MANAGEMENT'S DISCUSSION AND ANALYSIS

October 25, 2018

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1.0 Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Sept. 30**	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31
($ millions, except where indicated)	**2018**	2018	2018	2017	2017	2017	2017	2016
Production *(mboe/day)*	**296.7**	295.5	300.4	320.4	317.7	319.5	334.0	327.0
Gross revenues and Marketing and other(1)	**6,300**	5,983	5,262	5,534	4,713	4,351	4,348	3,865
Net earnings (loss)	**545**	448	248	672	136	(93)	71	186
Per share – Basic	**0.53**	0.44	0.24	0.66	0.13	(0.10)	0.06	0.19
Per share – Diluted	**0.53**	0.44	0.24	0.66	0.13	(0.10)	0.06	0.19
Adjusted net earnings (loss)(2)	**568**	474	245	665	136	10	73	(6)
Funds from operations(2)	**1,318**	1,208	895	1,014	891	715	686	662
Per share – Basic	**1.31**	1.20	0.89	1.01	0.89	0.71	0.68	0.66
Per share – Diluted	**1.31**	1.20	0.89	1.01	0.89	0.71	0.68	0.66

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

(2) *Adjusted net earnings (loss) and funds from operations are non-GAAP measures. The calculation of funds from operations changed in the second quarter of 2017. Prior periods have been revised to conform to current presentation. Refer to Section 10.3 for a reconciliation to the GAAP measures and an explanation of the changes.*

Performance

- Net earnings of $545 million in the third quarter of 2018 compared to net earnings of $136 million in the third quarter of 2017, with the increase primarily due to:
  - Higher earnings from crude oil marketing activities due to the widening of location pricing differentials between Canada and the U.S., which the Company is able to capture due to its committed capacity on the Keystone pipeline;
  - Higher realized crude oil prices;
  - Higher natural gas production from Asia Pacific;
  - Higher realized margins at the Lloydminster Upgrader; and
  - Higher realized U.S. Refining and Marketing margins.

  Partially offset by:
  - Lower Upstream production due to the factors described below.
- Funds from operations of $1,318 million in the third quarter of 2018 compared to $891 million in the third quarter of 2017, with the increase primarily attributed to the same factors noted above for net earnings.
- Production decreased by 21.0 mboe/day or 7 percent to 296.7 mboe/day in the third quarter of 2018 compared to the third quarter of 2017 as a result of:
  - Lower crude oil and natural gas production in Western Canada due to the disposition of select legacy assets in 2017;
  - Lower heavy crude oil production due to natural declines and reduced optimization activities in the Company's non-thermal developments;
  - Lower crude oil production in Asia Pacific due to the expiry of the Company's participation in Wenchang in the fourth quarter of 2017;

- Lower production from Atlantic due to a high water cut well at North Amethyst combined with natural well declines; and
- Lower bitumen production from the Tucker Thermal Project and Sunrise Energy Project due to planned turnaround and maintenance.

Partially offset by:

- Higher natural gas and natural gas liquids ("NGL") production from the Liwan and BD projects; and
- Higher NGL production from Western Canada.

2.0 Husky Business Overview

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

2.1 Corporate Strategy

The Company's business strategy is to focus on returns from investment in a deep portfolio of opportunities that can generate increased funds from operations and free cash flow.

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

Integrated Corridor

The Company's business in the Integrated Corridor includes crude oil, bitumen, natural gas and NGL production from Western Canada, the Lloydminster upgrading and asphalt refining complex, the Prince George Refinery, 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 Q3 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 marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, 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 in Western Canada, Asia Pacific and Atlantic.

Exploration and Production

Thermal Developments

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

Total bitumen production, including Lloyd thermal bitumen projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 117,300 bbls/day in the third quarter of 2018.

Lloyd Thermal Bitumen Projects
The Company expects to bring on 60,000 bbls/day of long-life thermal bitumen production through to 2021.

Development continued at the 10,000 bbls/day Rush Lake 2 Thermal Project. Construction of the Central Processing Facility ("CPF") was completed and first steam was achieved in late July. First production commenced in October 2018, with ramp-up to 10,000 bbls/day design capacity expected by the first quarter of 2019.

At the Dee Valley Thermal Project, drilling of the second pad was completed in the third quarter of 2018. Construction on the CPF continued and is ahead of schedule with concrete works completed, all modules delivered to site and set, Once-Through Steam Generators ("OTSG") assembled, with mechanical, electrical, and building construction underway. First oil is now expected in the fourth quarter of 2019, compared to a previous expected timeframe of 2020.

At the Spruce Lake Central Thermal Project, drilling of the first well pad was completed in the third quarter of 2018, and piling for the CPF is underway. First production is expected in 2020.

At the Spruce Lake North Project, site clearing is in progress with production expected in late 2020.

