MANAGEMENT'S DISCUSSION AND ANALYSIS

1.0 Financial Summary

Selected Annual Information *($ millions, except where indicated)*	**2018**	2017	2016
Gross revenues and Marketing and other	**22,587**	18,946	13,224
Net earnings (loss) by business segment			
Upstream	**790**	260	1,091
Downstream	**1,000**	448	342
Corporate	**(333)**	78	(511)
Net earnings	**1,457**	786	922
Net earnings per share – basic	**1.41**	0.75	0.88
Net earnings per share – diluted	**1.40**	0.75	0.88
Cash flow – operating activities	**4,134**	3,704	1,971
Funds from operations(1)	**4,004**	3,306	2,198
Ordinary dividends per common share	**0.450**	0.075	—
Dividends per cumulative redeemable preferred share, series 1	**0.60**	0.60	0.73
Dividends per cumulative redeemable preferred share, series 2	**0.74**	0.57	0.42
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	**35,225**	32,927	32,260
Total debt(2)	**5,747**	5,440	5,339
Net debt(2)	**2,881**	2,927	4,020

(1) *Funds from operations is a non-GAAP measure. The calculation of funds from operations changed in the second quarter of 2017. Prior periods have been revised to conform with the current period presentation. 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 a Canadian 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 focus on returns from investment in a deep portfolio of opportunities that can generate increased cash flow from operating activities and funds from operations.

The Company has two main businesses: (i) an integrated Canada-U.S. Upstream and Downstream corridor ("Integrated Corridor"); and (ii) production located offshore the east coast of Canada ("Atlantic") and offshore China and Indonesia ("Asia Pacific") (Atlantic and Asia Pacific collectively, "Offshore").

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 percent working interest and operatorship), and the Lima, Toledo (50 percent working interest) and Superior refineries 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 Atlantic and Asia Pacific. Each area generates high-netback production, with near and long-term investment potential.

2.2 Operations Overview and 2018 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 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.

On January 16, 2019, the Company announced that its offer to acquire all of the outstanding common shares of MEG Energy Corp. expired, as the minimum tender threshold was not satisfied, and the Company decided not to extend its offer.

Exploration and Production

Thermal Developments

The Company continued to advance its inventory of thermal projects in 2018. These long-life developments are being built with modular, repeatable designs and require low sustaining capital once brought online.

Total bitumen production, including Lloyd thermal projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 124,200 bbls/day in 2018.

Lloyd Thermal Projects

The Company is phasing execution of its long-life thermal projects to optimize capital efficiency and project execution. In 2018, the Company completed two land deals to create two Thermal hubs, one at Spruce Lake, and one at Dee Valley. This has resulted in the expectation that the Edam Central project will be completed in 2022, rather than the previously disclosed timeframe of late 2021, and in Westhazel being reprioritized.

The following table shows major projects and their status as at December 31, 2018:

Project Name	Estimated Production (bbls/day)	Expected Project Production Date	Project Status
Rush Lake 2	10,000	First quarter of 2019	Completed ahead of schedule with first production achieved in October 2018 and nameplate capacity of 10,000 bbls/day reached in November 2018.
Dee Valley	10,000	Fourth quarter of 2019	Work continued, with drilling of the second well pad completed and construction of the Central Processing Facility ("CPF") continuing ahead of schedule. As of the end of 2018, the CPF was 80 percent complete.
Spruce Lake Central	10,000	2020	Construction of the CPF commenced in 2018.
Spruce Lake North	10,000	Around the end of 2020	Site clearing was completed in 2018.
Spruce Lake East	10,000	Around the end of 2021	Sanctioned in November 2018, with regulatory approval received in 2019. Prioritized ahead of Westhazel.
Edam Central	10,000	2022	Regulatory permit was received in early January 2019.
Dee Valley 2	10,000	2023	Regulatory applications were submitted in 2018, with approval expected in 2019.
Westhazel	10,000	Reprioritized	Regulatory applications were submitted in 2018, with approval expected in 2019. Reprioritized in order to optimize thermal sequence.

In February 2019, the Pike's Peak thermal bitumen plant was closed down as it reached the end of its useful life. The plant achieved first production in September 1981 and produced 78 mmbbls over its useful life.

Tucker Thermal Project

Work to debottleneck the CPF and Tucker field was completed in the third quarter of 2018. Subsequently, production ramped up and nameplate capacity of 30,000 bbls/day was achieved in October 2018, with a daily production record of 31,700 bbls/day achieved in late November. Production for 2018 and December 2018 averaged 22,400 bbls/day and 27,500 bbls/day, respectively.

Production in 2019 is expected to be impacted by government-mandated production curtailment in Alberta. While specific volume reductions are uncertain, production in the first quarter of 2019 could be impacted by as much as 5,000 bbls/day.

Sunrise Energy Project

Total annual production in 2018 averaged 50,000 bbls/day (25,000 bbls/day Husky working interest). During the fourth quarter of 2018, maintenance activities were completed and the project reached its nameplate capacity of 60,000 bbls/day. Record production of 62,600 bbls/day was achieved in late December. December production averaged 59,000 bbls/day (29,500 bbls/day Husky working interest).

Production in 2019 is expected to be impacted by government-mandated production curtailment in Alberta. While specific volume reductions are uncertain, production in the first quarter of 2019 could be impacted by as much as 15,000 bbls/day (7,500 bbls/day Husky working interest).

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 2019 is expected to be impacted by government-mandated production curtailment in Alberta.

Cold and Enhanced Oil Recovery
In 2018, the Company sanctioned a full field polymer injection project at Aberfeldy and has opportunities to expand to other areas.

During the year, the Company operated five carbon dioxide ("CO_2") injection enhanced oil recovery ("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 Lashburn facility in Saskatchewan.

Western Canada
The Company continues to execute its resource play strategy in Western Canada to advance developments in the Spirit River (predominantly Wilrich) and Montney formations.

Oil and Natural Gas Resource Plays
A drilling program targeting the Spirit River Formation, in the Ansell and Kakwa areas, continued with 21 wells drilled in 2018, and 25 completed.

A drilling program targeting the oil and liquids-rich gas Montney Formation in the Wembley and Karr areas is continuing with seven wells drilled in 2018, and six completed.

Asia Pacific
The Company's Asia Pacific business produces natural gas and NGL in the South China Sea and the Madura Strait offshore Indonesia. Natural gas is sold into the South China and East Java markets under long-term contracts with set prices that include escalation factors. NGL in both regions are sold at market prices.

The Company's interests include 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 consists of the operating BD field, the MDA, MBH, MDK and MAC developments and three additional discoveries. The Company has rights to additional exploration blocks offshore Taiwan and Indonesia, and has signed a Strategic Cooperation Agreement with China National Offshore Oil Corporation Limited ("CNOOC") on two offshore areas in the northern part of the South China Sea for additional exploration opportunities in the future.

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 79,900 boe/day (39,200 boe/day Husky working interest) in 2018. Production consisted of natural gas production of 377 mmcf/day and NGL production of 17,100 bbls/day.

Construction continues at Liuhua 29-1, the third deepwater gas field of the Liwan Gas Project. All of the major contracts have been executed and detailed design work is underway. The Environment Impact Assessment was approved by the Ministry of Ecology and Environment in January 2019. Drilling of the remaining three wells is expected to commence in the first quarter of 2019, which will add to the four previously drilled wells. First gas production from this seven-well development is expected around the end of 2020, with target production of 45 mmcf/day of natural gas (Husky working interest) and 1,800 bbls/day of NGL (Husky working interest) when fully ramped up. The Company holds a working interest of 75 percent in this field development.

Blocks 15/33 and 16/25
The Company is progressing commercial development plans following the successful drilling and testing of an exploration well on Block 15/33.

During the third quarter of 2018, the Company drilled one exploration well at the nearby exploration Block 16/25 which encountered non-commercial hydrocarbons. Additional evaluation work is being conducted and a second exploration well may be drilled in the 2020 timeframe.

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

Blocks 22/11 and 23/07
The Company and CNOOC signed two Production Sharing Contracts ("PSCs") for Blocks 22/11 and 23/07 in the Beibu Gulf area of the South China Sea in the first half of 2018. The Company is the operator of both blocks with a working interest of 100 percent during the exploration phase. In the event of a commercial discovery, CNOOC may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases.

Block DW-1
During 2017, on Block DW-1 offshore Taiwan, the Company completed the acquisition of three-dimensional seismic survey data. Analysis of the data is ongoing to identify potential drilling prospects on the block.

Indonesia

Madura Strait
The BD Project achieved its total daily sales target of 100 mmcf/day of natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGL (2,400 bbls/day Husky working interest) in the third quarter of 2018. Total natural gas production averaged 78 mmcf/day (31 mmcf/day Husky working interest) and NGL production averaged 6,200 bbls/day (2,500 bbls/day Husky working interest) in 2018.

At the MDA and MBH fields, the two shallow water platforms have been fully installed and preparations are underway to drill the five MDA and two MBH field production wells in 2019. Gas production and sales are expected to commence in the 2020 timeframe, following completion of the Floating Production Unit ("FPU") which will be used to process and compress the gas. Subsequently, an additional shallow water field, named MDK, is scheduled to be developed and tied into the FPU. The processed gas from these three fields will be tied directly into the East Java subsea pipeline system and sold to the East Java market under long-term contracts with set prices that include escalation factors.

Pre-engineering activities and approvals progressed at the MAC field, where an approved Plan of Development is in place. Additional discoveries in the region are being evaluated for potential development.

Anugerah
During 2015, the Company acquired two-dimensional and three-dimensional seismic survey data on the contract area, which was required during the first three years of the PSC. An analysis of that data and offset block information indicates that drilling is not economic and the block will be relinquished.

Atlantic

The Company's Atlantic portfolio has short and long-term opportunities that provide for high return production growth off the coast of Newfoundland and Labrador.

White Rose Field and Satellite Extensions
Project activity continues to ramp-up on the West White Rose Project. Construction of the concrete gravity structure began in the first half of 2018 at the purpose-built graving dock in Argentia, Newfoundland and Labrador. The structure's base slab was completed in mid-September and the structure was poured to a height of 46 metres during the 2018 construction season. First production is expected in 2022.

The Company continues to progress a subsea program to offset natural reservoir declines through infill drilling and workover operations at the White Rose field and satellite extensions. During the third quarter of 2018, two well workovers were completed. Two additional infill wells are being completed and are expected to be brought online before mid-year 2019, instead of the previously stated timeframe of the fourth quarter of 2018.

In late January 2019, the Company began a staged ramp-up of production at the White Rose field. The field had been shut-in since mid-November, after a flowline connector failed near the South White Rose Extension, causing a spill of approximately 250 cubic metres of oil. The Company and its certifying authority have completed inspections of the *SeaRose* floating production, storage and offloading ("FPSO") vessel as well as subsea infrastructure. Regulatory approval has been received for plans to recover the damaged flowline connector. An investigation into the cause of the incident is underway.

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 and further delineation in the area is planned. The Company has a 68.875 percent ownership interest, with partners Suncor Energy and Nalcor Energy Oil and Gas holding 26.125 percent and five percent, 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, accessing markets through Husky's Upgrader and Asphalt Refinery. 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 commenced construction of the Ansell Corser Gas Plant.

LLB Direct – Cold Lake Gathering System to Hardisty
LLB Direct Pipeline and an associated 300,000-barrel operational tank at Hardisty came online in the fourth quarter of 2018, fulfilling an important component of HMLP's growth strategy in the Lloydminster region. The 20-inch line, with an initial 100,000 bbl/day capacity, provides the Company and third-party customers on the Cold Lake Gathering System with direct access to Hardisty, while simultaneously relieving congestion on the mainline system between Lloydminster and Hardisty.

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 under construction and is expected to add 120 mmcf/day of processing capacity when it is scheduled to come online in the fourth quarter of 2019.

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 also 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 Lloydminster Upgrader, and its Ohio and Wisconsin refineries.

Downstream Operations

Downstream operations in the Integrated Corridor in Canada include upgrading of heavy crude oil feedstock into synthetic crude oil ("Upgrading"), refining crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol ("Canadian Refined Products"). It also includes refining of crude oil 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 flexibility in 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 the margin on refined product pricing for its Western Canada heavy oil, bitumen and light oil production and assists in mitigating market volatility.

Upgrading

The heavy oil upgrading facility, located in Lloydminster, Saskatchewan, has a throughput capacity of 82,000 bbls/day. The Lloydminster 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 Lloydminster 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 29,000 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 combined capacity of 260 million litres per year.

Prince George Refinery
The Prince George Refinery in British Columbia has a throughput capacity of 12,000 bbls/day and produces low sulphur gasoline and ultra-low sulphur diesel.

