MANAGEMENT'S DISCUSSION AND ANALYSIS

July 25, 2019

Table of Contents

1.0 Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Jun. 30**	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30
($ millions, except where indicated)	**2019**	2019	2018	2018	2018	2018	2017	2017
Production *(mboe/day)*	**268.4**	285.2	304.3	296.7	295.5	300.4	320.4	317.7
Gross revenues and Marketing and other	**5,386**	4,645	5,042	6,300	5,983	5,262	5,534	4,713
Net earnings	**370**	328	216	545	448	248	672	136
Per share – Basic	**0.36**	0.32	0.21	0.53	0.44	0.24	0.66	0.13
Per share – Diluted	**0.36**	0.31	0.16	0.53	0.44	0.24	0.66	0.13
Cash flow – operating activities	**760**	545	1,313	1,283	1,009	529	1,351	894
Funds from operations[1]	**802**	959	583	1,318	1,208	895	1,014	891
Per share – Basic	**0.80**	0.95	0.58	1.31	1.20	0.89	1.01	0.89
Per share – Diluted	**0.80**	0.95	0.58	1.31	1.20	0.89	1.01	0.89

[1] *Funds from operations is a non-GAAP measure. Refer to Section 10.3 for a reconciliation to the corresponding GAAP measure.*

Performance

- Net earnings of $370 million in the second quarter of 2019 compared to net earnings of $448 million in the second quarter of 2018, with the decrease primarily due to:
  - Lower earnings from Upstream operations due to lower production and lower global crude oil commodity benchmark prices;
  - Lower earnings from crude oil marketing activities due to the tightening of location pricing differentials between Canada and the U.S.;
  - Lower realized Upgrading margins; and
  - Lower earnings from the Canadian and U.S. Refining operations due to the turnarounds at the Prince George and BP-Husky Toledo refineries in the second quarter of 2019.

  Partially offset by:
  - Higher tax recoveries related to the reduction in the Alberta provincial corporate tax rate that was substantively enacted in the second quarter of 2019; and
  - Higher realized Upstream crude oil pricing due to narrowing of the Canadian light/heavy oil differential.
- Cash flow – operating activities and funds from operations were $760 million and $802 million, respectively, in the second quarter of 2019 compared to $1,009 million and $1,208 million, respectively, in the second quarter of 2018, with the decrease primarily attributed to:
  - Lower earnings from Upstream operations due to lower production and lower global crude oil commodity benchmark prices; and
  - Lower earnings from the Canadian and U.S. Refining operations due to the turnarounds at the Prince George and BP-Husky Toledo refineries in the second quarter of 2019.

- Production decreased by 27.1 mboe/day or nine percent to 268.4 mboe/day in the second quarter of 2019 compared to the second quarter of 2018 primarily due to:
    - Lower heavy crude oil production due to government-mandated production quotas in Alberta and natural declines;
    - Lower production from Atlantic due to limited production from the White Rose field;
    - Lower bitumen production as a result of planned turnarounds at a number of the Saskatchewan thermal plants and at the Sunrise Energy Project; and
    - Lower production from the Liwan Gas Project due to lower nominations from the gas buyer in Guangdong, China.

  Partially offset by:
    - Higher natural gas and natural gas liquids ("NGL") production from the BD Project.

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 generate returns from investing in a deep portfolio of opportunities across two main businesses: (i) an integrated Canada-U.S. Upstream and Downstream corridor ("Integrated Corridor"); and (ii) production located offshore the east coast of Canada ("Atlantic") and offshore China and Indonesia ("Asia Pacific") (Atlantic and Asia Pacific collectively, "Offshore"). These investments contribute to increasing margins, funds from operations and earnings. The investments combined with the protection provided by a strong balance sheet, integration and largely fixed price contracts in Asia Pacific results in a business that is resilient to market volatility while preserving upside.

Integrated Corridor

The Company's business in the Integrated Corridor includes crude oil, bitumen, natural gas and 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 Asia Pacific and Atlantic. Each area generates high-netback production, with near and long-term investment potential.

2.2 Operations Overview and Q2 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.

Exploration and Production

Thermal Developments

The Company continued to advance its inventory of thermal projects in the second quarter of 2019. These long-life developments are being built with modular, repeatable designs and require low sustaining capital once brought online.

Total thermal bitumen production, including Lloyd thermal projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 120,400 bbls/day (Husky working interest) in the second quarter of 2019. Production for the quarter was impacted by planned turnarounds at six of the Saskatchewan thermal plants, a planned turnaround at the Sunrise Energy Project, and government-mandated production quotas in Alberta.

Lloyd Thermal Bitumen Projects

The following table shows major projects and their status as at June 30, 2019:

Project Name	Estimated Production Capacity (bbls/day)	Expected Project Production Date	Project Status
Dee Valley	10,000	Third quarter of 2019, compared to a previously disclosed timeframe of the fourth quarter of 2019	Facility and well site construction substantially complete. Commissioning is in progress, first steam was achieved on June 30, 2019, with first oil following in the third quarter of 2019.
Spruce Lake Central	10,000	Second half of 2020	Site piling, concrete work and drilling are all complete. Once-Through Steam Generators have been received on-site and module setting is underway.
Spruce Lake North	10,000	Around the end of 2020	Site piling has been completed, concrete work is in progress and first modules are ready to ship to site.
Spruce Lake East	10,000	Around the end of 2021	Regulatory approval has been received, and lease construction is underway.
Edam Central	10,000	2022	Regulatory approval has been received.
Dee Valley 2	10,000	2023	Regulatory approval has been received.

Tucker Thermal Project

Production in the second quarter of 2019 averaged 24,000 bbls/day and was impacted by the government-mandated production quotas in Alberta.

Sunrise Energy Project

Total production in the second quarter of 2019 averaged 45,400 bbls/day (22,700 bbls/day Husky working interest) and was impacted by the government-mandated production quotas in Alberta. In addition, a planned turnaround was successfully completed during the quarter on one of the two Central Processing Facility plants.

Western Canada

Oil and Natural Gas Resource Plays

A drilling program targeting the liquids-rich Cardium and Spirit River Formations, in the Ansell and Kakwa areas, continued with 10 wells drilled and completed in 2019.

A drilling program targeting the oil and liquids-rich gas Montney Formation continued with three wells drilled at Wembley and one well drilled at Sinclair in 2019.

Non-Thermal Developments

The Company is managing the natural decline in Cold Heavy Oil Production with Sand operations with an active optimization program, as well as ongoing investment in Enhanced Oil Recovery ("EOR") projects. Production in the second quarter of 2019 was impacted by government-mandated production quotas in Alberta.

Asia Pacific

China

Block 29/26

Total production from Liwan 3-1 and Liuhua 34-2 averaged 69,100 boe/day (34,000 boe/day Husky working interest) in the second quarter of 2019. Total production consisted of natural gas production of 329.5 mmcf/day and NGL production of 14,200 bbls/day.

Construction continues at Liuhua 29-1, the third deepwater gas field of the Liwan Gas Project. Drilling of the remaining three wells was completed during the second quarter of 2019, which added to the four previously drilled wells. The completion program for all seven wells commenced in April 2019, and is expected to be completed by the end of 2019. Pipeline work for the project began in the second quarter of 2019, and the initial pipe lay program is expected to be completed in the third quarter of 2019.

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. Additional appraisal work is underway on the block and the block boundaries have been extended.

