Cenovus Energy Inc.

Management's Discussion and Analysis (unaudited)

For the Year Ended December 31, 2022

(Canadian Dollars)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the year ended December 31, 2022

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated February 15, 2023 should be read in conjunction with our December 31, 2022 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 15, 2023 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 Audit Committee of the Cenovus Board of Directors ("the Board"), reviewed and recommended the MD&A for approval by the Board, which occurred on February 15, 2023. Additional information about Cenovus, including our quarterly and annual reports, 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 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 ("NYSE"). 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 commercial fuel operations across Canada.

Our operations involve activities across the full value chain to develop, produce, refine, 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.

Our Strategy

Our strategy is focused on maximizing shareholder value through competitive cost structures and optimizing margins, while delivering top-tier safety performance and sustainability leadership. The Company prioritizes Free Funds Flow generation through all price cycles to manage our balance sheet, increase shareholder returns through dividend growth and share repurchases, reinvest in our business and diversify our portfolio.

On December 6, 2022, we announced our 2023 budget focused on disciplined capital allocation, investment plans to progress opportunities across our integrated portfolio, cost control and positioning the Company for continued growth in shareholder returns. Our 2023 guidance dated December 5, 2022, 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 price cycle is a key element of Cenovus's capital allocation framework. In April 2022, we announced our updated capital allocation framework to continue to strengthen our balance sheet, which enables flexibility in both high and low commodity price environments, and improves our shareholder value proposition. We have set an ultimate Net Debt Target of $4 billion, which serves as a floor on Net Debt. We plan to return incremental value to shareholders, through share buybacks and/or variable dividends, as follows:

- 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 shareholder returns.

Excess Free Funds Flow for the quarter is defined as Free Funds Flow(1):

- Minus base dividends paid on common shares.
- Minus dividends paid on preferred shares.
- Minus other uses of cash, including settlement of decommissioning liabilities and principal repayment of leases.
- Minus any net 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 commodity price cycle.

Share buybacks 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 a variable dividend payable for that quarter, if the remainder is greater than $50 million. Where the value of share buybacks in a quarter is greater than or equal to the targeted value of returns, no variable dividend will be paid for that quarter.

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

On September 30, 2022, our long-term debt was $8.8 billion, resulting in a Net Debt position of $5.3 billion. Therefore, our returns to shareholders target for the three months ended December 31, 2022, was 50 percent of that quarter's Excess Free Funds Flow. During the three months ended December 31, 2022, we generated cash from operating activities of $3.0 billion, Excess Free Funds Flow of $786 million and returned $387 million to our shareholders through share buybacks. Returns to shareholders through share buybacks were within $50 million of our Target Return, as such no variable dividend was declared for the quarter.

($ millions)	Three Months Ended December 31, 2022
Excess Free Funds Flow (1)	**786**
Target Return (2)	**393**
Less: Purchase of Common Shares Under our Normal Course Issuer Bid ("NCIB")	**(387)**
Amount Available for Variable Dividend	**6**

(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 September 30, 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 December 31, 2022.

On December 31, 2022, our Net Debt position was $4.3 billion and as a result our returns to shareholders target for the three months ended March 31, 2023, will be 50 percent of the first quarter's Excess Free Funds Flow.

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, 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. These provide 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 converts heavy oil and bitumen into synthetic crude oil, diesel, asphalt and other ancillary products. Cenovus also owns and operates the Bruderheim crude-by-rail terminal and two ethanol plants. The Company's commercial fuels business across Canada is included in this segment. Cenovus markets its production and third-party commodity trading volumes in an effort to use its integrated network of assets to maximize value.
- **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.

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 in the Canadian Manufacturing segment and sold to the Oil Sands segment, and unrealized profits in inventory. Eliminations are recorded based on current market prices.

In September 2022, the Company completed the divestiture of the majority of the retail fuels business. As a result, Management elected to aggregate the remaining commercial fuels business and the historical retail fuels business into the Canadian Manufacturing segment. The marketing operations of the Canadian Manufacturing segment have similar products and services, customer types, distribution methods and operate in the same regulatory environment as the commercial fuels business. The commercial fuels business includes cardlock, bulk plant and travel centre locations across Canada. Comparative periods have been re-presented to reflect this change.

YEAR IN REVIEW

In 2022, we continued to focus on health and safety and drive competitive cost structures. High commodity prices in both our upstream and downstream businesses combined with solid upstream operating performance and good operating performance in our operated downstream assets drove strong financial results and allowed us to significantly reduce our total debt. We optimized our asset portfolio as we closed the acquisition of Sunrise and announced the acquisition of Toledo, which will provide us full ownership and operatorship of both assets. In addition, we completed the restructuring of our Atlantic assets and reached an agreement with our partners to restart the West White Rose project. We also sold our Tucker, Wembley and retail assets. These transactions enhanced Cenovus's core strength in the oil sands and will further optimize margins through increased physical integration of our upstream and downstream assets. Lastly, we improved our shareholder value proposition through an updated shareholder returns and capital allocation framework. The framework returns incremental value back to shareholders through share buybacks and/or variable dividends.

Summary of Annual Results

($ millions, except where indicated)	2022	Percent Change	2021	Percent Change	2020
Upstream Production Volumes [(1)] (MBOE/d)	**786.2**	**(1)**	791.5	68	471.7
Downstream Crude Oil Throughput [(2)] (Mbbls/d)	**493.7**	**(3)**	508.0	173	185.9
Revenues [(3)]	**66,897**	**44**	46,357	242	13,543
Operating Margin [(4)]	**14,263**	**52**	9,373	918	921
Cash From (Used In) Operating Activities	**11,403**	**93**	5,919	2,068	273
Adjusted Funds Flow [(4)]	**10,978**	**51**	7,248	6,095	117
Per Share – Basic [(4)] ($)	**5.63**	**57**	3.59	3,490	0.10
Per Share – Diluted [(4)] ($)	**5.47**	**55**	3.54	3,440	0.10
Capital Investment	**3,708**	**45**	2,563	205	841
Free Funds Flow [(4)]	**7,270**	**55**	4,685	N/A	(724)
Net Earnings (Loss) [(5)]	**6,450**	**999**	587	N/A	(2,379)
Per Share – Basic ($)	**3.29**	**1,119**	0.27	N/A	(1.94)
Per Share – Diluted ($)	**3.20**	**1,085**	0.27	N/A	(1.94)

(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 have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.
(4) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(5) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.

Summary of Annual Results

($ millions, except where indicated)	2022	Percent Change	2021	Percent Change	2020
Total Assets	**55,869**	**3**	54,104	65	32,770
Total Long-Term Liabilities	**20,259**	**(13)**	23,191	69	13,704
Long-Term Debt, Including Current Portion	**8,691**	**(30)**	12,385	66	7,441
Net Debt	**4,282**	**(55)**	9,591	34	7,184
Cash Returns to Shareholders					
Common Shares – Base Dividends	**682**	**288**	176	129	77
Base Dividends Per Common Share ($)	**0.350**	**298**	0.088	40	0.063
Common Shares – Variable Dividends	**219**	**N/A**	—	—	—
Variable Dividends Per Common Share ($)	**0.114**	**N/A**	—	—	—
Purchase of Common Shares Under NCIB	**2,530**	**855**	265	N/A	—
Preferred Share Dividends	**26**	**(24)**	34	N/A	—

In 2022, we delivered on our strategy through five key strategic objectives:

Top Tier Safety Performance and Sustainability Leadership

Underpinning everything we do is the safety of our people and communities, and the integrity of our assets. Safety, asset integrity and corporate governance are foundational to our business, and are the backbone for all of our operations. We promote a safety culture in all aspects of our work and use a variety of programs to always keep safety top of mind. In 2022, we:

- Delivered safe operations at our operated assets.
- Completed planned turnarounds at the operated Lloydminster Upgrader (the "Upgrader") and Lloydminster Refinery in our downstream operations. In addition, we completed a planned turnaround at Christina Lake in our upstream operations in the second quarter.
- Completed planned turnarounds at the non-operated Toledo, Wood River and Borger refineries in our downstream operations.
- Continued our focus on achieving our targets in each of our five Environmental, Social and Governance ("ESG") focus areas. 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.
- Actively participated in industry collaborations including the Pathways Alliance.

We continue to work with our partners of our non-operated downstream assets to improve the safety performance.

Competitive Cost Structures and Optimizing Margins

In 2022, we:

- Targeted additional cost savings and margin enhancements through further physical integration of upstream assets with downstream assets, which shortened the value chain and reduced condensate costs associated with heavy oil transportation.
- Improved efficiencies across Cenovus to drive incremental capital, operating, and general and administrative cost reductions.

Maintaining and Further Reducing Debt Levels

In 2022, we generated cash from operating activities of $11.4 billion and Free Funds Flow of $7.3 billion, enabling us to substantially decrease Net Debt.

- As at December 31, 2022, our long-term debt, including current portion, was $8.7 billion (December 31, 2021 – $12.4 billion) and our Net Debt position was $4.3 billion (December 31, 2021 – $9.6 billion).
- We deleveraged our balance sheet by purchasing US$2.6 billion in principal of notes due between 2023 and 2043, and $750 million in principal of notes due in 2025.
- Our Net Debt to Adjusted EBITDA Ratio was 0.3 times and our Net Debt to Adjusted Funds Flow Ratio was 0.4 times at December 31, 2022.

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.

In 2022, we generated cash from operating activities of $11.4 billion and Free Funds Flow of $7.3 billion, primarily due to high commodity prices combined with solid upstream operating performance. WTI averaged approximately US$94 per barrel in 2022, the highest annual average since 2013, and an increase of approximately 40 percent from 2021. North American market crack spreads also reached historic highs during the year.

In 2022, we continued to optimize our top-tier asset portfolio and grow Free Funds Flow.

In our upstream business:

- We sold our Tucker asset and our Wembley assets for total net proceeds of $951 million.
- We reached an agreement with our partners to restart the West White Rose project in the Atlantic region offshore Newfoundland and Labrador. Major construction is expected to restart in the first quarter of 2023.
- We acquired the remaining 50 percent interest in Sunrise (the "Sunrise Acquisition") from BP Canada Energy Group ULC ("BP Canada") for net proceeds of $394 million, a variable payment with a maximum cumulative value of $600 million expiring in eight quarters subsequent to August 31, 2022, and our 35 percent position in the undeveloped Bay du Nord project offshore Newfoundland and Labrador.
- We achieved first oil at our Spruce Lake North thermal plant in the third quarter of 2022.
- In Indonesia, we achieved first gas production from the MBH and MDA fields in the fourth quarter of 2022.
- Received regulatory approval in December 2022 to develop the Ipiatik asset in the Foster Creek area.

In our downstream business:

- We announced an agreement to purchase the remaining 50 percent interest in the Toledo Refinery from BP (the "Toledo Acquisition"). The transaction is expected to close at the end of February 2023.
- We closed the sale of 337 gas stations within our retail fuels network for net cash proceeds of $404 million.

In addition, we sold our investment in Headwater Exploration Inc. for proceeds of $110 million.

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. In 2022:

- We renewed our NCIB, which expired on November 8, 2022. Under our new NCIB (the "2023 NCIB"), we are authorized to purchase up to 136.7 million of the Company's common shares between November 9, 2022, and November 8, 2023.
- We purchased and cancelled 112 million common shares for $2.5 billion through our NCIBs in 2022.
- We returned $901 million to common shareholders through base dividends of $0.350 per common share and variable dividends of $0.114 per common share.

We declared dividends for the first quarter of 2023:

- On February 15, 2023, the Board declared a first quarter base dividend of $0.105 per common share payable on March 31, 2023, to common shareholders of record as at March 15, 2023.
- On February 15, 2023, the Board declared first quarter dividends for our preferred shares of $9 million, payable on March 31, 2023, to preferred shareholders of record as at March 15, 2023.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results — Upstream

	2022	Percent Change	2021	Percent Change	2020
Upstream Production Volumes by Segment [1] (MBOE/d)					
Oil Sands	**588.7**	**1**	583.6	53	381.7
Conventional	**127.2**	**(5)**	133.6	49	89.9
Offshore	**70.3**	**(6)**	74.4	N/A	—
Total Production Volumes	**786.2**	**(1)**	791.5	68	471.7
Upstream Production Volumes by Product					
Bitumen (Mbbls/d)	**570.3**	**2**	561.3	47	381.7
Heavy Crude Oil (Mbbls/d)	**16.3**	**(19)**	20.2	648	2.7
Light Crude Oil (Mbbls/d)	**19.1**	**(15)**	22.5	400	4.5
NGLs (Mbbls/d)	**36.2**	**(5)**	38.3	96	19.5
Conventional Natural Gas (MMcf/d)	**866.1**	**(3)**	895.5	136	379.0
Total Production Volumes (MBOE/d)	**786.2**	**(1)**	791.5	68	471.7
Total Upstream Sales Volumes [2] (MBOE/d)	**696.4**	**(1)**	700.8	67	420.5
Netback [3][4] ($/BOE)	**53.21**	**44**	37.04	267	10.09
Oil and Gas Reserves (MMBOE)					
Total Proved	**6,082**	**—**	6,077	21	5,030
Probable	**2,787**	**27**	2,201	33	1,656
Total Proved Plus Probable	**8,869**	**7**	8,278	24	6,686

(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 520 MMcf per day for the year ended December 31, 2022 (517 MMcf per day for the year ended December 31, 2021).
(3) Upstream revenue as found in Note 1 of the Consolidated Financial Statements was $36.3 billion for the year ended December 31, 2022 ($25.4 billion for the year ended December 31, 2021).
(4) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

In 2022, total crude oil, NGLs and natural gas production was consistent with 2021. The factors below increased production in 2022 compared with 2021:

- New wells coming online at Foster Creek and Christina Lake in 2022 and the second half of 2021.
- The Sunrise Acquisition on August 31, 2022.
- First oil at the Spruce Lake North thermal plant in the third quarter of 2022.
- A planned turnaround and operational outages at Foster Creek in the second quarter of 2021.
- First gas production at the MBH and MDA fields in Indonesia in the fourth quarter of 2022.

The factors below decreased production in 2022 compared with 2021:

- The disposition of the Tucker asset on January 31, 2022.
- Planned maintenance and an unplanned outage at Foster Creek in the third quarter of 2022.
- Planned turnaround activity at Christina Lake in the second quarter of 2022.
- The disposition of the Wembley asset on February 28, 2022, and the East Clearwater and Kaybob divestitures in the second half of 2021.
- As part of the decision to restart the West White Rose project, we transferred a 12.5 percent working interest in the White Rose field and satellite extensions to our partner on May 31, 2022.

Oil and Gas Reserves

Based on our reserves reports prepared by independent qualified reserves evaluators ("IQREs"), total proved reserves and total proved plus probable reserves at December 31, 2022 were approximately 6.1 billion BOE and 8.9 billion BOE, respectively. Total proved reserves were consistent with 2021, and proved plus probable reserves increased seven percent compared with 2021.

Additional information about our reserves is included in the Oil and Gas Reserves section of this MD&A.

Selected Operating Results — Downstream

	2022	Percent Change	2021	Percent Change	2020
Downstream Crude Oil Throughput (Mbbls/d)					
Canadian Manufacturing	**92.9**	**(13)**	106.5	N/A	—
U.S. Manufacturing	**400.8**	**—**	401.5	116	185.9
Total Throughput	**493.7**	**(3)**	508.0	173	185.9
Fuel Sales [(1)] (millions of litres/d)	**6.2**	**(10)**	6.9	N/A	—

(1) On September 13, 2022, we closed the sale of 337 gas stations within our retail fuels network. We retained our commercial fuels business, which includes cardlock, bulk plant and travel centre locations.

In the Canadian Manufacturing segment, throughput decreased 13.6 thousand barrels per day in 2022 compared with 2021. We completed planned turnarounds at both the Lloydminster Upgrader and Lloydminster Refinery in the second quarter of 2022. In addition, there were multiple temporary unplanned outages at the Upgrader in 2022. In 2021, the Upgrader and Lloydminster Refinery ran at or near capacity throughout the year.

In the U.S. Manufacturing segment, total throughput was consistent in 2022 compared with 2021:

- The Lima Refinery had unplanned operational issues in the first quarter of 2022 coming out of the 2021 fourth quarter turnaround. The refinery performed well during the remainder of the year, achieving crude utilization of 90 percent in 2022.
- At the Toledo Refinery, we completed a significant planned turnaround from April to early August 2022. The refinery remains shut down in a safe state following an incident on September 20, 2022.
- We completed two planned turnarounds at the Wood River Refinery in the second and fourth quarters of 2022. The second quarter turnaround was delayed due to cold weather, resulting in labour shortages and cost overruns. In early December, there was an incident at the Wood River Refinery that resulted in damage to one of the units and reduced throughput.
- We completed a turnaround at the Borger Refinery in the first and second quarter of 2022. In addition, the refinery had unplanned operational outages in the fourth quarter of 2022.
- We commenced commissioning for the restart of the Superior Refinery in December 2022.

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.

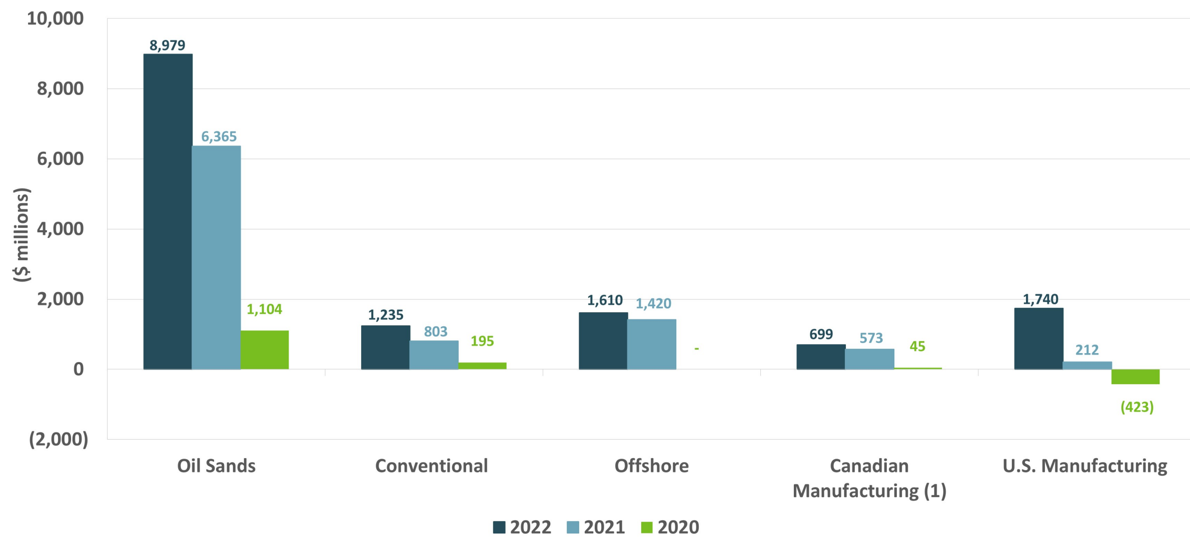
($ millions)	2022	2021 [(1)(2)]	2020
Gross Sales	**79,229**	54,102	14,523
Less: Royalties	**4,868**	2,454	371
Revenues	**74,361**	51,648	14,152
Expenses			
Purchased Product	**39,334**	27,170	5,959
Transportation and Blending	**12,194**	8,714	4,764
Operating Expenses	**6,839**	5,499	2,261
Realized (Gain) Loss on Risk Management Activities	**1,731**	892	247
Operating Margin	**14,263**	9,373	921

(1) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

(2) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no change to total Operating Margin.

Operating Margin by Segment

Year Ended December 31, 2022



(1) *Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuel business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details.*

Operating Margin increased in 2022, mainly due to higher average realized sales prices, resulting from higher benchmark pricing. In addition, realized refining margins almost doubled in our downstream business due to significantly higher market crack spreads from 2021.

These increases in Operating Margin were partially offset by:

- Increased blending costs due to higher condensate prices.
- Higher royalties and fuel costs in our upstream operations, both resulting from significantly higher commodity pricing.
- Increased realized risk management losses on the settlement of benchmark prices relative to our risk management contract prices in 2022. In the second quarter of 2022, all WTI risk management contracts related to our crude oil sales price risk management activities were closed.
- Planned turnarounds and unplanned outages in our downstream operations in 2022, which impacted sales volumes and operating expenses.
- In our realized margin, higher Renewable Identification Numbers ("RINs") costs impacting our U.S. Manufacturing segment.
- Increased transportation costs due to increased tariffs combined with higher sales volumes at Foster Creek, Christina Lake and Sunrise.
- Higher operating expenses at the Superior Refinery. Costs increased compared with 2021 as we prepared for restart.
- Increased electricity and chemical costs in our upstream operations.

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.

($ millions)	2022	2021	2020
Cash From (Used in) Operating Activities	**11,403**	5,919	273
(Add) Deduct:			
Settlement of Decommissioning Liabilities	**(150)**	(102)	(42)
Net Change in Non-Cash Working Capital	**575**	(1,227)	198
Adjusted Funds Flow	**10,978**	7,248	117

Cash from operating activities and Adjusted Funds Flow were higher in 2022, primarily due to:

- Increased Operating Margin, as discussed above.
- Lower finance costs which decreased $262 million in 2022 compared with 2021, primarily due to long-term debt purchases in 2021 and 2022.
- Decreased integration and transaction costs, a decline of $243 million in 2022 compared with 2021. The integration of Cenovus and Husky is substantially complete.

The increase was partially offset by higher cash taxes and higher quarterly contingent payments in 2022.

Cash from operating activities also increased as the net change in non-cash working capital increased by $1.8 billion compared to 2021. The increase was due to higher income tax payable and lower accounts receivable, offset by higher inventory at December 31, 2022 compared with December 31, 2021.

Net Earnings (Loss)

($ millions)	**2022 vs. 2021**	2021 vs. 2020
Net Earnings (Loss), Comparative Year	**587**	(2,379)
Increase (Decrease) due to:		
Operating Margin	**4,890**	8,452
Corporate and Eliminations:		
General and Administrative	**(16)**	(557)
Finance Costs	**262**	(546)
Integration and Transaction Costs	**243**	(320)
Unrealized Foreign Exchange Gain (Loss)	**(677)**	181
Revaluation Gains	**549**	—
Re-measurement of Contingent Payments	**413**	(655)
Gain (Loss) on Divestiture of Assets	**40**	148
Other Income (Loss), net	**223**	349
Other [(1)]	**308**	(194)
Unrealized Risk Management Gain (Loss)	**57**	36
Depreciation, Depletion and Amortization	**1,207**	(2,422)
Exploration Expense	**(83)**	73
Income Tax Recovery (Expense)	**(1,553)**	(1,579)
Net Earnings (Loss), Current Year	**6,450**	587

(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.*

Net earnings improved significantly compared with 2021 due to:

- Increased Operating Margin, as discussed above.
- Net impairment charges in the fourth quarter of 2022 of $266 million, compared with net impairment charges of $1.6 billion in the fourth quarter of 2021.
- Revaluation gains of $549 million related to the Sunrise Acquisition in the third quarter of 2022.
- A loss on re-measurement of the contingent payments of $162 million compared with $575 million in 2021. The final payment related to the FCCL Partnership was made in July 2022. Re-measurements related to the Sunrise Acquisition began in the third quarter of 2022.
- Finance costs of $820 million compared with $1.1 billion in 2021, mainly due to a lower average long-term debt balance in 2022.
- Integration and transaction costs of $106 million, compared with $349 million in 2021.
- Higher other income primarily due to insurance proceeds related to the Superior Refinery.
- A realized foreign exchange gain of $22 million in 2022 compared to realized foreign exchange losses of $138 million in 2021. The gains in 2022 related to working capital were partially offset by losses on the purchase of debt.

The increase in net earnings in 2022 was partially offset by:

- Higher income tax expense.
- Unrealized foreign exchange losses as the Canadian dollar at December 31, 2022, weakened relative to the U.S. dollar.

Net Debt

As at ($ millions)	**December 31, 2022**	December 31, 2021
Short-Term Borrowings	**115**	79
Current Portion of Long-Term Debt	**—**	—
Long-Term Debt	**8,691**	12,385
Total Debt	**8,806**	12,464
Less: Cash and Cash Equivalents	**(4,524)**	(2,873)
Net Debt	**4,282**	9,591

Long-term debt decreased by $3.7 billion and Net Debt decreased by $5.3 billion from December 31, 2021. In 2022, we purchased US$2.6 billion of principal related to notes due between 2023 and 2043, and paid a premium on redemption of US$41 million, collectively. In addition, we paid $750 million to purchase the full principal amount outstanding of our 3.55 percent unsecured notes due in 2025 at par. The decrease in long-term debt was partially offset as the Canadian dollar weakened relative to the U.S. dollar on December 31, 2022, impacting our U.S. dollar debt.

Capital Investment (1)

($ millions)	**2022**	2021	2020
Upstream			
Oil Sands	**1,792**	1,019	427
Conventional	**344**	222	78
Offshore	**310**	175	—
Total Upstream	**2,446**	1,416	505
Downstream			
Canadian Manufacturing (2)	**117**	68	33
U.S. Manufacturing	**1,059**	995	243
Total Downstream	**1,176**	1,063	276
Corporate and Eliminations	**86**	84	60
Total Capital Investment	**3,708**	2,563	841

(1) Includes expenditures on property, plant and equipment ("PP&E"), exploration and evaluation ("E&E") assets, and capitalized interest. Excludes cost incurred in our equity-accounted investment in Indonesia.
(2) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details.

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

Conventional capital investment in 2022 focused on drilling, completion and tie-in activities, and infrastructure projects to support multi-year development.

Offshore capital investment in 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 2022 focused primarily on the Superior Refinery rebuild, and refining reliability initiatives at the Wood River, Borger and Toledo refineries, and yield optimization projects at the Wood River Refinery.

Drilling Activity

	Net Stratigraphic Test Wells and Observation Wells			**Net Production Wells** (1)		
	2022	2021	2020	**2022**	2021	2020
Foster Creek (2)	**68**	32	38	**29**	6	—
Christina Lake (3)	**—**	25	117	**31**	18	—
Sunrise	**15**	—	—	**10**	2	—
Lloydminster Thermal	**98**	115	—	**33**	46	—
Lloydminster Conventional Heavy Oil	**8**	15	—	**11**	3	—
Tucker (4)	**6**	—	—	**—**	—	—
	195	187	155	**114**	75	—

(1) SAGD well pairs in the Oil Sands segment are counted as a single producing well.
(2) Includes Ipiatik.
(3) Includes Narrows Lake.
(4) The Tucker asset was sold on January 31, 2022.

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.

	2022			2021			2020		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in	Drilled	Completed	Tied-in
Conventional	**31**	**35**	**36**	27	19	18	6	1	3

In the Offshore segment, we drilled and completed nine (3.6 net) planned development wells at the MBH, MDA and MAC fields in Indonesia in 2022 (2021 — drilled one exploration well in China). We achieved first gas production at the MBH and MDA fields in the fourth quarter of 2022.

Future Capital Investment

Future Capital Investment is a specified financial measure. See the Specified Financial Measures Advisory of this MD&A. Our 2023 guidance dated December 5, 2022, is available on our website at cenovus.com.

The following table shows guidance for 2023:

	Capital Investment ($ millions)	**Production** (MBOE/d)	**Crude Throughput** (Mbbls/d)
Upstream			
Oil Sands	**2,200 - 2,400**	**582 - 642**	
Conventional	**350 - 450**	**125 - 140**	
Offshore	**600 - 700**	**65 - 78**	
Downstream	**800 - 900**		**610 - 660**
Corporate and Eliminations	**40 - 50**		

2023 guidance for total capital investment is between $4.0 billion and $4.5 billion. This includes sustaining capital of approximately $2.8 billion, and between $1.2 billion and $1.7 billion in optimization and growth capital.

Sustaining capital is mainly related to:

- Investment in the Oil Sands segment.
- Safety and reliability initiatives in the Canadian Manufacturing segment.
- The planned restart of the Superior Refinery.
- Offsetting natural declines and optimizing gas handling infrastructure in the Conventional segment.

Optimization and growth capital including downstream initiatives that will further mitigate the Company’s exposure to light-heavy differentials. Optimization and growth capital is mainly related to:

- Construction of the West White Rose project and the completion of the Terra Nova ALE project.
- Progressing the Narrows Lake tie-back to Christina Lake.
- Continued optimization of Foster Creek and the Lloydminster thermal projects.
- Application of Cenovus’s operating model at Sunrise.
- Margin expansion and debottlenecking opportunities in our downstream assets, which include feedstock replacement at the Lloydminster Refinery as part of the Company’s Rewire Alberta initiative.
- Increasing heavy crude oil conversion capacity and distillate output at the Wood River and Borger refineries.

