MANAGEMENT'S DISCUSSION AND ANALYSIS

1.0 Financial Summary

Selected Annual Information *($ millions, except where indicated)*	**2019**	2018	2017
Gross revenues and Marketing and other	**20,306**	22,587	18,946
Net earnings (loss) by business segment			
Upstream	**(1,590)**	790	260
Downstream	**332**	1,000	448
Corporate	**(112)**	(333)	78
Net earnings	**(1,370)**	1,457	786
Net earnings (loss) per share – basic	**(1.40)**	1.41	0.75
Net earnings (loss) per share – diluted	**(1.41)**	1.40	0.75
Cash flow – operating activities	**2,971**	4,134	3,704
Funds from operations[(1)]	**3,251**	4,004	3,306
Ordinary dividends per common share declared for the year	**0.500**	0.450	0.075
Dividends per cumulative redeemable preferred share, series 1	**0.60**	0.60	0.60
Dividends per cumulative redeemable preferred share, series 2	**0.85**	0.74	0.57
Dividends per cumulative redeemable preferred share, series 3	**1.13**	1.13	1.13
Dividends per cumulative redeemable preferred share, series 5	**1.13**	1.13	1.13
Dividends per cumulative redeemable preferred share, series 7	**1.15**	1.15	1.15
Total assets	**33,122**	35,225	32,927
Total debt[(2)]	**5,520**	5,747	5,440
Net debt[(2)]	**3,745**	2,881	2,927

(1) *Funds from operations is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.*

(2) *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 an international integrated energy company and is based in Calgary, Alberta. The Company's common shares are 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 are 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 Upstream and Downstream business segments.

2.1 Corporate Strategy

The Company's business strategy is to generate returns from investing in a deep portfolio of projects and other opportunities across 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 collectively with Atlantic, "Offshore"). These investments are intended to provide for increasing margins, funds from operations and earnings. A strong balance sheet, deep physical integration and largely fixed price contracts in Asia Pacific provide resilience to market volatility, while preserving upside exposure to rising commodity prices.

Integrated Corridor

The Company's business in the Integrated Corridor includes crude oil, bitumen, natural gas and natural gas liquids ("NGL") production from Western Canada, the Lloydminster upgrading and asphalt refining complex, Husky Midstream Limited Partnership (35% working interest and operatorship) and the Lima Refinery, the BP-Husky Toledo Refinery (50% working interest) and the Superior Refinery in the U.S. Midwest. Natural gas production from the Western Canada portfolio is closely aligned with the Company's energy requirements for refining and thermal bitumen production and acts as a natural hedge.

Offshore

The Company's Offshore business includes operations, development and exploration in Asia Pacific and Atlantic.

2.2 Operations Overview and 2019 Highlights

Upstream Operations

Upstream operations in the Integrated Corridor and Offshore include exploration for, and development and production of, crude oil, bitumen, natural gas and NGL ("Exploration and Production") and the marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke. Additionally, Upstream operations include pipeline transportation, the blending of crude oil and natural gas and storage of crude oil, diluent and conventional natural gas ("Infrastructure and Marketing"). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Western Canada, Atlantic and Asia Pacific.

Exploration and Production

Thermal Developments

The Company continued to advance its inventory of thermal projects in 2019, with the commencement of production in August 2019 at its Dee Valley Thermal Project in Saskatchewan. These long-life developments are being built with modular, repeatable designs and require low sustaining capital once brought online.

Total thermal bitumen production, including Lloyd thermal projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 128,800 bbls/day in 2019 (Husky working interest). Production was impacted by government-mandated production quotas in Alberta and planned turnarounds at the Sunrise Energy Project and nine of the Saskatchewan thermal plants.

Lloyd Thermal Projects

The following table shows major projects and their status as at December 31, 2019:

Project Name	Nameplate Capacity (bbls/day)	Expected Project Production Date	Project Status
Dee Valley	10,000	On production August 2019	First steam was achieved on June 30, 2019, with first oil on August 24, 2019. Reached nameplate capacity on September 30, 2019.
Spruce Lake Central[(1)]	10,000	Mid-Year 2020	Central Processing Facility ("CPF") construction is complete and module setting on well pads has begun. Overall project is 90% complete.
Spruce Lake North	10,000	Around the end of 2020	CPF fabrication and module setting is complete. Overall project is 50% complete.
Spruce Lake East	10,000	Around the end of 2021	Regulatory approvals have been received, and lease construction is complete. Procurement and fabrication programs are in progress.
Edam Central	10,000	2022	Regulatory approvals have been received.
Dee Valley 2	10,000	2023	Project sanctioned in November 2019, and regulatory approvals have been received.

(1) *Previously expected to start production by the second half of 2020.*

Tucker Thermal Project

Total annual production in 2019 averaged 23,700 bbls/day and was impacted by the government-mandated production quotas in Alberta.

Sunrise Energy Project

Total annual production in 2019 averaged 49,200 bbls/day (24,600 bbls/day Husky working interest) and was impacted by the government-mandated production quotas in Alberta and a planned turnaround at one of the two CPFs in the second quarter of 2019.

Non-Thermal Developments

The Company is managing the natural decline in cold heavy oil production with sand ("CHOPS") operations with an active optimization program as well as using waterflooding and polymer injection technology.

Production in Cold and Enhanced Oil Recovery ("EOR") consists of a combination of production technologies including CHOPS, horizontal wells and EOR projects.

In 2018, the Company sanctioned a full-field polymer injection project at Aberfeldy, and injection began in 2019.

During 2019, the Company operated three carbon dioxide ("CO_2") injection EOR pilot projects and a CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant. The liquefied CO_2 is used in the ongoing EOR piloting program. The Company is also piloting several types of CO_2 capture technology at its Pikes Peak South facility in Saskatchewan.

Total annual production in 2019 averaged 34,400 bbls/day and was also impacted by the government-mandated production quotas in Alberta.

Western Canada

The Company continues to execute its resource play strategy in Western Canada to advance developments in the Montney Formation.

Oil and Natural Gas Resource Plays

The Company drilled five wells at Wembley and Karr, which completed the 2019 Montney drilling program. The Company had six Wembley wells producing at the end of 2019 with five Karr wells producing in January 2020.

Asia Pacific

The Company's Asia Pacific business produces conventional natural gas and NGL in the South China Sea and the Madura Strait offshore Indonesia. Conventional natural gas is sold into the South China and East Java markets under long-term contracts. NGL in both regions is sold at market prices.

The Company's interests include participating interests in the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields on Block 29/26, and Blocks 15/33, 16/25, 22/11 and 23/07 located in the South China Sea. The Madura Strait assets consist of the producing BD field, the MDA, MBH, MDK and MAC developments and three additional discoveries. The Company has participating interests in additional exploration blocks offshore Taiwan and Indonesia, and has signed a Strategic Cooperation Agreement with China National Offshore Oil Corporation Limited ("CNOOC") covering two offshore areas in the South China Sea for additional exploration opportunities.

The Company continues to develop its contracted price natural gas business in China and Indonesia, further protecting the Company from commodity price instability.

China

Block 29/26

Total production from Liwan 3-1 and Liuhua 34-2 averaged 73,200 boe/day (35,900 boe/day Husky working interest) in 2019. Total production consisted of conventional natural gas production of 349 mmcf/day and NGL production of 15,100 bbls/day.

Substantial construction work was completed in 2019 at the Liuhua 29-1 development project, the third deepwater gas field to be developed as part of the Liwan Gas Project. During 2019, the remaining three wells were drilled, and all seven wells in the full field development were fully completed. The production pipeline and the mono-ethylene glycol supply line were engineered, fabricated and installed. The project is now approximately 80% complete, and construction activities will resume in March 2020. During 2020, the control system and connecting flow lines will be installed and the Field will be placed in production. First gas production from the Liuhua 29-1 field is expected by the end of 2020. Husky holds a 75% working interest in this field. CNOOC holds the remaining 25% working interest.

Block 15/33

The Company is progressing commercial development plans following the successful drilling and testing of the XJ34-3-2 exploration well. The block boundaries have been expanded and additional exploration and appraisal drilling is planned in 2020.

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 may assume a participating partnership interest of up to 51% in the block.

Block 16/25

The Company drilled one exploration well in the third quarter of 2018, which encountered non-commercial hydrocarbons. This block was released and the costs written off in 2019 after technical evaluations were completed.

Blocks 22/11 and 23/07

The Company and CNOOC signed two Production Sharing Contracts ("PSC") for Blocks 22/11 and 23/07 in the Beibu Gulf area of the South China Sea in the first half of 2018. Initial evaluation work of existing data on these two blocks is currently being carried out to assess exploration potential. The Company has elected to move into the second exploration phase for Block 23/07.

The Company is the operator of both blocks with a working interest of 100% during the exploration phase. In the event of a commercial discovery, CNOOC may assume a participating partnership interest of up to 51% in either or both blocks.

Indonesia

Madura Strait

Total production averaged 19,700 boe/day (7,900 boe/day Husky working interest) in 2019. Production consisted of conventional natural gas production of 82 mmcf/day and NGL production of 6,100 bbls/day.

At the MDA and MBH fields, the two shallow water platforms have been fully installed. Five MDA and two MBH field production wells are expected to be drilled in the 2020 timeframe pending regulatory approval. Contracting for a floating production unit to process the gas is also planned to be finalized during 2020 with fabrication to take place in 2020/2021. Gas production and sales are planned to commence in 2021 with gas sales under government approved contracts into the East Java gas market. Subsequently, an additional shallow water field, MDK, is scheduled to be developed via a separate platform and tied into the MDA and MBH infrastructure.

Anugerah

The Company previously acquired 2-D and 3-D seismic survey data on the contract area. An analysis of that data and data from offset blocks indicated that exploratory drilling would not be economic. The block will be relinquished in February 2020.

Atlantic

The Company's Atlantic business provides production growth opportunities offshore Newfoundland and Labrador.

White Rose Field and Satellite Extensions

A staged and orderly ramp-up of production commenced in January 2019 following a November 2018 spill from a flowline connector at the South White Rose Extension ("SWRX"). The flowline connector was replaced in the second quarter of 2019. Full production was restored to the White Rose field and satellite extensions in mid-August, following regulatory approvals to resume operations from the SWRX and North Amethyst Drill Centres.

Construction of the West White Rose Project continued on multiple fronts including the platform's concrete gravity structure. A fourth slipform was completed on the platform's outer caisson, and the first three interior decks were installed. The project is now approximately 57% complete. First production is expected around the end of 2022.

Atlantic Exploration

The Company continued to evaluate the results of a recent discovery at the A-24 exploration well north of the White Rose field. The Company has a 68.875% ownership interest, with partners Suncor Energy and Nalcor Energy Oil and Gas holding 26.125% and 5%, respectively.

Infrastructure and Marketing

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, providing feedstock for the Upgrader and Asphalt Refinery, and to Hardisty where it connects to downstream pipelines accessing markets across Canada and the United States. The Hardisty Terminal acts as the exclusive blending hub for Western Canada Select ("WCS"). HMLP is in the process of diversifying its operations beyond the Lloydminster and Hardisty area and has completed construction of the Ansell Corser Gas Plant.

Saskatchewan Gathering System Expansion

A multi-year expansion program is underway and will provide transportation of diluent and heavy oil blend for several additional thermal plants.

Ansell Corser Gas Plant

The new gas processing plant is now in service, adding 120 mmcf/day of processing capacity.

Hardisty Tanks

Construction is underway for 1.5 mmbbls of storage at the Hardisty Terminal and is scheduled for completion by the end of 2020.

Commodity Marketing

The Company has developed its commodity marketing operations to include the acquisition of third-party volumes to enhance the value of its midstream assets. The Company markets both its own and third-party production of crude oil, synthetic crude oil, NGL, natural gas and sulphur. Additionally, the Company markets petroleum coke, a by-product from the Upgrader and its Ohio and Wisconsin refineries.

Downstream Operations

Downstream operations in the Integrated Corridor in Canada include upgrading heavy crude oil feedstock into synthetic crude oil and diesel ("Upgrading"), refining of crude oil, producing ethanol and marketing heavy and synthetic crude oil, refined petroleum products including gasoline, diesel, ethanol-blended fuels, asphalt and ancillary products ("Canadian Refined Products"). It also includes crude oil refining in the U.S. to produce and market diesel fuels, gasoline, jet fuel and asphalt ("U.S. Refining and Marketing"). Upgrading, Canadian Refined Products and U.S. Refining and Marketing all process and refine natural resources into marketable products and are grouped together as the Downstream business segment due to the similar nature of their products and services.

The Company's Downstream operations target three primary objectives: increasing feedstock flexibility to bring the best-priced crude to the Company's refineries; improving the range of its products to capitalize on opportunities; and enhancing market access to achieve the best returns. The Company's focused integration strategy helps to capture margins on refined product pricing for its Western Canada heavy oil, bitumen and light oil production and assists in mitigating market volatility.

Upgrading

The Upgrader has a throughput capacity of 80,000 bbls/day. 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.

Canadian Refined Products

Lloydminster Asphalt Refinery
The Lloydminster Asphalt Refinery in Lloydminster, Alberta, has a throughput capacity of 30,000 bbls/day and is integrated with the local heavy 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.

Prince George Refinery
On November 1, 2019, the Company completed the sale of its Prince George Refinery to Tidewater Midstream and Infrastructure Ltd. for $215 million in cash plus an inventory closing adjustment of approximately $53.5 million.

Retail and Commercial Network
The Company is a major regional motor fuel marketer with an average of 553 retail marketing locations in 2019, including bulk plants and travel centres, with strategic land positions in Western Canada and Ontario.

On January 8, 2019, the Company announced its intention to market and potentially sell its Canadian Retail and Commercial Fuels Network. The strategic review continues to progress.