An exploration well was drilled on Block 16/25 in 2018, which did not encounter commercial hydrocarbons. This well was written off in the second quarter of 2019.

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, China National Offshore Oil Corporation Limited ("CNOOC") may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases by paying their share of Husky's prior expenditures.

Blocks 22/11 and 23/07

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

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 by paying their share of Husky's prior expenditures.

Indonesia

Madura Strait

Total natural gas production averaged 86.7 mmcf/day (34.0 mmcf/day Husky working interest) and NGL production averaged 6,500 bbls/day (2,500 bbls/day Husky working interest) in the second quarter of 2019. Improvements in the processing equipment were made to increase the throughput capacity of the system.

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. Due to regulatory delays, gas production and sales are expected to commence in 2021, rather than around the end of 2020 as originally expected, 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 via a separate platform 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.

Atlantic

White Rose Field and Satellite Extensions

Project activity continues to ramp-up on the West White Rose Project. Construction of the concrete gravity structure ("CGS") and related topsides continued to advance in the second quarter of 2019. In addition, two of three planned slipforms on the CGS have been completed at the dry-dock in Argentia, Newfoundland and Labrador. The third is planned to begin in August 2019. First production is expected around the end of 2022.

Two infill wells were completed and brought online in the second quarter of 2019, at the White Rose field.

An investigation into the cause of the November 2018 spill from a flowline connector near the South White Rose Extension continued. The Company has been taking a methodical approach to resuming full field production at the White Rose field. Consistent with this approach, the Southern Drill Centre was returned to production in early June, following flowline flushing, integrity inspections and acceptance tests. The Company's share of daily production from the field is approximately 11,000 bbls/day. The North Amethyst and South White Rose Extension drill centres are expected to return to production during the third quarter of 2019.

Atlantic Exploration

The Company and its partners drilled the Tiger's Eye D-17 exploration well approximately 10 kilometres south of the *SeaRose* floating production, storage and offloading vessel, which did not encounter commercial hydrocarbons and was written off. The Company has a 40 percent ownership interest in this well.

The Company continued to evaluate the results of its 2018 discovery at the A-24 exploration well north of the White Rose field. 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

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 Plant

The new gas processing plant is 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.

Downstream Operations

Downstream operations in the Integrated Corridor in Canada includes upgrading of heavy crude oil feedstock into synthetic crude oil ("Upgrading"), refining crude oil, producing ethanol and marketing of heavy and synthetic crude oil, refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products ("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.

Canadian Refined Products

During the first quarter of 2019, the Company announced a strategic review to market and potentially sell the Prince George Refinery and its Canadian Retail and Commercial Network. This process continued through the second quarter of 2019.

U.S. Refining and Marketing

Lima Refinery

Crude Oil Flexibility Project

The Company's crude oil flexibility project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada, providing the ability to swing between light and heavy crude oil feedstock. The project is expected to be completed by the end of 2019. This schedule coordinates project work with normal maintenance to provide for higher levels of sustained throughput.

Superior Refinery

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 is expected to commence in the third quarter of 2019, once design work is complete and permits are obtained. The investment in the rebuild is estimated to be more than US$400 million, of which the Company anticipates a substantial portion will be recovered from property damage insurance. The refinery will be rebuilt with the same throughput capacity and will be able to produce a full slate of products, including asphalt, gasoline, diesel and fuel oils. Full operations are expected to resume in 2021.

2.3 Financial Strategic Plan

During the second quarter of 2019:

- The Company filed a universal short form base shelf prospectus (the "2019 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada. The 2019 Canadian Shelf Prospectus replaced the Company's Canadian universal short form base shelf prospectus which expired on April 30, 2019;
- The Company repaid the maturing 6.15 percent notes issued under a trust indenture dated June 14, 2002. The amount paid to note holders was $402 million;
- The Company extended the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on March 9, 2020, to March 9, 2024;
- The Board of Directors declared a quarterly dividend of $0.125 per common share, or $126 million, for the first quarter of 2019. The dividends were paid on July 2, 2019, to shareholders of record at the close of business on June 10, 2019; and
- Dividends of $8 million were declared on preferred shares for the second quarter of 2019, and were paid on July 2, 2019, to shareholders of record at the close of business on June 10, 2019.

3.0 Business Environment

Average Benchmarks

Average Benchmarks Summary		Three months ended Jun. 30 2019	Mar. 31 2019	Dec. 31 2018	Sept. 30 2018	Jun. 30 2018	Six months ended Jun. 30 2019	Jun. 30 2018
West Texas Intermediate ("WTI") crude oil[1]	*(US$/bbl)*	**59.82**	54.90	58.81	69.50	67.88	**57.36**	65.37
Brent crude oil[2]	*(US$/bbl)*	**68.82**	63.20	67.54	75.23	74.35	**66.02**	70.54
Light sweet at Edmonton	*($/bbl)*	**73.85**	66.53	42.68	81.92	80.58	**70.19**	76.32
Western Canadian Select ("WCS") at Hardisty[3]	*(US$/bbl)*	**49.14**	42.61	19.38	47.25	48.61	**45.88**	43.60
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**61.71**	52.12	12.83	54.01	53.15	**56.91**	45.23
WTI/Lloyd crude blend differential	*(US$/bbl)*	**10.28**	11.88	39.32	22.06	19.08	**11.08**	21.50
Condensate at Edmonton	*(US$/bbl)*	**55.86**	50.56	45.28	66.65	68.83	**53.21**	65.93
NYMEX natural gas[4]	*(US$/mmbtu)*	**2.64**	3.15	3.64	2.90	2.80	**2.89**	2.90
NOVA Inventory Transfer ("NIT") natural gas	*($/GJ)*	**1.11**	1.84	1.80	1.28	0.97	**1.48**	1.37
Chicago Regular Unleaded Gasoline	*(US$/bbl)*	**81.40**	63.41	67.34	86.61	84.75	**72.56**	78.99
Chicago Ultra-low Sulphur Diesel	*(US$/bbl)*	**81.50**	77.10	85.42	92.21	89.14	**79.33**	85.31
Chicago 3:2:1 crack spread	*(US$/bbl)*	**21.61**	13.08	13.38	19.04	18.30	**17.46**	15.64
U.S./Canadian dollar exchange rate	*(US$)*	**0.748**	0.752	0.757	0.765	0.775	**0.750**	0.783
Canadian $ Equivalents[5]								
WTI crude oil	*($/bbl)*	**79.97**	73.01	77.69	90.85	87.59	**76.48**	83.49
Brent crude oil	*($/bbl)*	**92.00**	84.04	89.22	98.34	95.94	**88.02**	90.09
WCS at Hardisty	*($/bbl)*	**65.70**	56.66	25.60	61.76	62.72	**61.18**	55.68
WTI/Lloyd crude blend differential	*($/bbl)*	**13.74**	15.80	51.94	28.84	24.62	**14.77**	27.46
NYMEX natural gas	*($/mmbtu)*	**3.53**	4.19	4.81	3.79	3.61	**3.86**	3.70

(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 monthly average U.S./Canadian dollar exchange rates.*

Crude Oil Benchmarks

Global crude oil benchmarks in the second quarter of 2019 decreased relative to the second quarter of 2018. WTI averaged US$59.82/bbl during the second quarter of 2019, compared to US$67.88/bbl during the second quarter of 2018. Brent averaged US$68.82/bbl during the second quarter of 2019, compared to US$74.35/bbl during the second quarter of 2018. WCS averaged US$49.14/bbl during the second quarter of 2019, compared to US$48.61/bbl during the second quarter of 2018.

