MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE PERIOD ENDED MARCH 31, 2021

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 May 6, 2021 should be read in conjunction with our March 31, 2021 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2020 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2020 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of May 6, 2021, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The interim MD&As and the annual MD&A are reviewed by the Audit Committee and recommended for approval by the Cenovus Board of Directors ("the Board"). Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

On January 1, 2021, pursuant to a plan of arrangement under the Business Corporations Act (Alberta), Husky Energy Inc. ("Husky") became a wholly-owned subsidiary of Cenovus. Husky was subsequently amalgamated with Cenovus on March 31, 2021 (the "amalgamation") under the Canada Business Corporations Act and ceased to make separate filings as a reporting issuer. Unless the context requires otherwise, any reference herein to Husky refers to the business and operations of Husky prior to the amalgamation. In connection with its acquisition of Husky and in accordance with applicable securities laws, Cenovus filed a business acquisition report on March 26, 2021 containing the pro forma financial statements of the combined company as at December 31, 2020. Additional information concerning Husky's business and assets as at December 31, 2020 may be found in the annual information form of Husky dated February 8, 2021 for the year ended December 31, 2020 (the "Husky AIF") and Husky's management's discussion and analysis of the financial and operating results for the year ended December 31, 2020 (the "Husky MD&A"), each of which is filed and available on SEDAR under Husky's profile at sedar.com.

Basis of Presentation

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

Non-GAAP Measures and Additional Subtotals

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Netbacks, Adjusted Funds Flow, Free Funds Flow, Net Debt, Capitalization and Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. In addition, Operating Margin is considered an additional subtotal found in Note 1 of our interim Consolidated Financial Statements. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation, if applicable, of each non-GAAP measure or additional subtotal is presented in the Operating and Financial Results, Liquidity and Capital Resources, or Advisory sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian-based integrated energy company headquartered in Calgary, Alberta. Our common shares and warrants are listed on the Toronto ("TSX") and New York ("NYSE") stock exchanges and our cumulative redeemable preferred shares Series 1, 2, 3, 5 and 7 are listed on the TSX. We are the third largest Canadian-based oil and natural gas producer and the second largest Canadian refiner and upgrader, with operations in Canada, the United States ("U.S.") and the Asia Pacific region. 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, refining and retail operations in Canada and the U.S.

Our operations involve activities across the full value chain to develop, transport, produce 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 contributes to our bottom line by capturing value from oil and gas production through to the sale of finished products like transportation fuels.

During the first quarter of 2021, crude oil production from our Oil Sands assets averaged 553,396 barrels per day which is generally aligned with our downstream crude oil throughput of 469,100 barrels per day. Total upstream production averaged 769,254 barrels of oil equivalent ("BOE") per day.

Cenovus and Husky Arrangement

On January 1, 2021, Cenovus and Husky closed the transaction to combine the two companies through a plan of arrangement ("the Arrangement") pursuant to which Cenovus acquired all the issued and outstanding common shares of Husky in exchange for common shares and common share purchase warrants of Cenovus. In addition, all of the issued and outstanding Husky preferred shares were exchanged for Cenovus preferred shares with substantially identical terms.

The Arrangement combines high quality oil sands and heavy oil assets with extensive trading, supply and logistics infrastructure, and downstream assets, which creates opportunities to optimize the margin captured across the heavy oil value chain. With the combination of processing capacity and market access outside Alberta for the majority of the Company's oil sands and heavy oil production, exposure to Alberta heavy oil price differentials is reduced while maintaining exposure to global commodity prices. The Company has a cost-and-market-advantaged asset portfolio, and prioritizes free funds flow generation, balance sheet strength and returns to shareholders.

Our Strategy

Our strategy remains focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. Our diverse and integrated portfolio will help us to deliver stable cash flow through price cycles while maintaining safe and reliable operations. We remain focused on sustainably growing shareholder returns and reducing Net Debt (as defined in this MD&A). The diverse portfolio of projects and other opportunities across our business are expected to allow us to leverage increased economies of scale to better compete in an increasingly consolidated energy industry. We believe that maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility. Our financial framework has established an interim Net Debt target of $10 billion and longer term, $8 billion or lower which is in line with a target of a Net Debt to Adjusted EBITDA ratio of less than two times. We plan to use our capital allocation framework to evaluate disciplined investments in our portfolio against dividends, share repurchases and managing to the optimal debt level while maintaining investment grade status. Our investment focus will be on areas where we believe we have the greatest competitive advantage to generate the highest returns and incorporate Environmental, Social and Governance ("ESG") considerations into our business plan.

On January 28, 2021 we announced our 2021 budget focused on sustaining capital and generating Free Funds Flow to strengthen the balance sheet, accelerated by capturing transaction-related synergies across the organization. 2021 guidance dated January 28, 2021 remains unchanged and is available on our website at cenovus.com.

Our Operations

The Company operates through the following reportable segments:

Upstream Segments

- **Oil Sands,** includes the development and production of bitumen and heavy oil in northern Alberta and Saskatchewan. Cenovus's oil sands assets include Foster Creek, Christina Lake, Sunrise (jointly owned with BP Canada Energy Group ULC ("BP Canada") and operated by Cenovus) and Tucker oil sands projects, as well as Lloydminster thermal and cold and enhanced oil recovery assets ("EOR"). 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 other third-party commodity trading volumes through access to capacity on third-party pipelines, export terminals and storage facilities which provides flexibility for market access to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Offshore,** includes offshore operations, exploration and development activities in China and the east coast of Canada, as well as the equity-accounted investment in the Husky-CNOOC Madura Ltd. ("HCML") joint venture in Indonesia.

Downstream Segments

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

Corporate and Eliminations, primarily includes Cenovus-wide costs for general and administrative, financing activities, foreign exchange gain and loss and gain and loss on risk management on corporate related derivative instruments. 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 and crude oil production used as feedstock by the Canadian Manufacturing and U.S. Manufacturing segments. Eliminations are recorded at transfer prices based on current market prices.

To conform to the presentation adopted for the current period's operating segments, the following comparatives prior to January 1, 2021 have been reclassified:

- The Company's market optimization activities, previously reported in the Refining and Marketing segment, have been reclassified to the Oil Sands and Conventional segments.
- The Bruderheim crude-by-rail terminal results, previously reported under the Refining and Marketing segment, have been reclassified to the Canadian Manufacturing segment.
- The refining activities in the U.S. with the operator Phillips 66, previously reported in the Refining and Marketing segment, have been reclassified to the U.S. Manufacturing segment.
- The Company's unrealized gain and loss on risk management, previously reported in the Corporate and Eliminations segment, have been reclassified to the reportable segment to which the derivative instrument relates.

The Arrangement was accounted for using the acquisition method pursuant to IFRS 3, "*Business Combinations*". Under the acquisition method, assets and liabilities are measured at their estimated fair value on the date of acquisition with the exception of income tax, stock-based compensation, lease liabilities and right-of-use ("ROU") assets. The total consideration was allocated to the tangible and intangible assets acquired and liabilities assumed. Comparative figures in this MD&A include Cenovus results prior to the closing of the Arrangement on January 1, 2021 and does not reflect any historical data from Husky. Significant differences on operating and financial results compared with 2020 are primarily the result of the Arrangement.

QUARTERLY RESULTS OVERVIEW

During the first quarter, operating variables under Management's control performed very well. Cenovus closed the Arrangement to combine with Husky and focused on health and safety as top priority while maintaining our low operating and capital cost structure. The commodity price environment during the first quarter was buoyed by the increased pace of the novel coronavirus ("COVID-19") vaccinations and further supported by the Organization of Petroleum Exporting Countries ("OPEC") production cuts.

($ millions, except where indicated)	2021 Q1	2020 Q4	2020 Q3	2020 Q2	2020 Q1	2019 Q4	2019 Q3	2019 Q2	2019 Q1
Production Volumes (BOE/d)	**769,254**	467,202	471,799	465,415	482,594	467,448	448,496	443,318	447,270
Crude Throughput (1) (Mbbls/d)	**469**	169	191	163	221	228	233	237	188
Revenues (2)(3)	**9,150**	3,426	3,659	2,174	3,961	4,838	4,736	5,603	5,004
Operating Margin (2)	**1,879**	625	594	291	(589)	864	1,080	1,277	1,239
Cash From (Used in) Operating Activities	**228**	250	732	(834)	125	740	834	1,275	436
Adjusted Funds Flow (4)	**1,141**	333	407	(469)	(154)	679	917	1,075	998
Net Earnings (Loss)	**220**	(153)	(194)	(235)	(1,797)	113	187	1,784	110
Per Share (5) ($)	**0.10**	(0.12)	(0.16)	(0.19)	(1.46)	0.09	0.15	1.45	0.09
Capital Investment (6)	**547**	242	148	147	304	317	294	248	317
Net Debt (7)	**13,340**	7,184	7,530	8,232	7,421	6,513	6,802	7,088	8,139
Cash Dividends									
Common Shares	**35**	-	-	-	77	77	60	62	61
Per Common Share ($)	**0.0175**	-	-	-	0.0625	0.0625	0.0500	0.0500	0.0500
Preferred Shares	**9**	-	-	-	-	-	-	-	-

(1) Represents Cenovus's net interest in refining operations. The comparative periods have been restated to Cenovus's net interest.
(2) Additional subtotal found in Note 1 of the interim Consolidated Financial Statements and defined in this MD&A.
(3) Comparative figures have been re-presented for portion of inventory write-downs reclassified to royalties.
(4) Non-GAAP measure defined in this MD&A. Comparative figures have been re-presented to conform with the definition in this MD&A.
(5) Represented on a basic and diluted per share basis.
(6) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.
(7) Non-GAAP measure defined in this MD&A. Includes long-term debt and short-term borrowings assumed at fair value of $6,642 million as part of the Arrangement.

Crude oil prices improved significantly in the first quarter compared with all of 2020. Continued OPEC discipline, rising COVID-19 vaccinations, and anticipated economic recoveries are supporting commodity markets. West Texas Intermediate ("WTI") benchmark crude oil prices averaged 25 percent higher than the first quarter of 2020. Western Canadian Select ("WCS") benchmark prices averaged US$45.37 per barrel, 77 percent higher than US$25.64 per barrel in the first quarter of 2020. These increases in benchmark prices resulted in an average realized upstream price of $54.22 per BOE compared with $22.47 per BOE for the first quarter of 2020. The Chicago 3-2-1 crack spread averaged US$12.93 per barrel, 47 percent higher than US$8.79 per barrel in the first quarter of 2020.

Operationally, our upstream and downstream assets performed very well. Our upstream production averaged 769,254 BOE per day in the first quarter, compared with 482,594 BOE per day in the first quarter of 2020. Foster Creek and Christina Lake production was comparable to the first quarter of 2020, and we added significant production from assets acquired in the Arrangement.

Our downstream crude throughput averaged 469,100 barrels per day in the first quarter compared with 221,100 barrels per day in the first quarter of 2020. Assets acquired in the Arrangement averaged 299,000 barrels per day in the first quarter of 2021. Our U.S. refineries ran below capacity primarily due to economic run cuts due to low market crack spreads early in the quarter and planned turnarounds at our Wood River and Borger refineries. We were also impacted by unplanned events, including an outage at the Lima Refinery in early February and winter storm Uri that affected parts of our operations in the U.S. Manufacturing segment.

In the first quarter we incurred $245 million on integration expenditures, including capital of $22 million, of the $500 million to $550 million expected as integration work continues throughout the year. Year to date expenditures occurred earlier than budgeted, and we expect to achieve our synergies from the Arrangement earlier as a result.

In the first quarter we:

- Generated cash flow from operating activities of $228 million, which included integration costs of $223 million and long-term incentive costs of $235 million related to the accelerated payout to employees in connection with the Arrangement. Adjusted funds flow for the quarter was $1,141 million.
- Used our expanded pipeline capacity out of Alberta to transport additional heavy oil from our Foster Creek and Christina Lake oil sands operations to the U.S. to access higher market pricing at lower transportation costs

compared with the first quarter of 2020 when we shipped the similar heavy oil volumes to the U.S. by rail and pipe.

- Generated an operating margin of $1,879 million compared with negative $589 million in the first quarter of 2020, due to higher average realized crude oil, NGLs and natural gas sales prices and higher market crack spreads, and non-cash inventory write-downs recorded in the first quarter of 2020.
- Achieved single-day record production at our Lloydminster thermal assets.

Cenovus remains committed to the health and safety of its workforce and the public while providing essential services. Physical distancing measures continue to be taken to maintain the health and safety of our people and to help mitigate the risk of COVID-19 at our workplaces. We continue to monitor the changing COVID-19 situation and respond accordingly in a timely manner. Mandatory work-from-home measures remained in place for the quarter and continue to be in place for all non-essential staff at our combined offices and worksites in Alberta, Saskatchewan and Manitoba, pending further review. The full scope of our operations will continue to take direction from local health authorities regarding their COVID-19 workplace mandates. Staff levels at sites and offices have and will continue to follow guidance received from the applicable federal, provincial, state and local governments and public health officials.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results

	Three Months Ended March 31, 2021	Percent Change	2020
Upstream Production Volumes			
Oil Sands (barrels/d)			
Foster Creek	**163,090**	**-**	163,820
Christina Lake	**222,888**	**-**	223,216
Sunrise [1]	**27,740**	**100**	-
Tucker	**23,119**	**100**	-
Lloydminster Thermal	**96,036**	**100**	-
Lloydminster Cold/EOR	**20,523**	**100**	-
Total Oil Sands Crude Oil (barrels/d)	**553,396**	**43**	387,036
Conventional (BOE/d)	**135,933**	**42**	95,558
Offshore (BOE/d)			
Asia Pacific [2]	**60,832**	**100**	-
Atlantic	**16,920**	**100**	-
Offshore Total (BOE/d)	**77,752**	**100**	-
Total Production Volumes (BOE/d)	**769,254**	**59**	482,594
Total Upstream Sales Volumes [3] (BOE/d)	**690,473**	**58**	435,880
Downstream Manufacturing and Retail			
Canadian Manufacturing Crude Throughput (Mbbls/d)			
Lloydminster Upgrader	**78**	**100**	-
Lloydminster Refinery	**28**	**100**	-
Canadian Manufacturing Total (Mbbls/d)	**106**	**100**	-
U.S. Manufacturing Crude Throughput (Mbbls/d)			
Lima Refinery	**125**	**100**	-
Wood River and Borger refineries [1]	**170**	**(23)**	221
Toledo Refinery [1]	**68**	**100**	-
U.S. Manufacturing Total (Mbbls/d)	**363**	**64**	221
Total Throughput (Mbbls/d)	**469**	**112**	221
Retail (millions of litres/d)			
Fuel sales, including wholesale	**6.5**	**100**	-

(1) Represents Cenovus's 50 percent interest in Sunrise operations, Wood River, Borger and Toledo refinery operations.
(2) Reported production volumes reflect Cenovus's 40 percent interest in the Madura-BD gas project. Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(3) Has been reduced for natural gas volumes used for internal consumption by the Oil Sands segment.

Upstream Production Volumes

Oil Sands production increased primarily due to an additional 167,418 barrels per day from assets acquired in the Arrangement. Production at Foster Creek and Christina Lake were relatively flat compared with the first quarter of 2020 and production continues to be optimized as commodity prices improve.

Conventional production increased in the first quarter of 2021 primarily due to 50,556 BOE per day from assets acquired as part of the Arrangement, combined with new wells brought on production during the quarter. The increase is partially offset by natural declines and the sale of our Marten Hills assets in December 2020, which produced 3,165 BOE per day in the first quarter of 2020.

Offshore production in the first quarter of 2021 was composed entirely of production from assets acquired in the Arrangement.