On January 8, 2019, the Company announced its intention to market and potentially sell the Prince George Refinery.

Retail and Commercial Network

The Company is a major regional motor fuel marketer with an average of 557 retail marketing locations in 2018, 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 Retail and Commercial Network.

U.S. Refining and Marketing

Lima Refinery

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

In 2016, the Company completed the first stage of the crude oil flexibility project and the refinery is now able to process up to 10,000 bbls/day of heavy crude oil feedstock. The project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from western Canada when completed, providing the ability to swing between light and heavy crude oil feedstock.

The timing of completion for the crude oil flexibility project is expected to be late 2019. This schedule coordinates project work with normal maintenance to provide higher levels of sustained production.

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 percent by the Company and 50 percent 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 content naphthenic acids ("high-TAN") crude oil to support production from the Sunrise Energy Project. The refinery's nameplate capacity remained unchanged.

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.

2.3 Superior Refinery Incident

On April 26, 2018, the Superior Refinery experienced an incident while preparing for a major turnaround. Operations at the refinery remain suspended. An engineering contractor has been appointed to oversee design work and rebuild of the refinery. The rebuild will commence once design work is complete and permits are obtained. Operations are expected to resume in 2020.

As at December 31, 2018, the Company derecognized $56 million of assets damaged in the incident in the U.S. Refining and Marketing segment. In addition, the Company accrued pre-tax insurance recoveries for property damage, rebuild costs, business interruption and clean-up costs associated with the incident of $468 million.

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. The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. Debt to funds from operations and debt to capital employed are both non-GAAP measures (refer to Sections 6.4 and 9.3). The Company is committed to retaining its investment grade credit ratings to support access to debt capital markets. The Company 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 in Western Canada and the continued transition to higher margin production. Refer to Section 6.0 for additional information on the Company's liquidity and capital resources.

On February 28, 2018, the Board of Directors reinstated the quarterly common share cash dividend of $0.075 per share. On July 26, 2018, the quarterly common share cash dividend was increased to $0.125 per share.

3.0 The 2018 Business Environment

The Company's operations were significantly influenced by domestic and international factors in 2018, including, but not limited to, the following:

- Global crude oil benchmarks strengthened in the first half of 2018 due to market rebalancing, but weakened towards the end of the year due to record levels of oil production from the world's largest producers leading to increased global inventories, combined with uncertainties regarding future global demand.
- North American natural gas benchmarks continued to be weak in 2018 due to infrastructure constraints combined with lower demand for Canadian natural gas in the U.S. as a result of increased U.S. shale oil production.
- A continued emphasis on the environment, the impacts of climate change, health and safety, 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 a strong infrastructure 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.
- On December 2, 2018, the Government of Alberta set province-wide mandatory oil production cuts in an attempt to rebalance the market. This curtailment was effective as of January 1, 2019, and is expected to continue through 2019.
- Alternative and improved extraction methods have rapidly evolved in North American and international onshore and offshore activity.

Major business factors are considered in the formulation of the Company's short and long-term business strategy.

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, 2018.

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		2018	2017
West Texas Intermediate ("WTI") crude oil[1]	*(US$/bbl)*	**64.77**	50.95
Brent crude oil[2]	*(US$/bbl)*	**70.97**	54.28
Light sweet at Edmonton	*($/bbl)*	**69.31**	62.91
WCS at Hardisty[3]	*(US$/bbl)*	**38.46**	38.98
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**39.33**	44.36
WTI/Lloyd crude blend differential	*(US$/bbl)*	**26.09**	11.76
Condensate at Edmonton	*(US$/bbl)*	**60.95**	51.57
NYMEX natural gas[4]	*(US$/mmbtu)*	**3.09**	3.11
Nova Inventory Transfer ("NIT") natural gas	*($/GJ)*	**1.45**	2.30
Chicago Regular Unleaded Gasoline	*(US$/bbl)*	**78.07**	66.22
Chicago Ultra-low Sulphur Diesel	*(US$/bbl)*	**87.08**	69.05
Chicago 3:2:1 crack spread	*(US$/bbl)*	**15.94**	16.31
U.S./Canadian dollar exchange rate	*(US$)*	**0.772**	0.771
Canadian $ Equivalents[5]			
WTI crude oil	*($/bbl)*	**83.90**	66.08
Brent crude oil	*($/bbl)*	**91.93**	70.40
WCS at Hardisty	*($/bbl)*	**49.82**	50.56
WTI/Lloyd crude blend differential	*($/bbl)*	**33.80**	15.25
NYMEX natural gas	*($/mmbtu)*	**4.00**	4.03

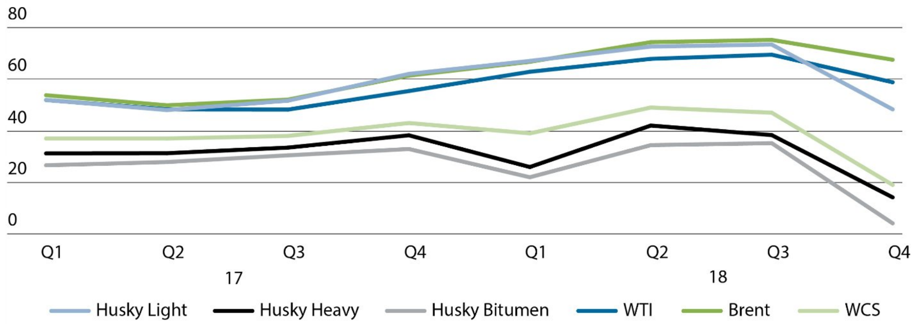
(1) *Calendar month average of settled prices for WTI at Cushing, Oklahoma.*
(2) *Calendar month average of settled prices for Dated Brent.*
(3) *WCS is a heavy blended crude oil, comprised of conventional and bitumen crude oils blended with diluent which terminals at Hardisty, Alberta. Quoted prices 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 price. 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 fixed long-term sales contracts.

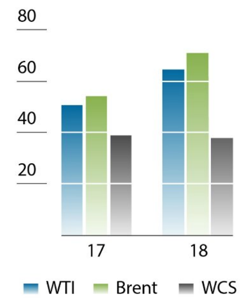
The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil and bitumen. In the Upgrading business, heavy crude oil feedstock is processed into light synthetic 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 62 percent heavy crude oil and bitumen feedstock at the BP-Husky Toledo Refinery. The Company's Retail and Commercial Network relies primarily on supply contracts to purchase refined products for resale in the retail distribution network, as well as production from the Prince George Refinery and 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)



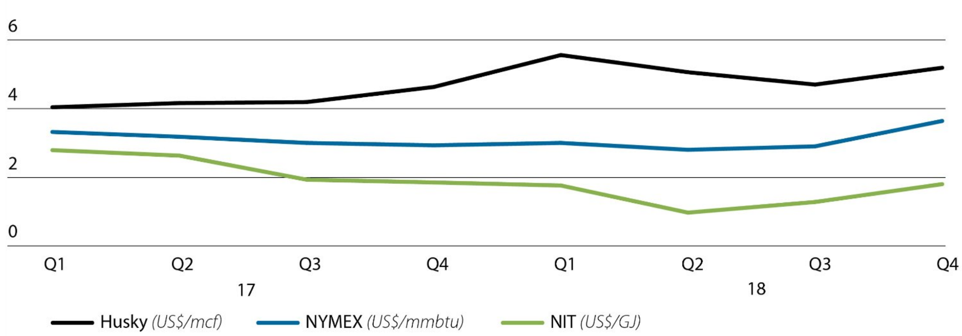
Global crude oil benchmarks strengthened in the first half of 2018 due to market rebalancing, but weakened towards the end of the year due to record levels of oil production from the world's largest producers leading to increased global inventories, combined with uncertainties regarding future global demand. Furthermore, the WCS benchmark weakened towards the end of 2018 primarily due to an oversupply of Canadian crude oil resulting from continued transportation constraints. Consequently the WCS benchmark traded at a greater discount compared to other North American benchmarks. WTI averaged US$64.77/bbl in 2018 compared to US$50.95/bbl in 2017. Brent averaged US$70.97/bbl in 2018 compared to US$54.28/bbl in 2017. WCS averaged US$38.46/bbl in 2018 compared to US$38.98/bbl in 2017.

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. 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 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 75 percent heavy crude oil and bitumen in 2018 compared to 70 percent in 2017.

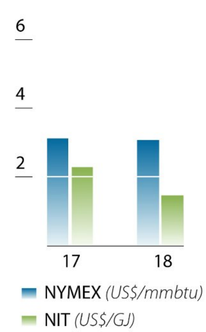
The Company's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate. The price of condensate at Edmonton increased in 2018 compared to 2017, primarily due to the increase in crude oil benchmark pricing.

Natural Gas Benchmarks

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



Average NYMEX and NIT



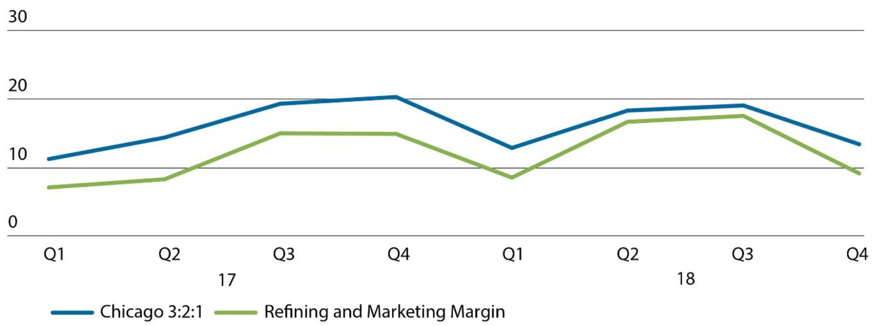
The price received by the Company for natural gas production from Western Canada is primarily driven by the NIT near-month contract price of natural gas, while the price received by the Company for production from Asia Pacific is determined by long-term contracts that include escalation factors.

The NIT natural gas price benchmark decreased in 2018 compared to 2017, primarily due to the continued oversupply of natural gas in North America.

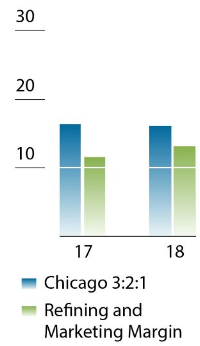
North American natural gas is consumed internally by the Company's Upstream and Downstream operations, helping to mitigate the impact of weak natural gas benchmark prices on results.

Refining Benchmarks

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



Average Crack Spread
(US$/bbl)



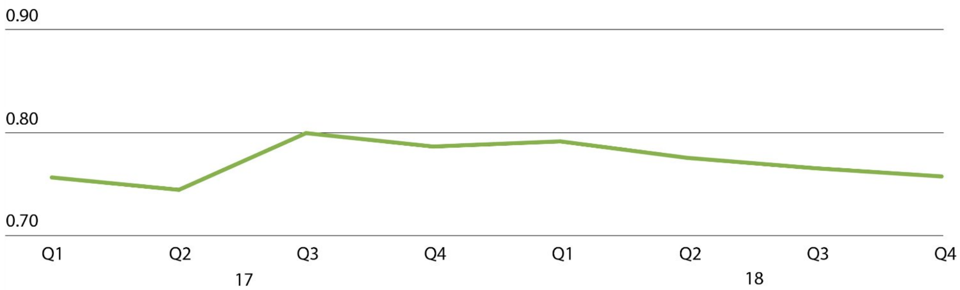
The Chicago 3:2:1 crack spread is a key indicator for U.S. refining margins and reflects refinery gasoline output that is approximately twice the distillate output, and is calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of distillate fuel less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not reflect the actual crude purchase costs or the product configuration of a specific refinery. The Chicago Regular Unleaded Gasoline and the Chicago Ultra-low Sulphur Diesel average benchmark prices are the standard products included in the Chicago 3:2:1 crack spread. The Chicago 3:2:1 crack spread is based on last in first out ("LIFO") accounting, which is a non-GAAP measure (refer to Section 9.3).

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

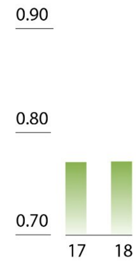
The Company's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil. The product slates produced at the Lima, BP-Husky Toledo and Superior refineries contain between 13 and 38 percent 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

Average U.S./Canadian Dollar Exchange Rate
(US$ per Cdn$)



Average U.S./Canadian Dollar Exchange Rate
(US$ per Cdn$)



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$0.772 in 2018 compared to US$0.771 in 2017.