The price received by the Company for crude oil production from Western Canada is primarily driven by the price of WTI, adjusted to Western Canada. 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 79 percent heavy crude oil and bitumen in the second quarter of 2019 compared to 76 percent in the second quarter of 2018.

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

Natural Gas Benchmarks

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

North American natural gas 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

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

The Company's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil. The product slates produced at the Lima and BP-Husky Toledo refineries contain between 11 and 12 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

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$0.748 in the second quarter of 2019 compared to US$0.775 in the second quarter of 2018.

A portion of the Company's long-term sales contracts in Asia Pacific are priced in Chinese Yuan ("RMB"). An increase in the value of the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region. The Canadian dollar averaged RMB 5.102 in the second quarter of 2019 compared to RMB 4.942 in the second quarter of 2018.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in the second quarter of 2019 on earnings before income taxes and net earnings on an annualized basis. The table below reflects what the effect would have been on the financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the second quarter of 2019. Each separate item in the sensitivity analysis shows the approximate effect of an increase in that variable only; all other variables are held constant. While these sensitivities are indicative for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or upon greater magnitudes of change.

Sensitivity Analysis	2019 Second Quarter 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]	**59.82**	*US $1.00/bbl*	**85**	**0.08**	**62**	**0.06**
NYMEX benchmark natural gas price[5]	**2.64**	*US $0.20/mmbtu*	**—**	**—**	**—**	**—**
WTI/Lloyd crude blend differential[6]	**10.28**	*US $1.00/bbl*	**(1)**	**—**	**—**	**—**
Canadian asphalt margins	**23.52**	*Cdn $1.00/bbl*	**10**	**0.01**	**7**	**0.01**
Canadian light oil margins	**0.036**	*Cdn $0.005/litre*	**13**	**0.01**	**10**	**0.01**
Chicago 3:2:1 crack spread	**21.61**	*US $1.00/bbl*	**115**	**0.11**	**90**	**0.09**
Exchange rate (US $ per Cdn $)[3][7]	**0.748**	*US $0.01*	**(70)**	**(0.07)**	**(52)**	**(0.05)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as at June 30, 2019.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent-based production.*
(5) *Includes impact of natural gas consumption by the Company.*
(6) *Excludes impact on Canadian asphalt operations.*
(7) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

4.0 Results of Operations

4.1 Upstream

Exploration and Production

Exploration and Production Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2019**	2018	**2019**	2018
Gross revenues	**1,252**	1,284	**2,436**	2,368
Royalties	**(83)**	(99)	**(154)**	(179)
Net revenues	**1,169**	1,185	**2,282**	2,189
Purchases of crude oil and products	**—**	1	**—**	1
Production, operating and transportation expenses	**385**	384	**800**	741
Selling, general and administrative expenses	**69**	77	**148**	153
Depletion, depreciation, amortization and impairment ("DD&A")	**430**	434	**852**	881
Exploration and evaluation expenses	**86**	40	**116**	70
Gain on sale of assets	**—**	—	**(2)**	(4)
Other – net	**(35)**	27	**115**	31
Share of equity investment gain	**(15)**	(17)	**(27)**	(21)
Financial items	**49**	21	**82**	41
Provisions for income taxes	**50**	60	**46**	81
Net earnings	**150**	158	**152**	215

Second Quarter

Exploration and Production net revenues decreased by $16 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to lower production, partially offset by higher average realized sales prices, both of which are described in more detail below.

Exploration and evaluation expenses increased by $46 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to higher expensed drilling, which is described in more detail in the Exploration and Evaluation Expenses section.

Financial items increased by $28 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to higher finance expenses arising from the adoption of IFRS 16 in 2019.

Six Months

Exploration and Production net revenues increased by $93 million compared to the same period in 2018, primarily due to higher average realized sales prices, partially offset by lower production, both of which are described in more detail below.

Exploration and evaluation expenses increased by $46 million compared to the same period in 2018, primarily due to the same factors which impacted the second quarter.

Other – net increased by $84 million compared to the same period in 2018, primarily due to profit or loss elimination between segments.

Financial items increased by $41 million compared to the same period in 2018, primarily due to the same factors which impacted the second quarter.

Provisions for income taxes decreased by $35 million compared to the same period in 2018, primarily due to lower earnings before income taxes in 2019.

Average Sales Prices Realized

Average Sales Prices Realized	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
Crude oil and NGL *($/bbl)*				
Light and Medium crude oil	**77.07**	92.23	**75.26**	86.59
NGL[1]	**50.22**	54.13	**47.96**	54.56
Heavy crude oil	**63.15**	54.22	**56.45**	43.42
Bitumen	**58.32**	44.41	**52.28**	36.13
Total crude oil and NGL average	**60.13**	53.83	**54.52**	47.03
Natural gas average *($/mcf)*[1]	**6.19**	6.53	**6.67**	6.78
Total average *($/boe)*	**53.35**	49.74	**50.20**	45.30

[1] *Reported average NGL and natural gas prices 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.*

Second Quarter

The average sales prices realized by the Company for crude oil and NGL production increased by 12 percent in the second quarter of 2019 compared to the second quarter of 2018, primarily due to narrowing of the Canadian light/heavy oil differential.

The average sales prices realized by the Company for natural gas production decreased by five percent in the second quarter of 2019 compared to the second quarter of 2018, primarily due to lower production from the Liwan Gas Project due to lower nominations from the gas buyer in Guangdong, China.

Six Months

The average sales prices realized by the Company for crude oil and NGL production increased by 16 percent compared to the same period in 2018, primarily due to the same factors which impacted the second quarter.

The average sales prices realized by the Company for natural gas production decreased by two percent compared to the same period in 2018, primarily due to the same factors which impacted the second quarter.

Daily Gross Production

Daily Gross Production	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
Crude Oil and NGL *(mbbls/day)*				
Western Canada				
Light and Medium crude oil	**7.4**	9.0	**8.2**	9.1
NGL	**10.7**	12.3	**12.5**	11.8
Heavy crude oil	**28.9**	38.5	**28.3**	39.0
Bitumen[1]	**120.4**	123.2	**125.3**	123.3
	167.4	183.0	**174.3**	183.2
Atlantic				
White Rose and Satellite Fields – light crude oil	**8.3**	15.9	**5.6**	19.5
Terra Nova – light crude oil	**3.9**	4.8	**4.3**	5.0
	12.2	20.7	**9.9**	24.5
Asia Pacific				
Liwan – NGL[2]	**7.1**	7.7	**7.4**	7.9
Madura –NGL[3]	**2.5**	1.8	**2.6**	1.4
	9.6	9.5	**10.0**	9.3
	189.2	213.2	**194.2**	217.0
Natural gas *(mmcf/day)*				
Western Canada	**279.6**	285.0	**290.6**	281.9
Asia Pacific				
Liwan[2]	**161.5**	180.3	**171.0**	180.0
Madura[3]	**34.0**	28.7	**34.2**	23.7
	195.5	209.0	**205.2**	203.7
	475.1	494.0	**495.8**	485.6
Total *(mboe/day)*	**268.4**	295.5	**276.8**	297.9

(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 interim financial statement purposes.*

Crude Oil and NGL Production

Second Quarter

Crude oil and NGL production decreased by 24.0 mbbls/day in the second quarter of 2019 compared to the second quarter of 2018, primarily due to a reduction of heavy crude oil production due to government-mandated production quotas in Alberta and natural declines, lower production from Atlantic due to limited production from the White Rose field, lower bitumen production as a result of planned turnarounds at six of the Saskatchewan thermal plants, and the impact of government-mandated production quotas in Alberta at the Sunrise Energy Project.

