MANAGEMENT'S DISCUSSION AND ANALYSIS

1.0 Financial Summary

Selected Annual Information *($ millions, except where indicated)*	2020	2019	2018[(1)]
Gross revenues and Marketing and other[(1)]	**13,492**	20,225	22,587
Net earnings (loss) by business segment			
Integrated Corridor[(2)]	**(7,195)**	(567)	1,269
Offshore[(3)]	**(2,419)**	(693)	523
Corporate	**(402)**	(110)	(335)
Net earnings (loss)	**(10,016)**	(1,370)	1,457
Net earnings (loss) per share – basic	**(10.00)**	(1.40)	1.41
Net earnings (loss) per share – diluted	**(10.00)**	(1.41)	1.40
Cash flow – operating activities	**841**	2,971	4,134
Funds from operations[(4)]	**494**	3,251	4,004
Ordinary dividends per common share declared during the year	**0.1625**	0.5000	0.4500
Dividends per cumulative redeemable preferred share, series 1	**0.60**	0.60	0.60
Dividends per cumulative redeemable preferred share, series 2	**0.66**	0.85	0.74
Dividends per cumulative redeemable preferred share, series 3	**1.17**	1.13	1.13
Dividends per cumulative redeemable preferred share, series 5	**1.14**	1.13	1.13
Dividends per cumulative redeemable preferred share, series 7	**1.07**	1.15	1.15
Total assets	**19,687**	33,122	35,225
Total debt[(5)]	**6,157**	5,520	5,747
Net debt[(5)]	**5,422**	3,745	2,881

(1) *Gross revenues and Marketing and other results reported for 2019 have been recast to reflect a change in reclassification of intersegment sales eliminations and a change in presentation of Integrated Corridor and Offshore business units. The results for 2018 have not been recast for this change.*
(2) *The Integrated Corridor business segment includes Lloydminster Heavy Oil Value Chain, Oil Sands, Western Canada Production, U.S. Refining and Canadian Refined Products.*
(3) *The Offshore business segment includes Asia Pacific and Atlantic.*
(4) *Funds from operations is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.*
(5) *Total debt is a non-GAAP measure that equals the sum of long-term debt, long-term debt due within one year and short-term debt. Net debt is a non-GAAP measure that equals total debt less cash and cash equivalents. Refer to Section 9.3 for reconciliations to the corresponding GAAP measures.*

2.0 Husky Business Overview

Husky Energy Inc. ("Husky" or the "Company") is a Canadian integrated energy company and is based in Calgary, Alberta. The Company's common shares were listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and the Cumulative Redeemable Preferred Shares Series 1, Series 2, Series 3, Series 5 and Series 7 were listed under the symbols "HSE.PR.A", "HSE.PR.B", "HSE.PR.C", "HSE.PR.E" and "HSE.PR.G", respectively. The Company operates in Canada, the United States and the Asia Pacific region with Integrated Corridor and Offshore business units (as such terms are defined below).

On January 4, 2021, Husky announced the transaction to strategically combine with Cenovus Energy Inc. ("Cenovus") had closed (the "Cenovus Transaction"). The Cenovus Transaction was completed through a definitive arrangement agreement under which Cenovus and Husky agreed to combine in an all-stock transaction. Pursuant to the transaction agreement, Husky common shareholders received 0.7845 of a Cenovus common share and 0.0651 of a Cenovus common share purchase warrant in exchange for each Husky common share. In addition, Husky preferred shareholders exchanged each Husky preferred share for one Cenovus preferred share with substantially identical terms. Husky's common shares and preferred shares were delisted by the TSX at the close of market on January 5, 2021. The combined company operates as Cenovus Energy Inc.

This MD&A is for the year ended December 31, 2020, and is in respect of Husky and its consolidated entities and considers the completion of the Cenovus Transaction.

2.1 Corporate Strategy

The Company has two main businesses: (i) an integrated Canada-U.S. upstream and downstream corridor ("Integrated Corridor"); and (ii) production located offshore the east coast of Canada ("Atlantic") and offshore China and Indonesia ("Asia Pacific" and with Atlantic, collectively "Offshore"). Husky has prudently managed its business during the COVID-19 pandemic, focused on safe and reliable operations, strong capital discipline with reinforced liquidity, and the implementation of sustainable cost saving measures.

Integrated Corridor

The Company's business in the Integrated Corridor includes: (i) the Lloydminster Heavy Oil Value Chain; (ii) Oil Sands; (iii) Western Canada Production; (iv) U.S. Refining; and (v) Canadian Refined Products.

The **Lloydminster Heavy Oil Value Chain** includes the exploration for, and development and production of, heavy crude oil and bitumen, and production of ethanol. Blended heavy crude oil and bitumen are either sold directly to the Canadian market or transported utilizing the Husky Midstream Limited Partnership ("HMLP") pipeline systems to the Keystone pipeline and other pipelines to be sold in the U.S. downstream market. Heavy crude oil can be upgraded at the Company's Lloydminster upgrading and asphalt refining complex into synthetic crude oil, diesel fuel and asphalt. This business also includes the marketing and transportation of both the Company's own production and third-party commodity trading volumes of heavy crude oil, synthetic crude oil, asphalt and ancillary products. The sale and transportation of the Company's production and third-party commodity trading volumes are managed through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S. The Company is able to capture price differences between the two markets by utilizing infrastructure capacity to deliver production and/or third-party commodity trading volumes from Canada to the U.S. market.

The **Oil Sands** business includes the exploration for, and development and production of, bitumen within the Sunrise Energy Project. It also includes the marketing and transportation of the Company's and third-party production of bitumen through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S.

The **Western Canada Production** business includes the exploration for, and development and production of, light crude oil, conventional natural gas and natural gas liquids ("NGL") in Western Canada. The Company's conventional natural gas and NGL 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.

The **U.S. Refining** business includes the refining of crude oil at the Lima Refinery, the BP-Husky Toledo Refinery and the Superior Refinery in the U.S. Midwest to produce diesel fuel, gasoline, jet fuel, asphalt and other products. The Company also markets its own and third-party volumes of refined petroleum products including gasoline and diesel fuel.

The **Canadian Refined Products** business includes the marketing of its own and third-party volumes of refined petroleum products, including gasoline and diesel, through petroleum outlets.

Offshore

The Company's Offshore business includes operations, development and exploration in Asia Pacific and Atlantic. The price received for Asia Pacific production is largely based on long-term contracts and crude oil production from Atlantic is primarily driven by the price of Brent.

2.2 Operations Overview and 2020 Highlights

Integrated Corridor Operations Overview

Lloydminster Heavy Oil Value Chain

Thermal Developments

The Company has an inventory of Saskatchewan thermal projects. These long-life developments are built with modular, repeatable designs and require low sustaining capital once brought online. Late in the first quarter of 2020, market conditions changed materially due to both the COVID-19 pandemic and falling commodity prices. Given the flexible nature of these projects, the Company ramped down activity on all future thermal projects.

Lloydminster thermal production and Tucker thermal production have been ramped up to full rates following a deliberate ramp down late in the first quarter of 2020 in response to market conditions. A planned turnaround began at the Tucker Thermal Project in September and was completed in mid-October.

Lloydminster Thermal Projects

The following table shows major projects and their status as at December 31, 2020:

Project Name	Nameplate Capacity (bbls/day)	Expected Project Production Date	Project Status
Spruce Lake Central	10,000	On Production	First oil was achieved on August 26, 2020 with design capacity reached in early December.
Spruce Lake North	10,000	2024	Central Processing Facility ("CPF") is 81% complete. CPF construction has been placed on hold. Overall project is 69% complete.

The remaining projects were placed on hold due to deteriorating market conditions in 2020 and are undergoing re-evaluation of production options to maximize value.

Cold Heavy Oil Production

Production in Cold and Enhanced Oil Recovery ("EOR") consists of a combination of production technologies including cold heavy oil production with sand ("CHOPS") operations with an active optimization program as well as using waterflooding and polymer injection technology.

Production remained low through the end of 2020, compared to 2019, following a deliberate ramp down which began late in the first quarter of 2020 in response to market conditions.

Upgrading

The Upgrader produces synthetic crude oil, diluent and ultra-low sulphur diesel. Synthetic crude oil is used as refinery feedstock for the production of transportation fuels in Canada and the U.S. In addition, the Upgrader recovers diluent, which is blended with the heavy crude oil and bitumen prior to pipeline transportation to reduce viscosity and facilitate its movement, and returns it to the field to be reused.

The planned maintenance turnaround for the Upgrader was completed in October. During the turnaround, additional projects were completed that increased crude throughput capacity to 81,500 bbls/day and increased diesel production capacity from 6,000 bbls/day to 10,000 bbls/day.

Lloydminster Asphalt Refinery

The Asphalt Refinery in Lloydminster, Alberta, has a throughput capacity of 30,000 bbls/day and is integrated with the local heavy crude oil and bitumen production, as well as transportation and upgrading infrastructure. The Company is the largest marketer of paving asphalt in Western Canada.

Ethanol Plants

The Company is the largest producer of ethanol in Western Canada. The Company has two ethanol plants, one in Lloydminster, Saskatchewan and one in Minnedosa, Manitoba, with a combined capacity of 260 million litres per year.

Husky Midstream Limited Partnership

Husky Midstream Limited Partnership ("HMLP") has approximately 2,200 kilometres of pipeline in the Lloydminster region, storage at Hardisty and Lloydminster, and other ancillary assets. The pipeline systems transport blended heavy crude oil to Lloydminster, accessing markets through the Upgrader and the Asphalt Refinery. Blended heavy crude oil and bitumen from the field and synthetic crude oil from the upgrading operations are transported south to Hardisty, Alberta to a connection with the major export trunk pipelines. The Hardisty Terminal acts as the exclusive blending hub for Western Canada Select, the largest heavy crude oil benchmark pricing point in North America. HMLP has diversified its operations with the Ansell Corser Gas Plant, with 120 mmcf/day of processing capacity.

Saskatchewan Gathering System Expansion

A multi-year expansion program that will provide transportation of diluent and heavy crude oil blend for additional thermal plants has been suspended. Construction is complete on the Spruce Lake Central phase of the program.

Hardisty Tanks

Construction is complete on 1.5 mmbbls of incremental storage at the Hardisty Terminal and this new capacity has been put into service.

Oil Sands

Production at the Sunrise Energy Project has ramped up to full rates. A planned second quarter turnaround at Plant 1B has been deferred to 2021.

Western Canada Production

Production was impacted by the shut-in of uneconomic production late in the first quarter of 2020 in response to market conditions. Activity can be ramped up as conditions allow.

U.S. Refining

Lima Refinery

The Lima Refinery in Ohio has a crude oil throughput capacity of 175,000 bbls/day and produces low sulphur gasoline, gasoline blend stocks, ultra-low sulphur diesel, jet fuel, petrochemical feedstock and other by-products.

The crude oil flexibility project was commissioned during the first quarter of 2020 and is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada, providing the ability to swing between light and heavy crude oil feedstock.

Throughput volumes continue to be optimized in line with market conditions.

BP-Husky Toledo Refinery

The BP-Husky Toledo Refinery in Ohio has a nameplate throughput capacity of 160,000 bbls/day and produces low sulphur gasoline, ultra-low sulphur diesel, aviation fuels, and by-products. The crude oil refinery is owned 50% by the Company and 50% by BP Products North America Inc. (“BP”), and is operated by BP.

Throughput volumes continue to be optimized in line with market conditions.

Superior Refinery

On April 26, 2018, the Superior Refinery experienced an incident while preparing for a major turnaround and was taken out of operation. The rebuild is ongoing and the Company anticipates a substantial portion of the investment will be recovered from property damage insurance. The refinery is being rebuilt with a nameplate processing capacity of 49,000 bbls/day, including capability to process up to 34,000 bbls/day of heavy crude oil while producing asphalt, gasoline and diesel.

Canadian Refined Products

The Company is a major regional motor fuel marketer with an average of 549 retail marketing locations in 2020, including bulk plants and travel centres, with strategic land positions in Western Canada and Ontario.

On April 20, 2020, the Company announced it has suspended the strategic review of its Canadian Retail and Commercial Fuels Network due to the market environment.

Offshore Operations Overview

Asia Pacific

China

Block 29/26

Construction work was completed during the third quarter of 2020 at the Liuhua 29-1 field, the third deepwater gas field of the Liwan Gas Project. First gas production and sales from the development started in November 2020. This seven well subsea development has been fully built and installed. It utilizes the existing Liwan gas gathering system, the facilities located on the central processing platform and the Gaolan onshore gas plant. The gas buyer began taking 40 mmcf/day (30 mmcf/day Husky working interest) on November 4, 2020 and gas liquids sales began the same month. The gas sales ramped up to 47 mmcf/day (35 mmcf/day Husky working interest) starting in 2021. The Company's share of revenues from this field reflects its 75% working interest plus exploration cost recovery. CNOOC Limited holds the remaining 25% working interest. The project was completed ahead of schedule and below the budgeted cost.

An amendment to the gas sales agreement for the Liwan 3-1 field was executed in the third quarter of 2020. The amendment is effective from August 1, 2020 until April 30, 2022, and has the effect of increasing the volume of gas the buyer must take or pay during the term, and lowering the effective price of this gas. Following April 30, 2022, the original gas sales agreement terms will take effect. Husky anticipates no material impact to its cash flow from the Liwan 3-1 field as a result.

Block 15/33

During the third quarter of 2020, an agreement was signed between the Company and CNOOC Limited to extend the end of the second phase of the exploration period of the petroleum contract to December 31, 2021. This will allow for additional drilling and testing on the shallow water block planned for 2021.

The Company is the operator of the block with a working interest of 100% during the exploration phase. In the event of a commercial discovery, CNOOC Limited may assume a participating partnership interest of up to 51% during the development phase. Under the Production Sharing Contracts ("PSC"), the corresponding share of exploration costs is to be recovered from production allocated to the Company.

Block 16/25

An agreement was signed between the Company and CNOOC Limited in the third quarter of 2020 to extend the first phase of the exploration period to April 30, 2022, relinquish the contract area of Block 16/25 and to drill the second obligatory exploration well of the first phase of the exploration period at another selected exploration PSC area.

Block 23/07 and 22/11

The Company and CNOOC Limited signed PSCs for Block 22/11 and Block 23/07 in the Beibu Gulf area of the South China Sea in 2018. The Company entered into the second exploration phase of two years in the first quarter of 2020, and committed to drill one exploration well before November 30, 2021. Block 22/11 was relinquished in the first quarter of 2020.

The Company is the operator of Block 23/07 with a working interest of 100% during the exploration phase. In the event of a commercial discovery, CNOOC Limited may assume a participating partnership interest of up to 51% during the development phase. Under the PSC, the corresponding share of exploration costs is to be recovered from production allocated to the Company.

Indonesia

Madura Strait

At the MDA and MBH fields, the Indonesian government regulatory body approved amendments to the Floating Production Unit ("FPU") construction contract to facilitate third party financing. The contracting consortium has ordered long lead equipment and is completing shipyard selection while they finalize financing for FPU construction. Pending completion of financing and construction of the vessel, gas production and sales are expected to begin in 2022. An additional shallow water field, MDK, is scheduled to be developed via a separate platform and tied into the MDA and MBH infrastructure.

At the stand-alone MAC field development, tendering for engineering, procurement and construction of all required facilities was completed early in the first quarter of 2020. Tendering for the Mobile Offshore Production Unit is in progress and a final investment decision is expected in 2021.

In Indonesia, the government regulatory body has made provisions for certain industrial gas buyers to have their gas purchase price reduced as a subsidy for certain utilities. The result is that the sales price of gas from a portion of the BD field gas production has been reduced, however, the government is compensating the affected PSC contractors by way of lower royalty payments. Husky anticipates no material impact to its cash flow from the BD field as a result.

Anugerah

An analysis of previously acquired data and data from offset blocks indicated that exploratory drilling would not be economic. Therefore, this block was relinquished in February 2020 with no further commitments.

Atlantic

White Rose Field and Satellite Extensions

In early September 2020, the Company announced a review of the West White Rose Project. Major construction was suspended in March 2020 due to impacts related to the global COVID-19 pandemic and most activities will remain suspended in 2021. Options beyond 2021 continue to be evaluated. The project is approximately 60% complete.

Offshore Newfoundland and Labrador, the *SeaRose* FPSO vessel remained in production at the White Rose field with enhanced screening provisions and physical distancing measures for site workers.

A 14-day planned maintenance turnaround was safely and successfully completed on the *SeaRose* FPSO during the third quarter of 2020.

Terra Nova Field

The *Terra Nova* FPSO is being preserved quayside as the operator and partners determine next steps. Production operations at the Terra Nova field have been suspended since December 2019.

Exploration

In October 2020, the Canada-Newfoundland and Labrador Offshore Petroleum Board issued a Significant Discovery Licence for the Harpoon O-85 well.

Actual Production and Throughput

The following table shows actual daily production and throughput for 2020 and 2019.

Production & Throughput	2020	2019
Integrated Corridor *(mboe/day)*		
Lloydminster Heavy Oil Value Chain		
Lloydminster Thermal Projects	**81.0**	80.5
Tucker Thermal Project	**18.3**	23.7
Cold Heavy Oil Production/Enhanced Oil Recovery	**24.7**	34.4
Oil Sands	**22.4**	24.6
Western Canada Production	**57.6**	66.7
Integrated Corridor total *(mboe/day)*	**204.0**	229.9
Offshore *(mboe/day)*		
Asia Pacific[(1)]	**50.4**	43.8
Atlantic	**17.6**	16.4
Offshore total *(mboe/day)*	**68.0**	60.2
Total production *(mboe/day)*	**272.0**	290.1
Light & medium crude oil *(mbbls/day)*	**24.8**	25.0
NGL *(mbbls/day)*	**21.2**	22.6
Heavy crude oil & bitumen *(mbbls/day)*	**143.2**	159.0
Conventional natural gas *(mmcf/day)*	**496.9**	500.9
Total production *(mboe/day)*	**272.0**	290.1
Upgrading	**63.8**	74.9
Lloydminster Refinery	**28.0**	26.4
Prince George Refinery	**—**	7.2
Lima Refinery	**138.2**	136.4
BP-Husky Toledo Refinery	**65.4**	63.1
Superior Refinery	**—**	—
Total throughput *(mbbls/day)*	**295.4**	308.0

(1) *Includes Husky's working interest production from the BD Project (40%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

Integrated Corridor

During the year ended December 31, 2020, production decreased primarily due to:

- the safe and orderly reduction, or shut-in, of production beginning in March 2020 to align with changing market conditions; and
- the planned turnaround at the Tucker Thermal Project during the third and fourth quarter of 2020.

Partially offset by:

- Lloydminster thermal projects ramping up to full rates by late in the third quarter of 2020 and the Spruce Lake Central thermal project reaching design capacity in early December 2020; and
- the Tucker Thermal Project and Oil Sands ramping up to full rates by the fourth quarter of 2020.

During the year ended December 31, 2020, throughput decreased primarily due to:

- optimization of the Lima Refinery's, the BP-Husky Toledo Refinery's and the Upgrader's operating rates in line with market demand for refined products;
- the planned turnaround at the Upgrader completed in October 2020; and
- the sale of the Prince George refinery completed on November 1, 2019.

Partially offset by:

- the planned turnaround at the BP-Husky Toledo Refinery during the second and third quarters of 2019; and
- the planned turnaround at the Lima Refinery during the third and fourth quarters of 2019.

Offshore

During the year ended December 31, 2020, Offshore production increased primarily due to:

- higher production from the Liwan Gas Project, including commencement of production at Liuhua 29-1 in November 2020; and
- higher production from the White Rose field, which resumed full production in mid-August 2019.

Partially offset by:

- lower production from the Terra Nova field due to suspended operations.

Production and Throughput Guidance

The following table shows the updated and previous issued production and throughput guidance for 2020.

Production & Throughput Guidance	Updated Guidance[1] March 12, 2020	Previous Guidance[1] December 2, 2019
Upstream production *(mboe/day)*	275 - 300	295 - 310
Downstream throughput *(mbbls/day)*	320 - 340	320 - 340

(1) *Includes curtailment allowance of 5,000 bbls/day in first half of 2020*

On April 20, 2020, the Company announced that Integrated Corridor production was being aligned with upgrading and refining requirements as throughput was optimized in line with the changing market conditions. As a result, no further updated production and throughput guidance for 2020 was provided.

Actual Capital Expenditures

The following table shows actual capital expenditures for 2020 and 2019.

Capital Expenditures[1][2]

($ millions)	**2020**	2019
Integrated Corridor		
Lloydminster Heavy Oil Value Chain	**594**	956
Oil Sands	**9**	38
Western Canada Production	**57**	194
U.S. Refining[3]	**489**	768
Canadian Refined Products	**5**	73
	1,154	2,029
Offshore		
Asia Pacific[4]	**123**	347
Atlantic	**245**	925
	368	1,272
Corporate	**65**	131
Total	**1,587**	3,432

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(2) *Includes capital expenditures used for exploration, development and acquisitions.*
(3) *Includes Superior Refinery rebuild capital.*
(4) *Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

Integrated Corridor Operations

Lloydminster Heavy Oil Value Chain

During 2020, $594 million (36%) was invested in the Lloydminster Heavy Oil Value Chain compared to $956 million (28%) in 2019. Capital expenditures in 2020 related primarily to construction work at the Spruce Lake Central and Spruce Lake North thermal projects, and the turnaround at the Upgrader.

Oil Sands

During 2020, $9 million (1%) was invested in Oil Sands compared to $38 million (1%) in 2019. Capital expenditures in 2020 related primarily to sustainment activities.

Western Canada Production

During 2020, $57 million (4%) was invested in Western Canada Production compared to $194 million (6%) in 2019. Capital expenditures in 2020 related primarily to resource play development targeting the Spirit River Formation at Ansell and the Montney Formation at Wembley.

U.S. Refining

During 2020, $489 million (31%) was invested in U.S. Refining compared to $768 million (22%) in 2019. Capital expenditures in 2020 related primarily to the ongoing rebuild of the Superior Refinery and the crude oil flexibility project at the Lima Refinery, which was commissioned during the first quarter of 2020.

Canadian Refined Products

During 2020, $5 million (1%) was invested in Canadian Refined Products compared to $73 million (2%) in 2019. Capital expenditures in 2019 related primarily to a planned turnaround at the Prince George Refinery, which was sold in the fourth quarter of 2019.

Offshore Operations

Asia Pacific

During 2020, $123 million (8%) was invested in Asia Pacific compared to $347 million (10%) in 2019. Capital expenditures in 2020 related primarily to the development of Liuhua 29-1.

Atlantic

During 2020, $245 million (15%) was invested in Atlantic compared to $925 million (27%) in 2019. Capital expenditures in 2020 related primarily to the West White Rose Project.

Corporate

During 2020, $65 million (4%) was invested in Corporate compared to $131 million (4%) in 2019.

Drilling Activity

Integrated Corridor Operations

The following table discloses the number of wells drilled during 2020 and 2019:

	2020		2019	
Wells Drilled *(wells)*[1]	**Gross**	**Net**	Gross	Net
Thermal developments	**65**	**65**	68	65
Non-thermal developments	**25**	**25**	47	47
Western Canada	**12**	**8**	21	17
Total	**102**	**98**	136	129

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*

Offshore Operations

No new wells were drilled in Offshore operations during 2020.

3.0 The 2020 Business Environment

The Company's operations were significantly influenced by domestic and international factors in 2020, including, but not limited to, the following:

- Significant crude oil demand reduction as a result of measures taken by governments around the world to contain the COVID-19 pandemic, and volatility continuing throughout the year;
- Increased global crude oil supplies in the first and second quarters of 2020 as OPEC negotiations broke down;
- The Government of Alberta's mandatory production quotas introduced in 2019 were lifted in December 2020;
- A continued emphasis on health and safety, the environment, the impacts of climate change, enterprise risk management, resource sustainability and corporate social responsibility concerns.
- Alternative and improved extraction methods have rapidly evolved in North American and international onshore and offshore regions.