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 Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [1]

(Average US$/bbl, unless otherwise indicated)	2022	Percent Change	2021	2020	Q4 2022	Q4 2021
Dated Brent	**101.19**	**43**	70.73	41.67	**88.71**	79.73
WTI	**94.23**	**39**	67.91	39.40	**82.65**	77.19
Differential Dated Brent-WTI	**6.96**	**147**	2.82	2.27	**6.06**	2.54
WCS at Hardisty	**76.01**	**39**	54.87	26.80	**56.99**	62.55
Differential WTI-WCS	**18.22**	**40**	13.04	12.60	**25.66**	14.64
WCS (C$/bbl)	**98.51**	**43**	68.73	35.59	**77.42**	78.71
WCS at Nederland	**85.77**	**34**	64.09	35.86	**67.65**	71.62
Differential WTI-WCS at Nederland	**8.46**	**121**	3.82	3.54	**15.00**	5.57
Condensate (C5 @ Edmonton)	**93.78**	**38**	68.20	37.16	**83.40**	79.13
Differential WTI-Condensate (Premium)/Discount	**0.45**	**N/A**	(0.29)	2.24	**(0.75)**	(1.94)
Differential WCS-Condensate (Premium)/Discount	**(17.77)**	**(33)**	(13.33)	(10.36)	**(26.41)**	(16.58)
Average (C$/bbl)	**121.78**	**42**	85.47	49.44	**113.25**	99.64
Synthetic @ Edmonton	**98.66**	**49**	66.28	36.25	**86.79**	75.40
Differential WTI-Synthetic (Premium)/Discount	**(4.43)**	**N/A**	1.63	3.15	**(4.14)**	1.79
Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**120.63**	**42**	85.07	45.24	**102.80**	91.84
Chicago Ultra-low Sulphur Diesel ("ULSD")	**143.85**	**67**	86.37	50.08	**140.95**	96.53
Refining Benchmarks						
Chicago 3-2-1 Crack Spread [2]	**34.15**	**95**	17.54	7.54	**32.87**	16.06
Group 3 3-2-1 Crack Spread [2]	**33.21**	**86**	17.82	8.67	**29.99**	15.82
Renewable Identification Numbers ("RINs")	**7.72**	**14**	6.76	2.48	**8.54**	6.11
Natural Gas Prices						
AECO (C$/Mcf)	**5.56**	**56**	3.56	2.24	**5.58**	4.94
NYMEX (US$/Mcf)	**6.64**	**73**	3.84	2.08	**6.26**	5.83
Foreign Exchange Rates						
US$ per C$1 - Average	**0.769**	**(4)**	0.798	0.746	**0.737**	0.794
US$ per C$1 - End of Period	**0.738**	**(6)**	0.789	0.785	**0.738**	0.789
RMB per C$1 - Average	**5.170**	**—**	5.147	5.147	**5.241**	5.073

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

Crude Oil and Condensate Benchmarks

In 2022, global crude oil prices improved significantly compared to 2021. Prices rose steadily through 2021 and during the first half of 2022 as global supply and demand balances remained tight, while inventories were low. Demand for crude oil and refined products continued to grow towards pre-pandemic levels despite macroeconomic challenges, weakness in Chinese consumption due to COVID-19 lockdowns, and geopolitical uncertainty around Russia's invasion of Ukraine. Crude oil supply grew considerably in 2022 but struggled to match growing demand, with nearly all short-term supply sources accessed to meet demand, including unprecedented releases of U.S. government strategic petroleum reserves ("SPRs"). Global spare production capacity remains low.

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.

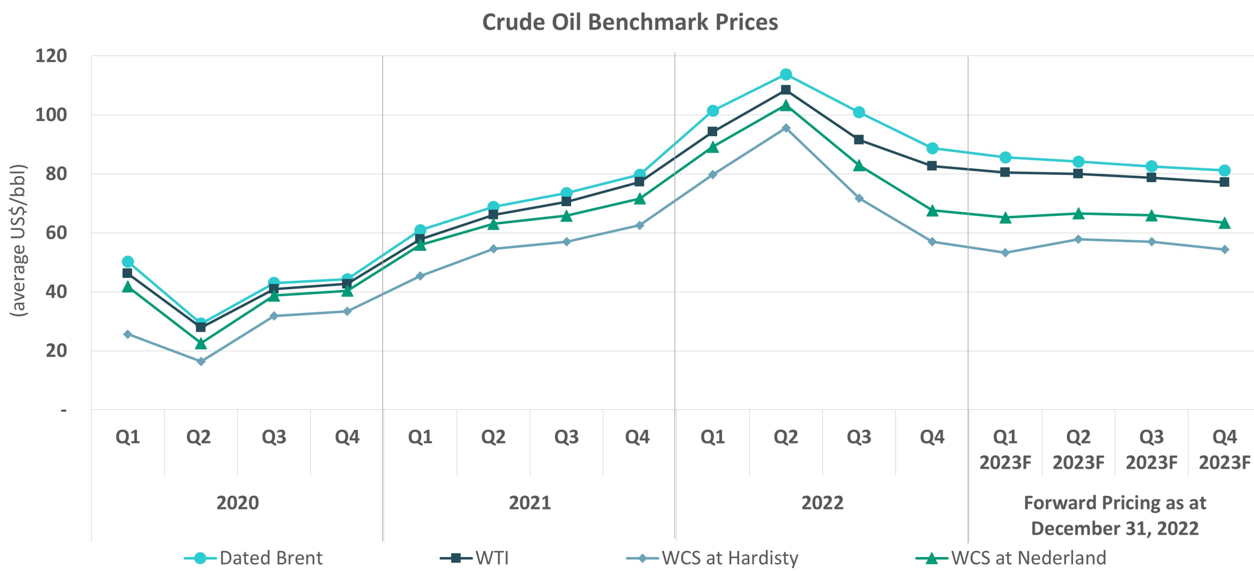
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent. The Brent-WTI differential widened compared with 2021 due to higher shipping costs and supply disruptions as a result of Russia's invasion of Ukraine.

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WCS at Hardisty differential to WTI is a function of the quality differential of light and heavy crude and the cost of transport. In 2022, the average WTI-WCS differential at Hardisty widened compared to 2021, primarily due to a wider quality differential at the U.S. Gulf Coast ("USGC") outlined below, as well as higher production activity in Western Canada.

WCS at Nederland is a heavy oil benchmark for sales of our product at the USGC. The WTI-WCS at Nederland differential is representative of the heavy oil quality discount and is influenced by global heavy oil refining capacity and global heavy oil supply. The WTI-WCS at Nederland differential widened significantly compared with 2021, particularly in the second half of 2022. It is mainly attributed to reduced demand due to planned and unplanned refinery maintenance, high global refining utilization, volatile refined product pricing and increased supply due to some incremental medium and heavy oil barrels into the market from OPEC+, and from the release of volume from SPRs in the U.S.

In Canada, 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 2022 compared with 2021 as a result of widespread upgrader maintenance in Western Canada and strong refinery demand for light crude oil. In 2022, the WTI-Synthetic differential was at a premium compared with a discount in 2021 as synthetic crudes continue to be supported by strong demand for refined products.



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.

The average Edmonton condensate benchmark remained near parity with WTI in 2022 as Alberta demand for condensate is strong and supply remains tight.

Refining Benchmarks

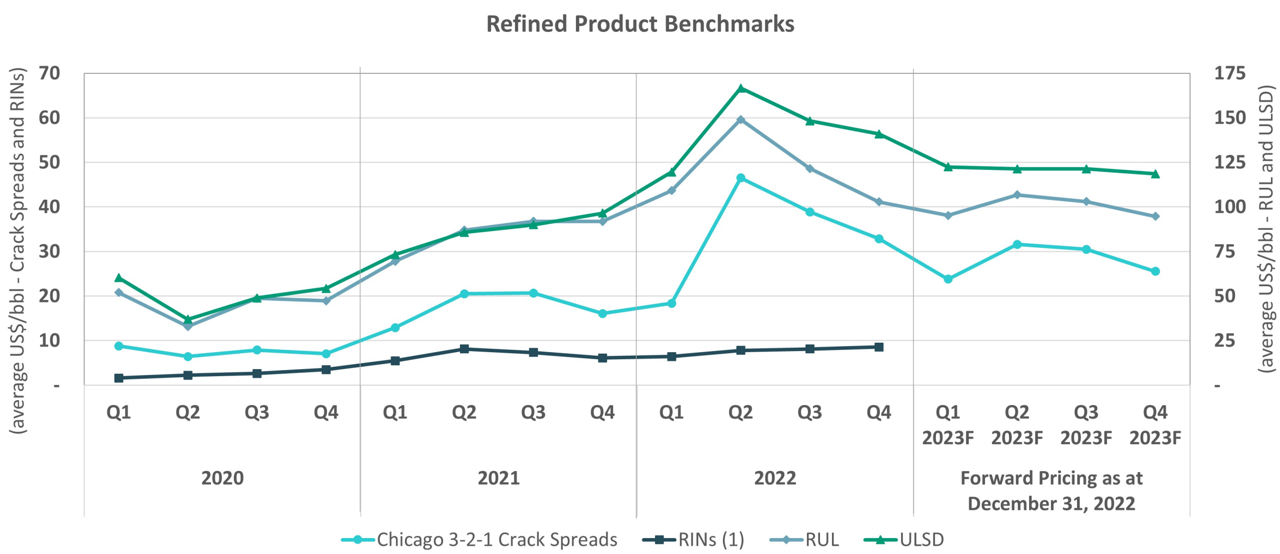
RUL and ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded 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 the Borger Refinery.

Average Chicago refined product prices increased significantly in 2022 compared with 2021. While gasoline prices strengthened year-over-year, the increase in market crack spreads were primarily driven by a substantial rise in distillate prices. The strength in market crack spreads and refined product prices has also been driven by refinery rationalization since the beginning of the pandemic, leading to high refinery utilization globally, combined with low global inventories of refined products. RINs costs remain high as a result of a tight biofuel market, rising feedstock prices and uncertainty around policies that drive RINs demand.

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 generally reflects 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; where feedstocks are acquired and 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 significantly in 2022, compared with 2021, due to a rebound in U.S. domestic demand and high liquified natural gas exports, coupled with a muted supply response and strong global pricing amid Russian supply concerns. Average AECO prices also increased significantly in 2022 compared with 2021 along with NYMEX prices, but the differentials between AECO and NYMEX widened slightly due to higher Western Canadian production as well as planned and unplanned pipeline maintenance limiting egress at points during 2022. The price received for our Asia Pacific natural gas production is largely based on long-term contracts.

Foreign Exchange Benchmarks

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 our U.S. and Asia Pacific operations.

In 2022, the Canadian dollar on average weakened relative to the U.S. dollar compared with 2021, positively impacting our revenues year-over-year. The Canadian dollar weakened relative to the U.S. dollar as at December 31, 2022, compared with December 31, 2021, resulting in unrealized foreign exchange losses of $365 million on the translation of our U.S. dollar debt into Canadian dollars.

A portion of our long-term sales contracts in the 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 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 interest income, short-term borrowing costs, reported decommissioning liabilities and fair value measurements 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, and could negatively impact our cash flow and financial results.

As at December 31, 2022, the Bank of Canada's Policy Interest Rate was 4.25 percent, an increase from 0.25 percent on December 31, 2021, due to concerns over inflation. On January 25, 2023, the rate increased a further 0.25 percent to 4.50 percent.

OUTLOOK

COMMODITY PRICE OUTLOOK

Crude oil prices improved significantly in 2022, but waned in the second half of the year due to demand concerns amid a weakening macroeconomic environment and COVID-19 lockdowns in China. The geopolitical premium associated with Russian supply uncertainty also faded in the back half of 2022 as Russian exports of crude oil and refined products remained resilient. Crude oil price trajectory remains uncertain and volatile amid a market with unpredictable key drivers and government policy playing a large role in supply and demand dynamics. Policies regarding Russia, Iran and Venezuela are among key factors that will drive energy supply and shifting global trade patterns. OPEC+ policy will continue to be a key driver of crude oil prices and the recent announcement of a cut to the group's production quotas is supportive of pricing.

Overall, 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, the refilling or release of SPRs and OPEC+ policy. In addition, potential incremental COVID-19 outbreaks and variants, weakening global 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 oil processing capacity as long as supply stays within Canadian crude oil export capacity.
- We expect market crack spreads will remain volatile. Economic effects of the ongoing Russian invasion of Ukraine 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 NYMEX and AECO prices to remain strong but increasing supply and limited LNG export capacity from North America will put downward pressure on 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 and downstream refined products production are exposed to movements in the WTI crude oil price. Natural gas and NGLs production associated with our Conventional operations provide 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 spreads in all of these markets. We will continue to monitor market fundamentals and optimize run rates at our refineries accordingly.

Our exposure to crude differentials includes light-heavy and light-medium price differentials. The light-medium price differential exposure is focused on light-medium crudes in the U.S. Midwest market region where we have the majority of our 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 closed 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 contracts for management of price exposures associated with crude oil, crude oil differentials, condensate, natural gas liquids, refined products, refining margins, natural gas, electricity and renewable power contracts.

KEY PRIORITIES FOR 2023

At Cenovus, our purpose is to energize the world to make people's lives better. Our strategy continues to focus on maximizing shareholder value through competitive cost structures and optimizing margins while delivering top-tier safety performance and sustainability leadership. We prioritize 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 of our portfolio.

Our 2023 priorities will focus on:

Top Tier Safety and Operational Performance

Safe and reliable operations are our number one priority. We strive to ensure safe and reliable operations across our portfolio, including top-tier health and safety performance.

We will continue to target improved downstream operating performance, including the safe return of the Superior Refinery to full operations and, following the close of the Toledo Acquisition, integration of the Toledo Refinery with a focus on demonstrating consistent and reliable performance at our operated assets.

Sustainability Leadership

Sustainability has always been deeply engrained in Cenovus's culture. We have established ambitious targets in our five ESG focus areas and continue to progress tangible plans to meet these targets. Our five ESG focus areas are:

- Climate & GHG Emissions.
- Water Stewardship.
- Biodiversity.
- Indigenous reconciliation.
- Inclusion & diversity.

Additional information on management's efforts and performance across ESG focus areas, including our ESG targets and plans to achieve them, are available in Cenovus's 2021 ESG report on our website at cenovus.com.

Cost Leadership

We aim to maximize shareholder value through competitive cost structures and optimized margins. While we strive to optimize our cost structure in all areas of our business, one of our focus areas will be to optimize infrastructure, reduce operating and capital costs, and reduce GHG emissions at our conventional assets.

Financial Discipline and Free Funds Flow Growth

We are focused on achieving and maintaining targeted debt levels while positioning Cenovus for resiliency through commodity price cycles. We plan to continue to deliver meaningful returns to shareholders in alignment with our financial and shareholder returns framework.

Returns-Focused Capital Allocation

We continue to take a disciplined approach to allocating capital to projects that generate returns at the bottom of the commodity price cycle and provide opportunities to sustainably grow shareholder returns.

We plan to materially progress the West White Rose project while remaining on track to deliver first oil in 2026.

REPORTABLE SEGMENTS

UPSTREAM

Oil Sands

In 2022, we:

- Delivered safe and reliable operations.
- Produced 586.6 thousand barrels of crude oil per day.
- Generated Operating Margin of $9.0 billion, an increase of $2.6 billion compared with 2021 primarily due to higher average realized sales prices.
- Sold our Tucker asset for net proceeds of $730 million on January 31, 2022. Crude oil production at the time of sale was approximately 20 thousand barrels per day.
- Purchased the remaining 50 percent interest in Sunrise from BP Canada on August 31, 2022, giving Cenovus full ownership and further enhancing our core strength in oil sands. The Sunrise Acquisition immediately added over 20 thousand barrels per day of crude oil production, and more than offset lost production from the sold Tucker asset.
- Achieved first oil at our Spruce Lake North thermal plant in September. Production averaged approximately 12.0 thousand barrels per day in the fourth quarter.
- Received regulatory approval in December 2022 to develop the Ipiatik asset in the Foster Creek area. This is expected to provide future bitumen feedstock to the Foster Creek plant. Pad construction is expected to begin in 2024 and we anticipate first steam in 2029.
- Invested capital of $1.8 billion primarily on sustaining activities at Christina Lake, Foster Creek, the Lloydminster thermal assets and Sunrise.
- Achieved a Netback of $49.10 per BOE.

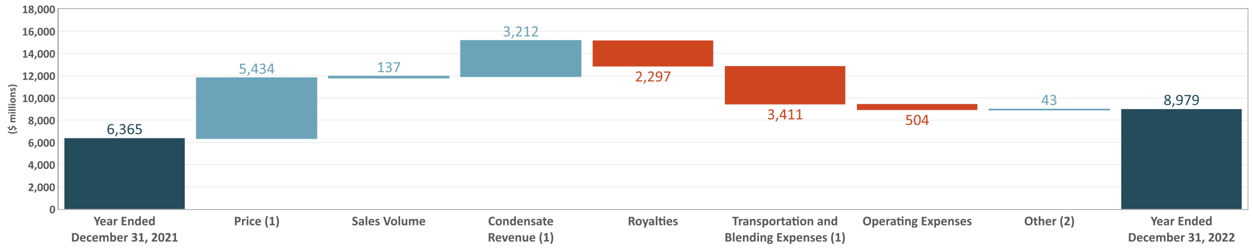
Financial Results

($ millions)	2022	2021 [1]	2020
Revenues			
Gross Sales	**34,775**	22,827	8,804
Less: Royalties	**4,493**	2,196	331
	30,282	20,631	8,473
Expenses			
Purchased Product	**4,810**	2,404	1,262
Transportation and Blending	**12,036**	8,625	4,683
Operating	**2,930**	2,451	1,156
Realized (Gain) Loss on Risk Management	**1,527**	786	268
Operating Margin	**8,979**	6,365	1,104
Unrealized (Gain) Loss on Risk Management	**(68)**	18	57
Depreciation, Depletion and Amortization	**2,763**	2,666	1,687
Exploration Expense	**9**	16	9
(Income) Loss from Equity-Accounted Affiliates	**8**	(5)	—
Segment Income (Loss)	**6,267**	3,670	(649)

(1) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

Operating Margin Variance

Year Ended December 31, 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

	2022	2021	2020
Total Sales Volumes (MBOE/d)	**585.8**	579.9	386.6
Total Realized Price [1] ($/BOE)	**91.70**	62.82	28.64
Crude Oil Production by Asset (Mbbls/d)			
Foster Creek	**191.0**	179.9	163.2
Christina Lake	**246.5**	236.8	218.5
Sunrise [2]	**31.3**	25.9	—
Lloydminster Thermal	**99.9**	97.7	—
Lloydminster Conventional Heavy Oil	**16.3**	20.2	—
Tucker [3]	**1.6**	21.0	—
Total Crude Oil Production [4] (Mbbls/d)	**586.6**	581.5	381.7
Natural Gas [5] (MMcf/d)	**12.3**	12.6	—
Total Production (MBOE/d)	**588.7**	583.6	381.7
Effective Royalty Rate (percent)	**25.2**	18.7	11.6
Transportation and Blending Cost [1] ($/BOE)	**7.89**	7.23	8.70
Operating Expense [1] ($/BOE)	**13.75**	11.52	7.84
Per Unit DD&A [1] ($/BOE)	**11.90**	11.28	10.40

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

(2) *Represents Cenovus's 50 percent interest in Sunrise up to August 31, 2022. On August 31, 2022, we acquired the remaining 50 percent interest from BP Canada.*

(3) *The Tucker asset was 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

Our heavy oil and bitumen production 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.

Our realized sales price averaged $91.70 per BOE in 2022 compared with $62.82 per BOE in 2021 due to higher WTI benchmark prices, partially offset by wider WTI-WCS differentials. To improve our realized sales price, we sold approximately 20 percent (2021 – 20 percent) of our crude oil volumes at U.S. destinations.

For the year ended December 31, 2022, gross sales included $4.5 billion (2021 – $2.1 billion), 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.

For the year ended December 31, 2022, gross sales included $358 million (2021 – $329 million), 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.

Cenovus makes storage and transportation decisions about utilizing our marketing and transportation infrastructure, including storage and pipeline assets, to optimize product mix, delivery points, and 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.

In 2022, we incurred realized risk management losses of $1.5 billion, of which $431 million related to the early liquidation of WTI positions in the second quarter. In 2022, we recorded unrealized risk management gains of $68 million on our crude oil and condensate financial instruments.

Production Volumes

Oil Sands crude oil production increased slightly to 586.6 thousand barrels per day in 2022 compared with 581.5 thousand barrels per day in 2021.

We sold the Tucker asset on January 31, 2022, resulting in decreased production of 19.4 thousand barrels per day in 2022 compared with 2021.

Production at Foster Creek increased 11.1 thousand barrels per day to 191.0 thousand barrels per day in 2022 compared with 2021, due to new wells coming online in 2022 and the last half of 2021. In addition, we completed a planned turnaround in the second quarter of 2021. The increase was partially offset as production reached peak levels in the fourth quarter of 2021 due to the timing of well pads starting up. Also offsetting the increase was planned maintenance and an unplanned outage in the third quarter of 2022.

Production at Christina Lake increased 9.7 thousand barrels per day to 246.5 thousand barrels per day in 2022 compared with 2021. We added incremental production from redevelopment wells drilled in 2022 and the last half of 2021. The increase was offset by a planned turnaround in the second quarter of 2022.

The Sunrise Acquisition was completed on August 31, 2022 and added 5.4 thousand barrels per day of production in 2022 compared with 2021. The increase in production at Sunrise in 2022 was partially offset by base declines and wells taken offline in preparation for a redevelopment program.

Production from our Lloydminster thermal assets increased slightly in 2022 compared with 2021. The Spruce Lake North thermal plant achieved first oil in August, and production averaged approximately 12.0 thousand barrels per day in the fourth quarter. The increase was partially offset by base declines at other thermal plants and wells taken offline in preparation for a redevelopment program in the fourth quarter of 2022 and into 2023.

Lloydminster conventional heavy oil production decreased marginally in 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. For the year ended December 31, 2022, royalties were $4.5 billion (2021 – $2.2 billion).

Expenses

Transportation and Blending

In 2022, blending costs rose $3.2 billion to $10.3 billion compared with 2021. The increases were largely due to higher condensate prices.

Transportation costs increased $179 million to $1.7 billion in 2022 compared with 2021. The increases were primarily due to higher costs as discussed below combined with increased sales volumes at Foster Creek, Christina Lake and Sunrise.

Per-unit Transportation Expenses

Transportation costs were $7.89 per BOE in 2022 up slightly from $7.23 per BOE in 2021.

At Foster Creek, per-unit transportation costs increased 12 percent to $11.78 per barrel in 2022 compared with 2021. The increase was mainly due to increased tariffs, partially offset by reduced reliance on rail. For the year ended December 31, 2022, we shipped 40 percent (2021 – 35 percent), of our volumes from Foster Creek to U.S. destinations.

At Christina Lake, transportation costs were $6.51 per barrel in 2022, consistent with $6.19 per barrel in 2021.

At Sunrise, transportation costs were $12.26 per barrel in 2022, consistent with $12.14 per barrel in 2021, as we shipped a similar percentage of our total volumes to the U.S.

At our Other Oil Sands assets, transportation costs in 2022 were $3.49 per barrel, compared with $4.01 per barrel in 2021. In the first quarter of 2021, we stopped shipping volumes to U.S. destinations to optimize our pipeline capacity, reducing per-unit costs year-over-year.

Operating

Primary drivers of our operating expenses in 2022 were fuel, workforce, chemical, repairs and maintenance, and electricity costs. Total operating expenses increased largely due to higher fuel costs as a result of higher natural gas prices. AECO benchmark natural gas prices increased 56 percent in 2022 compared with 2021. In addition, total operating expenses increased due to higher electricity, repairs and maintenance and chemical costs. Chemical costs and electricity costs are also influenced by rising crude oil and natural gas benchmark prices. We have experienced minimal inflationary pressures on our costs, as we manage our costs by securing long-term contracts, working with vendors and purchasing long-lead items to mitigate future cost escalations.

Unit Operating Expenses (1)

($/BOE)	**2022**	**Percent Change**	2021	Percent Change	2020
Foster Creek					
Fuel	**6.07**	**49**	4.07	44	2.83
Non-Fuel	**6.52**	**(2)**	6.67	4	6.41
Total	**12.59**	**17**	10.74	16	9.24
Christina Lake					
Fuel	**5.07**	**44**	3.52	61	2.18
Non-Fuel	**4.87**	**3**	4.72	2	4.61
Total	**9.94**	**21**	8.24	21	6.79
Sunrise					
Fuel	**7.01**	**26**	5.58	—	—
Non-Fuel	**10.48**	**(9)**	11.57	—	—
Total	**17.49**	**2**	17.15	—	—
Other Oil Sands (2)					
Fuel	**7.35**	**50**	4.91	—	—
Non-Fuel	**15.10**	**29**	11.73	—	—
Total	**22.45**	**35**	16.64	—	—
Total	**13.75**	**19**	11.52	47	7.84

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

Per-unit fuel prices increased largely due to higher natural gas prices as discussed above.

Foster Creek per-unit non-fuel costs were consistent with 2021. Higher chemical, electricity and repairs and maintenance costs were offset by higher sales volumes.

Christina Lake per unit non-fuel costs were consistent with 2021. Higher electricity and repairs and maintenance costs were offset by higher sales volumes in 2022.

Sunrise per unit non-fuel costs decreased in 2022 compared with 2021. The decrease in non-fuel costs were primarily related to the planned turnaround costs in the second quarter of 2021, partially offset by higher electricity, chemical and workover costs in 2022.

Per-unit non-fuel costs at our Other Oil Sands assets increased in 2022 compared with 2021, primarily due to higher chemical and workover costs.

Netbacks

($/BOE)	**2022**	2021	2020
Sales Price [(1)]	**91.70**	62.82	28.64
Royalties [(1)]	**20.96**	10.38	2.34
Transportation [(1)]	**7.89**	7.23	8.70
Operating Expenses [(1)]	**13.75**	11.52	7.84
Netback [(2)]	**49.10**	33.69	9.76

(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 year ended December 31, 2022, DD&A remained relatively consistent at $2.8 billion, compared with $2.7 billion in 2021. The average depletion rate for the year ended December 31, 2022, was $11.90 per BOE, compared with $11.28 per BOE in 2021.

Conventional

In 2022, we:

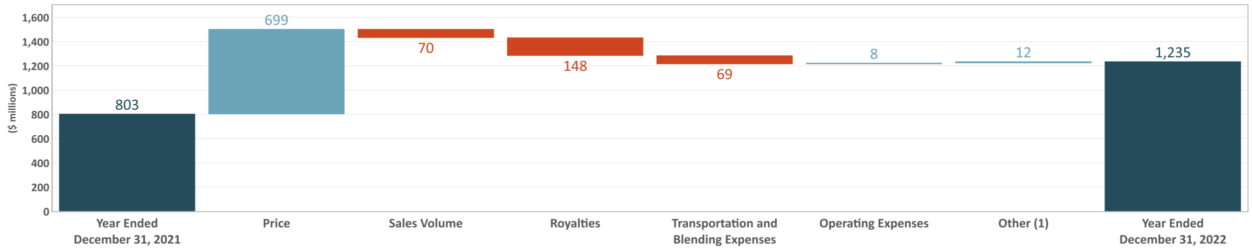
- Delivered safe and reliable operations.
- Sold our assets in the Wembley area for net proceeds of $221 million on February 28, 2022.
- Generated Operating Margin of $1.2 billion, an increase of $432 million compared with 2021, largely due to higher average realized sales prices.
- Invested capital of $344 million focused on drilling, completion and tie-in activities, and infrastructure projects to support multi-year development.
- Achieved a Netback of $27.43 per BOE.

Financial Results

($ millions)	**2022**	2021	2020
Revenues			
Gross Sales	**4,332**	3,235	904
Less: Royalties	**298**	150	40
	4,034	3,085	864
Expenses			
Purchased Product	**2,023**	1,655	268
Transportation and Blending	**143**	74	81
Operating	**541**	551	320
Realized (Gain) Loss on Risk Management	**92**	2	—
Operating Margin	**1,235**	803	195
Unrealized (Gain) Loss on Risk Management	**13**	1	—
Depreciation, Depletion and Amortization	**370**	3	880
Exploration Expense	**1**	(3)	82
Segment Income (Loss)	**851**	802	(767)

Operating Margin Variance

Year Ended December 31, 2022



(1) Reflects Operating Margin from processing facilities.

Operating Results

	2022	2021	2020
Total Sales Volumes (MBOE/d)	**127.2**	133.4	89.8
Total Realized Price [(1)] ($/BOE)	**48.15**	31.20	17.84
Heavy Crude Oil ($/bbl)	**—**	—	31.45
Light Crude Oil ($/bbl)	**118.64**	76.32	42.78
NGLs ($/bbl)	**63.22**	42.93	22.04
Conventional Natural Gas ($/Mcf)	**6.50**	4.07	2.37
Production by Product			
Heavy Crude Oil (Mbbls/d)	**—**	—	2.7
Light Crude Oil (Mbbls/d)	**7.5**	8.4	4.5
NGLs (Mbbls/d)	**23.8**	25.6	19.5
Conventional Natural Gas (MMcf/d)	**576.1**	597.6	379.0
Total Production (MBOE/d)	**127.2**	133.6	89.9
Conventional Natural Gas Production (percentage of total)	**75**	75	70
Crude Oil and NGLs Production (percentage of total)	**25**	25	30
Effective Royalty Rate (percent)	**15.4**	10.3	7.9
Transportation Costs [(1)] ($/BOE)	**3.16**	1.53	2.46
Operating Expense [(1)] ($/BOE)	**11.18**	10.66	8.99
Per Unit DD&A [(1)] ($/BOE)	**8.23**	9.11	9.85

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

Revenues

Price

Our total realized sales price increased in 2022, due to higher crude oil and natural gas benchmark prices.

For the year ended December 31, 2022, gross sales included $2.0 billion (2021 – $1.7 billion), relating to third-party sourced volumes, which are not included in our realized prices or our Netbacks. Refer to the Specified Financial Measures Advisory of this MD&A for more detail.

For the year ended December 31, 2022, revenues included amounts relating to processing and transportation activities undertaken for third-parties of $71 million (2021 – $61 million), which are not included in our realized prices or our Netbacks. Refer to the Specified Financial Measures Advisory of this MD&A for more detail.

Production Volumes

Production volumes decreased 6.4 thousand BOE per day in 2022 compared with 2021, mainly due to asset sales in the first quarter of 2022 and the second half of 2021, and natural declines. The production decrease is partially offset by 36 net new wells (2021 – 18 net new wells) brought on production during the year, combined with production from well reactivations and workover activity.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Total royalties and effective royalty rates increased in 2022 compared with 2021, 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 $69 million in 2022, compared with 2021. Per-unit transportation costs averaged $3.16 per BOE in 2022, compared with $1.53 per BOE in 2021.

Operating

Primary drivers of our operating expenses in 2022, were repairs and maintenance, workforce, electricity, property taxes and lease costs. Operating expenses per BOE in the year ended December 31, 2022, increased compared with 2021 primarily due to higher workover, energy and electricity costs, combined with lower sales volumes. Total operating expenses in 2022 were flat compared with 2021, due to the same factors that increased operating expenses per BOE, partially offset by asset sales in the first quarter of 2022 and the second half of 2021.