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 RMB relative to the Canadian dollar will increase the revenues received in Canadian dollars from the sale of natural gas commodities in the region. The Canadian dollar averaged RMB 5.104 in 2018 compared to RMB 5.208 in 2017.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in 2018 on earnings before income taxes and net earnings. The table below reflects what the expected effect would have been on the financial results for 2018 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2018. 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	2018 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]	**64.77**	*US$1.00/bbl*	**96**	**0.10**	**70**	**0.07**
NYMEX benchmark natural gas price[5]	**3.09**	*US$0.20/mmbtu*	**—**	**—**	**—**	**—**
WTI/Lloyd crude blend differential[6]	**26.09**	*US$1.00/bbl*	**(7)**	**(0.01)**	**(5)**	**(0.01)**
Canadian asphalt margins	**27.82**	*Cdn $1.00/bbl*	**10**	**0.01**	**8**	**0.01**
Canadian light oil margins	**0.042**	*Cdn $0.005/litre*	**14**	**0.01**	**10**	**0.01**
Chicago 3:2:1 crack spread	**15.94**	*US$1.00/bbl*	**112**	**0.11**	**87**	**0.09**
Exchange rate (US $ per Cdn $)[3][7]	**0.772**	*US$0.01*	**(59)**	**(0.06)**	**(44)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as of December 31, 2018.*
(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.*

4.0 Results of Operations

4.1 Segment Earnings

Segmented Earnings	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[1]	
($ millions)	**2018**	2017	**2018**	2017	**2018**	2017
Upstream						
Exploration and Production	**288**	239	**223**	174	**2,656**	1,476
Infrastructure and Marketing	**780**	118	**567**	86	**—**	—
Downstream						
Upgrading	**496**	151	**361**	110	**62**	230
Canadian Refined Products	**216**	142	**158**	104	**74**	87
U.S. Refining and Marketing	**619**	371	**481**	234	**665**	313
Corporate	**(471)**	(597)	**(333)**	78	**121**	114
Total	**1,928**	424	**1,457**	786	**3,578**	2,220

[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)*	**2018**	2017
Gross revenues	**4,330**	4,978
Royalties	**(335)**	(363)
Net revenues	**3,995**	4,615
Production, operating and transportation expenses	**1,527**	1,650
Selling, general and administrative expenses	**296**	265
Depletion, depreciation, amortization and impairment ("DD&A")	**1,811**	2,237
Exploration and evaluation expenses	**149**	146
Gain on sale of assets	**(2)**	(42)
Other – net	**(120)**	6
Share of equity investment gain	**(51)**	(12)
Financial items	**97**	126
Provisions for income taxes	**65**	65
Net earnings	**223**	174

Exploration and Production net revenues decreased by $620 million in 2018 compared to 2017, primarily due to lower average realized sales prices combined with lower production, both of which are described in more detail below.

Selling, general and administrative expenses increased by $31 million in 2018 compared to 2017, primarily due to higher employee costs.

Gain on sale of assets decreased by $40 million in 2018 compared to 2017, primarily due to the disposition of select legacy assets in Western Canada in 2017.

Other – net for Exploration and Production increased by $126 million in 2018 compared to 2017, primarily due to profit or loss elimination between segments.

Share of equity investment gain increased by $39 million in 2018 compared to 2017, primarily due to the investment in the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method. The BD Project reached first production in the third quarter of 2017.

Financial items decreased by $29 million in 2018 compared to 2017, primarily due to higher capitalized interest expense due to thermal projects and West White Rose project.

Average Sales Prices Realized

Average Sales Prices Realized	2018	2017
Crude oil and NGL *($/bbl)*		
Light & Medium crude oil	**83.71**	67.36
NGL[(1)]	**55.72**	44.18
Heavy crude oil	**39.26**	43.38
Bitumen	**30.17**	38.20
Total crude oil and NGL average	**42.16**	46.09
Natural gas average *($/mcf)*[(1)]	**6.64**	5.52
Total average *($/boe)*	**41.50**	42.47

(1) *Reported average NGL and natural gas prices include Husky's working interest production from the BD Project (40 percent). 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 decreased by nine percent in 2018 compared to 2017, primarily due to widening of the Canadian light/heavy oil differential.

The average sales prices realized by the Company for natural gas increased by 20 percent in 2018 compared to 2017. The increase was primarily due to a higher percentage of fixed priced natural gas production from both the Liwan Gas Project and BD Project relative to total natural gas production.

Daily Gross Production

Daily Gross Production	2018	2017
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light and Medium crude oil	**9.4**	12.1
NGL	**12.0**	10.5
Heavy crude oil	**36.8**	44.4
Bitumen[(1)]	**124.2**	119.1
	182.4	186.1
Atlantic		
White Rose and Satellite Fields – light crude oil	**17.4**	30.0
Terra Nova – light crude oil	**4.0**	4.0
	21.4	34.0
Asia Pacific		
Wenchang – light crude oil	**—**	5.3
Liwan and Wenchang – NGL[(2)]	**8.4**	7.0
Madura – NGL[(3)]	**2.5**	0.6
	10.9	12.9
	214.7	233.0
Natural gas *(mmcf/day)*		
Western Canada	**291.0**	378.2
Asia Pacific		
Liwan[(2)]	**184.8**	152.9
Madura[(3)]	**31.2**	8.0
	216.0	160.9
	507.0	539.1
Total *(mboe/day)*	**299.2**	322.9

(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 percent).*
(3) *Reported production volumes include Husky's working interest production from the BD Project (40 percent). 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 18.3 mbbls/day, or eight percent, in 2018 compared to 2017. The decrease was primarily due to lower production in Atlantic due to the suspension of operations on the *SeaRose* FPSO vessel in January and November 2018, a high water cut well at North Amethyst combined with natural well declines, a reduction of heavy crude oil production due to natural declines and reduced optimization activities in the Company's non-thermal developments, lower crude oil production in Asia Pacific due to the expiry of the Company's participation in the Wenchang oilfield PSC in late 2017, and lower production in Western Canada as a result of the disposition of select legacy assets in 2017. The decreases were partially offset by increased bitumen production from the Company's thermal projects, combined with increased NGL production in Asia Pacific and Western Canada.

Natural Gas Production

Natural gas production decreased by 32.1 mmcf/day, or six percent, in 2018 compared to 2017. In Western Canada, natural gas production decreased by 87.2 mmcf/day, primarily due to the disposition of select legacy assets in 2017. In Asia Pacific, natural gas production increased by 55.1 mmcf/day, primarily due to increased gas demand at the Liwan Gas Project and higher production from the BD Project.

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	**2018**	2017
Crude oil and NGL		
Light & Medium crude oil	**22**	25
NGL[(1)]	**10**	6
Heavy crude oil	**11**	14
Bitumen	**29**	33
Crude oil and NGL	**72**	78
Natural gas[(1)]	**28**	22
Total	**100**	100

(1) *Reported average NGL and natural gas revenue include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

2019 Production Guidance and 2018 Actual

	Guidance	**Year ended December 31**	Guidance
Gross Production	2019	**2018**	2018
Canada			
Light & Medium crude oil *(mbbls/day)*	29 - 31	**31**	35 - 36
NGL *(mbbls/day)*	12 - 13	**12**	10 - 11
Heavy crude oil & bitumen *(mbbls/day)*	155 - 163	**161**	162 - 164
Natural gas *(mmcf/day)*	297 - 307	**291**	285 - 290
Canada total *(mboe/day)*	246 - 258	**252**	255 - 259
Asia Pacific			
Light crude oil *(mbbls/day)*	3 - 3	**—**	0 - 0
NGL *(mbbls/day)*[(1)]	6 - 7	**11**	10 - 11
Natural gas *(mmcf/day)*[(1)]	210 - 220	**216**	210 - 215
Asia Pacific total *(mboe/day)*	44 - 47	**47**	45 - 46
Total *(mboe/day)*	290 - 305	**299**	300 - 305

(1) *Includes Husky's working interest production from the BD Project (40 percent). 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, 2018 was marginally under the production guidance, primarily due to the factors that impacted crude oil and NGL production discussed above. The expected total production volumes in 2019 will remain comparable to 2018 after factoring in the reductions associated with Government of Alberta curtailment and partial suspension of operations at the White Rose field in Atlantic. The 2019 production guidance reflects curtailment affecting production at the Tucker Thermal Project, the Sunrise Energy Project and the conventional heavy oil business.

Factors that could potentially impact the Company's production performance in 2019 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 increases in commodity pricing, which may result in the decision to accelerate near-term growth projects, or 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, blowouts, 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)*	**2018**	2017
Western Canada	**9**	7
Atlantic	**8**	9
Asia Pacific[1]	**7**	6
Total	**8**	7

[1] *Reported royalties include Husky's working interest from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for interim financial statement purposes.*

Royalty rates for Western Canada increased by two percent in 2018 compared to 2017, primarily due to higher WTI prices for the majority of 2018. Royalty rates for Atlantic decreased by one percent in 2018 compared to 2017, primarily due to lower production combined with higher eligible costs. Royalty rates for Asia Pacific increased by one percent in 2018 compared to 2017, primarily due to higher production from the BD Project which has higher royalty rates than the Liwan Gas Project.

Operating Costs

Operating Costs *($ millions)*	**2018**	2017
Western Canada	**1,218**	1,331
Atlantic	**213**	213
Asia Pacific	**95**	94
Total	**1,526**	1,638
Per unit operating costs *($/boe)*	**14.00**	13.93

Total Exploration and Production operating costs were $1,526 million in 2018 compared to $1,638 million in 2017. Total per unit operating costs averaged $14.00/boe in 2018 compared to $13.93/boe in 2017. The increase in per unit operating costs was primarily due to the factors discussed below.

Per unit operating costs in Atlantic averaged $27.21/bbl in 2018 compared to $17.12/bbl in 2017. The increase in per unit operating costs was primarily due to lower production.

Per unit operating costs in Western Canada averaged $14.48/boe in 2018 compared to $14.67/boe in 2017. The decrease in per unit operating costs was primarily due to lower energy costs and the continued ramp-up at the Sunrise Energy Project.

Per unit operating costs in Asia Pacific averaged $5.53/boe in 2018 compared to $6.47/boe in 2017. The decrease in per unit operating costs was primarily due to higher production at the Liwan Gas and BD projects.

Exploration and Evaluation Expenses

Exploration and Evaluation Expenses *($ millions)*	2018	2017
Seismic, geological and geophysical	**102**	113
Expensed drilling	**41**	22
Expensed land	**6**	11
Total	**149**	146

Exploration and Evaluation expenses were $149 million in 2018 compared to $146 million in 2017.

Depletion, Depreciation, Amortization and Impairment

DD&A expense decreased by $426 million in 2018 compared to 2017, primarily due to lower production in 2018, the recognition of a pre-tax impairment charge of $173 million in 2017, and additional heavy oil and bitumen reserves bookings in the fourth quarter of 2017. In 2018, total DD&A excluding impairment averaged $16.99/boe compared to $17.61/boe in 2017.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were higher in 2018 compared to 2017, reflecting increased spending across the portfolio. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[1] *($ millions)*	2018	2017
Exploration		
Western Canada	**99**	63
Thermal developments	**7**	8
Atlantic	**73**	67
Asia Pacific[2]	**52**	10
	231	148
Development		
Western Canada	**332**	196
Thermal developments	**874**	534
Non-thermal developments	**110**	106
Atlantic	**916**	417
Asia Pacific[2]	**148**	2
	2,380	1,255
Acquisitions		
Western Canada	**4**	25
Thermal developments	**41**	48
	45	73
Total	**2,656**	1,476

(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 2018, $435 million (16 percent) was invested in Western Canada compared to $284 million (19 percent) in 2017. Capital expenditures in 2018 related primarily to resource play development targeting the Spirit River Formation in the Ansell and Kakwa areas and the Montney Formation in the Wembley and Karr areas.

Thermal Developments

During 2018, $922 million (35 percent) was invested in thermal developments compared to $590 million (40 percent) in 2017. Capital expenditures in 2018 related primarily to the development of the Rush Lake 2 Thermal Project, and construction work at the Dee Valley and Spruce Lake Central thermal projects.

Non-Thermal Developments

During 2018, $110 million (four percent) was invested in non-thermal developments compared to $106 million (seven percent) in 2017. Capital expenditures in 2018 related primarily to sustainment activities.

Atlantic

During 2018, $989 million (37 percent) was invested in Atlantic compared to $484 million (33 percent) in 2017. Capital expenditures in 2018 related primarily to the development of the West White Rose Project and sustainment and development activities at the White Rose field and satellite extensions.

Asia Pacific

During 2018, $200 million (eight percent) was invested in Asia Pacific compared to $12 million (one percent) in 2017. Capital expenditures in 2018 related primarily to the continued development of Liuhua 29-1, and the exploration of Blocks 15/33 and 16/25.