Major business factors are considered in formulating short and long-term business strategies.

The Company is exposed to a number of risks inherent in the exploration for, and development, production, marketing, transportation, storage, refining, and sale of, crude oil, liquids-rich natural gas and related products. For a discussion on risk and risk management, see Section 5.0 and the Company's Annual Information Form for the year ended December 31, 2020.

Average Benchmarks

Commodity prices, refining crack spreads and foreign exchange rates are some of the most significant factors that affect the results of the Company's operations. The following average benchmarks have been provided to assist in understanding the Company's financial results.

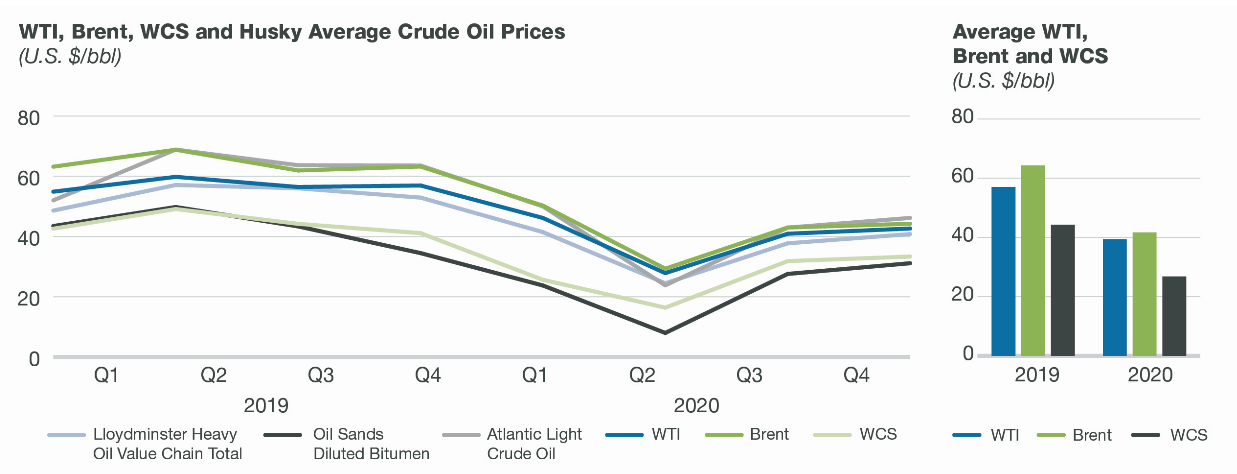
Average Benchmarks Summary		2020	2019
West Texas Intermediate ("WTI") crude oil[(1)]	*(US$/bbl)*	**39.40**	57.03
Brent crude oil[(2)]	*(US$/bbl)*	**41.70**	64.30
Western Canada Select ("WCS") at Hardisty[(3)]	*(US$/bbl)*	**26.81**	44.28
WCS at Cushing[(4)]	*(US$/bbl)*	**35.08**	52.10
Light/heavy crude oil differential for WTI less WCS at Hardisty	*(US$/bbl)*	**12.59**	12.75
Light/heavy crude oil differential for WTI less WCS at Cushing	*(US$/bbl)*	**4.32**	4.93
Condensate at Edmonton	*($/bbl)*	**49.45**	70.20
Synthetic at Edmonton	*($/bbl)*	**48.27**	74.90
NYMEX natural gas[(5)]	*(US$/mmbtu)*	**2.08**	2.63
Nova Inventory Transfer ("NIT") natural gas	*($/GJ)*	**2.12**	1.54
Chicago Regular Unleaded Gasoline	*(US$/bbl)*	**44.85**	70.29
Chicago Ultra-low Sulphur Diesel	*(US$/bbl)*	**50.13**	78.00
Chicago 3:2:1 crack spread	*(US$/bbl)*	**7.21**	15.80
Canadian/U.S. dollar exchange rate	*(US$)*	**0.746**	0.754
Canadian dollar/Chinese Yuan ("RMB") exchange rate	*(RMB)*	**5.147**	5.208
Canadian $ Equivalents[(6)]			
WTI crude oil	*($/bbl)*	**52.82**	75.64
Brent crude oil	*($/bbl)*	**55.90**	85.27
WCS at Hardisty	*($/bbl)*	**35.94**	58.72
WCS at Cushing	*($/bbl)*	**47.02**	69.10
NYMEX natural gas	*($/mmbtu)*	**2.79**	3.49
Synthetic/WTI differential	*($/bbl)*	**(4.55)**	(0.74)

(1) *Calendar month average of settled prices for WTI at Cushing, Oklahoma.*
(2) *Calendar month average of settled prices for Dated Brent.*
(3) *WCS is a heavy blended crude oil, comprised of conventional and bitumen crude oils blended with diluent. Quoted prices are indicative of the Index for WCS at Hardisty, Alberta, set in the month prior to delivery.*
(4) *Quoted prices are indicative of the Index for WCS at Cushing, Oklahoma, set in the month prior to delivery.*
(5) *Prices quoted are average settlement prices during the period.*
(6) *Prices quoted are calculated using U.S. dollar benchmark commodity prices and monthly average U.S./Canadian dollar exchange rates.*

As an integrated producer, the Company's profitability is largely determined by realized prices for crude oil and natural gas, margins on committed pipeline capacity and refinery margins, as well as the effect of changes in the U.S./Canadian dollar exchange rate. All of the Company's crude oil production and the majority of its natural gas production receive the prevailing market prices. The price realized for crude oil is determined by North American and global factors. The price realized for natural gas production from Western Canada is determined primarily by North American fundamentals since virtually all natural gas production in North America is consumed by North American customers. In Asia Pacific, the natural gas price received is determined by long-term contracts.

The refining business is heavily impacted by the price of crude oil, as the largest cost factor is crude oil feedstock, a portion of which is heavy crude oil and bitumen. At the Upgrader, heavy crude oil feedstock is processed into light synthetic crude oil. The Company's U.S. Refining segment processes a mix of different types of crude oil from various sources, but the mix is primarily light sweet crude oil at the Lima Refinery and approximately 75% heavy crude oil and bitumen feedstock at the BP-Husky Toledo Refinery. The Canadian Refined Products segment relies primarily on supply contracts to purchase refined products for resale in the retail distribution network, as well as diesel from the Upgrader.

Crude Oil Benchmarks

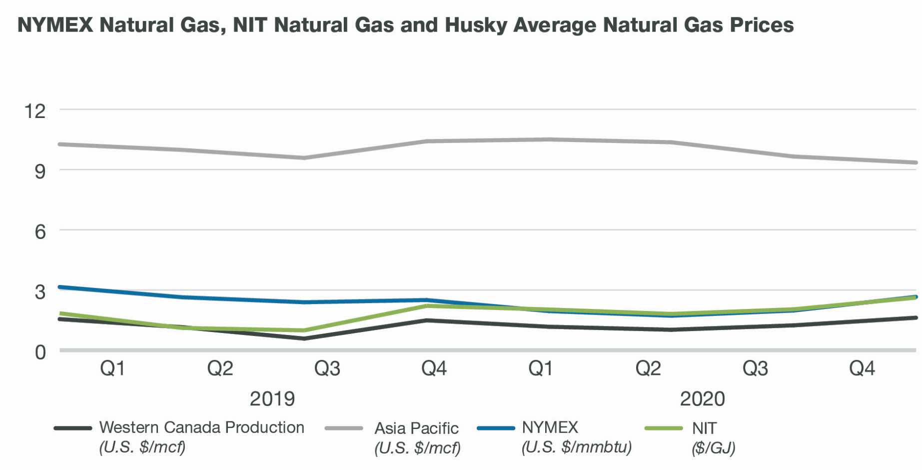


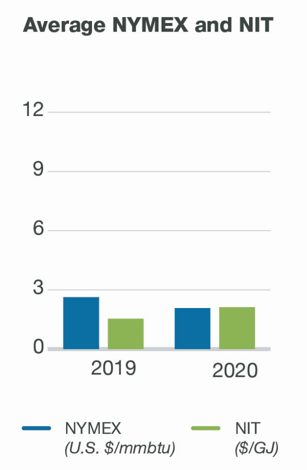
Global crude oil benchmarks weakened in 2020 primarily due to reduced demand as a result of the COVID-19 pandemic. WTI averaged US$39.40/bbl in 2020 compared to US$57.03/bbl in 2019. Brent averaged US$41.70/bbl in 2020 compared to US$64.30/bbl in 2019. WCS averaged US$26.81/bbl in 2020 compared to US$44.28/bbl in 2019.

The price received by the Company for crude oil production in the Integrated Corridor is primarily driven by the price of WTI, adjusted to Western Canada for location and quality. The price received by the Company for crude oil production from Atlantic and for NGL production from Asia Pacific is primarily driven by the price of Brent. A significant portion of the Company's crude oil production in the Integrated Corridor is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil and can be impacted by the geographical market to which it is exported. The Company's crude oil and NGL production was 76% heavy crude oil and bitumen in 2020 compared to 77% in 2019. The Company upgrades heavy crude oil and bitumen into a sweet synthetic crude oil, the Husky Synthetic Blend ("HSB"), at the Upgrader. The price realized by 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 synthetic to WTI differential. The remaining blended heavy crude oil production that the Company does not upgrade or refine at Lloydminster is delivered to either Canadian markets or U.S. markets through pipeline systems. Therefore, the price received by the Company can be impacted by both Canadian heavy crude oil pricing and U.S. Gulf Coast heavy crude oil pricing.

The Company's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate. The price of condensate at Edmonton decreased in 2020 compared to 2019, primarily due to the decrease in crude oil benchmark pricing.

Natural Gas Benchmarks

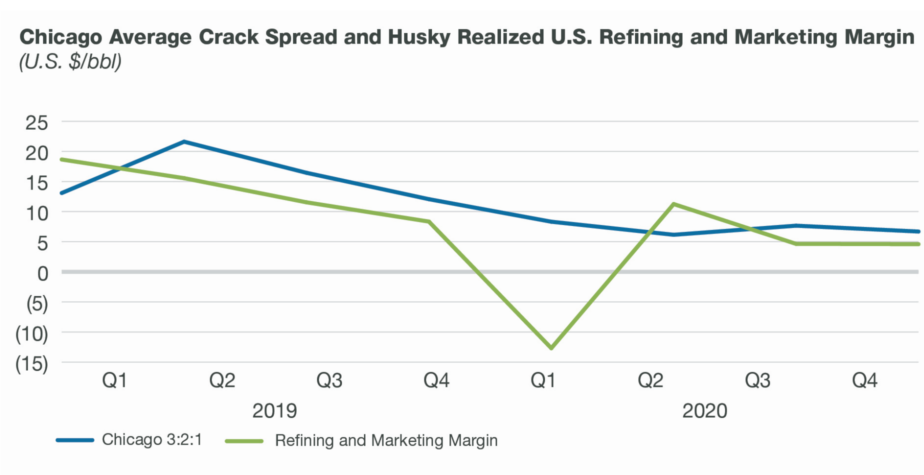


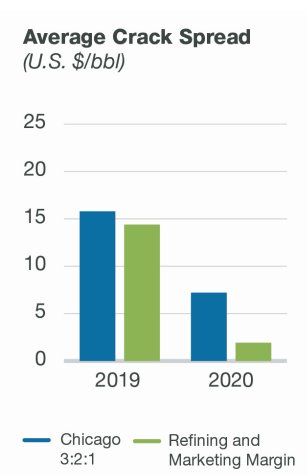


The price received by the Company for natural gas from Western Canada Production is largely driven by the NIT near-month contract price of natural gas and the location differential (net of transportation costs) between NIT and the market prices in the hubs at the end of the Company's long-haul export pipelines. The price received by the Company for production from Asia Pacific is determined by long-term contracts.

North American natural gas has been consumed internally by the Company's Integrated Corridor operations, helping to mitigate the impact of weak natural gas benchmark prices on results.

Refining Benchmarks





Lloydminster Heavy Oil Value Chain

The Company produces HSB, diesel fuel and asphalt at the Lloydminster upgrading and asphalt refining complex. The price realized for HSB, diesel fuel and asphalt is primarily driven by the supply and demand of refined products in Western Canada and the U.S. market.

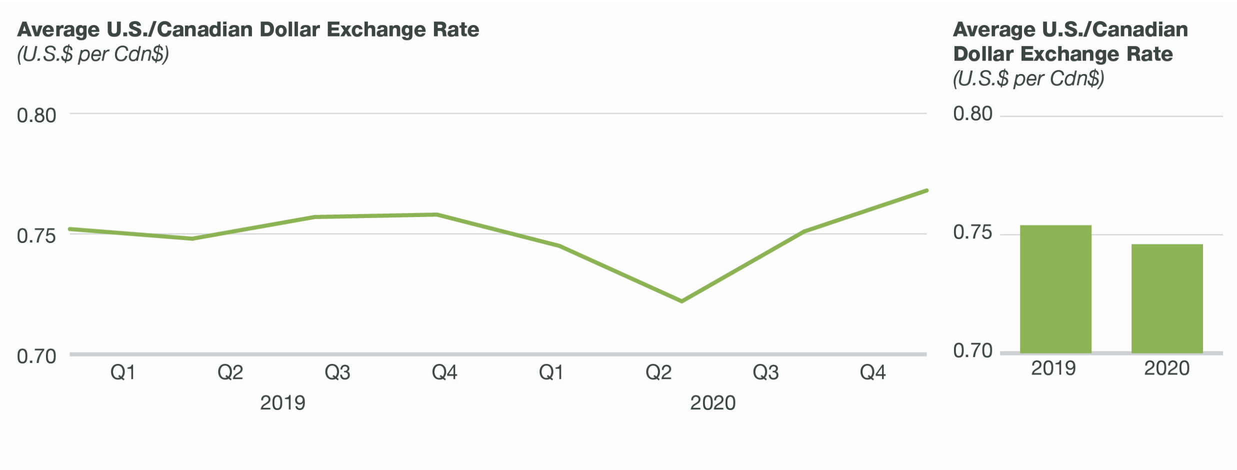
U.S. Refining

The Chicago 3:2:1 crack spread is a key indicator for U.S. Midwest refining margins and reflects refinery gasoline output that is approximately twice the distillate output, and is calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of distillate fuel less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not reflect the actual crude purchase costs or the product configuration of a specific refinery. The Chicago Regular Unleaded Gasoline and the Chicago Ultra-low Sulphur Diesel average benchmark prices are the standard products included in the Chicago 3:2:1 crack spread.

The Chicago 3:2:1 crack spread is a gross margin based on the prices of unblended fuels. The cost of purchasing Renewable Identification Numbers ("RINs") or physically blending biofuel into a final gasoline or diesel product has not been deducted from the Chicago 3:2:1 gross margin. The market value of gasoline or distillate that has been blended may be lower than the value of unblended petroleum products given the value a buyer of unblended petroleum can gain by generating RINs through blending. The Company sells both blended and unblended fuels with the goal of maximizing margins net of RINs purchases.

The Company's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil. The product slates produced at the Lima and BP-Husky Toledo refineries contain approximately 14% of other products that are sold at discounted market prices compared to gasoline and distillate. The Company's realized refining margins are accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

Foreign Exchange



The majority of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities and refined products whose prices are determined by reference to U.S. benchmark prices. The majority of the Company's non-hydrocarbon related expenditures are denominated in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, changes in foreign exchange rates impact the translation of U.S. and Asia Pacific operations and U.S. dollar denominated debt. The Canadian dollar averaged US$0.746 in 2020 compared to US$0.754 in 2019.

A portion of the Company's 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. The Canadian dollar averaged RMB 5.147 in 2020 compared to RMB 5.208 in 2019.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in 2020 on earnings before income taxes and net earnings. The table below reflects what the expected effect would have been on the financial results for 2020 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2020. Each separate item in the sensitivity analysis shows the approximate effect of an increase in that variable only; all other variables are held constant. While these sensitivities are indicative for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or upon greater magnitudes of change.

Sensitivity Analysis	2020 Average	Increase	Effect on Earnings before Income Taxes[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	**39.40**	*US$1.00/bbl*	**88**	**0.09**	**66**	**0.07**
NYMEX benchmark natural gas price[5]	**2.08**	*US$0.20/mmbtu*	**—**	**—**	**—**	**—**
WTI/WCS at Cushing differential	**4.32**	*US$1.00/bbl*	**(7)**	**(0.01)**	**(5)**	**—**
Canadian asphalt margins	**20.14**	*Cdn $1.00/bbl*	**11**	**0.01**	**8**	**0.01**
Chicago 3:2:1 crack spread	**7.21**	*US$1.00/bbl*	**103**	**0.10**	**80**	**0.08**
Exchange rate (US $ per Cdn $)[3][6]	**0.746**	*US$0.01*	**(25)**	**(0.02)**	**(18)**	**(0.02)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as of December 31, 2020.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent-based production.*
(5) *Includes impact of natural gas consumption by the Company.*
(6) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

The Company's five-year plan was updated at its Investor Day in May 2019, which included guidance for 2020 of cash flow - operating activities and funds from operations, each in the range of $4.4 billion, and a free cash flow projection of $1.0 billion. These projections were based on several pricing assumptions, including WTI benchmark crude at US$60/bbl, Brent crude oil at US$65/bbl and a Chicago 3:2:1 crack spread of US$16.50 US/bbl.

In December 2019 the Company issued corporate guidance which included a revised projection for 2020 free cash flow of $500 million based on revised price assumptions (WTI benchmark crude at US$55/bbl, Brent Crude oil at US$65/bbl, and a NYMEX 321 crack spread of US$18/bbl). Free cash flow in 2020 was negative $1.1 billion (free cash flow is a non-GAAP measure, see section 9.3 for a reconciliation to the corresponding GAAP measure).

Actual cash flow - operating activities, funds from operations and free cash flow differed materially due to the market impact of the COVID-19 pandemic and other domestic and international factors that impacted our business, which are described above.

4.0 Results of Operations

4.1 Segment Earnings

Segmented Earnings	Earnings (Loss) before Income Taxes		Net Earnings (Loss)	
($ millions)	**2020**	2019	**2020**	2019
Integrated Corridor				
Lloydminster Heavy Oil Value Chain	**(1,743)**	688	**(1,309)**	504
Oil Sands	**(1,814)**	(744)	**(1,362)**	(545)
Western Canada Production	**(759)**	(1,055)	**(570)**	(772)
U.S. Refining	**(5,046)**	319	**(3,925)**	248
Canadian Refined Products	**(39)**	(2)	**(29)**	(2)
Offshore	**(3,232)**	(961)	**(2,419)**	(693)
Corporate	**(371)**	(414)	**(402)**	(110)
Total	**(13,004)**	(2,169)	**(10,016)**	(1,370)

4.2 Integrated Corridor

Integrated Corridor Consolidated

Integrated Corridor Earnings Summary *($ millions)*	**2020**	2019
Revenues, net of royalties	**11,873**	18,458
Operating margin[1]	**(69)**	2,578
Expenses		
Depletion, depreciation, amortization and impairment ("DD&A")	**9,090**	3,731
Exploration and evaluation	**182**	167
Gain on sale of assets	**(24)**	(7)
Other - net	**(100)**	(672)
Share of equity investment loss (income)	**32**	(9)
Financial items	**152**	162
Recovery of income taxes	**(2,206)**	(227)
Net loss	**(7,195)**	(567)

[1] *Operating margin is a non-GAAP measure. Refer to Section 9.3.*

Integrated Corridor Financial Highlights

Change in results for the year ended December 31, 2020

($ millions)

Operating margin	**Decreased**	Decreased primarily due to lower realized crude oil and refined product pricing and lower margins in the Lloydminster Heavy Oil Value Chain and the U.S. Refining segments, as a result of the significant decline in crude oil and refined product prices.
DD&A	**Increased**	Increased primarily due to the recognition of a pre-tax impairment charge of $7,527 million in the Lloydminster Heavy Oil Value Chain, Oil Sands, Western Canada Production and U.S. Refining segments due to declines in forecasted commodity prices, reduced capital investment and delayed future development plans; partially offset by the recognition of a pre-tax impairment charge of $1,841 million in 2019.
Other - net income	**Decreased**	Decreased primarily due to lower insurance recoveries recognized for business interruption and incident costs associated with the Superior Refinery.
Share of equity investment loss	**Increased**	Increased primarily due to lower income from HMLP.
Recovery of income taxes	**Increased**	Increased primarily due to lower earnings before income taxes.

Lloydminster Heavy Oil Value Chain

Lloydminster Heavy Oil Value Chain Operating Margin Summary

($ millions, except where indicated)	**2020**	2019
Gross revenues[1]		
Synthetic crude oil and refined products	**1,626**	2,364
Blended crude oil[2]	**1,500**	2,197
Other revenues[3]	**627**	1,040
	3,753	5,601
Royalties	**(92)**	(160)
Marketing and other[1]	**22**	52
Revenue, net of royalties	**3,683**	5,493
Expenses		
Purchases of crude oil and products[1]	**1,827**	2,395
Production, operating and transportation expenses[1]	**1,059**	1,212
Selling, general and administrative expenses	**204**	155
Operating margin[4]	**593**	1,731
Select operating data:		
Total sales volumes *(mboe/day)*	**175.6**	174.7
Synthetic crude oil and refined products	**78.2**	81.0
Blended crude oil	**97.4**	93.7
Total realized price per unit sold *($/boe)*	**48.63**	71.52
Synthetic crude oil and refined products	**56.78**	79.96
Blended crude oil	**42.09**	64.23
Total daily gross production *(mboe/day)*	**124.0**	138.6
Medium crude oil *(mbbls/day)*	**1.4**	1.5
Heavy crude oil *(mbbls/day)*	**21.4**	30.2
Bitumen *(mbbls/day)*	**99.3**	104.2
Conventional natural gas *(mmcf/day)*	**11.2**	15.7
Total throughput *(mbbls/day)*	**91.8**	101.3
Upgrading throughput *(mbbls/day)*[5]	**63.8**	74.9
Lloydminster Refinery throughput *(mbbls/day)*[6]	**28.0**	26.4
Unit operating cost *($/boe)*[7][9]	**10.99**	13.48
Unit operating margin *($/boe)*[8][9]	**13.13**	30.67

(1) *Results reported for 2019 have been recast to reflect a change in reclassification of intersegment sales eliminations and a change in presentation of the Integrated Corridor and Offshore.*
(2) *Blended heavy crude oil and bitumen.*
(3) *Includes revenues from pipeline construction activities, the Lloydminster and Minnedosa Ethanol plants and processing income.*
(4) *Operating margin is a non-GAAP measure. Refer to Section 9.3.*
(5) *Throughput includes diluent returned to the field.*
(6) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(7) *Excludes operating costs not directly attributable to the sale of synthetic crude and refined product, and blended crude oil.*
(8) *Excludes revenue and expenses not directly attributable to sale of synthetic crude and refined product, and blended crude oil.*
(9) *Per unit cost calculated based on sales volumes.*

Lloydminster Heavy Oil Value Chain Financial Highlights

Change in results for the year ended December 31

($ millions)

Synthetic crude oil and refined products revenues	**Decreased**	Decreased primarily due to lower realized pricing from HSB and asphalt sales.
Blended crude oil revenues	**Decreased**	Decreased primarily due to lower commodity pricing.
Other revenues	**Decreased**	Decreased primarily due to lower marketing revenue from third party light crude oil sales, combined with lower construction revenue.
Royalties	**Decreased**	Decreased primarily due to lower bitumen and heavy crude oil production, combined with lower realized sales prices.
Marketing and other	**Decreased**	Decreased primarily due to limited arbitrage opportunities driven by narrowed price differentials between the Canadian and U.S. markets and forward commodity pricing trending lower than spot prices.
Purchases of crude oil and products	**Decreased**	Decreased primarily due to lower blending costs as a result of the decline in condensate prices.
Production, operating and transportation expenses	**Decreased**	Decreased primarily due to cost savings initiatives and reduced operational activity.