In November 2017, the Company sanctioned two new 10,000 bbls/day thermal projects. First production from these two projects is expected in the second half of 2021.

Tucker Thermal Project
Total production at the Tucker Thermal Project is expected to reach its 30,000 bbls/day design capacity around the end of 2018, previously expected to reach nameplate capacity by the end of 2018. In support of reaching design capacity, a planned turnaround was completed in the third quarter of 2018.

Sunrise Energy Project
Total production averaged 49,400 bbls/day (24,700 bbls/day Husky working interest) during the third quarter of 2018. Production in the quarter was impacted by steam limitations due to OTSG maintenance activity. The project is expected to near nameplate capacity around the end of 2018, previously expected to reach nameplate capacity by the end of 2018.

Ten infill wells have been drilled in 2018 and are expected to come online in the fourth quarter of 2018.

Western Canada
Oil and Natural Gas Resource Plays
An accelerated drilling program from an 18-well program to a 25-well development program in the Spirit River formation, in the Ansell and Kakwa areas, is underway with 15 wells drilled in 2018, and 13 completed.

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

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 using waterflooding, polymer injection technology, and enhanced oil recovery.

Asia Pacific
China
Block 29/26
Construction continues at Liuhua 29-1, the third deepwater gas field of the Liwan Gas Project. All of the major contracts have been executed and detailed design work is underway. Drilling of three additional wells is scheduled to commence in the fourth quarter of 2018, once the Environmental Impact Assessment is approved by the Ministry of Ecology and Environment, which will add to the four previously drilled wells. First gas production from this seven-well development is expected around the end of 2020, with target net production of 45 mmcf/day natural gas and 1,800 bbls/day NGL when fully ramped up.

The Company holds a working interest of 75 percent in this field development.

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

During the third quarter of 2018, the Company drilled one exploration well at the nearby exploration Block 16/25 which encountered hydrocarbons. Additional evaluation work is being conducted.

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.

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. 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.

Indonesia

Madura Strait

During the third quarter of 2018, the BD Project achieved its gross daily sales target and reached average gross natural gas production of 100 mmcf/day (40 mmcf/day Husky working interest) and gross NGL production of 10,400 bbls/day (4,200 bbls/day Husky working interest).

At the MDA and MBH fields, the two shallow water platforms have been fully installed and preparations are underway to drill the five MDA and two MBH field production wells in 2019, previously expected to be drilled in the second half of 2018. Gas production and sales are expected to start in 2020, previously expected to start in the second half of 2019, following completion of the Floating Production Unit ("FPU") which will be used to process and compress the gas. An additional shallow water field, named MDK, is scheduled to be developed and tied into the FPU in 2021. The processed gas from these three fields will be tied directly into the East Java subsea pipeline system and sold to the East Java market under long-term contracts with set prices that include escalation factors.

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 began in the first half of 2018 at the purpose-built graving dock in Argentia, Newfoundland and Labrador. The structure's base slab was completed in mid-September and the first round of slip forming is scheduled for the fourth quarter of 2018. First production is expected in 2022.

The Company continues to progress a subsea program to offset natural reservoir declines through infill drilling and workover operations at the White Rose field and satellite extensions. During the third quarter of 2018, two well workovers were completed and two additional infill wells are scheduled to come online around the fourth quarter of 2018.

Atlantic Exploration

The Company continued to evaluate the results of a recent discovery at the A-24 exploration well north of the White Rose field and further delineation opportunities in the area are currently being evaluated. 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 ("HMLP")

LLB Direct – Cold Lake Gathering System to Hardisty

During 2017, HMLP commenced the construction of a new 150-kilometre pipeline system in Alberta, which creates additional pipeline capacity to handle the expected growth in the Company's thermal operations in Alberta and Saskatchewan. The construction is ahead of schedule and is expected to be completed in the fourth quarter of 2018.

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 including Rush Lake 2.

Ansell Corser Plant

The new gas processing plant is now under construction and is expected to add 120 mmcf/day of processing capacity when it comes online in the fourth quarter of 2019.

Downstream Operations

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

U.S. Refining and Marketing

Lima Refinery

Crude Oil Flexibility Project

The crude oil flexibility project is expected to be completed by the end of 2019. The 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.

Better Together - Proposed Acquisition of MEG Energy Corp.

On October 2, 2018, the Company announced that it has commenced an unsolicited offer to acquire all of the outstanding common shares of MEG Energy Corp. ("MEG"). Under the terms and subject to the conditions of the offer, each MEG shareholder will have the option to choose to receive consideration per MEG share of $11 in cash or 0.485 of a Husky share, subject to maximum aggregate cash consideration of $1 billion and a maximum aggregate number of Husky shares issued of approximately 107 million. The transaction was valued at $6.4 billion at the time of announcement, which includes approximately $3.1 billion of MEG's net debt.