U.S. Refining and Marketing

Lima Refinery
The Lima Refinery in Ohio has a crude oil throughput capacity of 175,000 bbls/day, depending on the crude slate, 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 at the Lima Refinery 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. The Refinery completed a planned turnaround in the fourth quarter of 2019 and made final tie-ins for the project. The project was completed in early 2020 and the refinery will ramp up to full rates during the first quarter of 2020.

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 Corporation North America Inc. ("BP"), and is operated by BP. The Company and BP completed a feedstock optimization project in 2016, allowing the refinery to process up to 70,000 bbls/day of high-TAN crude oil to support production from the Sunrise Energy Project. The refinery's nameplate capacity remained unchanged.

During the second and third quarters of 2019, the refinery underwent a planned turnaround.

Superior Refinery
The Superior Refinery has a permitted throughput capacity of 50,000 bbls/day and an operating capacity of 45,000 bbls/day as configured. The refinery produces motor fuel products and asphalt from light and heavy crude oil originating from North Dakota and Western Canada.

On April 26, 2018, the Superior Refinery experienced an incident while preparing for a major turnaround and was taken out of operation. During 2019, demolition, site preparation work and permitting were completed, and the rebuild work commenced. The investment in the rebuild is estimated to be approximately US$750 million, of which the Company anticipates a substantial portion will be recovered from property damage insurance. This represents a change from the previous estimate of greater than US$400 million, with the change being due to a more complete assessment of the extent of equipment damage from the April 26, 2018 incident. The Company anticipates that lost income through April 2020 will be compensated by business interruption insurance. The refinery is being rebuilt with the same configuration, and with the capability to run continuously at the 45,000 bbl/day operating capacity and will be able to produce a full slate of products, including asphalt, gasoline and diesel. Full operations are expected to resume in 2021.

2.3 Business Segments – January 1, 2020

Effective January 1, 2020, the Company's businesses were reorganized under two new business segments: (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 collectively with Atlantic, "Offshore"). The Company will no longer operate under Upstream and Downstream business segments.

Integrated Corridor

The Company's business in the Integrated Corridor includes: crude oil, bitumen, conventional natural gas, NGL and ethanol production from Western Canada; marketing and transportation of the Company's and other producers' production; the Upgrader and Asphalt Refinery; Husky Midstream Limited Partnership (35% working interest and operatorship); the Lima Refinery, the BP-Husky Toledo Refinery (50% working interest) and the Superior Refinery in the U.S. Midwest; and the marketing of refined petroleum products including gasoline, diesel and ethanol blended fuels through petroleum outlets. Conventional natural gas production from the Western Canada portfolio is closely aligned with the Company's energy requirements for refining and thermal bitumen production and acts as a natural hedge.

Offshore

The Company's Offshore business includes operations, development and exploration in Asia Pacific and Atlantic.

2.4 Financial Strategic Plan

The Company is committed to ensuring it has sufficient liquidity, financial flexibility and access to long-term capital to fund its growth. The Company maintains undrawn committed term credit facilities with a portfolio of creditworthy financial institutions and other sources of liquidity to provide timely access to funding to supplement cash flow.

The Company intends to maintain a healthy balance sheet to provide financial flexibility. Management of debt levels is a priority for Husky given long-term growth plans and future expected volatility in commodity prices. The Company's long-term objective is to maintain a debt to funds from operations ratio of less than 2.0 times. Debt to funds from operations is a non-GAAP measure (refer to Sections 6.4 and 9.3). The Company is also committed to retaining its investment grade credit ratings to support access to debt capital markets and has taken measures to maintain its strong financial position through commodity cycles. Past measures included, but were not limited to, a reduction of budgeted capital spending, temporary suspension of the quarterly common share dividend, the sale of non-core assets and the continued transition to higher margin production. Refer to Section 6.0 for additional information on the Company's liquidity and capital resources.

3.0 The 2019 Business Environment

The Company's operations were significantly influenced by domestic and international factors in 2019, including, but not limited to, the following:

- Global crude oil inventory levels remained high as the U.S. became a net oil exporter and the world's largest oil producer.
- North American natural gas benchmarks continued to be weak due to infrastructure constraints combined with lower demand for Canadian natural gas in the U.S. as a result of increased U.S. shale production.
- The Government of Alberta set province-wide mandatory production quotas to restrict oil supplies entering the market.
- A continued emphasis on health and safety, the environment, the impacts of climate change, enterprise risk management, resource sustainability and corporate social responsibility concerns.
- Transportation constraints on crude oil produced in Western Canada. The oil and gas industry continues to work with stakeholders to develop a strong network of transportation infrastructure, including pipelines, rail, marine and trucks. The development of this network continues to be an important challenge for the industry to obtain market access for the growing supply of crude oil from the Western Canadian oil sands.
- Alternative and improved extraction methods have rapidly evolved in North American and international onshore and offshore regions.

The Company considers major business factors in formulating its 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, 2019.

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		2019	2018
West Texas Intermediate ("WTI") crude oil[1]	(US$/bbl)	**57.03**	64.77
Brent crude oil[2]	(US$/bbl)	**64.30**	70.97
Light sweet at Edmonton	($/bbl)	**69.22**	69.31
WCS at Hardisty[3]	(US$/bbl)	**44.28**	38.46
Lloyd heavy crude oil at Lloydminster	($/bbl)	**54.21**	39.33
WTI/Lloyd crude blend differential	(US$/bbl)	**12.40**	26.09
Condensate at Edmonton	(US$/bbl)	**52.86**	60.95
NYMEX natural gas[4]	(US$/mmbtu)	**2.63**	3.09
Nova Inventory Transfer ("NIT") natural gas	($/GJ)	**1.54**	1.45
Chicago Regular Unleaded Gasoline	(US$/bbl)	**70.29**	78.07
Chicago Ultra-low Sulphur Diesel	(US$/bbl)	**78.00**	87.08
Chicago 3:2:1 crack spread	(US$/bbl)	**15.80**	15.94
U.S./Canadian dollar exchange rate	(US$)	**0.754**	0.772
Canadian $ Equivalents[5]			
WTI crude oil	($/bbl)	**75.64**	83.90
Brent crude oil	($/bbl)	**85.27**	91.93
WCS at Hardisty	($/bbl)	**58.72**	49.82
WTI/Lloyd crude blend differential	($/bbl)	**16.45**	33.80
NYMEX natural gas	($/mmbtu)	**3.49**	4.00

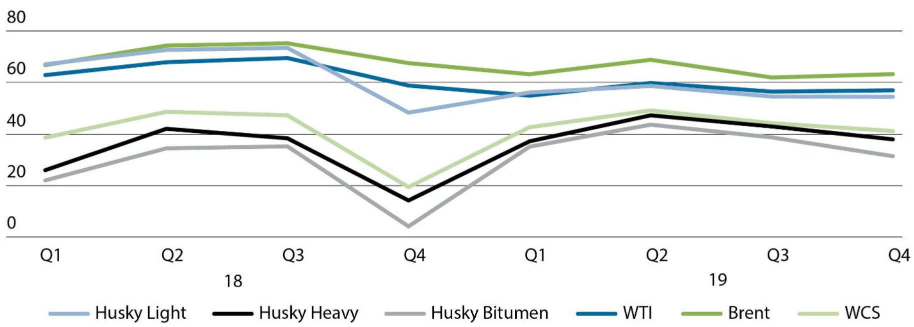
(1) *Calendar month average of settled prices for WTI at Cushing, Oklahoma.*
(2) *Calendar month average of settled prices for Dated Brent.*
(3) *WCS is a heavy blended crude oil, comprised of conventional and bitumen crude oils blended with diluent which terminals at Hardisty, Alberta. Quoted prices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

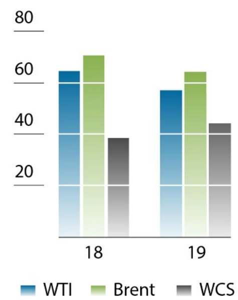
The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil and bitumen. In the Upgrading business, heavy crude oil feedstock is processed into light synthetic crude oil. The Company's U.S. Refining and Marketing business 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 46% heavy crude oil and bitumen feedstock at the BP-Husky Toledo Refinery. The Company's Canadian Retail and Commercial Fuels Network relies primarily on supply contracts to purchase refined products for resale in the retail distribution network, as well as diesel from the Lloydminster Upgrader.

Crude Oil Benchmarks

West Texas Intermediate, Brent, Western Canada Select and Husky Average Crude Oil Prices
(US$/bbl)



Average WTI, Brent and WCS
(US$/bbl)



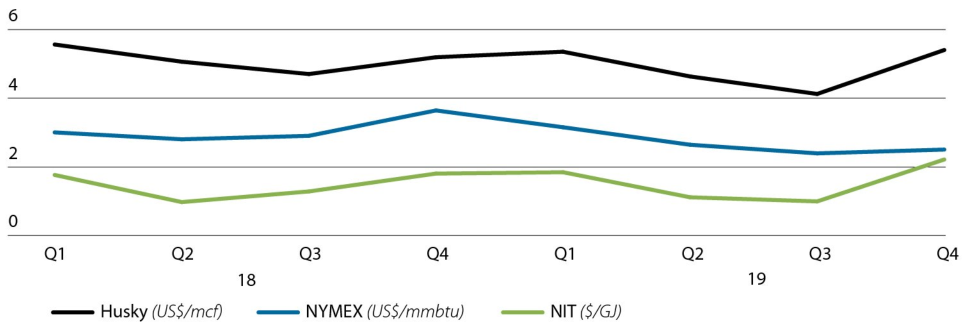
Global crude oil benchmarks remained weakened in 2019 primarily due to a continued oversupply as the U.S became a net oil exporter and the world's largest oil producer. Conversely, the WCS benchmark strengthened in 2019 as the Government of Alberta set province-wide mandatory production quotas to restrict oil supplies entering the market, and consequently the differential between the WCS benchmark and other North American benchmarks tightened in 2019 compared to 2018. WTI averaged US$57.03/bbl in 2019 compared to US$64.77/bbl in 2018. Brent averaged US$64.30/bbl in 2019 compared to US$70.97/bbl in 2018. WCS averaged US $44.28/bbl in 2019 compared to US$38.46/bbl in 2018.

The price received by the Company for crude oil production from Western Canada 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 from Western Canada is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. The Company's crude oil and NGL production was 77% heavy crude oil and bitumen in 2019 compared to 75% in 2018.

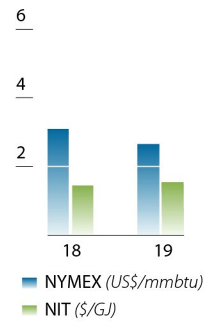
The Company's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate. The price of condensate at Edmonton decreased in 2019 compared to 2018, primarily due to the decrease in crude oil benchmark pricing.

Natural Gas Benchmarks

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices



Average NYMEX and NIT

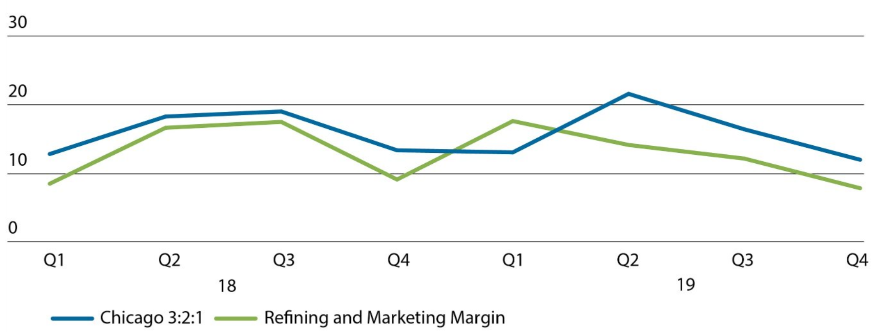


The price received by the Company for natural gas production from Western Canada is primarily driven by the NIT near-month contract price of natural gas, while the price received by the Company for production from Asia Pacific is determined by long-term contracts.

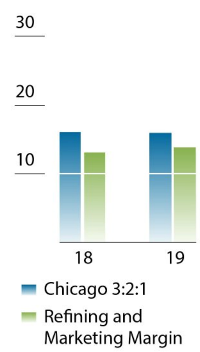
North American natural gas is consumed internally by the Company's Upstream and Downstream operations, helping to mitigate the impact of weak natural gas benchmark prices on results.

Refining Benchmarks

Chicago Average Crack Spread and Husky Realized U.S. Refining and Marketing Margin
(US$/bbl)



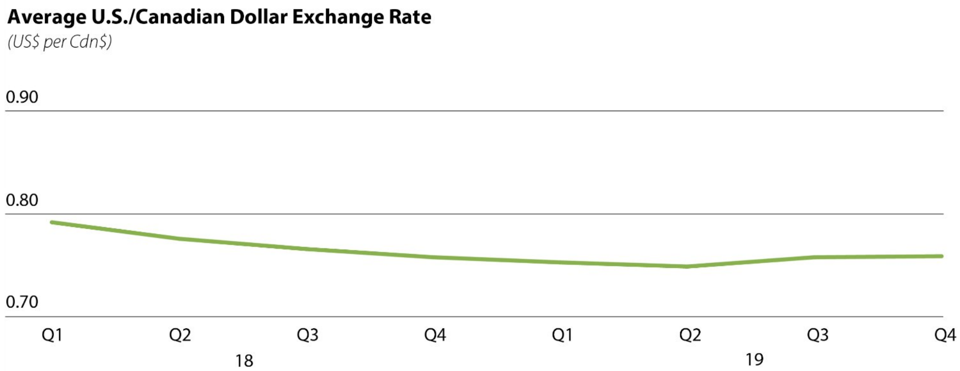
Average Crack Spread
(US$/bbl)



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 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 between 11% and 13% 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. 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, changes in foreign exchange rates impact the translation of U.S. Downstream and Asia Pacific operations and U.S. dollar denominated debt. The Canadian dollar averaged US$0.754 in 2019 compared to US$0.772 in 2018.