Lloydminster Heavy Oil Value Chain Operational Highlights

Change in operational performance for the year ended December 31

Total realized price per unit sold *($/boe)*		
Synthetic crude oil and refined products	**Decreased**	Decreased primarily due to the significant decline in commodity price benchmarks and an unfavourable synthetic differential.
Blended crude oil	**Decreased**	Decreased primarily due to the significant decline in commodity price benchmarks.
Unit operating cost *($/bbl)*	**Decreased**	Decreased primarily due to cost savings initiatives and reduced operational activity.
Unit operating margin *($/bbl)*	**Decreased**	Decreased primarily due to the decline in refined product and crude oil prices.

Oil Sands

Oil Sands Operating Margin Summary

($ millions, except where indicated)	**2020**	2019
Gross revenues[(1)]	**306**	649
Royalties	**(2)**	(13)
Marketing and other	**(48)**	4
Revenues, net of royalties	**256**	640
Expenses		
Purchases of crude oil and products[(1)]	**153**	246
Production, operating and transportation expenses	**114**	140
Selling, general and administrative expenses	**24**	27
Operating margin[(2)]	**(35)**	227
Select operating data:		
Total sales volumes		
Diluted bitumen *(mbbls/day)*	**26.7**	30.9
Total realized price per unit sold		
Diluted bitumen *($/bbl)*	**31.45**	56.72
Total daily gross production		
Bitumen *(mbbls/day)*	**22.4**	24.6
Unit operating cost *($/bbl)*[(3)]	**11.68**	12.41
Unit operating margin *($/bbl)*[(3)]	**(1.34)**	20.03

(1) *Results reported for 2019 have been recast to reflect a change in reclassification of intersegment sales eliminations and a change in presentation of the Integrated Corridor and Offshore business units.*
(2) *Operating margin is a non-GAAP measure. Refer to Section 9.3.*
(3) *Per unit cost calculated based on sales volumes.*

Oil Sands Financial Highlights

Change in results for the year ended December 31

($ millions)

Gross revenues	**Decreased**	Decreased primarily due to lower average WCS benchmark prices, combined with lower volume of diluted bitumen sales.
Marketing and other	**Decreased**	Decreased primarily due to the limited arbitrage opportunities driven by tightened price differentials between the Canadian and U.S. markets.
Purchases of crude oil and products	**Decreased**	Decreased primarily due to lower diluent prices and volumes purchased, combined with the impact of a third-party pipeline outage in September 2020.
Production, operating and transportation expenses	**Decreased**	Decreased primarily due to cost saving initiatives and reduced operational activity.

Oil Sands Operational Highlights

Change in operational performance for the year ended December 31

Total sales volumes *(mbbls/day)*	**Decreased**	Decreased primarily due to lower diluent sales as a result of a third-party pipeline outage in September 2020 and lower bitumen production from the Sunrise Energy Project.
Total realized price per unit sold *($/bbl)*	**Decreased**	Decreased primarily due to the significant decline in global commodity prices.
Unit operating margin *($/bbl)*	**Decreased**	Decreased primarily due to lower average WCS prices and lower sales volumes.

Western Canada Production

Western Canada Production Operating Margin Summary

($ millions, except where indicated)	2020	2019
Gross revenues[1]	**367**	514
Royalties	**(10)**	(41)
Marketing and other[1]	**15**	99
Revenues, net of royalties	**372**	572
Expenses		
Purchases of crude oil and products[1]	**22**	40
Production, operating and transportation expenses[1]	**250**	313
Selling, general and administrative expenses	**64**	106
Operating margin[2]	**36**	113
Select operating data:		
Total sales volumes *(mboe/day)*[3]	**57.6**	66.7
Light crude oil *(mbbls/day)*	**5.7**	7.0
NGL *(mbbls/day)*	**10.2**	12.7
Conventional natural gas *(mmcf/day)*	**250.0**	281.6
Total realized price per unit sold *($/boe)*	**15.97**	20.27
Light crude oil *($/bbl)*	**39.50**	65.02
Conventional natural gas & NGL *($/mcf)*	**2.23**	2.51
Unit operating cost *($/boe)*	**11.84**	12.84

(1) Results reported for 2019 have been recast to reflect a change in reclassification of intersegment sales eliminations and a change in presentation of the Integrated Corridor and Offshore business units.
(2) Operating margin is a non-GAAP measure. Refer to Section 9.3.
(3) Sales volumes approximate total daily gross production.

Western Canada Production Financial Highlights

Change in results for the year ended December 31

($ millions)

Gross revenues	**Decreased**	Decreased primarily due to lower sales volumes and lower realized crude oil and NGL prices in 2020.
Royalties	**Decreased**	Decreased primarily due to lower realized prices and production volumes.
Marketing and other	**Decreased**	Decreased primarily due to reduced margin in natural gas exports as the Canada to U.S. gas price spread weakened.
Production, operating and transportation expenses	**Decreased**	Decreased primarily due to cost saving initiatives and reduced activities.
Selling, general and administrative expenses	**Decreased**	Decreased primarily due to cost saving initiatives and reduced activities.

Western Canada Production Operational Highlights

Change in operational performance for the year ended December 31

Total sales volumes *(mboe/day)*	**Decreased**	Decreased primarily due to shut-ins of uneconomic production in response to market conditions.
Total realized price per unit sold *($/boe)*	**Decreased**	Decreased primarily due to the significant decline in commodity benchmarks.

U.S. Refining

U.S. Refining Operating Margin Summary

($ millions, except where indicated)	**2020**	2019
Gross revenues[(1)]	**6,636**	10,253
Marketing and other[(1)]	**40**	23
Revenues	**6,676**	10,276
Expenses		
Purchases of crude oil and products	**6,500**	8,934
Production, operating and transportation expenses[(1)]	**797**	872
Selling, general and administrative expenses	**72**	51
Operating margin[(2)]	**(693)**	419
Select operating data:		
Total throughput *(mbbls/day)*	**203.6**	199.5
Lima Refinery *(mbbls/day)*[(3)]	**138.2**	136.4
BP-Husky Toledo Refinery *(mbbls/day)*[(3)(4)]	**65.4**	63.1
Unit refining and marketing margin *(US$/bbl crude throughput)*[(5)]	**1.93**	14.40
Refinery inventory *(mmbbls)*[(6)]	**8.5**	5.0

(1) *Results reported for 2019 have been recast to reflect a change in reclassification of intersegment sales eliminations and a change in presentation of the Integrated Corridor and Offshore business units.*
(2) *Operating margin is a non-GAAP measure. Refer to Section 9.3.*
(3) *Includes all crude oil feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(4) *Reported throughput volumes include Husky's working interest from the BP-Husky Toledo Refinery (50%).*
(5) *Refining and marketing margin is a non-GAAP measure. Refer to Section 9.3.*
(6) *Feedstock and refined products are included in refinery inventory.*

U.S. Refining Financial Highlights

Change in results for the year ended December 31

($ millions)

Gross revenues	**Decreased**	Decreased primarily due to the lower average realized refined product prices.
Purchases of crude oil and products	**Decreased**	Decreased primarily due to lower crude oil feedstock costs.
Production, operating and transportation expenses	**Decreased**	Decreased primarily due to planned turnarounds at the Lima and BP-Husky Toledo Refineries in 2019.

U.S. Refining Operational Highlights

Change in operational performance for the year ended December 31

Unit refining and marketing margin *(US$/bbl crude throughput)*	**Decreased**	Decreased primarily due to tightening refining margins.

Canadian Refined Products

Canadian Refined Products Operating Margin Summary

($ millions, except where indicated)	**2020**	2019
Gross revenues	**1,488**	2,425
Expenses		
Purchases of crude oil and products	**1,349**	2,175
Production, operating and transportation expenses	**65**	153
Selling, general and administrative expenses	**44**	9
Operating margin[1]	**30**	88
Select operating data:		
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**6.7**	7.4
Fuel sales per retail outlet *(thousands of litres/day)*	**12.1**	12.7

(1) *Operating margin is a non-GAAP measure. Refer to Section 9.3.*

Canadian Refined Products Financial Highlights

Change in results for the year ended December 31

($ millions)		
Gross revenues	**Decreased**	Decreased primarily due to the sale of the Prince George Refinery in the fourth quarter of 2019 and the decline in gasoline and diesel prices.
Purchases of crude oil and products	**Decreased**	Decreased primarily due to the sale of the Prince George Refinery in the fourth quarter of 2019 and the decline in gasoline and diesel prices.
Production, operating and transportation expenses	**Decreased**	Decreased primarily due to cost saving initiatives and the sale of the Prince George Refinery in the fourth quarter of 2019.

4.3 Offshore

Offshore Consolidated

Offshore Earnings Summary

($ millions, except where indicated)	2020	2019
Revenues, net of royalties	**1,428**	1,444
Operating margin[(1)]	**1,046**	1,065
Expenses		
DD&A	**3,738**	1,661
Exploration and evaluation	**551**	380
Gain on sale of assets	**(1)**	(1)
Other - net	**(5)**	1
Share of equity investment income	**(39)**	(50)
Financial items	**34**	35
Recovery of income taxes	**(813)**	(268)
Net loss	**(2,419)**	(693)

(1) *Operating margin is a non-GAAP measure. Refer to Section 9.3.*

Offshore Financial Highlights

Change in results for the year ended December 31

($ millions)

DD&A	**Increased**	Increased primarily due to the recognition of a pre-tax impairment of $3,104 million in Atlantic operations resulting from sustained declines in forecasted crude oil prices and management's decision to delay capital investment in the West White Rose Project, partially offset by the recognition of a pre-tax impairment charge of $908 million in 2019.
Exploration and evaluation	**Increased**	Increased primarily due to the recognition of a pre-tax write-down of $439 million related to certain Exploration and Evaluation assets in the Atlantic operation. The write-down was primarily due to changes in management's future development plans resulting from sustained declines in forecasted prices for crude oil. The increase is partially offset by the recognition of a pre-tax write-down of $245 million in 2019.
Recovery of income taxes	**Increased**	Increased primarily due to lower earnings before taxes in 2020.

Asia Pacific

Asia Pacific Operating Margin Summary

($ millions, except where indicated)	2020	2019
Gross revenues	1,179	1,060
Royalties	(69)	(60)
Revenues, net of royalties	1,110	1,000
Expenses		
Production, operating and transportation expenses	78	71
Selling, general and administrative expenses	37	49
Operating margin(1)	995	880
Select operating data:		
Total sales volume *(mboe/day)*(2)(3)(4)	50.4	43.8
NGL *(mbbls/day)*(2)(3)	11.0	9.9
Conventional natural gas *(mmcf/day)*(3)(4)	235.7	203.4
Total realized price per unit sold *($/boe)*	73.37	78.47
NGL *($/bbl)*	50.68	72.70
Conventional natural gas *($/mcf)*	13.33	13.36
Unit operating cost *($/boe)*(5)	5.64	6.03

(1) *Operating margin is a non-GAAP measure. Refer to Section 9.3.*
(2) *Sales volumes approximates total daily gross production.*
(3) *Reported sales volumes include Husky's working interest production from the Liwan Gas Project.*
(4) *Reported sales volumes include Husky's working interest production from the BD Project (40%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*
(5) *Reported operating costs include Husky's working interest production from the BD Project (40%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

Asia Pacific Financial Highlights

Change in results for the year ended December 31

($ millions)

Gross revenues	**Increased**	Increased primarily due to higher sales volumes, which was partially offset by lower average realized NGL prices.

Asia Pacific Operational Highlights

Change in operational performance for the year ended December 31

Total sales volume *(mboe/day)*	**Increased**	Increased primarily due to higher production from the Liwan Gas Project including commencement of production at Liuhua 29-1 in November 2020.
Average sales price realized		
NGL ($/bbl)	**Decreased**	Decreased primarily due to the significant decline in global commodity prices.

Atlantic

Atlantic Operating Margin Summary

($ millions, except where indicated)	**2020**	2019
Gross revenues	**336**	493
Royalties	**(18)**	(49)
Revenues, net of royalties	**318**	444
Expenses		
Purchases of crude oil and products[(1)]	**32**	(16)
Production, operating and transportation expenses	**197**	269
Selling, general and administrative expenses	**38**	6
Operating margin[(2)]	**51**	185
Select operating data:		
Total sales volumes		
Light crude oil *(mbbls/day)*	**17.8**	15.9
Total realized price per unit sold		
Light crude oil *($/bbl)*	**51.43**	84.99
Total daily gross production		
Light crude oil *(mbbls/day)*	**17.6**	16.4
Unit operating cost *($/bbl)*[(3)]	**27.45**	43.44

(1) Results reported for 2019 have been recast to reflect a change in reclassification of intersegment sales eliminations and a change in presentation of the Integrated Corridor and Offshore business units.
(2) Operating margin is a non-GAAP measure. Refer to Section 9.3.
(3) Per unit cost calculated based on sales volumes.

Atlantic Financial Highlights

Change in results for the year ended December 31

($ millions)

Gross revenues	**Decreased**	Decreased primarily due to lower realized sales pricing, partially offset by higher sales volumes.
Royalties	**Decreased**	Decreased primarily due to the same factors that impacted gross revenues.
Purchases of crude oil and products	**Increased**	Increased primarily due to the timing difference between production and sales.
Production, operating and transportation expenses	**Decreased**	Decreased primarily due to well intervention scopes completed in 2019.

Atlantic Operational Highlights

Change in operational performance for the year ended December 31

Total sales volumes *(mbbl/day)*	**Increased**	Increased primarily due to higher production combined with timing differences between production and sales.
Total realized price per unit sold *($/boe)*	**Decreased**	Decreased primarily due to the significant decline in crude oil benchmark prices.
Unit operating cost *($/bbl)*	**Decreased**	Decreased primarily due to higher sales volumes and lower operating costs.

4.4 Corporate

Corporate Summary

($ millions) income (expense)	2020	2019
Selling, general and administrative expenses	(262)	(290)
DD&A	(92)	(104)
Other – net	157	16
Net foreign exchange gain	14	44
Finance income	18	71
Finance expense	(206)	(151)
Recovery of (provisions for) income taxes	(31)	304
Net loss	(402)	(110)

The Corporate segment reported a net loss of $402 million in 2020 compared to a net loss of $110 million in 2019. Other-net income increased by $141 million, primarily due to pre-tax recoveries for the Canadian Emergency Wage Subsidy of $82 million, and a net realized and unrealized gain of $79 million on the Company's commodity short-term hedging program. Finance income decreased by $53 million primarily due to a lower cash and cash equivalents balance. Finance expense increased by $55 million primarily due to an increase in the long-term debt balance and lower capitalized interest as a result of reduced capital activity. Recovery of income taxes decreased by $335 million primarily due to the recognition of tax recoveries in 2019 related to the reduction of the Alberta provincial corporate tax rate that was substantively enacted in the second quarter of 2019.

Net foreign exchange gain decreased by $30 million due to the items noted below.

Foreign Exchange Summary

($ millions, except where indicated)	2020	2019
Non-cash working capital	7	17
Other foreign exchange	7	27
Net foreign exchange gain	14	44
U.S./Canadian dollar exchange rates:		
At beginning of year	US$0.771	US$0.733
At end of year	US$0.784	US$0.771

Included in other foreign exchange are realized and unrealized gains and losses on working capital and intercompany financing. The foreign exchange gains and losses on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period. The Company manages its exposure to foreign currency fluctuations with the goal of minimizing the impact of foreign exchange gains and losses on the consolidated financial statements.

Consolidated Income Taxes

Consolidated Income Taxes

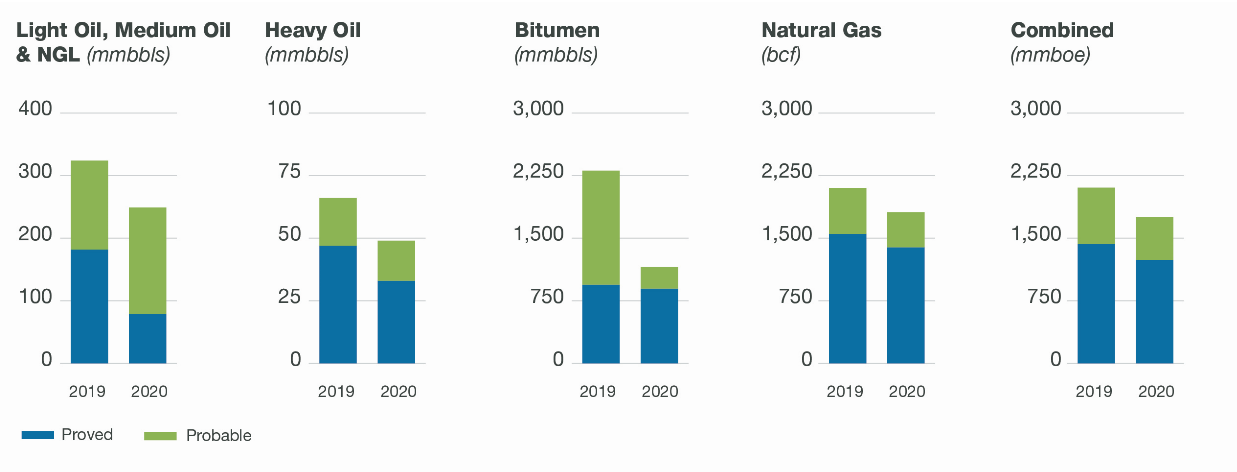
($ millions)	2020	2019
Recovery of income taxes	(2,988)	(799)
Cash income taxes paid	135	41

Consolidated income taxes were a recovery of $2,988 million in 2020 compared to a recovery of $799 million in 2019. The increase in consolidated income taxes recovery was primarily due to a $2,654 million deferred income tax recovery associated with the recognition of pre-tax impairment and exploration asset write-down charge of $11,220 million in 2020. The increase was offset by a $741 million deferred income tax recovery associated with the recognition of pre-tax impairment and exploration asset write-down charge of $3,080 in the fourth quarter of 2019.

4.5 Oil and Gas Reserves

The Company's reserves disclosure was prepared in accordance with Canadian Securities Administrators' National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") effective December 31, 2020 with a preparation date of January 25, 2021.

Proved and Probable Reserves at December 31:



Note: All Lloydminster thermal reserves are classified as bitumen.

The Company's complete oil and gas reserves disclosure, prepared in accordance with NI 51-101, is contained in the Company's Annual Information Form for the year ended December 31, 2020, which is available at www.sedar.com, and certain supplementary oil and gas reserves disclosure prepared in accordance with U.S. disclosure requirements is contained in the Company's Form 40-F, which is available at www.sec.gov and on the Company's website at www.huskyenergy.com.

Sproule Associates Limited ("Sproule"), an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit and review of the Company's oil and gas reserves estimates. Sproule issued an audit opinion on January 25, 2021 stating that the Company's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions are, in aggregate, reasonable and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the Canadian Oil and Gas Evaluation Handbook.

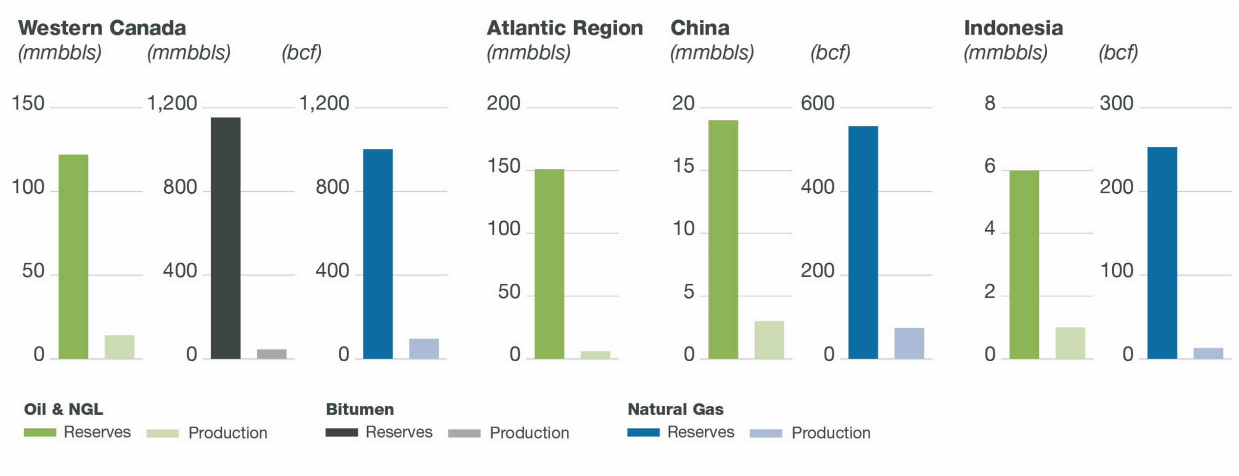
The effective date of the reserves estimates in this MD&A is December 31, 2020 which was prior to completion of the Cenovus Transaction. As a result of the Cenovus Transaction, the Company's development plans and capital expenditure plans may change as the Company and Cenovus integrate their operations, which may impact the Company's reserves estimates.

At December 31, 2020, the Company's proved oil and gas reserves were 1,241 mmboe, down from 1,431 mmboe at the end of 2019. The Company's 2020 reserves replacement ratio, defined as net changes to proved reserves divided by total production during the period, was negative 10% excluding economic revisions (negative 91% including economic revisions).

Major changes to proved reserves in 2020 included:

- Western Canada Extensions & Improved Recovery additions of 31 mmboe associated with 17 mmboe from Western Canada conventional natural gas including new locations (89 bcf of conventional natural gas and 2 mmbbls of NGL), 11 mmbbls primarily from Sunrise, and 3 mmbbls mainly from cold heavy crude oil production new drills.
- Net negative technical revisions in Canada of 48 mmboe mainly associated with 32 mmboe of conventional natural gas and associated NGL revisions (negative 83 bcf conventional natural gas and 18 mmbbls of NGL), primarily due to performance analysis and revised development plans in response to current market conditions. An additional 9 mmboe negative technical revisions of bitumen are mainly from Sunrise due to deferred capital plans. Net negative technical revisions of 7 mmboe in Atlantic are primarily due to the Terra Nova suspension causing a transfer to probable, offset by positive performance in White Rose.
- Net positive technical revisions for offshore China of 16 mmboe (71 bcf conventional natural gas and 4 mmbbls of NGL) mainly due to transfers from probable and the expanded GSA in Liwan 3-1. Net negative technical revisions in Indonesia of 5 mmboe (32 bcf of conventional natural gas) are due to expiring agreements, which are currently being renegotiated, associated with project delays.
- Economic factors reduction of 81 mmboe associated with significantly lower oil prices in North America. As a result, the West White Rose Project proved reserves were transferred to probable. Cold heavy crude oil reserves were reduced by 9 mmbbls as a result of economics and shut-in wells.