Netbacks

($/BOE)	**2022**	2021	2020
Sales Price [1]	**48.15**	31.20	17.84
Royalties [1]	**6.38**	3.06	1.23
Transportation and Blending [1]	**3.16**	1.53	2.46
Operating Expenses [1]	**11.18**	10.66	8.99
Netback [2]	**27.43**	15.95	5.16

(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

For the year ended December 31, 2022, total Conventional DD&A was $370 million (2021 – $3 million). The increase was due to impairment reversals of $378 million in 2021.

The average depletion rate for 2022 was $8.23 per BOE (2021 – $9.11 per BOE). The average depletion rate excludes the impact of impairments and impairment reversals.

Offshore

In 2022, we:

- Delivered safe and reliable operations.
- Completed the dry-dock portion of the Terra Nova ALE project. We expect the Terra Nova field to resume production in the second quarter of 2023.
- Announced our decision to proceed with the completion of the West White Rose project.
- Sold our 35 percent position in the undeveloped Bay du Nord project offshore Newfoundland and Labrador as part of our consideration in the Sunrise Acquisition.
- Generated Operating Margin of $1.6 billion, an increase of $190 million compared with 2021, largely due to higher average realized sales prices, partially offset by increased operating expenses and lower sales volumes.
- Earned a Netback of $68.90 per BOE.
- Invested capital of $310 million mainly for the Terra Nova ALE and the West White Rose projects in the Atlantic region.

In September 2021, Cenovus announced an agreement with its partners to restructure its working interest in the Atlantic region and proceed with the ALE project for Terra Nova. The agreement increased Cenovus's working interest in Terra Nova to 34 percent from 13 percent and, pending a decision to restart the West White Rose Project, would decrease Cenovus's working interest in the White Rose field and satellite extensions by 12.5 percent.

On May 31, 2022, Cenovus and its partners announced the restart of the West White Rose project resulting in the reduction of our working interest in the White Rose field and satellite extensions. The West White Rose project is anticipated to have peak production of 80 thousand barrels per day (45 thousand barrels per day, net to Cenovus) with first oil expected in the first half of 2026. Total capital required to achieve first oil is expected to be approximately $2.0 billion to $2.3 billion net to Cenovus. At December 31, 2022, the project was around 65 percent complete. Since our decision to restart the project, we have invested approximately $85 million in 2022.

At our equity-accounted assets in Indonesia, we drilled and completed two MBH field development wells and five MDA field development wells planned for the year. We achieved first gas production from the MBH and MDA fields in the fourth quarter of 2022. In Indonesia we also have the MAC and MDK fields under development. At the MAC field, we drilled and completed two development wells in the fourth quarter of 2022, of the three planned at the field. We expect first gas production from the MAC and MDK fields by 2023 and 2025, respectively.

In China, we finalized an agreement in the second quarter that increases gas sales at Liuhua 29-1 for the duration of the contract. This partially offsets 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. In addition, in the first quarter we terminated the production sharing contract ("PSC") at Block 23/07, which was in the exploration phase, and never produced or had drilling activity.

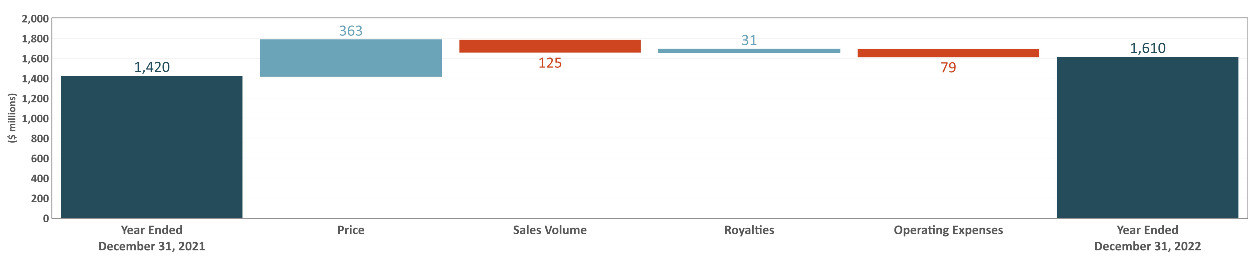
Financial Results

	2022			2021		
($ millions)	**Asia Pacific**	**Atlantic**	**Offshore**	Asia Pacific	Atlantic	Offshore
Revenues						
Gross Sales	**1,442**	**578**	**2,020**	1,342	440	1,782
Less: Royalties	**80**	**(3)**	**77**	79	29	108
	1,362	**581**	**1,943**	1,263	411	1,674
Expenses						
Transportation and Blending	**—**	**15**	**15**	—	15	15
Operating	**114**	**204**	**318**	103	136	239
Operating Margin [(1)]	**1,248**	**362**	**1,610**	1,160	260	1,420
Depreciation, Depletion and Amortization			**585**			492
Exploration Expense			**91**			5
(Income) Loss from Equity-Accounted Affiliates			**(23)**			(47)
Segment Income (Loss)			**957**			970

(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

Year Ended December 31, 2022



Operating Results

	2022	2021
Total Sales Volumes (MBOE/d)	**70.0**	73.5
Atlantic	**11.3**	13.2
Asia Pacific (1)	**58.7**	60.3
Total Realized Price (2) ($/BOE)	**89.72**	74.75
Atlantic - Light Crude Oil ($/bbl)	**140.65**	91.01
Asia Pacific (1) ($/BOE)	**79.96**	71.19
NGLs ($/bbl)	**110.05**	79.83
Conventional Natural Gas ($/Mcf)	**11.98**	11.48
Production by Product		
Atlantic - Light Crude Oil (Mbbls/d)	**11.6**	14.1
Asia Pacific (1)		
NGLs (Mbbls/d)	**12.4**	12.7
Conventional Natural Gas (MMcf/d)	**277.7**	285.3
Asia Pacific Total (MBOE/d)	**58.7**	60.3
Total Production (MBOE/d)	**70.3**	74.4
Effective Royalty Rate (percent)		
Atlantic	**(0.5)**	6.7
Asia Pacific (1)	**11.5**	8.4
Operating Expense (2) ($/BOE)	**12.64**	9.86
Atlantic	**42.03**	28.34
Asia Pacific (1)	**7.00**	5.80
Per Unit DD&A (2) ($/BOE)	**30.76**	25.62

(1) Reported sales volumes, associated per unit values and royalty rates reflect Cenovus's 40 percent interest in HCML. 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 2022 compared with 2021, primarily due to higher Brent benchmark pricing.

Production Volumes

Asia Pacific production decreased slightly in 2022 compared with 2021, due to changes to contracts at Liwan 3-1 and Liuhua 29-1 resulting in a net decrease in production. The decrease was partially offset by first gas production at the MBH and MDA fields in Indonesia in the fourth quarter of 2022.

Atlantic production decreased slightly in 2022 compared with 2021, due to the decrease in Cenovus's working interest at the White Rose field and satellite extensions in the second quarter of 2022. Light crude oil from production at the White Rose fields is offloaded from the SeaRose FPSO to tankers and stored at an onshore terminal before shipment to buyers, which results in a timing difference between production and sales.

Royalties

Royalty rates in China and Indonesia are governed by production sharing contracts in which production is shared with the Chinese and Indonesian governments. The effective royalty rate for 2022 was 11.5 percent (2021 – 8.4 percent). The increase 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 fields are based on an amended agreement between our working interest partners and the Government of Newfoundland and Labrador. For 2022, retroactive to January 1, 2022, we paid a basic royalty of 1.0 percent of gross sales from the White Rose fields and 1.0 percent of gross sales from the satellite extensions. As a result, royalties were negative $3 million in 2022 (2021 – $29 million).

Expenses

Operating

Primary drivers of our Asia Pacific operating expenses in 2022 were repairs and maintenance, insurance and workforce. Total and per-unit operating expenses increased marginally year-over-year, primarily due to planned maintenance in China in the second and third quarter, combined with lower production in China. Also contributing to the increase in per-unit operating expenses were costs related to the MBH and MDA fields coming online in the fourth quarter of 2022.

Primary drivers of our Atlantic operating expenses in 2022 were vessel and helicopter costs, repairs and maintenance, and workforce. Total operating expenses increased mainly due to continued preparations for the Terra Nova FPSO's return to field and a higher working interest in the Terra Nova field. The increase was partially offset by the working interest restructuring on the White Rose fields in the second quarter of 2022. Per-unit operating expenses increased due to lower sales volumes, combined with increased costs at Terra Nova discussed above.

Transportation

Transportation in the Atlantic region remained consistent year-over-year and include the cost of transporting crude oil from the SeaRose FPSO unit to onshore via tankers, as well as storage costs.

Netbacks

	2022			
($/BOE, except where indicated)	**China**	**Indonesia** (1)	**Atlantic** ($/bbl)	**Total Offshore**
Sales Price (2)	**81.99**	**70.66**	**140.65**	**89.72**
Royalties (2)	**4.57**	**30.19**	**(0.74)**	**7.57**
Transportation and Blending (2)	**—**	**—**	**3.79**	**0.61**
Operating Expenses (2)	**5.62**	**13.32**	**42.03**	**12.64**
Netback (3)	**71.80**	**27.15**	**95.57**	**68.90**

	2021			
($/BOE, except where indicated)	China	Indonesia (1)	Atlantic ($/bbl)	Total Offshore
Sales Price (2)	72.44	64.52	91.01	74.75
Royalties (2)	4.25	14.93	6.07	5.96
Transportation and Blending (2)	—	—	3.02	0.54
Operating Expenses (2)	5.10	9.55	28.34	9.86
Netback (3)	63.09	40.04	53.58	58.39

(1) Reported sales volumes, associated per unit values and royalty rates reflect Cenovus's 40 percent interest in HCML. 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 2022, total Offshore DD&A was $585 million (2021 – $492 million). The average depletion rate in 2022 was $30.76 per BOE, (2021 – $25.62 per BOE).

Exploration Expense

In 2022, we recorded exploration expense of $91 million, primarily due to a $58 million write-off related to our decision not to pursue development at Block 15/33 in China, penalties related to terminating the PSC at Block 23/07 in China and spending at Bay du Nord in the Atlantic region prior to its divestiture.

DOWNSTREAM

Canadian Manufacturing

In 2022, we:

- Delivered safe operations.
- Completed planned turnarounds at the Upgrader and Lloydminster Refinery in the second quarter.
- Averaged combined crude utilization of 84 percent at the Upgrader and Lloydminster Refinery. There were several unplanned outages, primarily at the Upgrader in 2022.
- Generated Operating Margin of $699 million, an increase of $126 million compared with 2021, primarily due to a higher upgrading differential, and higher distillate and asphalt pricing, partially offset by the impact of turnaround activities and unplanned outages on sales volumes and operating expenses.
- We closed the sales of 337 gas stations within our retail fuels network for net cash proceeds of $404 million.

Following the sale of the retail business, we retained our commercial fuels business, which at December 31, 2022, includes 170 cardlock, bulk plant and travel center locations. The commercial fuels business and historical retail fuels business are aggregated into the Canadian Manufacturing segment. The marketing operations of the Canadian Manufacturing segment have similar products and services, customer types, distribution methods and operate in the same regulatory environment as the commercial fuels business. The commercial fuels business includes cardlock, bulk plant and travel centre locations across Canada.

Financial Results

($ millions)	2022	2021 (1)	2020
Revenues	**7,792**	6,215	82
Purchased Product	**6,389**	5,156	—
Gross Margin (2)	**1,403**	1,059	82
Expenses			
Operating	**704**	486	37
Operating Margin	**699**	573	45
Depreciation, Depletion and Amortization	**208**	226	8
Segment Income (Loss)	**491**	347	37

(1) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details.
(2) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Select Operating Results

	2022	2021	2020
Heavy Crude Oil Throughput Capacity (Mbbls/d)	**110.5**	110.5	—
Lloydminster Upgrader	**81.5**	81.5	—
Lloydminster Refinery	**29.0**	29.0	—
Heavy Crude Oil Throughput (Mbbls/d)	**92.9**	106.5	—
Lloydminster Upgrader	**68.7**	79.0	—
Lloydminster Refinery	**24.2**	27.5	—
Crude Utilization (1) (percent)	**84**	96	—
Refined Products Output (Mbbls/d)	**93.4**	107.9	—
Upgrading Differential (2)	**32.84**	16.83	—
Refining Margin (3)(4) ($/bbl)	**33.92**	18.09	—
Lloydminster Upgrader (4)	**36.04**	18.96	—
Lloydminster Refinery (4)	**27.91**	15.60	—
Unit Operating Expense (5) ($/bbl)	**13.91**	7.55	—
Ethanol Production (millions of litres/d)	**0.8**	0.7	—
Rail			
Volumes Loaded (6) (Mbbls/d)	**1.8**	12.1	30.4
Fuel Sales (7)			
Fuel Sales (millions of litres/d)	**6.2**	6.9	—
Fuel Sales per Outlet (thousands of litres/d)	**15.0**	13.0	—

(1) Based on crude oil throughput volumes and results of operations at the Upgrader and Lloydminster Refinery.
(2) Based on benchmark price differential between heavy oil feedstock and synthetic crude.
(3) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A. Revenues from the Upgrader for the year ended December 31, 2022, were $3.8 billion (2021 – $3.2 billion). Revenues from the Lloydminster Refinery for the year ended December 31, 2022, were $1.1 billion (2021 – $816 million).
(4) Comparative information has been re-presented to include marketing activities.
(5) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A. Comparative information has been re-presented to include only operating expenses and throughput at the Upgrader and Lloydminster Refinery.
(6) Volumes transported outside of Alberta, Canada.
(7) On September 13, 2022, we closed the sales of 337 gas stations within our retail fuels network. We retained our commercial fuels business, which includes approximately 170 cardlock, bulk plant and travel centre locations. Total fuel sales volumes include the historical retail business and the remaining commercial fuels business. For the period of September 14, 2022 to December 31, 2022, the commercial fuels business averaged 0.7 million litres per day of gasoline sales volumes and 4.6 million litres per day of diesel fuel sales volumes, for a total of 5.3 million litres per day of sales volumes.

In 2022, crude oil throughput decreased 13.6 thousand barrels per day compared with 2021 due to planned turnarounds at the Lloydminster Upgrader and Lloydminster Refinery completed in the second quarter. Cold weather impacts and operational outages reduced throughput at the Upgrader in the fourth quarter of 2022. The Upgrader returned to full rates in the middle of January 2023. In addition, there were temporary unplanned outages at the Upgrader in the first and third quarters of 2022.

Revenues and Gross Margin

The Lloydminster Upgrader processes 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.

The Lloydminster Refinery processes 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 2022, revenues increased by $1.6 billion to $7.8 billion, mainly due to higher synthetic crude oil benchmark prices and higher asphalt and industrial products prices. In addition, revenues from our commercial fuels business and historical retail network increased due to significantly higher benchmark gasoline and diesel prices. The increase in total revenues year-over-year was partially offset by lower sales volumes.

Gross margin increased $344 million in 2022 compared with 2021, due to a higher upgrading differential and higher margins on asphalt and industrial products. The year-over-year increase was offset by lower sales volumes, the 2021 settlement of a take-or-pay contract of $55 million and reduced activity at the Bruderheim crude-by-rail terminal.

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

Operating Expenses

Primary drivers of operating expenses in 2022 were repairs and maintenance, workforce and energy costs. Total operating costs increased in 2022 compared with 2021, primarily due to planned turnarounds and operational outages, combined with higher energy costs, maintenance, workforce and chemical costs.

Per-unit operating expenses increased primarily due to the same factors discussed above, combined with lower crude oil throughput volumes. Per-unit operating costs apply only to operating costs and throughput at the Upgrader and Lloydminster Refinery.

DD&A

In 2022, Canadian Manufacturing DD&A was $208 million, compared with $226 million in 2021.

U.S. Manufacturing

In 2022, we:

- Delivered safe operations at our operated assets.
- Generated Operating Margin of $1.7 billion, an increase of $1.5 billion compared with 2021, largely due to significantly higher market crack spreads.
- Achieved crude utilization of 90 percent at the Lima Refinery.
- Completed a significant planned turnaround at the non-operated Toledo Refinery, from April and through to early August. On September 20, 2022, there was an incident at the Toledo Refinery. The refinery remains shut down in a safe state.
- Completed planned turnarounds at the non-operated Wood River and Borger refineries in the first and second quarters, and an additional planned turnaround at the Wood River Refinery in September and October.
- Commenced commissioning activities for the Superior Refinery restart in December 2022 and will progress into the first quarter of 2023. The refinery remains on schedule to ramp up to full operations in the second quarter of 2023.
- Averaged crude utilization of 80 percent and crude oil throughput of 400.8 thousand barrels per day across all U.S. Manufacturing assets.
- Invested capital of $1.1 billion focused primarily on the Superior Refinery rebuild, and refining reliability initiatives at the Wood River, Borger and Toledo refineries, and yield optimization projects at the Wood River Refinery.

On August 8, 2022, we announced an agreement with BP to acquire their 50 percent interest in the Toledo Refinery in Ohio. The Toledo Acquisition will provide us full ownership and operatorship and further integrate our heavy oil production and refining capabilities. The transaction is expected to give us an additional 80.0 thousand barrels per day of downstream throughput capacity, including 45.0 thousand barrels per day of heavy oil refining capacity, with opportunities to further optimize our heavy oil value chain through integration with our upstream assets. The transaction is expected to close at the end of February 2023.

Financial Results

($ millions)	**2022**	2021	2020
Revenues	**30,310**	20,043	4,733
Purchased Product	**26,112**	17,955	4,429
Gross Margin (1)	**4,198**	2,088	304
Expenses			
Operating	**2,346**	1,772	748
Realized (Gain) Loss on Risk Management	**112**	104	(21)
Operating Margin	**1,740**	212	(423)
Unrealized (Gain) Loss on Risk Management	**18**	1	(1)
Depreciation, Depletion and Amortization	**640**	2,381	728
Segment Income (Loss)	**1,082**	(2,170)	(1,150)

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

Select Operating Results

	2022	2021	2020
Crude Oil Throughput Capacity (Mbbls/d)	**552.5**	502.5	247.5
Lima Refinery	**175.0**	175.0	—
Superior Refinery [(1)]	**50.0**	—	—
Toledo Refinery [(2)]	**80.0**	80.0	—
Wood River and Borger Refineries [(2)]	**247.5**	247.5	247.5
Crude Oil Throughput (Mbbls/d)	**400.8**	401.5	185.9
Lima Refinery	**157.9**	126.9	—
Superior Refinery [(1)]	**—**	—	—
Toledo Refinery [(2)]	**36.3**	69.9	—
Wood River and Borger Refineries [(2)]	**206.6**	204.7	185.9
Throughput by Product (Mbbls/d)			
Heavy Crude Oil	**116.1**	138.7	74.6
Light and Medium Crude Oil	**284.7**	262.8	111.3
Crude Utilization (percent)	**80**	80	75
Refining Margin [(3)(4)] ($/bbl)	**28.70**	14.25	4.47
Unit Operating Expense [(4)(5)] ($/bbl)	**16.04**	12.09	11.00

(1) The Superior Refinery commenced commissioning in December 2022. The permitted capacity is 50.0 Mbbls/d and is not included in the crude utilization calculation.
(2) Represents Cenovus's 50 percent interest in the non-operated Wood River, Borger and Toledo refinery operations.
(3) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(4) Based on crude oil throughput volumes and operating results at Wood River, Borger, Lima, Toledo and Superior refineries.
(5) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

In 2022, total crude utilization across the segment was 80 percent (2021 – 80 percent):

- The Lima Refinery had unplanned operational issues in the first quarter of the year following the turnaround completed in late 2021. The refinery performed well in the remainder of the year, until the winter storm Elliott events in December. Lima returned to normal rates in early January 2023. Crude utilization in 2022 was 90 percent (2021 – 73 percent).
- At the Toledo Refinery, we completed a significant planned turnaround starting in April and ramped up to full rates by mid-August 2022. On September 20, 2022, there was an incident at the Toledo Refinery. The refinery remains shut down in a safe state. Crude utilization in 2022 was 45 percent (2021 – 87 percent).
- We completed two planned turnarounds at the Wood River Refinery in 2022. The spring turnaround was delayed due to cold weather, resulting in labour shortages and cost overruns. The second turnaround was completed in September and October. In December 2022, an incident occurred at the Wood River Refinery that reduced throughput. Crude utilization has steadily increased since the first week of January 2023, and the refinery is currently operating at a substantial proportion of normal throughput. The refinery is expected to return to normal rates in the second quarter of 2023.
- We completed a turnaround at the Borger Refinery in the first and second quarters of 2022. In addition, the refinery had unplanned operational outages in the fourth quarter of 2022. The refinery returned to full rates by January 2023.
- Combined crude utilization for the Wood River and Borger refineries was 83 percent (2021 – 83 percent).

Early in the year, we operated at reduced rates at the Toledo, Lima and Wood River refineries due to low market crack spreads. In December, throughput at all the U.S. Manufacturing sites was significantly impacted by extreme cold weather. Wood River and Borger were also impacted by outages on a third party pipeline that brings feedstock to the refineries. Cold weather also impacted Toledo delaying the start up of certain operational areas that could be restarted.

The Superior Refinery commenced commissioning in December and will progress into the first quarter of 2023. The refinery is expected to ramp up to full operations in the second quarter of 2023.

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 $10.3 billion to $30.3 billion in 2022 compared with 2021. The increase was primarily due to significantly higher refined product pricing.

Gross margin increased $2.1 billion to $4.2 billion in 2022 compared with 2021, largely due to significantly improved market crack spreads. In 2022, RINs costs were $1.1 billion (2021 – $880 million). RINs prices averaged US$7.72 per barrel in 2022, compared with US$6.76 in 2021.

In 2022, we incurred realized risk management losses of $112 million (2021 – $104 million), which included a $36 million loss on the early liquidation of WTI positions in the second quarter. In 2022, we recorded unrealized losses of $18 million (2021 – $1 million) on our crude oil and refined products financial instruments.

Operating Expenses

Primary drivers of operating expenses in 2022 were repairs and maintenance, workforce, and energy costs.

Operating expenses increased $574 million in 2022, compared with 2021. The increase was mainly due to costs related to:

- Planned turnarounds at the Toledo, Wood River and Borger refineries.
- Increased maintenance and preparation work at the Superior Refinery as we prepare for restart.
- Higher energy and utility pricing.
- Higher workforce and chemical costs.

In 2022, per-unit operating expenses increased $3.95 per barrel of crude oil throughput in 2022, compared with 2021. The increase was primarily due to the same factors as discussed above. Superior Refinery operating expenses are included in per-unit operating expenses.

DD&A

U.S. Manufacturing DD&A was $640 million in 2022, compared with $2.4 billion in 2021. DD&A decreased compared with 2021 due to impairment charges of $1.9 billion recorded in the fourth quarter of 2021 related to the Lima, Wood River and Borger cash generating units ("CGUs"). In the fourth quarter of 2022, we recorded net impairment charges of $266 million. Refer to Note 11 of the Consolidated Financial Statements for further details.

CORPORATE AND ELIMINATIONS

In 2022, our corporate risk management activities resulted in:

- Unrealized risk management gains of $89 million (2021 – $18 million). Unrealized risk management gains in 2022 relate to renewable power contracts and foreign exchange risk management contracts.
- Realized risk management losses of $31 million related to foreign exchange risk management contracts. Losses of $101 million in 2021 were mainly due to the realization of WTI put and call option contracts acquired as part of the Arrangement.

Expenses

($ millions)	**2022**	2021	2020
General and Administrative	**865**	849	292
Finance Costs	**820**	1,082	536
Interest Income	**(81)**	(23)	(9)
Integration and Transaction Costs	**106**	349	29
Foreign Exchange (Gain) Loss, Net	**343**	(174)	(181)
Revaluation (Gains)	**(549)**	—	—
Re-measurement of Contingent Payments	**162**	575	(80)
(Gain) Loss on Divestiture of Assets	**(269)**	(229)	(81)
Other (Income) Loss, Net	**(532)**	(309)	40
	865	2,120	546

General and Administrative

Primary drivers of our general and administrative expenses were employee long-term incentive costs, workforce costs and information technology costs. General and administrative expenses, excluding stock-based compensation expense, declined $198 million year-over-year, primarily due to the provision for incentive rewards related to reaching our synergy targets in 2021. Stock-based compensation expense increased significantly by $214 million due to changes in our share price in 2022. Our closing common share price on December 31, 2022, was $26.27, an increase from $15.51 on December 31, 2021.

Finance Costs

Finance costs decreased by $262 million in 2022 compared with 2021 primarily as a result of debt purchases that lowered the Company's average long-term debt in 2022 compared with 2021. In addition, we recorded a net discount on the redemption of long-term debt of $29 million in 2022. Comparatively, we recorded a $121 million net premium on the redemption of long-term debt in 2021. 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 year ended December 31, 2022, was 4.7 percent (2021 – 4.6 percent).

Integration and Transaction Costs

We incurred $90 million of integration costs as a result of the Arrangement, not including capital expenditures, in 2022, compared with $349 million in 2021. The integration of Cenovus and Husky is substantially complete.

In 2022, we incurred $95 million of Total Arrangement Integration Costs(1), which include capital expenditures (2021 – $402 million).

Transaction costs of $16 million were recognized in net earnings (loss) for the year ended December 31, 2022 associated with the Sunrise Acquisition and the pending Toledo Acquisition.

Foreign Exchange

($ millions)	**2022**	2021	2020
Unrealized Foreign Exchange (Gain) Loss	**365**	(312)	(131)
Realized Foreign Exchange (Gain) Loss	**(22)**	138	(50)
	343	(174)	(181)

In 2022, unrealized foreign exchange losses of $365 million were mainly as a result of the translation of our U.S. dollar denominated debt. Realized foreign exchange gains of $22 million were recorded in 2022, related to net gains on working capital, offset by losses on the purchase of long-term debt.

Revaluation Gains

Cenovus recognized revaluation gains of $549 million in the third quarter of 2022 as part of the Sunrise Acquisition. As required by IFRS 3, when an acquirer achieves control in stages, the previously held interest is remeasured to fair value at the acquisition date with any gain or loss recognized in net earnings (loss). Refer to Note 5 of the Consolidated Financial Statements for further details.

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

Re-measurement of Contingent Payments

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, and the final payment was made in July 2022. In 2022, we paid $631 million under this agreement, which was recognized as cash flow from operating activities and reduced Adjusted Funds Flow.

In connection with the Sunrise Acquisition, Cenovus agreed to make quarterly variable payments to BP Canada for up to eight quarters subsequent to August 31, 2022, if the average WCS crude oil price in a quarter exceeds $52.00 per barrel. The quarterly payment is calculated as $2.8 million plus the difference between the average WCS price less $53.00 multiplied by $2.8 million, for any of the eight quarters the average WCS price is equal to or greater than $52.00 per barrel. If the average WCS price is less than $52.00 per barrel, no payment will be made for that quarter. The maximum cumulative variable payment is $600 million. For accounting purposes, the variable payment will be re-measured at fair value at each reporting date until the earlier of the cumulative maximum $600 million is reached or the eight quarters have lapsed, with changes in fair value recognized in net earnings (loss). The variable payment was recorded at a fair value of $600 million on the date of acquisition using an option pricing model.

As at December 31, 2022, the fair value of the variable payment was estimated to be $419 million resulting in a non-cash re-measurement gain of $89 million. The first quarterly period ended on November 30, 2022. As at December 31, 2022, $92 million is payable under this agreement.

As of December 31, 2022, average WCS forward pricing for the remaining term of the variable payment is approximately $72.79 per barrel.

(Gain) Loss on Divestiture of Assets

In 2022, we recognized a gain on divestiture of assets of $269 million (2021 – $229 million), due to the closing of the sales of our Tucker and Wembley assets in the first quarter, the divestiture of 12.5 percent of our interest in the White Rose field and satellite extensions in the second quarter, and the divestiture of 337 gas stations within our retail fuels network in the third quarter.

Other (Income) Loss, Net

In 2022, other income increased by $223 million compared with 2021, primarily due to insurance proceeds related to 2018 incidents at the Superior Refinery and in the Atlantic region and funding received under the Government of Alberta's Site Rehabilitation Program which provides qualifying entities funding to abandon and reclaim oil and gas sites. The increase was partially offset by the settlement of a legal claim in favour of Cenovus in the third quarter of 2021.

DD&A

DD&A for year ended December 31, 2022, was $113 million (2021 – $118 million).

Income Tax

($ millions)	2022	2021	2020
Current Tax			
Canada	**1,252**	104	(14)
United States	**104**	—	1
Asia Pacific	**262**	171	—
Other International	**21**	1	—
Current Tax Expense (Recovery)	**1,639**	276	(13)
Deferred Tax Expense (Recovery)	**642**	452	(838)
Total Tax Expense (Recovery)	**2,281**	728	(851)

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 year ended December 31, 2022, the Company recorded a current tax expense related to operations in all jurisdictions that Cenovus operates. The increase is due to higher earnings compared to 2021 and the tax deductions available to calculate taxable income and losses available to offset that taxable income.