A portion of the Company's long-term sales contracts in Asia Pacific are priced in Chinese Yuan ("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 5.208 in 2019 compared to RMB 5.104 in 2018.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in 2019 on earnings before income taxes and net earnings. The table below reflects what the expected effect would have been on the financial results for 2019 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2019. 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	2019 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]	**57.03**	*US$1.00/bbl*	**93**	**0.09**	**68**	**0.07**
NYMEX benchmark natural gas price[5]	**2.63**	*US$0.20/mmbtu*	**—**	**—**	**—**	**—**
WTI/Lloyd crude blend differential[6]	**12.40**	*US$1.00/bbl*	**(8)**	**(0.01)**	**(6)**	**(0.01)**
Canadian asphalt margins	**25.12**	*Cdn $1.00/bbl*	**10**	**0.01**	**7**	**0.01**
Canadian light oil margins	**0.035**	*Cdn $0.005/litre*	**14**	**0.01**	**10**	**0.01**
Chicago 3:2:1 crack spread	**15.80**	*US$1.00/bbl*	**98**	**0.10**	**76**	**0.08**
Exchange rate (US $ per Cdn $)[3][7]	**0.754**	*US$0.01*	**(73)**	**(0.07)**	**(54)**	**(0.05)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as of December 31, 2019.*
(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) *Excludes impact on Canadian asphalt operations.*
(7) *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 2019 of cash flow - operating activities and funds from operations in the range of $4.1 - $4.3 billion, a free cash flow projection of $800 million (compared to ($181) actual free cash flow, which is a non-GAAP measure, see Section 9.3 for a reconciliation to the corresponding GAAP measure, Upstream production in the range of 290,000 - 305,000 boe/day and Downstream throughput of 355,000 bbls/day. These projections were based on several pricing assumptions, including WTI benchmark crude at $60 US per barrel, Brent crude oil at $65 US per barrel and a Chicago 3:2:1 crack spread of $16.50 US per barrel.

Actual 2019 results differed materially due to a combination of a weaker oil price environment and several unplanned events, including a longer than anticipated ramp-up of production at the SWRX, the impact of government-mandated production quotas in Alberta and an extended turnaround at the Lima Refinery to complete the tie-in of the crude oil flexibility project.

4.0 Results of Operations

4.1 Segment Earnings

Segmented Earnings	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[1]	
($ millions)	**2019**	2018	**2019**	2018	**2019**	2018
Upstream						
Exploration and Production	**(2,348)**	288	**(1,706)**	223	**2,346**	2,656
Infrastructure and Marketing	**159**	780	**116**	567	**2**	—
Downstream						
Upgrading	**132**	496	**97**	361	**59**	62
Canadian Refined Products	**(7)**	216	**(5)**	158	**119**	74
U.S. Refining and Marketing	**309**	619	**240**	481	**768**	665
Corporate	**(414)**	(471)	**(112)**	(333)	**138**	121
Total	**(2,169)**	1,928	**(1,370)**	1,457	**3,432**	3,578

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the year. Includes Exploration and Production assets acquired through acquisition, but excludes assets acquired through corporate acquisition.*

4.2 Upstream

Exploration and Production

Exploration and Production Earnings Summary *($ millions)*	**2019**	2018
Gross revenues	**4,958**	4,330
Royalties	**(323)**	(335)
Net revenues	**4,635**	3,995
Production, operating and transportation expenses	**1,634**	1,527
Selling, general and administrative expenses	**297**	296
Depletion, depreciation, amortization and impairment ("DD&A")	**4,312**	1,811
Exploration and evaluation expenses	**547**	149
Gain on sale of assets	**(3)**	(2)
Other – net	**86**	(120)
Share of equity investment gain	**(50)**	(51)
Financial items	**160**	97
Provisions for (recovery of) income taxes	**(642)**	65
Net earnings (loss)	**(1,706)**	223

Exploration and Production net revenues increased by $640 million in 2019 compared to 2018, primarily due to higher average realized sales prices, partially offset by lower production, both of which are described in more detail below.

Production, operating and transportation expenses increased $107 million in 2019 compared to 2018, which is described in more detail under "Operating Costs".

Exploration and evaluation expenses increased by $398 million in 2019 compared to 2018, primarily due to higher expensed drilling, which is described in more detail under "Exploration and Evaluation Expenses".

Depletion, depreciation, amortization and impairment expense increased by $2,501 million in 2019 compared to 2018, primarily due to a pre-tax impairment charge of $2,405 million recognized on certain crude oil and natural gas assets, which is described in more detail under "Depletion, Depreciation, Amortization and Impairment".

Other – net increased by $206 million in 2019 compared to 2018, primarily due to profit or loss elimination between segments.

Financial items increased by $63 million in 2019 compared to 2018, primarily due to higher finance expenses arising from the adoption of IFRS 16 in 2019.

Recovery of income taxes increased by $707 million in 2019 compared to 2018, primarily due to lower earnings before income taxes in 2019.

Average Sales Prices Realized

Average Sales Prices Realized	2019	2018
Crude oil and NGL *($/bbl)*		
Light & Medium crude oil	**72.85**	83.71
NGL[(1)]	**44.99**	55.72
Heavy crude oil	**54.70**	39.26
Bitumen	**49.00**	30.17
Total crude oil and NGL average	**52.28**	42.16
Natural gas average *($/mcf)*[(1)]	**6.44**	6.64
Total average *($/boe)*	**48.37**	41.50

(1) Reported average NGL and conventional natural gas prices 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.

The average sales prices realized by the Company for crude oil and NGL production increased by 24% in 2019 compared to 2018, primarily due to the narrowing of the Canadian light/heavy oil differential, partially offset by the lower global benchmark crude oil prices.

The average sales prices realized by the Company for natural gas production decreased by 3% in 2019 compared to 2018, primarily due to lower production from the Liwan Gas Project.

Daily Gross Production

Daily Gross Production	2019	2018
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light and Medium crude oil	**8.5**	9.4
NGL	**12.7**	12.0
Heavy crude oil	**30.2**	36.8
Bitumen[(1)]	**128.8**	124.2
	180.2	182.4
Atlantic		
White Rose and Satellite Fields – light crude oil	**12.3**	17.4
Terra Nova – light crude oil	**4.1**	4.0
	16.4	21.4
Asia Pacific		
Liwan – NGL[(2)]	**7.4**	8.4
Madura – NGL[(3)]	**2.5**	2.5
	9.9	10.9
	206.5	214.7
Conventional natural gas *(mmcf/day)*		
Western Canada	**297.5**	291.0
Asia Pacific		
Liwan[(2)]	**171.0**	184.8
Madura[(3)]	**32.4**	31.2
	203.4	216.0
	500.9	507.0
Total *(mboe/day)*	**290.0**	299.2

(1) Bitumen consists of production from thermal developments in Lloydminster, the Tucker Thermal Project located near Cold Lake, Alberta and the Sunrise Energy Project.
(2) Reported production volumes include Husky's working interest production from the Liwan Gas Project (49%).
(3) Reported production 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.

Crude Oil and NGL Production

Crude oil and NGL production decreased by 8.2 mbbls/day, or 4%, in 2019 compared to 2018. The decrease was primarily due to a reduction of heavy crude oil production due to government-mandated production quotas in Alberta and natural declines, combined with lower production from Atlantic due to the suspension of production from the White Rose field. The decreases were partially offset by increased bitumen production from the Company's Saskatchewan thermal projects in Lloydminster.

Conventional Natural Gas Production

Conventional natural gas production decreased by 6.1 mmcf/day, or 1%, in 2019 compared to 2018, primarily due to lower production from the Liwan Gas Project. The decrease was partially offset by the higher production at the Rainbow Lake development.

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	**2019**	2018
Crude oil and NGL		
Light & Medium crude oil	**13**	22
NGL[1]	**7**	10
Heavy crude oil	**12**	11
Bitumen	**45**	29
Crude oil and NGL	**77**	73
Natural gas[1]	**23**	28
Total	**100**	100

(1) *Reported average NGL and conventional natural gas revenue 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.*

2020 Production Guidance and 2019 Actual

	Guidance	**Year ended December 31**	Guidance
Gross Production	2020	**2019**	2019
Canada			
Light & Medium crude oil *(mbbls/day)*	23 - 25	**25**	29 - 31
NGL *(mbbls/day)*	12 - 13	**13**	12 - 13
Heavy crude oil & bitumen *(mbbls/day)*	169 - 178	**159**	155 - 163
Conventional Natural gas *(mmcf/day)*	270 - 280	**298**	297 - 307
Canada total *(mboe/day)*	249 - 263	**246**	246 - 258
Asia Pacific			
NGL *(mbbls/day)*[1]	9 - 11	**10**	9 - 10
Natural gas *(mmcf/day)*[1]	210 - 220	**203**	210 - 220
Asia Pacific total *(mboe/day)*	44 - 48	**44**	44 - 47
Total *(mboe/day)*	295 - 310	**290**	290 - 305

(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.*

Total production for the year ended December 31, 2019 was at the low end of production guidance, primarily due to the factors that impacted crude oil and NGL production discussed above. The 2020 production guidance reflects a curtailment assumption of 5 mbbls/d for the first half of the year.

Factors that could potentially impact the Company's production performance in 2020 include, but are not limited to:

- eventual outcome and impact of the government-mandated production curtailment in Alberta.
- changes in crude oil and natural gas prices such as decreases in commodity pricing, which may result in the decision to temporarily shut-in production or delay capital expenditures.
- performance of recently commissioned facilities, new wells brought onto production and unanticipated reservoir response from existing fields.
- unplanned or extended maintenance and turnarounds at any of the Company's operated or non-operated facilities, upgrading, refining, pipeline or offshore assets.
- business interruptions due to unexpected events such as severe weather, fires, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events.
- defaults by contracting parties whose services, goods or facilities are necessary for the Company's production.
- operations and assets which are subject to a number of political, economic and socio-economic risks.

Royalties

Royalties *(Percent)*	2019	2018
Western Canada	**7**	9
Atlantic	**9**	8
Asia Pacific[1]	**7**	7
Total	**7**	8

[1] *Reported royalties include Husky's working interest 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 interim financial statement purposes.*

The total royalty rate decreased in 2019, primarily due to lower royalty rates from thermal developments as a result of a change to the pre-payout status of a thermal property in the first quarter of 2019, combined with lower royalty rates from Western Canada as a result of a gas cost allowance credit in the third quarter of 2019. The decrease was partially offset by increased royalty rates for Atlantic due to a higher proportion of production from the Terra Nova field, which has a higher royalty rate.

Operating Costs

Operating Costs *($ millions)*	2019	2018
Western Canada	**1,296**	1,218
Atlantic	**252**	213
Asia Pacific	**96**	95
Total	**1,644**	1,526
Per unit operating costs *($/boe)*	**15.53**	14.00

Total Exploration and Production operating costs were $1,644 million in 2019 compared to $1,526 million in 2018. Total per unit operating costs averaged $15.53/boe in 2019 compared to $14.00/boe in 2018. The increase in per unit operating costs was primarily due to the factors discussed below.

Per unit operating costs in Atlantic averaged $42.20/bbl in 2019 compared to $27.21/bbl in 2018. The increase in per unit operating costs was primarily due to the costs associated with the flowline repair and well workover costs at the White Rose field, combined with lower production.

Per unit operating costs in Western Canada averaged $15.44/boe in 2019 compared to $14.48/boe in 2018. The increase in per unit operating costs was primarily due to higher energy and transportation costs, combined with lower production.

Per unit operating costs in Asia Pacific averaged $6.03/boe in 2019 compared to $5.53/boe in 2018. The increase in per unit operating costs was primarily due to lower production in 2019.

Exploration and Evaluation Expenses

Exploration and Evaluation Expenses *($ millions)*	2019	2018
Seismic, geological and geophysical	**131**	102
Expensed drilling	**409**	41
Expensed land	**7**	6
Total	**547**	149

Exploration and Evaluation expenses were $547 million in 2019 compared to $149 million in 2018. The increase in expensed drilling was primarily due to a pre-tax write-down of $339 million related to certain crude oil assets in Atlantic and Western Canada. The write-down was primarily due to changes in management's future development plans resulting from sustained declines in forecasted short and long-term crude oil prices.

Depletion, Depreciation, Amortization and Impairment

During 2019, the Company recognized a pre-tax impairment charge of $2,405 million within the Sunrise Energy Project, Western Canada and Atlantic. The impairment charge, reflected in the fourth quarter of 2019, 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.

In 2019, total DD&A excluding impairment averaged $18.46/boe compared to $16.99/boe in 2018.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were lower in 2019 compared to 2018, as further described below. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[1] *($ millions)*	**2019**	2018
Exploration		
Western Canada	**3**	99
Thermal developments	**16**	7
Non-thermal developments	**1**	—
Atlantic	**19**	73
Asia Pacific[2]	**7**	52
	46	231
Development		
Western Canada	**189**	332
Thermal developments	**748**	874
Non-thermal developments	**117**	110
Atlantic	**906**	916
Asia Pacific[2]	**340**	148
	2,300	2,380
Acquisitions		
Western Canada	**—**	4
Thermal developments	**—**	41
	—	45
Total	**2,346**	2,656

[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
[2] *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.*

Western Canada

During 2019, $192 million (8%) was invested in Western Canada compared to $435 million (16%) in 2018. Capital expenditures in 2019 related primarily to resource play development targeting the Montney Formation.

Thermal Developments

During 2019, $764 million (33%) was invested in thermal developments compared to $922 million (35%) in 2018. Capital expenditures in 2019 related primarily to the construction work at the Dee Valley, Spruce Lake Central and Spruce Lake North thermal projects.

Non-Thermal Developments

During 2019, $118 million (5%) was invested in non-thermal developments compared to $110 million (4%) in 2018. Capital expenditures in 2019 related primarily to drilling and advancing the Company's EOR program, particularly the Aberfeldy Polymer Project.