Proved Plus Probable Reserves and Production at December 31, 2020:



Reconciliation of Proved Reserves [1]

	Canada					International		Total		
	Western Canada				Atlantic					
(forecast prices and costs before royalties)	Light/ Medium Crude Oil & NGL *(mmbbls)*	Heavy Crude Oil *(mmbbls)*[2]	Bitumen *(mmbbls)*[2]	Conventional Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Conventional Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Conventional Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved reserves										
December 31, 2019	75	47	943	815	85	22	737	1,172	1,552	1,431
Technical revisions	(18)	—	(9)	(83)	(7)	4	39	(30)	(44)	(37)
Acquisitions	—	—	—	—	—	—	—	—	—	—
Dispositions	(1)	—	—	(10)	—	—	—	(1)	(10)	(3)
Discoveries, extensions and improved recovery	2	3	11	89	—	—	—	16	89	31
Economic factors	(2)	(9)	(3)	(14)	(64)	—	—	(78)	(14)	(81)
Production	(6)	(8)	(45)	(96)	(7)	(4)	(86)	(70)	(182)	(100)
Proved reserves December 31, 2020	**50**	**33**	**897**	**701**	**7**	**22**	**690**	**1,009**	**1,391**	**1,241**
Proved and probable reserves December 31, 2020	**73**	**49**	**1,153**	**1,002**	**151**	**25**	**810**	**1,451**	**1,812**	**1,753**
December 31, 2019	126	66	1,366	1,155	169	28	948	1,755	2,103	2,105

(1) *Numbers in the above table may not align with other disclosures due to rounding.*
(2) *Lloydminster thermal property reserves are classified as bitumen.*

Reconciliation of Proved Developed Reserves [1]

	Canada					International		Total		
	Western Canada				Atlantic					
(forecast prices and costs before royalties)	Light/ Medium Crude Oil & NGL *(mmbbls)*	Heavy Crude Oil *(mmbbls)*[2]	Bitumen *(mmbbls)*[2]	Conventional Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Conventional Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Conventional Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved developed reserves										
December 31, 2019	55	46	168	709	21	16	476	306	1,185	504
Technical revisions	(6)	—	6	(39)	(8)	4	72	(4)	33	1
Transfer from proved undeveloped	1	1	11	10	—	6	160	19	170	48
Acquisitions	—	—	—	—	—	—	—	—	—	—
Dispositions	(1)	—	—	(10)	—	—	—	(1)	(10)	(3)
Discoveries, extensions and improved recovery	1	2	—	21	—	—	—	3	21	6
Economic factors	(3)	(9)	(2)	(13)	—	—	—	(14)	(13)	(15)
Production	(6)	(8)	(45)	(96)	(6)	(4)	(86)	(69)	(182)	(100)
December 31, 2020	**41**	**32**	**138**	**582**	**7**	**22**	**622**	**240**	**1,204**	**441**

(1) *Numbers in the above tables may not align with other disclosures due to rounding.*
(2) *Lloydminster thermal property reserves are classified as bitumen.*

5.0 Risk and Risk Management

5.1 Enterprise Risk Management

The Company's enterprise risk management program supports decision-making via comprehensive and systematic identification and assessment of risks that could materially impact the results of the Company. Through this framework, the Company builds risk management and mitigation into strategic planning and operational processes for its business units through the adoption of standards and best practices. The Company has developed an enterprise risk matrix to identify risks to its people, the environment, its assets and its reputation, and to systematically mitigate these risks to an acceptable level.

The Company attempts to mitigate its financial, operational and strategic risks to an acceptable level through a variety of policies, systems and processes. The following provides a list of the most significant risks relating to the Company and its operations.

5.2 Significant Risk Factors

Operational and Safety Incidents

The Company's businesses are subject to inherent operational risks which have the potential to impact safety, the environment, its assets and its reputation. In general, the Company's operations are subject to operational risks, including, but not limited to: fires, loss of containment, blowouts, power outages, freeze-ups and other similar events; oil and natural gas leaks; encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; uncontrollable flows of oil, natural gas and well fluids; spills at truck terminals and hubs; spills associated with the loading and unloading of potentially harmful substances onto trucks; release of tailings or harmful substances into a water system; the breakdown or failure of equipment, pipelines and facilities, information systems and processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); releases or spills from shipping vessels; failure to maintain adequate supplies of spare parts; the compromise of information technology and control systems and related data; operator error; labour disputes; disputes with interconnected facilities and carriers; operational disruptions or apportionment on third-party systems or refineries, which may prevent the full utilization of the company's facilities and pipelines; epidemics or pandemics; and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, explosions, acts of sabotage and other similar events.

Failure to manage the hazards and associated risks effectively could result in potential fatalities, environmental impacts, interruptions to activities or use of assets, or loss of license to operate. The Company implements an Operational Integrity Management System designed to systematically identify, assess and manage operational and safety risks to tolerable levels. In addition, the Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

Commodity Price Volatility

The Company's results of operations and financial condition are dependent on the prices received for its refined products, crude oil, NGL and conventional natural gas production. Lower prices for crude oil, NGL and conventional natural gas could adversely affect the value and quantity of the Company's oil and gas reserves. The Company's reserves include significant quantities of heavier grades of crude oil that often trade at a discount to light crude oil. Heavier grades of crude oil are typically more expensive to produce, process, transport and refine into high-value refined products. Refining and transportation capacity for various grades of crude oil may be constrained from time to time, creating the need for additional refining and transportation capacity. Wider price differentials between heavier and lighter grades of crude oil could have a material adverse effect on the Company's results of operations and financial condition, reduce the value and quantities of the Company's heavier crude oil reserves and delay or cancel projects that involve the development of heavier crude oil resources. There is no guarantee that pipeline development projects or other transportation alternatives will provide sufficient transportation capacity and access to refining capacity to accommodate expected increases in North American heavy crude oil and bitumen production.

Prices for refined products and crude oil are based on world supply and demand. Supply and demand can be affected by several factors including, but not limited to, actions taken by OPEC, non-OPEC crude oil supply, social conditions in oil producing countries, the occurrence of natural disasters, general and specific economic conditions, technological developments, prevailing weather patterns, government regulation and policies and the availability of alternate sources of energy.

The Company's conventional natural gas production is currently located in Western Canada and Asia Pacific. Western Canada's conventional natural gas production is subject to North American market forces. North American natural gas supply and demand is affected by several factors including, but not limited to, the amount of conventional natural gas available to specific market areas either from the wellhead of existing or accessible conventional or unconventional sources (such as from shale) or from storage facilities, technological developments, prevailing weather patterns, the U.S. and Canadian economies, the occurrence of natural disasters and pipeline restrictions. The price received by the Company for production from Asia Pacific is determined by long-term contracts.

In certain instances, the Company 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. The Company may also use firm commitments for the purchase or sale of crude oil and conventional natural gas.

The fluctuations in refined products, crude oil and conventional natural gas prices are beyond the Company's control and could have a material adverse effect on the Company's results of operations and financial condition.

Commodity Price Risk

In certain instances, the Company uses derivative commodity instruments and futures contracts on commodity exchanges, including commodity put and call options under a short-term hedging program, to manage exposure to price volatility on a portion of its refined product, oil and gas production, and inventory or volumes in long distance transit. The Company may also use firm commitments for the purchase or sale of crude oil and conventional natural gas.

The Company's results will be impacted by a decrease in the price of crude oil and conventional natural gas inventory. The Company has crude oil inventories that are feedstock, held at terminals or part of the in-process inventories at its refineries and at offshore sites. Due to the integrated nature, the Company has a natural partial mitigation to the WCS differential risk. The Company also has conventional natural gas inventory that could have an impact on earnings based on changes in conventional natural gas prices. All these inventories are subject to a lower of cost or net realizable value test on a quarterly basis.

Reservoir Performance and Reserves Estimate Risk

Lower than projected reservoir performance on the Company's key growth projects could have a material adverse effect on the Company's results of operations, financial condition, business strategy and reserves. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and negatively affect the Company's reputation and investor confidence.

In order to maintain the Company's future production of crude oil, conventional natural gas and NGL and maintain the value of the reserves portfolio, additional reserves must be added through discoveries, extensions, improved recovery, performance related revisions and acquisitions. The production rate of oil and gas properties tends to decline as reserves are depleted while the associated unit operating costs increase. Maintaining an inventory of projects that can be developed depends upon, but is not limited to, obtaining and renewing rights to explore, develop and produce oil and natural gas, drilling success, completion of long lead time capital intensive projects on budget and on schedule and the application of successful exploitation techniques on mature properties.

The reserves data contained or referenced in this MD&A represent estimates only. The accurate assessment of oil and gas reserves is critical to the continuous and effective management of the Company's upstream assets. Reserves estimates support various investment decisions about the development and management of oil and gas properties. In general, estimates of economically recoverable crude oil and conventional natural gas reserves and the future net cash flow therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the effects of regulation by government agencies, including with respect to royalty payments, all of which may vary considerably from actual results. The Company uses all available information at the effective date of the evaluation and internal qualified reserves evaluators to prepare the reserves estimates. As required by NI 51-101, the Company obtains the opinion of an independent reserves auditor on the Company's reserves. The audit covers more than 75% of the future net revenue discounted at 10% attributable to proved plus probable reserves with the remainder reviewed by the independent qualified reserves auditor. However, given the best technical information and evaluation techniques, all such estimates are still to some degree uncertain. All reserves estimates involve a degree of ambiguity and, at times, rely on indirect measurement techniques to estimate the size and recoverability of the resource. While new technologies have increased the accuracy of these techniques, there remains the potential for human or systemic error in recording and reporting the magnitude of the Company's oil and gas reserves. Estimates of the economically recoverable oil and gas reserves attributable to any particular property or group of properties, and estimates of future net revenues expected therefrom, may differ substantially from actual results even though the total company reserves are shown to be reliable through the historical total company technical reserves revisions. The Company has a diverse portfolio of assets by product type, reservoir type and location which is a factor in mitigating specific property risks.

Restricted Market Access and Pipeline Interruptions

The Company's results of operations and financial condition depend upon the Company's ability to deliver products to the most attractive markets. The Company's results of operations could be materially adversely affected by restricted market access resulting from a lack of pipeline or other transportation alternatives to attractive markets as well as regulatory and/or other marketplace barriers. Interruptions and restrictions may be caused by the inability of a pipeline to operate, or they can be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. If oil production across North America experiences growth, the availability of infrastructure to carry the Company's products to the marketplace may be restricted in the next few years. Restricted market access may potentially have a material adverse effect on the Company's results of operations, financial condition and business strategy. Unplanned shutdowns and closures of its refineries or Upgrader may limit the Company's ability to deliver product with a material adverse effect on sales and results of operations.

Aviation Incidents

The Company's Offshore operations in Canada and China rely on regular travel by helicopter. A helicopter incident resulting in loss of life, facility shutdown or regulatory action could have a material adverse effect on the operations of the Company. This risk is managed through an aviation management process. Aviation Safety Reviews are conducted by third party specialist contractors to verify that helicopter service providers meet the Company's and industry standards with respect to aviation safety. The reviews include evaluation of aircraft type, effectiveness of the safety and maintenance management systems and competency and training programs for critical roles in the operation of helicopters. Helicopters chartered to support Husky Offshore operations must be fit for service and as such are fitted with multiple redundant systems to address a wide range of potential in-flight emergencies. Additional measures specific to the Company's challenging operating environments are specified in the Company's design requirements including anti- icing and floatation systems effective for the maximum allowable sea height operating limits. Pilots are trained to address potential emergency situations through regular real-time and simulator training aligned with industry best practice.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact the Company's personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or extremist incident targeted at a facility, office or offshore vessel/installation owned or operated by the Company could result in the interruption or cessation of key elements of the Company's operations. Outcomes of such incidents could have a material adverse effect on the Company's results of operations, financial condition and business strategy. The risk to employees and board members due to ongoing social unrest in Hong Kong is being managed through reduced travel and increased awareness and monitoring of the situation. The potential for detention and/ or incarceration of the Company's employees/contractors entering or working in China remains, and as a result, review and reconsideration for travel into China has become a business/corporate process.

The Company does not own proved or probable reserves in or near areas of armed conflict. According to the Uppsala Conflict Data Program, armed conflict is defined as "contested incompatibility that concerns government and/or territory over which the use of armed force between the military forces of two parties, of which at least one is the government of a state, has resulted in at least 25 battle-related deaths each year."

Skilled Workforce Attraction and Retention

Successful execution of the Company's strategy is dependent on ensuring the Company's workforce possesses the appropriate skill level. Failure to attract and retain personnel with the required skill levels could have a material adverse effect on the Company's financial condition and results of operations.

Partner Misalignment

Joint venture partners operate or jointly control a portion of the Company's assets in which the Company has an ownership interest. This can reduce the Company's control and ability to manage risks. The Company is at times dependent upon its partners for the successful execution of various projects. If a dispute with partners were to occur over the development and operation of a project or if partners were unable to fund their contractual share of the capital expenditures, a project could be delayed and the Company could be partially or totally liable for its partner's share of the project.

Major Project Execution

The Company manages a variety of oil and gas projects ranging from upstream to downstream assets across its global portfolio. The wide range of risks associated with project development and execution, as well as the commissioning and integration of new facilities with existing assets, can impact the economic viability of the Company's projects. Project risks may result in extended stakeholder consultation, additional environmental assessments and public hearings which may delay necessary environmental and regulatory approvals. Project risks may also manifest through schedule delays, cost overruns and commodity price drops. Some risks can impact the Company's safety and environmental records thereby negatively affecting the Company's reputation and social license to operate.

Government Regulation

Given the scope and complexity of the Company’s operations, the Company is subject to regulations and interventions by governments at the federal, provincial, state and municipal levels in the countries in which it conducts its operations, or development or exploratory activities. As these governments continually balance the needs of the community for economic growth with Indigenous interests and stakeholders, the Company recognizes that the magnitude of regulatory risks has the potential to change over time. Changes in government policy, legislation or regulations could impact the Company’s existing and planned projects as well as impose costs of compliance and increase capital expenditures and operating expenses. Examples of the Company’s regulatory risks include, but are not limited to, uncertain or negative interactions with governments, uncertain energy policies, uncertain climate policies, uncertain environmental and safety policies, penalties, taxes, royalties, government fees, reserves access, limitations or increases in costs relating to the exportation of commodities, production restrictions, restrictions on the acquisition of exploration and production rights and land tenure, expropriation or cancellation of contract rights, limitations on control over the development and abandonment of fields and loss of licences to operate.

Environmental Risks

Changes in environmental regulations could have a material adverse effect on the Company’s results of operations, financial condition and business strategy by requiring increased capital expenditures and operating costs or by impacting the quality of, formulation of or demand for the Company’s products, which may or may not be offset through market pricing.

The Company anticipates that further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, the introduction of emissions limits, increased compliance costs and approval delays for critical licences and permits. Public and investment community interest in environmental, social and governance issues has also increased significantly in recent years, as evidenced by the large number of signatories to the United Nations Principles for Responsible Investment.

It is not possible to accurately forecast the amount of additional investment in new or existing facilities required in the future for environmental protection or to address all new regulatory compliance requirements, such as reporting.

Climate Change Risks

Regulatory

Climate change regulations may become more onerous over time as governments implement policies to further reduce greenhouse gases (“GHG“) emissions. As these regulations continue to evolve, they could have a material adverse effect on the Company’s competitiveness, financial condition and results of operations through increased capital and operating costs and change in demand for refined products such as transportation fuels. Costs associated with levy payments for emerging climate change regulations may be significant.

In December 2018, the Government of Canada published the Regulatory Design Paper on the Clean Fuel Standard ("CFS") that focuses on the liquid fuel stream regulations. The final regulations for liquid fuels are planned for early 2021, with the regulations expected to come into force in 2022. In December 2020, the Canadian government announced it would not be going forward with legislation on the gaseous and solids streams of the CFS.

The Company’s U.S. Refining business could be exposed to increased costs related to Environmental Protection Agency’s (”EPA”) climate change rules by future U.S. GHG legislation that applies to the oil and gas industry, or consumption of petroleum products, or other legislation/regulation at the state or local level. Such legislation or regulations could require the Company’s U.S. Refining operations to significantly reduce emissions and/or purchase emissions credits, thereby increasing operating and capital costs, and could change the demand for refined products which may have a material adverse effect on the Company’s financial condition.

The Company complies with the Renewable Fuel Standard ("RFS") program in the U.S. by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market. Due to regulatory uncertainty and in part due to the U.S. fuel supply reaching the “blend wall” (the 10% limit prescribed by most automobile warranties), the price and availability of RINs have been volatile. The Company cannot predict the future prices of RINs and renewable fuel blendstocks, and the costs to obtain the necessary RINs and blendstocks could be material. The Company’s financial position and results of operations could be adversely affected if it is unable to pass the compliance costs on to its customers and if the Company pays significantly higher prices for RINs or blendstocks to comply with the RFS mandated standards.

Climatic Conditions

Extreme climatic conditions may also have material adverse effects on the Company's financial condition and results of operations. Weather and climate affect demand, and therefore, the predictability of the demand for energy is affected to a large degree by the predictability of weather and climate. In addition, the Company's exploration, production and construction operations, and the operations of major customers and suppliers, can be affected by extreme weather. This may result in cessation or diminishment of production, delay of exploration and development activities or delay of plant construction.

The Company operates in some of the harshest environments in the world, including offshore NL. Climate change may increase the frequency of severe weather conditions in these locations including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased creation of icebergs. Icebergs off the coast of NL may threaten Atlantic oil production facilities, cause damage to equipment and possible production disruptions, spills, other asset damage and human impacts.

Transition

In addition to emissions regulations and the physical risks of climate change, climate-related transition risks could have a material adverse effect on the Company's business, financial condition and results of operations, and could adversely impact the Company's reputation. For example, increased opposition to companies in the oil sands industry could lead to constrained access to insurance, liquidity and capital and changes in demand for the Company's products, which may impact revenue. Any increases in GHG emissions by the Company could lead to additional taxes and levies, which would increase the costs associated with certain projects. The potential need to develop new technologies to reduce the intensity of GHG emissions could require significant capital investment. Further, the Company may become subject to climate change litigation initiated by third parties. The Company's management monitors these risks and reports to the Board through management's Enterprise Risk Management framework.

Overall, the Company is not able to estimate at this time the degree to which climate change related regulatory, climatic conditions, and transition risks could impact the Company's financial and operating results.

Cybersecurity Threats

As an oil and gas producer, the Company's ability to operate effectively is dependent upon developing and maintaining information systems and infrastructure that support the financial and general operating aspects of the business. Concurrently, the oil and gas industry has become the subject of increased levels of cybersecurity threats.

The Company has security measures, policies and controls designed to protect and secure the integrity of its information technology systems. The Company takes a proactive approach by continuing to invest in technology, processes and people to help minimize the impact of the changing cyber landscape and enhance the Company's resilience to cyber incidents. However, cybersecurity threats frequently change and require ongoing monitoring and detection capabilities. Such cybersecurity threats include unauthorized access to information technology systems due to hacking, viruses and other causes for purposes of misappropriating assets or sensitive information, corrupting data or causing operational disruption. Cyber attacks could result in the loss or exposure of confidential information related to retail credit card information, personnel files, exploration activities, corporate actions, executive officer communications and financial results. The significance of any such event is difficult to quantify, but if the breach is material in nature, it could adversely affect the financial performance of the Company, its operations, its reputation and its standing and expose it to regulatory consequences and claims of third-party damage, all of which could materially adversely affect the Company's results of operations and financial condition if the situation is not resolved in a timely manner, or if the financial impact of such adverse effects is not alleviated through insurance policies.

Although to date the Company has not experienced any material losses relating to cyber attacks or other information security breaches, there can be no assurance that the Company will not incur such losses in the future. The Company's risk and exposure to these matters cannot be fully mitigated because of, among other things, the evolving nature of these threats.

International Operations

International operations can expose the Company to uncertain political, economic and other risks. The Company's operations in certain jurisdictions may be materially adversely affected by political, economic or social instability or events. These events may include, but are not limited to, onerous fiscal policy, renegotiation or nullification of agreements and treaties, imposition of onerous regulation, changes in laws governing existing operations, financial constraints, including currency restrictions and exchange rate fluctuations, unreasonable taxation and behaviour of public officials, joint venture partners or third-party representatives that could result in lost business opportunities for the Company. This could materially adversely affect the Company's interest in its foreign operations, results of operations and financial condition.

Litigation, Administrative Proceedings and Regulatory Actions

The Company may be subject to litigation, claims, administrative proceedings and regulatory actions, which may be material. Such claims could relate to environmental damage, climate change and the impacts thereof, failure to comply with applicable laws and regulations, breach of contract, tax, bribery and employment matters, which could result in an unfavourable decision, including fines, sanctions, monetary damages, temporary suspensions of operations or the inability to engage in certain operations or transactions. The outcome of such claims can be difficult to assess or quantify and may have a material adverse effect on the Company's reputation, financial condition and results of operations. The defence to such claims may be costly and could divert management's attention away from day-to-day operations.

Foreign Currency

The Company's results are affected by the exchange rates between various currencies including the Canadian and U.S. dollars. The majority of the Company's expenditures are in Canadian dollars while most of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in the Company's U.S. dollar-denominated debt and related interest expense, as expressed in Canadian dollars. The fluctuations in exchange rates are beyond the Company's control and could have a material adverse effect on the Company's results of operations and financial condition.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollar denominated revenue to hedge against these potential fluctuations. The Company also designates its U.S. denominated debt as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.

Interest Rate

Interest rate risk is the impact of fluctuating interest rates on financial condition. In order to manage interest rate risk and the resulting interest expense, the Company mitigates some of its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of its credit facilities and various financial instruments. The optimal mix maintained will depend on market conditions. The Company may also enter into interest rate swaps from time to time as an additional means of managing current and future interest rate risk.

Counterparty Credit

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties in a transaction fail to meet or discharge their obligation to the Company. The Company actively manages this exposure to credit and contract execution risk from both a customer and a supplier perspective. Internal credit policies have governed the Company's credit portfolio and have limited transactions according to a counterparty's and a supplier's credit quality. Counterparties for financial derivatives transacted by the Company are generally major financial institutions or counterparties with investment grade credit ratings.

Liquidity

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company's process for managing liquidity risk includes ensuring, to the extent possible, that it has access to multiple sources of capital.

Debt Covenants

The Company's credit facilities include financial covenants, which contain a consolidated debt to total capitalization covenant. If the Company does not comply with the covenants under these credit facilities, there is a risk that repayment could be accelerated.

Credit Rating Risk

Credit ratings affect the Company's ability to obtain both short-term and long-term financing and the cost of such financing. Additionally, the ability of the Company to engage in ordinary course derivative or hedging transactions and maintain ordinary course contracts with customers and suppliers on acceptable terms depends on the Company's credit ratings. A reduction in the current rating on the Company's debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in the Company's ratings outlook could materially adversely affect the Company's cost of financing and its access to sources of liquidity and capital. Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to the Company's securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

As at December 31, 2020, Husky had the following credit ratings:

	Standard and Poor's Rating Services ("S&P")	Moody's Investor Service ("Moody's")	Dominion Bond Rating Services Limited ("DBRS")
Outlook/Trend	On CreditWatch with Negative Implications	On Review for Downgrade	Under Review with Negative Implications
Senior Unsecured Debt	BBB	Baa2	BBB (high)
Series 1 Preferred Shares	P-3(high)		Pfd-3(high)
Series 2 Preferred Shares	P-3(high)		Pfd-3(high)
Series 3 Preferred Shares	P-3(high)		Pfd-3(high)
Series 5 Preferred Shares	P-3(high)		Pfd-3(high)
Series 7 Preferred Shares	P-3(high)		Pfd-3(high)
Commercial Paper			R-2(high)

With the closing of the Cenovus Transaction announced on January 4, 2021, all rating agencies revised their rating opinions and Husky's credit ratings now are:

	Standard and Poor's Rating Services ("S&P")	Moody's Investor Service ("Moody's")	Dominion Bond Rating Services Limited ("DBRS")	Fitch Ratings ("Fitch")
Outlook/Trend	Stable	Negative	Stable	Positive
Senior Unsecured Debt	BBB-	Baa3	BBB	BB+

Refer to section 6.3 for the full timeline of ratings actions. Husky preferred shares were delisted by the TSX at the close of market on January 5, 2021 and the preferred share ratings were transferred to Cenovus. DBRS Morningstar has discontinued and withdrawn its rating on the Commercial Paper at the request of the Company. As a result of Husky now being a subsidiary of Cenovus, Fitch has applied the BB+ Positive rating to Husky and its long-term debt.