Downstream Manufacturing

Throughput increased primarily due to 299,000 barrels per day from assets acquired in the Arrangement. In the U.S. Manufacturing segment, throughput ran at reduced rates early in the quarter due to low market crack spreads.

At the Wood River and Borger refineries, throughput was also impacted by planned maintenance turnarounds beginning early March and late February, respectively. The turnaround at Wood River is expected to be completed in mid-May and the turnaround at Borger was completed on April 7, 2021.

The Lima Refinery ramped up throughput in March as market crack spreads improved. Throughput was also impacted by a month-long unplanned outage and the impact of winter storm Uri on a key pipeline supplying the Lima Refinery's feedstock.

The Lloydminster Upgrader and Lloydminster Refinery ran at or near capacity throughout the quarter.

Further information on the changes in our financial and operating results can be found in the Reportable Segments section of this MD&A. Further 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.

Selected Consolidated Financial Results

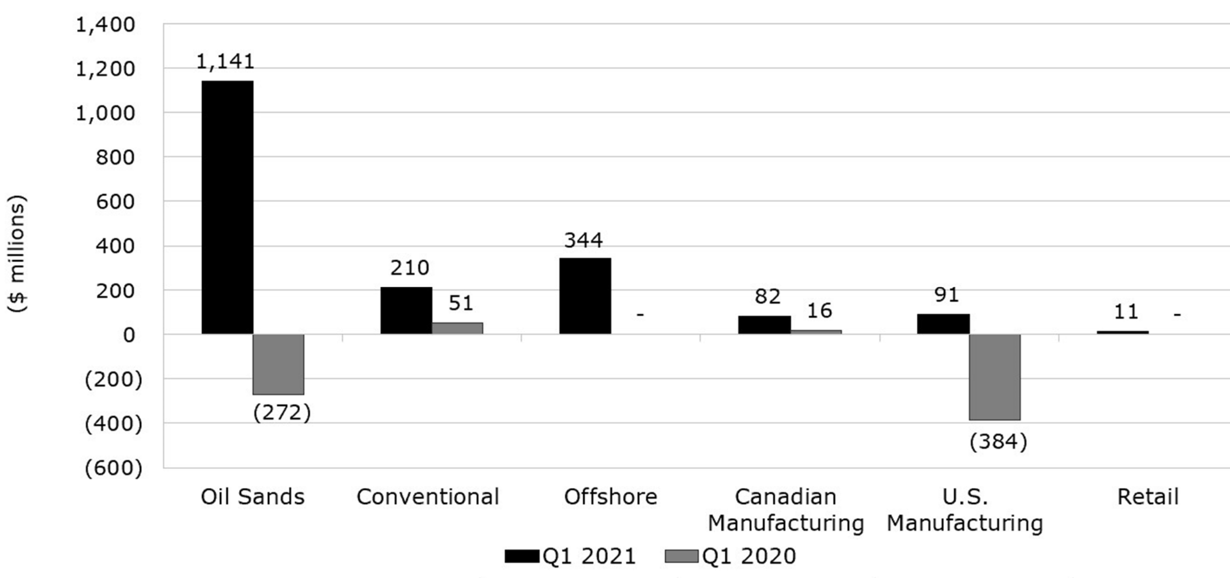
Operating Margin

Operating Margin is an additional subtotal found in Note 1 of the interim Consolidated Financial Statements 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. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Margin.

	Three Months Ended March 31,	
($ millions)	**2021**	2020 (1)
Gross Sales	**10,672**	4,238
Less: Royalties	**373**	54
Revenues	**10,299**	4,184
Expenses		
Purchased Product	**5,067**	2,197
Transportation and Blending	**1,800**	1,928
Operating Expenses	**1,302**	624
Realized (Gain) Loss on Risk Management Activities	**251**	24
Operating Margin	**1,879**	(589)

(1) Inventory write-downs prior to January 1, 2021, have been reclassified to royalties, purchased product, transportation and blending or operating expenses to conform with the current treatment of inventory write-downs.

Operating Margin by Segment



Operating Margin increased in 2021 compared with 2020 primarily due to:

- Higher average crude oil, NGLs and natural gas sales prices resulting from higher benchmark pricing.
- An increase in sales volumes from the assets acquired in the Arrangement.
- Higher Operating Margin from our Canadian Manufacturing and U.S. Manufacturing segments primarily due to throughput on assets acquired in the Arrangement and higher market crack spreads.
- Non-cash product inventory write-downs in the first quarter of 2020 of $345 million and $243 million related to our upstream and downstream assets, respectively.

These increases in Operating Margin were partially offset by decreased throughput at the Wood River and Borger refineries due to crude rate reductions and scheduled turnaround maintenance.

Additional details explaining the changes in Operating Margin can be found in the Reportable Segments section of this MD&A.

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

Adjusted Funds Flow is a non-GAAP 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, inventories (excluding non-cash inventory write-downs and reversals), income tax receivable, accounts payable and income tax payable.

	Three Months Ended March 31,	
($ millions)	**2021**	2020
Cash From (Used in) Operating Activities	**228**	125
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(11)**	(31)
Net Change in Non-Cash Working Capital	**(902)**	310
Adjusted Funds Flow (1)	**1,141**	(154)

(1) The comparative period has been restated to conform with the current period definition of Adjusted Funds Flow.

Cash From Operating Activities and Adjusted Funds Flow were higher in the three months ended March 31, 2021 compared with the first quarter of 2020 due to increased Operating Margin, as discussed above, partially offset by integration costs of $223 million and long-term incentives of $111 million paid related to the accelerated payout to Cenovus employees in connection with the Arrangement, higher finance costs and increased general and administrative expenses. The change in non-cash working capital in the first quarter of 2021 was primarily due to an increase in inventories and accounts receivable, partially offset by an increase in accounts payable.

The increase in inventories and accounts receivable was mainly due to the higher commodity prices and refined product pricing as well as a build in inventory relating to the turnaround activities at Wood River and Borger. The increase in accounts payable relates to higher commodity prices, offset by the settlement of the integration costs, long-term incentive costs to Cenovus employees as mentioned above and the payment of long-term incentives liability assumed as part of the Arrangement.

Net Earnings (Loss)

($ millions)	
Net Earnings (Loss) for the Three Months Ended March 31, 2020	**(1,797)**
Increase (Decrease) due to:	
Operating Margin	**2,468**
Corporate and Eliminations:	
Unrealized Risk Management Gain (Loss)	**170**
Unrealized Foreign Exchange Gain (Loss)	**796**
Re-measurement of Contingent Payment	**(317)**
Integration costs	**(223)**
General and Administrative	**(186)**
Finance costs	**(137)**
Expenses (1)	**(27)**
Depreciation, Depletion and Amortization	**(102)**
Exploration Expense	**(3)**
Income Tax Recovery (Expense)	**(422)**
Net Earnings (Loss) for the Three Months Ended March 31, 2021	**220**

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

Net Earnings of $220 million was significantly higher than our Net Loss of $1,797 million in 2020 due to higher Operating Margin, as discussed above, gains on non-operating unrealized foreign exchange and unrealized risk management compared with losses in the first quarter of 2020. This was partially offset by a loss on the re-measurement of the contingent payment of $187 million (2020 – $130 million gain) and integration costs, higher general and administrative costs, depreciation, depletion and amortization ("DD&A") expense and income tax expense as result of the Arrangement.

Net Debt

Net Debt is a non-GAAP measure used to monitor our capital structure. Net Debt is defined 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.

($ millions) As at	**March 31, 2021**	December 31, 2020
Short-Term Borrowings	**266**	121
Long-Term Debt	**13,947**	7,441
Less: Cash and Cash Equivalents	**(873)**	(378)
Net Debt	**13,340**	7,184

Net Debt increased $6,156 million during the three months ended March 31, 2021. The increase is primarily due to total debt, net of cash, with a fair value of $5,907 million assumed from the Arrangement on January 1, 2021, $902 million net changes in non-cash working capital as mentioned above and capital investments of $547 million, partially offset by adjusted funds flow of $1,141 million during the three months ended March 31, 2021.

Capital Investment (1) (2)

	Three Months Ended March 31,	
($ millions)	**2021**	2020
Upstream		
Oil Sands	**218**	194
Conventional	**66**	16
Offshore	**26**	-
	310	210
Downstream		
Canadian Manufacturing	**4**	10
U.S. Manufacturing	**205**	51
Retail	**1**	-
	210	61
Corporate and Eliminations	**27**	33
Capital Investment	**547**	304

(1) *Includes expenditures on PP&E and E&E assets.*
(2) *Prior periods have been reclassified to conform with current period's operating segments.*

Capital investment in the first quarter of 2021 increased compared with 2020 is reflective of the Arrangement and larger asset base.

Oil Sands capital investment in the first quarter of 2021 was primarily for sustaining production focused at Christina Lake, Foster Creek and the Lloydminster thermal assets.

Conventional capital investment focused on predictable short cycle, high return development wells which will improve underlying cost structures through volume enhancement and offset natural declines.

Offshore capital investment in the first quarter of 2021 was primarily preservation capital for the West White Rose project in the Atlantic. The West White Rose project was deferred in March of 2020 and remains deferred for 2021 while we continue to evaluate options.

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

Drilling Activity

Three Months Ended March 31,	Gross Stratigraphic Test Wells 2021	2020	Gross Production Wells (1) 2021	2020
Foster Creek	**17**	38	**-**	-
Christina Lake	**25**	42	**8**	-
Lloydminster Thermal	**-**	-	**13**	-
Lloydminster Cold/EOR	**-**	-	**2**	
Other (2)	**17**	75	**-**	-
	59	155	**23**	-

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

Stratigraphic test wells were drilled to help identify well pad locations for sustaining wells and to further progress the evaluation of emerging assets.

(net wells, unless otherwise stated)	**Three Months Ended March 31, 2021** Drilled	Completed	Tied-in	Three Months Ended March 31, 2020 Drilled	Completed	Tied-in
Conventional	**9**	**8**	**9**	-	-	2

There were no wells drilled, completed or tied-in during the first three months of 2021 in the Offshore segment.

Future Capital Investment

Our Oil Sands capital investment for 2021 is forecast to be between $850 million and $950 million, focused primarily on sustaining production at Christina Lake, Foster Creek and the Lloydminster thermal assets. Our Oil Sands production is expected to range between 524,000 barrels per day and 586,000 barrels per day.

Our Conventional capital investment for 2021 is forecast to be between $170 million and $210 million. This includes economic development in various plays to generate strong returns, improve underlying cost structures through volume enhancement and offset declines. Our Conventional production is expected to range between 132,000 BOE per day and 151,000 BOE per day.

Our Offshore capital investment is expected to be between $200 million and $250 million. This capital spend includes a planned well in China as well as preservation capital for the West White Rose project. Production from our Offshore segment is expected to range between 61,000 BOE per day and 72,000 BOE per day.

In 2021, we plan to invest between $1.0 billion and $1.2 billion in the U.S. Manufacturing, Canadian Manufacturing and Retail segments and will continue to focus on refining reliability and maintenance, safety projects and high-return optimization opportunities. We also plan to invest between $520 million and $570 million for the Superior Refinery rebuild project. The rebuild project is expected to further enhance our heavy oil value chain integration while further reducing the Company's exposure to WTI-WCS location differentials. Downstream throughput is expected to be in the range of 500,000 barrels per day to 550,000 barrels per day.

We expect to invest between $75 million and $100 million of corporate capital across the Company.

2021 Guidance dated January 28, 2021 is available on our website at cenovus.com.

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 the U.S./Canadian dollar and RMB/Canadian dollar average exchange rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates [1]

(Average US$/bbl, unless otherwise indicated)	**Q1 2021**	**Percent Change**	Q1 2020	Q4 2020
Brent [2]	**60.90**	**21**	50.26	44.22
WTI	**57.84**	**25**	46.17	42.66
Differential Brent-WTI	**3.06**	**(25)**	4.09	1.56
WCS at Hardisty ("WCS")	**45.37**	**77**	25.64	33.36
Differential WTI-WCS	**12.47**	**(39)**	20.53	9.30
WCS (C$/bbl)	**57.44**	**68**	34.11	43.41
WCS at Nederland	**55.93**	**34**	41.80	40.36
Differential WTI-WCS at Nederland	**1.91**	**(56)**	4.37	2.30
Condensate (C5 @ Edmonton)	**58.04**	**25**	46.28	42.54
Differential WTI-Condensate (Premium)/Discount	**(0.20)**	**82**	(0.11)	0.12
Differential WCS-Condensate (Premium)/Discount	**(12.67)**	**(39)**	(20.64)	(9.18)
Average (C$/bbl)	**73.49**	**19**	61.71	55.36
Synthetic @ Edmonton	**54.32**	**25**	43.48	39.60
WTI-Synthetic (Premium)/Discount Differential	**3.52**	**31**	2.69	3.06
Refined Product Prices				
Chicago Regular Unleaded Gasoline ("RUL")	**69.51**	**34**	51.99	47.31
Chicago Ultra-low Sulphur Diesel ("ULSD")	**73.28**	**21**	60.32	54.21
Refining Margin: 3-2-1 Crack Spreads [3]				
Chicago	**12.93**	**47**	8.79	7.05
Group 3	**15.67**	**44**	10.91	7.57
Renewable Identification Numbers ("RINs")	**5.49**	**247**	1.58	3.48
Natural Gas Prices				
AECO [4] (C$/Mcf)	**2.92**	**36**	2.14	2.77
NYMEX (US$/Mcf)	**2.69**	**38**	1.95	2.66
Foreign Exchange Rate				
US$ per C$1 - Average	**0.790**	**6**	0.744	0.768
US$ per C$1 - End of Period	**0.795**	**13**	0.705	0.785
RMB per C$1 - Average	**5.120**	**(2)**	5.194	5.084

(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) Calendar month average of settled prices for Dated Brent.
(3) 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.
(4) Alberta Energy Company ("AECO") natural gas monthly index.

Crude Oil and Condensate Benchmarks

In the first quarter of 2021, Brent and WTI crude oil benchmarks improved due to global roll out efforts of COVID-19 vaccines, anticipated economic recovery, declines in crude oil inventories, additional supply reductions from Saudi Arabia and continued discipline from OPEC and a group of 10 non-OPEC members (collectively, "OPEC+").

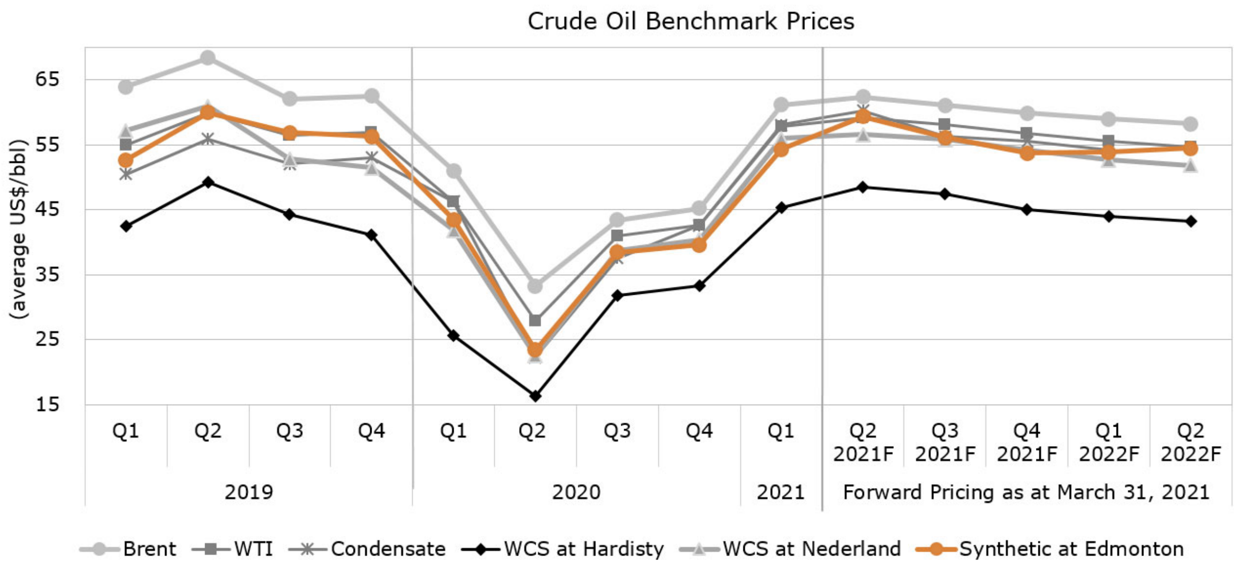
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and the Canadian dollar equivalent is the basis for determining royalty rates for a number of our crude oil properties. In the first quarter of 2021, the Brent-WTI differential narrowed compared with the first quarter of 2020 due to lower exports of crude oil from North America and reduced U.S. crude oil supply.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. In the first quarter of 2021, the WTI-WCS at Hardisty differential narrowed compared with the first quarter of 2020 due to some additional demand and takeaway capacity from the Western Canadian Sedimentary Basin ("WCSB").