Atlantic

During 2019, $925 million (39%) was invested in Atlantic compared to $989 million (37%) in 2018. Capital expenditures in 2019 related primarily to the development of the West White Rose Project and sustainment and development activities at the White Rose field.

Asia Pacific

During 2019, $347 million (15%) was invested in Asia Pacific compared to $200 million (8%) in 2018. Capital expenditures in 2019 related primarily to the continued development of Liuhua 29-1.

Exploration and Production Wells Drilled

Onshore Drilling Activity

The following table discloses the number of wells drilled during 2019 and 2018:

	2019		2018	
Wells Drilled *(wells)*[1]	**Gross**	**Net**	Gross	Net
Thermal developments	**68**	**65**	150	140
Non-thermal developments	**47**	**47**	31	26
Western Canada	**21**	**17**	46	45
Total	**136**	**129**	227	211

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

Offshore Drilling Activity

The following table discloses the Company's Offshore drilling activity during 2019:

Region	Well	Working Interest	Well Type
Atlantic	E-18 13	72.5%	Development
Atlantic	E-18 14	72.5%	Development
Atlantic	Tiger's Eye D-17	40%	Exploration
Asia Pacific	LH 29-1-A3	75%	Development
Asia Pacific	LH 29-1-A1	75%	Development
Asia Pacific	LH 29-1-A2	75%	Development

2020 Upstream Capital Expenditures Program

2020 Upstream Capital Expenditures Program *($ millions)*	
Thermal developments	**1,050 - 1,100**
Non-thermal developments and Western Canada	**225 - 250**
Atlantic	**1,075 - 1,150**
Asia Pacific[1]	**275 - 300**
Total Upstream capital expenditures	**2,625 - 2,800**

(1) *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.*

The 2020 Upstream capital expenditures program reflects a focus on near-term and medium-cycle projects in the Integrated Corridor business, including further growing the Lloydminister thermal bitumen portfolio. In the Offshore business, the capital expenditures program will support the continuation of construction at the Liuhua 29-1 field offshore China and the West White Rose Project in Atlantic.

The Company has budgeted $1,050 - $1,100 million in thermal developments for 2020, primarily for the development of the Spruce Lake North, Spruce Lake Central and Spruce Lake East thermal bitumen projects. The Company is making progress in its strategy to transition a greater percentage of production to long-life thermal bitumen production and the 2020 Upstream capital expenditures program will continue to build on this momentum.

The Company has budgeted $225 - $250 million in non-thermal developments and Western Canada for 2020, primarily for the planned EOR, consisting of polymer flooding at Golden Lake and horizontal drilling, drilling activities in the Spirit River and Montney formations, and sustainment and maintenance activities.

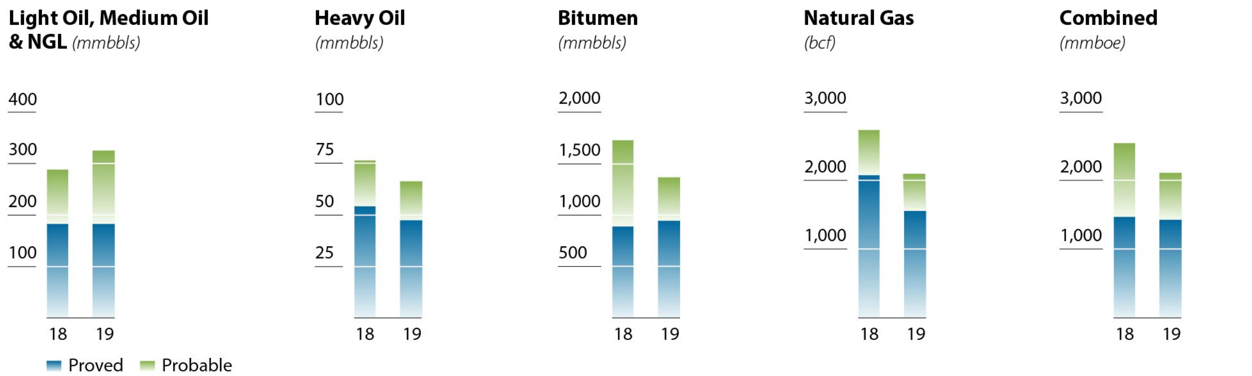
The Company has budgeted $1,075 - $1,150 million in Atlantic for 2020, primarily for the construction of the West White Rose Project.

The Company has budgeted $275 - $300 million in Asia Pacific for 2020, primarily for the continued development of the third field of the Liwan Gas Project, Liuhua 29-1.

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, 2019 with a preparation date of January 31, 2020.

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, 2019, 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.

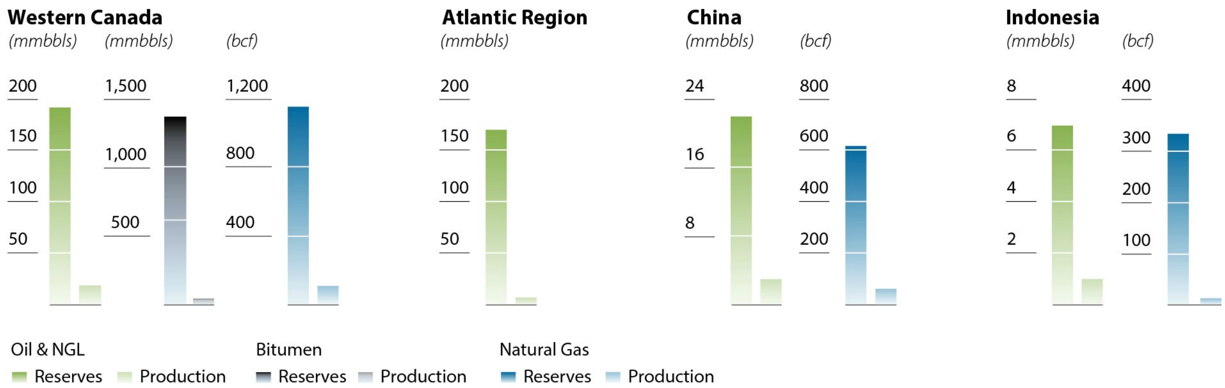
Sproule Associates Limited ("Sproule"), an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit and review of the Company's crude oil, natural gas and NGL reserves estimates. Sproule issued an audit opinion on January 31, 2020 stating that the Company's 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.

At December 31, 2019, the Company's proved oil and gas reserves were 1,431 mmboe, down from 1,471 mmboe at the end of 2018. The Company's 2019 reserves replacement ratio, defined as net additions of proved reserves divided by total production during the period, was 67% excluding economic revisions (62% including economic revisions).

Major changes to proved reserves in 2019 included:

- Western Canada Extensions & Improved Recovery additions of 168 mmboe which included 40 mmbbls from one new and 35 mmbbls from three existing Lloydminster bitumen SAGD projects (16 mmbbls transferred from probable reserves), 20 mmbbls at the Tucker Thermal Project (transferred from probable reserves), 15 mmbbls at the Sunrise Energy Project and 38 mmboe from Wembley (including 111 bcf of conventional natural gas and 19 mmbbls of NGL) and 5 mmboe from Wapiti from new locations.
- Discoveries included 27 bcf of conventional natural gas and 1 mmbbls of NGL for Liuhua 29-1 transferred from probable reserves as Technical Revisions.
- Western Canada Technical Revisions are associated with the updated long-term strategic plan where less liquid-rich gas plays are no longer funded. This resulted in a reduction of proved undeveloped reserves of 443 bcf (90% of the Technical Revisions) of conventional natural gas and 5 mmbbls of NGL.
- Economic Factors of 5 mmboe are mainly associated with lower gas prices in Western Canada.

Proved Plus Probable Reserves and Production at December 31, 2019:



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, 2018	65	54	890	1,288	93	24	783	1,126	2,071	1,471
Technical revisions	(7)	—	(13)	(496)	(2)	1	1	(21)	(495)	(103)
Acquisitions	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—
Discoveries, extensions and improved recovery	25	6	113	147	—	1	27	145	174	174
Economic factors	(1)	(1)	—	(15)	—	—	—	(2)	(15)	(5)
Production	(7)	(12)	(47)	(109)	(6)	(4)	(74)	(76)	(183)	(106)
Proved reserves December 31, 2019	**75**	**47**	**943**	**815**	**85**	**22**	**737**	**1,172**	**1,552**	**1,431**
Proved and probable reserves December 31, 2019	**126**	**66**	**1,366**	**1,155**	**169**	**28**	**948**	**1,755**	**2,103**	**2,105**
December 31, 2018	80	76	1,722	1,751	177	30	984	2,085	2,735	2,541

(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, 2018	56	53	142	804	24	20	528	295	1,332	517
Technical revisions	—	—	19	(49)	(2)	—	22	17	(27)	13
Transfer from proved undeveloped	2	1	51	36	5	—	—	59	36	65
Acquisitions	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—
Discoveries, extensions and improved recovery	5	5	3	41	—	—	—	13	41	19
Economic factors	(1)	(1)	—	(14)	—	—	—	(2)	(14)	(4)
Production	(7)	(12)	(47)	(109)	(6)	(4)	(74)	(76)	(183)	(106)
December 31, 2019	**55**	**46**	**168**	**709**	**21**	**16**	**476**	**306**	**1,185**	**504**

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

Infrastructure and Marketing

Infrastructure and Marketing Earnings Summary *($ millions)*	**2019**	2018
Gross revenues	**2,342**	2,211
Marketing and other	**189**	668
Expenses		
Purchases of crude oil and products	**2,336**	2,087
Production, operating and transportation expenses	**21**	23
Selling, general and administrative expenses	**9**	5
Depletion, depreciation, amortization and impairment	**12**	—
Other – net	**—**	2
Share of equity investment gain	**(9)**	(18)
Financial items	**3**	—
Provisions for income taxes	**43**	213
Net earnings	**116**	567

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $131 million and $249 million, respectively, in 2019 compared to 2018, primarily due to increased prices and additional costs incurred on the construction of the Saskatchewan Gathering System Expansion in 2019.

Marketing and other decreased by $479 million in 2019 compared to 2018, primarily due to the tightening of location differentials between Canada and the U.S.

Provisions for income taxes decreased by $170 million in 2019 compared to 2018, primarily due to lower earnings before income taxes in 2019.

4.3 Downstream

Upgrading

Upgrading Earnings Summary *($ millions, except where indicated)*	2019	2018
Gross revenues	**1,777**	1,750
Expenses		
Purchases of crude oil and products	**1,303**	928
Production, operating and transportation expenses	**217**	195
Selling, general and administrative expenses	**9**	7
Depletion, depreciation, amortization and impairment	**115**	123
Financial items	**1**	1
Provisions for income taxes	**35**	135
Net earnings	**97**	361
Upgrading throughput *(mbbls/day)*[(1)]	**74.9**	75.6
Total sales *(mbbls/day)*	**75.2**	74.7
Synthetic crude oil sales *(mbbls/day)*	**55.4**	52.9
Upgrading differential *($/bbl)*	**17.19**	29.05
Unit margin *($/bbl)*	**17.27**	30.15
Unit operating cost *($/bbl)*[(2)]	**7.94**	7.07

(1) *Throughput includes diluent returned to the field.*
(2) *Based on throughput.*

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

Upgrading gross revenues increased by $27 million in 2019 compared to 2018, primarily due to higher synthetic crude sales volumes, partially offset by lower realized prices for synthetic crude oil. The price of Husky Synthetic Blend averaged $74.35/bbl in 2019 compared to $75.55/bbl in 2018.

Upgrading purchases of crude oil and products increased by $375 million in 2019 compared to 2018, primarily due to an increase in the average cost of heavy crude oil feedstock driven by tighter light/heavy oil differential, partially offset by lower throughput volumes in 2019.

Provisions for income taxes decreased by $100 million in 2019 compared to 2018, primarily due to lower earnings before income taxes in 2019.

Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	2019	2018
Gross revenues	**3,122**	3,412
Expenses		
Purchases of crude oil and products	**2,571**	2,760
Production, operating and transportation expenses	**278**	265
Selling, general and administrative expenses	**53**	47
Depletion, depreciation, amortization and impairment	**218**	115
Gain on sale of assets	**(6)**	(2)
Other – net	**—**	(1)
Financial items	**15**	12
Provisions for (recovery of) income taxes	**(2)**	58
Net earnings (loss)	**(5)**	158
Number of fuel outlets(1)	**553**	557
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**7.4**	7.7
Fuel sales per retail outlet *(thousands of litres/day)*	**12.7**	12.3
Refinery throughput		
Prince George Refinery *(mbbls/day)*(2)(3)	**7.2**	10.7
Lloydminster Refinery *(mbbls/day)*(2)	**26.4**	27.1
Ethanol production *(thousands of litres/day)*	**823.0**	819.4

(1) *Average number of fuel outlets for period indicated.*
(2) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(3) *Sale of the Prince George Refinery closed on November 1, 2019.*

Canadian Refined Products gross revenues decreased by $290 million in 2019 compared to 2018, primarily due to lower product prices and lower sales volumes.

Canadian Refined Products purchases of crude oil and products decreased by $189 million in 2019 compared to 2018, primarily due to lower throughput volumes resulting primarily from a planned turnaround at the Prince George Refinery in the second quarter of 2019, combined with lower commodity prices.

Depletion, depreciation, amortization and impairment expense increased by $103 million in 2019 compared to 2018, primarily due to a pre-tax impairment charge of $90 million recognized on the Lloyd Ethanol Plant and Minnedosa Ethanol Plant. The impairment charge in 2019 was a result of sustained declines in forecasted ethanol margins.