General Economic Conditions

General economic conditions may have a material adverse effect on the Company's results of operations and financial condition. A decline in economic activity will reduce demand for petroleum products and adversely affect the price the Company receives for its commodities. The Company's cash flow could decline, assets could be impaired, future access to capital could be restricted and major development projects could be delayed or abandoned.

Competition

The energy industry is highly competitive with respect to gaining access to the resources required to increase oil and gas reserves and production, and gaining access to markets. The Company competes with others to acquire prospective lands, retain drilling capacity and field operating and construction services, obtain sufficient pipeline and other transportation capacity, gain access to and retain adequate markets for its products and services and gain access to capital markets. The Company's ability to successfully complete development projects could be materially adversely affected if it is unable to acquire economic supplies and services due to competition. Subsequent increases in the cost of or delays in acquiring supplies and services could result in uneconomic projects. The Company's competitors comprise all types of energy companies, some of which have greater resources.

Cost or Availability of Oil and Gas Field Equipment

The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at reasonable prices. Without compromising safety, overall quality and environmental impacts, the Company continually develops its approved suppliers base to provide undisrupted access to materials, equipment and services, while maintaining a competitive cost baseline via cost escalation mitigation strategies.

Financial Controls

While the Company has determined that its disclosure controls and procedures and internal controls over financial reporting are effective, such controls can only provide reasonable assurance with respect to financial statement preparation and disclosure. Failure to prevent, detect and correct misstatements could have a material adverse effect on the Company's results of operations and financial condition.

Possible Failure to Realize Anticipated Benefits of the Cenovus Transaction

Cenovus and Husky completed the Cenovus Transaction to create an integrated energy leader and realize certain benefits including, among other things, potential synergies and cost savings. Achieving the benefits of the Cenovus Transaction depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the combined company's ability to realize the anticipated growth opportunities and synergies from integrating the respective businesses of Cenovus and Husky following completion of the Cenovus Transaction.

Achieving the benefits of the Cenovus Transaction also depends on the ability of the combined company to effectively capitalize on its scale, scope and leadership position in the oil sands and wider oil and natural gas industry, to realize the anticipated capital and operating synergies, to profitably sequence the growth prospects of its asset base and to maximize the potential of its improved growth opportunities and capital funding opportunities as a result of combining the businesses and operations of Cenovus and Husky.

The integration of the Cenovus and Husky assets will require the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters. The integration process may result in the loss of key employees and the disruption of ongoing business and employee relationships that may adversely affect the combined company's ability to achieve the anticipated benefits of the Cenovus Transaction. A variety of factors, including those other risk factors set forth in this MD&A may adversely affect the ability to achieve the anticipated benefits of the Cenovus Transaction.

Entry into New Business Activities

Completion of the Cenovus Transaction has resulted in a combination of the business activities previously carried on by each of Husky and Cenovus as separate entities. The combination of these activities into the combined company may expose shareholders to different business risks than those to which they were exposed prior to the completion of the Cenovus Transaction. As a result of the changing risk profile of the companies, the combined company may be subject to review of its credit ratings, which may result in a downgrade or negative outlook being assigned to the combined company.

Most operational and strategic decisions and certain staffing decisions with respect to integration have not yet been made. These decisions and the integration of the two companies will present challenges to management, including the integration of systems, policies and personnel of the two companies which may be geographically separated, unanticipated liabilities and unanticipated costs. It is possible that the integration process could result in the loss of key employees, the disruption of the respective ongoing businesses or inconsistencies in standards, controls, procedures and policies that adversely affect the ability of management to maintain relationships with customers, suppliers, employees and other constituencies or to achieve the anticipated benefits of the Cenovus Transaction. The performance of the combined company's operations could be adversely affected if the combined company cannot retain key employees to assist in the integration and operation of Husky and Cenovus.

Any inability of management to successfully integrate the operations could have a material adverse effect on the business, financial condition and results of operations of the combined company.

Ongoing Impacts of the COVID-19 Pandemic

The recent COVID-19 pandemic, and actions taken, and that may be taken, by governmental authorities in response thereto, have resulted and may continue to result in, among other things: increased volatility in financial markets and foreign currency exchange rates; disruptions to global supply chains; adverse effects on the health and safety of the Company's workforce, or guidelines or restrictions to protect health and safety of such workforces, rendering employees unable to work or travel; temporary operational restrictions; and an overall slowdown in the global economy. In particular, the COVID-19 pandemic has resulted in, and may continue to result in, a reduction in the demand for, and prices of, commodities that are closely linked to the Company's financial performance, including crude oil, refined petroleum products (such as jet fuel, diesel and gasoline), natural gas and electricity, and also increases the risk that storage for crude oil and refined petroleum products could reach capacity in certain geographic locations in which the Company operates. A prolonged period of decreased demand for, and prices of, these commodities, and any applicable storage constraints, could also result in the Company voluntarily curtailing or shutting in production and a decrease in the Company's refined product volumes and refinery utilization rates, which could adversely impact the Company's business, financial condition and results of operations.

The COVID-19 pandemic continues to rapidly evolve and its effect on supply and demand patterns is expected to result in negative impacts on the Company's business, financial condition and results of operations over the near term. To the extent that the COVID-19 pandemic adversely affects the Company's business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described in this MD&A.

6.0 Liquidity and Capital Resources

6.1 Summary of Cash Flow

Cash Flow Summary *($ millions)*	**2020**	2019
Cash flow		
Operating activities	**841**	2,971
Financing activities	**274**	(817)
Investing activities	**(2,129)**	(3,197)

Cash Flow from Operating Activities

Cash flow generated from operating activities decreased by $2,130 million in 2020 compared to 2019. The decrease was primarily due to lower realized crude oil and refined product pricing and lower refining margins in the Lloydminster Heavy Oil Value Chain and the U.S. Refining segments, as a result of the significant decline in crude oil and refined product prices in 2020.

Cash Flow from Financing Activities

Cash flow generated for financing activities increased by $1,091 million in 2020 compared to 2019. The increase was primarily due to long-term debt issuances combined with lower common share dividend payments in 2020.

Cash Flow used for Investing Activities

Cash flow used for investing activities decreased by $1,068 million in 2020 compared to 2019. The decrease was primarily due to reduced capital expenditures in 2020.

6.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2020, the Company's working capital was $738 million compared to $302 million at December 31, 2019. The Company's working capital is as follows:

Working Capital *($ millions)*	**December 31, 2020**	December 31, 2019	Change
Cash and cash equivalents	**735**	1,775	(1,040)
Accounts receivable	**1,119**	1,499	(380)
Income taxes receivable	**—**	30	(30)
Inventories	**1,115**	1,486	(371)
Prepaid expenses	**161**	148	13
Accounts payable and accrued liabilities	**(2,129)**	(3,465)	1,336
Income taxes payable	**(27)**	—	(27)
Short-term debt	**(40)**	(550)	510
Long-term debt due within one year	**—**	(400)	400
Lease liabilities	**(102)**	(109)	7
Asset retirement obligations	**(94)**	(112)	18
Net working capital	**738**	302	436

The decrease in cash and cash equivalents was primarily due to lower cash flow from operating activities. The decrease in accounts receivable was primarily due to lower revenues in the fourth quarter of 2020 compared to the fourth quarter of 2019. The decrease in inventories was primarily due to lower commodity prices at the end of 2020 compared to 2019. The decrease in accounts payable and accrued liabilities was primarily due to lower capital expenditures, a lower common share dividend and timing of settlements in 2020 compared to 2019. The decrease in short-term debt and long-term debt due within one year was due to repayments in 2020.

6.3 Sources of Liquidity

Liquidity describes a company's ability to access cash. Sources of liquidity include cash and cash equivalents on hand, funds from operations, proceeds from the issuance of short and long-term debt, availability of short and long-term credit facilities and proceeds from asset sales. Since the Company operates in the upstream oil and gas industry, it requires significant cash to fund capital programs necessary to maintain or increase production, develop reserves, acquire strategic oil and gas assets and repay maturing debt.

During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of short and long-term capital resources. The Company believes that it has sufficient liquidity to sustain its operations, fund capital programs and meet non-cancellable contractual obligations and commitments in the short and long-term principally by cash generated from operating activities, cash on hand, the issuance of debt, borrowings under committed and uncommitted credit facilities and cash proceeds from asset sales.

At December 31, 2020, the Company had the following available credit facilities:

Credit Facilities *($ millions)*	Available	Unused
Operating facilities[1]	**975**	**508**
Syndicated credit facilities	**4,000**	**3,650**
	4,975	**4,158**

[1] *Consists of demand credit facilities.*

At December 31, 2020, the Company had $4,158 million of unused credit facilities of which $3,650 million were long-term committed credit facilities and $508 million were short-term uncommitted credit facilities. A total of $427 million short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $nil of long-term committed borrowing credit facilities was used in support of commercial paper. At December 31, 2020, the Company had $40 million of direct borrowing against the short-term uncommitted credit facilities. At December 31, 2020, the Company had $350 million outstanding under its $2.0 billion committed syndicated credit facility expiring June 19, 2022 (December 31, 2019 – no direct borrowings), and no direct borrowings under its $2.0 billion committed syndicated credit facility expiring March 9, 2024 (December 31, 2019 – no direct borrowings). The Company's ability to renew existing bank credit facilities and issuances of new debt are dependent upon maintaining an investment grade credit rating and the condition of capital and credit markets. Credit ratings may be affected by the Company's level of debt, from time to time.

The Company's leverage covenant under its credit facilities is a debt to capital ratio and calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the credit agreements divided by total debt and shareholders' equity. This covenant is used to assess the Company's financial strength. If the Company does not comply with the covenant under the credit facilities, there is risk that repayment could be accelerated. The Company was in compliance with this covenant under its credit facilities at December 31, 2020, and assessed the risk of non-compliance to be low.

Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. There were no amounts drawn on this demand credit facility at December 31, 2020.

On March 15, 2019, the Company issued US$750 million in senior unsecured notes. The notes bear an annual interest rate of 4.40% and are due on April 15, 2029. The Company raised the net proceeds of the offering for general corporate purposes, which included the repayment of certain outstanding debt securities that matured in 2019.

On May 1, 2019, the Company filed a universal short form base shelf prospectus (the "2019 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enabled the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada. As a result of the delisting of Husky's shares from the TSX, the Company is unable to sell securities under the 2019 Canadian Shelf Prospectus.

On June 17, 2019, the Company repaid the maturing 6.15% notes. The amount paid to note holders was $402 million.

On December 16, 2019, the Company repaid the maturing 7.25% notes. The amount paid to note holders was $987 million.

On March 3, 2020, the Company filed a universal short form base shelf prospectus (the "2020 U.S. Shelf Prospectus") with the Alberta Securities Commission. On March 4, 2020, the Company's related U.S. registration statement filed with the SEC containing the 2020 U.S. Shelf Prospectus became effective which enabled the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the U.S. During the period that the

2020 U.S. Shelf Prospectus and the related U.S registration statement were effective, securities could be offered in amounts, at prices and on terms set forth in a prospectus supplement. On January 26, 2021, the Company terminated the effectiveness of the U.S. registration statement.

On March 12, 2020, the Company repaid the maturing 5.00% notes. The principal paid to note holders was $400 million.

On April 7, 2020 the Company entered into a $500 million unsecured non-revolving term credit facility. Interest payable is based on pricing referenced to CAD Bankers' Acceptance or CAD Prime Rates. The facility was repaid on October 5, 2020.

On June 17, 2020, DBRS Morningstar downgraded Husky's issuer rating and senior unsecured notes and debentures rating to BBB(high) from A(low), its commercial paper rating to R-2(high) from R-1(low) and its preferred shares - cumulative rating to Pfd-3(high) from Pfd-2(low). All trends were negative. With this action, DBRS Morningstar removed the ratings from under review with negative implications which were placed on March 26, 2020 in response to the extreme price declines and heightened volatility in crude oil markets largely caused by the rapid spread of the COVID-19 pandemic and the concurrent crude oil-price war between OPEC, led by Saudi Arabia and Russia.

On June 30, 2020, S&P Global Ratings affirmed all of its ratings on Husky, including its 'BBB' issuer credit and senior unsecured debt ratings. At the same time, they also affirmed the P-3(High) rating on the Company's preferred shares. All trends remained negative.

On August 7, 2020, the Company issued $1.25 billion of notes. The notes have a coupon of 3.50% and are due on February 7, 2028. Proceeds were for general corporate purposes, which included the repayment of Husky's $500 million unsecured non-revolving term loan credit facility on October 5, 2020.

On August 11, 2020 Moody's affirmed its Baa2 stable issuer credit rating on Husky.

With the announcement of the Cenovus Transaction on October 25, all rating agencies adjusted their ratings opinions.

On October 25, 2020, DBRS Morningstar placed Husky's issuer rating and senior unsecured notes and debentures rating of "BBB(high)", commercial paper rating of R-2(high) and preferred shares - cumulative rating of Pfd-3(high) Under Review with Negative Implications.

On October 25, 2020, S&P placed Husky's "BBB" long-term issuer credit and senior unsecured debt rating and P-3(high) preferred share ratings on CreditWatch with Negative Implications.

On October 26, 2020, Moody's placed Husky's "Baa2" senior unsecured ratings On Review for Downgrade.

At December 31, 2020, the Company had unused capacity of $1.75 billion under the 2019 Canadian Shelf Prospectus and US$3.0 billion under the 2020 U.S. Shelf Prospectus and related U.S. registration statement.

With the closing of the Cenovus Transaction announced on January 4, 2021, all rating agencies finalized their rating opinions.

On January 4, 2021, DBRS Morningstar downgraded Husky's issuer rating and senior unsecured notes and debentures rating to "BBB" from "BBB (high)", preferred shares ratings to "Pfd-3" from "Pfd-3 (high)", and commercial paper to "R-2 (middle)" from "R-2 (high)" and assigned a stable outlook removing the ratings from Under Review with Negative Implications assigned on October 25, 2020.

On January 4, 2021, S&P lowered Husky's long-term issuer credit and senior unsecured debt rating to "BBB-" from "BBB" and preferred share ratings to "P-3" from "P-3(High)" and assigned a stable outlook, removing the CreditWatch with Negative Implications previously assigned on October 25, 2020.

On January 4, 2021, Moody's downgraded Husky's senior unsecured rating to "Baa3" from "Baa2" and assigned a negative outlook, removing the Under Review assigned on October 26, 2020.

On January 4, 2021, with Husky being a wholly-owned subsidiary of Cenovus, Fitch assigned a "BB+/RR4" rating to Husky's senior unsecured debt and assigned a positive outlook.

Husky's preferred shares were exchanged for Cenovus preferred shares pursuant to the Cenovus Transaction and those preferred share ratings have moved to Cenovus. DBRS Morningstar has also discontinued and withdrawn its rating on Husky's commercial paper at the request of the Company.

Net Debt

The Company had total debt of $6,157 million and cash and cash equivalents of $735 million at December 31, 2020, compared to total debt of $5,520 million and cash and cash equivalents of $1,775 million at December 31, 2019. The Company's net debt at December 31, 2020 increased by $1,677 million when compared to December 31, 2019:

Net Debt[1] *($ millions)*	**December 31, 2020**	December 31, 2019
Net debt at beginning of period	**(3,745)**	(2,881)
Change in net debt due to:		
Funds from operations[1]	**494**	3,251
Debt issue costs	**(7)**	(9)
Dividends on common shares	**(276)**	(503)
Dividends on preferred shares	**(35)**	(35)
Finance lease payments	**(111)**	(233)
Capital expenditures	**(1,587)**	(3,432)
Capitalized interest	**(60)**	(177)
Proceeds from asset sales	**30**	277
Investment in joint ventures	**(91)**	(40)
Change in non-cash working capital	**(65)**	(104)
Other	**7**	1
Effect of exchange rates on cash and cash equivalents	**(26)**	(48)
Effect of exchange rates on long-term debt	**50**	188
	(1,677)	(864)
Net debt at end of period	**(5,422)**	(3,745)

(1) *Net debt and funds from operations are non-GAAP measures. Refer to Section 9.3 for reconciliations to the corresponding GAAP measures.*

During the year ended December 31, 2020, the Company's capital expenditures were primarily funded by funds from operations and cash on hand. The Company's funds from operations are dependent on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates. Management prepares capital expenditure budgets annually which are regularly monitored and updated to adapt to changes in market factors. In addition, the Company requires authorizations for capital expenditures on projects, which assists with the management of capital.

6.4 Capital Structure

Capital Structure *($ millions)*	**December 31, 2020 Outstanding**
Total debt[1]	**6,157**
Shareholders' equity	**7,064**

(1) *Total debt is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.*

The Company's objectives when managing capital have been to maintain a flexible capital structure in order to optimize the cost of capital at acceptable risk, and maintain investor, creditor and market confidence to sustain the future development of the business. The Company has managed its capital structure and made adjustments as economic conditions and the risk characteristics of its underlying assets change. The Company considers its capital structure to include shareholders' equity and debt, which was $13.2 billion at December 31, 2020 (December 31, 2019 – $22.8 billion).

The Company has monitored its financing requirements and capital structure using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to funds from operations (refer to Section 9.3). At December 31, 2020, debt to capital employed was 46.6% (December 31, 2019 – 24.2%) and debt to funds from operations was 12.5 times (December 31, 2019 – 1.7 times). The increase in the Company's debt to funds from operations ratio reflects the impact of the sharp decline in the global economic environment from COVID-19 and falling commodity prices which resulted in significantly lower funds from operations. The Company has taken measures to strengthen its financial position and navigate through this commodity down cycle by, among other things, reducing the 2020 budgeted capital and operating spending, and reducing the quarterly common share dividend. The Company is subject to a leverage covenant in its credit facilities that limits debt to capital (subject to specific definitions in the credit agreements) to less than 65%, temporarily increased to 75% until the intended amalgamation of the Company and Cenovus is completed. The Company is in compliance with this covenant and considers the risk of non-compliance low. The Company also targets a debt to funds from operations ratio of less than 2.0 times over the longer term.

To facilitate the management of these ratios, the Company prepared annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment.

6.5 Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Other Commercial Commitments

In the normal course of business, the Company is obligated to make future payments. The following summarizes known non-cancellable contracts and other commercial commitments:

Contractual Obligations

Payments due by period ($ millions)	2021	2022-2023	2024-2025	Thereafter	Total
Long-term debt and interest on fixed rate debt	236	1,073	2,059	4,150	7,518
Operating agreements(1)	97	215	166	525	1,003
Firm transportation agreements(1)(4)	552	1,192	1,204	4,473	7,421
Unconditional purchase obligations(2)	1,766	1,904	1,423	3,324	8,417
Lease rentals and exploration work agreements	74	154	90	838	1,156
Obligations to fund equity investee(3)	54	153	166	280	653
Lease obligations(5)	195	346	297	2,031	2,869
Asset retirement obligations	94	192	173	9,111	9,570
	3,068	5,229	5,578	24,732	38,607

(1) *Included in operating agreements and firm transportation agreements are blending and storage agreements and transportation commitments of $1.2 billion and $1.7 billion respectively with HMLP.*

(2) *Includes processing services, distribution services, insurance premiums, drilling services, natural gas purchases and the purchase of refined petroleum products.*

(3) *Equity investee refers to the Company's investment in Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

(4) *Includes transportation commitments of $1.7 billion (2019 – $1.6 billion) that are subject to regulatory approval or have been approved, but are not yet in service. Terms are up to 20 years subsequent to the date of commencement.*

(5) *Refer to Note 10 in the 2020 consolidated financial statements.*

Other Obligations

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that decisions in any pending or threatened proceedings related to these and other matters, or any amount which it may be required to pay, would have a material adverse impact on its financial position, results of operations or liquidity.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time. Management believes that it has adequately provided for current and deferred income taxes.

In accordance with the provisions of the regulations of the People's Republic of China, the Company is required to deposit funds into separate accounts restricted to the funding of future asset retirement obligations in offshore China. As at December 31, 2020, the Company has deposited funds of $164 million, which has been reclassified as non-current.

The Company is also subject to various contingent obligations that become payable only if certain events or rulings occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess their impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

The Company has a number of contingent environmental liabilities, which individually have been estimated to be immaterial. These contingent environmental liabilities are primarily related to the migration of contamination at fuel outlets and certain legacy sites where the Company had previously conducted operations. The contingent environmental liabilities involved have been considered in aggregate and based on reasonable estimates the Company does not believe they will result, in aggregate, in a material adverse effect on its financial position, results of operations or liquidity.

Off-Balance Sheet Arrangements

The Company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the Company's financial condition, results of operations, liquidity or capital expenditures.

Standby Letters of Credit

On occasion, the Company issues letters of credit in connection with transactions in which the counterparty requires such security.

6.6 Transactions with Related Parties

The Company performs management services as the operator of the assets held by HMLP 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. HMLP charges an access fee to the Company for the use of its pipeline systems in performing the Company's blending business, and the Company also pays for transportation and storage services. These transactions were related party transactions as of December 31, 2020, as the Company has a 35% ownership interest in HMLP and the remaining ownership interests in HMLP belong to Power Assets Holdings Limited and CK Infrastructure Holdings Limited, which were affiliates of one of the Company's principal shareholders prior to completion of the Cenovus Transaction. For the year ended December 31, 2020, the Company charged HMLP $250 million related to construction costs and management services. For the year ended December 31, 2020, the Company had purchases from HMLP of $239 million related to the use of the pipeline for the Company's blending, transportation and storage activities. As at December 31, 2020, the Company had $23 million due from HMLP and $20 million due to HMLP.

6.7 Outstanding Share Data

Authorized:

- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: December 31, 2020

• common shares	1,005,121,738
• cumulative redeemable preferred shares, series 1	10,435,932
• cumulative redeemable preferred shares, series 2	1,564,068
• cumulative redeemable preferred shares, series 3	10,000,000
• cumulative redeemable preferred shares, series 5	8,000,000
• cumulative redeemable preferred shares, series 7	6,000,000
• stock options	18,883,146
• stock options exercisable	9,650,528

Husky common shares and preferred shares were delisted at the close of market on January 5, 2021. Husky stock options were converted to Cenovus stock options on January 5, 2021.

7.0 Critical Accounting Estimates and Key Judgments

The Company's consolidated financial statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Significant accounting policies are disclosed in Note 3 to the 2020 consolidated financial statements. Some of the Company's accounting policies require subjective judgment and estimation about uncertain circumstances.

7.1 Accounting Estimates

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and on a prospective basis. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained, and as the Company's operating environment changes. Specifically, amounts recorded for depletion, depreciation, amortization and impairment, recoveries from insurance claims, asset retirement obligations, assets and liabilities measured at fair value, employee future benefits, income taxes and reserves and contingencies are based on estimates.

In early March 2020, the World Health Organization declared the COVID-19 coronavirus outbreak to be a pandemic. Responses to the spread of COVID-19 have resulted in significant disruption to business operations and a significant increase in economic uncertainty, with more volatile commodity prices and currency exchange rates, and a marked decline in long-term interest rates. Although economies are beginning to re-open, these events are resulting in a challenging economic climate in which it is difficult to reliably estimate the length or severity of these developments and their financial impact. The results of the potential economic downturn and any potential resulting direct and indirect impact to the Company has been considered in management's estimates described above at the period end; however there could be a further prospective material impact in future periods.