WCS at Nederland is a heavy oil benchmark at the U.S. Gulf Coast ("USGC") which is representative of pricing for our sales in the USGC. WCS at Nederland crude oil prices were strong in the first quarter of 2021, consistent with increasing crude oil prices globally as refiners increased crude runs to adjust to increased demand for products. In the first quarter of 2021, WCS at Nederland benchmark prices relative to WTI narrowed compared with 2020. The narrowing was mainly attributed to strong coking demand and continued OPEC+ curtailment of medium and heavy crude oil.

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



Blending condensate with bitumen enables our production to be transported through pipelines. Our blending ratios, diluent volumes as a percentage of total blended volumes, range from approximately 23 percent to 31 percent. The WCS-Condensate differential is an important benchmark as a wider differential generally results in a decrease in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by USGC condensate prices plus the cost to transport the condensate to Edmonton. Our blending costs are also impacted by the timing of purchases and deliveries of condensate into inventory to be available for use in blending as well as timing of sales of blended product.

Average condensate benchmark prices were at a premium relative to WTI in Alberta in the first quarter of 2021 as a result of strong seasonal oil sands demand.

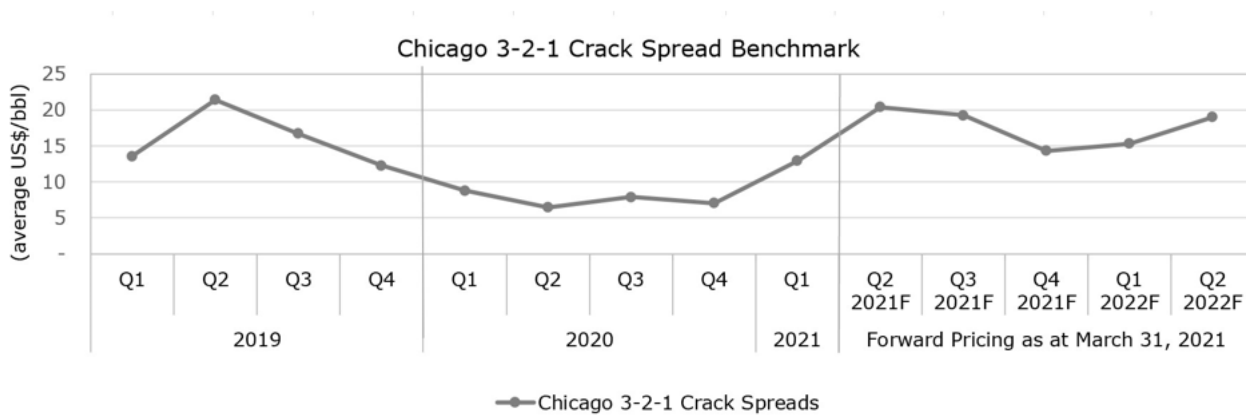
Refining Benchmarks

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

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

Average Chicago refined product prices increased in the first quarter of 2021, due to a combination of higher RINs costs as a result of a tight biofuel market and uncertainty around policies that drive RINs demand, as well as higher refined product demand due to the deployment of COVID-19 vaccines and increasing economic activity. Recovering refined product demand resulted in lower inventory levels which increased market crack spreads. As North American refining crack spreads are expressed on a WTI basis, while refined products are generally set by global prices, the strength of refining market crack spreads in the U.S. Midwest and Midcontinent will reflect the differential between Brent and WTI benchmark prices.

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



Natural Gas Benchmarks

Average NYMEX natural gas prices increased compared with the first three months of 2020 due to lower associated gas production and record high liquified natural gas exports. Average AECO prices improved alongside the NYMEX benchmark. The differential between AECO and NYMEX remained narrow as basin debottlenecking has allowed for ample access to domestic storage injections and lower pipeline utilization in the WCSB. 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 results. Likewise, as the Canadian dollar weakens, there is a positive impact on our reported results. 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. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars. In addition, changes in foreign exchange rates impact the translation of U.S. and Asia Pacific operations.

In the first quarter of 2021, the Canadian dollar on average strengthened relative to the U.S. dollar compared with the first three months of 2020, resulting in a negative impact on our revenues. The strengthening of the Canadian dollar relative to the U.S. dollar as at March 31, 2021 compared with December 31, 2020, resulted in unrealized foreign exchange gains of $130 million on the translation of our U.S. dollar debt.

A portion of our long-term sales contracts in Asia Pacific are priced in RMB. An increase in the value of the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region.

REPORTABLE SEGMENTS

UPSTREAM

OIL SANDS

On December 31, 2020, the Oil Sands segment included the Foster Creek, Christina Lake and Narrows Lake assets as well as other projects in the early stages of development.

On January 1, 2021, as part of the Arrangement, we acquired:

- Sunrise, a SAGD oil sands project located in the Athabasca region of northern Alberta. The Cenovus operated project is a 50 percent partnership with BP Canada;
- Tucker, an oil sands project located 30 kilometers northwest of Cold Lake, Alberta;
- Lloydminster thermal projects, consisting of bitumen production from 11 thermal plants, in the Lloydminster region of Saskatchewan;
- Lloydminster Cold and EOR, which produces heavy oil from the Lloydminster region of Alberta and Saskatchewan; and
- A 35 percent interest in the HMLP, which owns 2,200 kilometers of pipeline in the Lloydminster region and 5.9 million barrels of storage at Hardisty and Lloydminster. Financial results from HMLP are on an equity-accounted basis.

In the first quarter of 2021, we:

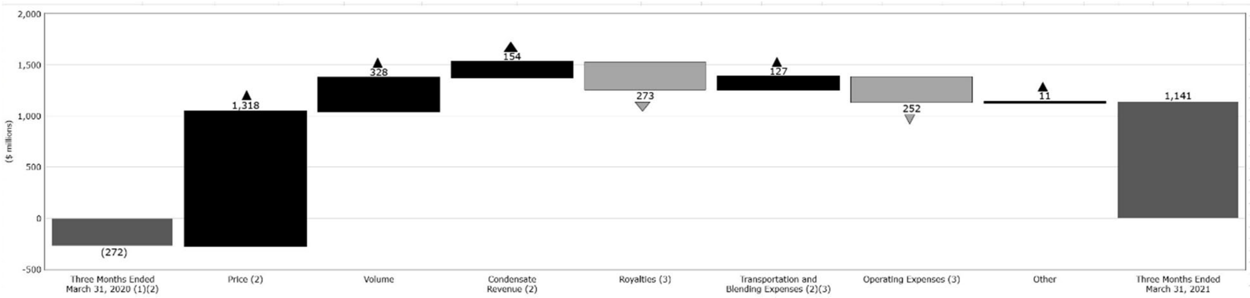
- Delivered safe and reliable operations;
- Achieved record single day production rates at our Lloydminster thermal assets;
- Generated Operating Margin of $1,141 million, an increase of $1,413 million compared with the first quarter of 2020 primarily due to higher average realized sales prices, added volumes from assets acquired as part of the Arrangement, and lower transportation and blending costs, partially offset by a higher realized loss on inventory price risk management; and
- Increased Netback from $2.58 per BOE in the first quarter of 2020 to $26.56 per BOE.

Financial Results

($ millions)	Three Months Ended March 31, 2021	2020 (1)
Gross Sales	**4,775**	2,434
Less: Royalties	**324**	51
Revenues	**4,451**	2,383
Expenses		
Purchased Product	**718**	405
Transportation and Blending	**1,778**	1,905
Operating	**585**	320
Realized (Gain) Loss on Risk Management	**229**	25
Operating Margin	**1,141**	(272)
Unrealized (Gain) Loss on Risk Management (2)	**(141)**	22
DD&A	**612**	411
Exploration Expense	**11**	3
Segment Income (Loss)	**659**	(708)

(1) Prior periods have been reclassified to conform with current period's operating segments.
(2) Unrealized gain and loss on risk management is recorded in the reportable segment to which the derivative instrument relates. Comparative periods have been reclassified as these amounts were recorded in the Corporate and Eliminations segment prior to January 1, 2021.

Operating Margin Variance



(1) Prior periods have been reclassified to conform with current period's operating segments.
(2) 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.
(3) Inventory write-downs prior to January 1, 2021, have been reclassified to royalties, purchased product, transportation and blending or operating expenses to conform with the current treatment of inventory write-downs.

Operating Results

	Three Months Ended March 31,	
	2021	2020
Total Sales Volumes (BOE/d)	**565,289**	397,971
Total Realized Price per Unit Sold ($/BOE)	**52.38**	22.35
Total Daily Crude Oil Production (bbl/d)	**553,396**	387,036
Foster Creek	**163,090**	163,820
Christina Lake	**222,888**	223,216
Sunrise (1)	**27,740**	-
Tucker	**23,119**	-
Lloydminster Thermal	**96,036**	-
Lloydminster Cold/EOR	**20,523**	-
Effective Royalty Rate (percent)	**14.4**	10.5
Per Unit Transportation and Blending Cost ($/BOE)	**8.06**	10.81
Per Unit Operating Cost ($/BOE)	**11.40**	7.75

(1) Represents Cenovus's 50 percent interest in Sunrise operations.

Revenues

Price

In the first quarter of 2021, our realized crude oil sales price was $52.38 per barrel compared with $22.35 per barrel in the first quarter of 2020. The increase in realized crude oil sales price was primarily due to higher WTI benchmark prices (US$57.84 per barrel compared with US$46.17 in the first quarter of 2020) and narrower WTI-WCS differentials (US$12.47 per barrel compared with US$20.53 in the in the first quarter of 2020).

In the first three months of 2021, gross sales of $672 million (2020 – $405 million) included third-party sourced volumes which are not included in our per-unit pricing metrics or our Netbacks.

In the first three months of 2021, gross sales included other amounts of $70 million (2020 – $6 million), which are not included in our per-unit pricing metrics or our Netbacks as it relates to construction, transportation and blending activities for third parties.

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

Cenovus makes storage and transportation decisions using our marketing and transportation infrastructure, including storage and pipeline assets to optimize product mix, delivery points, transportation commitments and customer diversification. In order to price protect our inventories associated with the storage or transportation decisions, Cenovus employs various price alignment strategies to reduce volatility in future cash flows to achieve stable cash flow while we are deleveraging our balance sheet through risk management contracts. Transactions typically span across periods, as such, these transactions reside across both realized and unrealized risk management. As the financial contracts settle, they will flow from unrealized to realized risk management gains and losses.

In the first quarter of 2021, we incurred a realized risk management loss due to the settlement of benchmark prices relative to our risk management contract prices; the underlying physical inventory sold in the quarter recognized a gain due to rising benchmark prices. In the first quarter of 2021, unrealized gains were recorded on our crude oil financial instruments primarily due to forward benchmark pricing falling below our risk management contract prices that related to future periods and the realization of settled positions. In a rising commodity price environment, we would expect to realize losses on our risk management activities but recognize gains on the underlying physical inventory sold in the period and the opposite to occur in a falling commodity price environment.

Production Volumes

Oil Sands production was 553,396 barrels per day in the first three months of 2021 compared with 387,036 barrels per day in the first three months of 2020.

Production levels increased in the first quarter of 2021 primarily due to 167,418 barrels per day from assets acquired as part of the Arrangement. Lloydminster thermal achieved record single day production rates. Our Tucker and Sunrise assets are producing at stable rates.

Production at Foster Creek and Christina Lake was relatively flat compared with the first quarter of 2020. In the first quarter of 2020, we optimized production to take advantage of the Special Production Allowance program and the easing of mandated production curtailments, partially offset by voluntary production cuts to address the collapse in crude oil prices in March 2020. We continue to optimize production in 2021 to take advantage of improving market conditions.

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, Sunrise and Tucker) are based on government prescribed pre and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price.

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

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

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

For our Saskatchewan properties, Lloydminster thermal and Lloydminster Cold/EOR, royalty calculations are based on an annual rate that is applied to each project. Pre-payout projects pay a flat one percent rate and post-payout projects are based on an annual estimated royalty rate determined for each project. Post-payout royalty rates range from two percent to 17 percent.

Effective royalty rates increased primarily due to higher realized pricing and higher Alberta oil sands sliding scale royalty rates, partially offset by lower rates on Saskatchewan production, all of which was acquired as part of the Arrangement.

Royalties increased by $273 million compared with the first quarter of 2020, mainly due to higher revenue as a result of higher realized pricing, combined with increased production resulting from assets acquired under the Arrangement.

Expenses

Transportation and Blending

Blending costs decreased $106 million compared with the first quarter of 2020, which included a $261 million non-cash inventory write-downs due to low forward benchmark pricing. At Foster Creek and Christina Lake, not including the inventory write-downs, blending costs were consistent with the first quarter of 2020 as volumes and condensate prices out of inventory were comparable. Blending rates at Sunrise are comparable to Foster Creek and Christina Lake. The remaining assets at Tucker, Lloydminster thermal and Lloydminster Cold/EOR typically have lower blending rates due to lower crude oil density.

Transportation costs decreased $21 million and per-unit transportation costs decreased $2.75 per barrel compared with the first quarter of 2020 primarily due to reduced rail volumes. Optimizing the use of the combined pipeline capacity out of Alberta following the Arrangement allowed heavy oil production from Foster Creek and Christina Lake to be shipped and sold to U.S. destinations with less reliance on rail. This resulted in transportation costs of $10.98 per barrel at Foster Creek and $6.65 per barrel at Christina Lake in the first quarter, a reduction of more than 23 percent and 18 percent, respectively, relative to the first quarter of 2020 when similar volumes were sold to U.S. destinations.

Operating

Primary drivers of our operating expenses in the first quarter of 2021 were fuel, workforce, chemical costs, repairs and maintenance, and workovers. Total operating costs increased primarily due to assets acquired from the Arrangement which have higher per barrel operating costs.

At Foster Creek and Christina Lake, per barrel fuel costs were $3.31 per barrel in the first quarter of 2021, an increase from $2.33 per barrel in the first quarter of 2020 mainly due to higher natural gas prices. Per barrel non-fuel costs were $6.11 in the first quarter of 2021, an increase from $5.42 per barrel in the first quarter of 2020 due to higher workforce costs.