QUARTERLY RESULTS

($ millions, except where indicated)	2022 Q4	2022 Q3	2022 Q2	2022 Q1	2021 Q4	2021 Q3	2021 Q2	2021 Q1
Average Commodity Prices (US$/bbl)								
Dated Brent	**88.71**	100.85	113.78	101.41	79.73	73.47	68.83	60.90
WTI	**82.65**	91.55	108.41	94.29	77.19	70.56	66.07	57.84
WCS at Hardisty	**56.99**	71.69	95.61	79.76	62.55	56.98	54.58	45.37
Chicago 3-2-1 Crack Spread	**32.87**	38.87	46.50	18.35	16.06	20.67	20.50	12.93
RINs	**8.54**	8.11	7.80	6.44	6.11	7.32	8.12	5.49
Upstream Production Volumes								
Bitumen (Mbbls/d)	**593.5**	568.2	540.3	578.8	606.0	576.5	528.6	532.9
Heavy Crude Oil (Mbbls/d)	**15.8**	16.8	16.4	16.2	18.9	20.5	20.8	20.5
Light Crude Oil (Mbbls/d)	**17.1**	16.0	20.8	21.9	17.8	22.6	24.4	25.6
NGLs (Mbbls/d)	**38.5**	32.1	36.7	37.6	35.6	35.5	41.1	41.1
Conventional Natural Gas (MMcf/d)	**852.0**	868.7	882.2	865.3	883.5	897.9	905.6	894.9
Total Production Volumes (MBOE/d)	**806.9**	777.9	761.5	798.6	825.3	804.8	765.9	769.3
Downstream Crude Oil Throughput [(1)] (Mbbls/d)	**473.5**	533.5	457.3	501.8	469.9	554.1	539.0	469.1
Revenues [(2)]	**14,063**	17,471	19,165	16,198	13,726	12,701	10,637	9,293
Operating Margin [(3)]	**2,782**	3,339	4,678	3,464	2,600	2,710	2,184	1,879
Cash From (Used in) Operating Activities	**2,970**	4,089	2,979	1,365	2,184	2,138	1,369	228
Adjusted Funds Flow [(3)]	**2,346**	2,951	3,098	2,583	1,948	2,342	1,817	1,141
Per Share - Basic [(3)] ($)	**1.22**	1.53	1.57	1.30	0.97	1.16	0.90	0.57
Per Share - Diluted [(3)] ($)	**1.19**	1.49	1.53	1.27	0.97	1.15	0.89	0.56
Capital Investment	**1,274**	866	822	746	835	647	534	547
Free Funds Flow [(3)]	**1,072**	2,085	2,276	1,837	1,113	1,695	1,283	594
Excess Free Funds Flow [(3)(4)]	**786**	1,756	2,020	2,615	1,169	1,626	1,244	462
Net Earnings (Loss) [(5)]	**784**	1,609	2,432	1,625	(408)	551	224	220
Per Share - Basic ($)	**0.40**	0.83	1.23	0.81	(0.21)	0.27	0.11	0.10
Per Share - Diluted ($)	**0.39**	0.81	1.19	0.79	(0.21)	0.27	0.11	0.10
Total Assets	**55,869**	55,086	55,894	55,655	54,104	54,594	53,384	53,378
Total Long-Term Liabilities	**20,259**	19,378	20,742	21,889	23,191	22,929	22,972	24,266
Long-Term Debt, Including Current Portion	**8,691**	8,774	11,228	11,744	12,385	12,986	13,380	13,947
Net Debt	**4,282**	5,280	7,535	8,407	9,591	11,024	12,390	13,340
Cash Returns to Shareholders								
Common Shares – Base Dividends	**201**	205	207	69	70	35	36	35
Base Dividends Per Common Share ($)	**0.105**	0.105	0.105	0.035	0.035	0.018	0.018	0.018
Common Shares – Variable Dividends	**219**	—	—	—	—	—	—	—
Variable Dividends Per Common Share ($)	**0.114**	—	—	—	—	—	—	—
Purchase of Common Shares Under NCIB	**387**	659	1,018	466	265	—	—	—
Preferred Share Dividends [(6)]	**—**	9	8	9	8	9	8	9

(1) Represents Cenovus's net interest in refining operations.
(2) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.
(3) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(4) New metric as of June 30, 2022, used to determine returns to shareholders.
(5) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.
(6) Preferred share dividends declared on November 1, 2022, were paid on January 3, 2023.

Fourth Quarter 2022 Results Compared with the Fourth Quarter 2021

The summary below compares financial and operating results for the three months ended December 31, 2022 compared with the same period in 2021.

Upstream Production Volumes

Total upstream production decreased 18.4 thousand BOE per day in the fourth quarter of 2022 compared with the same period in 2021.

Oil Sands crude oil production decreased 15.6 thousand barrels per day to 609.3 thousand barrels per day in 2022 compared with 2021. The decrease was primarily due to the sale of the Tucker asset on January 31, 2022. Crude oil production at the time of sale was approximately 20 thousand barrels per day. In addition, production decreased at Foster Creek as production reached peak levels in the fourth quarter of 2021 due to the timing of well pads starting up. Offsetting the decrease was the Sunrise Acquisition on August 31, 2022, and production of approximately 12.0 thousand barrels per day from the Spruce Lake North thermal plant in the fourth quarter of 2022. In the fourth quarter of 2022, we sold approximately 25 percent (2021 – 20 percent) of our Oil Sands crude oil volumes at U.S. destinations, improving our realized sales prices.

Conventional production was 125.5 thousand BOE per day in 2022, essentially unchanged from 125.3 thousand BOE per day in 2021. Production decreases from asset sales in the first quarter of 2022 were offset by 36 net new wells brought on production in the year-ended 2022, combined with production from well reactivations and workover activity.

Offshore production was 70.2 thousand BOE per day in 2022, compared with 73.1 thousand BOE per day in 2021. The decrease was primarily due to the working interest restructuring on the White Rose fields in the second quarter of 2022, combined with contract amendments in China. These were partially offset by first gas production at the MBH and MDA fields in Indonesia in the fourth quarter of 2022.

Downstream Manufacturing Throughput

Total crude oil throughput was consistent in the fourth quarter of 2022 compared with the same period in 2021.

Canadian Manufacturing throughput decreased 14.0 thousand barrels per day to 94.3 thousand barrels per day in 2022. Cold weather impacts and unplanned operational outages reduced throughput at the Upgrader in the fourth quarter of 2022. The Upgrader returned to full rates in the middle of January 2023. The Lloydminster Refinery had minor unplanned outages in the fourth quarter of 2022, but ran well in December and into 2023.

U.S. Manufacturing throughput increased 17.6 thousand barrels per day to 379.2 thousand compared with 2021, primarily due to the completion of a planned turnaround in the fourth quarter of 2021 at the Lima Refinery. The increase was partially offset by unplanned operational issues, weather-related impacts and third-party outages impacting the Lima, Wood River and Borger refineries in December, in addition to the shutdown of the Toledo Refinery, and Wood River running at reduced rates in December due to an operational incident.

Revenues

Revenues increased $337 million to $14.1 billion in 2022 compared with 2021. Downstream revenues increased $370 million primarily due to higher refined product pricing. Upstream revenues were flat compared with 2021, as higher realized prices in the Conventional segment were offset by lower sales volumes in the Atlantic region. Oil Sands revenues were consistent with 2021, due to flat sales volumes and realized prices year-over year.

Operating Margin

Operating Margin increased in the fourth quarter of 2022, primarily due to increased refining margins from our downstream business resulting from higher market crack spreads. The increase was partially offset by:

- Increased blending costs due to higher condensate prices impacting our Oil Sands segment.
- Higher Renewable Identification Numbers (“RINs”) costs impacting our U.S. Manufacturing segment.
- Increased transportation costs from our upstream business, due to increased tariff rates and higher rail costs due to pipeline outages in the quarter.

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

Cash from operating activities and Adjusted Funds Flow were higher in 2022, primarily due to increased Operating Margin, as discussed above, and no quarterly contingent payments in 2022 (2021 – $119 million). The increase was partially offset by higher cash taxes in 2022.

Cash from operating activities also increased as the change in non-cash working capital was $402 million greater than 2021. The increase was due to lower accounts receivable and higher income tax payable, partially offset by lower accounts payable on December 31, 2022, compared with September 30, 2022.

Net Earnings (Loss)

Net earnings in the fourth quarter of 2022 was $784 million compared with a net loss of $408 million 2021 due to:

- Net impairment charges in the fourth quarter of 2022 of $266 million, compared with net impairment charges of $1.6 billion in the fourth quarter of 2021.
- Higher operating margin, as discussed above.

The increase was partially offset by:

- Unrealized risk management losses of $37 million in 2022 (2021 – $222 million gain).
- Higher gain on divestiture of assets in 2021.

Capital Investment

Capital investment in the fourth quarter of 2022 was $1.3 billion, compared with $835 million in 2021. The increase is primarily due to higher capital spending in our upstream operations, including higher investment in Sunrise following the closing of the Sunrise Acquisition, incremental capital at Foster Creek, Christina Lake and Lloydminster thermal assets, increased drilling in the Conventional segment and work on the West White Rose project.

Excess Free Funds Flow

Excess Free Funds Flow was $786 million in the fourth quarter of 2022 (2021 – $1.2 billion). The decrease was due to higher capital spending and base dividends paid in 2022, partially offset by higher adjusted funds flow in 2022.

OIL AND GAS RESERVES

As at December 31, 2022 (before royalties)	Bitumen [(1)] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [(2)] (Bcf)	Total (MMBOE)
Total Proved	5,592	42	82	2,194	**6,082**
Probable	2,448	129	39	1,029	**2,787**
Total Proved Plus Probable	8,040	171	121	3,223	**8,869**

As at December 31, 2021 (before royalties)	Bitumen [(1)] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [(2)] (Bcf)	Total (MMBOE)
Total Proved	5,573	45	89	2,219	**6,077**
Probable	1,850	152	39	959	**2,201**
Total Proved Plus Probable	7,423	197	128	3,178	**8,278**

(1) Includes heavy crude oil that is not material.
(2) Includes shale gas that is not material.

Developments in 2022 compared with 2021 include:

- Bitumen gross total proved and gross total proved plus probable reserves increased by 19 million barrels and 617 million barrels, respectively. The increases were due to additions from the regulatory approval at Foster Creek, the Sunrise Acquisition and improved recovery performance at Sunrise and Lloydminster thermal, partially offset by the Tucker asset sale and current year production.
- Light and medium oil gross total proved and gross total proved plus probable reserves decreased by three million barrels and 26 million barrels, respectively. The decreases were due to the disposition of 12.5 percent of the Company's working interest in the White Rose field and satellite extensions, the Wembley asset sale and current year production, partially offset by additions from updates to the Atlantic region and Conventional segment development plans.
- NGLs gross total proved and gross total proved plus probable reserves decreased by seven million barrels each, due to dispositions in the Conventional segment and current year production, partially offset by additions from updates to the development plan and economic factors related to increased product pricing for the Conventional segment.
- Conventional natural gas gross total proved reserves decreased by 25 billion cubic feet due to the Wembley asset sale and current year production, partially offset by updates to the development plans, improved recovery performance, and economic factors due to improved product pricing for the Conventional segment. Conventional natural gas gross total proved plus probable reserves increased by 45 billion cubic feet due to updates to the development plan and economic factors due to improved product pricing for the Conventional segment, partially offset by the Wembley asset sale and current year production.

The reserves data is presented as at December 31, 2022 using an average of forecasts ("Average Forecast") by McDaniel & Associates Consultants Ltd., GLJ Ltd. and Sproule Associates Limited. The Average Forecast prices and costs are dated January 1, 2023. Comparative information as at December 31, 2021 uses the January 1, 2022 Average Forecast prices and costs.

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, "*Standards of Disclosure for Oil and Gas Activities*" is contained in our AIF for the year ended December 31, 2022. Our AIF is available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com. Material risks and uncertainties associated with estimates of reserves are discussed in this MD&A in the Risk Management and Risk Factors section and the Advisory section in this MD&A.

LIQUIDITY AND CAPITAL RESOURCES

During 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 enables 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 commodity price cycle.

We expect to fund our near-term cash requirements through cash from operating activities, the prudent use of our cash and cash equivalents and other sources of liquidity. This includes draws on our committed credit facility, draws on our uncommitted demand facilities and other corporate and financial opportunities which provide timely access to funding to supplement cash flow. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, Moody's Investor Service, DBRS Morningstar 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.

($ millions)	**2022**	2021	2020
Cash From (Used In)			
Operating Activities	**11,403**	5,919	273
Investing Activities	**(2,314)**	(942)	(863)
Net Cash Provided (Used) Before Financing Activities	**9,089**	4,977	(590)
Financing Activities	**(7,676)**	(2,507)	837
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**238**	25	(55)
Increase (Decrease) in Cash and Cash Equivalents	**1,651**	2,495	192

As at ($ millions)	**2022**	2021	2020
Cash and Cash Equivalents	**4,524**	2,873	378
Total Debt	**8,806**	12,464	7,562

Cash From (Used in) Operating Activities

For the year ended December 31, 2022, cash generated from operating activities increased compared with 2021 due to higher Operating Margin, changes in non-cash working capital, lower finance costs and lower integration and transaction costs.

Excluding the contingent payment, our adjusted working capital was $4.7 billion at December 31, 2022. At December 31, 2021, adjusted working capital excluding the contingent payment and assets held for sale and liabilities related to assets held for sale was $3.8 billion. 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 cash and inventories, partially offset by higher income tax payable and lower accounts receivable.

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 2022 compared with 2021 largely due to higher capital spending, cash paid on the Sunrise Acquisition in 2022 and cash acquired in the Arrangement in 2021. The increase was partially offset by higher proceeds from divestitures in 2022.

Cash From (Used in) Financing Activities

As part of our overall deleveraging in 2022, we:

- Paid US$402 million to purchase the full amount of our 3.80 percent unsecured notes due in 2023 and 4.00 percent unsecured notes due in 2024, with principal amounts of US$115 million and US$269 million, respectively. We paid a premium on redemption of US$18 million.
- Paid $750 million to purchase the full principal amount outstanding of our 3.55 percent unsecured notes due in 2025 at par.
- Paid US$2.2 billion to purchase unsecured notes due between 2025 and 2043, at a premium of US$23 million.

During 2022, net short-term borrowings increased by $34 million, related to draws on the WRB Refining LP uncommitted demand facilities.

In 2022, the Company purchased 112 million common shares through our NCIBs, at a volume weighted average price of $22.49 per common share for a total of $2.5 billion (December 31, 2021 – $265 million). The common shares were subsequently cancelled. During 2022, we paid base dividends of $682 million and variable dividends of $219 million on our common shares.

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.

	Three Months Ended December 31,		Year Ended December 31,		
($ millions)	**2022**	2021	**2022**	2021	2020
Cash From (Used in) Operating Activities	**2,970**	2,184	**11,403**	5,919	273
(Add) Deduct:					
Settlement of Decommissioning Liabilities	**(49)**	(35)	**(150)**	(102)	(42)
Net Change in Non-Cash Working Capital	**673**	271	**575**	(1,227)	198
Adjusted Funds Flow	**2,346**	1,948	**10,978**	7,248	117
Capital Investment	**1,274**	835	**3,708**	2,563	841
Free Funds Flow	**1,072**	1,113	**7,270**	4,685	(724)
Add (Deduct):					
Base Dividends Paid on Common Shares	**(201)**	(70)			
Dividends Paid on Preferred Shares	**—**	(8)			
Settlement of Decommissioning Liabilities	**(49)**	(35)			
Principal Repayment of Leases	**(74)**	(78)			
Acquisitions, Net of Cash Acquired	**(7)**	—			
Proceeds From Divestitures	**45**	247			
Excess Free Funds Flow	**786**	1,169			

Returns to Shareholders Target

($ millions)	Three Months Ended December 31, 2022	September 30, 2022	June 30, 2022
Excess Free Funds Flow	**786**	1,756	2,020
Target Return [(1)]	**393**	878	1,010
Less: Purchase of Common Shares Under NCIBs	**(387)**	(659)	(1,018)
Amount Available for Variable Dividend	**6**	219	(8)

(1) Based on our capital allocation framework, as a result of Net Debt as at September 30, 2022, June 30, 2022 and 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.

In the fourth quarter of 2022, we paid variable dividends of $219 million. Returns to shareholders through share buybacks were within $50 million of the fourth quarter Target Return, as such no variable dividend was declared for the quarter.

Short-Term Borrowings

As at December 31, 2022, US$170 million was drawn on the WRB uncommitted demand facility, of which the Company's proportionate share was US$85 million (C$115 million) (December 31, 2021 – US$125 million of which the Company's proportionate share was US$63 million (C$79 million)).

Long-Term Debt and Total Debt

Total Debt as at December 31, 2022, was $8.8 billion (December 31, 2021 – $12.5 billion), which includes $8.7 billion of long-term debt (December 31, 2021 – $12.4 billion). The decrease in Total Debt and long-term debt was due to the purchase of US$2.6 billion and $750 million of principal related to outstanding unsecured notes in 2022.

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

Available Sources of Liquidity

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

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**N/A**	**4,524**
Committed Credit Facility [(1)]		
Revolving Credit Facility – Tranche A	**November 10, 2026**	**3,700**
Revolving Credit Facility – Tranche B	**November 10, 2025**	**1,800**
Uncommitted Demand Facilities [(2)]		
Cenovus Energy Inc. [(3)]	**N/A**	**1,002**
WRB Refining LP [(4)]	**N/A**	**190**

(1) No amounts were drawn on the committed credit facility as at December 31, 2022 (December 31, 2021 - $nil).
(2) On November 24, 2022, the Company cancelled the SOSP uncommitted demand credit facility.
(3) Our uncommitted demand facilities includes $1.9 billion, of which $1.4 billion may be drawn for general purposes, or the full amount can be available to issue letters of credit. As at December 31, 2022, there were outstanding letters of credit aggregating to $490 million (December 31, 2021 – $565 million) and no direct borrowings.
(4) 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 December 31, 2022, US$170 million was drawn on these facilities, of which the Company's proportionate share was US$85 million (C$115 million) (December 31, 2021 – US$125 million of which the Company's proportionate share was US $63 million (C$79 million)).

On November 10, 2022, Cenovus amended its existing committed credit facility to decrease the capacity by $500 million to $5.5 billion and to extend the maturity dates.

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 December 31, 2022, the total outstanding principal amount of U.S. dollar denominated unsecured notes was US$4.8 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	(2,558)	(750)
As at December 31, 2022	**4,827**	**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 December 31, 2022, US$4.7 billion remained available under the base shelf prospectus for permitted offerings (December 31, 2021 – US$4.7 billion). Offerings under the base shelf prospectus are subject to market availability.

Financial Metrics

We monitor our capital structure and financing requirements using the Net Debt to Capitalization Ratio, Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio. Refer to Note 26 of the 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 Shareholders 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 used in the Net Debt to Adjusted EBITDA Ratio, as net earnings before finance costs, net of capitalized interest, interest income, income tax expense (recovery), DD&A, E&E write-down, goodwill impairments, unrealized (gain) loss on risk management, foreign exchange (gain) loss, revaluation (gains), re-measurement of contingent payment, (gain) loss on divestiture of assets, other (income) loss, net and share of (income) loss from equity-accounted affiliates 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	**2022**	2021	2020
Net Debt to Capitalization Ratio (percent)	**13**	29	30
Net Debt to Adjusted Funds Flow Ratio (times)	**0.4**	1.3	61.4
Net Debt to Adjusted EBITDA Ratio (times)	**0.3**	1.2	11.9

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.

Our Net Debt to Capitalization Ratio as at December 31, 2022 decreased compared with December 31, 2021, primarily due to higher net earnings and ongoing reductions in Net Debt.

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

Share Capital and Stock-Based Compensation Plans

As at December 31, 2022, there were approximately 1,909 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 32 of the 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 between November 9, 2021 and November 8, 2022. On November 7, 2022, we renewed the NCIB program to purchase up to an additional 136.7 million of the Company's common shares between November 9, 2022, and November 8, 2023. In 2022, Cenovus purchased and cancelled 112 million common shares for $2.5 billion (year ended December 31, 2021 – 17 million common shares for $265 million), at a volume weighted average price of $22.49 per common share through our NCIBs. Paid in surplus was reduced by $1.6 billion (December 31, 2021 – $120 million), representing the excess of the purchase price of the common shares over their average carrying value. From January 1, 2023, to February 13, 2023, the Company purchased an additional 1.4 million common shares for $36.8 million. As at February 13, 2023, 123.8 million common shares remain available for purchase under the 2023 NCIB.

As at December 31, 2022, there were approximately 56 million Cenovus Warrants outstanding (December 31, 2021 – 65 million Cenovus Warrants). Each Cenovus 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 Cenovus Warrants expire on January 1, 2026. Refer to Note 32 of the Consolidated Financial Statements for further details.

Refer to Note 34 of the 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 February 13, 2023	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,907,867**	**N/A**
Cenovus Warrants	**55,691**	**N/A**
Series 1 First Preferred Shares	**10,740**	**N/A**
Series 2 First Preferred Shares	**1,260**	**N/A**
Series 3 First Preferred Shares	**10,000**	**N/A**
Series 5 First Preferred Shares	**8,000**	**N/A**
Series 7 First Preferred Shares	**6,000**	**N/A**
Stock Options	**17,373**	**8,312**
Other Stock-Based Compensation Plans	**16,891**	**1,581**

Common Share Dividends

In 2022, we paid base dividends of $682 million or $0.350 per common share (2021 – $176 million or $0.088 per common share) and variable dividends of $219 million or $0.114 per common share (2021 – $nil).

The Board declared a first quarter base dividend of $0.105 per common share, payable on March 31, 2023, to common shareholders of record as at March 15, 2023.

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

Cumulative Redeemable Preferred Share Dividends

In 2022, dividends of $26 million were paid on the series 1, 2, 3, 5 and 7 preferred shares (December 31, 2021 — $34 million). The decrease from 2021 is related to timing differences between the declaration date and payment date. The declaration of preferred share dividends is at the sole discretion of the Board and is considered quarterly. The Board declared a first quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares of $9 million, payable on March 31, 2023, to preferred shareholders of record as of March 15, 2023.

Capital Investment Decisions

Our 2023 capital program is forecast to be between $4.0 billion and $4.5 billion, including approximately $2.8 billion of sustaining capital and between $1.2 billion to $1.7 billion of optimization and growth capital. Our Future Capital Investment is focused on disciplined capital allocation, investment plans to progress opportunities across our integrated portfolio, cost control and positioning the Company for continued growth in shareholder returns. We expect our annual upstream production to average between 800 thousand BOE per day and 840 thousand BOE per day and our downstream crude oil throughput average between 610 thousand barrels per day to 660 thousand barrels per day in 2023. Our 2023 guidance dated December 5, 2022, is available on our website at cenovus.com.

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. Commitments that have original maturities of less than one year are excluded from the table below. For further information, see Note 40 to the Consolidated Financial Statements.

Our total commitments were $33.0 billion as at December 31, 2022, of which $21.1 billion are for various transportation and storage commitments and $9.4 billion are for product purchase 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 December 31, 2022, include $2.2 billion related to long-term transportation and storage commitments.

As at December 31, 2022 ($ millions)	2023	2024	2025	2026	2027	Thereafter	Total
Commitments [1]							
Transportation and Storage [2]	1,747	2,011	1,542	1,416	1,360	13,005	**21,081**
Product Purchases [3]	1,626	1,509	922	922	922	3,457	**9,358**
Real Estate [4]	48	50	50	50	54	604	**856**
Obligation to Fund Equity-Accounted Affiliate [5]	92	105	96	96	91	143	**623**
Other Long-Term Commitments	381	90	75	74	65	395	**1,080**
Total Commitments	3,894	3,765	2,685	2,558	2,492	17,604	**32,998**
Long-Term Debt (Principal and Interest)	401	401	582	392	1,622	11,196	**14,594**
Decommissioning Liabilities	263	254	249	248	247	5,979	**7,240**
Contingent Payments	271	167	—	—	—	—	**438**
Lease Liabilities (Principal and Interest) [6]	426	407	339	320	276	2,889	**4,657**
Total Commitments and Obligations	5,255	4,994	3,855	3,518	4,637	37,668	**59,927**

(1) Commitments are reflected at Cenovus's proportionate share of the underlying contract.
(2) Includes transportation commitments of $9.1 billion (December 31, 2021 – $8.1 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 commencement of the contract.
(3) Prior to September 30, 2022, product purchases were included in Transportation and Storage.
(4) Relates to the non-lease components of lease liabilities consisting of operating costs and unreserved parking for office space. Excludes committed payments for which a provision has been provided.
(5) Relates to funding obligations for HCML.
(6) Lease contracts related to office space, our retail and commercial network, railcars, storage assets, drilling rigs and other refining and field equipment.

As at December 31, 2022, outstanding letters of credit issued as security for performance under certain contracts totaled $490 million (December 31, 2021 – $565 million).

Legal Proceedings

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

Transactions with Related Parties

Transactions with HMLP are related party transactions as we have a 35 percent ownership interest in HMLP. As the operator of the assets held by HMLP, we provide management services for which we recover shared service costs. We are also the contractor for HMLP and construct its assets on a cost recovery basis with certain restrictions. For the year ended December 31, 2022, we charged HMLP $188 million for construction and management services (2021 – $243 million).

We pay an access fee to HMLP for the use of its pipeline systems that are used by our blending business. We also pay HMLP for transportation and storage services. For the year ended December 31, 2022, we incurred costs of $263 million for the use of HMLP's pipeline systems, as well as transportation and storage services (2021 – $284 million).

RISK MANAGEMENT AND RISK FACTORS

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, without limitation, 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, repurchase our shares, pay dividends to our shareholders and fulfill our obligations (including debt servicing requirements) and/or may materially affect the market price of our securities.

Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of our risks and is integrated with the Cenovus Operations Integrity Management System ("COIMS"). In addition, we continuously monitor our risk profile as well as industry best practices.

Risk Governance

The ERM Policy, approved by our Board, outlines our risk management principles and expectations, as well as the roles and responsibilities of all staff. Building on the ERM Policy, we have established risk management standards, a risk management framework and risk assessment tools, including the Cenovus risk matrix. Our risk management framework contains the key attributes recommended by the International Organization for Standardization ("ISO") in its ISO 31000 – Risk Management Guidelines. The results of our ERM program are documented in semi-annual risk reports presented to our Board as well as through regular updates.

Risk Factors

The following discussion describes the financial, operational, regulatory, environmental, reputational, and other risks related to Cenovus. Each risk identified in this MD&A may individually, or in combination with other risks, have a material impact on, among other things, our business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, ability to fund share repurchases, dividend payments and/or business plans, and/or the market price of our securities. These factors should be considered when investing in securities of Cenovus.

Pandemic Risk

The COVID-19 pandemic remains a risk for the Company. While restrictions have ended or been relaxed in many parts of the world, other jurisdictions continue to impose measures to combat the virus. The COVID-19 pandemic (including the emergence of variant strains of COVID-19) and measures taken in response by governments and health authorities around the world have created ongoing uncertainty that has resulted in and may continue to result in restrictions on movement and businesses being maintained, re-imposed or imposed on a stricter basis, which could negatively impact our business, results of operations and financial condition.

The COVID-19 pandemic, or other pandemics, endemics or outbreaks, may increase our exposure to, and the magnitude of, each of the risks identified in this Risk Management and Risk Factors section of this MD&A and identified in other documents we file with securities regulators from time to time. The duration or extent of the impacts of the COVID-19 pandemic on our business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict with any degree of precision, and include but are not limited to: the severity, duration, spread or resurgence of COVID-19 or its variants; the timing, extent and effectiveness of actions taken to contain or treat COVID-19 or its variants, including the availability, distribution rate, effectiveness and public uptake of any vaccines or boosters; and the speed at which, and extent to which, normal economic and operating conditions resume.

There are no comparable recent events that provide guidance as to the effect the COVID-19 pandemic may have, and, as a result, the ultimate impact of the COVID-19 pandemic is highly uncertain and subject to change. The COVID-19 pandemic and the corresponding measures we take to protect the health and safety of our staff and the continuity of our business may result in new legal challenges and disputes, including, but not limited to, litigation involving contract parties or employees and class action claims.

Financial Risk

Commodity Prices

Our financial performance is significantly dependent on the prevailing prices of crude oil, refined products, natural gas and NGLs. Crude oil prices are impacted by a number of factors, including, but not limited to: global and regional supply of and demand for crude oil; the ability of producers and governments to replace reduced supply; processing and export capacity; global economic conditions; and activity; inflation and rising interest rates; the potential for a recession; market competitiveness; the actions of OPEC and other oil exporting nations, including, but not limited to, compliance or non-compliance with quotas agreed upon by OPEC members and decisions by OPEC not to impose production quotas on its members; the release of SPRs; developments related to the market for crude oil; levels of oil inventories; current and potential future environmental regulations, including regulations pertaining to the production and use of non-renewable resources; emissions, including, but not limited to carbon; market pricing and the accessibility and liquidity of these and related markets; prices and availability of alternate sources of energy; actions of domestic or foreign governments or regulatory bodies that may impact commodity prices; enforcement of government or environmental regulations; public sentiment towards the use of non-renewable resources, including crude oil; political stability and social conditions in oil-producing countries; market access constraints and transportation interruptions; terrorist threats; technological developments; economic sanctions; outbreak or continuation of a pandemic or war; the occurrence of natural disasters; and weather conditions.

The financial performance of our oil sands operations could also be impacted by discounted or reduced commodity prices for our oil sands production relative to certain international benchmark prices, due, in part, to constraints on the ability to transport and sell products to domestic and international markets and the quality of oil produced. Of particular importance to us are diluent cost and supply and the price differentials between bitumen and both light to medium crude oil and heavy crude oil. Bitumen is more expensive for refineries to process and therefore generally trades at a discount to the market price for light to medium crude oil and heavy crude oil which, along with higher diluent costs, can adversely affect our financial condition.

Our natural gas and NGL production is currently located in Western Canada and Asia Pacific. Natural gas and NGL prices are impacted by a number of factors, including, but not limited to: global and regional supply and demand for natural gas and NGLs; global economic conditions; market competitiveness; developments related to the market for liquefied natural gas; levels of natural gas and NGL inventories; export capacity; current and potential future environmental regulations, including regulations pertaining to the production and use of non-renewable resources; emissions, including, but not limited to carbon; market pricing and the accessibility and liquidity of these and related markets; prices and availability of alternate sources of energy; actions of domestic or foreign governments or regulatory bodies that may impact commodity prices; enforcement of government or environmental regulations; public sentiment towards the use of non-renewable resources, including natural gas and NGLs; political stability and social conditions in natural gas and NGL-producing countries; market access constraints and transportation interruptions; terrorist threats; technological developments; economic sanctions; outbreak or continuation of a pandemic or war; the occurrence of natural disasters; and weather conditions.

Refined product prices are impacted by a number of factors, including, but not limited to: global and regional supply and demand for refined products; the ability of producers and governments to replace reduced supply; global economic conditions and activity; inflation and rising interest rates; central bank policies; seasonal trends; the potential for a recession; market competitiveness; developments related to the market for refined products; levels of refined product inventories; refinery availability; planned and unplanned refinery maintenance; current and potential future environmental regulations, including the United States Renewable Fuel Standard ("RFS") and other regulations pertaining to the production and use of refined products and non-renewable resources; emissions, including, but not limited to carbon; market pricing and the accessibility and liquidity of these and related markets; prices and availability of alternate sources of energy; public sentiment towards the use of non-renewable resources, including refined products; market access constraints and transportation interruptions; terrorist threats; technological developments; economic sanctions; outbreak or continuation of a pandemic or war; the occurrence of natural disasters; and weather conditions.