Depletion, Depreciation, Amortization and Impairment

Eligible costs associated with oil and gas activities are capitalized on a unit of measure basis. Depletion expense is subject to estimates including petroleum and natural gas reserves, future petroleum and natural gas prices, estimated future remediation costs, future interest rates as well as other fair value assumptions. The aggregate of capitalized costs, net of accumulated DD&A, less estimated salvage values, is charged to DD&A over the life of the proved developed reserves using the unit of production method, except in the case of assets whose useful life is shorter or longer than the lifetime of the proved developed reserves of that field, in which case the straight-line method or a unit-of-production method based on total proved plus probable reserves is applied.

Impairment and Reversals of Impairment of Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment or reversal of impairment. Determining whether there are any indications of impairment, or reversal of impairment, requires significant judgment of external factors, such as an extended change in prices or margins for oil and gas commodities or products, a significant change in an asset's market value, a significant change and revision of estimated volumes, revision of future development costs, a change in the entity's market capitalization or significant changes in the technological, market, economic or legal environment that would have an adverse impact on the entity. If impairment, or reversal of impairments, is indicated the amount by which the carrying value is different from the estimated recoverable amount of the long-lived asset is charged to net earnings.

The determination of the recoverable amount for impairment, or reversal of impairment, involves the use of numerous assumptions and estimates. Estimates of future cash flows used in the evaluation of assets are made using management's forecasts of commodity prices, operating costs and future capital expenditures, marketing supply and demand, forecasted crack spreads, growth rate, discount rate and, in the case of oil and gas properties, expected production volumes. Expected production volumes take into account assessments of field reservoir performance and include expectations about proved and probable volumes and where applicable economically recoverable resources associated with interests in certain Husky properties which are risk-weighted utilizing geological, production, recovery, market price and economic projections. Either the cash flow estimates or the discount rate is risk-adjusted to reflect local conditions as appropriate. Future revisions to these assumptions impact the recoverable amount.

Impairment losses recognized for assets in prior years are assessed at the end of each reporting period for indications that the impairment has decreased or no longer exists. An impairment loss is reversed only to the extent that the carrying amount of the asset or cash generating units ("CGUs") does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

Asset Retirement Obligations

Estimating asset retirement obligations requires that the Company estimates costs that are many years in the future. Restoration technologies and costs are constantly changing, as are regulatory, political, environment, safety and public relations considerations. Inherent in the calculation of asset retirement obligations are numerous assumptions and estimates, including the ultimate settlement amounts, future third-party pricing, inflation factors, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in changes to the asset retirement obligations.

Fair Value of Financial Instruments

The Company's financial instruments include cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, derivatives, portions of other assets, lease liabilities and other long-term liabilities. Derivative instruments are measured at fair value through profit or loss. The Company's remaining financial instruments are measured at amortized cost. For financial instruments measured at amortized cost, the carrying values approximate their fair value with the exception of long-term debt.

The Company's financial assets and liabilities that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon the fair value hierarchy. Level 1 fair value measurements are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair value measurements of assets and liabilities in Level 2 include valuations using inputs other than quoted prices but for which all significant outputs are observable, either directly or indirectly. Level 3 fair value measurements are based on inputs that are unobservable and significant to the overall fair value measurement.

The fair values of derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. These estimates are also subject to change with fluctuations in commodity prices, interest rates, foreign currency exchange rates and estimates of non-performance. The actual settlement of a derivative instrument could differ materially from the fair value recorded and could impact future results.

Employee Future Benefits

The determination of the cost of the defined benefit pension plan and the other post-retirement benefit plans reflects a number of estimates that affect expected future benefit payments. These estimates include, but are not limited to, attrition, mortality, the rate of return on pension plan assets, salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The fair value of the plan assets is used for the purposes of calculating the expected return on plan assets.

Income Taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Estimates that require significant judgments are also made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where the transaction and calculations for which the ultimate tax determination are uncertain. All tax filings are subject to audit and potential reassessment, often after the passage of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Legal, Environmental Remediation and Other Contingent Matters

The Company is required to determine both whether a loss is probable based on judgment and interpretation of laws and regulations and whether the loss can be reasonably estimated. When a loss is determined it is charged to net earnings. The Company must continually monitor known and potential contingent matters and make appropriate provisions by charges to net earnings when warranted by circumstances.

7.2 Key Judgments

Management makes judgments regarding the application of IFRS for each accounting policy. Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include determination of technical feasibility and commercial viability, impairment assessments, the determination of CGUs, changes in reserve estimates, the determination of a joint arrangement, the designation of the Company's functional currency and the fair value of related party transactions.

Exploration and Evaluation Costs
Costs directly associated with an exploration well are initially capitalized as exploration and evaluation assets. Expenditures related to wells that do not find reserves or where no future activity is planned are expensed as exploration and evaluation expenses. Exploration and evaluation costs are excluded from costs subject to depletion until technical feasibility and commercial viability is assessed or production commences. At that time, costs are either transferred to property, plant and equipment or their value is impaired. Impairment is charged directly to net earnings. Drilling results, required operating costs and capital expenditure and estimated reserves are important judgments when making this determination and may change as new information becomes available.

Impairment of Financial Assets
A financial asset is assessed at the end of each reporting period to determine whether it is impaired based on objective evidence indicating that one or more events have had a negative effect on the estimated future cash flows of that asset. Objective evidence used by the Company to assess impairment of financial assets includes quoted market prices for similar financial assets and historical collection rates. Given that the calculations for the net present value of estimated future cash flows related to derivative financial assets require the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and expected production volumes, it is possible that the assumptions may change, which may require a material adjustment to the carrying value of financial assets.

Cash Generating Units
The Company's assets are grouped into respective CGUs, which is the smallest identifiable group of assets, liabilities and associated goodwill that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The determination of the Company's CGUs is subject to management's judgment.

Reserves
Oil and gas reserves are evaluated internally and audited by independent qualified reserve engineers. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty. Changes in reserve estimates can have an impact on reported net earnings through revisions to depletion, depreciation and amortization expense, in addition to determining possible impairments and reversal of impairments of property, plant and equipment.

Net reserves represent the Company's lessor royalty, overriding royalty and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalty interests. Assumptions reflect market and regulatory conditions, as applicable, as at the balance sheet date and could differ significantly from other points in time throughout the year or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Joint Arrangements
Joint arrangements represent activities where the Company has joint control established by a contractual agreement. Joint control requires unanimous consent for financial and operational decisions. A joint arrangement is either a joint operation, whereby the parties have rights to the assets and obligations for the liabilities, or a joint venture, whereby the parties have rights to the net assets.

Classification of a joint arrangement as either joint operation or joint venture requires judgment. Management's considerations include, but are not limited to, determining if the arrangement is structured through a separate vehicle and whether the legal form and contractual arrangements give the entity direct rights to the assets and obligations for the liabilities within the normal course of business. Other facts and circumstances are also assessed by management, including the entity's rights to the economic benefits of assets and its involvement and responsibility for settling liabilities associated with the arrangement.

Functional and Presentation Currency
Functional currency is the currency of the primary economic environment in which the Company and its subsidiaries operate and is normally the currency in which the entity primarily generates and expends cash. The designation of the Company's functional currency is a management judgment based on the composition of revenues and costs in the locations in which it operates.

Related Party Judgments and Estimates

The Company entered into transactions and agreements in the normal course of business with certain related parties, joint arrangements and associates. Proceeds for disposition of assets to related parties are recognized at fair value, based on discounted cash flow forecast from those assets. Independent opinions of the fair value may be obtained. Changes in the assumptions used to determine these fair values may result in a material difference in the proceeds and any gain or loss on disposition.

8.0 Recent Accounting Standards and Changes in Accounting Policies

Recent Accounting Standards

The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Change in Accounting Policy

The Company has not adopted any changes to material accounting policies during the fiscal year ended December 31, 2020.

9.0 Reader Advisories

9.1 Forward-Looking Statements

Certain statements in this document are forward-looking statements and information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this document are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "is estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "schedules" and "outlook"). In particular, forward-looking statements in this document include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally, and the company's target debt to funds from operations ratio;

- with respect to Oil Sands, the expected timing of a planned turnaround at Plant 1B at the Sunrise Energy Project;

- with respect to U.S. Refining: anticipated insurance recoveries for property damage associated with the Superior Refinery rebuild; and expectations regarding the operating capacity and capabilities of the rebuilt Superior Refinery;

- with respect to the Company's Offshore business in Asia Pacific: the expected impact of the gas sales agreement amendment on cash flow from Liwan 3-1; the expected timing of additional drilling and testing at Block 15/33; the expected timing of commencement of production and gas sales at MDA and MBH; development of the MDK field; and the expected timing of a final investment decision at the MAC field; and

- with respect to the Company’s Offshore business in the Atlantic, expectations regarding the suspension of activities at the West White Rose Project.

In addition, statements relating to “reserves“ are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserves and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company’s forward-looking statements have been based on assumptions and factors concerning future events, including the timing of regulatory approvals, that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third party consultants, suppliers and regulators, among others.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to the Company.

The Company's Annual Information Form for the year ended December 31, 2020, this MD&A and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

New factors emerge from time to time and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

9.2 Oil and Gas Reserves Reporting

Disclosure of Oil and Gas Reserves and Other Oil and Gas Information

Unless otherwise indicated: (i) reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, has been audited and reviewed by Sproule, an independent qualified reserves auditor, have an effective date of December 31, 2020 and represent the Company's working interest share (ii) projected and historical production volumes quoted are gross, which represents the total or the Company's working interest, as applicable share before deduction of royalties (iii) all Husky working interest production volumes quoted are before deduction of royalties; and (iv) historical production volumes provided are for the year ended December 31, 2020.

The Company uses the term "barrels of oil equivalent" (or "boe"), which is consistent with other oil and gas companies' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of conventional natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not represent value equivalency at the wellhead.

The Company uses the term reserves replacement ratio, which is consistent with other oil and gas companies' disclosures. Reserves replacement ratios for a given period are determined by taking the Company's proved reserve changes for that period divided by the Company's upstream gross production for the same period. Reserves changes include: revisions, purchases, sales, improved recovery, discoveries and extensions. The reserves replacement ratio measures the amount of reserves changes to a company's reserves base during a given period relative to the amount of oil and gas produced during that same period. A company's reserves replacement ratio must be at least 100% for the company to maintain its reserves. Reserves replacement ratios that exclude economic factors will exclude the impacts that changing oil and gas prices, inflation, and exchange rates and the regulatory curtailment imposed by the Alberta government have.

Note to U.S. Readers

The Company reports its reserves information in accordance with Canadian practices and specifically in accordance with NI 51-101. Because the Company is permitted to prepare its reserves and resources information in accordance with Canadian disclosure requirements, it may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the SEC.

9.3 Non-GAAP Measures

Disclosure of non-GAAP Measures

The Company uses measures primarily based on IFRS and also uses some secondary non-GAAP measures. The non-GAAP measures included in this MD&A and related disclosures are: debt to capital, debt to capital employed, debt to funds from operations, funds from operations, free cash flow, operating margin, net debt, total debt, refining and marketing margin and sustaining capital. None of these measures are used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for debt to capital employed or debt to funds from operations. These are useful complementary measures that are used by management in assessing the Company's financial performance, efficiency and liquidity, and they may be used by the Company's investors for the same purpose. The non-GAAP measures do not have standardized meanings prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other issuers. They are common in the reports of other companies but may differ by definition and application. All non-GAAP measures are defined below.

Debt to Capital

Debt to capital is a non-GAAP measure and is equal to total debt and certain adjusting items specified in the Company's credit agreement divided by total debt and shareholder's equity. Management believes this measure assists management and investors in evaluating the Company's financial strength.

Debt to Capital Employed

Debt to capital employed percentage is a non-GAAP measure and is equal to total debt divided by capital employed. Capital employed is equal to total debt and shareholders' equity. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

Debt to Funds from Operations

Debt to funds from operations is a non-GAAP measure and is equal to total debt divided by funds from operations. Funds from operations is equal to cash flow - operating activities excluding change in non-cash working capital. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of debt to funds from operations for the periods ended December 31, 2020, 2019 and 2018:

Debt to Funds from Operations *($ millions)*	**December 31, 2020**	December 31, 2019	December 31, 2018
Total debt	**6,157**	5,520	5,747
Funds from operations	**494**	3,251	4,004
Debt to funds from operations	**12.5**	1.7	1.4

Funds from Operations and Free Cash Flow

Funds from operations is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Funds from operations equals cash flow – operating activities excluding change in non-cash working capital. Management believes that impacts of non-cash working capital items on cash flow – operating activities may reduce comparability between periods, accordingly, funds from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance of the Company in the stated period compared to prior periods.

Free cash flow is a non-GAAP measure, which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Free cash flow is presented to assist management and investors in analyzing operating performance by the business in the stated period. Free cash flow equals funds from operations less capital expenditures.

The following tables show the reconciliation of net earnings (loss) to funds from operations and free cash flow, and related per share amounts for the periods ended:

Reconciliation of Cash Flow		Year ended	
	Dec. 31	Dec. 31	Dec. 31
($ millions)	**2020**	2019	2018
Net earnings (loss)	**(10,016)**	(1,370)	1,457
Items not affecting cash:			
Accretion	**104**	106	97
Depletion, depreciation, amortization and impairment	**12,920**	5,496	2,591
Inventory write-down to net realizable value	**7**	15	60
Exploration and evaluation expenses	**594**	355	29
Deferred income taxes (recoveries)	**(3,190)**	(974)	396
Foreign exchange gain	**(3)**	(26)	(6)
Stock-based compensation	**16**	(2)	44
Gain on sale of assets	**(25)**	(8)	(4)
Unrealized market to market loss (gain)	**10**	44	(150)
Share of equity investment loss (gain)	**(7)**	(59)	(69)
Gain on insurance recoveries for damage to property	**(19)**	(207)	(253)
Other	**67**	12	21
Settlement of asset retirement obligations	**(39)**	(276)	(181)
Deferred revenue	**(115)**	(42)	(100)
Distribution from joint ventures	**190**	187	72
Change in non-cash working capital	**347**	(280)	130
Cash flow – operating activities	**841**	2,971	4,134
Change in non-cash working capital	**(347)**	280	(130)
Funds from operations	**494**	3,251	4,004
Capital expenditures	**(1,587)**	(3,432)	(3,578)
Free cash flow	**(1,093)**	(181)	426
Funds from operations – basic	**0.49**	3.23	3.98
Funds from operations – diluted	**0.49**	3.23	3.98

Reconciliation of Cash Flow	Three months ended							
	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31
($ millions)	**2020**	2020	2020	2020	2019	2019	2019	2019
Net earnings (loss)	**(926)**	(7,081)	(304)	(1,705)	(2,341)	273	370	328
Items not affecting cash:								
Accretion	**26**	27	25	26	27	26	26	27
Depletion, depreciation, amortization and impairment	**1,620**	8,636	590	2,074	3,520	703	643	630
Inventory write-down to net realizable value	**(38)**	45	(362)	362	15	—	—	—
Exploration and evaluation expenses	**(2)**	598	(2)	—	332	—	23	—
Deferred income taxes	**(439)**	(2,030)	(137)	(584)	(789)	22	(250)	43
Foreign exchange loss (gain)	**(7)**	2	(1)	3	(11)	(1)	(2)	(12)
Stock-based compensation (recovery)	**29**	(3)	8	(18)	(13)	(9)	13	7
Gain on sale of assets	**(8)**	(9)	(2)	(6)	(3)	(3)	—	(2)
Unrealized mark to market loss (gain)	**24**	(19)	96	(91)	(13)	4	(4)	57
Share of equity investment loss (gain)	**(8)**	1	10	(10)	5	(19)	(23)	(22)
Gain on insurance recoveries for damage to property	**(19)**	—	—	—	(194)	(13)	—	—
Other	**60**	1	7	(1)	11	5	5	(9)
Settlement of asset retirement obligations	**(9)**	(3)	(3)	(24)	(90)	(73)	(41)	(72)
Deferred revenue	**(23)**	(34)	(41)	(17)	(14)	(7)	(5)	(16)
Distribution from joint ventures	**23**	17	134	16	27	113	47	—
Change in non-cash working capital	**114**	(69)	(28)	330	397	(221)	(42)	(414)
Cash flow - operating activities	**417**	79	(10)	355	866	800	760	545
Change in non-cash working capital	**(114)**	69	28	(330)	(397)	221	42	414
Funds from operations	**303**	148	18	25	469	1,021	802	959
Capital expenditures	**(311)**	(354)	(310)	(612)	(894)	(868)	(858)	(812)
Free cash flow	**(8)**	(206)	(292)	(587)	(425)	153	(56)	147
Funds from operations – basic	**0.30**	0.15	0.02	0.02	0.47	1.02	0.80	0.95
Funds from operations – diluted	**0.30**	0.15	0.02	0.02	0.47	1.02	0.80	0.95

Operating Margin

Operating margin is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "revenue, net of royalties" as determined in accordance with IFRS, as an indicator of financial performance. Operating margin is presented to assist management and investors in analyzing operating performance of the Company in the stated period. Operating margin equals revenues net of royalties less purchases of crude oil and products, production, operating and transportation expenses, and selling, general and administrative expenses.

The following table shows the reconciliation of operating margins for the Integrated Corridor and Offshore business segments for the three months and years ended December 31:

Operating margin	Three months ended December 31				Year ended December 31			
	Integrated Corridor		Offshore		Integrated Corridor		Offshore	
($ millions)	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Revenues, net of royalties	**3,119**	4,400	**410**	433	**11,873**	18,458	**1,428**	1,444
Expenses								
Purchases of crude oil and products	**2,285**	3,288	**37**	(18)	**9,249**	12,842	**32**	(16)
Production, operating and transportation expenses	**577**	709	**66**	89	**2,285**	2,690	**275**	340
Selling, general and administrative expenses	**100**	85	**18**	11	**408**	348	**75**	55
Operating margin	**157**	318	**289**	351	**(69)**	2,578	**1,046**	1,065

Net Debt

Net debt is a non-GAAP measure that equals total debt less cash and cash equivalents. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of total debt to net debt as at December 31, 2020, 2019 and 2018:

Net Debt *($ millions)*	**December 31, 2020**	December 31, 2019	December 31, 2018
Total debt	**6,157**	5,520	5,747
Cash and cash equivalents	**(735)**	(1,775)	(2,866)
Net debt	**5,422**	3,745	2,881

Total debt

Total debt is a non-GAAP measure that equals the sum of long-term debt, long-term debt due within one year and short-term debt. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of total debt as at December 31, 2020, 2019 and 2018:

Total Debt *($ millions)*	**December 31, 2020**	December 31, 2019	December 31, 2018
Short-term debt	**40**	550	200
Long-term debt due within one year	**—**	400	1,433
Long-term debt	**6,117**	4,570	4,114
Total debt	**6,157**	5,520	5,747

Refining and Marketing Margin

Refining and marketing margin is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "gross revenue" as determined in accordance with IFRS, as an indicator of financial performance. Refining and marketing margin is presented to assist management and investors in analyzing operating performance of the Company in the stated period. Refining and marketing margin equals gross revenue and marketing and other less purchases of crude oil and products.

Sustaining Capital

Sustaining capital is the additional development capital that is required by the business to maintain production and operations at existing levels. Development capital includes the cost to drill, complete, equip and tie-in wells to existing infrastructure. Sustaining capital does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

9.4 Additional Reader Advisories

Intention of Management's Discussion and Analysis

This Management's Discussion and Analysis is intended to provide an explanation of financial and operational performance compared with prior periods and the Company's prospects and plans. It provides additional information that is not contained in the Company's consolidated financial statements.

Review by the Audit Committee

This Management's Discussion and Analysis was reviewed by the Company's Audit Committee and approved by the Board of Directors on February 8, 2021. Any events subsequent to that date could materially alter the veracity and usefulness of the information contained in this document.

Additional Husky Documents Filed with Securities Commissions

This Management's Discussion and Analysis dated February 8, 2021, should be read in conjunction with the 2020 consolidated financial statements and related notes. Readers are also encouraged to refer to the Company's interim reports filed for 2020, which contain Management's Discussion and Analysis and consolidated financial statements, and the Company's Annual Information Form for the year ended December 31, 2020, filed separately with Canadian securities regulatory authorities, and annual Form 40-F filed with the SEC, the U.S. federal securities regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and www.huskyenergy.com.

Use of Pronouns and Other Terms

"Husky" and "the Company" refer to Husky Energy Inc. on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, comparisons of results are for the years ended December 31, 2020 and 2019 and the Company's financial position at December 31, 2020 and 2019.

Reclassifications and Materiality for Disclosures

Certain prior year amounts have been reclassified to conform to current year presentation. Materiality for disclosures is determined on the basis of whether the information omitted or misstated would cause a reasonable investor to change his or her decision to buy, sell or hold Husky's securities.

Additional Reader Guidance

Unless otherwise indicated:

- Financial information is presented in accordance with IFRS as issued by the IASB.
- All dollar amounts are in Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represents the Company's working interest share before royalties.
- Prices are presented before the effect of hedging.
- This MD&A is for the year ended December 31, 2020, and is in respect of Husky and its consolidated entities and considers the completion of the Cenovus Transaction.

Terms

Asia Pacific	*Includes oil and gas exploration and production activities located offshore China and Indonesia*
Asphalt Refinery	*The asphalt refinery owned by the Company and located in Lloydminster, Alberta*
Atlantic	*Includes upstream oil and gas exploration and production activities located offshore Newfoundland and Labrador*
Bitumen	*Bitumen is a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds or 10,000 centipoise measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods*
Capital employed	*Long-term debt, long-term debt due within one year, short-term debt and shareholders' equity*
Capital expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Debt to capital	*Total debt and certain adjusting items specified in the Company's credit agreement divided by total debt and shareholder's equity*
Debt to capital employed	*Long-term debt, long-term debt due within one year and short-term debt divided by capital employed*
Debt to funds from operations	*Long-term debt, long-term debt due within one year and short-term debt divided by funds from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil and bitumen to facilitate transmissibility of the oil through a pipeline*
Feedstock	*Raw materials which are processed into petroleum products*
Free cash flow	*Funds from operations less capital expenditures*
Funds from operations	*Cash flow - operating activities excluding change in non-cash working capital*
Gross/net wells	*Gross refers to the total number of wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross reserves/production	*A company's working interest share of reserves/production before deduction of royalties*
Heavy crude oil	*Crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity*
Light crude oil	*Crude oil with a relative density greater than 31.1 degrees API gravity*
Medium crude oil	*Crude oil with a relative density that is greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity*
Net debt	*Total debt less cash and cash equivalents*
Net revenue	*Gross revenues less royalties*
NOVA Inventory Transfer ("NIT")	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Oil sands	*Sands and other rock materials that contain crude bitumen and include all other mineral substances in association therewith*
OPEC	*Organization of the Petroleum Exporting Countries*
Operating margin	*Revenues net of royalties less purchases of crude oil and products, production, operating and transportation expenses, and selling, general and administrative expenses.*
Probable reserves	*Those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves*

Proved developed reserves	*Those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing*
Proved reserves	*Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves*
RIN	*Renewable Identification Numbers*
Shareholders' equity	*Common shares, preferred shares, contributed surplus, retained earnings, accumulated other comprehensive income and non-controlling interest*
Stratigraphic test well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic crude oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Thermal	*Use of steam injection into the reservoir in order to enable heavy crude oil and bitumen to flow to the well bore*
Total debt	*Long-term debt including long-term debt due within one year and short-term debt*
Turnaround	*Performance of scheduled plant or facility maintenance requiring the complete or partial shutdown of the plant or facility operations*
Upgrader	*The heavy crude oil upgrading facility owned and operated by the Company and located in Lloydminster, Saskatchewan*

Units of Measure

bbls	*barrels*	*mboe*	*thousand barrels of oil equivalent*
bbls/day	*barrels per day*	*mboe/day*	*thousand barrels of oil equivalent per day*
bcf	*billion cubic feet*	*mcf*	*thousand cubic feet*
boe	*barrels of oil equivalent*	*mcfge*	*million cubic feet of gas equivalent*
boe/day	*barrels of oil equivalent per day*	*mmbbls*	*million barrels*
CO_2e	*carbon dioxide equivalent*	*mmboe*	*million barrels of oil equivalent*
GJ	*gigajoule*	*mmbtu*	*million British Thermal Units*
mbbls	*thousand barrels*	*mmcf*	*million cubic feet*
mbbls/day	*thousand barrels per day*	*mmcf/day*	*million cubic feet per day*

9.5 Disclosure Controls and Procedures

Disclosure Controls and Procedures

Husky's management, under supervision of the Acting Chief Executive Officer & Chief Financial Officer, have evaluated the effectiveness of Husky's disclosure controls and procedures (as defined in the rules of the SEC and the Canadian Securities Administrators ("CSA") as at December 31, 2020, and have concluded that such disclosure controls and procedures are effective.