Exploration and Production Wells Drilled

Onshore Drilling Activity

The following table discloses the number of wells drilled during 2018 and 2017:

	2018		2017	
Wells Drilled *(wells)*[1]	Gross	Net	Gross	Net
Thermal developments	**150**	**140**	64	64
Non-thermal developments	**31**	**26**	29	27
Western Canada	**46**	**45**	36	33
Total	**227**	**211**	129	124

[1] *Excludes service/stratigraphic test wells for evaluation purposes.*

Thermal developments consisted of drilling and completion activity related to the Sunrise Energy Project and the Dee Valley and Spruce Lake Central thermal projects. Western Canada drilling and completion activity increased primarily due to a drilling program targeting the Spirit River Formation in the Ansell and Kakwa areas, as well as a drilling program targeting the Montney Formation in the Wembley and Karr areas.

Offshore Drilling Activity

The following table discloses the Company's Offshore drilling activity during 2018:

Region	Well	Working Interest	Well Type
Atlantic	North Amethyst G-25 11	68.875 percent	Development
Atlantic	White Rose A-24	68.875 percent	Exploration
Asia Pacific	Block 15/33 XJ 34-3-2	100 percent	Exploration
Asia Pacific	Block 15/33 PY 3-6-1	100 percent	Exploration
Asia Pacific	Block 16/25 HZ 25-7-4	100 percent	Exploration

2019 Upstream Capital Expenditures Program

2019 Upstream Capital Expenditures Program *($ millions)*	
Thermal developments	**730 - 760**
Non-thermal developments	**100 - 110**
Western Canada	**180 - 190**
Atlantic	**1,120 - 1,190**
Asia Pacific[1]	**350 - 370**
Total Upstream capital expenditures	**2,480 - 2,620**

[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 2019 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 as well as the Ansell resource play in Western Canada. 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 $730 - $760 million in thermal developments for 2019, primarily for the development of the Dee Valley, Spruce Lake North and Spruce Lake Central thermal bitumen projects. Capital expenditures will also take place in support of environmental and regulatory work on Spruce Lake East which was sanctioned in the fourth quarter of 2018. The Company is making progress in its strategy to transition a greater percentage of production to long-life thermal bitumen production and the 2019 Upstream capital expenditures program will continue to build on this momentum.

The Company has budgeted $100 - $110 million in non-thermal developments for 2019, primarily for sustainment activities.

The Company has budgeted $180 - $190 million in Western Canada for 2019, primarily for the planned drilling activities in the Spirit River Formation in the Ansell and Kakwa areas as well as in the Montney Formation, and sustainment and maintenance activities.

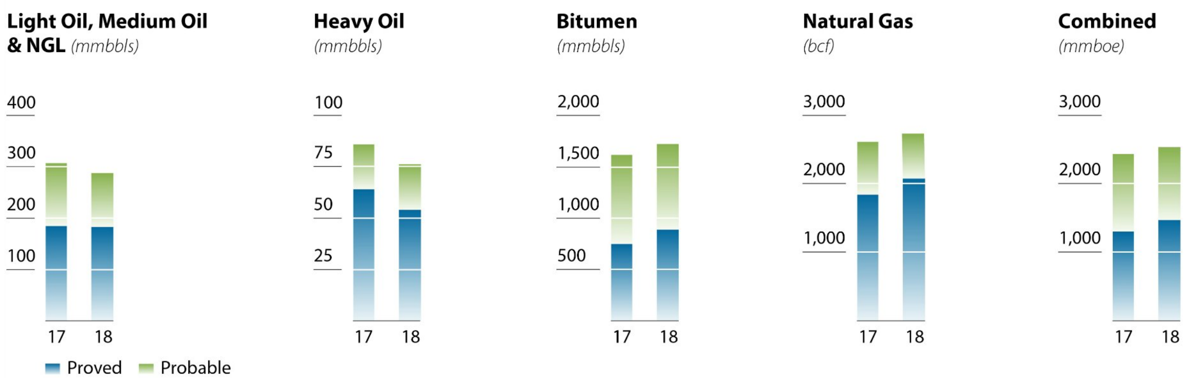
The Company has budgeted $1,120 - $1,190 million in Atlantic for 2019, primarily for the construction of the West White Rose Project.

The Company has budgeted $350 - $370 million in Asia Pacific in 2019, 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, 2018 with a preparation date of January 31, 2019.

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, 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 or on the Company's website at www.huskyenergy.com.

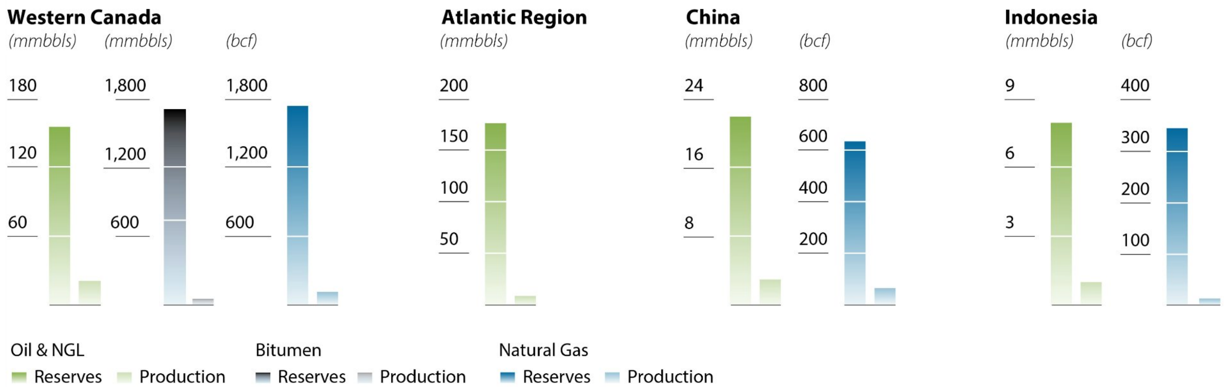
Sproule Associates Ltd. ("Sproule"), an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit and review of the Company's crude oil, natural gas and NGL reserves estimates. Sproule issued an audit opinion on January 31, 2019 stating that the Company's 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, 2018, the Company's proved oil and gas reserves were 1,471 mmboe, up from 1,301 mmboe at the end of 2017. The Company's 2018 reserves replacement ratio, defined as net additions divided by total production during the period, was 260 percent excluding economic revisions (255 percent including economic revisions).

Major changes to proved reserves in 2018 included:

- Discoveries, Extensions and Improved Recovery additions of 266 mmboe including 102 mmbbls at the Sunrise Energy Project from new locations as part of a full field optimized development plan, 63 mmbbls for two new Lloydminster thermal bitumen steam-assisted gravity drainage projects, first booking of Liuhua 29-1 of 31 mmboe, 43 mmboe in Ansell, Kakwa, North Blackstone, Wapiti and Wembley from new locations, and 8 mmbbls for additional reserves associated with the West White Rose Project.
- Technical revisions of 15 mmboe included 31 mmbbls added for the Lloydminster thermal bitumen projects and 9 mmboe added in China due to higher performance than last year's forecast. These were offset by a reduction of 23 mmbbls at the Sunrise Energy Project as a result of applying a more conservative estimate of the recovery factor early in the 50-year life of the field.

Proved Plus Probable Reserves and Production at December 31, 2018:



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]	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved reserves										
December 31, 2017	66	64	747	1,174	97	21	662	995	1,836	1,301
Technical revisions	(2)	2	8	4	(3)	2	47	7	51	15
Acquisitions	—	—	2	8	—	—	—	2	8	4
Dispositions	—	(1)	—	(2)	—	—	—	(1)	(2)	(1)
Discoveries, extensions and improved recovery	9	5	178	220	7	5	153	204	373	266
Economic factors	—	(3)	—	(10)	—	—	—	(3)	(10)	(5)
Production	(8)	(13)	(45)	(106)	(8)	(4)	(79)	(78)	(185)	(109)
Proved reserves December 31, 2018	**65**	**54**	**890**	**1,288**	**93**	**24**	**783**	**1,126**	**2,071**	**1,471**
Proved and probable reserves December 31, 2018	**80**	**76**	**1,722**	**1,751**	**177**	**30**	**984**	**2,085**	**2,735**	**2,541**
December 31, 2017	80	86	1,609	1,597	196	31	1,014	2,002	2,611	2,437

(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]	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved developed reserves										
December 31, 2017	62	64	162	823	37	21	561	346	1,384	575
Technical revisions	(2)	2	2	2	(5)	3	46	—	48	9
Transfer from proved undeveloped	1	—	21	24	—	—	—	22	24	26
Acquisitions	—	—	—	8	—	—	—	—	8	2
Dispositions	(1)	—	—	(2)	—	—	—	(1)	(2)	(1)
Discoveries, extensions and improved recovery	4	4	2	63	—	—	—	10	63	20
Economic factors	—	(4)	—	(8)	—	—	—	(4)	(8)	(5)
Production	(8)	(13)	(45)	(106)	(8)	(4)	(79)	(78)	(185)	(109)
December 31, 2018	**56**	**53**	**142**	**804**	**24**	**20**	**528**	**295**	**1,332**	**517**

(1) *Number 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)*	**2018**	2017
Gross revenues	**2,211**	1,976
Marketing and other	**668**	(40)
Expenses		
Purchases of crude oil and products	**2,087**	1,855
Production, operating and transportation expenses	**23**	13
Selling, general and administrative expenses	**5**	4
Depletion, depreciation, amortization and impairment	**—**	2
Loss on sale of assets	**—**	1
Other – net	**2**	(8)
Share of equity investment gain	**(18)**	(49)
Provisions for income taxes	**213**	32
Net earnings	**567**	86

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $235 million and $232 million, respectively, in 2018 compared to 2017, primarily due to increased volumes and prices.

Marketing and other increased by $708 million in 2018 compared to 2017, primarily due to crude oil marketing gains from widening location price differentials between Canada and the U.S., which the Company is able to capture due to its committed capacity on the Keystone pipeline.

Share of equity investment gain decreased by $31 million in 2018 compared to 2017, primarily due to higher maintenance expense and higher depreciation from HMLP in 2018.

Provisions for income taxes increased by $181 million in 2018 compared to 2017, primarily due to higher earnings before income taxes in 2018.

4.3 Downstream

Upgrading

Upgrading Earnings Summary *($ millions, except where indicated)*	2018	2017
Gross revenues	**1,750**	1,440
Expenses		
Purchases of crude oil and products	**928**	983
Production, operating and transportation expenses	**195**	197
Selling, general and administrative expenses	**7**	9
Depletion, depreciation, amortization and impairment	**123**	99
Financial items	**1**	1
Provisions for income taxes	**135**	41
Net earnings	**361**	110
Upgrading throughput *(mbbls/day)*[(1)]	**75.6**	68.5
Total sales *(mbbls/day)*	**74.7**	68.5
Synthetic crude oil sales *(mbbls/day)*	**52.9**	49.8
Upgrading differential *($/bbl)*	**29.05**	18.66
Unit margin *($/bbl)*	**30.15**	18.28
Unit operating cost *($/bbl)*[(2)]	**7.07**	7.88

(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.

Upgrading gross revenues increased by $310 million in 2018 compared to 2017, primarily due to higher realized prices for synthetic crude oil and higher sales volumes as the Lloydminster Upgrader was in a major planned turnaround in the second quarter of 2017. The price of Husky Synthetic Blend averaged $75.55/bbl in 2018 compared to $67.05/bbl in 2017.

Upgrading feedstock purchases decreased by $55 million in 2018 compared to 2017, primarily due to the decrease in the average cost of heavy crude oil feedstock.

Upgrading DD&A increased by $24 million in 2018 compared to 2017, primarily due to a higher depletable base in 2018 resulting from the capitalization of turnaround costs in 2017.

Provisions for income taxes increased by $94 million in 2018 compared to 2017, primarily due to higher earnings before income taxes in 2018.

Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	2018	2017
Gross revenues	**3,412**	2,787
Expenses		
Purchases of crude oil and products	**2,760**	2,219
Production, operating and transportation expenses	**265**	256
Selling, general and administrative expenses	**47**	53
Depletion, depreciation, amortization and impairment	**115**	111
Gain on sale of assets	**(2)**	(5)
Other – net	**(1)**	(1)
Financial items	**12**	12
Provisions for income taxes	**58**	38
Net earnings	**158**	104
Number of fuel outlets[1]	**557**	518
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**7.7**	7.3
Fuel sales per retail outlet *(thousands of litres/day)*	**12.3**	12.1
Refinery throughput		
Prince George Refinery *(mbbls/day)*[2]	**10.7**	11.2
Lloydminster Refinery *(mbbls/day)*[2]	**27.1**	26.8
Ethanol production *(thousands of litres/day)*	**819.4**	804.8

(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.*

Canadian Refined Products gross revenues increased by $625 million in 2018 compared to 2017, primarily due to higher product prices.

Canadian Refined Products purchases of crude oil and products increased by $541 million in 2018 compared to 2017, primarily due to higher commodity prices.