The financial performance of our refining operations is also impacted by the relationship, or margin, between refined product prices and the prices of refinery feedstock. Refining margins are subject to seasonal factors as production levels change to match seasonal demand. Sales volumes, prices, inventory levels and inventory values will fluctuate accordingly. Future refining margins are uncertain and decreases in refining margins may have a negative impact on our business, results of operations, cash flows and financial condition.

In addition, relating to the level of future demand (and corresponding price levels) for each of crude oil, refined products, natural gas and NGLs, there has been a significant increase in focus on the timing for and pace of the transition to a lower-carbon economy. See "Climate Change Transition – Demand and Commodity Prices" below. All of these factors are beyond our control and can result in a high degree of both cost and price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. See "Foreign Exchange Rates" below.

Fluctuations in the commodity prices, associated price differentials and refining margins may impact our ability to meet guidance targets, the value of our assets, our cash flows, level of shareholder returns and our ability to maintain our business and fund projects. A substantial decline in these commodity prices or an extended period of low commodity prices may result in an inability to meet all of our financial obligations as they come due, a delay or cancellation of existing or future drilling, development or construction programs, curtailment in production, unutilized long-term transportation commitments and/or low utilization levels at our refineries. Fluctuations in commodity prices, associated price differentials and refining margins impact our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

The commodity price risks noted above, as well as other risks such as market access constraints and transportation restrictions, reserves replacement and reserves estimates and cost management that are more fully described herein, may have a material impact on our business, financial condition, results of operations, cash flows and reputation and may be considered indicators of impairment. Another potential indicator of impairment is the comparison of the carrying value of our assets to our market capitalization.

As discussed in this MD&A, we conduct an assessment, at each reporting date, of the carrying value of our assets in accordance with IFRS. If crude oil, NGLs, refined product, and natural gas prices decline significantly and remain at low levels for an extended period of time, or if the costs of our development of such resources significantly increase, the carrying value of our assets may be subject to impairment and our net earnings could be adversely affected.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts, and market access commitments, and generally through our access to our committed credit facility. In certain instances, we will use derivative instruments to manage exposure to price volatility on a portion of our refined product, oil and gas production, inventory or volumes in long-distance transit. 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 37 and 38 of the Consolidated Financial Statements.

Hedging Activities

Our Market Risk Management Policy, which has been approved by our Board, allows Management to use derivative instruments, including exchange-traded futures contracts, commodity put and call options and other approved instruments such as non-exchange-traded instruments, as needed to help mitigate the impact of changes in crude oil and condensate prices and differentials, natural gas spreads, basis and prices, NGLs, electricity prices, refined product and crack spread margins, as well as fluctuations in foreign exchange rates and interest rates. We may also use fixed-price commitments for the purchase or sale of crude oil, natural gas, NGLs and refined products. We may also use derivative instruments in various operational markets to help optimize our supply costs or sales of our production.

These hedging activities may expose us to risks which may cause significant loss. These risks include, but are not limited to: changes in the valuation of the hedge instrument being poorly correlated to the change in the valuation of the underlying exposures being hedged; change in price of the underlying commodity or market value of the instrument; lack of market liquidity; insufficient counterparties to transact with; counterparty default; deficiency in systems or controls; human error; and the unenforceability of contracts.

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 3, 37 and 38 of the Consolidated Financial Statements.

Risks Associated with Derivative Financial Instruments

Derivative financial instruments expose us to the risk that a counterparty may 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 financial instruments related to natural gas, 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, ability to fund share repurchases and/or dividends and 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 3, 37 and 38 of the 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.

In a rising commodity price environment, we expect to realize losses on our risk management activities but recognize gains on the underlying physical inventory sold in the period, and we expect the opposite to occur in a falling commodity price environment. In 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 changing benchmark prices.

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.

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices and foreign exchange rates, with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuations in commodity prices on our open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

As at December 31, 2022	**Sensitivity Range**	**Increase**	**Decrease**
Crude Oil Commodity Price	± US$10.00/bbl Applied to WTI, Condensate and Related Hedges	**1**	**(1)**
WCS and Condensate Differential Price[1]	± US$2.50/bbl Applied to Differential Hedges Tied to Production	**13**	**(13)**
WCS (Hardisty) Differential Price	± US$5.00/bbl Applied to WCS Differential Hedges Tied to Production	**(1)**	**1**
Refined Products Commodity Price	± US$10.00/bbl Applied to Heating Oil and Gasoline Hedges	**(2)**	**2**
Natural Gas Basis Price	± US$0.50/MCF Applied to Natural Gas Basis Hedges	**1**	**(1)**
Power Commodity Price	± C$20.00/Megawatt Hour Applied to Power Hedges	**113**	**(113)**
U.S. to Canadian Dollar Exchange Rate	± 0.05 in the U.S. to Canadian Dollar Exchange Rate	**14**	**(17)**

(1) Excludes WCS (Hardisty) differential.

For further information on our risk management positions, see Notes 37 and 38 of the Consolidated Financial Statements.

Exposure to Counterparties

In the normal course of business, we enter into contractual relationships with suppliers, partners, lenders, customers and other counterparties for the provision and sale of goods and services and also in connection with our hedging activities, and in respect of asset or securities acquisitions and dispositions. If such counterparties do not fulfill their contractual obligations on a timely basis or at all, we may suffer financial losses or delays of our development plans, or we may have to forego other opportunities, all of which could materially impact our business, results of operations and financial condition.

Credit, Liquidity and Availability of Future Financing

The future development of our business may be dependent on our ability to obtain additional capital, including, but not limited to, debt and equity financing. Among other things, unpredictable financial markets, a sustained commodity price downturn or significant unanticipated expenses, or a change in law, market fundamentals, our credit ratings, business operations or investor or lender policy or sentiment, may impede our ability to secure and maintain cost-effective financing. Stakeholders are increasingly considering ESG matters, including climate-related targets, and failure to achieve our emissions reduction targets, or the perception that our targets are insufficient or will not be achieved, could adversely affect our ability to access cost-effective capital. An inability to access capital, on terms acceptable to us or at all, could affect our ability to make future capital expenditures, to maintain desirable financial ratios and to meet all of our financial obligations as they come due, potentially resulting in a material adverse effect on our business, financial condition, results of operations, cash flows, ability to comply with various financial and operating covenants, credit ratings and reputation.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic, business, regulatory, market and other conditions, some of which are beyond our control. If our operating and financial results are not sufficient to service current or future indebtedness, we may take actions such as reducing or suspending share repurchases and/or dividends, reducing or delaying business activities, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional capital that could have less favourable terms.

Our liquidity risk is mitigated through actively managing cash and cash equivalents, cash flow provided by operating activities, available credit facility capacity, and accessing the capital markets.

We are required to comply with various financial and operating covenants under our credit facility and the indentures governing our debt securities. We routinely review our covenants to ensure compliance. In the event that we do not comply with such covenants, our access to capital could be restricted or repayment could be accelerated.

Credit Ratings

Our Company and our capital structure are regularly evaluated by credit rating agencies. Credit ratings are based on our financial and operational strength and a number of factors not entirely within our control, including but not limited to, conditions affecting the oil and gas industry generally, industry risks associated with the transition to a lower-carbon economy, and the general state of the economy. There can be no assurance that one or more of our credit ratings will not be downgraded or withdrawn entirely by a rating agency.

A reduction in any of our credit ratings, particularly a downgrade below investment grade ratings, or a negative change in the Company's credit ratings outlook could adversely affect the cost and availability of borrowing, and access to sources of liquidity and capital. A failure to maintain our current credit ratings could affect our business relationships with counterparties, operating partners and suppliers.

If one or more of our credit ratings falls below certain ratings thresholds, we may be obligated to post collateral in the form of cash, letters of credit or other financial instruments in order to establish or maintain business arrangements. Additional collateral may be required due to further downgrades below certain ratings thresholds. Failure to provide adequate credit risk assurance to counterparties and suppliers may result in foregoing or having contractual business arrangements terminated.

Foreign Exchange Rates

Fluctuations in foreign exchange rates between various currencies may affect our results, particularly the U.S./Canadian dollar and Chinese Yuan ("RMB")/Canadian dollar exchange rates. Global prices for crude oil, refined products, and natural gas are generally set in U.S. dollars, while many of our operating and capital costs are in Canadian dollars. A change in the value of the Canadian dollar, as a result of changing benchmark lending rates, macroeconomic factors or otherwise, relative to the U.S. dollar will increase or decrease revenues, as expressed in Canadian dollars, received from the sale of oil and refined products, and from some of our natural gas sales. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in our U.S. dollar denominated debt and related U.S. dollar interest expense, as expressed in Canadian dollars. A portion of our long-term sales contracts in Asia Pacific are priced in RMB. A change in the value of the Canadian dollar relative to RMB will increase or decrease revenues, as expressed in Canadian dollars, received from the sale of natural gas and NGLs in the region. We may periodically enter into transactions to manage our exposure to exchange rate fluctuations. However, the fluctuations in exchange rates are beyond our control and could have a material adverse effect on our cash flows, results of operations and financial condition.

Interest Rates

Market interest rates are impacted by actions taken by central banks to stabilize the economy and moderate inflation. Interest rates have increased in response to inflation and additional rate increases may be implemented. Increases in interest rates could increase our net interest expense and affect how certain liabilities are recorded, both of which could negatively impact our cash flow and financial results. Additionally, we are exposed to interest rate fluctuations upon the refinancing of maturing long-term debt and potential future financings at prevailing interest rates. We may periodically enter into transactions to manage our exposure to interest rate fluctuations.

Dividend Payments and Purchase of Securities

The payment of dividends, whether base, variable or preferred, 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 risks identified in the Risk Management and Risk Factors section of this MD&A. Specifically, in connection with Cenovus's 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 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 and Excess Free Funds Flow, amount of share buybacks and other factors inherent with our capital allocation framework from time to time and our Net Debt and Excess Free Funds Flow may vary from time to time as a result of, among other things, our business plans, results of operations, financial condition and impact of any of the risks identified in the Risk Management and Risk Factors section of this MD&A. 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 as the capital allocation framework, and any share repurchases and payment of dividends thereunder, remains at the discretion of our Board and is dependent on, among other things, the factors described above. 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.

Disclosure Controls and Procedures and Internal Control Over Financial Reporting ("ICFR")

Based on their inherent limitations, disclosure controls and procedures and ICFR may not prevent or detect misstatements, and even those controls determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on our business, financial condition, results of operations, cash flows and reputation.

Operational Risk

Operational Considerations (Safety, Environment and Reliability)

Our operations are subject to risks generally affecting the energy industry and normally incidental to: (i) the storing, transporting, processing and marketing of crude oil, refined products, natural gas, NGLs and other related products; (ii) drilling and completion of onshore and offshore crude oil and natural gas wells; (iii) the operation and development of crude oil and natural gas properties; and (iv) the operation of refineries, terminals, pipelines and other transportation and distribution facilities in the jurisdictions in which we conduct our business, including at facilities operated by our partners or third-parties. These risks include but are not limited to: the effects of government actions or regulations, policies and initiatives; encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; fires; explosions; blowouts; loss of containment; gaseous leaks; power outages; migration of harmful substances into water systems; releases or spills, including releases or spills from offshore operations, shipping vessels or other marine transport incidents; aviation, railcar or road transportation incidents; iceberg incidents; uncontrollable flows of crude oil, natural gas or well fluids; failure to follow operating procedures or operate within established operating parameters; adverse weather conditions; corrosion; pollution; freeze-ups and other similar events; the breakdown or failure of equipment, pipelines and facilities, information technology and systems and processes; regular or unforeseen maintenance; the performance of equipment at levels below those originally intended; railcar incidents or derailments; failure to maintain adequate supplies of spare parts; the compromise of information technology and control systems and related data; operator error; labour disputes; disputes with interconnected facilities and carriers; planned or unplanned operational disruptions or apportionment on third-party systems or refineries, which may prevent the full utilization of such party's facilities and pipelines; spills at truck terminals and hubs; spills associated with the loading and unloading of potentially harmful substances; loss of product; unavailability of feedstock; price and quality of feedstock; epidemics or pandemics; catastrophic events, including, but not limited to, war, adverse sea conditions, acts of activism, vandalism or terrorism, extreme weather events and natural disasters and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites.

If any such risks materialize, they may interrupt operations, impact our reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology and control systems, related data, cause environmental damage that may include polluting water, land or air, and may result in regulatory action, fines, penalties, civil suits or criminal or regulatory charges against us, any of which may have a material adverse effect on our business, financial condition, results of operations, cash flows and reputation.

In addition, our oil sands operations are susceptible to reduced production, slowdowns, shutdowns and restrictions on our ability to produce higher value products due to the interdependence of our component systems. Delineation of the resources, the costs associated with production, including drilling wells for SAGD operations, and the costs associated with refining oil can entail significant capital outlays. The operating costs associated with oil production are largely fixed in the short-term and, as a result, operating costs per unit are largely dependent on levels of production.

To partially mitigate our risks, we have policies and an associated system of standards, processes and procedures to identify, assess and mitigate safety, operational and environmental risk across our operations. In addition, we attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations. However, not all potential occurrences and disruptions in respect of our assets or operations are insured or are insurable, and it cannot be guaranteed that our insurance coverage will be available or sufficient to fully cover any claims that may arise from such occurrences or disruptions. The occurrence of an event that is not fully covered by our insurance program could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Market Access Constraints and Transportation Restrictions

Our production is transported through various pipelines, terminals and marine, rail and truck networks, and our refineries are reliant on various pipelines and marine, rail and truck networks to transport feedstock and refined products to and from our facilities. Increased tariffs or disruptions in, or restricted availability of, pipeline service and/or marine, rail or truck transport, could adversely affect crude oil, refined products, natural gas and NGLs sales, projected production growth, upstream or refining operations and cash flows.

Interruptions or restrictions in the availability of these pipeline, terminals, marine, rail and truck systems may also limit the ability to deliver production volumes and could adversely impact commodity prices, sales volumes and/or the prices received for our products. These interruptions and restrictions may be caused by, among other things, the inability of the pipeline or marine, rail or truck networks to operate, or may be related to capacity constraints if supply into the system exceeds the infrastructure capacity. There can be no certainty that investments in new pipeline projects will be made by applicable third-party pipeline providers, that any applications to expand capacity will receive the required regulatory approvals, or that any such approvals will result in the construction of the pipeline project, or that such projects would provide sufficient transportation capacity.

There is no certainty that rail, marine transport and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on the pipeline system. In addition, our rail, marine and truck shipments may be impacted by service delays, shortages of skilled labour, inclement weather, vessel, railcar or truck availability, railcar derailment or other rail, marine or truck transport incidents and could adversely impact sales volumes or the price received for product or impact our reputation or result in legal liability, loss of life or personal injury, loss of equipment or property, or environmental damage. In addition, rail, marine and trucking regulations are constantly being reviewed to ensure the safe operation of the supply chain. Should regulations change, the costs of complying with those regulations will likely be passed on to shippers and may adversely affect our ability to transport by-rail, marine or truck transport or the economics associated with such transportation. Finally, planned or unplanned shutdowns, outages or closures of our refineries or third-party systems or refineries may limit our ability to deliver product with negative implications on our business, financial condition, results of operations and cash flows.

Reserves Replacement and Reserve Estimates

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels. Our financial condition, results of operations and cash flows are highly dependent upon successfully producing from current reserves and acquiring, discovering or developing additional reserves. Exploring for, developing or acquiring reserves is capital intensive. To the extent our cash flow is insufficient to fund capital expenditures and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our crude oil and natural gas reserves will be impaired. In addition, we may be unable to find and develop or acquire additional reserves to replace our crude oil and natural gas production at acceptable costs.

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows and revenue derived therefrom are based on a number of variable factors and assumptions including, but not limited to: geological and engineering estimates; product prices; future operating and capital costs; historical production from the properties and the assumed effects of regulation by governmental agencies, including royalty payments and taxes, and environmental and emissions related regulations and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines, rail transportation and processing facilities, all of which may cause actual results to vary materially from estimated results.

All such estimates are uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenue expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves may vary from current estimates and such variances may be material.

Estimates with respect to reserves that may be developed and produced in the future are often based on volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based on production history will result in variations, which may be material, in the estimated reserves.

The production rate of oil and gas properties tends to decline as reserves are depleted while the associated operating costs increase. Maintaining an inventory of developable projects to support future production of crude oil and natural gas depends on, among other things: obtaining and renewing rights to explore, develop and produce oil and natural gas; drilling success; completing long-lead time capital intensive projects on budget and on schedule; and the application of successful exploitation techniques on mature properties. Our business, reputation, financial condition, results of operations and cash flows are highly dependent upon successfully producing current reserves and adding additional reserves.

Cost Management and Inflation

Development, operating and construction costs are affected by a number of factors including, but not limited to: development, adoption and success of new technologies; inflationary price pressure; changes in regulatory compliance costs; scheduling delays; interruptions to existing market access infrastructure; failure to maintain quality construction and manufacturing standards; equipment limitations, including the cost or availability of oil and gas field equipment; commodity prices; higher steam-oil ratios in our Oil Sands operations; additional government or environmental regulations and supply chain disruptions, including access to skilled labour and critical third-party services. In addition, if our development, operating, construction or labour costs were to become subject to significant inflationary pressures, we may not be able to fully offset such higher costs through corresponding increases in commodity prices. Further, there can be no assurance that any governmental action to mitigate inflationary cycles will be taken or will be effective. Central banks have increased interest rates in response to inflation and additional rate increases may be implemented. Governmental actions, such as the imposition of higher interest rates or wage controls may also negatively impact the Company’s costs and magnify the impacts of other risks identified in the Risk Management and Risk Factors section of this MD&A, including those set out under the “Financial Risk - Interest Rates” section above.

Continued inflation, any governmental response thereto, our inability to manage costs, or our inability to secure equipment, materials, skilled labour or third-party services necessary to our business activities for the expected price, on the expected timeline, or at all, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Competition

The Canadian and international energy industry is highly competitive in all aspects, including accessing capital, the exploration for, and the development of, new and existing sources of supply, the acquisition of crude oil and natural gas interests and the refining, distribution and marketing of oil and gas products. We compete with other producers, refiners and marketers, some of which may have lower operating costs or greater resources than our Company does. Competitors may develop and implement technologies which are superior to those we employ. The oil and gas industry also competes with other industries in supplying energy, fuel and related products to consumers, including renewable energy sources which may become more prevalent in the future. Cenovus may not be able to compete successfully against current and future competitors, and competitive pressures on Cenovus could have a material adverse effect on our business, reputation, financial condition, results of operations and cash flows.

Project Execution

We manage a variety of oil, natural gas and refining projects across our global portfolio of assets, including the current rebuild of our Superior Refinery and the restart of the West White Rose Project. The wide range of risks associated with project development and execution, as well as the commissioning and integration of new facilities with existing assets, can impact the economic viability of our projects. These risks include, but are not limited to: our ability to obtain the necessary environmental and regulatory approvals; our ability to obtain favourable terms or to be granted access within land-use agreements; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of supply chain disruptions; the impact of general economic, business and market conditions including inflationary pressures; the impact of weather conditions; risk related to the accuracy of project cost estimates; our ability to finance capital expenditures and expenses; our ability to source or complete strategic transactions; the effect of the COVID-19 pandemic on project execution and timelines; and the effect of changing government regulation and public expectations in relation to the impacts of oil and gas operations on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving performance targets and objectives. Failure to manage these risks could affect our safety and environmental record and have a material adverse effect on our financial condition, results of operations and cash flows and reputation.

Partner Risks

Some of our assets are not operated or controlled by us or are held in partnership with others, including through joint ventures. Therefore, our results of operations and cash flows may be affected by the actions of third-party operators or partners in areas where our ability to control and manage risks may be reduced. We rely on the judgment and operating expertise of our partners in respect of the development and operation of such assets and to provide information on the status of such assets and related results of operations; however, we are, at times, dependent upon our partners for the successful execution of various projects, their management of operational issues and their reporting.

Our partners may have objectives and interests that do not align with or may conflict with our interests. No assurance can be provided that our future demands or expectations relating to such assets will be satisfactorily met in a timely manner or at all. If a dispute with a partner or partners were to occur over the development and operation of a project or if a partner or partners were unable to fund their contractual share of the capital expenditures, a project could be delayed, and we could be partially or totally liable for our partner's share of the project. Should one of our partners become insolvent, we may similarly be directed by applicable regulators to carry out obligations on behalf of our partner and may not be able to obtain reimbursement for these costs. Failure to manage these partner risks could have a material adverse effect on our business, financial condition, results of operations, reputation, and cash flows.

SAGD Technology

Current technologies used for the recovery of bitumen is energy intensive, including SAGD which requires significant consumption of natural gas in the production of steam used in the recovery process. The amount of steam required in the recovery process varies and therefore impacts costs. The performance of the reservoir affects the timing and levels of production using SAGD technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on our business, financial condition, results of operations, and cash flows. There are risks associated with growth and other capital projects that rely largely or partly on new technologies, the incorporation of such technologies into new or existing operations, and acceptance of new technologies in the market. The success of projects incorporating new technologies cannot be assured.

Technology, Information Systems and Data Privacy

We rely heavily on technology, including operating technology and information technology, to effectively operate our business. This may include on premise systems (such as networks, computer hardware and software), networks and telecommunications systems, mobile applications, cloud services and other technology systems and services. Such systems and services may be provided by third parties. In the event we are unable to access, use, rely upon, secure, upgrade, and take other steps to maintain or improve the efficiency, resiliency and efficacy of such systems and services, the operation of such systems and services could be interrupted, resulting in operational interruptions or the loss, corruption, or release of data.

In the ordinary course of business, we collect, use and store sensitive data, including intellectual property, proprietary information, business information, and personal information. Despite our security measures, our technology systems and services may be vulnerable to attacks (such as by hackers, cyberterrorists or other third parties) or to disruptions from staff or third-party error or malfeasance, or natural disasters and acts of state or industrial espionage, activism, terrorism, or war. These risks also include, but are not limited to, cyber-related fraud or attacks such as attempts to circumvent electronic communications controls, impersonating internal personnel or business partners to divert payments and financial assets to accounts controlled by the perpetrators, or introducing ransomware into one or more systems or services to extract a payment, among others.

Any such incident, breach, or disruption of our or our service providers' technology systems or services, or other vendor technology systems or services (including where a threat actor is successful in bypassing our cyber-security measures and business process controls), could result in loss or the exposure of internal, confidential, financial, proprietary, personal or other sensitive information. These could result in financial losses, remediation and recovery costs, legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, operational disruption, site shut-down, leaks or other negative consequences, including damage to our reputation, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Data protection and privacy is governed by a complex legal and regulatory framework that is rapidly evolving in the areas in which we operate. We must comply with increasingly complex and rigorous, and sometimes conflicting, regulatory standards enacted to protect business and personal information in Canada, the United States, and elsewhere. These laws impose additional obligations on companies regarding the handling of personal information and provide certain individual privacy rights to persons whose information is collected, used, stored, processed or disclosed. Compliance with existing, proposed and recently enacted laws and regulations can be costly and time consuming, and any failure to comply with these regulatory standards could subject us to legal and reputational risks. Misuse of or failure to secure personal information could also result in violation of data privacy laws and regulations, proceedings against the Company by governmental entities or others, imposition of fines by governmental authorities and damage to our reputation and credibility and could have a negative impact on financial condition. Compliance with such legislation may also result in increased operating costs. Failure to comply with such legislation may result in severe fines and penalties, which may adversely impact our reputation, financial condition, results of operations and cash flows.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact our personnel, or those of partners, customers, and suppliers, and could result in situations of injury, loss of life, extortion, hostage situations and/or kidnapping or unlawful confinement, destruction or damage to property of Cenovus or others, impact to the environment, and business interruption. A security threat, terrorist attack or activist incident targeted at a facility, terminal, pipeline, rail or trucking network, office or offshore vessel/installation owned or operated by Cenovus or any of our systems, services, infrastructure, market access routes, or partnerships could result in the interruption or cessation of key elements of our operations. Outcomes of such incidents could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Activism and Disruptions to Operations

Increasing public engagement and activism generally, and in connection with the energy industry and the continued development of fossil fuel-based energy, has, from time to time, resulted in temporary disruptions to oil and gas development, operations and transportation. Such opposition has not yet materially impacted our facilities directly; however, activist groups and individuals may engage in protests, demonstrations or blockades that may disrupt our facilities or operations, or to facilities or operations on which we rely. Any such disruptions may have an adverse impact on our business, operations, financial condition or reputation.

While we have systems, policies and procedures designed to prevent or limit the effects of such disruptive events, there can be no assurance that these measures will be sufficient and that such disruptions will not occur or, if they do occur, that they will be adequately addressed in a timely manner.

Leadership and Talent

Our success is dependent upon our Management, our leadership capabilities and the quality and competency of our workforce. If we are unable to attract and retain key personnel and critical and diverse talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our business, financial condition, results of operations, and our ability to meet our leadership related ESG targets.

Litigation and Claims

From time to time, we may be involved in demands, disputes, proceedings, arbitrations and/or litigation ("Claims") arising out of or related to our operations and other contractual relationships. Claims may be material. Due to the nature of our operations we may be involved with various types of Claims including, but not limited to, failure to comply with applicable laws and regulations including potential claims that we have violated laws related to discrimination and harassment, health and safety, the environment, breach of contract, negligence, product liability, antitrust, bribery and other forms of corruption, tax, securities class actions, derivative actions, patent infringement, privacy, employment, labour relations, personal injury and other Claims. We may be required to incur substantial expenses or devote significant resources in respect of any such Claims, which could result in unfavourable judgments, decisions, fines, sanctions, monetary damages, temporary or permanent suspensions of operations, or the inability to engage in certain transactions. The outcome of such claims can be difficult to assess or quantify and may have a material adverse effect on our business, reputation, financial condition and results of operations and cash flows. In addition, we may be subject to or impacted by climate change related litigation, including class actions. See "Climate Change Related Litigation" below.

Indigenous Land and Rights Claims

Opposition by Indigenous people to our Company, our operations, development or exploration in the jurisdictions in which we conduct business may adversely impact us. Such impacts include impacts to our reputation, relationship with host governments, local communities and other Indigenous communities, diversion of Management's time and resources, increased legal, regulatory and other advisory expenses, and could adversely impact our progress and ability to explore, develop and continue to operate properties.

Some Indigenous groups have established or asserted Indigenous rights and may have treaty rights to portions of Canada. There are outstanding Indigenous and treaty rights claims, which may include land title claims, on lands where we operate, and such claims, if successful, could have a material adverse impact on our operations or pace of growth. No certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Some Indigenous groups have also brought private nuisance claims against project operators for infringement of Indigenous rights. Such claims, if successful, could adversely affect our business, results of operations, financial condition or reputation.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous rights or affect treaty rights and, in certain circumstances, accommodate their interests. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals.

In addition, the Canadian federal government passed legislation which requires it to take all necessary measures to implement the United Nations Declaration on the Rights of Indigenous Peoples ("UNDRIP"). Other Canadian jurisdictions have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is ongoing and uncertain; additional processes have been and are expected to continue to be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Governmental Risk

Shifts in government policy by existing administrations or following changes in government in jurisdictions in which we operate or elsewhere can impact our operations and ability to grow our business. Restrictions on fossil fuel-based energy use, cross-border economic activity, and development of new infrastructure can impact our opportunities for continued growth. We are committed to working with all levels of government in the jurisdictions in which we operate to ensure we remain competitive and risks are understood, and mitigation strategies are implemented; however, we cannot guarantee the outcomes of changes in government policy which may adversely affect our business, results of operations, financial condition or reputation.

Regulatory Risk

The oil and gas industry and refining industry in general and our operations in particular are subject to regulation and intervention under international, federal, provincial, territorial, state, regional and municipal legislation in the countries in which we conduct operations, development or exploration in matters such as, but not limited to: land tenure; permitting of production projects; royalties; taxes (including income taxes); government fees; production rates; environmental protection; protection of certain species or lands; cumulative effects and/or impacts from all types of industrial development; provincial and federal land and water use designations or management plans; the reduction of GHG and other emissions; the export of crude oil, natural gas and other products; the transportation of crude-by-rail, pipeline or marine transport; generation, handling, storage, transportation, treatment and disposal of hazardous substance; the awarding or acquisition of exploration, development and production rights, oil sands or other interests; the imposition of specific drilling obligations; control over the development, abandonment and reclamation of fields (including restrictions on production) and/or facilities; and possibly expropriation or cancellation of contract rights. The petroleum refining sector in the U.S. has been and continues to be subject to intensive environmental regulations, oversight, and enforcement from both federal and state governments. Third-party non-governmental organizations ("NGOs") and citizen groups can also directly influence environmental regulations and have been active against the U.S. refinery sector for many years. Any changes to the regulatory regime, including the implementation of new regulations or the modification or changed interpretation of existing regulations could impact our existing and planned projects requiring increased capital investment, operating expenses or compliance costs, which could adversely impact our financial condition, results of operations, cash flows and reputation. To mitigate these risks, we have regulatory programs that cover stakeholder engagement, air emissions, water quantity and quality, deep disposal well operations, solid and hazardous waste management, spills, and legacy contamination issues.

Regulatory Approvals

Our operations require us to obtain approvals from various regulatory authorities and there are no guarantees that we will be able to obtain and maintain, or obtain and maintain on acceptable conditions, all necessary licenses, permits and other approvals that may be required to carry out certain exploration, development and operating activities on our properties. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder consultation, Indigenous consultation, consensus seeking and collaboration, environmental impact assessments and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and habitat assessments; and other commitments or obligations. Failure to obtain applicable regulatory approvals or satisfy any conditions on a timely basis or satisfactory terms could result in increased costs, project delays, abandonment and/or restructuring of projects.

Abandonment and Reclamation Cost Risk

We are subject to oil and gas asset abandonment, remediation and reclamation ("A&R") liabilities for our operations, development and exploration, including those imposed by regulation under federal, provincial, territorial, state, regional and municipal legislation in the jurisdictions in which we conduct operations, development or exploration.