The Company believes that acquiring MEG will create a combined Canadian energy company that will maintain a strong balance sheet and investment-grade credit ratings and that will increase the Company's free cash flow, funds from operations and production.

The Company has filed applications or notifications for regulatory review and approvals, as applicable, for the transaction under the Investment Canada Act (Canada), Competition Act (Canada), Transportation Act (Canada) and Hart-Scott-Rodino Act.

2.3 Superior Refinery Incident

Operations at the Superior Refinery remain suspended and an investigation into the cause of the April 26th incident is ongoing. The Company is currently focused on winterizing the site. An engineering contractor has been appointed to oversee design work for the rebuild, with the rebuild beginning once the investigation and design work are complete. Normal operations are not expected to resume until 2020.

As at September 30, 2018, the Company derecognized US$43 million of assets damaged in the incident in the U.S. Refining and Marketing segment. In addition, the Company accrued pre-tax insurance recoveries for property damage, rebuild costs and clean-up costs associated with the incident of US$106 million.

2.4 Financial Strategic Plan

During the third quarter of 2018:

- The Board of Directors declared a quarterly dividend of $0.125 per common share, or $126 million, for the second quarter of 2018. The dividends were paid on October 1, 2018, to shareholders of record at the close of business on August 27, 2018; and
- Dividends of $9 million were declared on preferred shares in the third quarter of 2018, and were paid on October 1, 2018, to shareholders of record at the close of business on August 27, 2018.

3.0 Business Environment

Average Benchmarks

Average Benchmarks Summary		Three months ended Sept. 30 2018	Jun. 30 2018	Mar. 31 2018	Dec. 31 2017	Sept. 30 2017	Nine months ended Sept. 30 2018	Sept. 30 2017
West Texas Intermediate ("WTI") crude oil[1]	*(US$/bbl)*	**69.50**	67.88	62.87	55.40	48.21	**66.75**	49.47
Brent crude oil[2]	*(US$/bbl)*	**75.23**	74.35	66.74	61.39	52.08	**72.11**	51.91
Light sweet at Edmonton	*($/bbl)*	**81.92**	80.58	72.06	69.02	56.74	**78.19**	60.88
Western Canadian Select ("WCS") at Hardisty[3]	*(US$/bbl)*	**47.25**	48.61	38.59	43.14	38.27	**44.82**	37.59
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**54.01**	53.15	37.31	47.97	44.05	**48.16**	43.16
WTI/Lloyd crude blend differential	*(US$/bbl)*	**22.06**	19.08	23.92	12.07	9.59	**21.68**	11.66
Condensate at Edmonton	*(US$/bbl)*	**66.65**	68.83	63.04	57.97	47.60	**66.17**	49.43
NYMEX natural gas[4]	*(US$/mmbtu)*	**2.90**	2.80	3.00	2.93	3.00	**2.90**	3.17
NOVA Inventory Transfer ("NIT") natural gas	*($/GJ)*	**1.28**	0.97	1.76	1.85	1.93	**1.34**	2.45
Chicago Regular Unleaded Gasoline	*(US$/bbl)*	**86.61**	84.75	72.96	73.17	66.40	**81.55**	63.89
Chicago Ultra-low Sulphur Diesel	*(US$/bbl)*	**92.21**	89.14	81.30	80.37	69.69	**87.62**	65.25
Chicago 3:2:1 crack spread	*(US$/bbl)*	**19.04**	18.30	12.84	20.28	19.30	**16.78**	14.98
U.S./Canadian dollar exchange rate	*(US$)*	**0.765**	0.775	0.791	0.786	0.799	**0.777**	0.766
Canadian $ Equivalents[5]								
WTI crude oil	*($/bbl)*	**90.85**	87.59	79.48	70.48	60.34	**85.91**	64.58
Brent crude oil	*($/bbl)*	**98.34**	95.94	84.37	78.10	65.18	**92.81**	67.77
WCS at Hardisty	*($/bbl)*	**61.76**	62.72	48.79	54.89	47.90	**57.68**	49.07
WTI/Lloyd crude blend differential	*($/bbl)*	**28.84**	24.62	30.24	15.36	12.00	**27.90**	15.22
NYMEX natural gas	*($/mmbtu)*	**3.79**	3.61	3.79	3.73	3.75	**3.73**	4.14

(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 third quarter of 2018 increased relative to the third quarter of 2017. WTI averaged US$69.50/bbl during the third quarter of 2018, compared to US$48.21/bbl during the third quarter of 2017. Brent averaged US$75.23/bbl during the third quarter of 2018, compared to US$52.08/bbl during the third quarter of 2017. WCS averaged US$47.25/bbl during the third quarter of 2018, compared to US$38.27/bbl during the third quarter of 2017.

