	—	—	—	**786**
Operating Margin	**8,588**	**—**	**10**	**—**	**147**	**(56)**	**8,689**

		Adjustments					Basis of Netback Calculation
Three Months Ended December 31, 2021 ($ millions)	**Total Upstream**	**Condensate**	**Third-Party Sourced**	**Internal Consumption** [(1)]	**Equity Adjustment** [(2)]	**Other** [(3)]	**Total Upstream**
Gross Sales	**8,237**	(2,201)	(1,079)	(241)	62	(146)	**4,632**
Royalties	**815**	—	—	—	29	—	**844**
Purchased Product	**1,198**	—	(1,079)	—	—	(119)	**—**
Transportation and Blending	**2,599**	(2,201)	—	—	—	—	**398**
Operating	**865**	—	(8)	(241)	7	(3)	**620**
Netback	**2,760**	**—**	**8**	**—**	**26**	**(24)**	**2,770**
Realized (Gain) Loss on Risk Management	**202**	—	—	—	—	—	**202**
Operating Margin	**2,558**	**—**	**8**	**—**	**26**	**(24)**	**2,568**

Three Months Ended September 30, 2021 ($ millions)	Total Upstream	Adjustments: Condensate	Adjustments: Third-Party Sourced	Adjustments: Internal Consumption (1)	Adjustments: Equity Adjustment (2)	Adjustments: Other (3)	Basis of Netback Calculation: Total Upstream
Gross Sales	7,354	(1,734)	(1,007)	(175)	60	(49)	4,449
Royalties	733	—	—	—	11	—	744
Purchased Product	1,074	—	(1,007)	—	—	(67)	—
Transportation and Blending	2,137	(1,734)	—	—	—	20	423
Operating	800	—	—	(175)	6	(11)	620
Netback	2,610	—	—	—	43	9	2,662
Realized (Gain) Loss on Risk Management	168	—	(2)	—	—	—	166
Operating Margin	2,442	—	2	—	43	9	2,496

Three Months Ended March 31, 2021 ($ millions)	Total Upstream	Adjustments: Condensate	Adjustments: Third-Party Sourced	Adjustments: Internal Consumption (1)	Adjustments: Equity Adjustment (2)	Adjustments: Other (3)	Basis of Netback Calculation: Total Upstream
Gross Sales	6,125	(1,540)	(1,024)	(149)	52	(90)	3,374
Royalties	373	—	—	—	7	—	380
Purchased Product	1,070	—	(1,024)	—	—	(46)	—
Transportation and Blending	1,972	(1,540)	—	—	—	(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) Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.
(2) Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the consolidated financial statements.
(3) Other includes construction, transportation and blending and third-party processing margin.

Oil Sands

Three Months Ended March 31, 2022 ($ millions)	Basis of Netback Calculation: Total Oil Sands	Adjustments: Condensate	Adjustments: Third-party Sourced	Adjustments: Other (1)	Total Oil Sands
Gross Sales	5,264	2,758	1,144	52	9,218
Royalties	1,082	—	—	—	1,082
Purchased Product	—	—	1,144	68	1,212
Transportation and Blending	397	2,758	—	1	3,156
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

Year Ended December 31, 2021 ($ millions)	Basis of Netback Calculation: Total Oil Sands	Adjustments: Condensate	Adjustments: Third-party Sourced	Adjustments: Other (1)	Total Oil Sands
Gross Sales	13,297	7,095	2,106	329	22,827
Royalties	2,196	—	—	—	2,196
Purchased Product	—	—	2,106	298	2,404
Transportation and Blending	1,530	7,095	—	—	8,625
Operating	2,437	—	—	14	2,451
Netback	7,134	—	—	17	7,151
Realized (Gain) Loss on Risk Management	786	—	—	—	786
Operating Margin	6,348	—	—	17	6,365

Three Months Ended December 31, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other [1]	Total Oil Sands
Gross Sales	3,841	2,201	537	138	6,717
Royalties	734	—	—	—	734
Purchased Product	—	—	537	119	656
Transportation and Blending	376	2,201	—	—	2,577
Operating	653	—	—	5	658
Netback	2,078	—	—	14	2,092
Realized (Gain) Loss on Risk Management	202	—	—	—	202
Operating Margin	1,876	—	—	14	1,890

Three Months Ended September 30, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other [1]	Total Oil Sands
Gross Sales	3,782	1,734	562	39	6,117
Royalties	669	—	—	—	669
Purchased Product	—	—	562	67	629
Transportation and Blending	400	1,734	—	(20)	2,114
Operating	615	—	—	1	616
Netback	2,098	—	—	(9)	2,089
Realized (Gain) Loss on Risk Management	166	—	—	—	166
Operating Margin	1,932	—	—	(9)	1,923

Three Months Ended March 31, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other [1]	Total Oil Sands
Gross Sales	2,669	1,540	643	66	4,918
Royalties	324	—	—	—	324
Purchased Product	—	—	643	46	689
Transportation and Blending	407	1,540	—	3	1,950
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) Other includes construction, transportation and blending margin.