Provisions for income taxes increased by $20 million in 2018 compared to 2017, primarily due to higher earnings before income taxes in 2018.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	**2018**	2017
Gross revenues	**11,770**	9,355
Expenses		
Purchases of crude oil and products	**10,334**	8,059
Production, operating and transportation expenses	**795**	563
Selling, general and administrative expenses	**22**	15
Depletion, depreciation, amortization and impairment	**450**	354
Other – net	**(464)**	(21)
Financial items	**14**	14
Provisions for income taxes	**138**	137
Net earnings	**481**	234
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*[(1)]	**151.1**	172.2
BP-Husky Toledo Refinery throughput *(mbbls/day)*[(1)(2)]	**71.1**	76.6
Superior Refinery throughput *(mbbls/day)*[(1)]	**11.7**	5.5
Refining and marketing margin *(US$/bbl crude throughput)*[(3)]	**13.03**	11.44
Refinery inventory *(mmbbls)*[(4)]	**6.9**	9.2

(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 percent).*
(3) *Prior period has been restated to include impact of U.S. product marketing margin.*
(4) *Feedstock and refined products are included in refinery inventory.*

U.S. Refining and Marketing gross revenues increased by $2,415 million in 2018 compared to 2017, primarily due to higher refined product prices partially offset by lower sales volumes as the Lima Refinery completed a major planned turnaround in late 2018.

U.S. Refining and Marketing purchases of crude oil and products increased by $2,275 million in 2018 compared to 2017, primarily due to higher commodity prices partially offset by lower throughput volumes as the Lima Refinery completed a major planned turnaround in late 2018.

Production, operating and transportation expenses increased by $232 million in 2018 compared to 2017, primarily due to the acquisition of the Superior Refinery in late 2017 and the incident at the refinery in April 2018.

DD&A expense increased by $96 million in 2018 compared to 2017, primarily due to the derecognition of assets damaged during the incident at the Superior Refinery.

Other – net increased by $443 million in 2018 compared to 2017, primarily due to pre-tax insurance recoveries for property damage, rebuild costs, business interruption and clean-up costs associated with the incident at the Superior Refinery.

Downstream Capital Expenditures

In 2018, Downstream capital expenditures totalled $801 million compared to $630 million in 2017. In Canada, capital expenditures of $136 million related primarily to the scheduled partial turnaround at the Lloydminster Upgrader in the second quarter of 2018, and various reliability and environmental activities at the Lloydminster and Prince George refineries. In the U.S., capital expenditures of $665 million related primarily to the turnaround and crude oil flexibility project at the Lima Refinery, the turnaround at the Superior Refinery, and various reliability and environmental initiatives at the Lima and BP-Husky Toledo refineries.

4.4 Corporate

Corporate Summary *($ millions) income (expense)*	**2018**	2017
Production, operating and transportation expenses	**2**	—
Selling, general and administrative expenses	**(277)**	(304)
Depletion, depreciation, amortization and impairment	**(92)**	(79)
Other – net	**8**	(6)
Net foreign exchange gain (loss)	**14**	(6)
Finance income	**52**	32
Finance expense	**(178)**	(234)
Recovery of income taxes	**138**	675
Net earnings (loss)	**(333)**	78

The Corporate segment reported a net loss of $333 million in 2018 compared to net earnings of $78 million in 2017. The change was primarily due to the recognition of a $436 million deferred tax recovery in 2017, related to the reduction of the U.S. Federal corporate tax rate that took effect at the beginning of 2018.

Finance income increased by $20 million in 2018 compared to 2017, primarily due to interest on short-term investments.

Finance expense decreased by $56 million in 2018 compared to 2017, primarily due to lower interest expense in 2018 from the repayment of long term debt in late 2017.

Net foreign exchange gain increased by $20 million due to the items noted below.

Foreign Exchange Summary *($ millions, except where indicated)*	**2018**	2017
Non-cash working capital loss	**(3)**	(3)
Other foreign exchange gain (loss)	**17**	(3)
Net foreign exchange gain (loss)	**14**	(6)
U.S./Canadian dollar exchange rates:		
At beginning of year	**US$0.799**	US$0.745
At end of year	**US$0.733**	US$0.799

Included in the other foreign exchange gain (loss) 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)*	**2018**	2017
Provisions for (recovery of) income taxes	**471**	(362)
Cash income taxes paid (recovered)	**37**	(41)

Consolidated income taxes were a provision of $471 million in 2018 compared to a recovery of $362 million in 2017. The increase in consolidated income taxes was primarily due to the recognition of a $436 million deferred tax recovery related to the U.S. tax reform changes enacted in December 2017, combined with higher earnings before income taxes in 2018.

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, Environmental and Safety Incidents

The Company's businesses are subject to inherent operational risks with respect to safety and the environment that require continuous vigilance. The Company seeks to minimize these operational risks by designing and building its facilities and conducting its operations in a safe and reliable manner using the Husky Operational Integrity Management System, an integrated management system that considers environmental requirements as well as process and occupational safety. Failure to manage the risks effectively could result in potential fatalities, serious injury, interruptions to activities or use of assets, damage to assets, environmental impact or loss of licence to operate. Enterprise risk management, emergency preparedness, business continuity and security policies and programs are in place for all operating areas and are adhered to on an ongoing basis. 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 natural gas production. Lower prices for crude oil, NGL and 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 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 heavy crude oil and bitumen is limited and planned increases of North American heavy crude oil and bitumen production may create the need for additional heavy oil and bitumen 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 the Organization of the Petroleum Exporting Countries ("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 natural gas production is currently located in Western Canada and Asia Pacific. Western Canada's 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 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.

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, 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.

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, 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 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 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 percent of the future net revenue discounted at 10 percent 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 Regulation

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, formulation or demand of products, which may or may not be offset through market pricing.

The Company anticipates further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, increased compliance costs and approval delays for critical licences and permits.

Climate Change Regulation

Climate change regulations may become more onerous over time as governments implement policies to further reduce greenhouse gases ("GHG") emissions. As part of long range planning, the Company assesses future compliance costs associated with regulations of GHG emissions in its operations and the evaluation of future projects, based on the Company's outlook for carbon pricing under current and pending regulations. The impact of recently announced regulations is being evaluated as provinces and the federal government finalize carbon pricing regulations. 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. The Company continues to monitor international and domestic efforts to address climate change, including international low carbon fuel standards and regulations and other emerging regulations in the jurisdictions in which the Company operates.

The Alberta Climate Leadership Plan began to be implemented in 2017. This plan includes an economy-wide carbon levy, rising to $30 per tonne in 2018 which applies to the Lloydminster Refinery, as well as a Carbon Competitiveness Incentive Regulation ("CCIR") that manages emissions at large final emitting facilities ("LFEs") including the Tucker Thermal Project and Sunrise Energy Project. Under the previous Specified Gas Emitters Regulation, which expired at the end of 2017, the Tucker Thermal Project generated over 500,000 tonnes of credits due to improved emission intensity performance. These credits are eligible to offset future compliance obligations under the CCIR. These regulations are not anticipated to have a material impact over the duration of the Company's five-year long-range plan. The CCIR is due for review in 2020, along with the federal carbon policy. Uncertainty regarding future regulations, including carbon price and the details of implementing the oil sands emission limit, make it difficult to predict the potential future impact on the Company.

In December 2017, the Government of Saskatchewan released "Prairie Resilience" a policy paper on climate change strategy in which it outlines multiple commitments across five areas designed to make Saskatchewan more resilient to the climatic, economic and policy impacts of climate change. As part of this strategy, the government developed output-based performance standards for large industrial emitters and a Climate Resilience Measurement Framework. The large industrial emitters regulations will apply to the Company's Lloydminster Upgrader and ethanol plant and Saskatchewan thermal projects to reduce emissions while considering the economic competitiveness of these sectors. The smaller facilities (emitting under 25,000 tonnes/year) will be exposed to the federal carbon levy. The cost impacts of this levy on the Company's cold heavy oil production may be measurable.

The cost of compliance with British Columbia's $35 per tonne carbon tax (increasing to $40 on April 1, 2019) and the Renewable and Low Carbon Fuel Requirements Regulation may materially adversely affect the Company's Prince George Refinery. Additionally, future regulations in support of British Columbia's commitment under its Climate Leadership Plan are uncertain.

The application of the federal carbon policy in Manitoba may significantly adversely affect the Company's Minnedosa ethanol plant in Manitoba.

The Newfoundland and Labrador performance-based regulation imposes a carbon price beginning at $20/tonne in 2019 and escalating to $50/tonne in 2022. The provincial Gasoline and Diesel Tax begins at $20/tonne and will be adjusted with a goal of Atlantic parity related to provincial taxation (including carbon tax) of fuel products. The carbon tax rates will only increase to match equivalent increases in carbon taxation programs in neighbouring Atlantic provinces. There are noted exemptions for exploration drilling and aviation fuels. However, the addition of this carbon tax to marine diesel will increase operating costs for the Company's Atlantic region operation.

Within the mandate of the Pan-Canadian Framework on Clean Growth and Climate Change, in May 2017, the Government of Canada released a technical paper on the federal carbon policy introducing two key elements: a carbon levy applied to gas that the Company uses at its facilities as well as retail fuel ($20 per tonne starting in 2019 and increasing by $10 annually to $50 per tonne in 2022), and an output-based pricing system for industrial facilities emitting GHGs above 50,000 tonnes of CO_2e per year. 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. Draft CFS regulations are expected to be published in mid-2019 and final regulations in 2020, with the regulations expected to come into force in 2022. The impact of the CFS is still uncertain.

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 or, 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 emission 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 U.S. Renewable Fuel Standard ("RFS") program, through the EPA-specified renewable volume obligation ("RVO"), requires refiners to add annually increasing amounts of renewable fuels to their petroleum products or to purchase RINs in lieu of such blending. Due to regulatory uncertainty and in part due to the U.S. fuel supply reaching the "blend wall" (the 10 percent limit prescribed by most automobile warranties), the price and availability of RINs have been volatile.

The Company complies with the RFS program in the U.S. by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market. 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.

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.

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.

Climatic Conditions

Extreme climatic conditions may 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 Newfoundland and Labrador. 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 Newfoundland and Labrador may threaten Atlantic oil production facilities, cause damage to equipment and possible production disruptions, spills, other asset damage and human impacts. The Company has in place a number of policies to protect people, equipment and the environment in the event of extreme weather conditions and ice melt conditions.

The Company's Atlantic operations have a robust ice management program, which uses a range of resources including a dedicated ice surveillance aircraft, as well as synergistic relationships with government agencies including Environment and Climate Change Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commence in February and continue until the risk has abated. In addition, Atlantic operators employ a series of supply and support vessels to actively manage ice and icebergs. These vessels are equipped with a variety of ice management tools including towing ropes, towing nets and water cannons. The Company also maintains a series of ad-hoc relationships with contractors, allowing the quick mobilization of additional resources as required. The Company regularly assesses all aspects of its ice management program in order to ensure that the program continues to evolve as more information about the characteristics of ice and icebergs in the Atlantic becomes available and as new technologies are developed. The Company continues to look at ways to improve its ability to predict and respond to sea ice and icebergs with ongoing research and development. Recent initiatives include the design and fabrication of modular, heavy weather nets with sensors and development of a Common Operating Picture on Husky's contracted geographic information systems software module including ice flight information, location, drift models, and pack ice drift model runs. The Company now has a dedicated ice management room onshore, which mirrors the offshore and allows for real-time monitoring of field operations. Additional research and development activity related to ice management is continuing.

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 Company's Board of Directors 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. There is a risk that the Company may have difficulty attracting and retaining personnel with the required skill levels. 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 Husky 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.

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.

On December 4, 2018, the Company entered into cash flow hedges using forward interest rate swaps to fix the underlying U.S. $500 million 10-year note fixed rate to December 15, 2019.

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.

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)

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.

6.0 Liquidity and Capital Resources

6.1 Summary of Cash Flow

Cash Flow Summary *($ millions)*	**2018**	2017
Cash flow		
Operating activities	**4,134**	3,704
Financing activities	**(325)**	363
Investing activities	**(3,521)**	(2,789)

Cash Flow from Operating Activities

Cash flow generated from operating activities increased by $430 million in 2018 compared to 2017. The increase was primarily due to an increase from the Company's Infrastructure and Marketing segment, higher realized prices for synthetic crude oil combined with decreased average cost of crude oil feedstock in the Company's upgrading operations, and increased production from the Company's Asia Pacific operations.

Cash Flow from (used for) Financing Activities

Cash flow used for financing activities increased by $688 million in 2018 compared to 2017. Financing activities in 2018 related primarily to the reinstatement of the quarterly cash dividend in 2018. Financing activities in 2017 related primarily to the net issuance of long-term debt.