We maintain estimates of our A&R liabilities; however, it is possible that these costs may change materially before decommissioning due to regulatory changes, technological changes, ecological risks, acceleration of decommissioning timelines, and inflation, among other variables. For our Atlantic Canada offshore operations, the present value cost for decommissioning and abandonment of the offshore wells and facilities is estimated based on known regulations, procedures and costs today for undertaking the decommissioning, the majority of which is projected to be incurred in the late 2030s.

In Alberta and Saskatchewan, the A&R liability regimes include orphan well funds that are funded through a levy imposed on licensees, including Cenovus, based on the licensees' proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites. The aggregate value of the A&R liabilities assumed has increased in recent years and will remain at elevated levels until a significant number of orphaned wells are decommissioned utilizing the orphan funds. The Alberta and Saskatchewan regulators may seek additional funding for such liabilities from industry participants, including Cenovus.

The AER has discretion in the consideration of licence eligibility, transfer applications and the requirement to post security or carry out A&R work. Permit holders that are considered high risk and/or have relatively high levels of A&R obligations within their asset bases may be negatively impacted, including our potential counterparties. This may result in future insolvencies and additional orphaned assets. In addition, this may impact our ability to transfer our licences, approvals or permits, and may result in increased costs and delays or require changes to our abandonment of projects and transactions.

We have an ongoing environmental monitoring program of owned and leased retail locations, and former owned or leased retail locations where we have retained environmental liability, and perform remediation where required to comply with contractual and legal obligations. The costs of such remediation depend on a number of uncertain factors such as the extent and type of remediation required. Due to uncertainties inherent in the estimation process, it is possible that existing estimates may need to be revised and that conditions may exist at various retail locations that require future expenditures. Such future costs may not be determinable due to the unknown timing and extent of corrective actions that may be required.

The impact on our business of any legislative, regulatory or policy decisions relating to the A&R liability regulatory regime in the jurisdictions in which we conduct operations, development or exploration cannot be reliably or accurately estimated. Any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and materially and adversely affect, among other things, our business, financial condition, results of operations and cash flows.

Royalty Regimes

Our cash flows may be directly affected by changes to royalty regimes. The governments of the jurisdictions where we have producing assets receive royalties on the production of hydrocarbons from lands in which they respectively own the mineral rights and which we produce under agreement with each respective government. Government regulation of royalties is subject to change for a number of reasons, including, among other things, political factors. In Canada, there are certain provincial mineral taxes payable on hydrocarbon production from lands other than Crown lands. The potential for changes in the royalty and mineral tax regimes applicable in the jurisdictions in which we operate, or changes to how existing royalty regimes are interpreted and applied by the applicable governments, creates uncertainty relating to the ability to accurately estimate future royalty rates or mineral taxes and could have a significant impact on our business, financial condition, results of operations and cash flows. An increase in the royalty rates or mineral taxes in jurisdictions where we have producing assets would reduce our earnings and could make, in the respective jurisdiction, future capital expenditures or existing operations uneconomic and may reduce the value of our associated assets.

Canada-United States-Mexico Agreement (“CUSMA”)

On July 1, 2020, the new CUSMA entered into force, which is known in the United States as the United States-Mexico-Canada Agreement (or “USMCA”), replacing the North American Free Trade Agreement (“NAFTA”). The investor-state dispute settlement provisions that were present within NAFTA will no longer be available in the CUSMA to protect future investments of Canadians in the U.S. or U.S. investments in Canada. For three years after the termination of NAFTA, existing legacy investments will maintain their access to the investor-state dispute settlement under NAFTA Chapter 11. However, starting July 1, 2023, such legacy disputes and disputes related to investments established or acquired on after July 1, 2020 will fall to the appropriate courts in the United States, or Cenovus may seek intervention of the Canadian government to pursue relief through state-to-state dispute resolution.

Labour Risk

We depend on unionized labour for the operation of certain facilities and may be subject to adverse employee relations and labour disputes, which may disrupt operations at such facilities. As of December 31, 2022, approximately 7 percent of our employees are represented by unions under collective bargaining agreements, which includes just over 50 percent of our U.S. workforce. At unionized worksites, there is risk that strikes or work stoppages could occur. Any strike or work stoppage (for any reason, including a health and safety shutdown) may have a material adverse effect on our business, safety, reputation, financial condition, results of operations and cash flows.

During periods of contract negotiation or in the event of a strike or work stoppage, mitigation and emergency operation plans come with significant additional expenditures to ensure continuity of operations. In addition, we may not be able to renew or renegotiate collective bargaining agreements on satisfactory terms or at all and a failure to do so may increase our costs. Any renegotiation of our existing collective bargaining agreements may result in terms that are less favourable to us, which may materially and adversely affect our financial condition, results of operations and cash flows.

Moreover, employees who are not currently represented by unions may seek union representation in the future and efforts may be made from time to time to unionize other portions of our workforce. Future unionization efforts or changes in legislation and regulations may result in labour shortages, higher labour costs, as well as wage, benefit, and other employment consequences, especially during critical maintenance and construction periods, all of which may increase our costs, reduce our revenues or limit our operational flexibility.

International Developments and Geopolitical Risk

We are exposed to the financial and operational risks associated with uncertain international relations. Our business includes Asia Pacific assets in the South China Sea and the Madura Strait offshore Indonesia, and includes cooperation agreements with China National Offshore Oil Corporation or its subsidiaries (collectively, “CNOOC”), which also operates certain of these assets.

Political developments impacting international trade, including trade disputes, increased tariffs and sanctions, particularly between the U.S. and China and Canada and China, may negatively impact markets and cause weaker macroeconomic conditions or drive political or national sentiment, weakening demand for crude oil, natural gas and refined products. For example, U.S. government trade policy has resulted in, and could result in more, U.S. trading partners adopting responsive trade policy and may make it more difficult or costly for us to operate in and export our products to those countries.

We may be affected by changes to bilateral relationships, the frameworks and global norms that govern international trade, and other geopolitical developments. This includes acute shocks (such as civil unrest or sanctions) and chronic stresses (such as political or business disputes and other forms of conflict, including military conflict) that may pose longer-term threats to our business. Unilateral action by, or changes in relations between, countries in which we operate, including the U.S. and China, and such countries' approach to multilateralism and trade protectionism can impact our ability to access markets, technology, talent and capital. Disruptions or unanticipated changes of this nature may affect our ability to sell our products for optimum value or access inputs required for effective operations and has the potential to adversely affect our financial condition.

Increased tensions between the U.S. and China caused by escalated military exercises around Taiwan and the South China Sea could lead to geopolitical uncertainty in the area, which may negatively impact our China business and operations, and ultimately affect our financial condition.

Moreover, our operations may be materially adversely affected by political, economic or social instability or events, including the renegotiation or nullification of agreements and treaties, the imposition of onerous regulations, embargoes, sanctions, and fiscal policy, changes in laws governing existing operations, financial constraints, including currency restrictions and exchange rate fluctuations, unreasonable taxation and the behaviour of international public officials, joint venture partners or third-party representatives. Specifically, our Asia Pacific assets expose us to the effects of the changing U.S.-China, Canada-China and EU-China relations.

In response to foreign sanctions, China has enacted multiple blocking laws intended to diminish the effectiveness and impact of foreign trade sanctions. Specifically, China has enacted regulations granting itself the ability to unilaterally nullify the effects of certain foreign restrictions that are deemed to be unjustified to Chinese nationals and entities, which came into force on January 9, 2021. Additionally, on June 10, 2021, China enacted the Anti-Foreign Sanctions Law. The Anti-Foreign Sanctions Law grants the right to take corresponding countermeasures if a foreign country violates international law and basic norms of international relations or adopts discriminatory restrictive measures against Chinese nationals and entities, and interferes in China's internal affairs. The language of the Anti-Foreign Sanctions Law is very broad, and beyond the laws themselves, little guidance has been provided regarding how the blocking laws will be enforced by the Chinese government and effectuated through the private rights of action created by these laws. The breadth and lack of specificity of such laws create additional risk and uncertainty for foreign companies operating in China, as they may result in conflicting rules and regulations in home and host countries.

Although formal export restrictions imposed against China and Chinese entities (including the placement of CNOOC on the U.S. Department of Commerce's Entity List) have not so far had a material impact on our business activities in Asia, increased export restrictions on China and Chinese entities may limit the range of certain supplies to our operations in Asia and have an adverse effect on operational efficiency, results of operations, financial condition or reputation.

It is possible that additional related actions taken by the U.S. (and its trading partners and allies), Canada, China and other nations may limit or restrict foreign companies' ability to participate in projects and operate in certain sectors of the Chinese economy, including the energy sector. The nature, extent and magnitude of the effect of dynamic trade relations cannot be accurately predicted and may have a material adverse impact on our business, prospects, financial condition, and results of operations, cash flows, and reputation.

U.S. and Canadian sanctions and trade controls related to China do not currently prevent or significantly impair our offshore operations in Asia, but they could do so in the future, particularly if U.S. sanctions and trade controls against CNOOC were to be expanded. We cannot accurately predict the implementation of U.S. or Canadian policy affecting any current or future activities by CNOOC, Cenovus's other international partners or Cenovus. Similarly, we cannot accurately predict whether U.S. restrictions will be further tightened or the impact of government action on Cenovus's offshore operations in Asia. It is possible that the U.S. or Canadian government may subject CNOOC or Cenovus's other international partners to restrictions or sanctions that may adversely impact our offshore operations in Asia.

In addition, to the extent there are business disputes or legal claims involving our business in China, there is the potential for Cenovus personnel to be subject to an entry/exit ban in China. Moreover, it is possible that, as a result of our partnership with CNOOC, we may be subject to negative media attention which may affect investors' perception of Cenovus in Canada, the U.S. and globally, and which may negatively affect our share price and reputation.

Geopolitical events, such as a shift in the relationship, an escalation or imposition of sanctions, tariffs or other trade tensions between the U.S. and China and Canada and China, may affect the supply, demand and price of crude oil, natural gas and refined products and therefore our financial condition. The timing, extent and fallout of the ongoing tensions between the U.S. and China, as well as Canada and China remain uncertain and the impact on our business is unknown.

Shifts in global power relations may also introduce greater uncertainty with respect to issues requiring global co-ordination (such as climate change, trade agreements, tax regulation, freedom of navigation and technology regulation), as well as raise questions on the efficacy of and trust in international institutions, including those that underpin international trade. These types of changes may cause restrictions or impose costs on our business and may inhibit our future opportunities or affect our financial condition.

Our financial condition, operations and business may be adversely affected by any of the foregoing risks associated with international relations and specifically those risks arising from evolving U.S.-China, Canada-China and EU-China relations. The nature, extent and magnitude of the effect of dynamic trade relations on us cannot be accurately predicted and may have a material adverse impact on our business, prospects, financial condition, results of operations, cash flows, and reputation.

The War in Ukraine

Uncertainty regarding the duration and ultimate effects of the Russia – Ukraine war may result in major disruptions in oil and natural gas supply and continuing commodity price volatility. Further, Canada, the U.S. and other countries have imposed significant sanctions on Russia and many Russian officials, agencies, NGOs, companies and individuals some of whom are involved in the energy business or are significant buyers of crude oil or other hydrocarbons. Cenovus does not conduct business with sanctioned entities or persons and has no operations or significant business in Russia, Ukraine or other regions affected by these sanctions. Consequently, these sanctions have not had a material impact on Cenovus or our business. However, the scope and impact of the war, and any related international action, including any future sanctions, cannot be accurately predicted and may have a material adverse impact on our business, prospects, financial condition, results of operations, cash flows, and reputation.

Climate-Related Risks

There is growing international concern regarding climate change and a significant increase in focus on the timing and pace of the transition to a lower-carbon economy. Governments, financial institutions, insurance companies, NGOs, environmental and governance organizations, institutional investors, social and environmental activists, shareholders, and individuals, are increasingly seeking to implement, among other things, regulatory and policy changes, changes in investment patterns, and modifications in energy consumption habits and trends which, individually and collectively are intended to or have the effect of accelerating the reduction in the global consumption of fossil fuel-based energy, the conversion of energy usage to less carbon-intensive forms and the general migration of energy usage away from fossil fuel-based forms of energy.

Climate change and its associated impacts may increase our exposure to, and magnitude of, each of the risks identified in the Risk Management and Risk Factors section of this MD&A. Overall, we are not able to estimate at this time the degree to which climate change related regulatory, climatic conditions, and climate-related transition risks could impact our business, financial condition, and results of operations. Our business, financial condition, results of operations, cash flows, reputation, access to capital and insurance, cost of borrowing, ability to fund dividend payments and/or business plans may, in particular, without limitation, be adversely impacted as a result of climate change and its associated impacts.

Transition Risks – Policy & Legal

Climate Change Regulation

We operate in several jurisdictions that regulate or have proposed to regulate GHG emissions, often with a view to transitioning to a lower-carbon economy. Some of these regulations are in effect while others remain in various phases of review, discussion or implementation. Uncertainties exist relating to the timing and effects of these emerging regulations and other contemplated legislation, including how they may be harmonized, making it difficult to accurately determine the cost impacts. Additional changes to climate change legislation may adversely affect our business, financial condition, results of operations and cash flows, which cannot be reliably or accurately estimated at this time.

The Government of Canada has announced the carbon tax will increase to $170/tonne CO2e by 2030. To reach that level, the price imposed on carbon will rise from the 2022 rate of $50/tonne CO2e by $15/tonne CO2e each year until 2030. To the extent a province's carbon pricing system does not meet the federal stringency requirements, the federal "backstop" regulations apply. Most of our Canadian-based large emitting facilities operate in British Columbia, Alberta, Saskatchewan, or Newfoundland and Labrador where provincial carbon pricing regulations apply. These provincial programs are expected to continue to be deemed equivalent to the federal carbon pricing system.

In July 2022, the Government of Canada released an oil and gas emissions cap discussion document. The government is currently considering the form that any future regulation designed to meet the goals of the emission cap will take. The options proposed in the discussion document are a cap-and-trade system (under the Canadian Environmental Protection Act (“CEPA”) that sets a regulated limit on emissions from the sector or modifying the pollution pricing benchmark requirements to create price-driven limits on emissions from the oil and gas sector. The government is expected to release details on the form of the emissions cap in 2023. The Government has also committed to engaging provinces, territories, and Indigenous organizations in an interim review of the benchmark by 2026 after which, regulatory measures designed to meet the goals of the emissions cap could come into force.

The Government of Canada has implemented regulation to enable the reduction of methane emissions from the crude oil and natural gas sector by 40 percent to 45 percent from 2012 levels by 2025. Regulatory requirements for fugitive equipment leaks and venting from well completion and compressors came into force on January 1, 2020. Further restrictions on facility production venting restrictions and venting limits for pneumatic equipment came into force on January 1, 2023. Certain provinces have since implemented provincial methane regulations that have been found to be equivalent with federal requirements. The Government of Canada has announced an additional target to reduce oil and gas methane emissions by at least 75 percent below 2012 levels by 2030. In November 2022 the Government of Canada published for comment, a proposed regulatory framework to support their methane emissions reduction target. The proposal includes source by source requirements as well as additional performance-based requirements and is to be regulated under CEPA.

The U.S. does not have federal legislation establishing targets for the reduction of, or setting individualized limits on, GHG emissions from our U.S. facilities. The Renewable Fuel Standard ("RFS") was created to reduce GHG emissions and risks from that program are described below. Additionally, the federal Environmental Protection Agency ("EPA") has and may continue to promulgate regulations concerning the reporting and control of GHG emissions. Since 2010, the EPA's Greenhouse Gas Reporting Program ("GHGRP") requires any facility releasing more than 25,000 tonnes of CO_2e emissions per year to report those emissions on an annual basis. In addition to reporting direct CO_2e emissions, the GHGRP requires refineries to estimate the CO_2e emissions from the potential subsequent combustion of the refinery's products. In early 2021, the U.S. rejoined the Paris Agreement and subsequently announced a 2030 target to reduce GHG emissions by 50 percent to 52 percent from 2005 levels. It is expected that this target will be met largely through clean energy incentives introduced under the Inflation Reduction Act as opposed to regulatory measures.

Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, changes in environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, potentially increasing the cost of construction, operation and abandonment. Other possible effects from emerging regulations may also include but are not limited to: increased compliance costs; permitting delays; and substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses. Further, emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis, required emissions reductions may not be technically or economically feasible to implement, in whole or in part, and failure to have access to resources or technology to meet emissions reduction requirements or other compliance mechanisms may have a material adverse effect on our business resulting in, among other things, fines, permitting delays, penalties and the suspension of operations.

The extent and magnitude of any adverse impacts of current or additional programs or regulations beyond reasonably foreseeable requirements cannot be reliably or accurately estimated at this time, in part because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the timeframes for compliance. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to us.

Low Carbon Fuel Standards

Existing and proposed environmental legislation and regulation developed by certain U.S. states, Canadian provinces and territories, the Canadian federal government and members of the European Union, regulating carbon fuel standards could result in increased costs and reduced revenue for us. The potential regulation may negatively affect the marketing of our bitumen, crude oil or refined products, and may require us to purchase emissions credits in order to effect sales in such jurisdictions.

Environment and Climate Change Canada published final regulations in 2022 for the Clean Fuel Standard under the Canadian Environmental Protection Act, 1999. The Clean Fuel Standard will replace the current Renewable Fuels Regulations, which requires producers and importers of transportation fuels to acquire a certain number of compliance units commensurate with the volumes of fuel they produce or import. The new regulatory framework will impose lifecycle carbon intensity requirements for certain liquid fuels and establish rules relating to the trading of compliance credits. Carbon intensity requirements under the Clean Fuel Standard regulation become more stringent over time and are differentiated between different types of fuels to reflect the associated emissions reduction potential. Regulated parties have some flexibility with respect to how to achieve lower-carbon fuels in Canada. The cost of compliance will depend on a number of factors including, but not limited to, credit market supply and demand dynamics, development costs associated with low carbon fuels, and technology developments that could reduce demand for liquid transportation fuels. The Clean Fuel Standard regulation has the potential to impact our business, financial condition, results of operations and cash flows, though at this time it is difficult to predict or quantify any such impacts.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that impose stringent and costly requirements. The EPA has implemented the RFS program that mandates that a certain volume of renewable fuel replace or reduce the quantity of certain petroleum-based transportation fuels sold or introduced in the U.S. Obligated Parties, including refiners or importers of gasoline or diesel fuel, must achieve compliance with targets set by the EPA by blending certain types of renewable fuel into transportation fuel, or by purchasing renewable identification numbers (RINs) from other parties on the open market. RINs are credits used for compliance, and are the “currency” of the RFS program.

Cenovus and our refinery operating partners comply with the RFS by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market, where prices fluctuate. We cannot predict the future prices of RINs and renewable fuel blendstocks, and the costs to obtain the necessary RINs and blendstocks could be material. Our financial position, results of operations and cash flows may be materially impacted if we are required to pay significantly higher prices for RINs or blendstocks to comply with the RFS mandated standards. We have an RFS program to help mitigate risk related to fluctuating RINs pricing.

Light-Duty Vehicle Greenhouse Gas Emission Standards

The U.S. EPA has mandated federal GHG emissions standards applicable to automakers by setting fuel economy standards related to passenger cars and light trucks for Model Years 2023 through 2026. The EPA’s stated intention for the rule is to prompt automakers to produce more electric vehicles and set a path to a zero-emissions transportation future. The EPA stated that it intends to initiate future rulemaking to establish multi-pollutant emissions standards for Model Year 2027 and beyond. The impact these standards may have on the future demand (and corresponding price levels) for our products is unknown and dependent upon a number of factors. In addition, the Canadian federal government has published proposed regulated sales targets for electric vehicles. See “Climate Change Transition – Demand and Commodity Prices” below.

Climate Change Related Litigation

In recent years there has been an increase in climate change related demands, disputes, and litigation in various jurisdictions including the U.S. and Canada, asserting various claims, including that energy producers contribute to climate change, that such entities are not reasonably managing business risks associated with climate change, and that such entities have not adequately disclosed business risks of climate change. While many of the climate change related actions are in preliminary stages of litigation, and in some cases assert novel or untested causes of action, there can be no assurance that legal, societal, scientific and political developments will not increase the likelihood of successful climate change related litigation against energy producers, including Cenovus. The outcome of any such litigation is uncertain and may materially impact our business, financial condition or results of operations. We may also be subject to adverse publicity associated with such matters, which may negatively affect public perception and our reputation, regardless of whether we are ultimately found responsible. We may be required to incur significant expenses or devote significant resources in defense against any such litigation.

Transition Risks – Technology

We depend on, among other things, the availability and scalability of existing and emerging technologies to meet our business goals, including our ESG targets. Limitations related to the development, adoption and success of these technologies or the development of disruptive technologies could have a negative impact on our long-term business resilience.

Transition Risks – Market

Demand and Commodity Prices

The recent increase in focus on the timing and pace of the transition to a lower-carbon economy and resulting trends will likely affect global energy demand and usage, including the composition of the types of energy generally used by industry and individual consumers. Under certain aggressive low-carbon scenarios, potential demand erosion could contribute to commodity price fluctuations and structural commodity price declines. However, it is not currently possible to predict the timelines for, and precise effects of, this transition to a potential lower-carbon economy, which will depend on a multitude of factors including increased decarbonization policies, the ability to develop adequate alternative sources of energy, technology development and adaptation including in the area of transportation electrification, the ability to conceptualize, develop and commercialize technologies for the production, storage and distribution of adequate supplies of alternative energy, consumption patterns, global growth, industrial activity, weather patterns and climate conditions, including as a result of climate change. All of these factors are beyond our control and could result in a high degree of price volatility for each of crude oil, natural gas, NGLs, electricity and refined products.

Market Access

Opposition to new and expanded pipeline projects have been influenced by, among other things, concerns about GHG emissions associated with fossil fuel-based energy development and end-use combustion of fuels. Additional concerns about pipeline spills can create opposition to pipeline projects at a local level. Our inability to optimize market access for either the delivery of our production or refining feedstock may negatively impact our business, financial condition, cash flows and results of operations.

Access to Capital and Insurance

Capital markets are adjusting to the risks that climate change poses and as a result, our ability to access capital and secure adequate or prudent insurance coverage may also be adversely affected in the event that financial institutions, investors, credit rating agencies, lenders and/or insurers adopt more restrictive decarbonization policies. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of our insurance policies could increase substantially and/or coverage may be reduced or become unavailable. As a result, we may not be able to renew our existing policies or procure other desirable insurance coverage, either on commercially reasonable terms, or at all. Additionally, certain financial institutions have taken actions or announced policies related to decarbonization of their loan portfolios. As a result, costs of financing could increase over time and we may not be able to refinance our debt, renew or extend credit facilities or procure additional financing at reasonable costs and interest rates, or at all. The future development of our business may be dependent upon our ability to obtain additional capital, including debt and equity financing. See “Credit, Liquidity and Availability of Future Financing” above.

Accuracy of Climate Scenarios and Assumptions

We integrate the potential impact of GHG regulations and the cost of carbon at various price levels into our business planning processes. To mitigate uncertainty surrounding future emissions regulation, we evaluate our development plans under a range of carbon-constrained scenarios. We have considered the International Energy Agency (“IEA”) scenarios in our strategic planning for several years and also conduct ongoing assessments of both public and private scenarios. Although management believes that our climate-related estimates are reasonable, aligned with current, pending and potential future regulations, and informed by the IEA's climate scenarios, they are based on numerous assumptions that, if false, may have a material adverse effect on our business, financial condition and results of operations. Specifically, climate-related estimates influence our financial planning and investment decisions. Since we plan and evaluate opportunities partially on the basis of climate-related estimates, variations between actual outcomes and our expectations may have a material adverse effect on our business, financial condition, results of operations, reputation and cash flows.

Shareholder Activism

Shareholder activism has been increasing in the energy industry, and investors may from time to time attempt to effect changes to our business, governance, or reporting practices with respect to climate change or otherwise, whether by shareholder proposals, public campaigns, proxy solicitations or otherwise. Such actions could adversely impact our business by distracting our Board and employees from core business operations, requiring us to incur increased advisory fees and related costs, interfering with our ability to successfully execute on strategic transactions and plans and provoking perceived uncertainty about the future direction of our business. In the event such activist shareholders are successful, Cenovus may be required to incur costs and dedicate time to adopting new practices. Such perceived uncertainty may, in turn, make it more difficult to retain employees and could result in significant fluctuation in the market price of our securities.

Transition Risks – Reputation and Public Perception of the Oil and Gas Sector

Development of fossil fuel-based energy, and in particular the Alberta oil sands, has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous reconciliation. Concerns about oil sands may, directly or indirectly, impair the profitability of our current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory, economic and operating uncertainty. Increased public opposition to and stigmatization of the oil and gas sector, and in particular the oil sands industry, could lead to constrained access to insurance, liquidity and capital and changes in demand for our products, which may adversely impact our business, financial condition or results of operations.

For example, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources. See “Reputation Risk” below.

Climate Change – Physical Risks

Systemic climatic changes or extreme climatic conditions may also have material adverse effects on our business, reputation, financial condition, results of operations and cash flows. Weather and climate affect demand, and therefore, the predictability of the demand for energy is affected to a large degree by the predictability of weather and climate. In addition, our exploration, refining, pipeline, production and construction operations, and the operations of major customers and suppliers, can be affected by acute physical climate risks, such as floods, forest fires, earthquakes, hurricanes, storms, extreme temperatures and other extreme weather events or natural disasters. This may result in cessation or diminishment of production or throughput, delay of exploration and development activities or delay of plant construction.

Climate change may also increase the frequency of severe weather conditions that may adversely impact our operations, business and financial results. For example, our Atlantic operations may be impacted by severe weather conditions, including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased creation of icebergs. Icebergs off the coast of Newfoundland and Labrador pose a risk to Atlantic oil production facilities. An operational incident as a result of severe weather conditions, has the potential to result in spills, asset damage, and production or refining disruption. Climate change may result in an increased level of risk resulting in increased or additional mitigation requirements.

Our other operations are also subject to chronic physical risks such as a shorter timeframe for our winter drilling program, changes in the water table and reduced access to water due to drought conditions. A systemic change in temperature or precipitation patterns could result in more challenging conditions for the construction of ice roads, execution of our winter drilling program and reclamation activities and could reduce the availability of water due to the increasing likelihood of drought conditions.

Environmental Regulation Risks

All phases of our operations are subject to environmental regulation pursuant to a variety of federal, provincial, territorial, state, regional and municipal laws, and regulations in the jurisdictions in which we operate (collectively, the “environmental regulations”). Environmental regulations provide that exploration areas, wells, facility sites, refineries and other properties and practices associated with our operations be constructed, operated, maintained, abandoned, reclaimed, and undertaken in accordance with the requirements set out therein. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications.

We anticipate that further changes in environmental legislation will occur, which may result in approval delays for critical licences and permits, stricter standards and enforcement, larger fines and liabilities, the introduction of emissions limits, increased compliance costs and increased costs for closure, controls on land and resource access, reclamation, and ecological restoration. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to our business.

Compliance with environmental regulations requires significant expenditures. Our future capital expenditures and operating expenses could continue to increase as a result of, among other things, developments in our business, operations, plans and objectives and changes to existing, or implementation of new, environmental regulations. Failure to comply with environmental regulations may result in, among other things, the imposition of fines, penalties, environmental protection orders, suspension of operations, prosecution, and could adversely affect our reputation. The costs of complying with environmental regulations and remedying noncompliance issues may have a material adverse effect on our business, financial condition, results of operations and cash flows. The implementation of new environmental regulations or changes in interpretation or the modification of existing environmental regulations affecting the crude oil, natural gas, NGL and refining industry generally could reduce demand for our products as well as shift hydrocarbon demand toward relatively lower-carbon sources and affect our long-term prospects.

U.S. environmental regulations and aggressive enforcement from regulators present challenges and risks to our U.S. operations. New emission standards, more stringent water quality standards, and regulation of emerging contaminants such as Per- and Polyfluoroalkyl Substances ("PFAS") can increase compliance costs, require capital projects, lengthen project implementation times, and have an adverse effect on our business, financial condition, results of operations and cash flows. U.S. regulators have proposed that certain PFAS be characterized as a regulatory defined hazardous waste, which could lead to additional cleanup liability at U.S. sites. See “Water Regulation” below.

Canadian Species at Risk Act

The Canadian federal Species at Risk Act, as well as provincial regulation regarding threatened or endangered species and their habitat may limit the pace and the amount of development or activity in areas identified as critical habitat for species of concern, such as woodland caribou. Recent petitions and litigation against the federal government in relation to their obligations under the Species at Risk Act have raised issues associated with the protection of species at risk and their critical habitat both federally and on a provincial level. In Alberta, a suite of initiatives has been undertaken to support caribou recovery, including the conservation agreements under the Species at Risk Act and the elaboration of sub-regional plans. If plans and actions undertaken by the provinces are deemed insufficient to support caribou recovery, the federal legislation includes the ability to implement measures that would preclude further development or modification of existing operations. The extent and magnitude of any potential adverse impacts of legislation on in situ oil sands project development and operations cannot be estimated, as uncertainty exists as to whether plans and actions undertaken by the provinces will be sufficient to support caribou recovery.

Canadian Federal Air Quality Management System

The Multi Sector Air Pollutants Regulations (“MSAPR”), issued under the Canadian Environmental Protection Act, 1999, seek to protect the environment and health of Canadians by setting mandatory, nationally consistent air pollutant emission standards. The MSAPR are aimed at equipment-specific Base-Level Industrial Emissions Requirements (“BLIERs”). Nitrogen oxide BLIERs from our non-utility boilers, heaters and stationary engines are regulated in accordance with specified performance standards. We anticipate that the MSAPR will result in adverse impacts to Cenovus including but not limited to capital investment required to retrofit existing equipment and increased operating costs.

Canadian Ambient Air Quality Standards (“CAAQS”) for nitrogen dioxide, sulphur dioxide, fine particulate matter and ozone were introduced as part of a national Air Quality Management System. Provinces may implement the CAAQS at the regional air zone level and air zone management actions may include more stringent emissions standards applicable to industrial sources from approval holders in regions where we operate that may result in adverse impacts including but not limited to capital investment related to retrofitting existing facilities and increased operating costs.