Six Months

Crude oil and NGL production decreased by 22.8 mbbls/day compared to the same period in 2018, primarily due to a reduction of heavy crude oil production due to government-mandated production quotas in Alberta and natural declines, combined with lower production from Atlantic due to limited production from the White Rose field. The decrease was partially offset by increased bitumen production from the Company's thermal projects, combined with increased NGL production from Western Canada and Asia Pacific.

Natural Gas Production

Second Quarter

Natural gas production decreased by 18.9 mmcf/day in the second quarter of 2019 compared to the second quarter of 2018, primarily due to lower production from the Liwan Gas Project due to lower nominations from the gas buyer in Guangdong, China. The decrease was partially offset by the higher production from the BD Project.

Six Months

Natural gas production increased by 10.2 mmcf/day compared to the same period in 2018, primarily due to higher production from the BD Project and the Rainbow Lake development, which was partially offset by lower nominations from the gas buyer in Guangdong, China.

2019 Production Guidance

The following table shows actual daily production for the six months ended June 30, 2019, and the year ended December 31, 2018, as well as the previously issued production guidance for 2019.

Gross Production	Guidance 2019	Actual Production: Six months ended June 30, 2019	Actual Production: Year ended December 31, 2018
Canada			
Light & medium crude oil *(mbbls/day)*	29 - 31	**18**	31
NGL *(mbbls/day)*	12 - 13	**13**	12
Heavy crude oil & bitumen *(mbbls/day)*	155 - 163	**154**	161
Natural gas *(mmcf/day)*	297 - 307	**291**	291
Canada total *(mboe/day)*	246 - 258	**233**	252
Asia Pacific			
Light crude oil *(mbbls/day)*	3 - 3	**—**	—
NGL *(mbbls/day)*(1)	6 - 7	**10**	11
Natural gas *(mmcf/day)*(1)	210 - 220	**205**	216
Asia Pacific total *(mboe/day)*	44 - 47	**44**	47
Total *(mboe/day)*	290 - 305	**277**	299

(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 interim financial statement purposes.*

Production for the six months ended June 30, 2019 reflects planned turnarounds, government-mandated production quotas in Alberta, a managed restart of White Rose operations as well as reduced demand in Asia Pacific driven by customer facility turnarounds. The second half of the year is expected to have higher production volumes as the Company exits the turnaround season, fully ramps up production at White Rose, and brings on the Dee Valley Thermal Project in Saskatchewan.

Royalties

Royalties *(Percent)*	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Western Canada(1)	**7**	8	**6**	8
Atlantic	**12**	11	**12**	8
Asia Pacific(2)	**7**	7	**7**	6
Total	**7**	8	**6**	8

(1) *Includes thermal and non-thermal developments.*
(2) *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.*

Second Quarter

Total royalty rates in the second quarter of 2019 were comparable to the second quarter of 2018.

Six Months

Total royalty rates decreased compared to the same period in 2018, primarily due to lower royalty rates from thermal developments as a result of a change to pre-payout status of a thermal property in the first quarter of 2019. The decrease was partially offset by increased royalty rates for Atlantic compared to the same period in 2018, primarily due to a higher proportion of production from the Terra Nova field, which has a higher royalty rate.

Operating Costs

Operating Costs	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2019**	2018	**2019**	2018
Western Canada[1]	**305**	304	**634**	599
Atlantic	**58**	56	**121**	101
Asia Pacific[2]	**24**	23	**49**	42
Total	**387**	383	**804**	742
Per unit operating costs *($/boe)*	**15.83**	14.22	**16.07**	13.78

(1) *Includes thermal and non-thermal developments.*

(2) *Reported operating costs 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.*

Second Quarter

Total Exploration and Production operating costs were $387 million in the second quarter of 2019 compared to $383 million in the second quarter of 2018. Total per unit operating costs averaged $15.83/boe in the second quarter of 2019 compared to $14.22/boe in the second quarter of 2018. The increase in per unit operating costs was primarily due to the factors discussed below.

Per unit operating costs in Atlantic averaged $52.75/bbl in the second quarter of 2019 compared to $29.65/bbl in the second quarter of 2018. The increase in per unit operating costs was primarily due to lower production at the White Rose field, combined with additional costs associated with flowline repair and additional well workover scope at Terra Nova.

Per unit operating costs in Western Canada averaged $15.66/boe in the second quarter of 2019 compared to $14.46/boe in the second quarter of 2018. The increase in per unit operating costs was primarily due to lower production.

Per unit operating costs in Asia Pacific averaged $6.18/boe in the second quarter of 2019 compared to $5.77/boe in the second quarter of 2018. The increase in per unit operating costs was primarily due to lower production from the Liwan Gas Project, partially offset by higher production from the BD Project.

Six Months

Total Exploration and Production operating costs were $804 million compared to $742 million in the same period in 2018. Total per unit operating costs averaged $16.07/boe compared to $13.78/boe in the same period in 2018. The increase in per unit operating costs was primarily due to the factors discussed below.

Per unit operating costs in Atlantic averaged $67.68/bbl compared to $22.65/bbl in the same period in 2018. The increase in per unit operating costs was primarily due to the same factors which impacted the second quarter.

Per unit operating costs in Western Canada averaged $15.75/boe compared to $14.41/boe in the same period in 2018. The increase in per unit operating costs was primarily due to higher electricity and natural gas costs.

Per unit operating costs in Asia Pacific averaged $6.15/boe compared to $5.40/boe in the same period in 2018. The increase in per unit operating costs was primarily due to planned maintenance costs at the Liwan Gas Project in the first quarter of 2019, combined with the same factors which impacted the second quarter.

Exploration and Evaluation Expenses

Exploration and Evaluation Expenses	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2019**	2018	**2019**	2018
Seismic, geological and geophysical	**24**	20	**52**	48
Expensed drilling	**60**	20	**60**	20
Expensed land	**2**	—	**4**	2
Total	**86**	40	**116**	70

Second Quarter

Exploration and Evaluation expenses in the second quarter of 2019 were $86 million compared to $40 million in the second quarter of 2018. The increase in expensed drilling was primarily due to the write off of the exploration wells drilled in Atlantic and Asia Pacific, which did not encounter commercial hydrocarbons.

Six Months

Exploration and Evaluation expenses in the first six months of 2019 were $116 million compared to $70 million in the same period in 2018. The increase in expensed drilling was primarily due to the same factors which impacted the second quarter.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were higher in the second quarter of 2019 compared to the second quarter of 2018, primarily due to the factors discussed below. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[1]	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2019**	2018	**2019**	2018
Exploration				
Western Canada	**—**	8	**—**	33
Thermal developments	**5**	2	**13**	3
Atlantic	**5**	56	**11**	59
Asia Pacific[2]	**1**	23	**2**	34
	11	89	**26**	129
Development				
Western Canada	**60**	35	**154**	126
Thermal developments	**180**	191	**380**	343
Non-thermal developments	**21**	15	**58**	30
Atlantic	**207**	162	**422**	337
Asia Pacific[2]	**87**	31	**145**	35
	555	434	**1,159**	871
Acquisitions				
Western Canada	**—**	—	**—**	4
Thermal developments	**—**	1	**—**	39
	—	1	**—**	43
Total	**566**	524	**1,185**	1,043

[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 interim financial statement purposes.*

Western Canada

During the first six months of 2019, $154 million (13 percent) was invested in Western Canada, compared to $163 million (16 percent) in the same period in 2018. Capital expenditures in 2019 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 Sinclair areas.