Adjustments to the Interim Consolidated Statements of Earnings (Loss)

Certain comparative information presented in the Consolidated Statements of Earnings (Loss) within the Oil Sands segment and Corporate and Eliminations segment was revised. See Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

During the three months ended December 31, 2021, the Company made adjustments to more appropriately record certain third-party purchases used for blending and optimization activities and to ensure consistent treatment of product swaps. As a result, revenues and purchased product increased with no impact to net earnings (loss), segment income (loss), cash flows or financial position. Refer to the annual Consolidated Financial Statements for the year ended December 31, 2021, for further details.

During the three months ended June 30, 2022, the Company has made adjustments to more appropriately reflect the cost of blending at our Lloydminster thermal and Lloydminster conventional heavy oil assets, which resulted in a reclassification of costs between purchased product and transportation and blending. An associated elimination entry was recorded in our Corporate and Eliminations segment to represent the change in the value of condensate that was extracted at our Canadian Manufacturing operations and sold back to the Oil Sands segment. As a result, purchased product decreased and transportation and blending increased, with no impact to net earnings (loss), segment income (loss), cash flows or financial position.

The following table reconciles the amounts previously reported in the interim Consolidated Statements of Earnings (Loss) to the corresponding revised amounts:

	Three Months Ended March 31, 2021			**Three Months Ended June 30, 2021**			**Three Months Ended September 30, 2021**			**Three Months Ended December 31, 2021**			**Three Months Ended March 31, 2022**		
($ millions)	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**
Oil Sands Segment															
Gross Sales	4,775	143	**4,918**	5,015	60	**5,075**	6,114	3	**6,117**	6,717	—	**6,717**	9,218	—	**9,218**
Purchased Product (1)(2)	718	(29)	**689**	574	(144)	**430**	822	(193)	**629**	868	(212)	**656**	1,483	(271)	**1,212**
Transportation and Blending	1,778	172	**1,950**	1,780	204	**1,984**	1,918	196	**2,114**	2,365	212	**2,577**	2,885	271	**3,156**
Corporate and Eliminations Segment															
Purchased Product	(973)	138	**(835)**	(1,110)	146	**(964)**	(1,244)	153	**(1,091)**	(1,561)	192	**(1,369)**	(1,497)	215	**(1,282)**
Transportation and Blending	(15)	(138)	**(153)**	(6)	(146)	**(152)**	(18)	(153)	**(171)**	(8)	(192)	**(200)**	(6)	(215)	**(221)**
Consolidated															
Gross Sales	9,523	143	**9,666**	11,110	60	**11,170**	13,431	3	**13,434**	14,541	—	**14,541**	17,383	—	**17,383**
Purchased Product	4,094	109	**4,203**	5,253	2	**5,255**	6,731	(40)	**6,691**	7,197	(20)	**7,177**	7,538	(56)	**7,482**
Transportation and Blending	1,785	34	**1,819**	1,796	58	**1,854**	1,923	43	**1,966**	2,379	20	**2,399**	2,919	56	**2,975**

(1) Revisions include $143 million for the three months ended March 31, 2021, $60 million for the three months ended June 30, 2022, $3 million for the three months ended September 30, 2021, and $nil for the three months ended December 31, 2021 and March 31, 2022, related to adjustments for product swaps and third-party purchases used in blending and optimization activities.

(2) Revisions include $172 million for the three months ended March 31, 2021, $204 million for the three months ended June 30, 2022, $196 million for the three months ended September 30, 2021, $212 million for the three months ended December 31, 2021, and $271 million for the three months ended March 31, 2022, to more appropriately reflect the cost of blending at our Lloydminster thermal and Lloydminster conventional heavy oil assets.

	Six Months Ended June 30, 2021			**Twelve Months Ended December 31, 2021**		
($ millions)	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**
Oil Sands Segment						
Gross Sales	9,790	203	**9,993**	22,827	—	**22,827**
Purchased Product (1)(2)	1,292	(173)	**1,119**	3,188	(784)	**2,404**
Transportation and Blending	3,558	376	**3,934**	7,841	784	**8,625**
Corporate and Eliminations Segment						
Purchased Product	(2,083)	284	**(1,799)**	(4,888)	629	**(4,259)**
Transportation and Blending	(21)	(284)	**(305)**	(47)	(629)	**(676)**
Consolidated						
Gross Sales	20,633	203	**20,836**	48,811	—	**48,811**
Purchased Product	9,347	111	**9,458**	23,481	(155)	**23,326**
Transportation and Blending	3,581	92	**3,673**	7,883	155	**8,038**

(1) Revisions include $203 million for the six months ended June 30, 2021, and $nil for the twelve months ended December 31, 2021, related to adjustments for product swaps and third-party purchases used in blending and optimization activities.

(2) Revisions include $376 million for the six months ended June 30, 2022, and $784 million for the twelve months ended December 31, 2021, to more appropriately reflect the cost of blending at our Lloydminster thermal and Lloydminster conventional heavy oil assets.