Management's Annual Report on Internal Control over Financial Reporting

The following report is provided by management in respect of Husky's internal controls over financial reporting (as defined in the rules of the SEC and the CSA):

1) Husky's management, under the supervision of the Acting Chief Executive Officer & Chief Financial Officer, is responsible for designing, establishing and maintaining adequate internal control over financial reporting for Husky. All 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.

2) Husky's management has used the Committee of Sponsoring Organizations of the Treadway Commission (2013) framework to evaluate the effectiveness of Husky's internal control over financial reporting.

3) As at December 31, 2020, management, under the supervision of the Acting Chief Executive Officer & Chief Financial Officer, evaluated the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective.

4) KPMG LLP, who has audited the consolidated financial statements of Husky for the year ended December 31, 2020, has also issued a report on internal controls over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States) that attests to the effectiveness Husky's internal controls over financial reporting.

Changes in Internal Control over Financial Reporting

There have been no changes in Husky's internal control over financial reporting during the year ended December 31, 2020, that have materially affected or are reasonably likely to materially affect its internal control over financial reporting.

10.0 Selected Quarterly Financial and Operating Information

10.1 Summary of Quarterly Results

Fourth Quarter Results Summary *($ millions, except where indicated)*	Three months ended **Dec. 31 2020**	 Dec. 31 2019
Gross revenues and marketing and other[(1)]		
Integrated Corridor		
Lloydminster Heavy Oil Value Chain	**1,065**	1,360
Oil Sands	**110**	134
Western Canada Production	**108**	166
U.S. Refining	**1,690**	2,321
Canadian Refined Products	**381**	658
Eliminations	**(200)**	(185)
Offshore	**438**	467
Total gross revenues and marketing and other	**3,592**	4,921
Net earnings (loss)		
Integrated Corridor		
Lloydminster Heavy Oil Value Chain	**171**	43
Oil Sands	**(498)**	(619)
Western Canada Production	**(118)**	(630)
U.S. Refining	**(69)**	(189)
Canadian Refined Products	**(7)**	(1)
Offshore	**(273)**	(778)
Corporate	**(132)**	(167)
Net loss	**(926)**	(2,341)
Per share – Basic	**(0.93)**	(2.34)
Per share – Diluted	**(0.92)**	(2.34)
Cash flow – operating activities	**417**	866
Funds from operations[(2)]	**303**	469
Per share – Basic	**0.30**	0.47
Per share – Diluted	**0.30**	0.47
Daily sales volume		
Integrated Corridor		
Lloydminster Heavy Oil Value Chain *(mboe/day)*	**175.9**	170.6
Synthetic crude oil and refined products *(mboe/day)*	**69.9**	80.1
Blended crude oil *(mboe/day)*[(3)]	**106.0**	90.5
Oil Sands		
Diluted bitumen *(mbbls/day)*	**30.1**	33.4
Western Canada Production *(mboe/day)*	**51.7**	66.9
Light crude oil *(mbbls/day)*	**4.6**	7.3
NGL *(mbbls/day)*	**9.4**	12.6
Conventional natural gas *(mmcf/day)*	**226.6**	281.7
Offshore		
Asia Pacific *(mboe/day)*[(4)(5)]	**55.9**	45.3
NGL *(mbbls/day)*[(4)(5)]	**12.3**	10.4
Conventional natural gas *(mmcf/day)*[(4)(5)]	**261.5**	209.7
Atlantic		
Light crude oil *(mbbls/day)*	**22.5**	22.2

Fourth Quarter Results Summary (continued)	**Dec. 31**	Dec. 31
($ millions, except where indicated)	**2020**	2019
Realized price per unit sold		
Integrated Corridor		
Lloydminster Heavy Oil Value Chain *($/boe)*	**53.14**	69.83
Synthetic crude oil and refined products *($/boe)*	**57.08**	78.75
Blended crude oil *($/boe)*[3]	**50.55**	61.94
Oil Sands		
Diluted bitumen *($/bbl)*	**40.55**	45.51
Western Canada Production *($/boe)*	**18.00**	22.58
Light crude oil *($/bbl)*	**39.13**	62.74
Conventional natural gas & NGL *($/mcf)*	**2.65**	2.94
Offshore		
Asia Pacific *($/boe)*	**68.52**	80.15
NGL *($/bbl)*	**52.55**	72.36
Conventional natural gas *($/mcf)*	**12.17**	13.74
Atlantic		
Light crude oil *($/bbl)*	**60.13**	83.88
Refinery throughput		
Upgrader *(mbbls/day)*[6]	**60.8**	79.6
Lloydminster Refinery *(mbbls/day)*[7]	**28.1**	28.2
Prince George Refinery *(mbbls/day)*[8]	**—**	3.9
Lima Refinery *(mbbls/day)*[7])	**137.4**	21.4
BP-Husky Toledo Refinery *(mbbls/day)*[7][9]	**66.1**	70.3
Superior Refinery *(mbbls/day)*[7]	**—**	—
Total throughput *(mbbls/day)*	**292.4**	203.4
Operating margin[2]		
Lloydminster Heavy Oil Value Chain *($/bbl)*[10]	**15.69**	29.37
Oil Sands *($/bbl)*	**14.71**	10.63
Western Canada Production *($/boe)*	**4.09**	7.30
Offshore		
Asia Pacific *($/boe)*	**54.63**	68.11
Atlantic *($/bbl)*	**15.66**	50.89
Retail fuel sales *(million of litres/day)*	**6.8**	7.4
U.S. Refining refining and marketing margin *(US$/bbl crude throughput)*[2]	**4.59**	8.34
U.S./Canadian dollar exchange rate *(US$)*	**0.768**	0.758

(1) Gross revenue and marketing and other results reported for 2019 have been recast to reflect a change in the classification of intersegment sales eliminations and a change in presentation of the Integrated Corridor and Offshore business units.
(2) Funds from operations, operating margin and refining and marketing margin are non-GAAP measures. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.
(3) Blended crude oil and bitumen.
(4) Reported sales volumes include Husky's working interest production from the Liwan Gas Project.
(5) Reported sales volumes include Husky's working interest production from the BD Project (40%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.
(6) Upgrading throughput includes diluent returned to the field.
(7) Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.
(8) Prince George Refinery was sold on November 1, 2019.
(9) Reported throughput volumes include Husky's working interest from the BP-Husky Toledo Refinery (50%).
(10) Excludes revenue and expenses not directly attributable to sale of synthetic crude and refined product, and blended crude oil.

Gross Revenue and Marketing and Other

The Company's consolidated gross revenues and marketing and other decreased by $1,329 million in the fourth quarter of 2020 compared to the fourth quarter of 2019.

In the Integrated Corridor business, gross revenues decreased primarily due to lower realized crude oil, refined product, gasoline and diesel pricing in the Lloydminster Heavy Oil Value Chain, U.S. Refining and Canadian Refined Products segments, as a result of the significant decline in benchmark commodity prices. The decrease is partially offset by higher throughput volumes at the Lima Refinery where a planned turnaround was completed in the fourth quarter of 2019.

In the Offshore business, gross revenues decreased primarily due to lower realized crude oil, natural gas and NGL pricing in Asia Pacific and Atlantic operations, combined with lower production from the Terra Nova field due to the suspension of operations in December 2019. The decrease is partially offset by higher sales volumes from Asia Pacific operations.

Net Earnings (Loss)

The Company's consolidated net loss decreased by $1,415 million in the fourth quarter of 2020 compared to the fourth quarter of 2019.

In the Integrated Corridor business, net loss decreased primarily due to after-tax impairment charges and derecognitions of $1,399 million in the fourth quarter of 2019 within the Sunrise Energy Project, Western Canada Production, Lloyd Ethanol Plant, Minnedosa Ethanol Plant and Lima Refinery. The decrease is partially offset by after-tax impairment charges of $443 million, lower insurance recoveries recognized for business interruption and incident costs associated with the Superior Refinery and lower realized crude oil and refined product pricing in the Lloydminster Heavy Oil Value Chain.

In the Offshore business, net loss decreased primarily due to an after-tax impairment charge of $690 million and an after-tax write-down of exploration and evaluation assets of $186 million within the Atlantic in the fourth quarter of 2019. The decrease was partially offset by after-tax impairment charges of $361 million, combined with the same factors that impacted gross revenue and marketing and other.

Cash Flow – Operating Activities and Funds from Operations

Cash flow – operating activities and funds from operations decreased by $449 million and $166 million, respectively, in the fourth quarter of 2020 compared to the fourth quarter of 2019, primarily due to the same factors that impacted gross revenue and marketing and other. The decrease is partially offset by lower production, operating and transportation expenses due to cost savings initiatives.

Daily Sales Volume

In the Lloydminster Heavy Oil Value Chain segment, daily sales volumes increased due to higher volumes of bitumen and heavy crude oil sales, partially offset by the planned turnaround at the Upgrader completed in October 2020.

In the Western Canada Production segment, daily sales volumes decreased due to the continued reduction, or shut-in, of production since March 2020 in response to market conditions.

During the fourth quarter of 2020, Offshore sales volumes increased primarily due to higher production from the Liwan Gas Project, including commencement of production at Liuhua 29-1 in November 2020, partially offset by lower production from the Terra Nova field due to the suspension of operations in December 2019.

Refinery Throughput

The Company's refinery throughput increased by 89.0 mbbls/day in the fourth quarter of 2020 primarily due to the planned turnaround at the Lima Refinery completed in the fourth quarter of 2019, partially offset by the planned turnaround at the Upgrader completed in October 2020.

Segmented Operational Information

Segmented Operational Information	2020				2019			
($ millions, except where indicated)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Gross revenues and Marketing and other								
Integrated Corridor								
Lloydminster Heavy Oil Value Chain	**1,065**	**936**	**633**	**1,141**	1,360	1,511	1,554	1,228
Oil Sands	**110**	**61**	**34**	**53**	134	182	198	139
Western Canada Production	**108**	**87**	**62**	**125**	166	140	107	200
U.S. Refining	**1,690**	**1,730**	**1,134**	**2,122**	2,321	2,743	2,837	2,375
Canadian Refined Products	**381**	**393**	**258**	**456**	658	611	582	574
Eliminations	**(200)**	**(141)**	**(108)**	**(153)**	(185)	(213)	(335)	(215)
Offshore	**438**	**313**	**395**	**369**	467	399	378	309
Total gross revenues and marketing and other	**3,592**	**3,379**	**2,408**	**4,113**	4,921	5,373	5,321	4,610
Net earnings (loss)								
Integrated Corridor								
Lloydminster Heavy Oil Value Chain	**171**	**(1,311)**	**(156)**	**(13)**	43	189	198	74
Oil Sands	**(498)**	**(502)**	**(19)**	**(343)**	(619)	21	18	35
Western Canada Production	**(118)**	**(192)**	**(39)**	**(221)**	(630)	(47)	(89)	(6)
U.S. Refining	**(69)**	**(3,248)**	**(74)**	**(534)**	(189)	121	117	199
Canadian Refined Products	**(7)**	**2**	**(15)**	**(9)**	(1)	(2)	(8)	9
Offshore	**(273)**	**(1,621)**	**38**	**(563)**	(778)	26	4	55
Corporate	**(132)**	**(209)**	**(39)**	**(22)**	(167)	(35)	130	(38)
Net earnings (loss)	**(926)**	**(7,081)**	**(304)**	**(1,705)**	(2,341)	273	370	328
Per share – Basic	**(0.93)**	**(7.05)**	**(0.31)**	**(1.71)**	(2.34)	0.26	0.36	0.32
Per share – Diluted	**(0.92)**	**(7.06)**	**(0.31)**	**(1.71)**	(2.34)	0.25	0.36	0.31
Cash flow – operating activities	**417**	**79**	**(10)**	**355**	866	800	760	545
Funds from operations[(1)]	**303**	**148**	**18**	**25**	469	1,021	802	959
Per share – Basic	**0.30**	**0.15**	**0.02**	**0.02**	0.47	1.02	0.80	0.95
Per share – Diluted	**0.30**	**0.15**	**0.02**	**0.02**	0.47	1.02	0.80	0.95
U.S./Canadian dollar exchange rate (US$)	**0.768**	**0.751**	**0.722**	**0.745**	0.758	0.757	0.748	0.752
Daily production, before royalties								
Crude oil & NGL production *(mbbls/day)*								
Light & Medium crude oil	**22.9**	**21.3**	**26.0**	**28.8**	33.3	30.5	19.6	16.5
NGL[(4)]	**21.6**	**21.5**	**21.7**	**20.3**	23.0	22.4	20.3	24.7
Heavy crude oil	**20.2**	**18.4**	**16.7**	**30.4**	32.6	31.6	28.9	27.6
Bitumen	**136.4**	**117.4**	**95.1**	**138.0**	137.8	126.4	120.4	130.3
Total crude oil & NGL production *(mbbls/day)*	**201.1**	**178.6**	**159.5**	**217.5**	226.7	210.9	189.2	199.1
Conventional Natural gas *(mmcf/day)*[(4)]	**498.8**	**478.8**	**522.0**	**488.7**	507.4	503.3	475.1	516.8
Total production *(mboe/day)*	**284.2**	**258.4**	**246.5**	**298.9**	311.3	294.8	268.4	285.2
Total sales volume								
Integrated Corridor								
Lloydminster Heavy Oil Value Chain *(mboe/day)*	**175.9**	**166.5**	**165.4**	**194.4**	170.6	186.9	184.8	156.0
Synthetic crude oil and refined products *(mboe/day)*	**69.9**	**77.6**	**78.8**	**86.5**	80.1	92.0	84.1	67.4
Blended crude oil *(mboe/day)*	**106.0**	**88.9**	**86.6**	**107.9**	90.5	94.9	100.7	88.6
Oil Sands								
Diluted bitumen *(mbbls/day)*	**30.1**	**21.6**	**19.8**	**35.2**	33.4	34.3	33.0	22.9
Western Canada Production *(mboe/day)* [(2)]	**51.7**	**55.7**	**60.5**	**62.6**	66.9	70.3	60.5	69.2
Light crude oil *(mbbls/day)*	**4.6**	**5.2**	**5.7**	**7.5**	7.3	7.9	5.8	7.3
Conventional natural gas & NGL *(mboe/day)*	**282.7**	**303.2**	**328.7**	**330.9**	357.5	374.1	328.1	371.5
Offshore								
Asia Pacific *(mboe/day)*[(2)(3)(4)]	**55.9**	**49.1**	**52.1**	**44.3**	45.3	41.5	42.2	46.1
NGL *(mbbls/day)*[(2)(3)]	**12.3**	**11.5**	**11.1**	**9.4**	10.4	9.4	9.6	10.3
Conventional natural gas *(mmcf/day)*[(3)(4)]	**261.5**	**225.6**	**245.9**	**209.7**	209.7	192.9	195.5	215.0
Atlantic								
Light crude oil *(mbbls/day)*	**22.5**	**7.3**	**26.0**	**15.4**	22.2	21.6	15.2	4.4

Segmented Operational Information (continued)	2020 Q4	2020 Q3	2020 Q2	2020 Q1	2019 Q4	2019 Q3	2019 Q2	2019 Q1
Total realized price per unit sold								
Integrated Corridor								
Lloydminster Heavy Oil Value Chain *($/boe)*	**53.14**	**50.27**	**33.93**	**55.67**	69.83	74.00	76.36	64.66
Synthetic crude oil and refined products *($/boe)*	**57.08**	**60.86**	**44.44**	**64.13**	78.75	79.51	86.60	73.83
Blended crude oil *($/boe)*	**50.55**	**41.03**	**24.36**	**48.87**	61.94	68.66	67.82	57.70
Oil Sands								
Diluted bitumen *($/bbl)*	**40.55**	**36.73**	**11.07**	**31.88**	45.51	57.29	66.58	57.82
Western Canada Production *($/boe)*	**18.00**	**16.29**	**10.86**	**18.92**	22.58	17.00	18.28	23.11
Light crude oil *($/bbl)*	**39.13**	**41.47**	**24.65**	**48.66**	62.74	65.12	70.23	60.25
Conventional natural gas & NGL *($/mcf)*	**2.65**	**2.28**	**1.57**	**2.47**	2.94	1.82	2.13	3.12
Offshore								
Asia Pacific *($/boe)*	**68.52**	**71.40**	**74.37**	**80.84**	80.15	74.17	79.55	79.73
NGL *($/bbl)*	**52.55**	**52.69**	**31.18**	**67.00**	72.36	68.04	78.04	72.33
Conventional natural gas *($/mcf)*	**12.17**	**12.85**	**14.35**	**14.10**	13.74	12.66	13.34	13.64
Atlantic								
Light crude oil *($/bbl)*	**60.13**	**57.20**	**32.97**	**67.11**	83.88	84.12	92.07	69.18
Unit upstream operating cost*($/boe)*(5)(6)	**12.88**	**13.93**	**13.12**	**14.29**	15.25	14.83	15.83	16.30
Unit operating margin(7)								
Integrated Corridor								
Lloydminster Heavy Oil Value Chain *($/boe)*(8)	**15.69**	**11.03**	**6.88**	**17.93**	29.37	30.47	33.31	29.26
Synthetic crude oil and refined products *($/boe)*	**21.42**	**15.35**	**14.25**	**30.94**	39.14	38.24	43.42	46.17
Blended crude oil *($/boe)*	**11.92**	**7.26**	**0.17**	**7.48**	20.73	22.94	24.88	16.43
Oil Sands								
Diluted bitumen *($/bbl)*	**14.71**	**17.48**	**(4.90)**	**(24.92)**	10.63	21.26	15.28	38.91
Western Canada Production *($/boe)*	**4.09**	**5.86**	**(3.05)**	**0.21**	7.30	3.69	(2.99)	9.59
Light crude oil *($/bbl)*	**0.53**	**9.93**	**0.36**	**16.94**	21.70	32.15	21.30	15.41
Conventional natural gas & NGL *($/mcf)*	**0.73**	**0.89**	**(0.57)**	**(0.35)**	0.92	0.03	(0.93)	1.48
Offshore								
Asia Pacific *($/boe)*	**54.63**	**59.29**	**64.94**	**68.11**	68.11	61.51	66.69	66.80
NGL *($/bbl)*	**39.30**	**40.30**	**23.51**	**53.46**	59.85	54.31	63.55	58.62
Conventional natural gas *($/mcf)*	**9.82**	**10.84**	**12.69**	**12.01**	11.75	10.60	11.27	11.52
Atlantic								
Light crude oil *($/bbl)*	**15.66**	**24.38**	**(2.81)**	**19.69**	50.89	41.60	25.35	(62.73)
Lloydminster Heavy Oil Value Chain								
Refinery throughput								
Upgrading *(mbbls/day)*(9)	**60.8**	**51.6**	**65.7**	**77.5**	79.6	75.6	73.4	71.2
Lloydminster Refinery *(mbbls/day)*(10)	**28.1**	**27.1**	**28.2**	**28.6**	28.2	28.3	26.1	22.8
U.S. Refining								
Refinery throughput(10)								
Lima Refinery *(mbbls/day)*	**137.4**	**153.7**	**130.0**	**131.4**	21.4	174.3	179.8	171.4
BP-Husky Toledo Refinery *(mbbls/day)*(11)	**66.1**	**67.7**	**57.4**	**70.3**	70.3	66.8	57.5	58.0
Superior Refinery *(mbbls/day)*	**—**	**—**	**—**	**—**	—	—	—	—
Canadian Refined Products								
Fuel sales *(millions of litres/day)*	**6.8**	**7.2**	**5.7**	**6.9**	7.4	7.5	7.2	7.5
Prince George Refinery throughput *(mbbls/day)*(12)	**—**	**—**	**—**	**—**	3.9	11.4	3.5	10.2

(1) *Funds from operations is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.*
(2) *Sales volumes approximates total daily gross production.*
(3) *Reported sales volumes include Husky's working interest production from the Liwan Gas Project.*
(4) *Reported production and sales volumes include Husky's working interest production from the BD Project (40%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*
(5) *Reported production volumes and associated per unit values include Husky's net working interest production from the Madura-BD Gas Project (40%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*
(6) *Excludes operating costs not directly attributable to the production of upstream products.*
(7) *Per unit cost calculated based on sales volumes.*
(8) *Excludes revenue and expenses not directly attributable to sale of synthetic crude and refined product, and blended crude oil.*
(9) *Upgrading throughput includes diluent returned to the field.*
(10) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(11) *Reported throughput volumes include Husky's working interest from the BP-Husky Toledo Refinery (50%).*
(12) *Sale of Prince George Refinery closed on November 1, 2019.*

Significant Items Impacting Gross Revenues, Net Earnings (Loss) and Funds from Operations

Variations in the Company's gross revenues, net earnings (loss) and funds from operations are primarily driven by changes in production volumes, commodity prices, commodity price differentials, refining crack spreads, foreign exchange rates and planned turnarounds. Significant declines in crude oil and crack spread benchmarks were partially offset by higher production at the Liwan Gas Project. This resulted in a decrease to the Company's gross revenues, net earnings and funds from operations. Other significant items which impacted gross revenues, net earnings and funds from operations over the last eight quarters include:

2020

Q4:

- The Company recognized a pre-tax impairment of $1,155 million in the Lloydminster Heavy Oil Value Chain, Oil Sands and Western Canada Production within the Integrated Corridor business and the Atlantic operation within the Offshore business, due to the sustained market impact from the COVID-19 pandemic, which has resulted in declines in forecasted long-term commodity prices, management's decision to reduce capital investment, delayed future development plans, and considered market indicators including the Cenovus Transaction.
- At the Liuhua 29-1 field at Liwan, first gas was achieved.
- At the Spruce Lake Central project, nameplate capacity was reached.
- At the Upgrader, projects were completed that increased crude throughput capacity to 81.5 mbbls/day and increased diesel production capacity from 6 mbbls/day to 10 mbbls/day.
- At the Hardisty Terminal, construction on 1.0 mmbbls of incremental storage was completed and put into service.
- The Company recognized $85 million in pre-tax insurance recoveries for rebuild costs, incident costs and business interruption associated with the incident at the Superior Refinery.
- The Company recognized $12 million in pre-tax recoveries for the Canadian Emergency Wage Subsidy.

Q3:

- The Company recognized a pre-tax impairment of $8,649 million, including exploration write-offs, in the Lloydminster Heavy Oil Value Chain, Oil Sands, Western Canada Production and U.S. Refining segments within the Integrated Corridor business and the Atlantic operation within the Offshore business, due to the sustained market impact from the COVID-19 pandemic, which has resulted in declines in forecasted long-term commodity prices, management's decision to reduce capital investment and delayed future development plans.
- At the Spruce Lake Central project, first oil was achieved.
- At the Hardisty Terminal, construction on 0.5 mmbbls of incremental storage was completed and put into service.
- The Company recognized $23 million in pre-tax recoveries for the Canadian Emergency Wage Subsidy.