Thermal Developments

During the first six months of 2019, $393 million (33 percent) was invested in thermal developments compared to $385 million (37 percent) in the same period in 2018. Capital expenditures in 2019 related primarily to construction work at the Dee Valley and the Spruce Lake Central and North thermal projects.

Non-Thermal Developments

During the first six months of 2019, $58 million (five percent) was invested in non-thermal developments compared to $30 million (three percent) in the same period in 2018. Capital expenditures in 2019 related primarily to drilling and advancing the Company's EOR program, particularly the Alberfeldy Polymer flood.

Atlantic

During the first six months of 2019, $433 million (37 percent) was invested in Atlantic compared to $396 million (38 percent) in the same period in 2018. Capital expenditures in 2019 related primarily to the development of the West White Rose Project and sustainment and development activities at the White Rose field.

Asia Pacific

During the first six months of 2019, $147 million (12 percent) was invested in Asia Pacific compared to $69 million (seven percent) in the same period in 2018. Capital expenditures in 2019 related primarily to the continued development of Liuhua 29-1.

Exploration and Production Wells Drilled

Onshore drilling activity

The following table discloses the number of wells drilled during the three and six months ended June 30, 2019 and 2018:

	Three months ended June 30,				Six months ended June 30,			
	2019		2018		**2019**		2018	
Wells Drilled *(wells)*[1]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Thermal developments	**7**	**7**	43	37	**47**	**47**	60	53
Non-thermal developments	**5**	**5**	—	—	**22**	**22**	4	4
Western Canada	**2**	**2**	—	—	**16**	**14**	11	10
Total	**14**	**14**	43	37	**85**	**83**	75	67

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

Offshore drilling activity

The following table discloses the Company's Offshore drilling activity during the six months ended June 30, 2019:

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

Infrastructure and Marketing

Infrastructure and Marketing Earnings (Loss) Summary	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2019**	2018	**2019**	2018
Gross revenues	**648**	634	**1,058**	1,080
Marketing and other	**(14)**	187	**144**	352
Expenses				
Purchases of crude oil and products	**686**	602	**1,087**	1,023
Production, operating and transportation expenses	**5**	15	**8**	17
Selling, general and administrative expenses	**2**	1	**3**	2
Depletion, depreciation, amortization and impairment	**4**	1	**6**	1
Other – net	**(2)**	—	**—**	2
Share of equity investment gain	**(8)**	(9)	**(18)**	(14)
Provisions for (recovery of) income taxes	**(15)**	57	**31**	109
Net earnings (loss)	**(38)**	154	**85**	292

Second Quarter

Infrastructure and Marketing gross revenues of $648 million in the second quarter of 2019 were comparable to the $634 million reported in second quarter of 2018.

Marketing and other decreased by $201 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to the tightening of location pricing differentials between Canada and the U.S.

Infrastructure and Marketing purchases of crude oil and products increased by $84 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to additional costs incurred on the construction of the Saskatchewan Gathering System Expansion.

Recovery of income taxes increased by $72 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to lower earnings before income taxes in the second quarter of 2019.

Six Months

Infrastructure and Marketing gross revenues of $1,058 million were comparable to the $1,080 million reported in the same period in 2018.

Marketing and other decreased by $208 million compared to the same period in 2018, primarily due to the same factors which impacted the second quarter.

Infrastructure and Marketing purchases of crude oil and products increased by $64 million compared to the same period in 2018, primarily due to the same factors which impacted the second quarter.

Provisions for income taxes decreased by $78 million compared to the same period in 2018, primarily due to lower earnings before income taxes in 2019.

4.2 Downstream

Upgrading

Upgrading Earnings (Loss) Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2019**	2018	**2019**	2018
Gross revenues	**457**	444	**857**	909
Expenses				
Purchases of crude oil and products	**375**	251	**632**	490
Production, operating and transportation expenses	**54**	46	**106**	92
Selling, general and administrative expenses	**3**	2	**5**	4
Depletion, depreciation, amortization and impairment	**28**	29	**57**	57
Provisions for (recovery of) income taxes	**(1)**	32	**15**	73
Net earnings (loss)	**(2)**	84	**42**	193
Upgrading throughput *(mbbls/day)*[(1)]	**73.4**	72.5	**72.3**	76.7
Total sales *(mbbls/day)*	**72.8**	69.1	**73.8**	74.3
Synthetic crude oil sales *(mbbls/day)*	**54.1**	47.1	**53.8**	51.5
Upgrading differential *($/bbl)*	**15.18**	26.67	**14.88**	29.49
Unit margin *($/bbl)*	**12.38**	30.69	**16.84**	31.16
Unit operating cost *($/bbl)*[(2)]	**8.08**	6.97	**8.10**	6.63

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

Second Quarter

Upgrading gross revenues increased by $13 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to higher sales volumes, partially offset by lower realized prices for synthetic crude oil. The price of Husky Synthetic Blend in the second quarter of 2019 averaged $79.59/bbl compared to $85.66/bbl in the second quarter of 2018.

Upgrading purchases of crude oil and products increased by $124 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to an increase in the average cost of heavy crude oil feedstock, combined with higher throughput volumes in the second quarter of 2019.

Recovery of income taxes increased by $33 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to lower earnings before income taxes in the second quarter of 2019.

Six Months

Upgrading gross revenues decreased by $52 million compared to the same period in 2018, primarily due to lower realized prices for synthetic crude oil, partially offset by higher synthetic crude sales volumes. The price of Husky Synthetic Blend averaged $74.56/bbl compared to $81.42/bbl in the same period in 2018.

Upgrading purchases of crude oil and products increased by $142 million compared to the same period in 2018, primarily due to an increase in the average cost of heavy crude oil feedstock, partially offset by lower throughput volumes in 2019.

Provisions for income taxes decreased by $58 million compared to the same period in 2018, primarily due to lower earnings before income taxes in 2019.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2019**	2018	**2019**	2018
Gross revenues	**804**	869	**1,458**	1,590
Expenses				
Purchases of crude oil and products	**671**	711	**1,174**	1,289
Production, operating and transportation expenses	**83**	72	**152**	132
Selling, general and administrative expenses	**13**	11	**27**	24
Depletion, depreciation, amortization and impairment	**33**	28	**67**	57
Financial items	**4**	3	**8**	6
Provisions for income taxes	**—**	12	**8**	22
Net earnings	**—**	32	**22**	60
Number of fuel outlets[(1)]	**554**	558	**554**	558
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*	**7.2**	7.5	**7.4**	7.5
Fuel sales per retail outlet *(thousands of litres/day)*	**11.8**	12.1	**11.9**	12.0
Refinery throughput				
Prince George Refinery *(mbbls/day)*[(2)]	**3.5**	8.8	**6.8**	10.3
Lloydminster Refinery *(mbbls/day)*[(2)]	**26.1**	26.8	**24.5**	27.7
Ethanol production *(thousands of litres/day)*	**789.7**	799.6	**825.5**	815.4

(1) *Average number of fuel outlets for period indicated.*
(2) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*

Second Quarter

Canadian Refined Products gross revenues decreased by $65 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to lower sales volumes.