The price received by the Company for crude oil production from Western Canada is primarily driven by the price of WTI, adjusted to Western Canada. The price received by the Company for crude oil production from Atlantic and for NGL production from Asia Pacific is primarily driven by the price of Brent. A portion of the Company's crude oil production from Western Canada is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. The Company's crude oil and NGL production was 72 percent heavy crude oil and bitumen in both the third quarter of 2018 and 2017.

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

Natural Gas Benchmarks

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

The price received by the Company for natural gas production from Western Canada is primarily driven by the NIT near-month contract price of natural gas, while the price received by the Company for production from Asia Pacific is determined by fixed long-term sales 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 the key indicator for U.S. refining margins and reflects refinery gasoline output that is approximately twice the distillate output, and is calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of distillate fuel less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not reflect the actual crude purchase costs or the product configuration of a specific refinery. The Chicago Regular Unleaded Gasoline and the Chicago Ultra-low Sulphur Diesel average benchmark prices are the standard products included in the Chicago 3:2:1 crack spread. The Chicago 3:2:1 crack spread is based on last in first out ("LIFO") accounting, which is a non-GAAP measure (refer to section 10.3).

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

The Company's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil. The product slates produced at the Lima, BP-Husky Toledo and Superior refineries contain between 14 to 42 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$0.765 in the third quarter of 2018 compared to US$0.799 in the third quarter of 2017.

A portion of the Company's long-term sales contracts in Asia Pacific are priced in Chinese Yuan ("RMB"). An increase in the value of RMB relative to the Canadian dollar will increase the revenues received in Canadian dollars from the sale of natural gas commodities in the region. The Canadian dollar averaged RMB 5.209 in the third quarter of 2018 compared to RMB 5.325 in the third quarter of 2017.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in the third quarter of 2018 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 third quarter of 2018. Each separate item in the sensitivity analysis shows the approximate effect of an increase in that variable only; all other variables are held constant. While these sensitivities are indicative for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or upon greater magnitudes of change.

Sensitivity Analysis	2018 Third 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]	**69.50**	*US $1.00/bbl*	**91**	**0.09**	**67**	**0.07**
NYMEX benchmark natural gas price[5]	**2.90**	*US $0.20/mmbtu*	**—**	**—**	**—**	**—**
WTI/Lloyd crude blend differential[6]	**22.06**	*US $1.00/bbl*	**—**	**—**	**—**	**—**
Canadian asphalt margins	**23.39**	*Cdn $1.00/bbl*	**13**	**0.01**	**9**	**0.01**
Canadian light oil margins	**0.044**	*Cdn $0.005/litre*	**15**	**0.01**	**11**	**0.01**
Chicago 3:2:1 crack spread	**19.04**	*US $1.00/bbl*	**113**	**0.11**	**88**	**0.09**
Exchange rate (US $ per Cdn $)[3][7]	**0.765**	*US $0.01*	**(87)**	**(0.09)**	**(64)**	**(0.06)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as at September 30, 2018.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent-based production.*
(5) *Includes impact of natural gas consumption by the Company.*
(6) *Excludes impact on Canadian asphalt operations.*
(7) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

4.0 Results of Operations

4.1 Upstream

Exploration and Production

Exploration and Production Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2018**	2017	**2018**	2017
Gross revenues	**1,319**	1,157	**3,687**	3,623
Royalties	**(106)**	(71)	**(285)**	(266)
Net revenues	**1,213**	1,086	**3,402**	3,357
Purchases of crude oil and products	**—**	—	**1**	1
Production, operating and transportation expenses	**398**	413	**1,139**	1,260
Selling, general and administrative expenses	**71**	63	**224**	181
Depletion, depreciation, amortization and impairment ("DD&A")	**461**	514	**1,342**	1,766
Exploration and evaluation expenses	**26**	31	**96**	108
Loss (gain) on sale of assets	**2**	3	**(2)**	(29)
Other – net	**(42)**	(7)	**(11)**	(31)
Share of equity investment loss (income)	**(12)**	1	**(33)**	1
Financial items	**27**	29	**68**	94
Provisions for income taxes	**68**	11	**149**	2
Net earnings	**214**	28	**429**	4

Third Quarter

Exploration and Production net revenues increased by $127 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher average realized sales prices partially offset by lower production, both of which are described in more detail below.

DD&A expense decreased by $53 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to lower production and additional heavy oil and bitumen reserve bookings in the fourth quarter of 2017.

Provisions for income taxes increased by $57 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher earnings before income taxes in the third quarter of 2018.

Nine Months

Exploration and Production net revenues increased by $45 million compared to the same period in 2017, primarily due to higher average realized sales prices partially offset by lower production, both of which are described in more detail below.