Q2:

- In the Integrated Corridor business, production and refinery operating rates were impacted by a deliberate ramp-down which began late in the first quarter of 2020 in response to market conditions as a result of the COVID-19 pandemic.
- The Company recognized $47 million in pre-tax recoveries for the Canadian Emergency Wage Subsidy.

Q1:

- The Company recognized a pre-tax impairment of $1,416 million, in the Oil Sands and Western Canada Production segments within the Integrated Corridor business and the Atlantic segment within the Offshore business, due to the market impact from the COVID-19 pandemic, which has resulted in declines in current and forecasted crude oil prices and management's decision to delay capital investment in the West White Rose Project.
- The Company commenced the safe and orderly reduction, or shut-in, of production within the Integrated Corridor, to align with the upgrading and refining requirements as throughput was optimized in line with the changing market conditions.
- At the Lima Refinery, the crude oil flexibility project was commissioned.

2019

Q4:

- The Company recognized a pre-tax impairment charge of $2,405 million in the Oil Sands and Western Canada Production segments within the Integrated Corridor business and the Atlantic segment within the Offshore business. The impairment charge was primarily due to sustained declines in forecasted short and long-term crude oil and natural gas prices and management's decision to reduce capital investment in these areas.
- The Company recognized a pre-tax write-down of $339 million related to certain Exploration and Evaluation assets in the Western Canada Production segment within the Integrated Corridor business and the Atlantic segment within the Offshore business. The write-down was primarily due to changes in management's future development plans resulting from sustained declines in forecasted short and long-term prices for crude oil.
- The Company recognized a pre-tax derecognition charge of $254 million on the carrying value of components replaced as part of the crude oil flexibility project at the Lima Refinery.
- The Company closed the sale of the Prince George Refinery to Tidewater Midstream and Infrastructure.

- The Company recognized a pre-tax impairment charge of $90 million on the Lloyd Ethanol Plant and Minnedosa Ethanol Plant, primarily due to sustained declines in forecasted ethanol margins.
- At the Spruce Lake Central project, construction on the CPF was completed.
- At the Wembley area, in the Montney Formation, six liquids-rich wells were started up.
- At the Liuhua 29-1 field at Liwan, the remaining four of seven wells were completed.
- At the Lima Refinery a planned turnaround was completed, with final tie-ins made for the crude oil flexibility project.
- The Company recognized $308 million in pre-tax insurance recoveries for rebuild costs, incident costs and business interruption associated with the incident at the Superior Refinery.

Q3:
- At the Dee Valley Thermal Project, first oil was achieved and nameplate capacity was reached.
- At the Spruce Lake North Thermal Project, concrete work was completed.
- At the Spruce Lake East Thermal Project, regulatory approval was received and lease construction was completed.
- At the Karr area, in the Montney Formation, one well was drilled.
- At the Liuhua 29-1 field at Liwan, three of the seven wells were fully completed.
- At the White Rose field and satellite extension, full production was restored.
- At the Superior Refinery, permits necessary for the rebuild were received and rebuilding work began.
- The Company recognized $138 million in pre-tax insurance recoveries for incident costs and business interruption associated with the incident at the Superior Refinery.

Q2:
- At the Dee Valley Thermal Project, first steam was achieved.
- At the Spruce Lake North Thermal Project, site piling was completed and concrete work progressed.
- At the Spruce Lake East Thermal Project, lease construction started.
- At the Dee Valley 2 and Edam Central Thermal Projects, regulatory approval was received.
- At the Ansell and Kakwa areas, in the liquids-rich Cardium and Spirit River formations, two wells were drilled and four were completed.
- At the Liuhua 29-1 field, three development wells were drilled.
- Two infill wells were completed at the White Rose field and satellite extensions.
- The Company wrote off the Tiger's Eye D-17 exploration well.
- An exploration well drilled on Block 16/25 in 2018, which did not encounter commercial hydrocarbons, was written off.
- The Company recognized $233 million in tax recoveries related to the reduction in the Alberta provincial corporate tax rate.
- The Company recognized $71 million in pre-tax insurance recoveries for incident costs and business interruption associated with the incident at the Superior Refinery.

Q1:
- At the Dee Valley Thermal Project, drilling and fabrication of the Central Processing Facility was completed.
- At the Spruce Lake Central Thermal Project, site piling, concrete work and drilling were all completed. Large vessel and module fabrication progressed.
- At the Spruce Lake North Thermal Project, site preparation was completed, and large vessel and module fabrication progressed.
- At the Spruce Lake East Thermal Project, site preparation was completed, regulatory approval was received, and site clearing commenced.
- At the Ansell and Kakwa areas, in the liquids-rich Cardium and Spirit River Formations, eight wells drilled and six completed.
- At the Sinclair and Wembley areas, in the Montney Formation, four wells were drilled.
- Two infill wells were drilled at the White Rose field and satellite extensions.
- The Company recognized $113 million in pre-tax insurance recoveries for incident costs and business interruption associated with the incident at the Superior Refinery.

Segmented Financial Information

	Lloydminster Heavy Oil Value Chain				Integrated Corridor Oil Sands				Western Canada Production			
2020 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	**1,048**	**932**	**603**	**1,170**	**109**	**68**	**26**	**103**	**98**	**85**	**65**	**119**
Royalties	**(31)**	**(36)**	**(8)**	**(17)**	**—**	**(1)**	**—**	**(1)**	**(4)**	**4**	**(1)**	**(9)**
Marketing and other	**17**	**4**	**30**	**(29)**	**1**	**(7)**	**8**	**(50)**	**10**	**2**	**(3)**	**6**
Revenues, net of royalties	**1,034**	**900**	**625**	**1,124**	**110**	**60**	**34**	**52**	**104**	**91**	**61**	**116**
Expenses												
Purchases of crude oil and products	**514**	**454**	**333**	**526**	**34**	**9**	**10**	**100**	**10**	**(1)**	**—**	**13**
Production, operating and transportation expenses	**273**	**261**	**234**	**291**	**30**	**26**	**23**	**35**	**60**	**56**	**60**	**74**
Selling, general and administrative expenses	**51**	**49**	**53**	**51**	**6**	**4**	**5**	**9**	**15**	**16**	**7**	**26**
Depletion, depreciation, amortization and impairment	**57**	**1,590**	**179**	**232**	**694**	**684**	**10**	**361**	**180**	**280**	**41**	**301**
Exploration and evaluation expenses	**1**	**154**	**—**	**27**	**(1)**	**—**	**—**	**—**	**—**	**1**	**—**	**—**
Loss (gain) on sale of assets	**(4)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(1)**	**(11)**	**(2)**	**(6)**
Other – net	**1**	**8**	**12**	**—**	**(4)**	**(8)**	**(7)**	**(7)**	**(7)**	**—**	**—**	**—**
	893	**2,516**	**811**	**1,127**	**759**	**715**	**41**	**498**	**257**	**341**	**106**	**408**
Earnings (loss) from operating activities	**141**	**(1,616)**	**(186)**	**(3)**	**(649)**	**(655)**	**(7)**	**(446)**	**(153)**	**(250)**	**(45)**	**(292)**
Share of equity investment income (loss)	**—**	**(14)**	**(15)**	**(3)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Financial items												
Net foreign exchange gains (losses)	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Finance income	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Finance expenses	**(11)**	**(12)**	**(12)**	**(12)**	**(14)**	**(14)**	**(14)**	**(15)**	**(4)**	**(5)**	**(5)**	**(5)**
	(11)	**(12)**	**(12)**	**(12)**	**(14)**	**(14)**	**(14)**	**(15)**	**(4)**	**(5)**	**(5)**	**(5)**
Earnings (loss) before income tax	**130**	**(1,642)**	**(213)**	**(18)**	**(663)**	**(669)**	**(21)**	**(461)**	**(157)**	**(255)**	**(50)**	**(297)**
Provisions for (recovery of) income taxes												
Current	**—**	**1**	**(2)**	**1**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Deferred	**(41)**	**(332)**	**(55)**	**(6)**	**(165)**	**(167)**	**(2)**	**(118)**	**(39)**	**(63)**	**(11)**	**(76)**
	(41)	**(331)**	**(57)**	**(5)**	**(165)**	**(167)**	**(2)**	**(118)**	**(39)**	**(63)**	**(11)**	**(76)**
Net earnings (loss)	**171**	**(1,311)**	**(156)**	**(13)**	**(498)**	**(502)**	**(19)**	**(343)**	**(118)**	**(192)**	**(39)**	**(221)**
Capital expenditures	**100**	**178**	**53**	**263**	**1**	**—**	**—**	**8**	**13**	**2**	**(5)**	**47**
Total assets	**6,650**	**6,210**	**7,756**	**7,959**	**993**	**1,583**	**2,210**	**2,333**	**707**	**1,068**	**1,284**	**1,369**

(1) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices. Segment results include transactions between segments.*

Integrated Corridor (continued)															
U.S. Refining				Canadian Refined Products				Eliminations[1]				Total			
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
1,704	1,737	1,131	2,064	381	393	258	456	(200)	(141)	(108)	(153)	3,140	3,074	1,975	3,759
—	—	—	—	—	—	—	—	—	—	—	—	(35)	(33)	(9)	(27)
(14)	(7)	3	58	—	—	—	—	—	—	—	—	14	(8)	38	(15)
1,690	1,730	1,134	2,122	381	393	258	456	(200)	(141)	(108)	(153)	3,119	3,033	2,004	3,717
1,582	1,604	884	2,430	345	351	231	422	(200)	(141)	(108)	(153)	2,285	2,276	1,350	3,338
199	195	183	220	15	17	17	16	—	—	—	—	577	555	517	636
17	12	21	22	11	10	10	13	—	—	—	—	100	91	96	121
59	4,091	137	132	16	16	15	15	—	—	—	—	1,006	6,661	382	1,041
—	—	—	—	—	—	—	—	—	—	—	—	—	155	—	27
—	—	—	—	1	(2)	1	—	—	—	—	—	(4)	(13)	(1)	(6)
(84)	—	—	—	—	(4)	—	—	—	—	—	—	(94)	(4)	5	(7)
1,773	5,902	1,225	2,804	388	388	274	466	(200)	(141)	(108)	(153)	3,870	9,721	2,349	5,150
(83)	(4,172)	(91)	(682)	(7)	5	(16)	(10)	—	—	—	—	(751)	(6,688)	(345)	(1,433)
—	—	—	—	—	—	—	—	—	—	—	—	—	(14)	(15)	(3)
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
(5)	(4)	(4)	(5)	(3)	(3)	(2)	(3)	—	—	—	—	(37)	(38)	(37)	(40)
(5)	(4)	(4)	(5)	(3)	(3)	(2)	(3)	—	—	—	—	(37)	(38)	(37)	(40)
(88)	(4,176)	(95)	(687)	(10)	2	(18)	(13)	—	—	—	—	(788)	(6,740)	(397)	(1,476)
1	5	(8)	2	—	—	—	—	—	—	—	—	1	6	(10)	3
(20)	(933)	(13)	(155)	(3)	—	(3)	(4)	—	—	—	—	(268)	(1,495)	(84)	(359)
(19)	(928)	(21)	(153)	(3)	—	(3)	(4)	—	—	—	—	(267)	(1,489)	(94)	(356)
(69)	(3,248)	(74)	(534)	(7)	2	(15)	(9)	—	—	—	—	(521)	(5,251)	(303)	(1,120)
118	95	113	163	1	1	1	2	—	—	—	—	233	276	162	483
4,469	4,415	8,710	8,881	625	735	732	763	—	—	—	—	13,444	14,011	20,692	21,305

Offshore				Corporate				Total			
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
438	313	395	369	—	—	—	—	3,578	3,387	2,370	4,128
(28)	(20)	(21)	(18)	—	—	—	—	(63)	(53)	(30)	(45)
—	—	—	—	—	—	—	—	14	(8)	38	(15)
410	293	374	351	—	—	—	—	3,529	3,326	2,378	4,068
37	(37)	22	10	—	—	—	—	2,322	2,239	1,372	3,348
66	75	64	70	—	—	—	—	643	630	581	706
18	16	23	18	78	73	67	44	196	180	186	183
592	1,952	183	1,011	22	23	25	22	1,620	8,636	590	2,074
67	460	15	9	—	—	—	—	67	615	15	36
—	—	(1)	—	(4)	4	—	—	(8)	(9)	(2)	(6)
(5)	—	—	—	30	(25)	(46)	(116)	(69)	(29)	(41)	(123)
775	2,466	306	1,118	126	75	46	(50)	4,771	12,262	2,701	6,218
(365)	(2,173)	68	(767)	(126)	(75)	(46)	50	(1,242)	(8,936)	(323)	(2,150)
8	13	5	13	—	—	—	—	8	(1)	(10)	10
—	—	—	—	32	4	28	(50)	32	4	28	(50)
2	2	2	1	1	2	2	13	3	4	4	14
(10)	(10)	(11)	(10)	(66)	(63)	(57)	(20)	(113)	(111)	(105)	(70)
(8)	(8)	(9)	(9)	(33)	(57)	(27)	(57)	(78)	(103)	(73)	(106)
(365)	(2,168)	64	(763)	(159)	(132)	(73)	(7)	(1,312)	(9,040)	(406)	(2,246)
45	37	35	33	7	28	10	7	53	71	35	43
(137)	(584)	(9)	(233)	(34)	49	(44)	8	(439)	(2,030)	(137)	(584)
(92)	(547)	26	(200)	(27)	77	(34)	15	(386)	(1,959)	(102)	(541)
(273)	(1,621)	38	(563)	(132)	(209)	(39)	(22)	(926)	(7,081)	(304)	(1,705)
62	69	130	107	16	9	18	22	311	354	310	612
4,570	4,874	7,224	7,486	1,673	2,525	1,543	2,294	19,687	21,410	29,459	31,085

2019 *($ millions)*	Lloydminster Heavy Oil Value Chain Q4	Q3	Q2	Q1	Integrated Corridor Oil Sands Q4	Q3	Q2	Q1	Western Canada Production Q4	Q3	Q2	Q1
Gross revenues	1,373	1,506	1,540	1,182	139	182	208	120	143	112	109	150
Royalties	(37)	(42)	(47)	(34)	(3)	(4)	(4)	(2)	(14)	(7)	(7)	(13)
Marketing and other	(13)	5	14	46	(5)	—	(10)	19	23	28	(2)	50
Revenues, net of royalties	1,323	1,469	1,507	1,194	131	178	194	137	152	133	100	187
Expenses												
Purchases of crude oil and products	559	637	705	494	61	73	100	12	8	18	12	2
Production, operating and transportation expenses	322	302	291	297	37	33	30	40	80	69	81	83
Selling, general and administrative expenses	35	44	37	39	7	7	6	7	29	26	24	27
Depletion, depreciation, amortization and impairment	303	210	192	236	862	28	25	23	784	80	93	77
Exploration and evaluation expenses	19	14	4	17	1	1	—	—	99	7	3	2
Loss (gain) on sale of assets	—	—	—	—	—	—	—	—	—	—	—	(2)
Other – net	3	(6)	4	8	(7)	(7)	(14)	—	5	(7)	3	—
	1,241	1,201	1,233	1,091	961	135	147	82	1,005	193	216	189
Earnings (loss) from operating activities	82	268	274	103	(830)	43	47	55	(853)	(60)	(116)	(2)
Share of equity investment income (loss)	(13)	4	8	10	—	—	—	—	—	—	—	—
Financial items												
Net foreign exchange gains (losses)	—	—	—	—	—	—	—	—	—	—	—	—
Finance income	—	—	—	—	—	—	—	—	—	—	—	—
Finance expenses	(12)	(13)	(12)	(11)	(15)	(15)	(21)	(8)	(7)	(5)	(6)	(6)
	(12)	(13)	(12)	(11)	(15)	(15)	(21)	(8)	(7)	(5)	(6)	(6)
Earnings (loss) before income tax	57	259	270	102	(845)	28	26	47	(860)	(65)	(122)	(8)
Provisions for (recovery of) income taxes												
Current	11	(3)	(6)	(4)	(3)	6	7	—	—	—	—	—
Deferred	3	73	78	32	(223)	1	1	12	(230)	(18)	(33)	(2)
	14	70	72	28	(226)	7	8	12	(230)	(18)	(33)	(2)
Net earnings (loss)	43	189	198	74	(619)	21	18	35	(630)	(47)	(89)	(6)
Capital expenditures	282	205	208	261	3	7	18	10	6	32	60	96
Total assets	8,312	8,172	7,982	7,900	2,757	3,546	3,567	3,630	1,709	2,427	2,512	2,543

[1] *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices. Segment results include transactions between segments.*

Integrated Corridor (continued)

U.S. Refining				Canadian Refined Products				Eliminations[1]				Total			
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
2,318	**2,743**	**2,855**	**2,337**	**658**	**611**	**582**	**574**	**(185)**	**(213)**	**(335)**	**(215)**	**4,446**	**4,941**	**4,959**	**4,148**
—	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(54)**	**(53)**	**(58)**	**(49)**
3	**—**	**(18)**	**38**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**8**	**33**	**(16)**	**153**
2,321	**2,743**	**2,837**	**2,375**	**658**	**611**	**582**	**574**	**(185)**	**(213)**	**(335)**	**(215)**	**4,400**	**4,921**	**4,885**	**4,252**
2,232	**2,417**	**2,406**	**1,879**	**613**	**549**	**518**	**495**	**(185)**	**(213)**	**(335)**	**(215)**	**3,288**	**3,481**	**3,406**	**2,667**
242	**197**	**218**	**215**	**28**	**40**	**47**	**38**	**—**	**—**	**—**	**—**	**709**	**641**	**667**	**673**
13	**13**	**13**	**12**	**1**	**3**	**2**	**3**	**—**	**—**	**—**	**—**	**85**	**93**	**82**	**88**
380	**117**	**122**	**116**	**17**	**22**	**22**	**22**	**—**	**—**	**—**	**—**	**2,346**	**457**	**454**	**474**
—	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**119**	**22**	**7**	**19**
—	**1**	**—**	**—**	**(2)**	**(4)**	**—**	**—**	**—**	**—**	**—**	**—**	**(2)**	**(3)**	**—**	**(2)**
(307)	**(163)**	**(76)**	**(108)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(306)**	**(183)**	**(83)**	**(100)**
2,560	**2,582**	**2,683**	**2,114**	**657**	**610**	**589**	**558**	**(185)**	**(213)**	**(335)**	**(215)**	**6,239**	**4,508**	**4,533**	**3,819**
(239)	**161**	**154**	**261**	**1**	**1**	**(7)**	**16**	**—**	**—**	**—**	**—**	**(1,839)**	**413**	**352**	**433**
—	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(13)**	**4**	**8**	**10**
—	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
—	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
(4)	**(5)**	**(5)**	**(4)**	**(2)**	**(4)**	**(3)**	**(4)**	**—**	**—**	**—**	**—**	**(40)**	**(42)**	**(47)**	**(33)**
(4)	**(5)**	**(5)**	**(4)**	**(2)**	**(4)**	**(3)**	**(4)**	**—**	**—**	**—**	**—**	**(40)**	**(42)**	**(47)**	**(33)**
(243)	**156**	**149**	**257**	**(1)**	**(3)**	**(10)**	**12**	**—**	**—**	**—**	**—**	**(1,892)**	**375**	**313**	**410**
—	**10**	**2**	**5**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**8**	**13**	**3**	**1**
(54)	**25**	**30**	**53**	**—**	**(1)**	**(2)**	**3**	**—**	**—**	**—**	**—**	**(504)**	**80**	**74**	**98**
(54)	**35**	**32**	**58**	**—**	**(1)**	**(2)**	**3**	**—**	**—**	**—**	**—**	**(496)**	**93**	**77**	**99**
(189)	**121**	**117**	**199**	**(1)**	**(2)**	**(8)**	**9**	**—**	**—**	**—**	**—**	**(1,396)**	**282**	**236**	**311**
241	**196**	**202**	**129**	**10**	**12**	**41**	**10**	**—**	**—**	**—**	**—**	**542**	**452**	**529**	**506**
8,645	**8,873**	**8,523**	**8,767**	**838**	**1,115**	**1,088**	**1,043**	**—**	**—**	**—**	**—**	**22,261**	**24,133**	**23,672**	**23,883**

Offshore				Corporate				Total			
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
467	**399**	**378**	**309**	**—**	**—**	**—**	**—**	**4,913**	**5,340**	**5,337**	**4,457**
(34)	**(28)**	**(25)**	**(22)**	**—**	**—**	**—**	**—**	**(88)**	**(81)**	**(83)**	**(71)**
—	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**8**	**33**	**(16)**	**153**
433	**371**	**353**	**287**	**—**	**—**	**—**	**—**	**4,833**	**5,292**	**5,238**	**4,539**
(18)	**4**	**19**	**(21)**	**—**	**—**	**—**	**—**	**3,270**	**3,485**	**3,425**	**2,646**
89	**86**	**79**	**86**	**—**	**—**	**—**	**—**	**798**	**727**	**746**	**759**
11	**14**	**15**	**15**	**120**	**42**	**85**	**43**	**216**	**149**	**182**	**146**
1,147	**221**	**164**	**129**	**27**	**25**	**25**	**27**	**3,520**	**703**	**643**	**630**
271	**19**	**79**	**11**	**—**	**—**	**—**	**—**	**390**	**41**	**86**	**30**
—	**(1)**	**—**	**—**	**(1)**	**1**	**—**	**—**	**(3)**	**(3)**	**—**	**(2)**
1	**—**	**—**	**—**	**(5)**	**(22)**	**9**	**2**	**(310)**	**(205)**	**(74)**	**(98)**
1,501	**343**	**356**	**220**	**141**	**46**	**119**	**72**	**7,881**	**4,897**	**5,008**	**4,111**
(1,068)	**28**	**(3)**	**67**	**(141)**	**(46)**	**(119)**	**(72)**	**(3,048)**	**395**	**230**	**428**
8	**15**	**15**	**12**	**—**	**—**	**—**	**—**	**(5)**	**19**	**23**	**22**
—	**—**	**—**	**—**	**20**	**(8)**	**2**	**30**	**20**	**(8)**	**2**	**30**
2	**—**	**—**	**1**	**12**	**24**	**16**	**19**	**14**	**24**	**16**	**20**
(10)	**(9)**	**(10)**	**(9)**	**(29)**	**(33)**	**(48)**	**(41)**	**(79)**	**(84)**	**(105)**	**(83)**
(8)	**(9)**	**(10)**	**(8)**	**3**	**(17)**	**(30)**	**8**	**(45)**	**(68)**	**(87)**	**(33)**
(1,068)	**34**	**2**	**71**	**(138)**	**(63)**	**(149)**	**(64)**	**(3,098)**	**346**	**166**	**417**
17	**36**	**35**	**37**	**7**	**2**	**8**	**8**	**32**	**51**	**46**	**46**
(307)	**(28)**	**(37)**	**(21)**	**22**	**(30)**	**(287)**	**(34)**	**(789)**	**22**	**(250)**	**43**
(290)	**8**	**(2)**	**16**	**29**	**(28)**	**(279)**	**(26)**	**(757)**	**73**	**(204)**	**89**
(778)	**26**	**4**	**55**	**(167)**	**(35)**	**130**	**(38)**	**(2,341)**	**273**	**370**	**328**
312	**380**	**300**	**280**	**40**	**36**	**29**	**26**	**894**	**868**	**858**	**812**
8,077	**9,073**	**8,917**	**9,122**	**2,784**	**3,406**	**3,565**	**4,369**	**33,122**	**36,612**	**36,154**	**37,374**