Canadian Refined Products purchases of crude oil and products decreased by $40 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to lower throughput volumes resulting primarily from a planned turnaround at the Prince George Refinery in the second quarter of 2019.

Six Months

Canadian Refined Products gross revenues decreased by $132 million compared to the same period in 2018, primarily due to the same factors which impacted the second quarter.

Canadian Refined Products purchases of crude oil and products decreased by $115 million compared to the same period in 2018, primarily due to lower commodity prices, combined with the same factors which impacted the second quarter.

Canadian Refined Products production, operating and transportation expenses increased by $20 million compared to the same period in 2018, primarily due to higher costs related to a planned turnaround at the Prince George Refinery in the second quarter of 2019.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Gross revenues	**2,791**	3,035	**5,074**	5,806
Expenses				
Purchases of crude oil and products	**2,342**	2,565	**4,170**	5,070
Production, operating and transportation expenses	**216**	217	**431**	380
Selling, general and administrative expenses	**9**	7	**16**	12
Depletion, depreciation, amortization and impairment	**122**	125	**238**	219
Other – net	**(76)**	(29)	**(184)**	(23)
Financial items	**5**	3	**9**	7
Provisions for income taxes	**39**	32	**88**	31
Net earnings	**134**	115	**306**	110
Select operating data:				
Lima Refinery throughput *(mbbls/day)*[(1)]	**179.8**	171.2	**175.7**	167.8
BP-Husky Toledo Refinery throughput *(mbbls/day)*[(1)(2)]	**57.5**	65.5	**57.5**	70.3
Superior Refinery throughput *(mbbls/day)*[(1)]	**—**	10.1	**—**	23.5
Refining and marketing margin *(US$/bbl crude throughput)*	**14.16**	16.66	**15.87**	12.37
Refinery inventory *(mmbbls)*[(3)]	**8.4**	9.3	**8.4**	9.3

[(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)] *Feedstock and refined products are included in refinery inventory.*

Second Quarter

U.S. Refining and Marketing gross revenues decreased by $244 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to lower sales volumes at the Superior and BP-Husky Toledo refineries and lower prices, partially offset by higher sales volumes at the Lima Refinery.

U.S. Refining and Marketing purchases of crude oil and products decreased by $223 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to lower throughput at the BP-Husky Toledo Refinery resulting from a planned turnaround in the second quarter of 2019.

Other – net income increased by $47 million in the second quarter of 2019 compared to the second quarter of 2018, primarily due to pre-tax insurance recoveries for business interruption and incident costs associated with the incident at the Superior Refinery.

Six Months

U.S. Refining and Marketing gross revenues decreased by $732 million compared to the same period in 2018, primarily due to the same factors which impacted the second quarter.

U.S. Refining and Marketing purchases of crude oil and products decreased by $900 million compared to the same period in 2018, primarily due to the realization of the lower cost crude oil feedstock, from late 2018, at the Lima Refinery during the first quarter of 2019, combined with the same factors which impacted the second quarter.

Production, operating and transportation expenses increased by $51 million compared to the same period in 2018, primarily due to costs associated with the incident at the Superior Refinery.

Other – net income increased by $161 million compared to the same period in 2018, primarily due to the same factors which impacted the second quarter.

Provisions for income taxes increased by $57 million compared to the same period in 2018, primarily due to higher earnings before income taxes in the second quarter of 2019.

Downstream Capital Expenditures

During the first six months of 2019, Downstream capital expenditures totalled $424 million compared to $246 million in the same period in 2018. In Canada, capital expenditures of $93 million related primarily to the polymer modified asphalt project at the Lloydminster Refinery and costs related to the planned turnaround at the Prince George Refinery. In the U.S., capital expenditures of $331 million related primarily to the crude oil flexibility project at the Lima Refinery and costs related to the turnaround at the BP-Husky Toledo Refinery.

4.3 Corporate

Corporate Summary ($ millions) income (expense)	Three months ended June 30, 2019	 2018	Six months ended June 30, 2019	 2018
Production, operating and transportation expenses	**—**	—	**1**	—
Selling, general and administrative expenses	**(86)**	(88)	**(129)**	(160)
Depletion, depreciation and amortization	**(26)**	(22)	**(53)**	(42)
Other – net	**(10)**	9	**(10)**	9
Net foreign exchange gain	**2**	3	**32**	25
Finance income	**17**	12	**36**	23
Finance expense	**(48)**	(46)	**(89)**	(94)
Recovery of income taxes	**277**	37	**303**	65
Net earnings (loss)	**126**	(95)	**91**	(174)

Second Quarter

The Corporate segment reported net earnings of $126 million in the second quarter of 2019 compared to a net loss of $95 million in the second quarter of 2018. Other – net increased by $19 million, primarily due to a higher unrealized loss on short-dated foreign exchange forwards, partially offset by the unrealized gain on the Company's commodity short-term hedging program. Recovery of income taxes increased by $240 million, primarily due to the factors discussed in the Consolidated Income Taxes section below.

Six Months

In the first six months of 2019, the Corporate segment reported net earnings of $91 million compared to a net loss of $174 million in the same period in 2018. Selling, general and administrative expenses decreased by $31 million, primarily due to lower stock based compensation expenses. Recovery of income taxes increased by $238 million, primarily due to the factors discussed in the Consolidated Income Taxes section below.

The net foreign exchange gain for the six months ended June 30, 2019, increased by $7 million due to items noted below.

Foreign Exchange Summary ($ millions, except where indicated)	Three months ended June 30, 2019	 2018	Six months ended June 30, 2019	 2018
Non-cash working capital loss	**(39)**	(2)	**(31)**	—
Other foreign exchange gain	**41**	5	**63**	25
Net foreign exchange gain	**2**	3	**32**	25
U.S./Canadian dollar exchange rates:				
At beginning of period	**US$0.749**	US$0.775	**US$0.733**	US$0.799
At end of period	**US$0.764**	US$0.761	**US$0.764**	US$0.761

Included in the other foreign exchange gain are realized and unrealized gains and losses on working capital and intercompany financing. The foreign exchange gains 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 condensed interim consolidated financial statements.

Consolidated Income Taxes

Consolidated Income Taxes ($ millions)	Three months ended June 30, 2019	 2018	Six months ended June 30, 2019	 2018
Provisions for (recovery of) income taxes	**(204)**	156	**(115)**	251
Cash income taxes paid (received)	**(6)**	37	**78**	60

Second Quarter

Consolidated income taxes were a recovery of $204 million in the second quarter of 2019 compared to a provision of $156 million in the second quarter of 2018. The decrease in consolidated income taxes was primarily due to the recognition of $233 million in tax recoveries related to the reduction in the Alberta provincial corporate tax rate that was substantively enacted in the second quarter of 2019.

Six Months

Consolidated income taxes were a recovery of $115 million compared to a provision of $251 million in the same period in 2018. The decrease in consolidated income taxes was primarily due to the same factors which impacted the second quarter.

5.0 Risk Management and Financial Risks

5.1 Risk Management

The Company is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's Annual Information Form dated February 26, 2019. The Company has processes in place designed to identify the principal risks of the business and has put in place what it believes is appropriate mitigation to manage such risks where possible. The Company's operational, political, environmental, financial, liquidity and contract and credit risks have not materially changed since December 31, 2018, which were discussed in the Company's MD&A for the year ended December 31, 2018.