Per barrel operating costs increased $3.65 per barrel to $11.40 per barrel in the first quarter of 2021 compared with the same period of 2020 due to higher per unit operating costs of the assets acquired in the Arrangement and increased Foster Creek and Christina Lake per barrels cost due to higher natural gas and workforce costs.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate accounts for expenditures incurred to date, together with estimated future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A each period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over total estimated life of the related asset as represented by proved reserves.

In the first quarter of 2021, DD&A increased $201 million compared with the same period in 2020 due to higher sales volumes as a result of the Arrangement. The average depletion rate for the first quarter of 2021 was $11.13 per barrel (2020 - $10.40 per barrel).

We depreciate our ROU assets on a straight-line or unit of production basis over the shorter of the estimated useful life or the lease term.

Netbacks (1) (2)

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

	Three Months Ended March 31,	
($/bbl)	**2021**	2020
Sales Price	**52.38**	22.35
Royalties (1)	**6.36**	1.21
Transportation and Blending (1) (2)	**8.06**	10.81
Operating Expenses (1)	**11.40**	7.75
Netback excluding Risk Management	**26.56**	2.58
Realized (Gain) Loss on Risk Management	**4.50**	0.69
Unrealized (Gain) Loss on Risk Management	**(2.78)**	0.61
Netback including Risk Management	**24.84**	1.28

(1) Netbacks do not reflect non-cash write-downs of product inventory or reversals of product inventory until realized when the product is sold.
(2) Netbacks reflect our margin on a per-barrel basis of unblended crude oil.

Our average Netback increased in the first quarter of 2021 compared with 2020, primarily due to higher realized sales prices and lower transportation costs as a result of lower crude-by-rail volumes, partially offset by higher royalties and operating costs.

CONVENTIONAL

On December 31, 2020, the Conventional segment included assets primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and NGLs. The assets are in Alberta and British Columbia and include interests in numerous natural gas processing facilities.

On January 1, 2021, as part of the Arrangement, we acquired assets primarily in the same areas mentioned above, and the Rainbow Lake operating area located approximately 900 kilometers northwest of Edmonton. The acquired assets include interests in several natural gas processing facilities.

In the first quarter of 2021, we:

- Delivered safe and reliable operations;
- Generated Operating Margin of $210 million, an increase of $159 million compared with the first quarter of 2020 due to higher average realized sales prices, and increased volumes from assets and inventories acquired as part of the Arrangement, partially offset by higher per-unit operating expenses from asset acquired as part of the Arrangement; and
- Increased Netback from $5.32 per BOE in the first quarter of 2020 to $15.80 per BOE.

Financial Results

($ millions)	Three Months Ended March 31, 2021	2020 [(1)]
Gross Sales	**776**	222
Less: Royalties	**24**	3
Revenues	**752**	219
Expenses		
Purchased Product	**381**	61
Transportation and Blending [(2)]	**18**	23
Operating	**142**	84
Realized (Gain) Loss on Risk Management	**1**	-
Operating Margin	**210**	51
Unrealized (Gain) Loss on Risk Management [(3)]	**(1)**	-
DD&A	**108**	408
Exploration Expense	**(4)**	-
Segment Income (Loss)	**107**	(357)

(1) Prior periods have been reclassified to conform with current period's operating segments.
(2) Netbacks do not reflect non-cash write-downs of product inventory or reversals of product inventory until realized when the product is sold.
(3) Unrealized gain and loss on risk management is recorded in the reportable segment to which the derivative instrument relates. Comparative periods have been reclassified as these amounts were recorded in the Corporate and Eliminations segment prior to January 1, 2021.

Operating Results

	Three Months Ended March 31, 2021	2020
Total Sales Volumes (BOE/d)	**135,933**	95,558
Crude Oil (bbls/d)	**8,646**	8,662
NGLS (bbls/d)	**28,209**	21,104
Natural Gas (MMcf/d)	**594**	395
Natural Gas Production (percentage of total)	**73**	69
Crude Oil and NGLs Production (percentage of total)	**27**	31
Total Realized Price per Unit Sold ($/BOE)	**30.32**	17.23
Crude Oil ($/bbl)	**61.59**	40.51
NGLS ($/bbl)	**38.02**	20.75
Natural Gas ($/mcf)	**4.23**	2.17
Effective Royalty Rate (percent)	**6.9**	2.6
Per Unit Transportation Cost ($/BOE)	**1.43**	2.55
Per Unit Operating Cost ($/BOE)	**11.09**	9.01

Revenues

Price

Our total realized sales price was $30.32 per BOE in the first quarter of 2021 compared with $17.23 per BOE in the same period in 2020 primarily due to higher crude oil and natural gas benchmark prices.

In the first three months of 2021, gross sales of $381 million (2020 – $61 million) included third-party sourced volumes which are not included in our per-unit pricing metrics or our Netbacks.

In the first three months of 2021, revenues included other amounts of $24 million (2020 – $11 million), which are not included our per-unit pricing metrics or our Netbacks as it relates to processing and transportation activities for third-parties.

Production Volumes

Conventional production was 135,933 BOE per day in the first three months of 2021 compared with 95,558 BOE per day in the first three months of 2020.

Production volumes increased in the first quarter of 2021 primarily due to 50,556 BOE per day from assets acquired as part of the Arrangement, combined with 11 new gross wells brought on production during the quarter. The increase is partially offset by natural declines and the sale of our Marten Hills assets in December 2020, which produced 3,165 BOE per day in the first quarter of 2020.

Royalties

The Conventional assets are subject to royalty regimes in both Alberta and British Columbia.

Effective royalty rates increased primarily due to higher realized prices and lower gas cost allowance credits.

Royalties increased by $21 million compared with the first quarter of 2020, primarily due to higher pricing combined with increased production resulting from assets acquired as part of the Arrangement.

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. Per-unit transportation costs averaged $1.43 per BOE (2020 – $2.55 per BOE), due to decreased contract rates and higher sales volumes compared with the first quarter of 2020.

Transportation costs decreased $5 million compared with the first quarter of 2020 primarily due to decreased per-unit transportation costs, partially offset by higher sales volumes.

Operating

Primary drivers of our operating expenses in the first quarter of 2021 were workforce, repairs and maintenance, property tax and lease costs, and electricity. Total operating costs increased $58 million primarily due to the assets acquired in the Arrangement.

Operating costs increased $2.08 per BOE to $11.09 per BOE in the first quarter of 2021 compared with the same period of 2020. The increase is primarily due to higher average operating costs on assets acquired as part of the Arrangement.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate accounts for expenditures incurred to date, together with estimated future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A each period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over total estimated life of the related asset as represented by proved reserves. The average depletion rate for the first quarter of 2021 was $8.64 per barrel (2020 - $10.80 per barrel).

In the first quarter of 2021, DD&A decreased $300 million primarily due to an impairment write-down of $315 million in 2020 and a lower depletable base as a result of impairment write-downs during the year ended December 31, 2020, partially offset by assets acquired in the Arrangement.

Netbacks

	Three Months Ended March 31,	
($/BOE)	**2021**	2020
Sales Price	**30.32**	17.23
Royalties	**2.00**	0.35
Transportation and Blending	**1.43**	2.55
Operating Expenses	**11.09**	9.01
Netback Excluding Realized Risk Management	**15.80**	5.32
Realized (Gain) Loss on Risk Management	**0.05**	-
Unrealized (Gain) Loss on Risk Management	**(0.01)**	-
Netback Including Realized Risk Management	**15.76**	5.32

Our average Netback increased in the first quarter of 2021 compared with 2020, primarily due to higher realized sales prices and lower transportation and blending costs, partially offset by higher royalties and operating costs.

OFFSHORE

The Offshore segment was acquired as part of the Arrangement and includes exploration and development activities in offshore China and the equity-accounted investment of HCML joint venture in Indonesia and offshore the east coast of Canada.

In the first quarter of 2021, we:

- Delivered safe and reliable operations;
- Generated Operating Margin of $344 million;
- Achieved record quarterly production rates at our Liwan gas project in China; and
- Achieved a Netback of $56.10 per BOE.

Offshore Consolidated

Financial Results

($ millions)	Three Months Ended March 31, 2021
Gross Sales	**431**
Less: Royalties	**25**
Revenues	**406**
Expenses	
Transportation and Blending	**4**
Operating	**58**
Operating Margin	**344**
DD&A	**125**
Exploration Expense	**(1)**
Share of (Income) Loss from Equity-Accounted Affiliates	**(12)**
Segment Income (Loss)	**232**

DD&A

In the Offshore segment, we deplete crude oil and natural gas properties using the unit-of-production method based on estimated proved developed producing reserves or proved plus probable reserves determined using forward prices and costs. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A each period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over total estimated life of the related asset as represented by proved developed producing or proved plus probable reserves. The average depletion rate for the first quarter of 2021 was $25.87 per barrel.

We depreciate our ROU assets on a straight-line basis over the shorter of the estimated useful life or the lease term.

Netbacks

	Three Months Ended March 31,2021			
($/BOE)	China	Indonesia	Atlantic	Total
Sales Price	**69.44**	**60.68**	**81.37**	**70.70**
Royalties	**3.70**	**8.26**	**5.70**	**4.67**
Transportation and Blending	**-**	**-**	**2.84**	**0.56**
Operating Expenses	**4.71**	**7.51**	**26.56**	**9.37**
Netback	**61.03**	**44.91**	**46.27**	**56.10**

Asia Pacific

Asia Pacific operations were acquired on January 1, 2021 as part of the Arrangement.

In China, the Liwan gas project includes working interests of 49 percent in natural gas developments at the Liwan 3-1 and Liuhua 34-2 producing fields and 75 percent in the Liuhua 29-1 producing field. Cenovus also has petroleum contracts in Blocks 15/33, 16/25 and 23/07 which are in the exploration phase. We expect to drill an exploration well at Block 15/33, which contains an existing discovery, in mid to late-2021. Cenovus has obtained partner agreement to drill an exploration commitment well in a different area outside of Block 16/25 before April 30, 2022.

In Indonesia, Cenovus has a 40 percent ownership interest in HCML that holds the Madura Strait production sharing contract license area. This license area includes the operating BD field, ongoing developments at the MDA, MBH and MDK discoveries; while development at the MAC field is expected to begin in mid-2021 if a final investment decision is approved by HCML. Financial results from HCML are accounted for using the equity method.

Cenovus also holds exploration rights to a block located southwest of the island of Taiwan in the South China Sea.

Financial Results

($ millions)	Three Months Ended March 31, 2021
Gross Sales	**321**
Less: Royalties	**17**
Revenues	**304**
Expenses	
Operating	**22**
Operating Margin	**282**

Operating Results

	Three Months Ended March 31,2021
Total Sales Volumes (1)(2)(3) (BOE/d)	**60,832**
NGLs (1)(2)(3) (bbls/d)	**12,919**
Natural Gas (1)(2)(3) (Mcf/d)	**288**
Total Realized Price per Unit Sold (3) ($/BOE)	**68.08**
NGLs (3) ($/bbl)	**69.66**
Natural Gas (3) ($/Mcf)	**11.28**
Effective Royalty Rate (3) (percent)	**6.5**
Per Unit Operating Cost (3) ($/BOE)	**5.14**

(1) Sales volumes approximates total daily production.
(2) Reported sales volumes include Cenovus's working interest from the Liwan gas project.
(3) Reported sales volumes, associated per unit values and royalty rates reflect Cenovus's 40 percent interest in the Madura-BD gas project. Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.

Revenues

Price

In the first quarter of 2021, our total realized sales price was $68.08 per BOE. The price we receive for natural gas is set under long-term contracts. The price we receive for NGLs is primarily driven by the price of Brent.

Production Volumes

Asia Pacific operations performed well, producing of 60,832 BOE per day in the first three months of 2021.

Royalties

Royalty rates are governed by production sharing contracts in which production is shared with the Chinese and Indonesian governments.

Expenses

Operating

Primary drivers of our operating expenses in the first quarter of 2021 were repairs and maintenance, insurance, and workforce.

Atlantic

Atlantic operations were acquired on January 1, 2021 as part of the Arrangement.

Cenovus's Atlantic exploration and development program is focused in the Jeanne d'Arc Basin and the Flemish Pass offshore Newfoundland and Labrador. The Jeanne d'Arc Basin contains the Hibernia, Terra Nova and Hebron fields, as well as the White Rose field and satellite extensions, including North Amethyst, West White Rose and South White Rose. In the Flemish Pass Basin, Cenovus holds a 35 percent non-operated working interest in each of the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. Cenovus is the operator of the White Rose field and satellite extensions and holds an ownership interest in the Terra Nova field, as well as several smaller undeveloped fields. Cenovus also holds exploration acreage offshore Newfoundland and Labrador.

Cenovus's production in the first quarter of 2021 is from the White Rose field and satellite extensions.

Production operations at the Terra Nova field have been suspended since December 2019. The Terra Nova floating production storage and offloading unit is being preserved quayside as the operator and partners determine next steps.

The West White Rose Project remains deferred for 2021 while Cenovus continues to evaluate its options.

Financial Results

($ millions)	Three Months Ended March 31,2021
Gross Sales	**110**
Less: Royalties	**8**
Revenues	**102**
Expenses	
Transportation	**4**
Operating	**36**
Operating Margin	**62**

Operating Results

	Three Months Ended March 31,2021
Total Sales Volumes	
Light Oil (bbls/d)	**14,945**
Total Realized Price per Unit Sold ($/bbl)	
Light Oil ($/bbl)	**81.37**
Total Daily Production	
Light Oil (bbls/d)	**16,920**
Effective Royalty Rate (percent)	**7.0**
Per Unit Operating Cost ($/bbl)	**26.56**

Revenues

Price

In the first quarter of 2021, our total realized sales price was $81.37 per barrel. The price we receive for light oil is primarily driven by the price of Brent.

Production and Sales Volumes

Atlantic operations performed well, producing of 16,920 barrels per day in the first three months of 2021.

Light oil from production at the White Rose field is offloaded from the SeaRose floating production storage and offloading unit (“SeaRose FPSO”) to tankers and stored at an onshore terminal before shipment to buyers. The result is a timing difference between production and sales. Our sales volumes were 14,945 BOE per day in the first quarter of 2021.

Royalties

Royalties at the White Rose field are based on an agreement between our working interest partners and the Government of Newfoundland and Labrador. We currently pay a basic royalty of 7.5 percent of gross sales at the White Rose field and 5.0 percent of gross sales at the satellite extensions.

Expenses

Operating

Primary drivers of our operating expenses in the first quarter of 2021 were repairs and maintenance, workforce, vessel costs and helicopter costs.

Transportation

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

DOWNSTREAM

CANADIAN MANUFACTURING

On December 31, 2020, Canadian Manufacturing operations included the Bruderheim crude-by-rail terminal.

On January 1, 2021, as part of the Arrangement, we acquired:

- The Lloydminster Upgrader which is designed to process blended heavy crude oil feedstock, creating high quality, low-sulphur synthetic crude oil and ultra-low sulphur diesel. The Lloydminster Upgrader has crude oil throughput capacity of 82 thousand barrels per day.
- The Lloydminster Refinery, which processes heavy crude oil and bitumen into asphalt products used in road construction and maintenance. The refinery also produces straight run gasoline, bulk distillates and industrial products. The Lloydminster Refinery has crude oil throughput capacity of 29 thousand barrels per day.
- Two ethanol plants in Lloydminster, Saskatchewan and Minnedosa, Manitoba.