Cash Flow used for Investing Activities

Cash flow used for investing activities increased by $732 million in 2018 compared to 2017. The increase was primarily due to increased capital expenditures in 2018.

6.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2018, the Company's working capital was $694 million compared to $2,109 million at December 31, 2017. A reconciliation of the Company's working capital is as follows:

Working Capital *($ millions)*	**December 31, 2018**	December 31, 2017	Change
Cash and cash equivalents	**2,866**	2,513	353
Accounts receivable	**1,355**	1,186	169
Income taxes receivable	**112**	164	(52)
Inventories	**1,232**	1,513	(281)
Prepaid expenses	**123**	145	(22)
Restricted cash	**—**	95	(95)
Accounts payable and accrued liabilities	**(3,159)**	(3,033)	(126)
Short-term debt	**(200)**	(200)	—
Long-term debt due within one year	**(1,433)**	—	(1,433)
Asset retirement obligations	**(202)**	(274)	72
Net working capital	**694**	2,109	(1,415)

The increase in cash and cash equivalents was primarily due to the higher global commodity prices for the majority of 2018. Fluctuations in accounts receivable and accounts payable were due to the timing of settlements in 2018 compared to 2017. The decrease in income taxes receivable was primarily due to the timing of expected tax refunds. The decrease in inventories was primarily driven by decreased market values in the fourth quarter of 2018. The decrease in restricted cash was primarily due to the expiry of the Company's participation in the Wenchang oilfield PSC in late 2017. The increase in long-term debt due within one year was due to the timing of debt maturities.

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, 2018, the Company had the following available credit facilities:

Credit Facilities *($ millions)*	Available	Unused
Operating facilities[1]	**900**	**461**
Syndicated credit facilities[2]	**4,000**	**3,800**
	4,900	**4,261**

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

At December 31, 2018, the Company had $4,261 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $461 million are short-term uncommitted credit facilities. A total of $439 million short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $200 million of long-term committed borrowing credit facilities was used in support of commercial paper. At December 31, 2018, the Company had no direct borrowing against committed credit facilities. The maturity dates for the Company's revolving syndicated credit facilities are March 9, 2020 and June 19, 2022. 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. This covenant is used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2018, 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, 2018.

On March 10, 2017, the Company issued $750 million of 3.60 percent notes due March 10, 2027. The notes are redeemable at the option of the Company at any time, subject to a make-whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 10 and September 10 of each year, beginning September 10, 2017. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On March 30, 2017, the Company filed a universal short form base shelf prospectus (the "2017 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 April 30, 2019. The 2017 Canadian Shelf Prospectus replaced the Company's Canadian universal short form base shelf prospectus which expired on March 23, 2017. During the 25-month period that the 2017 Canadian Shelf Prospectus is in effect, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On September 15, 2017, the Company repaid the maturing 6.20 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to note holders was $365 million, including $11 million of interest.

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. The 2018 U.S. Shelf Prospectus replaced the Company's U.S. universal short form base shelf prospectus which expired on January 22, 2018. 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.

As at December 31, 2018, the Company has $3.0 billion in unused capacity under the 2017 Canadian Shelf Prospectus and US$3.0 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 2017 Canadian Shelf Prospectus and 2018 U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

Net Debt

Net debt, a non-GAAP measure (see Section 9.3), is calculated as total debt less cash and cash equivalents. The Company had total debt of $5,747 million and cash and cash equivalents of $2,866 million at December 31, 2018, compared to total debt of $5,440 million and cash and cash equivalents of $2,513 million at December 31, 2017. The Company's net debt at December 31, 2018 decreased by $46 million when compared to December 31, 2017:

Net Debt(1) *($ millions)*	**December 31, 2018**	December 31, 2017
Net debt at beginning of period	**(2,927)**	(4,020)
Change in net debt due to:		
Funds from operations(1)	**4,004**	3,306
Capital expenditures	**(3,578)**	(2,220)
Capitalized interest	**(108)**	(68)
Corporate acquisition	**(15)**	(670)
Dividends on preferred shares	**(35)**	(34)
Dividends on common shares	**(402)**	—
Change in non-cash working capital	**485**	638
Proceeds from asset sales	**4**	192
Effect of exchange rates on cash and cash equivalents	**65**	(84)
Effect of exchange rates on long-term debt	**(307)**	284
Contribution payable payment	**—**	(142)
Contributions to joint ventures	**(40)**	(81)
Other	**(27)**	(28)
	46	1,093
Net debt at end of period	**(2,881)**	(2,927)

(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, 2018 and 2017, the Company's capital expenditures were 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.

On February 28, 2018, the Board of Directors reinstated the quarterly common share cash dividend of $0.075 per share. On July 26, 2018, the quarterly common share cash dividend was increased to $0.125 per share.

6.4 Capital Structure

Capital Structure ($ millions)	December 31, 2018 Outstanding
Total debt[(1)]	5,747
Shareholders' equity	19,614

(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 $25.4 billion at December 31, 2018 (December 31, 2017 – $23.4 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 capital structure and financing requirements 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). The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. At December 31, 2018, debt to capital employed was 22.7 percent (December 31, 2017 – 23.2 percent) and debt to funds from operations was 1.4 times (December 31, 2017 – 1.6 times), within the Company's targets.

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)	2019	2020-2021	2022-2023	Thereafter	Total
Long-term debt and interest on fixed rate debt	1,697	724	956	3,709	7,086
Operating leases[(1)]	233	245	259	1,186	1,923
Firm transportation agreements[(1)]	497	1,036	1,030	4,013	6,576
Unconditional purchase obligations[(2)]	1,620	2,447	1,209	4,822	10,098
Lease rentals and exploration work agreements	49	123	123	930	1,225
Obligations to fund equity investee[(3)]	53	147	146	395	741
Finance lease obligations[(4)]	69	138	104	1,014	1,325
Asset retirement obligations[(5)]	202	293	287	8,541	9,323
	4,420	5,153	4,114	24,610	38,297

(1) Included in the total of operating leases and firm transportation agreements are blending and storage agreements and transportation commitments of $1.1 billion and $1.9 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 17 in the 2018 consolidated financial statements.

(5) Asset retirement obligation amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets. The amounts are inclusive of $128 million of cash deposited into restricted accounts for funding of future asset retirement obligations in Asia Pacific and obligations related to Husky's working interest from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for interim financial statement purposes.

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, 2018, the Company has deposited funds of $128 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 percent 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, 2018, the Company charged HMLP $448 million related to construction costs and management services. For the year ended December 31, 2018, the Company had purchases from HMLP of $200 million related to the use of the pipeline for the Company's blending, transportation and storage activities. As at December 31, 2018, the Company had $140 million due from HMLP.

6.7 Outstanding Share Data

Authorized:

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

Issued and outstanding: February 21, 2019

• 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	19,934,692
• stock options exercisable	10,443,916

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 2018 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 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 result.

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. These transactions are on terms equivalent to those that prevail in arm's-length transactions. 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.

Leases
In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet while operating leases are recognized in the consolidated statements of income when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expense upon implementation. Optional exemptions to not recognize certain short-term leases or leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged.

The Company will adopt IFRS 16 on the effective date of January 1, 2019 and has selected the modified retrospective transition approach. The optional exemptions to not recognize certain short-term and low value leases will be applied.

For leases implemented January 1, 2019, the Company will recognize a right-of-use asset of $1.1 billion equal to the lease liability at the present value of the remaining lease payments discounted using the Company's incremental borrowing rate. The implementation of IFRS 16 does not have a material impact on the consolidated statements of income. Due to a change in classification of operating lease expenses, cash flow from operating activities will increase and cash flow from financing activities will decrease, with no overall impact to the cash position for the Company.

Change in Accounting Policy

Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15 Revenue from Contracts with Customers, deferring the effective date to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. The Company retrospectively adopted the standard on January 1, 2018. The adoption of IFRS 15 did not require any material adjustments to the amounts recorded in the consolidated financial statements; however, additional disclosures are presented in the consolidated financial statements.

Revenue is recognized when the performance obligations are satisfied and revenue can be reliably measured. Revenue is measured at the consideration specified in the contracts and represents amounts receivable for goods or services provided in the normal course of business, net of discounts, customs duties and sales taxes. Natural gas sales in Asia Pacific are under long-term, fixed price contracts. Substantially all other revenue is based on floating prices. Performance obligations associated with the sale of crude oil, crude oil equivalents, and refined products are satisfied at the point in time when the products are delivered to and title passes to the customer. Performance obligations associated with processing services, transportation, blending and storage, and marketing services are satisfied at the point in time when the services are provided.

Financial Instruments

In July 2014, the IASB issued IFRS 9 Financial Instruments to replace IAS 39, which provides a single model for classification and measurement based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial instruments. For financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than net earnings, unless this creates an accounting mismatch. IFRS 9 includes a new, forward-looking 'expected loss' impairment model that will result in a more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard was effective for annual periods beginning on January 1, 2018. The Company retrospectively adopted the standard on January 1, 2018. The adoption of IFRS 9 did not require any material adjustments to the consolidated financial statements.

Financial assets previously classified as loans and receivables (cash and cash equivalents, accounts receivable, restricted cash, and long-term receivables), as well as financial liabilities previously classified as other financial liabilities (accounts payable and accrued liabilities, short-term debt, and long-term debt) have been reclassified to amortized cost. The carrying value and measurement of all financial instruments remains unchanged. The Company's current process for assessing short-term receivables lifetime expected credit losses collectively in groups that share similar credit risk characteristics is unadjusted with the adoption of the new impairment model and resulted in no additional impairment allowance. Additionally, long-term receivables were assessed individually under the expected credit loss model and no impairment was concluded.

Amendments to IFRS 2 Share-based Payment

In June 2016, the IASB issued amendments to IFRS 2 to be applied prospectively for annual periods beginning on or after January 1, 2018. The amendments clarify how to account for certain types of share-based payment arrangements. The adoption of the amendments did not have a material impact on the Company's consolidated financial statements.

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 2019 production guidance, including guidance for specified areas and product types; the Company's objective of maintaining stated debt to funds from operations and debt to capital employed ratio targets; and the Company's 2019 Upstream capital expenditure program;
- with respect to the Company's thermal developments: estimated production and expected timing of first production from the Dee Valley, Spruce Lake Central, Spruce Lake North, Spruce Lake East, Edam Central, Dee Valley 2 and Westhazel projects; the expected timing of regulatory approvals for the Dee Valley 2 and Westhazel projects; and the expected impact of the Alberta government-mandated production curtailment on the Tucker Thermal Project and the Sunrise Energy Project;
- with respect to the Company's non-thermal developments, the expected impact of the Alberta government-mandated production curtailment;
- with respect to the Company's Western Canada resource plays, strategic and drilling plans;
- with respect to the Company's Offshore business in Asia Pacific: the expected timing of commencement of drilling of the remaining three wells at, and first gas production from, Liuhua 29-1; target production from Liuhua 29-1 when fully ramped up; the expected timing of drilling five MDA field production wells and two MBH field production wells, and the expected timing of first gas production and sales therefrom; timing for a second exploration well on Block 16/25; and the expected timing of development and tie-in of 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; the expected timing that two additional infill wells will be completed and come online at the White Rose field; and delineation plans at the A-24 exploration well;
- with respect to the Company's Infrastructure and Marketing business, the processing capacity expected to be added by the Ansell Corser Gas Plant when it comes online, and the expected timing thereof; and
- with respect to the Company's Downstream operating segment: plans to market and potentially sell the Prince George Refinery and the Retail and Commercial Network; the expected timing of completion of the crude oil flexibility project at the Lima Refinery; and the expected timing that operations at the Superior Refinery will resume.

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, 2018 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, 2018 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, 2018.

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 percent 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.

This document includes an estimate of net pay thickness at White Rose A-24, which estimate may be considered to be anticipated results under NI 51-101. The estimate was prepared internally. The risks and uncertainties associated with recovery of resources from A-24 include, but are not limited to: that Husky may encounter unexpected drilling results; the occurrence of unexpected events in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems; and other difficulties in producing petroleum reserves.

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 LIFO. 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 plus 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, 2018, 2017 and 2016:

Debt to Funds from Operations *($ millions)*	**December 31, 2018**	December 31, 2017	December 31, 2016
Total debt	**5,747**	5,440	5,339
Funds from operations	**4,004**	3,306	2,198
Debt to funds from operations	**1.4**	1.6	2.4

Funds from Operations and Free Cash Flow

Funds from operations is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Funds from operations equals cash flow – operating activities plus 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.

Funds from operations was restated in the second quarter of 2017 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of adjustments for settlement of asset retirement obligations and deferred revenue. Prior periods have been restated to conform to current presentation.