Recovery of income taxes increased by $60 million in 2019 compared to 2018, primarily due to lower earnings before income taxes in 2019.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	**2019**	2018
Gross revenues	**9,940**	11,770
Expenses		
Purchases of crude oil and products	**8,629**	10,334
Production, operating and transportation expenses	**869**	795
Selling, general and administrative expenses	**33**	22
Depletion, depreciation, amortization and impairment	**735**	450
Loss on sale of assets	**1**	—
Other – net	**(654)**	(464)
Financial items	**18**	14
Provisions for income taxes	**69**	138
Net earnings	**240**	481
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*(1)	**136.4**	151.1
BP-Husky Toledo Refinery throughput *(mbbls/day)*(1)(2)	**63.1**	71.1
Superior Refinery throughput *(mbbls/day)*(1)	**—**	11.7
Refining and marketing margin *(US$/bbl crude throughput)*	**13.83**	13.03
Refinery inventory *(mmbbls)*(3)	**5.0**	6.9

(1) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(2) *Reported throughput volumes include Husky's working interest from the BP-Husky Toledo Refinery (50%).*
(3) *Feedstock and refined products are included in refinery inventory.*

U.S. Refining and Marketing gross revenues decreased by $1,830 million in 2019 compared to 2018, primarily due to lower sales volume at the Lima and BP-Husky Toledo refineries, both of which completed planned turnarounds in 2019, and no sales volume at the Superior Refinery in 2019.

U.S. Refining and Marketing purchases of crude oil and products decreased by $1,705 million in 2019 compared to 2018, primarily due to lower throughput volumes at the Lima and BP-Husky Toledo refineries, both of which completed planned turnarounds in 2019, combined with the realization of lower cost crude oil feedstock, from late 2018, at the Lima Refinery, during the first quarter of 2019.

Production, operating and transportation expenses increased by $74 million in 2019 compared to 2018, primarily due to planned turnarounds at the Lima and BP-Husky Toledo Refineries in 2019.

Depletion, depreciation, amortization and impairment expense increased by $285 million in 2019 compared to 2018, primarily due to a pre-tax derecognition of $254 million on the carrying value of components replaced as part of the crude oil flexibility project at the Lima Refinery.

Other – net income increased by $190 million in 2019 compared to 2018, primarily due to pre-tax insurance recoveries for rebuild costs, incident costs and business interruption associated with the incident at the Superior Refinery.

Provisions for income taxes decreased by $69 million in 2019 compared to 2018, primarily due to lower earnings before income taxes in 2019.

Downstream Capital Expenditures

In 2019, Downstream capital expenditures totalled $946 million compared to $801 million in 2018. In Canada, capital expenditures of $178 million related primarily to a polymer modified asphalt project at the Lloydminster Refinery and the planned turnaround at the Prince George Refinery. In the U.S., capital expenditures of $768 million related primarily to the crude oil flexibility project at the Lima Refinery and costs related to the turnaround at the BP-Husky Toledo Refinery.

4.4 Corporate

Corporate Summary *($ millions) income (expense)*	**2019**	2018
Production, operating and transportation expenses	**2**	2
Selling, general and administrative expenses	**(292)**	(277)
Depletion, depreciation, amortization and impairment	**(104)**	(92)
Other – net	**16**	8
Net foreign exchange gain	**44**	14
Finance income	**71**	52
Finance expense	**(151)**	(178)
Recovery of income taxes	**302**	138
Net loss	**(112)**	(333)

The Corporate segment reported a net loss of $112 million in 2019 compared to a net loss of $333 million in 2018. The change was primarily due to the recognition of $233 million in tax recoveries related to the reduction in the Alberta provincial corporate tax rate that was substantively enacted in the second quarter of 2019.

Finance expense decreased by $27 million in 2019 compared to 2018, primarily due to lower interest expenses on long-term debt in 2019.

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

Foreign Exchange Summary *($ millions, except where indicated)*	**2019**	2018
Non-cash working capital gain (loss)	**17**	(3)
Other foreign exchange gain	**27**	17
Net foreign exchange gain	**44**	14
U.S./Canadian dollar exchange rates:		
At beginning of year	**US$0.733**	US$0.799
At end of year	**US$0.771**	US$0.733

Included in the other foreign exchange gain 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)*	**2019**	2018
Provisions for (recovery of) income taxes	**(799)**	471
Cash income taxes paid	**41**	37

Consolidated income taxes were a recovery of $799 million in 2019 compared to a provision of $471 million in 2018. The increase in recovery of income taxes was primarily due to a $741 million deferred income tax recovery associated with impairment, derecognition and exploration asset write-down charges recognized on crude oil and natural gas, and refinery assets located in Canada and United States, and $233 million in deferred income tax recovery related to the reduction in the Alberta provincial corporate tax rate that was substantively enacted in the second quarter of 2019.

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, 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 a number of 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 a number of factors including, but not limited to, the amount of 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.

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 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 natural gas.

The Company's results will be impacted by a decrease in the price of crude oil and 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 natural gas inventory that could have an impact on earnings based on changes in natural gas prices. All these inventories are subject to a lower of cost or net realizable value test on a quarterly basis.

Reservoir Performance 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, investor confidence and the Company's ability to deliver on its growth strategy.

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. To mitigate the effects of this, the Company must undertake successful exploration and development programs, increase the recovery factor from existing properties through applied technology and identify and execute strategic acquisitions of proved developed and undeveloped properties and unproved prospects. 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.

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. With growing oil production across North America and the limited availability of infrastructure to carry the Company's products to the marketplace, oil and natural gas transportation capacity is expected to 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.

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 activist 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 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 into or working in China has increased, 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."

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.

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.

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.

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.

Reserves Data, Future Net Revenue and Resource Estimates

The reserves data contained or referenced in the 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. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and could have a material adverse effect on the Company's reputation, investor confidence and ability to deliver on its growth business strategy.

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, development or exploratory activities. As these governments continually balance competing demands from different interest groups 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 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. A Proposed Regulatory Approach for the CFS was published in June 2019 and proposed regulations are expected to be published in Canada Gazette, Part I for early 2020. The final regulations for liquid fuels are planned for early 2021, with the regulations expected to come into force in 2022. Due to the uncertainty of the gaseous and solid fuel regulations, the full impact of the CFS is still unknown.

The Company's U.S. refining business may be materially adversely affected by the implementation of the Environmental Protection Agency's ("EPA") climate change rules by future U.S. GHG legislation that applies to the oil and gas industry or the consumption of petroleum products and by other U.S. climate change statutes at the federal or state level or by regulations imposed by other federal agencies or 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 and results of operations.

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 public 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.

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 govern the Company's credit portfolio and limit 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 including: cash and cash equivalents, cash from operating activities, undrawn credit facilities and capacity to raise capital from various debt and equity capital markets under its shelf prospectuses. The availability of capital under its shelf prospectuses is dependent on market conditions at the time of sale.

Debt Covenants

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

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.

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.

The Company is committed to retaining investment grade credit ratings to support access to capital markets and currently has 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	Stable	Stable	Stable
Senior Unsecured Debt	BBB	Baa2	A(low)
Series 1 Preferred Shares	P-3(high)		Pfd-2(low)
Series 2 Preferred Shares	P-3(high)		Pfd-2(low)
Series 3 Preferred Shares	P-3(high)		Pfd-2(low)
Series 5 Preferred Shares	P-3(high)		Pfd-2(low)
Series 7 Preferred Shares	P-3(high)		Pfd-2(low)
Commercial Paper			R-1(low)

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.

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.

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 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. The Audit Committee of the Board has oversight of the Company's risk mitigation strategies related to cybersecurity.

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.

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.

6.0 Liquidity and Capital Resources

6.1 Summary of Cash Flow

Cash Flow Summary *($ millions)*	**2019**	2018
Cash flow		
Operating activities	**2,971**	4,134
Financing activities	**(817)**	(325)
Investing activities	**(3,197)**	(3,521)

Cash Flow from Operating Activities

Cash flow generated from operating activities decreased by $1,163 million in 2019 compared to 2018. The decrease was primarily due to the tightening of the location differentials between Canada and the U.S., combined with lower Upstream and U.S. Refining volumes.

Cash Flow used for Financing Activities

Cash flow used for financing activities increased by $492 million in 2019 compared to 2018. Financing activities in 2019 related primarily to higher common share dividend payments, combined with higher finance expenses arising from the adoption of IFRS 16 in 2019.

Cash Flow used for Investing Activities

Cash flow used for investing activities decreased by $324 million in 2019 compared to 2018. The decrease was primarily due to proceeds from the sale of the Prince George Refinery and decreased capital expenditures in 2019.

6.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2019, the Company's working capital was $302 million compared to $694 million at December 31, 2018. A reconciliation of the Company's working capital is as follows:

Working Capital *($ millions)*	**December 31, 2019**	December 31, 2018	Change
Cash and cash equivalents	**1,775**	2,866	(1,091)
Accounts receivable	**1,499**	1,355	144
Income taxes receivable	**30**	112	(82)
Inventories	**1,486**	1,232	254
Prepaid expenses	**148**	123	25
Accounts payable and accrued liabilities	**(3,465)**	(3,159)	(306)
Short-term debt	**(550)**	(200)	(350)
Long-term debt due within one year	**(400)**	(1,433)	1,033
Lease liabilities	**(109)**	—	(109)
Asset retirement obligations	**(112)**	(202)	90
Net working capital	**302**	694	(392)

The decrease in cash and cash equivalents was primarily due to lower cash flow from operating activities. Fluctuations in accounts receivable and accounts payable were due to the timing of settlements in 2019 compared to 2018. The increase in inventories was primarily driven by the higher commodity prices at the end of 2019 compared to 2018, and a higher volume of crude oil feedstock inventory in U.S Refining and Marketing at the end of 2019 compared to 2018. The increase in short-term debt was due to increased borrowings on commercial paper. The decrease in long-term debt due within one year was due to the timing of debt maturities. The increase in lease liabilities was due to the adoption of IFRS 16 in 2019.

6.3 Sources of Liquidity

Liquidity describes a company's ability to access cash. Sources of liquidity include funds from operations, proceeds from the issuance of equity, 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 equity, the issuance of debt, borrowings under committed and uncommitted credit facilities and cash proceeds from asset sales. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

At December 31, 2019, the Company had the following available credit facilities:

Credit Facilities *($ millions)*	Available	Unused
Operating facilities[(1)]	**900**	**464**
Syndicated credit facilities[(2)]	**4,000**	**3,450**
	4,900	**3,914**

[(1)] *Consists of demand credit facilities.*
[(2)] *Commercial paper outstanding is supported by the Company's syndicated credit facilities.*

At December 31, 2019, the Company had $3,914 million of unused credit facilities of which $3,450 million are long-term committed credit facilities and $464 million are short-term uncommitted credit facilities. A total of $436 million short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $550 million of long-term committed borrowing credit facilities was used in support of commercial paper. At December 31, 2019, the Company had no direct borrowing against committed credit facilities. The maturity dates for the Company's revolving syndicated credit facilities are June 19, 2022 and March 9, 2024. The Company's ability to renew existing bank credit facilities and raise new debt is 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 share capital is not subject to external restrictions. The Company's leverage covenant under both of its revolving syndicated credit facilities is debt to capital 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 agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. These covenants are used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2019, 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, 2019.

On January 29, 2018, the Company filed a universal short form base shelf prospectus ("the 2018 U.S. Shelf Prospectus") with the Alberta Securities Commission. On January 30, 2018, the Company's related U.S. registration statement filed with the Securities and Exchange Commission ("SEC") containing the 2018 U.S. Shelf Prospectus became effective which enables 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. up to and including February 29, 2020. During the 25-month period that the 2018 U.S. Shelf Prospectus and the related U.S. registration statement are effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

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 enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including June 1, 2021. The 2019 Canadian Shelf Prospectus replaced the Company's Canadian universal short form base shelf prospectus which expired on April 30, 2019. During the 25-month period that the 2019 Canadian Shelf Prospectus is in effect, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

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.

As at December 31, 2019, the Company had $3.0 billion in unused capacity under the 2019 Canadian Shelf Prospectus and US$2.25 billion in unused capacity under the 2018 U.S. Shelf Prospectus and related U.S. registration statement. The ability of the Company to utilize the capacity under the 2019 Canadian Shelf Prospectus and the 2018 U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

Net Debt

The Company had total debt of $5,520 million and cash and cash equivalents of $1,775 million at December 31, 2019, compared to total debt of $5,747 million and cash and cash equivalents of $2,866 million at December 31, 2018. The Company's net debt at December 31, 2019 increased by $864 million when compared to December 31, 2018:

Net Debt[1] *($ millions)*	**December 31, 2019**	December 31, 2018
Net debt at beginning of period	**(2,881)**	(2,927)
Change in net debt due to:		
Funds from operations[1]	**3,251**	4,004
Long-term debt issuance	**1,000**	—
Long-term debt repayment	**(1,389)**	—
Short-term debt issuance, net	**350**	—
Debt issue costs	**(9)**	—
Dividends on common shares	**(503)**	(402)
Dividends on preferred shares	**(35)**	(35)
Finance lease payments	**(233)**	—
Capital expenditures	**(3,432)**	(3,578)
Capitalized interest	**(177)**	(108)
Corporate acquisition	**—**	(15)
Proceeds from asset sales	**277**	4
Investment in joint ventures	**(40)**	(40)
Change in non-cash working capital	**(104)**	485
Other	**1**	(27)
Effect of exchange rates on cash and cash equivalents	**(48)**	65
Effect of exchange rates on long-term debt	**227**	(307)
	(864)	46
Net debt at end of period	**(3,745)**	(2,881)

[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 years ended December 31, 2019 and 2018, the Company's capital expenditures were primarily funded by funds from operations. 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, 2019 Outstanding
Total debt[1]	5,520
Shareholders' equity	17,296

(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 are to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk, and to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes 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 $22.8 billion at December 31, 2019 (December 31, 2018 – $25.4 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors 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, 2019, debt to capital employed was 24.2% (December 31, 2018 – 22.7%) and debt to funds from operations was 1.7 times (December 31, 2018 – 1.4 times). 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%. 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 prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

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)	2020	2021-2022	2023-2024	Thereafter	Total
Long-term debt and interest on fixed rate debt	612	1,040	1,303	3,775	6,730
Operating agreements[1]	75	155	155	666	1,051
Firm transportation agreements[1]	576	1,189	1,188	4,203	7,156
Unconditional purchase obligations[2]	2,224	3,212	2,305	5,143	12,884
Lease rentals and exploration work agreements	79	102	113	866	1,160
Obligations to fund equity investee[3]	54	141	149	359	703
Lease obligations[4]	205	340	313	2,174	3,032
Asset retirement obligations	112	253	244	9,371	9,980
	3,937	6,432	5,770	26,557	42,696

(1) Included in the total of operating agreements and firm transportation agreements are blending and storage agreements and transportation commitments of $1.1 billion and $1.8 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) Refer to Note 10 in the 2019 consolidated financial statements.