Review of Environmental and Regulatory Processes

Increased environmental assessment obligations imposed by federal, provincial, territorial, state and municipal governments in the jurisdictions in which we conduct operations, development or exploration may create risk of increased costs and project development delays. The regulatory frameworks within the jurisdictions where we operate are constantly evolving and changing and may become more onerous or costly which may impede our ability to economically develop our resources. The extent and magnitude of any adverse impacts of changes to the regulatory framework on project development and operations cannot be estimated at this time.

The Impact Assessment Agency of Canada leads and coordinates federal impact assessments for all designated projects within Canada. Assessment considerations beyond the environment expressly include health, economic, social, and gender impacts, as well as considerations related to sustainability and Canada’s climate change commitments. For as long as the Alberta provincial government maintains the cap on oil sands emissions in Alberta and the cap has not been reached, our in-situ oil sands projects should be exempted from the application of the federal impact assessment system, provided a number of additional conditions are met. However, other types of projects would undergo a federal assessment, including those within our Atlantic operations.

Water Regulation

We utilize fresh water in certain operations, which is obtained under licenses issued within each respective jurisdiction’s regulations. If water use fees increase, the terms of the licences change or there are reductions in the amount of water available for our use, production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial condition. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. There is no assurance that if we require new licences or amendments to existing licences, that these licences or amendments will be granted on favourable terms. This may adversely affect our business, including the ability to operate our assets and execute development plans.

Our U.S. refineries are subject to water discharge requirements that necessitate treatment of wastewater prior to discharging. Permits for discharging water are renewed from time to time to incorporate new water quality standards and may require modifications and expansion of water treatment facilities at the sites. Pollutants such as selenium, total dissolved solids, arsenic, mercury, and others may require advanced wastewater treatment, and discharge levels will depend on the types of crude processed at our refineries. Non-compliance with permit limits can lead to enforcement actions by regulators including issuance of fines, orders to upgrade treatment plants, and suspension of operations. Federal and state regulators in the U.S. are currently addressing the emerging pollutant PFAS in water discharge permits by requiring installation of additional wastewater treatment units and requiring monitoring of PFAS in discharges.

Hydraulic Fracturing

Certain stakeholders have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and suggest that additional federal, provincial, territorial, state, regional and/or municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process.

In addition, some areas of British Columbia and Alberta have experienced increased localized frequency of seismic activity which has been associated with oil and gas operations. Although the occurrence of seismicity in relation to oil and gas operations is generally very low, it has been linked to deep disposal of wastewater in the U.S. and has been correlated with hydraulic fracturing in conjunction with horizontal drilling techniques in Western Canada, which has prompted legislative and regulatory initiatives intended to address these concerns.

New laws, regulations or permitting requirements regarding hydraulic fracturing may lead to limitations or restrictions to oil and gas development activities, operational delays, increased compliance costs, additional operating requirements, or increased third-party or governmental claims resulting in increased cost of doing business as well as impacting the amount of natural gas and oil that we are ultimately able to produce from our reserves.

Cenovus ESG Focus Areas, Targets and Ambitions

We have set ambitious, achievable targets for each of our five ESG focus areas, as discussed below, including reducing our absolute emissions, decreasing freshwater intensity, reclaiming more land, supporting Indigenous reconciliation and increasing the number of women in leadership positions. To achieve these goals and to respond to changing market demand, we may incur additional costs and invest in new technologies and innovation. It is possible that the return on these investments may be less than we expect, which may have an adverse effect on our business, financial condition and reputation.

Generally, our ESG targets and ambitions depend significantly on our ability to execute our current business strategy, which can be impacted by the numerous risks and uncertainties associated with our business and the industry in which we operate, as outlined in the Risk Management and Risk Factors section of this MD&A. We recognize that our ability to adapt to and succeed in a lower-carbon economy will be compared against our peers. Investors and stakeholders increasingly compare companies based on ESG-related performance, including climate-related performance. Failure to achieve our ESG targets and ambitions, or a perception among key stakeholders that our ESG targets and ambitions are insufficient or unattainable, could adversely affect our reputation and our ability to attract capital and insurance coverage.

There is also a risk that some or all of the expected benefits and opportunities of achieving the various ESG targets and ambitions may fail to materialize, may cost more to achieve or may not occur within the anticipated time periods. In addition, there are risks that the actions we take in implementing targets and ambitions relating to our ESG focus areas may have a negative impact on our existing business and increase capital expenditures, which could have a negative impact on our future operating and financial results.

Climate and GHG Emissions Target and Ambition

We have set a target to reduce our absolute scope 1 and 2 GHG emissions by 35 percent by year-end 2035 from 2019 levels and have a long-term ambition to achieve net zero emissions from our operations by 2050. Our ability to meet our 2035 GHG reduction target and 2050 net zero ambition are subject to numerous risks and uncertainties and our actions taken in implementing such target and ambition may also expose us to certain additional and/or heightened financial and operational risks. Furthermore, our long-term ambition of reaching net zero emissions by 2050 is inherently less certain due to the longer timeframe and certain factors outside of our control, including the commercial application of future technologies that may be necessary for us to achieve this long-term ambition.

A reduction in GHG emissions relies on, among other things, our ability to develop, access and implement commercially viable and scalable emission reduction strategies and related technology and products. In addition, there are other operational risks that may hinder our ability to successfully meet our GHG emission targets and goals, including: unexpected impediments to, or effects of, the implementation of methane abatement and electrification initiatives in our Conventional segment; the purchase of renewable electricity; the unavailability of, or limited benefits from, technology that is expected to be commercially viable in the near term and its associated future benefits, including SAGD enhancement technologies, such as solvent-aided process and solvent-driven process technologies, carbon capture, utilization and storage technology and downhole technology improvements; and a failure to capture the anticipated benefits of continued technological development, and industry collaboration and innovation to find solutions to reduce costs and GHG emissions. If we are unable to implement these strategies and technologies as planned without negatively impacting our expected operations or cost structure, or such strategies or technologies do not perform as expected, we may be unable to meet our 2035 GHG reduction target or 2050 net zero emissions ambition on the planned timelines, or at all.

In addition, achieving our 2035 GHG reduction target and 2050 net zero ambition relies on a stable regulatory framework, support from government, financial or otherwise, and will require capital expenditures and company resources, with the potential that actual costs may differ from our original estimates and the differences may be material. Furthermore, the cost of investing in emissions-reduction technologies, and the resultant change in the deployment of resources and focus, could have a negative impact on our business, financial condition, results of operations and cash flows.

Water Stewardship Targets

Our ability to reduce freshwater intensity by 20 percent in oil sands and in thermal operations from 2019 levels by year-end 2030 or maintain such improvements will depend on the commercial viability and scalability of relevant water reduction strategies and related steam and water usage technology and products. There are risks associated with relying largely or partly on new technologies, the incorporation of such technologies into new or existing operations and acceptance of new technologies in the market. In the event we are unable to effectively and efficiently deploy the necessary technology, or such strategies or technologies do not perform as expected, achieving our stated target of reducing our water intensity could be interrupted, delayed or abandoned.

Biodiversity Targets

Our biodiversity targets include the goal to reclaim 3,000 decommissioned well sites by year-end 2025 and to restore more habitat than we use within the Cold Lake caribou range by year-end 2030. Our ability to meet these targets is subject to various environmental and regulatory risks, which could impose significant costs, restrictions, liabilities, and obligations on us. See “Abandonment and Reclamation Cost Risk” above. In addition, an increase in operating costs, changes to market conditions and access to additional capital, if needed, could result in our inability to fund, and ultimately meet, our biodiversity targets on the current timelines, or at all.

Indigenous Reconciliation Targets

Our Indigenous reconciliation targets to spend a minimum of $1.2 billion with Indigenous owned or operated businesses between 2019 and year-end 2025 and attain Progressive Aboriginal Relations gold certification from the Canadian Council for Aboriginal Business by year-end 2025 are subject to a number of financial, operational and efficiency risks relating to actions taken in implementing such targets.

In addition, a failure or delay in achieving our Indigenous reconciliation targets may adversely affect our relationship with neighboring Indigenous businesses and communities and our broader reputation. If we are unable to maintain a positive relationship with Indigenous communities near our operations, our progress and ability to develop and operate properties in line with our current business and operational strategies may be adversely impacted.

Inclusion and Diversity Targets

Our inclusion and diversity focus area includes a target of women in leadership roles of at least 30 percent by year-end 2030 as well as an aspiration for our Board to have at least 40 percent representation from women, Indigenous peoples, persons with disabilities and members of visible minorities among non-management directors. Efforts to meet and maintain such targets may increase the time and costs associated with appointing and replacing key personnel. Further, an inability to hire or promote qualified candidates or a failure or delay in achieving our targets may influence our reputation with our stakeholders, attract litigation and impact recruitment initiatives. There are also risks associated with the collection of certain personal data in furtherance of these targets.

Reputation Risk

We rely on our reputation to build and maintain positive relationships with investors and other stakeholders, to recruit and retain staff, and to be a credible, trusted company. Any actions we take that influence public or key stakeholder opinions have the potential to impact our reputation, which may adversely affect our share price, development plans and ability to continue operations. There is increasing opposition from climate change activist organizations and the public towards oil and gas operations. See “Transition Risks – Reputation and Public Perception of the Oil and Gas Sector” above.

Other Risks

Dilutive Effect

We are authorized to issue, among other classes of shares, an unlimited number of common shares for consideration and on terms and conditions as established by our Board without the approval of our shareholders in certain instances. Any future issuances of Cenovus common shares or other securities exercisable or convertible into, or exchangeable for, Cenovus common shares may result in dilution to present and prospective Cenovus shareholders. The issuance of additional Cenovus common shares upon exercise, from time to time, of securities convertible into Cenovus common shares will have a further dilutive effect on the ownership interest of shareholders of Cenovus. Such issuances will have a dilutive effect on Cenovus's earnings per share, which could adversely affect the market price of Cenovus common shares and may adversely impact the value of our shareholders' investments.

It is also expected that, from time to time, we will grant additional equity awards to our employees and directors under our compensation plans. These additional equity awards will have a further dilutive effect on our earnings per share, which could also negatively affect the market price of Cenovus common shares and may adversely impact the value of our shareholders' investments.

Risks Relating to Acquisitions

We have completed, and may complete in the future, one or more acquisitions for various strategic reasons. Our ability to achieve the benefits of any acquisition will depend upon the actions of our counterparties; our ability, and the ability of our counterparties, to obtain the necessary shareholder, regulatory and third-party approvals, as applicable, and satisfy all conditions to closing; the risks inherent in the operation of the assets being acquired prior or subsequent to closing; the effectiveness of our diligence investigations; the physical condition of the assets upon closing; our ability to obtain indemnities and/or fund ongoing maintenance, repair and operation costs of the assets acquired; our ability to assess the integrity and reliability of the assets being acquired; our ability to successfully consolidate functions and integrate operations, procedures and personnel in a timely and efficient manner and to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with our existing assets and operations. The integration of acquired assets and operations requires the dedication of management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during the process. The integration process may result in the disruption of ongoing business and customer relationships that may adversely affect our ability to achieve the anticipated benefits of such acquisitions. Acquiring assets requires the assessment of their characteristics, including, among other things, estimated recoverable reserves, future production and throughput, commodity prices, revenues, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain and, as such, the acquired properties may not produce as expected, may not have the anticipated reserves and may be subject to increased costs and liabilities. Although the acquired assets are reviewed prior to completion of an acquisition, such reviews are not capable of identifying all existing or potentially adverse conditions. This risk may be magnified where the acquired assets are in geographic areas where we have not historically operated. Further, we may not be able to obtain or realize upon contractual indemnities from a seller for liabilities created prior to an acquisition and we may be required to assume the risk of the physical condition of the properties that may not perform in accordance with its expectations or require repair or other expenditures, the scope of which may be uncertain, result in increased costs and affect our ability, and timeline, to realize the benefits of the acquisition.

Risks Relating to Dispositions

We have completed, and may complete in the future, one or more dispositions for various strategic reasons. Various factors could materially affect our ability to dispose of assets in the future, including stock exchange, regulatory, third-party and corporate approvals, counterparties' ability to fulfill their obligations under agreements to affect dispositions, commodity prices, the availability of purchasers willing to purchase certain assets at prices and on terms acceptable to us, associated asset retirement obligations, due diligence, favourable market conditions, and the assignability of joint venture, partnership or other arrangements. These factors may also reduce the proceeds or value to our business. We may also retain certain liabilities for or agree to indemnification obligations in a sale transaction. The magnitude of any such retained liabilities or indemnification obligations may be difficult to quantify at the time of the transaction and could ultimately be material. Further, certain third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after the sale of certain assets, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the purchaser of the assets fails to perform its obligations. Should any of the risk associated with dispositions materialize, it could have an adverse effect on our business, financial condition or reputation.

Risks Related to Significant Shareholders of Cenovus

As of December 31, 2022, Hutchison Whampoa Europe Investments S.à r.l. ("Hutchison") and L.F. Investments S.à r.l. ("L.F. Investments") owned 16.6 percent and 12.1 percent of our common shares, respectively. The sale into the market of Cenovus common shares held by either Hutchison or L.F. Investments, whether through open market trades on the TSX or NYSE, through privately arranged block trades or pursuant to prospectus offerings made in accordance with the respective registration rights agreement that each of Hutchison and L.F. Investments has entered into with Cenovus, or market perception regarding Hutchison's or L.F. Investments' intention to sell Cenovus common shares, could adversely affect market prices for our common shares. While Hutchison and L.F. Investments are each subject to certain voting covenants pursuant to the terms of a standstill agreement they each entered into with Cenovus, each of Hutchison and L.F. Investments may be able to impact certain matters requiring Cenovus shareholder approval.

Market for Cenovus Warrants

There can be no assurance that an active public market for Cenovus Warrants will be sustained. If such a market is sustained, the market price of the Cenovus Warrants may be adversely affected by a variety of factors relating to Cenovus's business, including, but not limited to, fluctuations in our operating and financial results, the results of any public announcements made by us and our failure to meet analysts' expectations. In addition, the market price of the Cenovus common shares will significantly affect the market price of the Cenovus Warrants. This may result in significant volatility in the market price of the Cenovus Warrants and may negatively impact the value of the Cenovus Warrants.

Contingent Payments Payable relating to Sunrise Acquisition

In connection with the Sunrise Acquisition, we agreed to make contingent payments to BP Canada under certain circumstances. The amount of contingent payments vary depending on the Canadian dollar WCS price from time to time during the two-year period following the closing of the Sunrise Acquisition (August 31, 2022), and such payments are cumulatively capped at $600 million. This payment may be material in any given reporting period as the entire maximum payment could be reached in a single quarter and could have an adverse impact on our results of operations and financial condition.

Tax Laws

Income tax laws and regulations and other laws and government incentive programs may in the future be changed or interpreted in a manner that adversely affects us, our financial results and our shareholders. Tax authorities having jurisdiction over Cenovus may disagree with the manner in which we calculate our tax liabilities such that its provision for income taxes may not be sufficient, or such authorities could change their administrative practices to Cenovus's detriment or to the detriment of our shareholders. In addition, all of our tax filings are subject to audit by tax authorities who may disagree with such filings in a manner that adversely affects Cenovus and our shareholders.

The international tax environment continues to change as a result of tax policy initiatives and reforms under consideration related to the Base Erosion and Profit Shifting ("BEPS") project of the Organisation for Economic Co-operation and Development ("OECD"). Although the timing and methods of implementation vary, numerous countries including Canada have responded to the BEPS project by implementing, or proposing to implement, changes to tax laws and tax treaties at a rapid pace. These changes may increase our cost of tax compliance and affect our business, financial condition and results of operations in a manner that is difficult to quantify. We will continue to monitor and assess potential adverse impacts on our global tax situation as a result of the BEPS project.

In Canada, in the 2022 Fall Economic Statement released by the Department of Finance, a new tax on share buybacks by public corporations was proposed. Under the proposal, which would come into force on January 1, 2024, a two percent corporate-level tax would apply on the "net value" of all types of shares buybacks by public corporations in Canada. While there are few details available on the proposed tax, we will continue to monitor and assess any potential adverse impacts as more information becomes available.

A discussion of additional risks, should they arise after the date of this MD&A, which may impact our business, prospects, financial condition, results of operations and cash flows, and in some cases our reputation, can be found in our subsequently filed MD&A, available on SEDAR at sedar.com, on EDGAR at sec.gov and at cenovus.com.

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 Consolidated Financial Statements.

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 the Company's Consolidated Financial Statements.

Joint Arrangements

The classification of a joint arrangement that is held in a separate vehicle as either a joint operation or a joint venture requires judgment. Cenovus has a 50 percent interest in the following jointly controlled entities:

- WRB Refining LP ("WRB").
- BP-Husky Refining LLC ("Toledo").

It was determined that Cenovus has the rights to the assets and obligations for the liabilities of WRB and Toledo. As a result, the joint arrangements are classified as joint operations and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

Prior to August 31, 2022, Cenovus held a 50 percent interest in Sunrise, which was jointly controlled with BP Canada and met the definition of a joint operation under IFRS 11, "Joint Arrangements". As such, Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the Sunrise Acquisition, Cenovus controls Sunrise, as defined under IFRS 10, "Consolidated Financial Statements" ("IFRS 10") and, accordingly, Sunrise was consolidated.

In determining the classification of its joint arrangements under IFRS 11, "Joint Arrangements", the Company considered the following:

- The original intention of the joint arrangements was to form an integrated North American heavy oil business. Partnerships are "flow-through" entities.
- The agreements require the partners to make contributions if funds are insufficient to meet the obligations or liabilities of the corporation and partnerships. The past development of Sunrise, and the past and future development of WRB and Toledo, is dependent on funding from the partners by way of capital contribution commitments, notes payable and loans.
- WRB has third-party debt facilities to cover short-term working capital requirements. Up until November 2022, Sunrise also had third-party debt facilities.
- Sunrise was operated like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants in accordance with the partnership agreement. WRB and Toledo have very similar structures modified to account for the operating environment of the refining business.
- Cenovus, Phillips 66 and BP, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage, on the partners' behalf as the agreements prohibit the partners from undertaking these roles themselves. In addition, the joint arrangements do not have employees and, as such, are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Exploration and Evaluation Assets

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's internal approval process.

Identification of Cash-Generating Units

CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretation. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company's upstream, refining, crude-by-rail, railcars, storage tanks and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses and impairment reversals.

Recoveries from Insurance Claims

The Company uses estimates and assumptions on the amount recorded for insurance proceeds that are reasonably certain to be received. Accordingly, actual results may differ from these estimated recoveries.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that, if changed, could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

The evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could change assumptions used to determine the recoverable amount of the Company's PP&E and E&E assets and could affect the carrying value of those assets, may affect future development or viability of exploration prospects, may curtail the expected useful lives of oil and gas assets thereby accelerating depreciation charges and may accelerate decommissioning obligations increasing the present value of the associated provisions. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain. Environmental considerations are built into our estimates through the use of key assumptions used to estimate fair value including forward commodity prices, forward crack spreads and discount rates. The energy transition could impact the future prices of commodities. Pricing assumptions used in the determination of recoverable amounts incorporate markets expectations and the evolving worldwide demand for energy.

Changes to assumptions could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test recoverable amount and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands, Conventional and Offshore segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses. Recoverable amounts for the Company's manufacturing assets, crude-by-rail terminal and related ROU assets use assumptions such as throughput, forward commodity prices, discount rates, operating expenses and future capital expenditures. Recoverable amounts for the Company's real estate ROU assets use assumptions such as real estate market conditions which includes market vacancy rates and sublease market conditions, price per square footage, real estate space availability and borrowing costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence of liabilities and estimate the future value. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit-adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Fair Value of Assets Acquired and Liabilities Assumed in a Business Combination

The fair value of assets acquired, liabilities assumed and assets given up in a business combination, including contingent consideration and goodwill, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparable transactions and discounted cash flows. For the Company's upstream assets, key assumptions in the discounted cash flow models used to estimate fair value include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses. Estimated production volumes and quantity of reserves and resources for acquired oil and gas properties were developed by internal geology and engineering professionals and IQREs. For manufacturing assets, key assumptions used to estimate fair value include throughput, forward commodity prices, discount rates, operating expenses and future capital expenditures. Changes in these variables could significantly impact the carrying value of the net assets acquired.

Income Tax Provisions

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2022.

New Accounting Standards and Interpretations not yet Adopted

There are new accounting standards, amendments to accounting standards and interpretations that are effective for annual periods beginning on or after January 1, 2023, and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2022. These standards and interpretations are not expected to have a material impact on the Company's Consolidated Financial Statements or the Company's business.

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 December 31, 2022. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2022.

The effectiveness of our ICFR was audited as at December 31, 2022 by PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, as stated in their Report of Independent Registered Public Accounting Firm, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2022.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ADVISORY

Oil and Gas Information

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

Forward-looking Information

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

This forward-looking information is identified by words such as "anticipate", "believe", "capacity", "commit", "continue", "could", "estimate", "expect", "focus", "forecast", "future", "may", "objective", "opportunities", "option", "plan", "potential", "project", "progress", "scheduled", "seek", "strive", "target", and "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: Cenovus's key priorities for 2023 and beyond, including safety and operational performance, sustainability leadership, cost leadership, financial discipline and Free Funds Flow growth and returns-focused capital allocation; the focus of our 2023 budget; cost control; maximizing, growing or enhancing shareholder value and/or returns; returning incremental capital to shareholders beyond the base dividend; allocating and paying out Excess Free Funds Flow under the capital allocation framework; deleveraging the balance sheet; a lower risk profile; opportunistic share repurchases and variable dividend distributions; safety performance and culture; the Company's targets for each of its five ESG focus areas; Free Funds Flow generation, allocation, pay out and growth through commodity pricing cycles; upstream production and downstream throughput; the generation of predictable and stable cash flow; reduced risk and cash flow volatility; optimizing Cenovus's asset portfolio; funding near-term cash requirements and meeting payment obligations; gains and losses from risk management; maintaining investment grade credit ratings; Net Debt targets; disciplined capital allocation; ensuring sufficient liquidity through all stages of the economic cycle; strengthening and maintaining a strong balance sheet; flexibility in both high and low commodity price environments; managing capital structure; Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio; cost savings; cost structures and market optimization; interest expense; improving efficiencies to drive incremental capital, operating and general and administrative cost reductions; shortening and optimizing the value chain; reducing condensate costs associated with heavy oil transportation; maintaining the Company's capital program and sustaining the base dividend at US$45 WTI per barrel; mitigating the impact of volatility in light-heavy crude oil differentials; partially mitigating the impact of exposure to various prices for commodities and associated price differentials and refining margins; managing upstream production rates in response to pipeline capacity constraints, voluntary and mandated production curtailments and crude oil differentials; the timing of the restart of the Superior Refinery and achieving processing capacity; returning to normal processing rates at the Wood River Refinery; variable payments in respect of the Sunrise acquisition; 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; drilling activity, asset integrity and emissions initiatives in the conventional segment; initial production and exploration of new fields or projects; financial resilience; adjusting capital and operating spending, drawing down on credit facilities or repaying existing debt, issuing new debt, or issuing new shares; future capital investment, including for: portfolio adjustments, the impact of inflation, maintaining safe and reliable operations, sustaining Oil Sands production, sustaining drilling programs in the conventional segment, the Superior Refinery rebuild project, the Terra Nova ALE project and White Rose project, progressing the Narrows Lake tie-back to Christina Lake, refining operations and reliability and debottlenecking in our downstream assets, increasing heavy crude oil conversion capacity; the Company's exposure to light-heavy oil differentials regardless of crude oil production; the status and timing of closing the Toledo Acquisition and ramp up of throughput; applying the Company's operating model at Sunrise and adding to production from the Sunrise Acquisition; 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; 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 return to the field of the floating, production, storage and offloading unit for the Terra Nova ALE project and the resumption of production; first gas production from the MAC and MDK fields; drilling development wells and construction of production facilities and production therefrom; liabilities from legal proceedings; the Company's ability to partially mitigate the impact of commodity differentials; and the Company's outlook for commodities and the Canadian dollar, including the influences thereon, 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 acquisitions; the accuracy of any assessments undertaken in connection with acquisitions; forecast production and throughput volumes and timing thereof; 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 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; collaboration with the government, Pathways Alliance and other industry organizations; alignment of realized WCS and WCS prices used to calculate the variable payment to BP Canada; market and business conditions; forecast inflation and other assumptions inherent in the Company's 2023 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.

2023 guidance, as updated December 5, 2022, and available on cenovus.com, assumes: Brent prices of US$83.00 per barrel, WTI prices of US$77.00 per barrel; WCS of US$54.50 per barrel; Differential WTI-WCS of US$22.50 per barrel; AECO natural gas prices of $4.85 per thousand cubic feet; Chicago 3-2-1 crack spread of US$26.50 per barrel; and an exchange rate of $0.75 US$/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 COVID-19 workplace policies; the Company's ability to realize the anticipated benefits of acquisitions in a timely manner or at all; unforeseen or underestimated liabilities associated with 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 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 variable payment to BP Canada; 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 at facilities operated by our partners or third parties, such as blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, iceberg collisions, 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, adverse sea conditions, extreme weather events, natural disasters, acts of activism, 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 downstream operations 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 and diverse talent; possible failure to obtain and retain qualified leadership and personnel, and equipment in a timely and cost efficient manner; changes in labour demographics and relationships, including with any unionized workforces; unexpected abandonment and reclamation costs; changes in the regulatory frameworks, permits and approvals in any of the locations in which the Company operates or to any of the infrastructure upon which it relies; government actions or regulatory initiatives to curtail energy operations or pursue broader climate change agendas; changes to regulatory approval processes and land use designations, royalty, tax, environmental, GHG, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on the Company's business, its financial results and Consolidated Financial Statements; changes in general economic, market and business conditions; the impact of production agreements among OPEC and non-OPEC members; the political, social and economic conditions in the jurisdictions in which the Company operates or supplies; the status of the Company's relationships with the communities in which it operates, including with Indigenous communities; the occurrence of unexpected events such as protests, pandemics, war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, shareholder proposals and regulatory actions against the Company. In addition, there are risks that the effect of actions taken by us in implementing targets, commitments and ambitions for ESG focus areas may have a negative impact on our existing business, growth plans and future results from operations.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of the Company's material risk factors, see Risk Management and Risk Factors in this MD&A, and 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 AND DEFINITIONS

The following abbreviations and definitions 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		
OPEC	Organization of Petroleum Exporting Countries		
OPEC+	OPEC and a group of 10 non-OPEC members		
FPSO	Floating production storage and offloading unit		

Scope 1 emissions are direct GHG emissions from owned or operated facilities by the reporting company. This includes emissions from fuel combustion, venting, flaring, industrial processes and fugitive leaks from equipment. Cenovus accounts for emissions on a gross operatorship basis. The Company also reports its net-equity share of emissions from all of its assets.

Scope 2 emissions are indirect GHG emissions associated with the purchase or acquisition of electricity, steam, heat, or cooling for use at the owned or operated facility.

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 Arrangement Integration Costs, Adjusted Funds Flow, Adjusted Funds Flow Per Share – Basic, Adjusted Funds Flow Per Share – Diluted, Free Funds Flow, Excess Free Funds Flow, Gross Margin, Refining Margin, Unit Operating Expense, Per Unit DD&A 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.

	Upstream			Downstream			Total		
($ millions)	**2022**	2021 (1)	2020	**2022**	2021 (2)	2020	**2022**	2021 (1) (2)	2020
Revenues									
Gross Sales	**41,127**	27,844	9,708	**38,102**	26,258	4,815	**79,229**	54,102	14,523
Less: Royalties	**4,868**	2,454	371	**—**	—	—	**4,868**	2,454	371
	36,259	25,390	9,337	**38,102**	26,258	4,815	**74,361**	51,648	14,152
Expenses									
Purchased Product	**6,833**	4,059	1,530	**32,501**	23,111	4,429	**39,334**	27,170	5,959
Transportation and Blending	**12,194**	8,714	4,764	**—**	—	—	**12,194**	8,714	4,764
Operating	**3,789**	3,241	1,476	**3,050**	2,258	785	**6,839**	5,499	2,261
Realized (Gain) Loss on Risk Management	**1,619**	788	268	**112**	104	(21)	**1,731**	892	247
Operating Margin	**11,824**	8,588	1,299	**2,439**	785	(378)	**14,263**	9,373	921

	2022											
	Upstream				Downstream				Total			
	Three Months Ended				Three Months Ended				Three Months Ended			
($ millions)	**Q4**	Q3	Q2	Q1 (1)	**Q4**	Q3 (2)	Q2 (2)	Q1 (2)	**Q4**	Q3 (2)	Q2 (2)	Q1 (1) (2)
Revenues												
Gross Sales	**8,307**	10,238	11,685	10,897	**8,380**	10,887	10,719	8,116	**16,687**	21,125	22,404	19,013
Less: Royalties	**875**	1,226	1,582	1,185	**—**	—	—	—	**875**	1,226	1,582	1,185
	7,432	9,012	10,103	9,712	**8,380**	10,887	10,719	8,116	**15,812**	19,899	20,822	17,828
Expenses												
Purchased Product	**1,157**	2,397	1,461	1,818	**7,071**	9,694	8,919	6,817	**8,228**	12,091	10,380	8,635
Transportation and Blending	**2,962**	2,800	3,238	3,194	**—**	—	—	—	**2,962**	2,800	3,238	3,194
Operating	**955**	915	1,010	909	**759**	780	866	645	**1,714**	1,695	1,876	1,554
Realized (Gain) Loss on Risk Management	**134**	51	563	871	**(8)**	(77)	87	110	**126**	(26)	650	981
Operating Margin	**2,224**	2,849	3,831	2,920	**558**	490	847	544	**2,782**	3,339	4,678	3,464

(1) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

(2) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no impact to total downstream Operating Margin or total Operating Margin.