Production, operating and transportation expenses decreased by $121 million compared to the same period in 2017, primarily due to lower production and the dispositions of properties with higher unit operating costs in Western Canada.

Selling, general and administrative expenses increased by $43 million compared to the same period in 2017, primarily due to higher employee costs.

DD&A expense decreased by $424 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter combined with the recognition of a pre-tax impairment charge of $168 million in the second quarter of 2017.

Gain on sale of assets decreased by $27 million compared to the same period in 2017, primarily due to the disposition of select legacy assets in Western Canada in 2017.

Share of equity investment income increased by $34 million compared to the same period in 2017, primarily due to the investment in the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method. The BD Project reached first production in the third quarter of 2017.

Provisions for income taxes increased by $147 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter.

Average Sales Prices Realized

Average Sales Prices Realized	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Crude oil and NGL *($/bbl)*				
Light and Medium crude oil	**93.84**	63.13	**89.04**	64.50
NGL[(1)]	**60.08**	37.83	**56.61**	41.18
Heavy crude oil	**50.09**	41.89	**45.48**	41.73
Bitumen	**46.00**	38.14	**39.35**	36.93
Total crude oil and NGL average	**56.02**	43.62	**49.99**	44.43
Natural gas average *($/mcf)*[(1)]	**6.15**	5.25	**6.55**	5.39
Total average *($/boe)*	**50.44**	40.05	**47.02**	41.07

(1) *Reported average NGL and natural gas prices include Husky's net 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.*

Third Quarter

The average sales prices realized by the Company for crude oil and NGL production increased by 28 percent in the third quarter of 2018 compared to the third quarter of 2017, reflecting an increase in commodity benchmark prices.

The average sales prices realized by the Company for natural gas production increased by 17 percent in the third quarter of 2018 compared to the third quarter of 2017. The increase was primarily due to a higher percentage of fixed priced natural gas production from both the Liwan Gas Project and BD Project relative to total natural gas production.

Nine Months

The average sales prices realized by the Company for crude oil and NGL production increased by 13 percent compared to the same period in 2017, primarily due to the same the factors which impacted the third quarter.

The average sales prices realized by the Company for natural gas production increased by 22 percent compared to the same period in 2017, primarily due to the same factors which impacted the third quarter.

Daily Gross Production

Daily Gross Production	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Crude Oil and NGL *(mbbls/day)*				
Western Canada				
Light and Medium crude oil	**9.9**	11.1	**9.4**	12.5
NGL	**11.9**	11.4	**11.8**	10.1
Heavy crude oil	**34.6**	44.1	**37.6**	45.1
Bitumen[(1)]	**117.3**	117.7	**121.2**	118.5
	173.7	184.3	**180.0**	186.2
Atlantic				
White Rose and Satellite Fields – light crude oil	**21.0**	23.6	**20.0**	30.7
Terra Nova – light crude oil	**2.8**	2.1	**4.3**	3.7
	23.8	25.7	**24.3**	34.4
Asia Pacific				
Wenchang – light crude oil	**—**	5.9	**—**	6.2
Liwan and Wenchang – NGL[(2)]	**8.4**	7.9	**8.1**	6.8
Madura –NGL[(3)]	**4.2**	—	**2.3**	—
	12.6	13.8	**10.4**	13.0
	210.1	223.8	**214.7**	233.6
Natural gas *(mmcf/day)*				
Western Canada	**297.6**	379.5	**287.2**	390.4
Asia Pacific				
Liwan[(2)]	**181.9**	168.6	**180.6**	145.0
Madura[(3)]	**40.0**	15.3	**29.2**	5.1
	221.9	183.9	**209.8**	150.1
	519.5	563.4	**497.0**	540.5
Total *(mboe/day)*	**296.7**	317.7	**297.5**	323.7

(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 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

Third Quarter

Crude oil and NGL production decreased by 13.7 mbbls/day in the third quarter of 2018 compared to the third quarter of 2017, primarily due to lower production in Western Canada as a result of the disposition of select legacy assets in 2017, a reduction of heavy crude oil production due to natural declines and reduced optimization activities in the Company's non-thermal developments, lower crude oil production in Asia Pacific due to the expiry of the Company's participation in the Wenchang oilfield petroleum contract in late 2017, lower production from Atlantic due to a high water cut well at North Amethyst combined with natural well declines, and lower bitumen production from the Tucker Thermal Project and Sunrise Energy Project due to planned turnaround and maintenance activities. This was partially offset by increased NGL production in Western Canada and Asia Pacific.

Nine Months

Crude oil and NGL production decreased by 18.9 mbbls/day compared to the same period in 2017, primarily due to the same factors which impacted the third quarter combined with lower production in Atlantic due to a regulatory suspension of production operations on the *SeaRo*se floating production, storage and offloading ("FPSO") vessel in the first quarter of 2018.