During the three months ended December 31, 2019, the Company entered into a new agreement totaling an incremental $2.2 billion for a term of five years to purchase refined products for the purpose of supporting the retail network.

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, 2019, the Company has deposited funds of $142 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 are related party transactions, 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 are affiliates of one of the Company's principal shareholders. For the year ended December 31, 2019, the Company charged HMLP $424 million related to construction costs and management services. For the year ended December 31, 2019, the Company had purchases from HMLP of $219 million related to the use of the pipeline for the Company's blending, transportation and storage activities. As at December 31, 2019, the Company had $143 million due from HMLP and $16 million due to HMLP.

6.7 Outstanding Share Data

Authorized:

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

Issued and outstanding: February 24, 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	17,369,033
• stock options exercisable	9,586,551

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 2019 consolidated financial statements. Certain 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.

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 undivided gross working interest in total reserves after deducting 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

Leases

In January 2016, the IASB issued IFRS 16 Leases ("IFRS 16"), which replaces the existing IFRS guidance on leases: IAS 17 Leases ("IAS 17"). Under IAS 17, lessees were required to determine if the lease is a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the balance sheet while operating leases were recognized in the Consolidated Statements of Income (Loss) when the expense was incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for most lease contracts. The recognition of the present value of the lease payments for certain contracts previously classified as operating leases resulted in increases to assets, liabilities, depletion, depreciation and amortization and finance expense, and a decrease to production, operating and transportation expense, purchases of crude oil and products and selling, general and administrative expenses.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Accordingly, comparative information in the Company's financial statements are not restated.

On adoption, lease liabilities were measured at the present value of the remaining lease payments discounted using the Company's incremental borrowing rate on January 1, 2019. Right-of-use assets were measured at an amount equal to the lease liability. For leases previously classified as operating leases, the Company applied the exemption not to recognize right-of-use assets and liabilities for leases with a lease term of less than 12 months, excluded initial direct costs from measuring the right-of-use asset at the date of initial application and applied a single discount rate to a portfolio of leases with similar characteristics. For leases that were previously classified as finance leases under IAS 17, the carrying amount of the lease asset and lease liability remain unchanged upon transition and were determined at the carrying amount immediately before adoption date. Additionally, instead of an impairment review, the Company adjusted the right-of-use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application.

No adjustments were required upon transition to IFRS 16 for leases where the Company is a lessor. Under IFRS 16, the Company is required to assess the classification of a sub-lease with reference to the right-of-use asset, not the underlying asset. On transition, the Company reassessed the classification of any sub-lease contracts previously assessed under IAS 17. No changes to sublease classification or associated accounting treatment was required.

Financial Statement Impact

The recognition of the present value of lease payments resulted in an additional $1.3 billion of right-of-use assets and associated lease liabilities. The Company has recognized lease liabilities in relation to lease arrangements previously disclosed as operating lease commitments under IAS 17 that meet the criteria of a lease under IFRS 16. Upon recognition in the consolidated statement of financial position, the Company's weighted average incremental borrowing rate used in measuring lease liabilities was 3.58%.

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: the Company's general strategic plans and growth strategies; the Company's 2020 production guidance, including guidance for specified areas and product types; the Company's objective of maintaining stated debt to funds from operations; and the Company's 2020 Upstream capital expenditure program;
- with respect to the Company's thermal developments, the expected timing of first production from the Spruce Lake Central, Spruce Lake North, Spruce Lake East, Edam Central and Dee Valley 2 projects;
- with respect to the Company's Offshore business in Asia Pacific: the expected timing of commencement of construction activities, installation of the control system and connecting flow lines and first gas production at Liuhua 29-1; the expected timing of additional appraisal drilling at Block 15/33; the expected timing of drilling five MDA and two MBH field production wells, and the expected timing of first gas production and sales therefrom; the expected timing of development of a floating production unit to process gas at MDA and MBH; and plans to develop the additional MDK shallow water field;
- with respect to the Company's Offshore business in the Atlantic, the expected timing of first production from the West White Rose Project;
- with respect to the Company's Infrastructure and Marketing business, the expected timing of completion of construction of storage tanks at the Hardisty Terminal; and
- with respect to the Company's Downstream operating segment: plans to market and potentially sell the Retail and Commercial Fuels Network; the timing of ramp-up to full rates at the Lima Refinery; the expected investment in the rebuild of the Superior Refinery and anticipated insurance recoveries for property damage and lost income associated therewith; and the expected timing of resumption of full operations at the Superior Refinery.

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, 2019 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, 2019 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, 2019.

The Company uses the term barrels of oil equivalent ("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 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 but 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 incremental proved reserves additions for that period divided by the Company's Upstream gross production for the same period. The reserves replacement ratio measures the amount of reserves added 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. The reserves replacement ratio only measures the amount of reserves added to a company's reserve base during a given period. Reserves replacement ratios that exclude economic factors will exclude the impacts that changing oil and gas prices 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 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: funds from operations, free cash flow, total debt, net debt, operating netback, debt to capital employed, debt to funds from operations and sustaining capital. None of these measures is used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for operating netback, 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 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, 2019, 2018 and 2017:

Debt to Funds from Operations *($ millions)*	**December 31, 2019**	December 31, 2018	December 31, 2017
Total debt	**5,520**	5,747	5,440
Funds from operations	**3,251**	4,004	3,306
Debt to funds from operations	**1.7**	1.4	1.6

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.

Free cash flow was restated in the fourth quarter of 2018 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of investment in joint ventures. Prior periods have been restated to conform to current presentation.

The following table shows the reconciliation of net earnings to funds from operations and free cash flow, and related per share amounts for the three months and years ended December 31:

Reconciliation of Cash Flow	Three months ended		Year ended		
	Dec. 31	Dec. 31	**Dec. 31**	Dec. 31	Dec. 31
($ millions)	**2019**	2018	**2019**	2018	2017
Net earnings	**(2,341)**	216	**(1,370)**	1,457	786
Items not affecting cash:					
Accretion	**27**	25	**106**	97	112
Depletion, depreciation, amortization and impairment	**3,520**	662	**5,496**	2,591	2,882
Inventory write-down to net realizable value	**15**	60	**15**	60	—
Exploration and evaluation expenses	**332**	22	**355**	29	6
Deferred income taxes (recoveries)	**(789)**	25	**(974)**	396	(359)
Foreign exchange loss (gain)	**(11)**	1	**(26)**	(6)	(4)
Stock-based compensation	**(13)**	(50)	**(2)**	44	45
Gain on sale of assets	**(3)**	—	**(8)**	(4)	(46)
Unrealized market to market loss (gain)	**(13)**	(16)	**44**	(150)	56
Share of equity investment gain	**5**	(16)	**(59)**	(69)	(61)
Gain on insurance recoveries for damage to property	**(194)**	(253)	**(207)**	(253)	—
Other	**11**	2	**12**	21	16
Settlement of asset retirement obligations	**(90)**	(65)	**(276)**	(181)	(136)
Deferred revenue	**(14)**	(30)	**(42)**	(100)	(16)
Distribution from joint ventures	**27**	—	**187**	72	25
Change in non-cash working capital	**397**	730	**(280)**	130	398
Cash flow – operating activities	**866**	1,313	**2,971**	4,134	3,704
Change in non-cash working capital	**(397)**	(730)	**280**	(130)	(398)
Funds from operations	**469**	583	**3,251**	4,004	3,306
Capital expenditures	**(894)**	(1,265)	**(3,432)**	(3,578)	(2,220)
Free cash flow	**(425)**	(682)	**(181)**	426	1,086
Funds from operations – basic	**0.47**	0.58	**3.23**	3.98	3.29
Funds from operations – diluted	**0.47**	0.58	**3.23**	3.98	3.29

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, 2019, 2018 and 2017:

Net Debt *($ millions)*	**December 31, 2019**	December 31, 2018	December 31, 2017
Total debt	**5,520**	5,747	5,440
Cash and cash equivalents	**(1,775)**	(2,866)	(2,513)
Net debt	**3,745**	2,881	2,927

Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. Management believes this measurement assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. Operating netback is calculated as gross revenue less royalties, production and operating and transportation costs on a per unit basis.

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, 2019, 2018 and 2017:

Total Debt *($ millions)*	**December 31, 2019**	December 31, 2018	December 31, 2017
Short-term debt	**550**	200	200
Long-term debt due within one year	**400**	1,433	—
Long-term debt	**4,570**	4,114	5,240
Total debt	**5,520**	5,747	5,440

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 26, 2020. 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 26, 2020, should be read in conjunction with the 2019 consolidated financial statements and related notes. Readers are also encouraged to refer to the Company's interim reports filed for 2019, which contain Management's Discussion and Analysis and consolidated financial statements, and the Company's Annual Information Form for the year ended December 31, 2019, 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, 2019 and 2018 and the Company's financial position at December 31, 2019 and 2018.

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.

Terms

Asia Pacific	*Includes Upstream 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 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*
High-TAN	*A measure of acidity. Crude oils with a high content of naphthenic acids are referred to as high total acid number (TAN) crude oils or high acid crude oil. The TAN value is defined as the milligrams of Potassium Hydroxide required to neutralize the acidic group of one gram of the oil sample. Crude oils in the industry with a TAN value greater than 1 are referred to as high-TAN crudes*
HOIMS	*The Husky Operational Integrity Management System*
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*
Operating netback	*Gross revenue less royalties, operating costs and transportation costs on a per unit basis*
Plan of Development	*As it relates to the Company's operations in Indonesia, a Plan of Development represents development planning on one or more oil and gas fields in an integrated and optimal plan for the production of hydrocarbon reserves considering technical, economical and environmental aspects. An initial Plan of Development in a development area needs both SKK Migas and the Minister of Energy and Mineral Resources approvals. Subsequent Plans of Development in the same development area only need SKK Migas approval*
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*
Seismic survey	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
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 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 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 oil upgrading facility owned and operated by the Company and located in Lloydminster, Saskatchewan.*
Western Canada	*Includes Upstream oil and gas exploration and development activities located in Alberta, Saskatchewan and British Columbia*

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 Chief Executive Officer and the 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, 2019, 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 Chief Executive Officer and 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, 2019, management, under the supervision of the Chief Executive Officer and 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, 2019, 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, 2019, 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 2019**	 Dec. 31 2018
Gross revenues and Marketing and other		
Upstream		
Exploration and Production	**1,281**	643
Infrastructure and Marketing	**618**	678
Downstream		
Upgrading	**456**	307
Canadian Refined Products	**793**	821
U.S. Refining and Marketing	**2,222**	2,766
Corporate and Eliminations	**(489)**	(173)
Total gross revenues and marketing and other	**4,881**	5,042
Net earnings (loss)		
Upstream		
Exploration and Production	**(1,964)**	(206)
Infrastructure and Marketing	**(3)**	126
Downstream		
Upgrading	**48**	80
Canadian Refined Products	**(64)**	55
U.S. Refining and Marketing	**(192)**	213
Corporate and Eliminations	**(166)**	(52)
Net earnings (loss)	**(2,341)**	216
Per share – Basic	**(2.34)**	0.21
Per share – Diluted	**(2.34)**	0.16
Cash flow – operating activities	**866**	1,313
Funds from operations[1]	**469**	583
Per share – Basic	**0.47**	0.58
Per share – Diluted	**0.47**	0.58
Upstream		
Daily gross production		
Crude oil and NGL production *(mbbls/day)*[2]	**226.7**	214.7
Conventional natural gas production *(mmcf/day)*[2]	**507.4**	537.6
Total production *(mboe/day)*	**311.3**	304.3
Average sales prices realized *($/boe)*		
Crude oil and NGL *($/bbl)*[2]	**47.52**	18.93
Conventional natural gas *($/mcf)*[2]	**7.02**	6.86
Total average sales prices realized *($/boe)*	**46.06**	25.47
Downstream		
Refinery throughput		
Lloydminster Upgrader *(mbbls/day)*	**79.6**	71.8
Lloydminster Refinery *(mbbls/day)*	**28.2**	25.3
Prince George Refinery *(mbbls/day)*[3]	**3.9**	10.7
Lima Refinery *(mbbls/day)*	**21.4**	105.9
BP-Husky Toledo Refinery *(mbbls/day)*	**70.3**	73.2
Superior Refinery *(mbbls/day)*	**—**	—
Total throughput *(mbbls/day)*	**203.4**	286.9

Fourth Quarter Results Summary (continued)	Three months ended	
	Dec. 31	Dec. 31
($ millions, except where indicated)	**2019**	2018
Upgrading unit margin *($/bbl)*	**20.21**	29.13
Upgrading synthetic crude oil sales *(mbbls/day)*	**55.5**	53.8
Upgrading total sales *(mbbls/day)*	**78.0**	73.5
Retail fuel sales *(million of litres/day)*	**7.4**	8.0
Canadian light oil margins *($/litre)*	**0.032**	0.037
Lloydminster Refinery asphalt margin *($/bbl)*	**16.59**	41.50
U.S. Refining and Marketing margin *(US$/bbl crude throughput)*	**7.85**	9.12
U.S./Canadian dollar exchange rate *(US$)*	**0.758**	0.757

(1) *Funds from operations is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.*
(2) *Reported production volumes and associated per unit values 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 financial statement purposes.*
(3) *Prince George Refinery was sold on November 1, 2019.*

Gross Revenue and Marketing and Other

The Company's consolidated gross revenues and marketing and other decreased by $161 million in the fourth quarter of 2019 compared to the fourth quarter of 2018.