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 has been 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)	**2018**	2017	**2018**	2017	2016
Net earnings	**216**	672	**1,457**	786	922
Items not affecting cash:					
Accretion	**25**	28	**97**	112	126
Depletion, depreciation, amortization and impairment	**662**	647	**2,591**	2,882	2,462
Inventory write-down to net realizable value	**60**	—	**60**	—	9
Exploration and evaluation expenses	**22**	—	**29**	6	86
Deferred income taxes (recoveries)	**25**	(360)	**396**	(359)	29
Foreign exchange loss (gain)	**1**	1	**(6)**	(4)	(4)
Stock-based compensation	**(50)**	25	**44**	45	33
Gain on sale of assets	**—**	(13)	**(4)**	(46)	(1,634)
Unrealized market to market loss (gain)	**(16)**	57	**(150)**	56	38
Share of equity investment gain	**(16)**	(1)	**(69)**	(61)	(15)
Gain on insurance recoveries for damage to property	**(253)**	—	**(253)**	—	—
Other	**2**	8	**21**	16	24
Settlement of asset retirement obligations	**(65)**	(45)	**(181)**	(136)	(87)
Deferred revenue	**(30)**	(5)	**(100)**	(16)	209
Distribution from joint ventures	**—**	—	**72**	25	—
Change in non-cash working capital	**730**	337	**130**	398	(227)
Cash flow – operating activities	**1,313**	1,351	**4,134**	3,704	1,971
Change in non-cash working capital	**(730)**	(337)	**(130)**	(398)	227
Funds from operations	**583**	1,014	**4,004**	3,306	2,198
Capital expenditures	**(1,265)**	(745)	**(3,578)**	(2,220)	(1,705)
Free Cash Flow	**(682)**	269	**426**	1,086	493
Funds from operations – basic	**0.58**	1.01	**3.98**	3.29	2.19
Funds from operations – diluted	**0.58**	1.01	**3.98**	3.29	2.19

LIFO

The Chicago 3:2:1 market crack spread benchmark is based on LIFO inventory costing, a non-GAAP measure, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis, the comparable GAAP measure, crude oil feedstock costs included in realized margins reflect purchases made in previous months. Management believes that comparisons between LIFO and FIFO inventory costing assist management and investors in assessing differences in the Company's realized refining margins compared to the Chicago 3:2:1 market crack spread benchmark, which is commonly used by the Company's U.S. refining peers.

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, 2018, 2017 and 2016:

Net Debt *($ millions)*	**December 31, 2018**	December 31, 2017	December 31, 2016
Total debt	**5,747**	5,440	5,339
Cash and cash equivalents	**(2,866)**	(2,513)	(1,319)
Net debt	**2,881**	2,927	4,020

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, 2018, 2017 and 2016:

Total Debt *($ millions)*	**December 31, 2018**	December 31, 2017	December 31, 2016
Short-term debt	**200**	200	200
Long-term debt due within one year	**1,433**	—	403
Long-term debt	**4,114**	5,240	4,736
Total debt	**5,747**	5,440	5,339

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 25, 2019. 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 25, 2019, should be read in conjunction with the 2018 consolidated financial statements and related notes. Readers are also encouraged to refer to the Company's interim reports filed for 2018, which contain Management's Discussion and Analysis and consolidated financial statements, and the Company's Annual Information Form for the year ended December 31, 2018, 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. Husky's Management's Discussion and Analysis for the interim period ended December 31, 2018 is incorporated herein by reference.

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, 2018 and 2017 and the Company's financial position at December 31, 2018 and 2017.

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*
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 plus 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*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
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*
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*
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, 2018, 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, 2018, 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, 2018, 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 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, 2018, 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

	Three months ended	
Fourth Quarter Results Summary	**Dec. 31**	Dec. 31
($ millions, except where indicated)	**2018**	2017
Gross revenues and Marketing and other		
Upstream		
Exploration and Production	**643**	1,355
Infrastructure and Marketing	**678**	633
Downstream		
Upgrading	**307**	452
Canadian Refined Products	**821**	815
U.S. Refining and Marketing	**2,766**	2,755
Corporate and Eliminations	**(173)**	(476)
Total gross revenues and marketing and other	**5,042**	5,534
Net earnings (loss)		
Upstream		
Exploration and Production	**(206)**	170
Infrastructure and Marketing	**126**	(27)
Downstream		
Upgrading	**80**	48
Canadian Refined Products	**55**	39
U.S. Refining and Marketing	**213**	129
Corporate and Eliminations	**(52)**	313
Net earnings	**216**	672
Per share – Basic	**0.21**	0.66
Per share – Diluted	**0.16**	0.66
Cash flow – operating activities	**1,313**	1,351
Funds from operations[1]	**583**	1,014
Per share – Basic	**0.58**	1.01
Per share – Diluted	**0.58**	1.01
Upstream		
Daily gross production		
Crude oil and NGL production *(mbbls/day)*[2]	**214.7**	231.2
Natural gas production *(mmcf/day)*[2]	**537.6**	534.9
Total production *(mboe/day)*	**304.3**	320.4
Average sales prices realized *($/boe)*		
Crude oil and NGL *($/bbl)*[2]	**18.93**	51.06
Natural gas *($/mcf)*[2]	**6.86**	5.89
Total average sales prices realized *($/boe)*	**25.47**	46.69
Downstream		
Refinery throughput		
Lloydminster Upgrader *(mbbls/day)*	**71.8**	78.2
Lloydminster Refinery *(mbbls/day)*	**25.3**	30.1
Prince George Refinery *(mbbls/day)*	**10.7**	11.3
Lima Refinery *(mbbls/day)*	**105.9**	164.5
BP-Husky Toledo Refinery *(mbbls/day)*	**73.2**	81.0
Superior Refinery *(mbbls/day)*	**—**	22.0
Total throughput *(mbbls/day)*	**286.9**	387.1

Fourth Quarter Results Summary (continued)	Three months ended	
($ millions, except where indicated)	**Dec. 31 2018**	Dec. 31 2017
Upgrading unit margin *($/bbl)*	**29.13**	20.65
Upgrading synthetic crude oil sales *(mbbls/day)*	**53.8**	56.5
Upgrading total sales *(mbbls/day)*	**73.5**	77.9
Retail fuel sales *(million of litres/day)*	**8.0**	8.0
Canadian light oil margins *($/litre)*	**0.037**	0.052
Lloydminster Refinery asphalt margin *($/bbl)*	**41.50**	15.79
U.S. Refining and Marketing margin *(US$/bbl crude throughput)*(3)	**9.12**	14.89
U.S./Canadian dollar exchange rate *(US$)*	**0.757**	0.786

(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 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*
(3) *Prior period has been restated to include impact of U.S. product marketing margin.*

Gross Revenue and Marketing and Other

The Company's consolidated gross revenues and marketing and other decreased by $492 million in the fourth quarter of 2018 compared to the fourth quarter of 2017.

In the Upstream business segment, Exploration and Production gross revenues decreased primarily due to lower average realized sales prices combined with lower production. Infrastructure and Marketing gross revenues and marketing and other increased primarily due to crude oil marketing gains from widening location price differentials between Canada and the U.S., which the Company is able to capture due to its committed capacity on the Keystone pipeline.

In the Downstream business segment, gross revenues decreased primarily due to lower realized prices for synthetic crude oil in the Upgrading business segment.

Net Earnings (Loss)

The Company's consolidated net earnings decreased by $456 million in the fourth quarter of 2018 compared to the fourth quarter of 2017.

In the Upstream business segment, Exploration and Production net loss increased primarily due to the same factors which impacted gross revenue and marketing and other.

In the Downstream business segment, Upgrading net earnings increased primarily due to the widening of the light/heavy oil differentials. Canadian Refined Products and U.S. Refining and Marketing net earnings increased primarily due to lower average cost of crude oil feedstock and pre-tax insurance recoveries for property damage, rebuild costs and business interruption associated with the incident at the Superior Refinery in the fourth quarter of 2018 compared to the fourth quarter of 2017.

In the Corporate business segment, net loss increased primarily due to the recognition of a $436 million deferred tax recovery in 2017, related to the reduction of the U.S. Federal corporate tax rate that took effect at the beginning of 2018.

Cash Flow – Operating Activities and Funds from Operations

Cash flow – operating activities and funds from operations decreased by $38 million and $431 million, respectively, in the fourth quarter of 2018 compared to the fourth quarter of 2017, primarily due to the same factors which impacted the Upstream and Downstream business segment net earnings, excluding the pre-tax insurance recoveries for rebuild costs associated with the incident at the Superior Refinery. Funds from operations is a non-GAAP measure; refer to Section 9.3.

Daily Gross Production

Production decreased by 16.1 mbbls/day during the fourth quarter of 2018 compared to the fourth quarter of 2017 as a result of:

- Decreased crude oil production in Atlantic due to the suspension of operations on the *SeaRose* FPSO vessel;
- Decreased heavy crude oil production due to natural declines and reduced optimization activities in the Company's non-thermal developments;
- Decreased crude oil production in Asia Pacific due to the expiry of the Company's participation in the Wenchang oilfield PSC in late 2017; and
- Decreased crude oil and natural gas production in Western Canada as a result of the disposition of select legacy assets in 2017.

Partially offset by:

- Increased bitumen production from the Company's thermal projects;
- Increased natural gas and NGL production from the Liwan Gas and BD projects; and
- Increased NGL production in Western Canada.

Segmented Operational Information

Segmented Operational Information *($ millions, except where indicated)*	2018 Q4	 Q3	 Q2	 Q1	2017 Q4	 Q3	 Q2	 Q1
Gross revenues and Marketing and other								
Upstream								
Exploration and Production	**643**	**1,319**	**1,284**	**1,084**	1,355	1,157	1,215	1,251
Infrastructure and Marketing	**678**	**769**	**821**	**611**	633	509	425	369
Downstream								
Upgrading	**307**	**534**	**444**	**465**	452	377	227	384
Canadian Refined Products	**821**	**1,001**	**869**	**721**	815	802	602	568
U.S. Refining and Marketing[1]	**2,766**	**3,198**	**3,035**	**2,771**	2,755	2,292	2,135	2,173
Corporate and Eliminations	**(173)**	**(521)**	**(470)**	**(390)**	(476)	(424)	(253)	(397)
Total gross revenues and marketing and other	**5,042**	**6,300**	**5,983**	**5,262**	5,534	4,713	4,351	4,348
Net earnings (loss)								
Upstream								
Exploration and Production	**(206)**	**214**	**158**	**57**	170	28	(67)	43
Infrastructure and Marketing	**126**	**149**	**154**	**138**	(27)	10	33	70
Downstream								
Upgrading	**80**	**88**	**84**	**109**	48	9	5	48
Canadian Refined Products	**55**	**43**	**32**	**28**	39	38	12	15
U.S. Refining and Marketing	**213**	**158**	**115**	**(5)**	129	114	12	(21)
Corporate and Eliminations	**(52)**	**(107)**	**(95)**	**(79)**	313	(63)	(88)	(84)
Net earnings (loss)	**216**	**545**	**448**	**248**	672	136	(93)	71
Per share – Basic	**0.21**	**0.53**	**0.44**	**0.24**	0.66	0.13	(0.10)	0.06
Per share – Diluted	**0.16**	**0.53**	**0.44**	**0.24**	0.66	0.13	(0.10)	0.06
Cash flow – operating activities	**1,313**	**1,283**	**1,009**	**529**	1,351	894	813	646
Funds from operations[2]	**583**	**1,318**	**1,208**	**895**	1,014	891	715	686
Per share – Basic	**0.58**	**1.31**	**1.20**	**0.89**	1.01	0.89	0.71	0.68
Per share – Diluted	**0.58**	**1.31**	**1.20**	**0.89**	1.01	0.89	0.71	0.68
U.S./Canadian dollar exchange rate (US$)	**0.757**	**0.765**	**0.775**	**0.791**	0.786	0.799	0.744	0.756
Exploration and Production								
Daily production, before royalties								
Crude oil & NGL production *(mbbls/day)*								
Light & Medium crude oil	**22.6**	**33.7**	**29.7**	**37.5**	46.6	42.7	56.0	60.7
NGL[3]	**24.8**	**24.5**	**21.8**	**20.5**	21.4	19.3	17.2	14.2
Heavy crude oil	**34.4**	**34.6**	**38.5**	**39.7**	42.3	44.1	43.1	48.0
Bitumen	**132.9**	**117.3**	**123.2**	**123.2**	120.9	117.7	117.4	120.6
Total crude oil & NGL production *(mbbls/day)*	**214.7**	**210.1**	**213.2**	**220.9**	231.2	223.8	233.7	243.5
Natural gas *(mmcf/day)*[3]	**537.6**	**519.5**	**494.0**	**477.0**	534.9	563.4	514.8	543.1
Total production *(mboe/day)*	**304.3**	**296.7**	**295.5**	**300.4**	320.4	317.7	319.5	334.0
Average sales prices								
Light & Medium crude oil *($/bbl)*	**60.19**	**93.84**	**92.23**	**82.08**	77.05	63.13	63.27	66.70
NGL *($/bbl)*[3]	**53.36**	**60.08**	**54.13**	**55.03**	51.19	37.83	38.00	49.64
Heavy crude oil *($/bbl)*	**18.71**	**50.09**	**54.22**	**32.80**	48.64	41.89	42.06	41.28
Bitumen *($/bbl)*	**5.42**	**46.00**	**44.41**	**27.77**	41.88	38.14	37.46	35.20
Natural gas *($/mcf)*[3]	**6.86**	**6.15**	**6.53**	**7.03**	5.89	5.25	5.59	5.35
Operating costs *($/boe)*	**13.75**	**14.68**	**14.22**	**13.33**	13.20	14.12	14.65	13.75
Operating netbacks[3][4]								
Lloydminster Thermal *($/bbl)*[5]	**(0.05)**	**35.83**	**36.16**	**19.77**	33.98	27.38	24.14	24.88
Lloydminster Non-Thermal *($/boe)*[5]	**(11.80)**	**13.28**	**20.83**	**4.13**	19.36	12.46	12.70	14.80
Tucker Thermal *($/bbl)*[5]	**(5.08)**	**29.53**	**31.67**	**16.16**	31.79	28.35	24.09	23.53
Sunrise Energy Project *($/bbl)*[5]	**(25.60)**	**15.79**	**12.59**	**(5.62)**	16.50	16.05	11.67	2.24
Western Canada – Crude Oil *($/bbl)*[5]	**(1.70)**	**23.81**	**29.37**	**17.88**	12.99	3.64	12.03	19.18
Western Canada – NGL & natural gas *($/mcf)*[6]	**1.13**	**0.29**	**0.39**	**1.33**	0.15	0.12	1.01	1.05
Atlantic – Light Oil *($/bbl)*[5]	**23.19**	**68.20**	**57.79**	**65.23**	59.00	35.86	42.08	44.39
Asia Pacific – Light Oil, NGL & natural gas *($/boe)*[3][5]	**67.42**	**65.45**	**68.44**	**70.31**	65.31	61.81	61.90	64.43
Total *($/boe)*[5]	**9.42**	**31.30**	**31.31**	**24.37**	30.00	23.25	23.53	24.17