5.2 Financial Risks

The following provides an update on the Company's commodity price, interest rate and foreign currency risk management.

Commodity Price Risk Management

The Company uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its crude oil and natural gas production, and it also uses firm commitments for the purchase or sale of crude oil and natural gas. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable, inventory, other assets, accounts payable and accrued liabilities and other long-term liabilities. All derivatives are measured at fair value through profit or loss other than non-financial derivative contracts that meet the Company's own use requirements.

At June 30, 2019, the Company was party to crude oil purchase and sale derivative contracts to mitigate its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. The Company was also party to third party physical natural gas purchase and sale derivative contracts in order to mitigate commodity price fluctuations. Refer to Note 15 of the condensed interim consolidated financial statements.

During the six months ended June 30, 2019, the Company entered into a commodity short-term hedging program using put and call options to manage risks related to volatility of commodity prices.

WTI Crude Oil Call and Put Option Contracts[(1)]

Type	Transaction	Term	Volume (bbls/day)	Call Price (US$bbl)	Put Price (US$bbl)
Call options	Sold	July - September 2019	**29,945**	**65.42**	**—**
Put options	Bought	July - September 2019	**33,242**	**—**	**61.57**
Put options	Sold	July - September 2019	**6,319**	**—**	**48.20**

(1) *Prices reported are the weighted average prices for the period.*

Foreign Exchange Risk Management

At June 30, 2019, Cdn $4.1 billion or 69 percent of the Company's outstanding long-term debt was denominated in U.S. dollars. The U.S. denominated long-term debt, including amounts due within one year, is exposed to changes in the Canadian/U.S. exchange rate. As at June 30, 2019, Cdn $3.1 billion of the Company's total outstanding long-term debt has been designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.

For the three and six months ended June 30, 2019, the Company incurred an unrealized gain of $58 million and $123 million, respectively, arising from the translation of the debt, net of tax of $7 million and $17 million, respectively, which was recorded in hedge of net investment within other comprehensive income (loss) ("OCI").

Interest Rate Risk Management

The Company is exposed to fluctuations in short-term interest rates as Husky maintains a portion of its debt capacity in revolving and floating rate bank facilities and commercial paper and invests surplus cash in short-term debt instruments and money market instruments. The Company is also exposed to interest rate risk when fixed rate debt instruments are maturing and require refinancing or when new debt capital needs to be raised.

By maintaining a mix of both fixed and floating rate debt, the Company mitigates some of its exposure to interest rate changes. The optimal mix maintained will depend on market conditions. The Company may also enter into interest rate swaps as an additional means of managing current and future interest rate risk.

6.0 Liquidity and Capital Resources

6.1 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 June 30, 2019, the Company had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[1]	**900**	**450**
Syndicated credit facilities[2]	**4,000**	**3,800**
Total	**4,900**	**4,250**

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

At June 30, 2019, the Company had $4,250 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $450 million are short-term uncommitted credit facilities. A total of $450 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 June 30, 2019, the Company had no direct borrowing against committed credit facilities. The maturity dates for the Company's revolving syndicated credit facilities are June 19, 2022 and March 9, 2024. The Company's ability to renew existing bank credit facilities and raise new debt is dependent upon maintaining an investment grade credit rating and the condition of capital and credit markets. Credit ratings may be affected by the Company's level of debt, from time to time.

The Company's share capital is not subject to external restrictions. The Company's leverage covenant under both of its revolving syndicated credit facilities is debt to capital and calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. 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 June 30, 2019, and assessed the risk of non-compliance to be low.

Working capital is the amount by which current assets exceed current liabilities. At June 30, 2019, working capital was $645 million compared to $694 million at December 31, 2018.

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 June 30, 2019.

On January 29, 2018, the Company filed a universal short form base shelf prospectus ("the 2018 U.S. Shelf Prospectus") with the Alberta Securities Commission. On January 30, 2018, the Company's related U.S. registration statement filed with the SEC containing the 2018 U.S. Shelf Prospectus became effective which enables the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the U.S. up to and including February 29, 2020. During the 25-month period that the 2018 U.S. Shelf Prospectus and the related U.S registration statement are effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On March 15, 2019, the Company issued US$750 million senior unsecured notes. The notes bear an annual interest rate of 4.40 percent and are due on April 15, 2029. The Company intends to use the net proceeds of the offering for general corporate purposes, which may include, among other things, the repayment of certain outstanding debt securities maturing in 2019. The Company may invest funds it does not immediately require in short-term marketable debt securities.

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

On June 17, 2019, the Company repaid the maturing 6.15 percent notes issued under a trust indenture dated June 14, 2002. The amount paid to note holders was $402 million.

On June 27, 2019, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on March 9, 2020, was extended to March 9, 2024.

As at June 30, 2019, the Company had $3.0 billion in unused capacity under the 2019 Canadian Shelf Prospectus and US$2.25 billion in unused capacity under the 2018 U.S. Shelf Prospectus and related U.S. registration statement. The ability of the Company to utilize the capacity under the 2019 Canadian Shelf Prospectus and the 2018 U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

6.2 Capital Structure

Capital Structure *($ millions)*	**June 30, 2019 Outstanding**
Total debt[1]	**6,180**
Shareholders' equity	**19,709**

[1] *Total debt is a non-GAAP measure. Refer to Section 10.3 for a reconciliation to the corresponding GAAP measure.*

The Company considers its capital structure to include shareholders' equity and debt which totalled $25.9 billion as at June 30, 2019 (December 31, 2018 – $25.4 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to trailing funds from operations (refer to Section 10.3). The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to trailing funds from operations ratio of less than 2.0 times. At June 30, 2019, debt to capital employed was 23.9 percent (December 31, 2018 – 22.7 percent) and debt to trailing funds from operations was 1.7 times (December 31, 2018 – 1.4 times).

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.

6.3 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. These obligations represent contracts and other commitments that are known and non-cancellable. Refer to the Company's MD&A for the year ended December 31, 2018 under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and other commercial commitments as at December 31, 2018. During the three months ended June 30, 2019, there were no material changes to the Company's contractual obligations or non-cancellable commitments.

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.

6.4 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 Cheung Kong Infrastructure Holdings Limited, which are affiliates of one of the Company's principal shareholders. For the three and six months ended June 30, 2019, the Company charged HMLP $83 million and $196 million, respectively, related to construction and management services. For the three and six months ended June 30, 2019, the Company had purchases from HMLP of $55 million and $109 million, respectively, related to the use of the pipeline for the Company's blending, transportation and storage activities. As at June 30, 2019, the Company had $110 million due from HMLP.

7.0 Critical Accounting Estimates and Key Judgments

The application of some of the Company's accounting policies requires subjective judgment about uncertain circumstances. The potential effects of these estimates, as described in the Company's MD&A for the year ended December 31, 2018, as well as critical areas of judgment have not changed during the current period. The emergence of new information and changed circumstances may result in changes to actual results or changes to estimated amounts that differ materially from current estimates.

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.

Changes in Accounting Policies

Leases

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

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

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

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

The nature of the Company's leasing activities includes offshore drilling rigs, vessels and associated equipment for the use of developing reserves on oil and gas properties, tanks and terminals with dedicated storage capacity, pipelines where the Company has a right to substantially all the economic benefits, dedicated rail cars, retail marketing locations, and office space.