In the Upstream business segment, Exploration and Production gross revenues increased primarily due to higher average realized sales prices and production. Infrastructure and Marketing gross revenues and marketing and other decreased primarily due to the tightening of the location price differentials between Canada and the U.S. in 2019.

In the Downstream business segment, gross revenues decreased primarily due to lower throughput volumes as the Lima Refinery completed a planned turnaround in the fourth quarter of 2019.

Net Earnings (Loss)

The Company's consolidated net loss increased by $2,557 million in the fourth quarter of 2019 compared to the fourth quarter of 2018.

In the Upstream business segment, Exploration and Production net loss increased primarily due to an after-tax impairment charge of $1,822 million within the Sunrise Energy Project, Western Canada and Atlantic, combined with the same factors which impacted gross revenue and marketing and other.

In the Downstream business segment, U.S. Refining and Marketing net loss increased primarily due to an after-tax $198 million derecognition of the carrying value of components replaced as part of the crude oil flexibility project at the Lima Refinery, and Canadian Refined Products net loss increased primarily due to an after-tax impairment charge of $69 million recognized on the Lloyd Ethanol Plant and Minnedosa Ethanol Plant.

In the Corporate business segment, net earnings increased primarily due to work force adjustments during the fourth quarter of 2019.

Cash Flow – Operating Activities and Funds from Operations

Cash flow – operating activities and funds from operations decreased by $447 million and $114 million, respectively, in the fourth quarter of 2019 compared to the fourth quarter of 2018, primarily due to lower sales volume at the Lima Refinery, which completed a planned turnaround in the fourth quarter of 2019, tightening of location differentials between Canada and the U.S. and workforce adjustments.

Daily Gross Production

Production increased by 7.0 mbbls/day during the fourth quarter of 2019 compared to the fourth quarter of 2018 as a result of:

- Higher crude oil production from Atlantic due to higher production from the White Rose field, which resumed full production in mid-August 2019; and
- Higher bitumen production from the Company's thermal projects.

Partially offset by:

- Lower production from the Liwan Gas Project and BD Project; and
- Lower heavy crude oil production due to government-mandated production quotas in Alberta and natural declines.

Segmented Operational Information

Segmented Operational Information *($ millions, except where indicated)*	2019 Q4	2019 Q3	2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1
Gross revenues and Marketing and other								
Upstream								
Exploration and Production	**1,281**	**1,241**	**1,252**	**1,184**	643	1,319	1,284	1,084
Infrastructure and Marketing	**618**	**711**	**634**	**568**	678	769	821	611
Downstream								
Upgrading	**456**	**464**	**457**	**400**	307	534	444	465
Canadian Refined Products	**793**	**871**	**804**	**654**	821	1,001	869	721
U.S. Refining and Marketing	**2,222**	**2,644**	**2,791**	**2,283**	2,766	3,198	3,035	2,771
Corporate and Eliminations	**(489)**	**(537)**	**(552)**	**(444)**	(173)	(521)	(470)	(390)
Total gross revenues and marketing and other	**4,881**	**5,394**	**5,386**	**4,645**	5,042	6,300	5,983	5,262
Net earnings (loss)								
Upstream								
Exploration and Production	**(1,964)**	**106**	**150**	**2**	(206)	214	158	57
Infrastructure and Marketing	**(3)**	**34**	**(38)**	**123**	126	149	154	138
Downstream								
Upgrading	**48**	**7**	**(2)**	**44**	80	88	84	109
Canadian Refined Products	**(64)**	**37**	**—**	**22**	55	43	32	28
U.S. Refining and Marketing	**(192)**	**126**	**134**	**172**	213	158	115	(5)
Corporate and Eliminations	**(166)**	**(37)**	**126**	**(35)**	(52)	(107)	(95)	(79)
Net earnings (loss)	**(2,341)**	**273**	**370**	**328**	216	545	448	248
Per share – Basic	**(2.34)**	**0.26**	**0.36**	**0.32**	0.21	0.53	0.44	0.24
Per share – Diluted	**(2.34)**	**0.25**	**0.36**	**0.31**	0.16	0.53	0.44	0.24
Cash flow – operating activities	**866**	**800**	**760**	**545**	1,313	1,283	1,009	529
Funds from operations[(1)]	**469**	**1,021**	**802**	**959**	583	1,318	1,208	895
Per share – Basic	**0.47**	**1.02**	**0.80**	**0.95**	0.58	1.31	1.20	0.89
Per share – Diluted	**0.47**	**1.02**	**0.80**	**0.95**	0.58	1.31	1.20	0.89
U.S./Canadian dollar exchange rate (US$)	**0.758**	**0.757**	**0.748**	**0.752**	0.757	0.765	0.775	0.791
Exploration and Production								
Daily production, before royalties								
Crude oil & NGL production *(mbbls/day)*								
Light & Medium crude oil	**33.3**	**30.5**	**19.6**	**16.5**	22.6	33.7	29.7	37.5
NGL[(2)]	**23.0**	**22.4**	**20.3**	**24.7**	24.8	24.5	21.8	20.5
Heavy crude oil	**32.6**	**31.6**	**28.9**	**27.6**	34.4	34.6	38.5	39.7
Bitumen	**137.8**	**126.4**	**120.4**	**130.3**	132.9	117.3	123.2	123.2
Total crude oil & NGL production *(mbbls/day)*	**226.7**	**210.9**	**189.2**	**199.1**	214.7	210.1	213.2	220.9
Conventional Natural gas *(mmcf/day)*[(2)]	**507.4**	**503.3**	**475.1**	**516.8**	537.6	519.5	494.0	477.0
Total production *(mboe/day)*	**311.3**	**294.8**	**268.4**	**285.2**	304.3	296.7	295.5	300.4
Average sales prices								
Light & Medium crude oil *($/bbl)*	**71.67**	**71.32**	**77.07**	**73.09**	60.19	93.84	92.23	82.08
NGL *($/bbl)*[(2)]	**45.72**	**38.39**	**50.22**	**46.07**	53.36	60.08	54.13	55.03
Heavy crude oil *($/bbl)*	**50.01**	**56.71**	**63.15**	**49.38**	18.71	50.09	54.22	32.80
Bitumen *($/bbl)*	**41.39**	**51.09**	**58.32**	**46.64**	5.42	46.00	44.41	27.77
Conventional natural gas *($/mcf)*[(2)]	**7.02**	**5.44**	**6.19**	**7.12**	6.86	6.15	6.53	7.03
Operating costs *($/boe)*	**15.25**	**14.83**	**15.83**	**16.30**	13.75	14.68	14.22	13.33
Operating netbacks[(2)(3)]								
Lloydminster Thermal *($/bbl)*[(4)]	**31.19**	**38.25**	**44.34**	**34.50**	(0.05)	35.83	36.16	19.77
Lloydminster Non-Thermal *($/boe)*[(4)]	**11.54**	**14.92**	**22.32**	**10.83**	(11.80)	13.28	20.83	4.13
Tucker Thermal *($/bbl)*[(4)]	**28.01**	**41.46**	**47.25**	**33.50**	(5.08)	29.53	31.67	16.16
Sunrise Energy Project *($/bbl)*[(4)]	**10.61**	**26.37**	**32.85**	**14.54**	(25.60)	15.79	12.59	(5.62)
Western Canada – Crude Oil *($/bbl)*[(4)]	**(5.81)**	**10.49**	**(0.98)**	**15.58**	(1.70)	23.81	29.37	17.88
Western Canada – NGL & Conventional natural gas *($/mcf)*[(5)]	**0.68**	**(0.07)**	**(0.09)**	**1.06**	1.13	0.29	0.39	1.33
Atlantic – Light Oil *($/bbl)*[(4)]	**45.92**	**41.64**	**23.44**	**(16.82)**	23.19	68.20	57.79	65.23
Asia Pacific – Light Oil, NGL & Conventional natural gas *($/boe)*[(2)(4)]	**69.12**	**62.59**	**68.07**	**68.33**	67.42	65.45	68.44	70.31
Total *($/boe)*[(4)]	**27.48**	**29.31**	**33.61**	**27.69**	9.42	31.30	31.31	24.37

Segmented Operational Information (continued)	2019 Q4	2019 Q3	2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1
Upgrading								
Synthetic crude oil sales *(mbbls/day)*	**55.5**	**58.5**	**54.1**	**53.5**	53.8	54.9	47.1	56.0
Total sales *(mbbls/day)*	**78.0**	**75.3**	**72.8**	**74.8**	73.5	76.7	69.1	79.4
Upgrading differential *($/bbl)*	**21.83**	**17.22**	**15.18**	**14.56**	27.89	29.46	26.67	32.31
Canadian Refined Products								
Fuel sales *(millions of litres/day)*	**7.4**	**7.5**	**7.2**	**7.5**	8.0	7.7	7.5	7.4
Refinery throughput[6]								
Lloydminster Refinery *(mbbls/day)*	**28.2**	**28.3**	**26.1**	**22.8**	25.3	27.8	26.8	28.7
Prince George Refinery *(mbbls/day)*[8]	**3.9**	**11.4**	**3.5**	**10.2**	10.7	11.5	8.8	12.0
U.S. Refining and Marketing								
Refinery throughput[6]								
Lima Refinery *(mbbls/day)*	**21.4**	**174.3**	**179.8**	**171.4**	105.9	163.3	171.2	164.4
BP-Husky Toledo Refinery *(mbbls/day)*[7]	**70.3**	**66.8**	**57.5**	**58.0**	73.2	70.8	65.5	75.0
Superior Refinery *(mbbls/day)*	**—**	**—**	**—**	**—**	—	—	10.1	37.0

(1) *Funds from operations is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.*
(2) *Reported production volumes and associated per unit values 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 financial statement purposes.*
(3) *Operating netback is a non-GAAP measure. Refer to Section 9.3.*
(4) *Includes associated co-products converted to boe.*
(5) *Includes associated co-products converted to mcfge.*
(6) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(7) *Reported throughput volumes include Husky's working interest from the BP-Husky Toledo Refinery (50%).*
(8) *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. Stronger performance in the Upstream operations were offset by the lower realized upgrading margins and lower earnings in U.S. Refining and Marketing as the Lima Refinery completed a planned turnaround in late 2019, which were offset by insurance recoveries for the Superior Refinery. 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:

2019

Q4:

- The Company recognized a pre-tax impairment charge of $2,405 million within the Sunrise Energy Project, Western Canada and Atlantic. 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 Atlantic and Western Canada. 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.

2018

Q4:

- At the Rush Lake 2 Thermal Project, first production and nameplate capacity of 10,000 bbls/day were achieved.
- At the Spruce Lake North Thermal Project, site clearing was completed.
- At the Tucker Thermal Project, nameplate capacity of 30,000 bbls/day was achieved.
- At the Sunrise Energy Project, nameplate capacity of 60,000 bbls/day was achieved. Additionally, the 10 infill wells previously drilled came online.
- At the Ansell and Kakwa areas, a drilling program targeting the Spirit River Formation continued with six more wells drilled and 12 more were completed.
- At the Karr and Wembley areas, in the Montney Formation, three more wells were drilled and completed.
- On November 16, 2018, a flowline connector separated near the South White Rose Extension Drill Centre, causing a spill of approximately 250 cubic metres of oil. Production at the SeaRose FPSO was shut-in. Operations resumed in the first quarter of 2019.
- The Company is a non-operating partner in two exploration licences awarded in the November 2018 C-NLOPB land sale. The licences are adjacent to Terra Nova and White Rose in the Jeanne d'Arc Basin and will bring the Company's total licence holdings in the region to nine.
- The Company completed its 2018 planned scope of work on the Lima Refinery crude oil flexibility project.
- The Company accrued pre-tax insurance recoveries for property damage, rebuild costs and business interruption associated with the incident at the Superior Refinery of $331 million.

Q3:

- At the Rush Lake 2 Thermal Project, construction of the CPF was completed and first steam was achieved.
- At the Dee Valley Thermal Project, drilling of the second well pad was completed and construction of the CPF continued.
- At the Spruce Lake Central Thermal Project, drilling of the first well pad was completed and construction of the CPF commenced.
- At the Tucker Thermal Project, a planned turnaround was completed in support of reaching its 30,000 bbls/day design capacity.
- At the Ansell and Kakwa areas, an accelerated drilling program from an 18-well program to a 25-well development program continued with eight more wells drilled and nine more were completed.
- At the Karr and Wembley areas, in the Montney Formation, two more wells were drilled and three completed.
- An exploration well was drilled on Block 16/25 which encountered hydrocarbons. Additional evaluation work was conducted.
- At the Madura Strait, the BD Project achieved its gross daily sales targets of 100 mmcf/day of conventional natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGL (2,400 bbls/day Husky working interest).
- The Company accrued pre-tax insurance recoveries for property damage and clean-up costs associated with the incident at the Superior Refinery of $110 million.