Natural Gas Production

Third Quarter

Natural gas production decreased by 43.9 mmcf/day in the third quarter of 2018 compared to the third quarter of 2017. In Western Canada, natural gas production decreased by 81.9 mmcf/day, primarily due to the disposition of select legacy assets in 2017. In Asia Pacific, natural gas production increased by 38.0 mmcf/day, primarily due to increased gas demand at the Liwan Gas Project and higher production from the BD Project.

Nine Months

Natural gas production decreased by 43.5 mmcf/day compared to the same period in 2017, primarily due to the same factors which impacted the third quarter.

2018 Production Guidance

The following table shows actual daily production for the nine months ended September 30, 2018, and the year ended December 31, 2017, as well as updated production guidance for 2018 and the previously issued production guidance for 2018.

Gross Production	Updated Guidance 2018	Previous Guidance April 26, 2018	Actual Production: Nine months ended September 30, 2018	Actual Production: Year ended December 31, 2017
Canada				
Light & medium crude oil *(mbbls/day)*	35 - 36	41 - 43	**34**	46
NGL *(mbbls/day)*	10 - 11	10 - 11	**12**	10
Heavy crude oil & bitumen *(mbbls/day)*	162 - 164	168 - 173	**159**	164
Natural gas *(mmcf/day)*	285 - 290	280 - 290	**287**	378
Canada total *(mboe/day)*	255 - 259	266 - 275	**253**	283
Asia Pacific				
Light crude oil *(mbbls/day)*	0 - 0	0 - 0	**—**	5
NGL *(mbbls/day)*[1]	10 - 11	10 - 11	**10**	8
Natural gas *(mmcf/day)*[1]	210 - 215	200 - 210	**210**	161
Asia Pacific total *(mboe/day)*	45 - 46	43 - 46	**45**	40
Total *(mboe/day)*	300 - 305	310 - 320	**298**	323

(1) *Includes 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.*

Annual production guidance for 2018 has been revised and is now expected to average in the range of 300,000 - 305,000 boe/day. This is due to several factors, including a planned turnaround at the Tucker Thermal Project, planned maintenance at the Sunrise Energy Project, reduced optimization activities in the Company's non-thermal developments, third-party gas and power constraints and lower than anticipated Atlantic production due to well performance.

Royalties

Royalties *(Percent)*	Three months ended September 30, **2018**	Three months ended September 30, 2017	Nine months ended September 30, **2018**	Nine months ended September 30, 2017
Western Canada	**9**	6	**9**	7
Atlantic	**8**	6	**8**	10
Asia Pacific[1]	**7**	6	**7**	6
Total	**8**	6	**8**	7

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

Third Quarter

Total royalty rates were eight percent in the third quarter of 2018 compared to six percent in the third quarter of 2017. Royalty rates for Western Canada increased by three percent in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher average realized sales prices in 2018 combined with a gas cost allowance credit which reduced the net royalty rate in the third quarter of 2017. Royalty rates for Atlantic increased by two percent in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher production in the Terra Nova field which has a higher royalty rate.

Nine Months

In the first nine months of 2018, total royalty rates were eight percent compared to seven percent in the same period in 2017. Royalty rates for Western Canada increased by two percent compared to the same period in 2017, primarily due to the same factors which impacted the third quarter. Royalty rates for Atlantic decreased by two percent compared to the same period in 2017, primarily due to higher eligible costs partially offset by the same factors which impacted the third quarter.

Operating Costs

Operating Costs	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2018**	2017	**2018**	2017
Western Canada	**318**	336	**917**	1,020
Atlantic	**55**	59	**156**	166
Asia Pacific[1]	**28**	23	**70**	66
Total	**401**	418	**1,143**	1,252
Per unit operating costs *($/boe)*	**14.68**	14.12	**14.08**	14.17

[1] *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.*

Third Quarter

Total Exploration and Production operating costs were $401 million in the third quarter of 2018 compared to $418 million in the third quarter of 2017. Total per unit operating costs averaged $14.68/boe in the third quarter of 2018 compared to $14.12/boe in the third quarter of 2017. The increase in per unit operating costs was primarily due to the factors discussed below.

Per unit operating costs in Western Canada averaged $15.48/boe in the third quarter of 2018 compared to $14.48/boe in the third quarter of 2017. The increase in per unit operating costs was primarily due to a planned turnaround at the Tucker Thermal Project and planned maintenance at the Sunrise Energy Project during the third quarter of 2018.

Per unit operating costs in Atlantic averaged $25.22/bbl in the third quarter of 2018 compared to $24.98/bbl in the third quarter of 2017. The increase in per unit operating costs was primarily due to lower production in the third quarter of 2018 due to a high water cut well at North Amethyst combined with natural well declines.