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

In the first quarter of 2021, we:

- Delivered safe and reliable operations;
- Achieved an average combined crude utilization of 96 percent at the Lloydminster Upgrader and Refinery; and
- Generated Operating Margin of $82 million, an increase of $66 million compared with 2020 due to assets acquired in the Arrangement.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2021**	2020
Revenues	**806**	27
Purchased Product	**631**	-
Gross Margin	**175**	27
Expenses		
Operating	**93**	11
Operating Margin	**82**	16
DD&A	**43**	2
Segment Income (Loss)	**39**	14

Operating Results

	Three Months Ended March 31,	
	2021	2020
Crude Oil Throughput Capacity (Mbbls/d)	**111**	-
Lloydminster Upgrader (Mbbls/d)	**82**	-
Lloydminster Refinery (Mbbls/d)	**29**	-
Crude Oil Throughput (Mbbls/d)	**106**	-
Lloydminster Upgrader (Mbbls/d)	**78**	-
Lloydminster Refinery (Mbbls/d)	**28**	-
Refined Products Output (Mbbls/d)	**107**	-
Upgrading Differential (1)	**14.01**	-
Refining Margin ($/bbl) (2)	**18.40**	-
Operating Expense ($/bbl) (2)	**9.69**	-
Crude Utilization (percent) (2)	**96**	-
Crude-by-Rail Operations		
Volumes Loaded (3) (Mbbls/d)	**22**	96
Ethanol Production (thousands of litres/d)	**397**	-

(1) Based on benchmark price differentials between heavy oil feedstock and synthetic crude.
(2) Based on crude throughput volumes and results of operations at the Lloydminster Upgrader and Refinery.
(3) Volumes loaded and transported outside of Alberta.

Gross Margin

Upgrading operations process heavy crude oil into high value synthetic crude oil and low sulphur distillates. Upgrading profitability is primarily dependent on the differential between the cost of heavy crude oil feedstock and the sales price of synthetic crude oil and diesel.

Lloydminster Refinery operations process heavy crude oil into asphalt and industrial products. The gross margin is primarily dependent on asphalt market prices and the cost of heavy crude oil feedstock.

Operating Expense

Primary drivers of operating expenses in the first quarter of 2021 were workforce, repairs and maintenance, and energy costs. Unit operating expenses were $9.69 per barrel of crude throughput in the first three months of 2021.

DD&A

Canadian manufacturing assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 60 years. The service lives of these assets are reviewed on an annual basis. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. Canadian manufacturing DD&A was $43 million in the first quarter of 2021 compared with $2 million in 2020 as a result of assets acquired as part of the Arrangement.

U.S. MANUFACTURING

On December 31, 2020, U.S. Manufacturing operations included the jointly owned Wood River and Borger refineries with operator Phillips 66. We have a 50 percent interest in each refinery.

On January 1, 2021, as part of the Arrangement, we acquired:

- The Lima Refinery, of which we own 100 percent, located in Lima, Ohio. The refinery produces low sulphur gasoline, gasoline blend stocks, ultra-low sulphur diesel, jet fuel, petrochemical feedstock and other by-products;
- The Toledo Refinery, of which our interest is 50 percent, located near Toledo, Ohio. The refinery is jointly owned with operator BP. Products from the refinery include low sulphur gasoline, ultra-low sulphur diesel, aviation fuel, and other by-products; and
- The Superior Refinery, of which we own 100 percent, located in Superior, Wisconsin. On April 26, 2018, the refinery experienced an incident while preparing for a major turnaround and was taken out of operation. The refinery is being rebuilt and is expected to restart around the first quarter of 2023.

In the first quarter of 2021, we:

- Delivered safe and reliable operations,
- Continued to operate refineries below capacity in response to market conditions;
- Were impacted by a temporary unplanned outage at the Lima Refinery and a two-week disruption at the Mid-Valley pipeline, which transports feedstock to the Lima Refinery, negatively effecting throughput;
- Began planned maintenance turnarounds at Wood River and Borger refineries; and
- Achieved Operating Margin of $91 million, an increase of $475 million compared with 2020 due to higher refining margins, a non-cash inventory write-down of $243 million in 2020, and increased throughput and sales from assets acquired as part of the Arrangement, partially offset by lower crude oil throughput at the Wood River and Borger refineries and higher operating costs.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2021**	2020 (1)
Revenues	**3,437**	1,555
Purchased Product	**2,920**	1,731
Gross Margin	**517**	(176)
Expenses		
Operating	**405**	209
Realized (Gain) Loss on Risk Management	**21**	(1)
Operating Margin	**91**	(384)
Unrealized (Gain) Loss on Risk Management (2)	**10**	-
Depreciation, Depletion and Amortization	**114**	77
Segment Income (Loss)	**(33)**	(461)

(1) Prior periods have been reclassified to conform with current period's operating segments.

(2) Unrealized gain and loss on risk management are recorded in the reportable segment to which the derivative instrument relates to. Comparative periods have been reclassified as these amounts were recorded in the Corporate and Eliminations segment prior to January 1, 2021.

Select Operating Results

	Three Months Ended March 31,	
	2021	**2020**
Crude Oil Throughput Capacity (Mbbls/d)	**503**	248
WRB [1]	**248**	248
Lima Refinery	**175**	-
Toledo Refinery [1]	**80**	-
Crude Oil Throughput (Mbbls/d)	**363**	221
WRB [1]	**170**	221
Lima Refinery	**125**	-
Toledo Refinery [1]	**68**	-
Throughput by Product (Mbbls/d)		
Heavy Crude Oil	**120**	99
Light/Medium	**243**	122
Crude Utilization (percent)	**72**	89
Refining Margin [2] ($/bbl)	**15.84**	(8.75)
Operating Expense [2] ($/bbl)	**12.40**	10.39

(1) Represents Cenovus's 50 percent interest in Wood River, Borger and Toledo refinery operations.
(2) Based on crude oil throughput volumes and operating results at Wood River and Borger refineries, Lima Refinery and Toledo Refinery.

All refineries continue to optimize throughput as market conditions dictate. Throughput ran at reduced rates early in the quarter due to low market crack spreads.

At the Wood River and Borger refineries, crude oil throughput decreased further in the first quarter of 2021 due to planned maintenance turnarounds beginning in early March and late February, respectively. The turnaround at Wood River is expected to be completed in mid-May and the turnaround at Borger was completed on April 7, 2021.

At the Lima Refinery, we had a temporary unplanned outage due to an incident that shut down our fluid catalytic cracking unit. In addition, for two weeks in February, winter storm Uri disrupted the Mid-Valley pipeline which supplies the refinery's feedstock, further impacting throughput. Throughput rates began ramping up in March as market conditions improved.

Gross Margin

While market crack spreads are an indicator of margin from processing crude oil into refined products, the refining realized crack spread, which is the gross margin on a per-barrel basis, is affected by many factors, such as the variety of feedstock crude oil 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. Our feedstock costs are valued on a FIFO accounting basis.

In the first quarter of 2021, gross margin increased $693 million compared with the first quarter of 2020 driven by improved market crack spreads combined with a non-cash inventory write-down of $243 million in the first quarter of 2020 included in purchased product.

The increased cost of RINs partially offset improved refining margins. In the first quarter of 2021, the cost of RINs was $180 million compared with $32 million in the first quarter of 2020 due to higher RINs pricing and assets acquired in the Arrangement. RINs prices increased to US$5.49 per barrel in the first quarter of 2021 from US$1.58 per barrel in the first quarter of 2020.

Gross margin was further improved by additional throughput and sales volumes on assets acquired from the Arrangement, partially offset by implemented crude rate reductions and scheduled maintenance turnarounds at the Wood River and Borger refineries.

Operating Expense

Primary drivers of operating expenses in the first quarter of 2021 were repairs and maintenance, workforce costs, and utilities. In the first quarter of 2021, operating expenses increased $196 million compared with the first quarter of 2020. The increase was due to assets acquired in the Arrangement, combined with turnaround activities at Wood River and Borger refineries and higher utility pricing at the Lima and Borger refineries associated with the impacts of winter storm Uri.

DD&A

U.S. Manufacturing assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 60 years. The service lives of these assets are reviewed on an annual basis. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. U.S. manufacturing DD&A was $114 million in the first quarter of 2021 an increase of $37 million compared to the first quarter of 2020 as a result of assets acquired in the Arrangement.

RETAIL

Retail operations were acquired on January 1, 2021 as part of the Arrangement.

For the three months ended, March 31, 2021, our retail and commercial network averaged 540 independently operated Husky and Esso branded petroleum product outlets. Our retail and commercial operating model is balanced by corporate owned/dealer operated and branded dealer-owned-and-operated sites. The network consists of a variety of full- and self-serve retail stations, travel centres and cardlocks serving urban and rural markets across Canada, while our bulk distributors offer direct sales to commercial and agricultural markets in the prairie provinces.

Financial Results

($ millions)	Three months ended March 31, 2021
Gross Sales	**447**
Purchased Product	**417**
Gross Margin	**30**
Expenses	
Operating	**19**
Operating Margin	**11**
DD&A	**12**
Segment Income (Loss)	**(1)**

Select Operating Results

	Three months ended March 31, 2021
Fuel Sales Volume, including wholesale	
Fuel Sales (millions of litres/d)	**6.5**
Fuel Sales per Retail Outlet (thousands of litres/d)	**12.0**

Gross Margin

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

Operating expenses

Primary drivers of our operating expenses in the first quarter of 2021 were repairs and maintenance, property tax, workforce and utilities.

DD&A

Retail assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 60 years. The service lives of these assets are reviewed on an annual basis. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. Retail DD&A was $12 million in the first quarter of 2021 as a result of retail assets acquired in the Arrangement.

CORPORATE AND ELIMINATIONS

In the first quarter of 2021, our risk management activities resulted in:

- Unrealized risk management gains of $16 million (2020 – $nil) due to the realization of settled positions and changes in commodity prices during the three months ended March 31, 2021;
- Realized risk management losses of $89 million (2020 – $nil) due to the realization of WTI put and call option contracts acquired as part of the Arrangement; and
- Realized foreign exchange risk management losses of $2 million (2020 – loss of $5 million).

Expenses

($ millions)	Three Months Ended March 31, 2021	2020
General and Administrative [1]	**163**	(23)
Finance Costs	**244**	107
Interest Income	**(4)**	(1)
Foreign Exchange (Gain) Loss, Net	**(117)**	637
Integration Costs	**223**	-
Re-measurement of Contingent Payment	**187**	(130)
(Gain) Loss on Divestiture of Assets	**(12)**	1
Other (Income) Loss, Net [2]	**(72)**	(6)
	612	585

(1) Onerous contract provisions of $2 million in 2020 have been reclassified to general and administrative expenses.
(2) Research costs of $3 million in 2020 have been reclassified to Other (Income) Loss, Net.

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs, employee long-term incentive costs, information technology costs and operating costs associated with our real estate portfolio. In the first quarter of 2021, general and administrative expenses were higher due to a larger workforce and higher long-term incentive costs due to increased share price.

Finance Costs

In the first quarter of 2021, finance costs increased by $137 million primarily due to long-term debt assumed as part of the Arrangement.

The weighted average interest rate on outstanding debt for the three months ended March 31, 2021 was 4.5 percent (2020 – 5.0 percent).

Integration Costs

We incurred $223 million of costs as a result of the Arrangement, not including capital expenditures. Integration costs include $145 million of severance payments, $65 million of transaction costs and $13 million in other integration related costs. Transaction costs exclude share issuance costs related to common shares, preferred shares and warrants.

Foreign Exchange

($ millions)	Three Months Ended March 31, 2021	2020
Unrealized Foreign Exchange (Gain) Loss	**(139)**	657
Realized Foreign Exchange (Gain) Loss	**22**	(20)
	(117)	637

In the first quarter of 2021, unrealized foreign exchange gains of $139 million were recorded primarily as a result of the translation of our U.S. dollar denominated debt.

Re-measurement of Contingent Payment

Related to Foster Creek and Christina Lake production, Cenovus agreed to make quarterly payments to ConocoPhillips Company and certain of its subsidiaries ("ConocoPhillips") during the five years subsequent to the closing date of the acquisition from ConocoPhillips of their 50 percent interest in the FCCL Partnership on May 17, 2017 ("the Conoco Acquisition"), for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. The quarterly payment is $6 million for each dollar that the WCS price exceeds $52 per barrel. There are no maximum payment terms. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment.

The contingent payment is accounted for as a financial option. The fair value of $217 million as at March 31, 2021 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. For the three months ended March 31, 2021, a non-cash re-measurement loss of $187 million was recorded. For the three months ended March 31, 2021, $33 million is payable under this agreement.

Average WCS forward pricing for the remaining term of the contingent payment is $57.38 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately $54.26 per barrel and $61.41 per barrel.

Other (Income) Loss, Net

In the first quarter of 2021, other income increased by $66 million primarily due to business interruption and rebuild insurance proceeds of $45 million related to the Superior Refinery and $19 million on Headwater Exploration Inc. warrants revaluation.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements, office furniture and certain ROU assets. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. ROU assets are depreciated on a straight-line basis over the estimated useful life of the asset or the lease term. DD&A in the first three months ended March 31, 2021 was $31 million (2020 - $45 million). The decrease in DD&A was primarily due to an impairment loss of $8 million related to leasehold improvements in the first quarter of 2020.

Income Tax

	Three Months Ended March 31,	
($ millions)	**2021**	2020
Current Tax		
Canada	**12**	-
Asia Pacific	**34**	-
Other International	**1**	-
Current Tax Expense (Recovery)	**47**	-
Deferred Tax Expense (Recovery)	**27**	(348)
Total Tax Expense (Recovery)	**74**	(348)

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

For the three months ended March 31, 2021, the Company recorded a current tax expense primarily related to Asia Pacific operations in China as well as provincial tax from Cenovus operations in Canada. The increase is due to Asia Pacific operations acquired in the Arrangement and higher earnings compared with the first quarter of 2020.

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

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended March 31,	
($ millions)	**2021**	2020
Cash From (Used In)		
Operating Activities	**228**	125
Investing Activities	**204**	(321)
Net Cash Provided (Used) Before Financing Activities	**432**	(196)
Financing Activities	**39**	182
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**24**	(12)
Increase (Decrease) in Cash and Cash Equivalents	**495**	(26)

	March 31, 2021	December 31, 2020
Cash and Cash Equivalents	**873**	378
Debt (1)	**14,213**	7,562

(1) Includes long-term debt and short-term borrowings.

Cash From (Used in) Operating Activities

For the first three months of 2021, cash generated by operating activities increased compared with 2020 mainly due to higher Operating Margin, primarily offset by changes in non-cash working capital, integration costs and increased general and administrative expenses and finance costs as discussed in the Corporate and Eliminations section of this MD&A.

Excluding the current portion of the contingent payment, our working capital was $2,098 million at March 31, 2021 compared with $653 million at December 31, 2020. The increase in working capital is primarily due to increased accounts receivable and accrued revenues and inventories partially offset by increased accounts payable and accrued liabilities.

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

Cash From (Used in) Investing Activities

Cash provided from investing activities was higher in the first quarter of 2021 compared with 2020 primarily due to cash of $735 million acquired as part of the Arrangement partially offset by higher capital spending in the first quarter.

Cash From (Used in) Financing Activities

During the first quarter, we issued $107 million in short-term borrowings and $50 million of revolving long-term debt. In the first quarter of 2020, we repurchased US$100 million of unsecured notes for cash of US$81 million.

Total Debt

Total debt, including short-term borrowings, as at March 31, 2021 was $14,213 million (December 31, 2020 – $7,562 million). The increase in total debt was mainly due to the assumption of debt at closing of the Arrangement on January 1, 2021 with a fair value of $6,642 million. The principal amount of debt assumed that is owed to lenders between 2022 and 2037 is $5,751 million.

As at March 31, 2021, we were in compliance with all of the terms of our debt agreements.

Common Share Dividends

In the first quarter of 2021, we paid dividends of $35 million or $0.0175 per common share (2020 – $77 million or $0.0625 per common share). The declaration of dividends is at the sole discretion of the Company's Board of Directors and is considered quarterly.