($ millions)	2021											
	Upstream [1]				Downstream [2]				Total [1] [2]			
	Three Months Ended				Three Months Ended				Three Months Ended			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues												
Gross Sales [1]	8,237	7,354	6,128	6,125	8,010	7,422	6,226	4,600	16,247	14,776	12,354	10,725
Less: Royalties	815	733	533	373	—	—	—	—	815	733	533	373
	7,422	6,621	5,595	5,752	8,010	7,422	6,226	4,600	15,432	14,043	11,821	10,352
Expenses												
Purchased Product [1]	1,198	1,074	717	1,070	7,223	6,600	5,410	3,878	8,421	7,674	6,127	4,948
Transportation and Blending [1]	2,599	2,137	2,006	1,972	—	—	—	—	2,599	2,137	2,006	1,972
Operating	865	800	791	785	689	537	515	517	1,554	1,337	1,306	1,302
Realized (Gain) Loss on Risk Management	202	168	188	230	56	17	10	21	258	185	198	251
Operating Margin	2,558	2,442	1,893	1,695	42	268	291	184	2,600	2,710	2,184	1,879

(1) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

(2) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no impact to total downstream Operating Margin or total Operating Margin.

Operating Margin by Asset

	Three Months Ended December 31, 2022			Year Ended December 31, 2022		
($ millions)	Asia Pacific	Atlantic	Offshore [1]	Asia Pacific	Atlantic	Offshore [2]
Revenues						
Gross Sales	**359**	**86**	**445**	**1,442**	**578**	**2,020**
Less: Royalties	**20**	**1**	**21**	**80**	**(3)**	**77**
	339	**85**	**424**	**1,362**	**581**	**1,943**
Expenses						
Transportation and Blending	**—**	**3**	**3**	**—**	**15**	**15**
Operating	**26**	**58**	**84**	**114**	**204**	**318**
Operating Margin	**313**	**24**	**337**	**1,248**	**362**	**1,610**

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

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

	Three Months Ended December 31, 2021			Year Ended December 31, 2021		
($ millions)	Asia Pacific	Atlantic	Offshore [1]	Asia Pacific	Atlantic	Offshore [2]
Revenues						
Gross Sales	377	143	520	1,342	440	1,782
Less: Royalties	26	8	34	79	29	108
	351	135	486	1,263	411	1,674
Expenses						
Transportation and Blending	—	5	5	—	15	15
Operating	29	44	73	103	136	239
Operating Margin	322	86	408	1,160	260	1,420

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

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

Total Arrangement Integration Costs

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

	Year Ended December 31,	
($ millions)	**2022**	2021
Integration Costs [1]	**90**	349
Capitalized Integration Costs [2]	**5**	53
Total Arrangement Integration Costs	**95**	402

(1) See Note 8 of the Consolidated Financial Statements.
(2) Included in capital expenditures on the 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. Adjusted Funds Flow Per Share – Basic is defined as Adjusted Funds Flow divided by the basic weighted average number of shares. Adjusted Funds Flow Per Share – Diluted is defined as Adjusted Funds Flow divided by the diluted weighted average number of shares.

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 was a new metric as of June 30, 2022.

	2022				2021			
($ millions)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Cash From (Used in) Operating Activities	**2,970**	4,089	2,979	1,365	2,184	2,138	1,369	228
(Add) Deduct:								
Settlement of Decommissioning Liabilities	**(49)**	(55)	(27)	(19)	(35)	(38)	(18)	(11)
Net Change in Non-Cash Working Capital	**673**	1,193	(92)	(1,199)	271	(166)	(430)	(902)
Adjusted Funds Flow	**2,346**	2,951	3,098	2,583	1,948	2,342	1,817	1,141
Capital Investment	**1,274**	866	822	746	835	647	534	547
Free Funds Flow	**1,072**	2,085	2,276	1,837	1,113	1,695	1,283	594
Add (Deduct):								
Base Dividends Paid on Common Shares	**(201)**	(205)	(207)	(69)	(70)	(35)	(36)	(35)
Dividends Paid on Preferred Shares	**—**	(9)	(8)	(9)	(8)	(9)	(8)	(9)
Settlement of Decommissioning Liabilities	**(49)**	(55)	(27)	(19)	(35)	(38)	(18)	(11)
Principal Repayment of Leases	**(74)**	(78)	(75)	(75)	(78)	(70)	(77)	(75)
Acquisitions, Net of Cash Acquired	**(7)**	(389)	(1)	—	—	—	—	(7)
Proceeds From Divestitures	**45**	407	112	950	247	83	100	5
Payment on Divestiture of Assets	**—**	—	(50)	—	—	—	—	—
Excess Free Funds Flow	**786**	1,756	2,020	2,615	1,169	1,626	1,244	462

($ millions)	Year Ended December 31, 2022	2021	2020
Cash From (Used in) Operating Activities	**11,403**	5,919	273
(Add) Deduct:			
Settlement of Decommissioning Liabilities	**(150)**	(102)	(42)
Net Change in Non-Cash Working Capital	**575**	(1,227)	198
Adjusted Funds Flow	**10,978**	7,248	117
Capital Investment	**3,708**	2,563	841
Free Funds Flow	**7,270**	4,685	(724)

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 December 31, 2022

($ millions)	Basis of Refining Margin Calculation: Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Manufacturing [2]
Revenues	905	240	1,145	627	1,772
Purchased Product	574	170	744	580	1,324
Gross Margin	331	70	401	47	448

Operating Statistics	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Throughput (Mbbls/d)	68.4	25.9	94.3
Refining Margin ($/bbl)	52.60	29.36	46.21

Three Months Ended September 30, 2022 [3][4]

($ millions)	Basis of Refining Margin Calculation: Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Manufacturing [2]
Revenues	999	387	1,386	782	2,168
Purchased Product	747	286	1,033	714	1,747
Gross Margin	252	101	353	68	421

Operating Statistics	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Throughput (Mbbls/d)	71.3	27.2	98.5
Refining Margin ($/bbl)	38.33	40.33	38.88

(1) Includes ethanol operations, crude-by-rail operations and the commercial fuels business.
(2) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.
(3) Comparative information has been represented for the Canadian Manufacturing refining margins to include marketing activities.
(4) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no impact to total downstream Operating Margin or total Operating Margin.

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [2]	Total Canadian Manufacturing [3] [4]
	Three Months Ended June 30, 2022 [1]				
	Basis of Refining Margin Calculation				
Revenues	**1,162**	**243**	**1,405**	**840**	**2,245**
Purchased Product	**1,012**	**210**	**1,222**	**760**	**1,982**
Gross Margin	**150**	**33**	**183**	**80**	**263**

	Operating Statistics		
	Lloydminster Upgrader	**Lloydminster Refinery**	**Lloydminster Upgrader and Lloydminster Refinery Total**
Heavy Crude Oil Throughput (Mbbls/d)	**64.6**	**16.3**	**80.9**
Refining Margin ($/bbl)	**25.54**	**22.22**	**24.87**

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [2]	Total Canadian Manufacturing [3] [4]
	Three Months Ended March 31, 2022 [1]				
	Basis of Refining Margin Calculation				
Revenues	**756**	**186**	**942**	**665**	**1,607**
Purchased Product	**585**	**143**	**728**	**605**	**1,333**
Gross Margin	**171**	**43**	**214**	**60**	**274**

	Operating Statistics		
	Lloydminster Upgrader	**Lloydminster Refinery**	**Lloydminster Upgrader and Lloydminster Refinery Total**
Heavy Crude Oil Throughput (Mbbls/d)	**70.7**	**27.4**	**98.1**
Refining Margin ($/bbl)	**26.98**	**17.33**	**24.28**

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [2]	Total Canadian Manufacturing [3]
	Year Ended December 31, 2022				
	Basis of Refining Margin Calculation				
Revenues	**3,822**	**1,056**	**4,878**	**2,914**	**7,792**
Purchased Product	**2,918**	**809**	**3,727**	**2,662**	**6,389**
Gross Margin	**904**	**247**	**1,151**	**252**	**1,403**

	Operating Statistics		
	Lloydminster Upgrader	**Lloydminster Refinery**	**Lloydminster Upgrader and Lloydminster Refinery Total**
Heavy Crude Oil Throughput (Mbbls/d)	**68.7**	**24.2**	**92.9**
Refining Margin ($/bbl)	**36.04**	**27.91**	**33.92**

(1) Comparative information has been represented for the Canadian Manufacturing refining margins to include marketing activities.
(2) Includes ethanol operations, crude-by-rail operations and the commercial fuels business.
(3) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.
(4) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no impact to total downstream Operating Margin or total Operating Margin.

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [2]	Total Canadian Manufacturing [3] [4]
	Three Months Ended December 31, 2021 [1]				
	Basis of Refining Margin Calculation				
Revenues	1,044	205	1,249	607	1,856
Purchased Product	887	172	1,059	529	1,588
Gross Margin	157	33	190	78	268

	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
	Operating Statistics		
Heavy Crude Oil Throughput (Mbbls/d)	80.4	27.9	108.3
Refining Margin ($/bbl)	21.26	12.77	19.07

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [2]	Total Canadian Manufacturing [3] [4]
	Year Ended December 31, 2021 [1]				
	Basis of Refining Margin Calculation				
Revenues	3,245	816	4,061	2,154	6,215
Purchased Product	2,698	659	3,357	1,799	5,156
Gross Margin	547	157	704	355	1,059

	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
	Operating Statistics		
Heavy Crude Oil Throughput (Mbbls/d)	79.0	27.5	106.5
Refining Margin ($/bbl)	18.96	15.60	18.09

(1) Comparative information has been represented for the Canadian Manufacturing refining margins to include marketing activities.

(2) Includes ethanol operations, crude-by-rail operations and the commercial fuels business.

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

(4) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no impact to total downstream Operating Margin or total Operating Margin.

U.S. Manufacturing

($ millions)	Three Months Ended December 31, 2022	2021
Revenues [1]	**6,608**	6,154
Purchased Product [1]	**5,747**	5,635
Gross Margin	**861**	519
Crude Oil Throughput (Mbbls/d)	**379.2**	361.6
Refining Margin ($/bbl)	**24.70**	15.63

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

($ millions)	Year Ended December 31, 2022	2021	2020
Revenues [1]	**30,310**	20,043	4,733
Purchased Product [1]	**26,112**	17,955	4,429
Gross Margin	**4,198**	2,088	304
Crude Oil Throughput (Mbbls/d)	**400.8**	401.5	185.9
Refining Margin ($/bbl)	**28.70**	14.25	4.47

(1) Found in Note 1 of the 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 and exclude risk management activities. 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

		Adjustments					Basis of Netback Calculation
Three Months Ended December 31, 2022 ($ millions)	Total Upstream [1]	Condensate	Third-Party Sourced	Internal Consumption [2]	Equity Adjustment [3]	Other [4]	Total Upstream
Gross Sales	8,307	(2,415)	(1,063)	(349)	77	(123)	4,434
Royalties	875	—	—	—	27	(1)	901
Purchased Product	1,157	—	(1,063)	—	—	(94)	—
Transportation and Blending	2,962	(2,415)	—	—	—	(4)	543
Operating	955	—	—	(349)	15	(11)	610
Netback	2,358	—	—	—	35	(13)	2,380
Realized (Gain) Loss on Risk Management	134	—	—	—	—	—	134
Operating Margin	2,224	—	—	—	35	(13)	2,246

		Adjustments					Basis of Netback Calculation
Three Months Ended December 31, 2021 ($ millions)	Total Upstream [1]	Condensate	Third-Party Sourced	Internal Consumption [2]	Equity Adjustment [3]	Other [4]	Total Upstream
Gross Sales [5]	8,237	(2,201)	(1,079)	(241)	62	(146)	4,632
Royalties	815	—	—	—	29	—	844
Purchased Product [5]	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

(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 have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.*

Year Ended December 31, 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	41,127	(10,307)	(6,524)	(1,170)	271	(429)	22,968
Royalties	4,868	—	—	—	116	(12)	4,972
Purchased Product	6,833	—	(6,524)	—	—	(309)	—
Transportation and Blending	12,194	(10,307)	—	—	—	(39)	1,848
Operating	3,789	—	—	(1,170)	36	(39)	2,616
Netback	13,443	—	—	—	119	(30)	13,532
Realized (Gain) Loss on Risk Management	1,619	—	(8)	—	—	—	1,611
Operating Margin	11,824	—	8	—	119	(30)	11,921

Year Ended December 31, 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)	27,844	(7,095)	(3,761)	(710)	224	(390)	16,112
Royalties	2,454	—	—	—	52	—	2,506
Purchased Product (5)	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

Year Ended December 31, 2020 ($ 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)	9,708	(3,452)	(1,559)	—	(295)	(58)	4,344
Royalties	371	—	—	(1)	—	—	370
Purchased Product (5)	1,530	—	(1,559)	—	—	29	—
Transportation and Blending	4,764	(3,452)	—	1	—	—	1,313
Operating	1,476	—	—	—	(295)	(72)	1,109
Netback	1,567	—	—	—	—	(15)	1,552
Realized (Gain) Loss on Risk Management	268	—	—	—	—	—	268
Operating Margin	1,299	—	—	—	—	(15)	1,284

(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 have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

Oil Sands

Three Months Ended December 31, 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	1,282	1,453	222	745	3,702	4	3,706
Royalties	338	344	13	88	783	1	784
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	255	157	42	39	493	—	493
Operating	194	221	60	257	732	3	735
Netback	495	731	107	361	1,694	—	1,694
Realized (Gain) Loss on Risk Management							59
Operating Margin							1,635

Three Months Ended December 31, 2022 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	**Condensate**	**Third-party Sourced**	**Other [2]**	**Total Oil Sands [3]**
Gross Sales	3,706	2,415	500	110	6,731
Royalties	784	—	—	—	784
Purchased Product	—	—	500	94	594
Transportation and Blending	493	2,415	—	14	2,922
Operating	735	—	—	(2)	733
Netback	1,694	—	—	4	1,698
Realized (Gain) Loss on Risk Management	59	—	—	—	59
Operating Margin	1,635	—	—	4	1,639

Three Months Ended December 31, 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	1,304	1,441	189	903	3,837	4	3,841
Royalties	280	345	7	102	734	—	734
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	166	140	28	42	376	—	376
Operating	184	194	39	230	647	6	653
Netback	674	762	115	529	2,080	(2)	2,078
Realized (Gain) Loss on Risk Management							202
Operating Margin							1,876

Three Months Ended December 31, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	**Condensate**	**Third-party Sourced**	**Other [2]**	**Total Oil Sands [3]**
Gross Sales [4]	3,841	2,201	537	138	6,717
Royalties	734	—	—	—	734
Purchased Product [4]	—	—	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

Year Ended December 31, 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	6,723	7,951	950	3,967	19,591	18	19,609
Royalties	1,783	2,244	59	390	4,476	6	4,482
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	814	588	135	149	1,686	—	1,686
Operating	870	898	193	960	2,921	20	2,941
Netback	3,256	4,221	563	2,468	10,508	(8)	10,500
Realized (Gain) Loss on Risk Management							1,527
Operating Margin							8,973

(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 have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

Year Ended December 31, 2022 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	**Condensate**	**Third-party Sourced**	**Other** (2)	**Total Oil Sands** (3)
Gross Sales	19,609	10,307	4,501	358	34,775
Royalties	4,482	—	—	11	4,493
Purchased Product	—	—	4,501	309	4,810
Transportation and Blending	1,686	10,307	—	43	12,036
Operating	2,941	—	—	(11)	2,930
Netback	10,500	—	—	6	10,506
Realized (Gain) Loss on Risk Management	1,527	—	—	—	1,527
Operating Margin	8,973	—	—	6	8,979

Year Ended December 31, 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	4,341	5,115	616	3,212	13,284	13	13,297
Royalties	767	1,078	20	330	2,195	1	2,196
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	686	526	111	207	1,530	—	1,530
Operating	701	700	157	858	2,416	21	2,437
Netback	2,187	2,811	328	1,817	7,143	(9)	7,134
Realized (Gain) Loss on Risk Management							786
Operating Margin							6,348

Year Ended December 31, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales (4)	13,297	7,095	2,106	329	22,827
Royalties	2,196	—	—	—	2,196
Purchased Product (4)	—	—	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

Year Ended December 31, 2020 ($ millions)	Basis of Netback Calculation		
	Foster Creek	Christina Lake	Total Oil Sands
Gross Sales	1,859	2,194	4,053
Royalties	95	235	330
Purchased Product	—	—	—
Transportation and Blending	667	565	1,232
Operating	558	551	1,109
Netback	539	843	1,382
Realized (Gain) Loss on Risk Management			268
Operating Margin			1,114

Year Ended December 31, 2020 ($ millions)	Basis of Netback Calculation	Adjustments				
	Total Oil Sands	Condensate	Third-party Sourced	Inventory Write-down (5)	Other (2)	Total Oil Sands (3)
Gross Sales (4)	4,053	3,452	1,290	—	9	8,804
Royalties	330	—	—	1	—	331
Purchased Product (4)	—	—	1,290	—	(28)	1,262
Transportation and Blending	1,232	3,452	—	(1)	—	4,683
Operating	1,109	—	—	—	47	1,156
Netback	1,382	—	—	—	(10)	1,372
Realized (Gain) Loss on Risk Management	268	—	—	—	—	268
Operating Margin	1,114	—	—	—	(10)	1,104

(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 have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.
(5) Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold. These amounts are net of inventory write-down reversals.

Conventional

	Basis of Netback Calculation	Adjustments		
Three Months Ended December 31, 2022 ($ millions)	Conventional	Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	555	563	13	1,131
Royalties	69	—	1	70
Purchased Product	—	563	—	563
Transportation and Blending	47	—	(10)	37
Operating	135	—	3	138
Netback	304	—	19	323
Realized (Gain) Loss on Risk Management	75	—	—	75
Operating Margin	229	—	19	248

	Basis of Netback Calculation	Adjustments		
Three Months Ended December 31, 2021 ($ millions)	Conventional	Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	450	542	8	1,000
Royalties	47	—	—	47
Purchased Product	—	542	—	542
Transportation and Blending	17	—	—	17
Operating	128	8	(2)	134
Netback	258	(8)	10	260
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	258	(8)	10	260

	Basis of Netback Calculation	Adjustments		
Year Ended December 31, 2022 ($ millions)	Conventional	Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	2,238	2,023	71	4,332
Royalties	297	—	1	298
Purchased Product	—	2,023	—	2,023
Transportation and Blending	147	—	(4)	143
Operating	520	—	21	541
Netback	1,274	—	53	1,327
Realized (Gain) Loss on Risk Management	84	8	—	92
Operating Margin	1,190	(8)	53	1,235

	Basis of Netback Calculation	Adjustments		
Year Ended December 31, 2021 ($ millions)	Conventional	Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	1,519	1,655	61	3,235
Royalties	150	—	—	150
Purchased Product	—	1,655	—	1,655
Transportation and Blending	74	—	—	74
Operating	521	8	22	551
Netback	774	(8)	39	805
Realized (Gain) Loss on Risk Management	—	2	—	2
Operating Margin	774	(10)	39	803

	Basis of Netback Calculation	Adjustments		
Year Ended December 31, 2020 ($ millions)	Conventional	Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	586	269	49	904
Royalties	40	—	—	40
Purchased Product	—	269	(1)	268
Transportation and Blending	81	—	—	81
Operating	295	—	25	320
Netback	170	—	25	195
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	170	—	25	195

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

Offshore

Three Months Ended December 31, 2022 ($ millions)	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Other [2]	Total Offshore [3]
	Basis of Netback Calculation					Adjustments		
Gross Sales	359	77	436	86	522	(77)	—	445
Royalties	20	27	47	1	48	(27)	—	21
Purchased Product	—	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	3	3	—	—	3
Operating	24	17	41	48	89	(15)	10	84
Netback	315	33	348	34	382	(35)	(10)	337
Realized (Gain) Loss on Risk Management					—	—	—	—
Operating Margin					382	(35)	(10)	337

Three Months Ended December 31, 2021 ($ millions)	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Total Offshore [3]
	Basis of Netback Calculation					Adjustment	
Gross Sales	377	62	439	143	582	(62)	520
Royalties	26	29	55	8	63	(29)	34
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	5	5	—	5
Operating	23	12	35	45	80	(7)	73
Netback	328	21	349	85	434	(26)	408
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					434	(26)	408

Year Ended December 31, 2022 ($ millions)	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Other [2]	Total Offshore [3]
	Basis of Netback Calculation					Adjustments		
Gross Sales	1,442	271	1,713	578	2,291	(271)	—	2,020
Royalties	80	116	196	(3)	193	(116)	—	77
Purchased Product	—	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	15	15	—	—	15
Operating	99	51	150	175	325	(36)	29	318
Netback	1,263	104	1,367	391	1,758	(119)	(29)	1,610
Realized (Gain) Loss on Risk Management					—	—	—	—
Operating Margin					1,758	(119)	(29)	1,610

Year Ended December 31, 2021 ($ millions)	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Total Offshore [2]
	Basis of Netback Calculation					Adjustment	
Gross Sales	1,342	224	1,566	440	2,006	(224)	1,782
Royalties	79	52	131	29	160	(52)	108
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	15	15	—	15
Operating	94	33	127	137	264	(25)	239
Netback	1,169	139	1,308	259	1,567	(147)	1,420
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					1,567	(147)	1,420

(1) Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the consolidated financial statements.
(2) Relates to costs in the Atlantic.
(3) 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 December 31, 2022	2021	Year Ended December 31, 2022	2021	2020
Oil Sands					
Foster Creek	**184.7**	194.5	**189.4**	178.8	164.9
Christina Lake	**246.5**	239.1	**247.5**	232.7	221.7
Sunrise [(2)]	**42.0**	29.9	**30.2**	25.2	—
Other Oil Sands	**118.5**	141.2	**118.7**	143.2	—
Total Oil Sands [(2)]	**591.7**	604.7	**585.8**	579.9	386.6
Conventional	**125.5**	125.3	**127.2**	133.4	89.8
Sales before Internal Consumption	**717.2**	730.0	**713.0**	713.3	476.4
Less: Internal Consumption [(3)]	**(93.4)**	(88.8)	**(86.6)**	(86.0)	(55.9)
Sales after Internal Consumption	**623.8**	641.2	**626.4**	627.3	420.5
Offshore					
Asia Pacific - China	**47.1**	52.7	**48.2**	50.8	—
Asia Pacific - Indonesia	**12.8**	9.8	**10.5**	9.5	—
Asia Pacific - Total	**59.9**	62.5	**58.7**	60.3	—
Atlantic	**7.3**	15.0	**11.3**	13.2	—
Total Offshore	**67.2**	77.5	**70.0**	73.5	—
Total Sales	**691.0**	718.7	**696.4**	700.8	420.5

(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.

Adjustments to the Consolidated Statements of Earnings (Loss) and Segmented Disclosures

Certain comparative information presented in the Consolidated Statements of Earnings (Loss) within the Oil Sands, Canadian Manufacturing, historical Retail and Corporate and Eliminations segments were revised.

During the three months ended June 30, 2022, the Company made adjustments to more appropriately reflect the cost of blending at the 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 the Corporate and Eliminations segment to re-present the change in the value of condensate that was extracted at the 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), financial position or cash flows. Refer to the interim Consolidated Financial Statements for the periods ended June 30, 2022, for further details.

In September 2022, the Company completed the divestiture of the majority of the retail fuels business. As a result, Management elected to aggregate the remaining commercial fuels business and the historical retail fuels business into the Canadian Manufacturing segment. Comparative periods have been re-presented to reflect this change, with no impact to net earnings (loss), financial position or cash flows. Refer to the Consolidated Financial Statements for further details.

The following tables reconcile the amounts previously reported in the interim Consolidated Statements of Earnings (Loss) for the respective period or the December 31, 2021 Consolidated Financial Statements, to the corresponding revised amounts:

	Three Months Ended March 31, 2022			**Three Months Ended June 30, 2022**			**Three Months Ended September 30, 2022**		
($ millions)	Reported	Revision	**Revised**	Reported	Revision	**Revised**	Reported	Revision	**Revised**
Oil Sands Segment									
Purchased Product	1,483	(271)	**1,212**						
Transportation and Blending	2,885	271	**3,156**						
	4,368	—	**4,368**						
Canadian Manufacturing Segment									
Gross Sales	1,044	563	**1,607**	1,521	724	**2,245**	1,478	690	**2,168**
Purchased Product	806	529	**1,335**	1,294	686	**1,980**	1,095	655	**1,750**
Operating Expenses	124	27	**151**	180	31	**211**	134	38	**172**
Depreciation, Depletion and Amortization	42	8	**50**	64	8	**72**	37	5	**42**
	72	(1)	**71**	(17)	(1)	**(18)**	212	(8)	**204**
Retail Segment									
Gross Sales	694	(694)	**—**	849	(849)	**—**	881	(881)	**—**
Purchased Product	660	(660)	**—**	811	(811)	**—**	846	(846)	**—**
Operating Expenses	27	(27)	**—**	31	(31)	**—**	38	(38)	**—**
Depreciation, Depletion and Amortization	8	(8)	**—**	8	(8)	**—**	5	(5)	**—**
	(1)	1	**—**	(1)	1	**—**	(8)	8	**—**
Corporate and Eliminations Segment									
Gross Sales	(1,761)	131	**(1,630)**	(1,782)	125	**(1,657)**	(2,619)	191	**(2,428)**
Purchased Product	(1,497)	346	**(1,151)**	(1,111)	125	**(986)**	(2,267)	191	**(2,076)**
Transportation and Blending	(6)	(215)	**(221)**	(188)	—	**(188)**	(119)	—	**(119)**
	(258)	—	**(258)**	(483)	—	**(483)**	(233)	—	**(233)**
Consolidated									
Gross Sales	17,383	—	**17,383**	20,747	—	**20,747**	18,697	—	**18,697**
Purchased Product	7,538	(56)	**7,482**	9,396	—	**9,396**	10,012	—	**10,012**
Transportation and Blending	2,919	56	**2,975**	3,048	—	**3,048**	2,684	—	**2,684**
Operating Expenses	1,287	—	**1,287**	1,481	—	**1,481**	1,439	—	**1,439**
Depreciation, Depletion and Amortization	1,030	—	**1,030**	1,132	—	**1,132**	1,047	—	**1,047**
	4,609	—	**4,609**	5,690	—	**5,690**	3,515	—	**3,515**

	Three Months Ended March 31, 2021			Three Months Ended June 30, 2021			Three Months Ended September 30, 2021			Three Months Ended December 31, 2021			Year Ended December 31, 2021		
($ millions)	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**
Oil Sands Segment															
Purchased Product	861	(172)	**689**	634	(204)	**430**	825	(196)	**629**	868	(212)	**656**	3,188	(784)	**2,404**
Transportation and Blending	1,778	172	**1,950**	1,780	204	**1,984**	1,918	196	**2,114**	2,365	212	**2,577**	7,841	784	**8,625**
	2,639	—	**2,639**	2,414	—	**2,414**	2,743	—	**2,743**	3,233	—	**3,233**	11,029	—	**11,029**
Canadian Manufacturing Segment															
Gross Sales	806	357	**1,163**	1,088	409	**1,497**	1,215	484	**1,699**	1,363	493	**1,856**	4,472	1,743	**6,215**
Purchased Product	631	327	**958**	807	374	**1,181**	986	443	**1,429**	1,128	460	**1,588**	3,552	1,604	**5,156**
Operating Expenses	93	19	**112**	92	29	**121**	99	25	**124**	104	25	**129**	388	98	**486**
Depreciation, Depletion and Amortization	43	12	**55**	43	13	**56**	41	11	**52**	40	23	**63**	167	59	**226**
	39	(1)	**38**	146	(7)	**139**	89	5	**94**	91	(15)	**76**	365	(18)	**347**
Retail Segment															
Gross Sales	447	(447)	**—**	501	(501)	**—**	592	(592)	**—**	618	(618)	**—**	2,158	(2,158)	**—**
Purchased Product	417	(417)	**—**	466	(466)	**—**	551	(551)	**—**	585	(585)	**—**	2,019	(2,019)	**—**
Operating Expenses	19	(19)	**—**	29	(29)	**—**	25	(25)	**—**	25	(25)	**—**	98	(98)	**—**
Depreciation, Depletion and Amortization	12	(12)	**—**	13	(13)	**—**	11	(11)	**—**	23	(23)	**—**	59	(59)	**—**
	(1)	1	**—**	(7)	7	**—**	5	(5)	**—**	(15)	15	**—**	(18)	18	**—**
Corporate and Eliminations Segment															
Gross Sales	(1,149)	90	**(1,059)**	(1,276)	92	**(1,184)**	(1,450)	108	**(1,342)**	(1,831)	125	**(1,706)**	(5,706)	415	**(5,291)**
Purchased Product	(973)	228	**(745)**	(1,110)	238	**(872)**	(1,244)	261	**(983)**	(1,561)	317	**(1,244)**	(4,888)	1,044	**(3,844)**
Transportation and Blending	(15)	(138)	**(153)**	(6)	(146)	**(152)**	(18)	(153)	**(171)**	(8)	(192)	**(200)**	(47)	(629)	**(676)**
	(161)	—	**(161)**	(160)	—	**(160)**	(188)	—	**(188)**	(262)	—	**(262)**	(771)	—	**(771)**
Consolidated															
Gross Sales	9,666	—	**9,666**	11,170	—	**11,170**	13,434	—	**13,434**	14,541	—	**14,541**	48,811	—	**48,811**
Purchased Product	4,237	(34)	**4,203**	5,313	(58)	**5,255**	6,734	(43)	**6,691**	7,197	(20)	**7,177**	23,481	(155)	**23,326**
Transportation and Blending	1,785	34	**1,819**	1,796	58	**1,854**	1,923	43	**1,966**	2,379	20	**2,399**	7,883	155	**8,038**
Operating Expenses	1,134	—	**1,134**	1,144	—	**1,144**	1,150	—	**1,150**	1,288	—	**1,288**	4,716	—	**4,716**
Depreciation, Depletion and Amortization	1,045	—	**1,045**	1,036	—	**1,036**	1,153	—	**1,153**	2,652	—	**2,652**	5,886	—	**5,886**
	1,465	—	**1,465**	1,881	—	**1,881**	2,474	—	**2,474**	1,025	—	**1,025**	6,845	—	**6,845**