Per unit operating costs in Asia Pacific averaged $5.98/boe in the third quarter of 2018 compared to $5.83/boe in the third quarter of 2017.

Nine Months

In the first nine months of 2018, total Exploration and Production operating costs were $1,143 million compared to $1,252 million in the same period in 2017. Total per unit operating costs averaged $14.08/boe compared to $14.17/boe in the same period in 2017. The decrease in per unit operating costs was primarily due to the factors discussed below.

Per unit operating costs in Western Canada averaged $14.76/boe compared to $14.87/boe in the same period in 2017. The decrease in per unit operating costs was primarily due to dispositions of properties in Western Canada with higher per unit operating costs partially offset by the same factors which impacted the third quarter.

Per unit operating costs in Atlantic averaged $23.51/bbl compared to $17.68/bbl in the same period in 2017. The increase in per unit operating costs was primarily due to the same factors which impacted the third quarter combined with lower production due to a regulatory suspension of production operations on the *SeaRose* FPSO vessel in the first quarter of 2018.

Per unit operating costs in Asia Pacific averaged $5.62/boe compared to $6.40/boe in the same period in 2017. The decrease in per unit operating costs was primarily due to higher production at the Liwan Gas and BD projects.

Exploration and Evaluation Expenses

Exploration and Evaluation Expenses	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2018**	2017	**2018**	2017
Seismic, geological and geophysical	**22**	26	**70**	76
Expensed drilling	**1**	3	**21**	22
Expensed land	**3**	2	**5**	10
Total	**26**	31	**96**	108

Third Quarter

Exploration and Evaluation expenses in the third quarter of 2018 were $26 million compared to $31 million in the third quarter of 2017. The decrease in seismic, geological and geophysical expense of $4 million, was primarily due to decreased seismic operations in Asia Pacific.

Nine Months

In the first nine months of 2018, Exploration and Evaluation expenses were $96 million, compared to $108 million in the same period in 2017. The decrease was primarily due to the same factors which impacted the third quarter.

Exploration and Production Capital Expenditures

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

Exploration and Production Capital Expenditures[1]	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2018**	2017	**2018**	2017
Exploration				
Western Canada	**32**	27	**65**	47
Thermal developments	**—**	—	**3**	1
Atlantic	**6**	1	**65**	66
Asia Pacific[2]	**18**	3	**52**	6
	56	31	**185**	120
Development				
Western Canada	**100**	39	**226**	91
Thermal developments	**234**	131	**577**	357
Non-thermal developments	**24**	20	**54**	52
Atlantic	**255**	134	**592**	264
Asia Pacific[2]	**45**	—	**80**	—
	658	324	**1,529**	764
Acquisitions				
Western Canada	**—**	—	**4**	25
Thermal developments	**1**	—	**40**	42
	1	—	**44**	67
Total	**715**	355	**1,758**	951

(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

In the first nine months of 2018, $295 million (17 percent) was invested in Western Canada, compared to $163 million (17 percent) in the same period in 2017. Capital expenditures in 2018 related primarily to resource play development targeting the Spirit River formation in the Ansell and Kakwa areas and the Montney formation in the Karr and Wembley areas.

Thermal Developments

In the first nine months of 2018, $620 million (35 percent) was invested in thermal developments compared to $400 million (42 percent) in the same period in 2017. Capital expenditures in 2018 related primarily to the continued development of the Rush Lake 2 Thermal Project, and construction work at the Dee Valley and Spruce Lake Central thermal projects.

Non-Thermal Developments

In the first nine months of 2018, $54 million (three percent) was invested in non-thermal developments compared to $52 million (five percent) in the same period in 2017. Capital expenditures in 2018 related primarily to sustainment activities.

Atlantic

In the first nine months of 2018, $657 million (37 percent) was invested in Atlantic compared to $330 million (35 percent) in the same period in 2017. Capital expenditures in 2018 related primarily to the development of the West White Rose Project and sustainment and development activities at the White Rose field and satellite extensions.

Asia Pacific

In the first nine months of 2018, $132 million (eight percent) was invested in Asia Pacific compared to $6 million (one percent) in the same period in 2017. Capital expenditures in 2018 related primarily to the continued development of Liuhua 29-1, and the exploration of Blocks 15/33 and 16/25.