Cumulative Redeemable Preferred Share Dividends

In the first quarter of 2021, dividends of $9 million were paid on the Series 1, 2, 3, 5, and 7 preferred shares. The declaration of preferred share dividends is at the sole discretion of the Company's Board of Directors and is considered quarterly.

Available Sources of Liquidity

The following sources of liquidity are available at March 31, 2021:

($ millions)	Term	Amount Available
Cash and Cash Equivalents	**Not applicable**	**873**
Committed Credit Facilities		
$2.0 Billion Revolving Credit Facility	**June 2022**	**1,600**
$1.2 Billion Revolving Credit Facility – Tranche B	**November 2022**	**1,200**
$3.3 Billion Revolving Credit Facility – Tranche A	**November 2023**	**3,300**
$2.0 Billion Revolving Credit Facility	**March 2024**	**2,000**
Uncommitted Demand Facilities		
Cenovus Energy Inc.	**Not applicable**	**1,830**
WRB Refining LP ("WRB") (Cenovus's proportionate share)	**Not applicable**	**62**
Sunrise Oil Sands Partnership (Cenovus's proportionate share)	**Not applicable**	**5**

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

Under the terms of Cenovus's committed credit facilities, the Company is required to maintain a debt to capitalization ratio, as defined in the debt agreements, not to exceed 65 percent. The Company is well below this limit.

Committed Credit Facilities

We have total committed credit facilities of $8.5 billion. As at March 31, 2021, there was $400 million drawn on the committed credit facilities (December 31, 2020 - $nil).

Uncommitted Demand Facilities

We have uncommitted demand facilities of $2.5 billion in place, of which $1.5 billion may be drawn for general purposes or the full amount can be available to issue letters of credit. As at March 31, 2021 the Company had drawn $140 million on these facilities (December 31, 2020 - $nil) and there were outstanding letters of credit aggregating to $565 million (December 31, 2020 - $441 million).

WRB has uncommitted demand facilities of US$300 million (our proportionate share - US$150 million) available to cover short-term working capital requirements. As at March 31, 2021, US$201 million was drawn on these facilities, of which US$101 million ($126 million) was our proportionate share (December 31, 2020 – $121 million).

Sunrise Oil Sands Partnership has an uncommitted demand credit facility of $10 million available for general purposes. Our proportionate share is $5 million. There were no amounts drawn on this demand credit facility at March 31, 2021 (December 31, 2020 – $nil).

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

Effective March 31, 2021, Cenovus Energy Inc., as a result of the Arrangement and subsequent amalgamation of Husky Energy Inc. into Cenovus Energy Inc., became the direct obligor under the existing US$500 million 3.95 percent notes due 2022, US$750 million 4.00 percent notes due 2024, $750 million 3.55 percent notes due 2025, $750 million 3.60 percent notes due 2027, $1,250 million 3.50 percent notes due 2028, US$750 million 4.40 percent notes due 2029, US$387 million 6.80 percent notes due 2037 and other direct obligations of Husky.

Base Shelf Prospectus

We have a base shelf prospectus in place 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 October 2021. As at March 31, 2021, US$3.7 billion remained available under the base shelf prospectus for permitted offerings.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Net Debt to Adjusted EBITDA and Net Debt to Capitalization. We define our non-GAAP measure of 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. We define Capitalization as Net Debt plus Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense (recovery), DD&A, exploration expense, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, other income (loss), net, and share of income (loss) from equity-accounted investees calculated on a trailing twelve-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

	March 31, 2021	December 31, 2020
Net Debt to Capitalization [1] (percent)	**36**	30
Net Debt to Adjusted EBITDA (times)	**5.2x**	11.9x

(1) Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.

We target a Net Debt to Adjusted EBITDA ratio of less than 2.0 times, and substantially lower, over the long-term. This ratio may periodically be above the target due to factors such as persistently low commodity prices. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure the Company has 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, repurchase our common shares for cancellation, issue new debt, or issue new shares.

As at March 31, 2021, our Net Debt to Adjusted EBITDA was 5.2 times. Net Debt to Adjusted EBITDA decreased compared with the fourth quarter of 2020 as a result of higher Operating Margin in the first quarter in 2021, offset by an increase in our Net Debt acquired as part of the Arrangement.

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

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

Share Capital and Stock-Based Compensation Plans

Under the Arrangement, we acquired each issued and outstanding Husky common shares in consideration for the issuance of 0.7845 Cenovus common shares plus 0.0651 Cenovus warrants. We issued 788.5 million Cenovus common shares with a fair value of $6.1 billion, based on the December 31, 2020 closing share price of $7.75, as reported on the TSX. In addition, 65.4 million common share purchase warrants were issued. Each whole warrant entitles the holder to acquire one Cenovus common share for a period of five years at an exercise price of $6.54 per share. The fair value of the warrants was estimated to be $216 million. We also acquired all the issued and outstanding Husky preferred shares in exchange for 36.0 million Cenovus first preferred shares with substantially identical terms and a fair value of $519 million.

We have a number of stock-based compensation plans which include stock options with associated net settlement rights, performance share units ("PSUs"), restricted share units ("RSUs") and deferred share units ("DSUs"). In connection with the Arrangement, at the closing of the transaction on January 1, 2021, outstanding Husky stock options were replaced by Cenovus replacement stock options ("Cenovus replacement stock options"). Each Cenovus replacement stock option entitles the holder to acquire 0.7845 of a Cenovus common share at an exercise price per share of a Husky stock option divided by 0.7845. The fair value of the replacement stock options was estimated to be $9 million.

As at March 31, 2021, there were approximately 2,017 million common shares outstanding (2020 – 1,229 million common shares). Refer to Note 21 of the interim Consolidated Financial Statements for more details.

Refer to Note 23 of the interim Consolidated Financial Statements for more details on our stock option plan and our PSU, RSU and DSU Plans.

Our outstanding share data is as follows:

As at April 30, 2021	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares [1]	**2,017,510**	**N/A**
Common Share Warrants	**65,317**	**N/A**
Preferred Shares Series 1	**10,740**	**N/A**
Preferred Shares Series 2	**1,260**	**N/A**
Preferred Shares Series 3	**10,000**	**N/A**
Preferred Shares Series 5	**8,000**	**N/A**
Preferred Shares Series 7	**6,000**	**N/A**
Stock Options [1]	**43,550**	**29,450**
Other Stock-Based Compensation Plans	**14,998**	**1,524**

(1) *Includes Cenovus replacement stock options (defined above) issued pursuant to the Arrangement in replacement of all issued and outstanding Husky stock options.*

Capital Investment Decisions

Our 2021 capital program is forecast to be between $2.3 billion and $2.7 billion. Our investment is focused on maintaining safe and reliable operations while positioning the Company to drive enhanced shareholder value and includes sustaining capital of approximately $2.1 billion to deliver upstream production of approximately 755,000 BOE per day and downstream throughput of approximately 525,000 barrels per day.

($ millions)	Three Months Ended March 31, 2021	2020
Adjusted Funds Flow	**1,141**	(154)
Total Capital Investment	**547**	304
Free Funds Flow [1]	**594**	(458)
Cash Dividends	**44**	77
	550	(535)

(1) *Free Funds Flow is a non-GAAP measure defined as Adjusted Funds Flow less capital investment.*

Our approach on the financial framework remains consistent with the parameters we have set for Cenovus in prior years. We will continue to evaluate all opportunities based on a US$45.00 per barrel WTI price with the objective of maintaining a prudent and flexible capital structure and strong balance sheet metrics. This approach positions us to be financially resilient in times of lower cash flows. Balance sheet strength continues to be a top priority and we plan to continue to direct our Free Funds Flow towards debt reduction. We continue to target a Net Debt to EBITDA ratio of less than 2.0 times.

We remain committed to investment-grade credit ratings and strengthening our ratings from current levels. This includes our continued focus on allocating Free Funds Flow to reduce Net Debt to less than $10 billion and targeting a longer-term Net Debt level at or below $8 billion. The Adjusted Funds Flow is expected to fully fund sustaining capital and shareholder distributions going forward once one-time integration costs associated with the Arrangement are complete.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Obligations are primarily related to transportation agreements, our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. Obligations that have original maturities of less than one year are excluded. For further information, see the notes to the March 31, 2021 interim Consolidated Financial Statements and December 31, 2020 Consolidated Financial Statements.

The Arrangement resulted in the assumption of non-cancellable contracts and other commercial commitments. On January 1, 2021, we assumed total commitments of $17.6 billion, of which $7.4 billion were for various transportation commitments. Transportation commitments include $1.7 billion that are subject to regulatory approval or have been approved but are not yet in service.

Our total commitments were $33.2 billion as at March 31, 2021, of which $20.6 billion are for various transportation and storage commitments. Terms are up to 20 years subsequent to the date of commencement and should help align with the Company's future transportation requirements.

As at March 31, 2021, there were no amounts included in the transportation and storage commitments related to the Keystone XL pipeline due to the cancellation of our transportation services agreement related to the project (December 31, 2020 - $7.0 billion).

Our commitments with HMLP at March 31, 2021 include $2.6 billion related to transportation and storage contracts.

We continue to focus on mid-term strategies to broaden market access for our crude oil production including supporting proposed pipeline projects to transport our production to new markets in the U.S. and globally as well as moving our crude oil production to market by rail. We continue to assess all options to maximize the value of our crude oil.

As at March 31, 2021, outstanding letters of credit issued as security for performance under certain contracts totaled $565 million (December 31, 2020 – $441 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.

Contingent Payment

In connection with the Conoco Acquisition and related to certain of our oil sands production, we agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. As at March 31, 2021, the estimated fair value of the contingent payment was $217 million. As at March 31, 2021, $33 million was payable under the agreement. See the Corporate and Eliminations section of this MD&A for more details.

Transactions with Related Parties

Transactions with HMLP are related party transactions as the Company has a 35 percent ownership interest in HMLP.

As the operator of the assets held by HMLP, Cenovus provides management services for which it recovers shared service costs.

The Company is also the contractor for HMLP and constructs its assets on a cost recovery basis with certain restrictions. For the three months ended March 31, 2021, the Company charged HMLP $32 million for construction and management services.

The Company pays an access fee to HMLP for the use of its pipeline systems that are used by Cenovus's blending business. Cenovus also pays HMLP for transportation and storage services. For the three months ended March 31, 2021, the Company incurred costs of $72 million for the use of HMLP's pipeline systems, as well as transportation and storage services.

RISK MANAGEMENT AND RISK FACTORS

For a full understanding of the risks that impact us, the following discussion should be read in conjunction with the Risk Management and Risk Factors section of our 2020 annual MD&A.

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

The following provides an update on our risks.

Canada's National Carbon-Pricing Regime

On March 25, 2021, the Supreme Court of Canada ("SCC") released its judgement confirming the constitutionality of Canada's national carbon-pricing regime. Several Canadian provinces had previously launched constitutional challenges to Canada's national carbon-pricing regime and as Canada's highest appeal court the SCC's decision is the final ruling on this matter. See "Risk Management and Risk Factors – Climate-Related Risks – Transition Risks – Policy & Legal – Climate Change Regulation" in our 2020 annual MD&A for a description of the risks associated with Canada's national carbon-pricing regime.

Obligor Under Husky's Existing Notes

Effective March 31, 2021, Cenovus Energy Inc. amalgamated with its wholly owned subsidiary Husky Energy Inc. under the provisions of the *Canada Business Corporations Act*. As a result of the amalgamation, Cenovus Energy Inc. became the direct obligor under Husky's existing US$500 million 3.95 percent notes due 2022, US$750 million 4.00 percent notes due 2024, $750 million 3.55 percent notes due 2025, $750 million 3.60 percent notes due 2027, $1,250 million 3.50 percent notes due 2028, US$750 million 4.40 percent notes due 2029, US$387 million 6.80 percent notes due 2037, and other direct obligations of Husky. See "Risk Management and Risk Factors – Other Risks – Risks Related to the Arrangement – Increased Indebtedness" in our 2020 annual MD&A.

Financial Risk

Commodity Prices

Fluctuations in commodity prices, associated price differentials and refining margins impact our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing. We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts, market access commitments and generally through our access to committed credit facilities. In certain instances, Cenovus will use derivative instruments to manage exposure to price volatility on a portion of its 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 25 and 26 to the interim Consolidated Financial Statements.

Risks Associated with Derivative Financial Instruments

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

Financial instruments also expose us to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. Financial instruments may limit the benefit to us if commodity prices, interest or foreign exchange rates change. These risks are managed through hedging limits authorized according to our *Market Risk Management Policy*.

Impact of Financial Risk Management Activities

Cenovus makes storage and transportation decisions using our marketing and transportation infrastructure, including storage and pipeline assets to optimize product mix, delivery points, transportation commitments and customer diversification. In order to price protect our inventories associated with the storage or transport decisions, Cenovus employs various price alignment strategies to reduce volatility in future cash flows to achieve stable cash flow while we are deleveraging our balance sheet through risk management contracts.

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

In the first quarter of 2021, we incurred a realized risk management loss due to the settlement of benchmark prices relative to our risk management contract prices; the underlying physical inventory sold in the quarter recognized a gain due to rising benchmark prices. In the first quarter of 2021, unrealized gains were recorded on our crude oil financial instruments primarily due to forward benchmark pricing falling below our risk management contract prices that related to future periods and the realization of settled positions. In a rising commodity price environment, we would expect to realize losses on our risk management activities, but recognize gains on the underlying physical inventory sold in the period and the opposite to occur in a falling commodity price environment.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions and 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 our annual and interim Consolidated Financial Statements. A full list of the key sources of estimation uncertainty can be found in our annual Consolidated Financial Statements for the year ended December 31, 2020. During the three months ended March 31, 2021, the Company made updates to its critical judgments in applying accounting policies and key sources of estimation uncertainty including the assessment of joint arrangements, recoveries from insurance claims, functional currency for the Company's subsidiaries and the far value of related party transactions. Updates to critical judgments and key sources of estimation relate to changes in the operations of the Company as a result of the close of the Arrangement. Further information can be found in Note 3 to the interim Consolidated Financial Statements.

Changes in Accounting Policies

During the three months ended March 31, 2021, as a result of the close of the Arrangement, the Company updated its significant accounting policies including those around principles of consolidation, revenue recognition, employee benefit plans, related party transactions, cash and cash equivalents, property, plant and equipment, share capital and warrants and stock based compensation. Further information can be found in Note 3 to the interim Consolidated Financial Statements.

New Accounting Standards and Interpretations not yet Adopted

There are new standards, amendments to accounting standards and interpretations that are effective for annual periods beginning or after January 1, 2021. There were no new or amended accounting standards or interpretations issued during the three months ended March 31, 2021 that are expected to have a material impact on our interim Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at March 31, 2021. 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 internal control over financial reporting. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at March 31, 2021.

On January 1, 2021, Cenovus and Husky closed the Arrangement to combine the two companies. As permitted by and in accordance with, National Instrument 52-109, *"Certification of Disclosure in Issuers' Annual and Interim Filings"*, and guidance issued by the U.S. Securities and Exchange Commission, Management has limited the scope and design of ICFR and DC&P to exclude the controls, policies and procedures in respect of the business acquired from Husky. Such scope limitation is primarily due to the time required for Management to assess the ICFR and DC&P relating to Husky in a manner consistent with our other operations. Further integration will take place throughout the year as processes and systems align.

Assets attributable to Husky as at March 31, 2021 represented approximately 35 percent of Cenovus's total assets, and revenues attributable to Husky for the period January 1 to March 31, 2021 represented approximately 50 percent of Cenovus's total revenues for the quarter ended March 31, 2021.

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.