Segmented Operational Information (continued)	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1
Upgrading								
Synthetic crude oil sales *(mbbls/day)*	**53.8**	**54.9**	**47.1**	**56.0**	56.5	58.2	30.3	54.1
Total sales *(mbbls/day)*	**73.5**	**76.7**	**69.1**	**79.4**	77.9	79.4	40.3	76.2
Upgrading differential *($/bbl)*	**27.89**	**29.46**	**26.67**	**32.31**	21.46	13.60	18.70	20.88
Canadian Refined Products								
Fuel sales *(millions of litres/day)*	**8.0**	**7.7**	**7.5**	**7.4**	8.0	8.1	6.5	6.4
Refinery throughput[(7)]								
Lloydminster Refinery *(mbbls/day)*	**25.3**	**27.8**	**26.8**	**28.7**	30.1	30.0	19.5	28.0
Prince George Refinery *(mbbls/day)*	**10.7**	**11.5**	**8.8**	**12.0**	11.3	11.9	9.7	11.8
U.S. Refining and Marketing								
Refinery throughput[(7)]								
Lima Refinery *(mbbls/day)*	**105.9**	**163.3**	**171.2**	**164.4**	164.5	178.3	174.1	172.0
BP-Husky Toledo Refinery *(mbbls/day)*[(8)]	**73.2**	**70.8**	**65.5**	**75.0**	81.0	77.3	71.1	77.0
Superior Refinery *(mbbls/day)*[(9)]	**—**	**—**	**10.1**	**37.0**	22.0	—	—	—

(1) *During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings.*
(2) *Funds from operations is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.*
(3) *Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*
(4) *Operating netback is a non-GAAP measure. Refer to Section 9.3.*
(5) *Includes associated co-products converted to boe.*
(6) *Includes associated co-products converted to mcfge.*
(7) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(8) *Reported throughput volumes include Husky's working interest from the BP-Husky Toledo Refinery (50 percent).*
(9) *The Superior Refinery was acquired on November 8, 2017.*

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 crude oil prices realized by the Company for the majority of 2018, and increased Asia Pacific production throughout the year, resulted in an increase to 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:

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 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 works is being conducted.
- At the Madura Strait, the BD Project achieved its gross daily sales targets of 100 mmcf/day of 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 is underway with seven wells drilled and four completed.
- Production operations on the *SeaRose* FPSO vessel were suspended for nine days due to a regulatory suspension.

2017

Q4:

- On November 8, 2017, the Company completed the purchase of the Superior Refinery, a 50,000 bbls/day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet Specialty Products Partners, L.P. for $670 million (US$527 million) in cash, which includes $108 million (US$85 million) of working capital.
- At the Tucker Thermal Project, drilling of the new 15-well pad was completed in the second quarter and steaming commenced in the fourth quarter of 2017.
- At the Sunrise Energy Project production continued to ramp-up and the 14 previously drilled well pairs were tied in, with 13 well pairs producing.
- Production from 10 wells of the 16-well program in the Ansell and Kakwa areas was achieved. Due to improved operating efficiencies, drilling times were reduced by 30 percent during 2017, contributing to a 22 percent reduction in per-well drilling costs.
- At Karr in the Montney Formation, two wells were drilled in the third quarter and production was achieved in the fourth quarter.
- Production continued to ramp-up at the BD Project. The first lifting of NGL occurred mid-October.
- An additional infill well was completed at the main White Rose field, which was tied back to the *SeaRose* FPSO, providing for improved capital efficiencies.
- The sale of select assets in Western Canada to third parties was completed, representing approximately 17,600 boe/day for gross proceeds of approximately $65 million resulting in an after-tax gain of $9 million.
- The recognition of $436 million in deferred tax recovery related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018.

Q3:

- First production was achieved at the BD Project in the Madura Strait. NGL were produced and stored on the FPSO.
- Nine wells of a 16-well program in the Ansell and Kakwa areas were completed by the third quarter.
- Production from one well at Wembley in the Montney Formation commenced.
- At South White Rose, an oil production well and a supporting water injection well were completed.
- The consolidation of a single expanded truck transport network of approximately 160 sites was completed during the quarter.

Q2:

- The Company recognized an after-tax impairment expense of $123 million related to crude oil and natural gas assets located in Western Canada in the Upstream Exploration and Production segment. The impairment charges were the result of changes in the development plans and reinforced by market transactions.
- Lloydminster Upgrader and Lloydminster Asphalt Refinery throughput and sales volumes were lower due to major planned turnarounds at the Lloydminster Upgrader and Lloydminster Asphalt Refinery.
- The sale of select assets in Western Canada to third parties was completed, representing approximately 2,600 boe/day for gross proceeds of approximately $123 million, resulting in an after-tax gain of $23 million.

Q1:

- First oil was achieved at the Tucker Thermal Project's new eight-well pad.
- First oil was achieved from a North Amethyst infill well.

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.*

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**

2017 ($ millions)	Upstream								Downstream			
	Exploration and Production[1]				Infrastructure and Marketing				Upgrading			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	1,355	1,157	1,215	1,251	704	513	426	333	452	377	227	384
Royalties	(97)	(71)	(91)	(104)	—	—	—	—	—	—	—	—
Marketing and other	—	—	—	—	(71)	(4)	(1)	36	—	—	—	—
Revenues, net of royalties	1,258	1,086	1,124	1,147	633	509	425	369	452	377	227	384
Expenses												
Purchases of crude oil and products	(1)	—	1	—	657	495	408	295	304	287	144	248
Production, operating and transportation expenses	390	413	430	417	7	1	2	3	49	45	54	49
Selling, general and administrative expenses	84	63	61	57	1	1	1	1	3	1	3	2
Depletion, depreciation, amortization and impairment	471	514	705	547	—	1	1	—	30	31	19	19
Exploration and evaluation expenses	38	31	56	21	—	—	—	—	—	—	—	—
Loss (gain) on sale of assets	(13)	3	(33)	1	—	—	—	1	—	—	—	—
Other – net	37	(7)	(39)	15	(6)	10	(9)	(3)	—	—	—	—
	1,006	1,017	1,181	1,058	659	508	403	297	386	364	220	318
Earnings (loss) from operating activities	252	69	(57)	89	(26)	1	22	72	66	13	7	66
Share of equity investment income (loss)	13	(1)	(1)	1	(12)	13	24	24	—	—	—	—
Financial items												
Net foreign exchange gains (losses)	—	—	—	—	—	—	—	—	—	—	—	—
Finance income	1	2	1	1	—	—	—	—	—	—	—	—
Finance expenses	(33)	(31)	(35)	(32)	—	—	—	—	—	(1)	—	—
	(32)	(29)	(34)	(31)	—	—	—	—	—	(1)	—	—
Earnings (loss) before income tax	233	39	(92)	59	(38)	14	46	96	66	12	7	66
Provisions for (recovery of) income taxes												
Current	(8)	(25)	12	(13)	—	—	—	—	24	12	4	23
Deferred	71	36	(37)	29	(11)	4	13	26	(6)	(9)	(2)	(5)
	63	11	(25)	16	(11)	4	13	26	18	3	2	18
Net earnings (loss)	170	28	(67)	43	(27)	10	33	70	48	9	5	48
Capital expenditures[4]	525	355	307	289	—	—	—	—	14	27	168	21
Total assets	17,920	18,021	18,275	18,802	1,364	1,447	1,338	1,422	1,263	1,261	1,179	1,129

(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) *During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings.*

(4) *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.*

Downstream (continued)								Corporate and Eliminations[2]				Total			
Canadian Refined Products				U.S. Refining and Marketing[3]											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
815	802	602	568	2,755	2,292	2,135	2,173	(476)	(424)	(253)	(397)	5,605	4,717	4,352	4,312
—	—	—	—	—	—	—	—	—	—	—	—	(97)	(71)	(91)	(104)
—	—	—	—	—	—	—	—	—	—	—	—	(71)	(4)	(1)	36
815	802	602	568	2,755	2,292	2,135	2,173	(476)	(424)	(253)	(397)	5,437	4,642	4,260	4,244
647	650	477	445	2,316	1,876	1,894	1,973	(476)	(424)	(253)	(397)	3,447	2,884	2,671	2,564
66	63	67	60	151	135	137	140	—	—	—	—	663	657	690	669
19	12	11	11	4	4	3	4	121	61	63	59	232	142	142	134
28	27	27	29	90	82	93	89	28	18	17	16	647	673	862	700
—	—	—	—	—	—	—	—	—	—	—	—	38	31	56	21
—	(5)	—	—	—	—	—	—	—	—	—	—	(13)	(2)	(33)	2
(1)	—	—	—	(14)	10	(14)	(3)	(3)	12	(3)	—	13	25	(65)	9
759	747	582	545	2,547	2,107	2,113	2,203	(330)	(333)	(176)	(322)	5,027	4,410	4,323	4,099
56	55	20	23	208	185	22	(30)	(146)	(91)	(77)	(75)	410	232	(63)	145
—	—	—	—	—	—	—	—	—	—	—	—	1	12	23	25
—	—	—	—	—	—	—	—	5	2	(11)	(2)	5	2	(11)	(2)
—	—	—	—	—	—	—	—	10	9	8	5	11	11	9	6
(3)	(3)	(3)	(3)	(4)	(4)	(3)	(3)	(59)	(58)	(62)	(55)	(99)	(97)	(103)	(93)
(3)	(3)	(3)	(3)	(4)	(4)	(3)	(3)	(44)	(47)	(65)	(52)	(83)	(84)	(105)	(89)
53	52	17	20	204	181	19	(33)	(190)	(138)	(142)	(127)	328	160	(145)	81
18	11	6	10	(4)	5	1	—	(14)	(31)	(18)	(16)	16	(28)	5	4
(4)	3	(1)	(5)	79	62	6	(12)	(489)	(44)	(36)	(27)	(360)	52	(57)	6
14	14	5	5	75	67	7	(12)	(503)	(75)	(54)	(43)	(344)	24	(52)	10
39	38	12	15	129	114	12	(21)	313	(63)	(88)	(84)	672	136	(93)	71
25	14	37	11	122	88	52	51	59	27	16	12	745	511	580	384
1,548	1,533	1,516	1,503	7,580	6,676	6,769	7,035	3,252	3,219	3,295	3,003	32,927	32,157	32,372	32,894