9.0 Outstanding Share Data

Authorized:

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

Issued and outstanding: July 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	20,046,410
• stock options exercisable	10,836,387

10.0 Reader Advisories

10.1 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 intended use of proceeds of the US$750 million senior unsecured notes offering; and the Company's objective of maintaining stated debt to funds from operations and debt to capital employed ratio targets;

- with respect to the Company's thermal developments, estimated production capacity and expected timing of first production from the Dee Valley, Spruce Lake Central, Spruce Lake North, Spruce Lake East, Edam Central and Dee Valley 2 projects;

- with respect to the Company's Offshore business in Asia Pacific: the expected timing of completion of the completion program for the seven wells at Liuhua 29-1; the expected timing of completion of the initial pipe lay program at Liuhua 29-1; the expected timing of first gas production and sales from the MDA and MBH fields; and development plans for the additional MDK shallow water field;

- with respect to the Company's Offshore business in the Atlantic: the expected timing of commencement of construction of the third slipform on the CGS at the West White Rose Project; the expected timing of first production from the West White Rose Project; and the expected timing of return to production at the North Amethyst and South White Rose Extension drill centres;

- with respect to the Company's Infrastructure and Marketing business: expansion plans for the Saskatchewan Gathering System; and 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 Canadian Retail and Commercial Network; the expected timing of completion of the crude oil flexibility project at the Lima Refinery; the expected timing and cost of the rebuild of the Superior Refinery and anticipated insurance recoveries; and the expected timing of resumption of full operations at the Superior Refinery.

There are numerous uncertainties inherent in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from 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.

10.2 Cautionary Note Required by National Instrument 51-101

Unless otherwise noted: (i) projected and historical production volumes disclosed are gross, which represents, as applicable, the total or the Company's working interest share before deduction of royalties; and (ii) all Husky working interest production volumes disclosed are before deduction of royalties.

The Company uses the term "barrels of oil equivalent" (or "boe"), which is consistent with other oil and gas companies' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of 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.

10.3 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, total debt, debt to capital employed, debt to trailing funds from operations and sustaining capital. None of these measures is used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for debt to capital employed or debt to trailing 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 used in this MD&A and related disclosures 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 measure assists management and investors in evaluating the Company's financial strength.

Debt to Trailing Funds from Operations

Debt to trailing funds from operations is a non-GAAP measure and is equal to total debt divided by the 12-month trailing funds from operations as at June 30, 2019. Trailing funds from operations is equal to cash flow – operating activities plus change in non-cash working capital annualized using 12-month rolling figures. Management believes this measure assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of debt to trailing funds from operations for the periods ended June 30, 2019, and December 31, 2018:

Debt to Trailing Funds from Operations

($ millions)	**June 30, 2019**	December 31, 2018
Total debt	**6,180**	5,747
Trailing funds from operations	**3,662**	4,004
Debt to trailing funds from operations	**1.7**	1.4

Funds from Operations

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.

The following table shows the reconciliation of net earnings to funds from operations and related per share amounts for the periods ended:

Reconciliation of Cash Flow	Three months ended							
	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30
($ millions)	**2019**	2019	2018	2018	2018	2018	2017	2017
Net earnings	**370**	328	216	545	448	248	672	136
Items not affecting cash:								
Accretion	**26**	27	25	23	25	24	28	27
Depletion, depreciation, amortization and impairment	**643**	630	662	672	639	618	647	673
Inventory write-down to net realizable value	**—**	—	60	—	—	—	—	—
Exploration and evaluation expenses	**23**	—	22	—	7	—	—	1
Deferred income taxes	**(250)**	43	25	156	138	77	(360)	52
Foreign exchange loss (gain)	**(2)**	(12)	1	(6)	(2)	1	1	(3)
Stock-based compensation	**13**	7	(50)	40	33	21	25	11
Gain on sale of assets	**—**	(2)	—	—	—	(4)	(13)	(2)
Unrealized mark to market loss (gain)	**(4)**	57	(16)	(22)	(26)	(86)	57	31
Share of equity investment gain	**(23)**	(22)	(16)	(18)	(26)	(9)	(1)	(12)
Gain on insurance recoveries for damage to property	**—**	—	(253)	—	—	—	—	—
Other	**5**	(9)	2	(2)	19	2	8	9
Settlement of asset retirement obligations	**(41)**	(72)	(65)	(45)	(22)	(49)	(45)	(23)
Deferred revenue	**(5)**	(16)	(30)	(25)	(25)	(20)	(5)	(9)
Distribution from equity investment	**47**	—	—	—	—	72	—	—
Change in non-cash working capital	**(42)**	(414)	730	(35)	(199)	(366)	337	3
Cash flow – operating activities	**760**	545	1,313	1,283	1,009	529	1,351	894
Change in non-cash working capital	**42**	414	(730)	35	199	366	(337)	(3)
Funds from operations	**802**	959	583	1,318	1,208	895	1,014	891
Funds from operations – basic	**0.80**	0.95	0.58	1.31	1.20	0.89	1.01	0.89
Funds from operations – diluted	**0.80**	0.95	0.58	1.31	1.20	0.89	1.01	0.89

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 measure assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of total debt for the periods ended June 30, 2019 and December 31, 2018:

Total Debt		
($ millions)	**June 30, 2019**	December 31, 2018
Short-term debt	**200**	200
Long-term debt due within one year	**1,382**	1,433
Long-term debt	**4,598**	4,114
Total debt	**6,180**	5,747

Sustaining Capital

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

10.4 Additional Reader Advisories

This MD&A should be read in conjunction with the condensed interim consolidated financial statements and related notes.

Readers are encouraged to refer to the Company's MD&A for the year ended December 31, 2018, the 2018 consolidated financial statements, the Annual Information Form dated February 26, 2019 filed with Canadian securities regulatory authorities and the 2018 Form 40-F filed with the U.S. Securities and Exchange Commission for additional information relating to the Company. These documents are available at *www.sedar.com*, at *www.sec.gov* and at *www.huskyenergy.com*.

Use of Pronouns and Other Terms Denoting Husky

In this MD&A, the terms "Husky" and the "Company" denote the corporate entity Husky Energy Inc. and its subsidiaries on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended June 30, 2019 and the six months ended June 30, 2019 are compared to the results for the three months ended June 30, 2018 and the six months ended June 30, 2018. Discussions with respect to the Company's financial position as at June 30, 2019 are compared to its financial position as at December 31, 2018. Amounts presented within this MD&A are unaudited.

Additional Reader Guidance

- The condensed interim consolidated financial statements and comparative financial information included in this MD&A have been prepared in accordance with IAS 34, "Interim Financial Reporting" as issued by the IASB.
- All dollar amounts are in Canadian dollars, unless otherwise indicated.
- Prices are presented before the effect of hedging.
- There have been no changes to the Company's internal controls over financial reporting ("ICFR") for the three months ended June 30, 2019 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

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 trailing funds from operations	*Long-term debt, long-term debt due within one year and short-term debt divided by trailing 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*
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*
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 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*
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*
Sustaining capital	*The additional development capital that is required by the business to maintain production and operations at existing levels. Development capital includes the cost to drill, complete, equip and tie-in wells to existing infrastructure.*
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/day*	*thousand barrels of oil equivalent per day*
bbls/day	*barrels per day*	*mcf*	*thousand cubic feet*
boe	*barrels of oil equivalent*	*mmbbls*	*million barrels*
boe/day	*barrels of oil equivalent per day*	*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*
mboe	*thousand barrels of oil equivalent*		