OUTLOOK

Energy markets have moved in a positive direction since 2020 but we believe that the remainder of 2021 will continue to face uncertainty. The scale of resurgence and variants of COVID-19 cases is likely to result in crude oil and refined products markets volatility through the remainder of the year. OPEC+ policy continues to support balancing the market and the group has indicated that supply will gradually be brought back through the year as demand improves. Government policy and stimulus measures are driving expectations of global economic recovery and improving energy consumption. In many regions globally the COVID-19 vaccination roll-out has progressed slowly, however U.S. deployment is very encouraging. Continued successful distribution of COVID-19 vaccines and easing of restrictions will be supportive of demand. There is optimism around the summer driving season and an increase in demand for refined products in second half of 2021.

Our focus remains on maintaining the strength of our balance sheet. We have ample liquidity, top-tier assets which we are able to effectively manage to respond to price signals, one of the lowest cost structures in the industry and have demonstrated our ability to reduce discretionary capital, all of which should allow us to continue to adapt to potential ongoing market volatility.

We continue to monitor the overall market dynamics to assess how we manage our upstream production levels. Our assets can respond to market signals and ramp production up or down accordingly. Our decisions around production levels and refinery crude run rates will be focused on maximizing the value we receive for our products. We expect our annual upstream production to average between 730,000 BOE per day and 780,000 BOE per day and total downstream throughput of 500,000 barrels per day to 550,000 barrels per day.

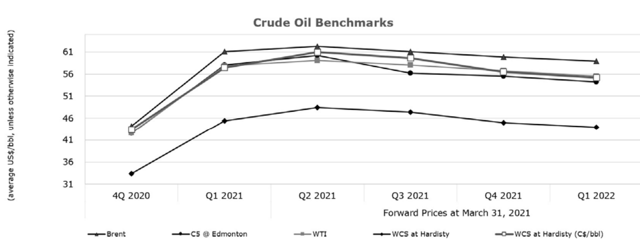
We continue to work towards achieving approximately $400 million of the estimated annual corporate and operating synergies and approximately $600 million of the estimated capital allocation synergies this year. Over the longer-term, we anticipate additional cost savings and margin enhancements based on further physical integration of upstream assets with downstream assets, which is expected to shorten the value chain and reduce condensate costs associated with heavy oil transportation. We continue to look for additional opportunities to reduce operating, capital, and general and administrative spending and increase our margins through strong operating performance and cost leadership while focusing on safe and reliable operations.

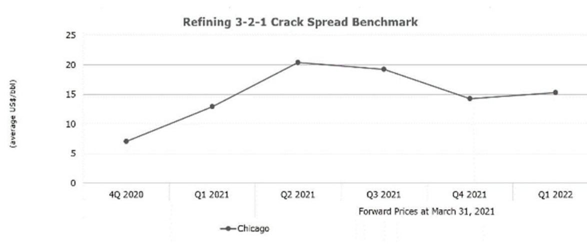
The following outlook commentary is focused on the next twelve months.

Commodity Prices Underlying our Financial Results

Our commodity pricing outlook is influenced by the following:

- We expect the general outlook for crude oil and refined product prices will be volatile and tied primarily to the supply and demand response to the current uncertain price environment, the impact of oversupply, global demand impacts amid COVID-19 concerns, and effectiveness and successful distribution of COVID-19 vaccines;
- The degree to which OPEC+ members (including Russia) continue to maintain crude oil production cuts;
- We expect that the WTI-WCS differential in Alberta will remain largely tied to the extent to which supply cuts are sustained, the potential start-up of Enbridge Inc.'s Line 3 Replacement Project, the completion of the Trans Mountain Expansion project, and the level of crude-by-rail activity; and
- Refining market crack spreads in 2021 are expected to be higher than 2020 as demand rebounds but are also increasing to offset the rising cost of RINs. Margins are likely to continue to fluctuate, adjusting for seasonal trends, and refining run cuts in North America.

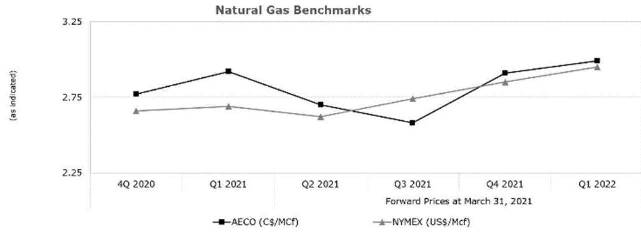


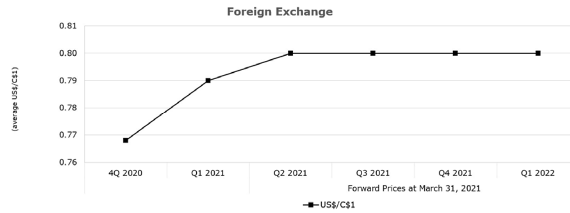


Natural gas prices have rebounded from the 2020 lows and the forward curve shows that the market expects AECO prices to maintain these levels in 2021. Production declines from both associated gas and dry gas, along with rebounding U.S. demand and liquified natural gas exports should continue to tighten North American gas fundamentals for the remainder of 2021 and result in stronger prices than 2020 on an annual basis.

Natural gas and NGLs production associated with our Conventional assets provide improved upstream integration for the fuel, solvent and blending requirements at our Oil Sands operations.

We expect the Canadian dollar to continue to be tied to crude oil prices, the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise or lower benchmark lending rates relative to each other, and emerging macro-economic factors.





Our upstream crude oil production and most of our downstream refined products are exposed to movements in the WTI crude oil price. With the closing of the Arrangement, our exposure has grown on both the upstream and downstream sides of our business.

Our refining capacity is now focused in the U.S. Midwest along with smaller exposures in the USGC and Alberta, exposing Cenovus to the market crack spread in all of these markets.

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

- Transportation commitments and arrangements – using our existing firm service commitments for takeaway capacity and supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets;
- Integration – having heavy oil refining capacity capable of processing Canadian heavy oil. From a value perspective, our refining business positions us to capture value from both the WTI-WCS differential for Canadian crude oil as well as from spreads on refined products;
- Marketing agreements – limiting the impact of fluctuations in upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners;
- 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; and
- Financial hedge transactions – limiting the impact of fluctuations in crude oil and refined product prices by entering into financial transactions related to our inventory price exposures.

Key Priorities For 2021

In the current commodity price environment, we continue to focus on maintaining balance sheet strength and liquidity. Enhancing our financial resilience and flexibility while continuing to deliver safe and reliable operations will continue to be a top priority during these uncertain times.

Our corporate strategy focuses on maximizing shareholder value through cost leadership and realizing the best margins for our products. We expect to remain focused on disciplined capital investment allocation among the full suite of assets for the Company, and continued cost leadership to achieve margin improvement. The Company prioritizes ongoing environmental, social and governance leadership and integration of sustainability considerations into our business decisions.

Safe and Reliable Operations

Safe and reliable operations are our number one priority. Safety continues to be a core value that informs all of the decisions we make. We will continue to promote a safety culture in all aspects of our work and use a variety of programs to keep safety top of mind at all times.

Ensure Smooth Integration

In addition to financial and operating synergies, our focus is to create stability for our workforce and advance the high-performing culture of the combined Company. We aim to build an industry-leading people experience and advance leadership, commercial capability and inclusion & diversity programs. We also aim to enable continuity of business performance through practical, effective systems integration and optimization. We will refresh our vision, mission and values to reflect the Company going forward.

Capture Synergies and Maintain Cost Leadership

Capturing the annual corporate and operating cost synergies of approximately $400 million is well underway and is expected through the consolidation of information technology systems, eliminating other service overlaps, and through reductions to combined workforce and corporate overhead costs.

Over the longer term, we anticipate additional cost savings and margin enhancements based on further physical integration. The integration of upstream assets with downstream and transportation, storage, and logistics portfolio is expected to shorten the value chain and reduce condensate costs associated with heavy oil transportation over the longer term. We continue to look for ways to improve efficiencies across Cenovus to drive incremental capital, operating and general and administrative cost reductions.

Disciplined Capital Investment

We released our 2021 guidance on January 28, 2021 for the Company and anticipate our total capital expenditures to be between $2.3 billion and $2.7 billion, including sustaining capital of approximately $2.1 billion and costs of $520 million to $570 million (excluding insurance proceeds) for the Superior Refinery rebuild. We will continue to be disciplined with our capital. The 2021 guidance is available on our website at cenovus.com.

Our upstream production is expected to range between 730,000 BOE per day and 780,000 BOE per day for 2021. Downstream throughput is expected to be in the range of 500,000 barrels per day to 550,000 barrels per day for 2021. Capturing the estimated $600 million in annual capital allocation synergies is underway across the Company by optimizing sustaining capital to the highest quality assets while maintaining safe and reliable operations across our portfolio.

As at March 31, 2021, our Net Debt position was $13.3 billion. The estimated incremental annual Free Funds Flow from identified near-term synergies with the closing of the Arrangement is expected to accelerate balance sheet deleveraging. Through a combination of cash on hand and available capacity on our committed credit facilities and demand facilities, we have approximately $10.9 billion of liquidity. We will continue to focus on allocating Free Funds Flow to reduce Net Debt to less than $10 billion and target a longer-term Net Debt level at or below $8 billion.

Maintaining Financial Resilience

We have top-tier assets, one of the lowest cost structures in our industry and a strong balance sheet, all of which position us to withstand the challenges of the current market environment. Our capital planning process is flexible, and spending can be reduced in response to commodity prices and other economic factors so we can maintain our financial resilience. Our financial framework and flexible business plan allow multiple options to manage our balance sheet. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices.

The Company's priority will be to maximize Free Funds Flow by focusing investments on sustaining capital expenditures which will position us to direct available Free Funds Flow to the balance sheet and allow us to achieve a Net Debt target of $10 billion which approximates a Net Debt to Adjusted EBITDA target of less than 2.0 times, without the need for asset dispositions.

The low funds flow volatility, breakeven prices and corporate sustaining costs supports an investment grade profile and lower cost of capital through the commodity price cycle. We remain committed to maintaining or re-establishing investment grade credit ratings.

Shareholder Returns

After achieving our balance sheet objectives, the Company's free funds profile is expected to enable sustainable growth in shareholder distributions.

Environmental, Social and Governance

We are committed to ESG leadership. This includes ambitious ESG targets, robust management systems and transparent performance reporting. The Company will continue working to earn its position as a global energy supplier of choice by advancing clean technology and reducing emissions intensity. This includes the ambition of achieving net zero emissions by 2050. We will also continue building upon our strong local community relationships, with a focus on Indigenous economic reconciliation.

Cenovus recently completed a robust ESG materiality assessment to identify the ESG topics that are most impactful to our new portfolio and highest priority for our stakeholders. Based on feedback from both internal and external stakeholders, climate and greenhouse gas emissions, Indigenous reconciliation, water stewardship, biodiversity and inclusion & diversity were established as ESG focus areas for the Company. In addition, delivering safe and reliable operations and demonstrating strong governance remain foundational to the Company and how we manage our business. As the Company updates long-term business plans and strategy we are also working to set meaningful targets for the new portfolio as a result of the close of the Arrangement. Once that work is complete this year and approved by the Board, the new targets for each of the five ESG focus areas and plans to achieve them will be disclosed.

ADVISORY

Oil and Gas Information

Barrels of Oil Equivalent – natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (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 certain forward-looking statements and forward-looking information (collectively referred to as "forward-looking information") within the meaning of applicable securities legislation, including the *U.S. Private Securities Litigation Reform Act of 1995*, about our current expectations, estimates and projections about the future, based on certain assumptions made by us in light of our experience and perception of historical trends. Although we believe that the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking information in this document is identified by words such as "achieve", "aim", "anticipate", "believe", "can be", "capacity", "committed", "commitment", "continue", "could", "deliver", "drive", "enhance", "ensure", "estimate", "expect", "focus", "forecast", "forward", "future", "guidance", "maintain", "may", "objective", "outlook", "plan", "position", "potential", "priority", "re-establishing", "seek", "strategy", "should", "target", "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: strategy, priorities and related milestones; schedules and plans; anticipated benefits of the Arrangement, including: achieving approximately $400 million in annual corporate and operating synergies and approximately $600 million in capital allocation synergies in 2021, achieving longer term cost savings and margin enhancements based on further physical integration, reducing our exposure to Alberta heavy oil price differentials while maintaining exposure to global commodity prices, reducing condensate costs associated with heavy oil transportation over the longer term, accelerating balance sheet deleveraging, consolidation of information technology systems, elimination of services overlaps, workforce reductions and achieving sustainable growth in shareholder distributions; achieving synergies from the Arrangement earlier than originally anticipated; actions taken in response to COVID-19 in our workplaces; improving efficiencies to drive incremental capital, operating and general and administrative cost reductions; the ability of our assets to respond to market signals and ramp up production accordingly; statements and expectations relating to our 2021 budget; maximizing the value per barrel from heavy oil production through our integrated network of assets; optimising refinery throughput; our ability to partially mitigate the impact of crude oil and refined product differentials through transportation commitments, integration, marketing agreements, dynamic storage, traditional storage tanks and financial hedge transactions; maintaining and re-establishing investment grade credit ratings; directing Free Funds Flow towards debt reduction and achieving Net Debt of less than $10 billion; achieving our Net Debt to Adjusted EBITDA target of less than 2.0 times, and substantially lower over the long-term, without the need for asset dispositions; a longer-term Net Debt level at or below $8 billion; focus on maximizing shareholder value; disciplined capital investment and cost leadership to realize the best margins for our products and environmental benefits; maintaining liquidity; delivering a stable cash flow through price cycles and commodity price volatility and preserving a resilient balance sheet; becoming more competitive by leveraging increased economies of scale; expectations regarding achievement of the 2021 guidance based on current production volumes and operating expenses; expected production and throughput levels; the integration of ESG considerations into our business plan; becoming a global energy supplier of choice by advancing clean technology and reducing emissions intensity; ambitions to achieve net zero emissions by 2050; plans to strengthen local community relationships, with a focus on Indigenous economic reconciliation; plans to set and achieve new ESG targets; evaluating disciplined investment in our portfolio against dividends, share repurchases and managing to optimal debt level while maintaining investment grade status; focusing investment on areas where we believe we have the greatest competitive advantage; continued volatility of crude oil and refined product markets as a result of COVID-19; maintaining a high level of capital discipline and managing our capital structure to help ensure the Company has sufficient liquidity through all stages of the economic cycle; expectations of global economic recovery and improving energy consumption; future opportunities for oil and natural gas development; forecast operating and financial results, including forecast sales prices, costs and cash flows; our ability to satisfy payment obligations as they become due; priorities for and approach to capital investment decisions or capital allocation, including decisions pertaining to new projects and phases; planned capital expenditures and investments, including the amount, timing and funding sources thereof; our 2021 capital program; expected development, drilling and exploration and the timing thereof; all statements with respect to our 2021 guidance estimates; our ability to manage our production well rates in response to pipeline capacity constraints, storage constraints and crude oil price differentials; our ability to take steps to partially mitigate against wider WTI and WCS price differentials; our expectation that the general outlook for light crude oil prices will be tied primarily to the supply and demand response to the current uncertain price environment, the impact of oversupply, and global demand impacts amid COVID-19 concerns; our expectation that the WTI-WCS differential in Alberta will remain largely tied to the extent to which supply cuts are sustainable, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, the completion of the Trans Mountain Expansion project, and the level of crude-by-rail activity; the correlation between the pace of oil demand recovery and vaccine distribution; the degree to which