Q2:

- At the Dee Valley Thermal Project, drilling of the first well pad was completed and construction of the CPF commenced.
- At the Spruce Lake Central Thermal Project, site clearing was completed.
- At the Tucker Thermal Project, production from the remaining five wells of the 15-well D West pad commenced.
- At the Sunrise Energy Project, two infill wells commenced production, and the remaining three of 10 infill wells were drilled.
- At the Karr and Wembley areas, in the Montney Formation, two wells were drilled.
- Construction to develop Liuhua 29-1 commenced.
- Two exploration wells were drilled on Block 15/33 in the South China Sea. The first well was a success and the second well, which was drilled on a separate structure, did not encounter commercial hydrocarbons and was written off.
- The Company and CNOOC signed two PSCs for Blocks 22/11 and 23/07 in the Beibu Gulf area of the South China Sea.
- At the West White Rose Project, construction of the concrete gravity structure commenced at the purpose-built graving dock in Argentia, Newfoundland and Labrador.
- An exploration well was drilled north of the main White Rose field. The well encountered a net pay thickness of more than 85 metres of oil-bearing sandstone. The discovery continues to be evaluated and further delineation of the area is planned.
- On April 26, 2018, a fire occurred at the Superior Refinery and operations were suspended. The Company has insurance to cover business interruption, third-party liability and property damage. The Company accrued pre-tax insurance recoveries for property damage associated with the incident of $27 million.

Q1:

- At the Rush Lake 2 Thermal Project, drilling of the 12 SAGD injector-producer well pairs was completed and construction of the CPF continued.
- At the Dee Valley Thermal Project, drilling of the first well pad commenced.
- At the Spruce Lake North and Central thermal projects, site clearing commenced.
- At the Tucker Thermal Project, production from the first 10 wells of the new D West pad commenced.
- At the Sunrise Energy Project, production commenced at the last well pair of the 14 previously drilled well pairs. Two infill wells commenced steaming, and seven out of 10 infill wells were drilled.
- At the Ansell and Kakwa areas, production commenced at the remaining six wells of the 16-well 2017 drilling program. Additionally, an 18-well development program commenced with seven wells drilled and four completed.
- Production operations on the *SeaRose* FPSO vessel were suspended for nine days due to a regulatory suspension.

Segmented Financial Information

	Upstream								Downstream			
	Exploration and Production[1]				Infrastructure and Marketing				Upgrading			
2019 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	**1,281**	**1,241**	**1,252**	**1,184**	**608**	**676**	**648**	**410**	**456**	**464**	**457**	**400**
Royalties	**(88)**	**(81)**	**(83)**	**(71)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Marketing and other	**—**	**—**	**—**	**—**	**10**	**35**	**(14)**	**158**	**—**	**—**	**—**	**—**
Revenues, net of royalties	**1,193**	**1,160**	**1,169**	**1,113**	**618**	**711**	**634**	**568**	**456**	**464**	**457**	**400**
Expenses												
Purchases of crude oil and products	**—**	**—**	**—**	**—**	**591**	**658**	**686**	**401**	**311**	**360**	**375**	**257**
Production, operating and transportation expenses	**435**	**399**	**385**	**415**	**9**	**4**	**5**	**3**	**54**	**57**	**54**	**52**
Selling, general and administrative expenses	**71**	**78**	**69**	**79**	**6**	**—**	**2**	**1**	**(3)**	**7**	**3**	**2**
Depletion, depreciation, amortization and impairment	**2,963**	**497**	**430**	**422**	**2**	**4**	**4**	**2**	**29**	**29**	**28**	**29**
Exploration and evaluation expenses	**390**	**41**	**86**	**30**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Loss (gain) on sale of assets	**(1)**	**—**	**—**	**(2)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Other – net	**(11)**	**(18)**	**(35)**	**150**	**—**	**—**	**(2)**	**2**	**—**	**—**	**—**	**—**
	3,847	**997**	**935**	**1,094**	**608**	**666**	**695**	**409**	**391**	**453**	**460**	**340**
Earnings (loss) from operating activities	**(2,654)**	**163**	**234**	**19**	**10**	**45**	**(61)**	**159**	**65**	**11**	**(3)**	**60**
Share of equity investment income (loss)	**8**	**15**	**15**	**12**	**(13)**	**4**	**8**	**10**	**—**	**—**	**—**	**—**
Financial items												
Net foreign exchange gains (losses)	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Finance income	**3**	**—**	**(1)**	**1**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Finance expenses	**(42)**	**(39)**	**(48)**	**(34)**	**(1)**	**(2)**	**—**	**—**	**—**	**(1)**	**—**	**—**
	(39)	**(39)**	**(49)**	**(33)**	**(1)**	**(2)**	**—**	**—**	**—**	**(1)**	**—**	**—**
Earnings (loss) before income tax	**(2,685)**	**139**	**200**	**(2)**	**(4)**	**47**	**(53)**	**169**	**65**	**10**	**(3)**	**60**
Provisions for (recovery of) income taxes												
Current	**8**	**(9)**	**33**	**—**	**—**	**—**	**(2)**	**2**	**22**	**12**	**6**	**23**
Deferred	**(729)**	**42**	**17**	**(4)**	**(1)**	**13**	**(13)**	**44**	**(5)**	**(9)**	**(7)**	**(7)**
	(721)	**33**	**50**	**(4)**	**(1)**	**13**	**(15)**	**46**	**17**	**3**	**(1)**	**16**
Net earnings (loss)	**(1,964)**	**106**	**150**	**2**	**(3)**	**34**	**(38)**	**123**	**48**	**7**	**(2)**	**44**
Capital expenditures[3]	**564**	**597**	**566**	**619**	**1**	**—**	**—**	**1**	**30**	**13**	**12**	**4**
Total assets	**17,533**	**19,956**	**19,847**	**20,025**	**1,661**	**1,619**	**1,504**	**1,458**	**1,203**	**1,219**	**1,178**	**1,204**

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*

(3) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period. Includes Exploration and Production assets acquired through acquisition, and excludes assets acquired through corporate acquisition.*

Segmented Financial Information Con't

Downstream (continued)								Corporate and Eliminations[2]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
793	871	804	654	2,222	2,644	2,791	2,283	(489)	(537)	(552)	(444)	4,871	5,359	5,400	4,487
—	—	—	—	—	—	—	—	—	—	—	—	(88)	(81)	(83)	(71)
—	—	—	—	—	—	—	—	—	—	—	—	10	35	(14)	158
793	871	804	654	2,222	2,644	2,791	2,283	(489)	(537)	(552)	(444)	4,793	5,313	5,303	4,574
691	706	671	503	2,140	2,319	2,342	1,828	(489)	(537)	(552)	(444)	3,244	3,506	3,522	2,545
57	69	83	69	241	197	216	215	—	(1)	—	(1)	796	725	743	753
13	13	13	14	10	7	9	7	119	44	86	43	216	149	182	146
119	32	33	34	380	117	122	116	27	24	26	27	3,520	703	643	630
—	—	—	—	—	—	—	—	—	—	—	—	390	41	86	30
(2)	(4)	—	—	—	1	—	—	—	—	—	—	(3)	(3)	—	(2)
—	—	—	—	(307)	(163)	(76)	(108)	(4)	(22)	10	—	(322)	(203)	(103)	44
878	816	800	620	2,464	2,478	2,613	2,058	(347)	(492)	(430)	(375)	7,841	4,918	5,073	4,146
(85)	55	4	34	(242)	166	178	225	(142)	(45)	(122)	(69)	(3,048)	395	230	428
—	—	—	—	—	—	—	—	—	—	—	—	(5)	19	23	22
—	—	—	—	—	—	—	—	20	(8)	2	30	20	(8)	2	30
—	—	—	—	—	—	—	—	11	24	17	19	14	24	16	20
(3)	(4)	(4)	(4)	(4)	(5)	(5)	(4)	(29)	(33)	(48)	(41)	(79)	(84)	(105)	(83)
(3)	(4)	(4)	(4)	(4)	(5)	(5)	(4)	2	(17)	(29)	8	(45)	(68)	(87)	(33)
(88)	51	—	30	(246)	161	173	221	(140)	(62)	(151)	(61)	(3,098)	346	166	417
(4)	35	(1)	8	—	10	2	5	6	3	8	8	32	51	46	46
(20)	(21)	1	—	(54)	25	37	44	20	(28)	(285)	(34)	(789)	22	(250)	43
(24)	14	—	8	(54)	35	39	49	26	(25)	(277)	(26)	(757)	73	(204)	89
(64)	37	—	22	(192)	126	134	172	(166)	(37)	126	(35)	(2,341)	273	370	328
19	23	54	23	241	196	202	129	39	39	24	36	894	868	858	812
1,287	1,663	1,656	1,604	8,691	8,799	8,462	8,768	2,747	3,356	3,507	4,315	33,122	36,612	36,154	37,374

Segmented Financial Information

	Upstream								Downstream			
	Exploration and Production[(1)]				Infrastructure and Marketing				Upgrading			
2018 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	643	1,319	1,284	1,084	530	601	634	446	307	534	444	465
Royalties	(50)	(106)	(99)	(80)	—	—	—	—	—	—	—	—
Marketing and other	—	—	—	—	148	168	187	165	—	—	—	—
Revenues, net of royalties	593	1,213	1,185	1,004	678	769	821	611	307	534	444	465
Expenses												
Purchases of crude oil and products	(1)	—	1	—	497	567	602	421	110	328	251	239
Production, operating and transportation expenses	388	398	384	357	4	2	15	2	51	52	46	46
Selling, general and administrative expenses	72	71	77	76	2	1	1	1	1	2	2	2
Depletion, depreciation, amortization and impairment	469	461	434	447	(1)	—	1	—	36	30	29	28
Exploration and evaluation expenses	53	26	40	30	—	—	—	—	—	—	—	—
Loss (gain) on sale of assets	—	2	—	(4)	—	—	—	—	—	—	—	—
Other – net	(109)	(42)	27	4	1	(1)	—	2	—	—	—	—
	872	916	963	910	503	569	619	426	198	412	328	315
Earnings (loss) from operating activities	(279)	297	222	94	175	200	202	185	109	122	116	150
Share of equity investment income (loss)	18	12	17	4	(2)	6	9	5	—	—	—	—
Financial items												
Net foreign exchange gains (losses)	—	—	—	—	—	—	—	—	—	—	—	—
Finance income	—	2	1	9	—	—	—	—	—	—	—	—
Finance expenses	(29)	(29)	(22)	(29)	—	—	—	—	—	(1)	—	—
	(29)	(27)	(21)	(20)	—	—	—	—	—	(1)	—	—
Earnings (loss) before income tax	(290)	282	218	78	173	206	211	190	109	121	116	150
Provisions for (recovery of) income taxes												
Current	(233)	(46)	(106)	(99)	193	14	84	63	40	47	36	45
Deferred	149	114	166	120	(146)	43	(27)	(11)	(11)	(14)	(4)	(4)
	(84)	68	60	21	47	57	57	52	29	33	32	41
Net earnings (loss)	(206)	214	158	57	126	149	154	138	80	88	84	109
Capital expenditures[(3)]	898	715	524	519	—	—	(15)	15	9	9	33	11
Total assets	19,175	18,410	18,263	18,070	1,301	1,529	1,519	1,417	1,149	1,308	1,275	1,270

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*
(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*
(3) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period. Includes Exploration and Production assets acquired through acquisition, and excludes assets acquired through corporate acquisition.*

Segmented Financial Information Con't

Downstream (continued)								Corporate and Eliminations[2]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
821	1,001	869	721	2,766	3,198	3,035	2,771	(173)	(521)	(470)	(390)	4,894	6,132	5,796	5,097
—	—	—	—	—	—	—	—	—	—	—	—	(50)	(106)	(99)	(80)
—	—	—	—	—	—	—	—	—	—	—	—	148	168	187	165
821	1,001	869	721	2,766	3,198	3,035	2,771	(173)	(521)	(470)	(390)	4,992	6,194	5,884	5,182
637	834	711	578	2,523	2,741	2,565	2,505	(173)	(521)	(470)	(390)	3,593	3,949	3,660	3,353
67	66	72	60	193	222	217	163	(2)	—	—	—	701	740	734	628
11	12	11	13	5	5	7	5	21	96	88	72	112	187	186	169
29	29	28	29	102	129	125	94	27	23	22	20	662	672	639	618
—	—	—	—	—	—	—	—	—	—	—	—	53	26	40	30
—	(2)	—	—	—	—	—	—	—	—	—	—	—	—	—	(4)
(1)	—	—	—	(334)	(107)	(29)	6	1	—	(9)	—	(442)	(150)	(11)	12
743	939	822	680	2,489	2,990	2,885	2,773	(126)	(402)	(369)	(298)	4,679	5,424	5,248	4,806
78	62	47	41	277	208	150	(2)	(47)	(119)	(101)	(92)	313	770	636	376
—	—	—	—	—	—	—	—	—	—	—	—	16	18	26	9
—	—	—	—	—	—	—	—	(2)	(9)	3	22	(2)	(9)	3	22
—	—	—	—	—	—	—	—	16	13	12	11	16	15	13	20
(3)	(3)	(3)	(3)	(3)	(4)	(3)	(4)	(41)	(43)	(46)	(48)	(76)	(80)	(74)	(84)
(3)	(3)	(3)	(3)	(3)	(4)	(3)	(4)	(27)	(39)	(31)	(15)	(62)	(74)	(58)	(42)
75	59	44	38	274	204	147	(6)	(74)	(158)	(132)	(107)	267	714	604	343
41	15	19	25	3	2	2	2	(18)	(19)	(17)	(18)	26	13	18	18
(21)	1	(7)	(15)	58	44	30	(3)	(4)	(32)	(20)	(10)	25	156	138	77
20	16	12	10	61	46	32	(1)	(22)	(51)	(37)	(28)	51	169	156	95
55	43	32	28	213	158	115	(5)	(52)	(107)	(95)	(79)	216	545	448	248
22	23	18	11	296	196	118	55	40	25	30	26	1,265	968	708	637
1,431	1,578	1,578	1,547	8,566	8,209	8,003	7,926	3,603	3,641	3,354	3,057	35,225	34,675	33,992	33,287