OPEC+ members will continue to maintain production cuts; our expectation that our capital investment and near-term cash requirements will be funded through cash from operating activities and prudent use of our balance sheet capacity including draws on our credit and demand facilities and other corporate and financial opportunities that may be available to us; focus on mid-term strategies to broaden market access for our crude oil production;; our ability to preserve our financial resilience; our priorities, including for 2021; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact; exchange and interest rates; potential impacts of various risks, including those related to commodity prices and climate change; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof, and anticipated impact on the Consolidated Financial Statements; the immateriality of the effects of any liabilities that may arise out of legal claims associated with the normal course of our operations; the availability and repayment of our credit facilities; potential asset sales; expected impacts of the contingent payment to ConocoPhillips; and the development of a new five-year business plan for the combined Company in 2021. Readers are cautioned not to place undue reliance on forward-looking information as our 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 Cenovus and others that apply to the industry generally. The factors or assumptions on which our 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; our ability to realize the benefits and anticipated cost synergies associated with the Arrangement; Cenovus's ability to successfully integrate the business of Husky, including new business activities, assets, operating areas, regulatory jurisdictions, personnel and business partners for Cenovus; the accuracy of any assessments undertaken in connection with the Arrangement and any resulting *pro forma* information; our forecast production volumes are subject to potential further ramp down of production based on business and market conditions; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; the absence of significant adverse changes to legislation and regulations, Indigenous relations, interest rates, 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 Cenovus 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 Cenovus'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 our share price and market capitalization over the long term; opportunities to repurchase shares for cancellation at prices acceptable to us; cash flows, cash balances on hand and access to credit and demand facilities being sufficient to fund capital investments; foreign exchange rate risk, including with respect to our US$ debt and refining capital and operating expenses; our ability to reduce our 2021 oil sands production, including without negative impacts to our assets; realization of expected capacity to store within our oil sands reservoirs barrels not yet produced, including that we 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 crude oil differentials have narrowed; the WTI-WCS differential in Alberta remains largely tied to the extent to which voluntary economically driven supply cuts are made, the potential start-up of the Enbridge Inc.'s Line 3 Replacement Program, the completion of Trans Mountain Expansion project, and the level of crude-by-rail activity; the ability of our refining capacity, dynamic storage, existing pipeline commitments and financial hedge transactions to partially mitigate a portion of our WCS crude oil volumes against wider differentials; production declines from both associated gas and dry gas, along with rebounding U.S. demand and liquified natural gas exports should tighten North American gas fundamentals further in 2021 and result in stronger prices than 2020 on an annual 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; future use and development of technology and associated expected future results; our ability to obtain necessary regulatory and partner approvals; the successful, timely and cost effective implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; the sufficiency of existing cash balances, internally generated cash flows, existing credit facilities, management of the Corporation's asset portfolio and access to capital markets to fund future development costs and dividends, including any increase thereto; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; our ability to complete asset sales, including with desired transaction metrics and within the timelines we expect; the stability of general domestic and global economic, market and business conditions; forecast inflation and other assumptions inherent in Cenovus's 2021 guidance available on cenovus.com and as set out below; our future results relative to the 2021 guidance based on current production volumes and operating expenses; expected impacts of the contingent payment to ConocoPhillips; alignment of realized WCS and WCS prices used to calculate the contingent payment to ConocoPhillips; our ability to access and implement all technology and equipment necessary to achieve expected future results and that such results are realized; our ability to implement capital projects or stages thereof in a successful and timely manner; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2021 guidance, as updated January 28, 2021 and available on cenovus.com, assumes: Brent prices of US$49.50/bbl, WTI prices of US$46.50/bbl; WCS of US$32.50/bbl; Differential WTI-WCS of US$14.00/bbl; AECO natural gas prices of $2.50/Mcf; Chicago 3-2-1 crack spread of US$11.00/bbl; and an exchange rate of $0.78 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially from the forward-looking information, include, but are not limited to: the effect of the COVID-19 pandemic on our business, including any related restrictions, containment, and treatment measures taken by varying levels of government in the jurisdictions in which we operate; the success of our new COVID-19 workplace policies and the return of our people to our workplace; our ability to achieve the benefits and anticipated cost synergies anticipated with the Arrangement in a timely manner or at all; Cenovus's ability to successfully integrate Husky's business with its own in a timely and cost effective manner or at all; the effects of entering new business activities; unforeseen or undisclosed liabilities associated with the Arrangement; the inaccuracy of any assessments undertaken in connection with the Arrangement and any resulting *pro forma* information; the inaccuracy of any information provided by Husky; our ability to access or implement some or all of the technology necessary to efficiently and effectively operate our assets and achieve expected future results; the effect of Cenovus's increased indebtedness; the effect of new significant shareholders; volatility of and other assumptions regarding commodity prices; foreign exchange risk, including related to agreements denominated in foreign currencies; our continued liquidity is sufficient to sustain operations through a prolonged market downturn; WTI-WCS differential in Alberta does not remain largely tied to the extent to which voluntary economically driven supply cuts are made, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, the completion of the Trans Mountain Expansion project, and the level of crude-by-rail activity; our ability to achieve lower transportation costs as a result of temporarily suspending the crude-by-rail program; our ability to realize the expected impacts of our capacity to store within our 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 our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; the accuracy of our share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in our 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 our crude-by-rail terminal, including health, safety and environmental risks; our ability to maintain desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans; our ability to utilize tax losses in the future; the accuracy of our reserves, future production and future net revenue estimates; the accuracy of our accounting estimates and judgments; our ability to replace and expand oil and 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 our assets or goodwill from time to time; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated operations and business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events resulting in operational interruptions, including blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, gaseous leaks, migration of harmful substances, loss of containment, releases or spills, including releases or spills from offshore facilities and shipping vessels at terminals or hubs and as a result of pipeline or other leaks, corrosion, epidemics or pandemics, and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, iceberg incidents, acts of vandalism and terrorism, and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, such as labour, materials, natural gas and other energy sources used in oil sands processes and increased insurance deductibles or premiums; the cost and availability of equipment necessary to our operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and Cenovus'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 our business, including potential cyberattacks; geo-political and other risks associated with our international operations; risks associated with climate change and our assumptions relating thereto; the timing and the costs of well and pipeline construction; our 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 our ability to attract and retain, critical talent; possible failure to obtain and retain qualified leadership and personnel, and equipment in a timely and cost efficient manner; changes in labour demographics and relationships, including with any unionized workforces; unexpected abandonment and reclamation costs; changes in the regulatory frameworks, permits and approvals in any of the locations in which we operate or to any of the infrastructure upon which we rely; 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, greenhouse gas, 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 our business, our financial results and our 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 we operate or supply; the status of our relationships with the communities in which we operate, 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 us.

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 our material risk factors, see Risk Management and Risk Factors in this MD&A, and to the risk factors described in other documents Cenovus 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 Corporation's website at cenovus.com. Additional information concerning Husky's business and assets as of December 31, 2020 may be found in the Husky AIF and Husky MD&A, each of which is filed and available on SEDAR under Cenovus's profile at sedar.com.

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

ABBREVIATIONS

The following abbreviations have been used in this document:

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

NETBACK RECONCILIATIONS

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

Total Production

Upstream Financial Results

	Per Interim Consolidated Financial Statements			
Three Months Ended March 31, 2021 ($ millions)	**Oil Sands (1)**	**Conventional (1)**	**Offshore (1)**	**Total Upstream**
Gross Sales	**4,775**	**776**	**431**	**5,982**
Royalties	**324**	**24**	**25**	**373**
Purchased Product	**718**	**381**	**-**	**1,099**
Transportation and Blending	**1,778**	**18**	**4**	**1,800**
Operating	**585**	**142**	**58**	**785**
Netback	**1,370**	**211**	**344**	**1,925**
Realized (Gain) Loss on Risk Management	**229**	**1**	**-**	**230**
Operating Margin	**1,141**	**210**	**344**	**1,695**
Unrealized (Gain) Loss on Risk Management	**(141)**	**(1)**	**-**	**(142)**

	Per Interim Consolidated Financial Statements	Adjustments					Basis of Netback Calculation
Three Months Ended March 31, 2021 ($ millions)	**Total Upstream**	**Condensate**	**Third-party Sourced**	**Internal Consumption (2)**	**Equity Adjustment (3)**	**Other (4)**	**Total Upstream**
Gross Sales	**5,982**	(1,368)	(1,053)	(149)	52	(94)	**3,370**
Royalties	**373**	-	-	-	7	-	**380**
Purchased Product	**1,099**	-	(1,053)	-	-	(46)	**-**
Transportation and Blending	**1,800**	(1,368)	-	-	-	-	**432**
Operating	**785**	-	-	(149)	5	(12)	**629**
Netback	**1,925**	-	-	-	40	(36)	**1,929**
Realized (Gain) Loss on Risk Management	**230**	**-**	**-**	**-**	**-**	**-**	**230**
Operating Margin	**1,695**	**-**	**-**	**-**	**40**	**(36)**	**1,699**
Unrealized (Gain) Loss on Risk Management	**(142)**	**-**	**-**	**-**	**-**	**1**	**(141)**

	Per Interim Consolidated Financial Statements			
Three Months Ended March 31, 2020 ($ millions) (5)	**Oil Sands (1)**	**Conventional (1)**	**Offshore (1)**	**Total Upstream**
Gross Sales	**2,434**	**222**	**-**	**2,656**
Royalties	**51**	**3**	**-**	**54**
Purchased Product	**405**	**61**	**-**	**466**
Transportation and Blending	**1,905**	**23**	**-**	**1,928**
Operating	**320**	**84**	**-**	**404**
Netback	**(247)**	**51**	**-**	**(196)**
Realized (Gain) Loss on Risk Management	**25**	**-**	**-**	**25**
Operating Margin	**(272)**	**51**	**-**	**(221)**
Unrealized (Gain) Loss on Risk Management	**22**	**-**	**-**	**22**

	Per Interim Consolidated Financial Statements	Adjustments					Basis of Netback Calculation
Three Months Ended March 31, 2020 ($ millions) (5)	**Total Upstream**	**Condensate**	**Third-party Sourced**	**Inventory Write-Down**	**Internal Consumption (2)**	**Other (4)**	**Total Upstream**
Gross Sales	2,656	(1,213)	(466)	-	(68)	(17)	**892**
Royalties	54	-	-	(7)	-	-	**47**
Purchased Product	466	-	(466)	-	-		**-**
Transportation and Blending	1,928	(1,213)	-	(301)	-	(1)	**413**
Operating	404	-	-	(27)	(68)	(18)	**291**
Netback	(196)	-	-	335	-	2	**141**
Realized (Gain) Loss on Risk Management	**25**	**-**	**-**	**-**	**-**	**-**	**25**
Operating Margin	**(221)**	**-**	**-**	**335**	**-**	**2**	**116**
Unrealized (Gain) Loss on Risk Management	**22**	**-**	**-**	**-**	**-**	**-**	**22**

(1) 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 for consolidated financial statement purposes.
(4) Other includes construction, transportation and blending and third-party processing margin.
(5) Prior periods have been reclassified to conform with current period's operating segments.

Oil Sands

Three Months Ended March 31, 2021 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands [2]	Total Bitumen and Heavy Oil	Natural Gas and Medium Oil	Total Oil sands
	Basis of Netback Calculation						
Gross Sales	852	995	118	691	2,656	9	2,665
Royalties	107	167	2	48	324	-	324
Purchased Product	-	-	-	-	-	-	-
Transportation and Blending	173	130	27	80	410	-	410
Operating	169	164	31	207	571	8	579
Netback	403	534	58	356	1,351	1	1,352
Realized (Gain) Loss on Risk Management							229
Operating Margin							1,123
Unrealized (Gain) Loss on Risk Management							(141)

Three Months Ended March 31, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			Per Interim Consolidated Financial Statements [1]
	Total Oil Sands	Condensate	Third-party Sourced	Other [3]	Total Oil Sands
Gross Sales	2,665	1,368	672	70	4,775
Royalties	324	-	-	-	324
Purchased Product	-	-	672	46	718
Transportation and Blending	410	1,368	-	-	1,778
Operating	579	-	-	6	585
Netback	1,352	-	-	18	1,370
Realized (Gain) Loss on Risk Management	229	-	-	-	229
Operating Margin	1,123	-	-	18	1,141
Unrealized (Gain) Loss on Risk Management	(141)	-	-	-	(141)

Three Months Ended March 31, 2020 ($ millions) [4]	Foster Creek	Christina Lake	Sunrise	Other Oil Sands [2]	Total Bitumen and Heavy Oil	Natural Gas and Medium Oil	Total Oil Sands
	Basis of Netback Calculation						
Gross Sales	417	393	-	-	810	-	810
Royalties	23	21	-	-	44	-	44
Purchased Product	-	-	-	-	-	-	-
Transportation and Blending	221	170	-	-	391	-	391
Operating	143	138	-	-	281	-	281
Netback	30	64	-	-	94	-	94
Realized (Gain) Loss on Risk Management							25
Operating Margin							69
Unrealized (Gain) Loss on Risk Management							22

Three Months Ended March 31, 2020 ($ millions) [3]	Basis of Netback Calculation	Adjustments				Per Interim Consolidated Financial Statements [1]
	Total Oil Sands	Condensate	Third-party Sourced	Inventory Write-down	Other	Total Oil Sands
Gross Sales	810	1,213	405	-	6	2,434
Royalties	44	-	-	7	-	51
Purchased Product	-	-	405	-	-	405
Transportation and Blending	391	1,213	-	301	-	1,905
Operating	281	-	-	27	12	320
Netback	94	-	-	(335)	(6)	(247)
Realized (Gain) Loss on Risk Management	25	-	-	-	-	25
Operating Margin	69	-	-	(335)	(6)	(272)
Unrealized (Gain) Loss on Risk Management	22	-	-	-	-	22

(1) Found in Note 1 of the Interim Consolidated Financial Statements.
(2) Includes Tucker, Lloydminster Thermal and Lloydminster cold and enhanced oil recovery assets.
(3) Other includes construction, transportation and blending margin.
(4) Prior periods have been reclassified to conform with current period's operating segments.

Conventional

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

Three Months Ended March 31, 2020 ($ millions)	Basis of Netback Calculation	Adjustments		Per Interim Consolidated Financial Statements (1)
	Conventional	**Third-party Sourced**	**Other (2)**	**Conventional**
Gross Sales	150	61	11	222
Royalties	3	-	-	3
Purchased Product	-	61	-	61
Transportation and Blending	22	-	1	23
Operating	78	-	6	84
Netback	47	-	4	51
Realized (Gain) Loss on Risk Management	-	-	-	-
Operating Margin	47	-	4	51
Unrealized (Gain) Loss on Risk Management	-	-	-	-

(1) Found in Note 1 of the Interim Consolidated Financial Statements.
(2) Reflects operating margin from processing facility.
(3) Prior periods have been reclassified to conform with current period's operating segments.

Offshore

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

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

Sales Volumes [1]

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

(BOE/d, unless otherwise stated)	2021	2020
Oil Sands		
Foster Creek	**174,955**	**169,207**
Christina Lake	**217,506**	**228,764**
Sunrise	**28,757**	**-**
Other Oil Sands	**144,071**	**-**
Total Oil Sands	**565,289**	**397,971**
Conventional	**135,933**	**95,558**
Sales before Internal Consumption	**701,222**	**493,529**
Less: Internal Consumption [2]	**(86,526)**	**(57,649)**
Offshore		
Asia Pacific - China	**51,386**	**-**
Asia Pacific - Indonesia	**9,446**	**-**
Atlantic	**14,945**	**-**
Total Offshore	**75,777**	**-**
Total Sales	**690,473**	**435,880**

(1) Presented on dry bitumen basis.
(2) Less natural gas volumes used for internal consumption by the Oil Sands segment.