Exploration and Production Wells Drilled

Onshore drilling activity

The following table discloses the number of wells drilled during the three and nine months ended September 30, 2018 and 2017:

	Three months ended September 30,				Nine months ended September 30,			
	2018		2017		**2018**		2017	
Wells Drilled *(wells)*[(1)]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Thermal developments	**52**	**48**	12	9	**112**	**101**	54	51
Non-thermal developments	**5**	**1**	—	—	**9**	**5**	—	—
Western Canada	**15**	**14**	5	5	**26**	**24**	18	16
Total	**72**	**63**	17	14	**147**	**130**	72	67

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

Offshore drilling activity

The following table discloses the Company's drilling activity during the nine months ended September 30, 2018:

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

Infrastructure and Marketing

Infrastructure and Marketing Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2018**	2017	**2018**	2017
Gross revenues	**601**	513	**1,681**	1,272
Purchases of crude oil and products	**567**	495	**1,590**	1,198
Infrastructure gross margin	**34**	18	**91**	74
Marketing and other	**168**	(4)	**520**	31
Total Infrastructure and Marketing gross margin	**202**	14	**611**	105
Production, operating and transportation expenses	**2**	1	**19**	6
Selling, general and administrative expenses	**1**	1	**3**	3
Depletion, depreciation, amortization and impairment	**—**	1	**1**	2
Loss on sale of assets	**—**	—	**—**	1
Other – net	**(1)**	10	**1**	(2)
Share of equity investment income	**(6)**	(13)	**(20)**	(61)
Provisions for income taxes	**57**	4	**166**	43
Net earnings	**149**	10	**441**	113

Third Quarter

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $88 million and by $72 million, respectively, in the third quarter of 2018 compared to the third quarter of 2017, primarily due to increased volumes and prices.

Marketing and other increased by $172 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to crude oil marketing gains from widening location price differentials between Canada and the U.S., which the Company is able to capture due to its committed capacity on the Keystone pipeline.

Provisions for income taxes increased by $53 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher earnings before income taxes in the third quarter of 2018.

Nine Months

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $409 million and by $392 million, respectively, compared to the same period in 2017, primarily due to the same factors which impacted the third quarter.

Marketing and other increased by $489 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter.

Share of equity investment income decreased by $41 million compared to the same period in 2017, primarily due to lower revenue and higher maintenance expenses from HMLP in 2018.

Provisions for income taxes increased by $123 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter.

4.2 Downstream

Upgrading

Upgrading Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2018**	2017	**2018**	2017
Gross revenues	**534**	377	**1,443**	988
Purchases of crude oil and products	**328**	287	**818**	679
Gross margin	**206**	90	**625**	309
Production, operating and transportation expenses	**52**	45	**144**	148
Selling, general and administrative expenses	**2**	1	**6**	6
Depletion, depreciation, amortization and impairment	**30**	31	**87**	69
Financial items	**1**	1	**1**	1
Provisions for income taxes	**33**	3	**106**	23
Net earnings	**88**	9	**281**	62
Upgrading throughput *(mbbls/day)*(1)	**77.2**	76.7	**76.9**	65.2
Total sales *(mbbls/day)*	**76.7**	79.4	**75.1**	65.3
Synthetic crude oil sales *(mbbls/day)*	**54.9**	58.2	**52.6**	47.6
Upgrading differential *($/bbl)*	**29.46**	13.60	**29.38**	17.73
Unit margin *($/bbl)*	**29.19**	12.32	**30.48**	17.33
Unit operating cost *($/bbl)*(2)	**7.32**	6.38	**6.86**	8.31

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

Third Quarter

Upgrading gross revenues increased by $157 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher realized prices for synthetic crude oil partially offset by lower sales as a result of increased inventory of Husky Synthetic Blend in response to pipeline apportionment. The price of Husky Synthetic Blend in the third quarter of 2018 averaged $88.94/bbl compared to $60.43/bbl in the third quarter of 2017.

Upgrading feedstock purchases increased by $41 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to the increase in the average cost of crude oil feedstock.

Upgrading gross margin increased by $116 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to the widening of the light/heavy oil differentials. The upgrading differential averaged $29.46/bbl in the third quarter of 2018, an increase of $15.86/bbl or 117 percent, compared to the third quarter of 2017. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend.

Provisions for income taxes increased by $30 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher earnings before income taxes in the third quarter of 2018.

Nine Months

Upgrading gross revenues increased by $455 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter combined with higher sales volumes as the Lloydminster Upgrader was in a major planned turnaround in the second quarter of 2017. The price of Husky Synthetic Blend averaged $84.16/bbl compared to $64.74/bbl in the same period in 2017.

Upgrading feedstock purchases increased by $139 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter combined with higher sales as the Lloydminster Upgrader was in a major planned turnaround in the second quarter of 2017.

Upgrading gross margin increased by $316 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter combined with higher sales volumes as the Lloydminster Upgrader was in a major planned turnaround in the second quarter of 2017. The upgrading differential averaged $29.38/bbl, an increase of $11.65/bbl or 66 percent compared to the same period in 2017.

Provisions for income taxes increased by $83 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2018**	2017	**2018**	2017
Gross revenues	**1,001**	802	**2,591**	1,972
Purchases of crude oil and products	**834**	650	**2,123**	1,572
Gross margin				
Fuel	**34**	35	**93**	95
Refining	**43**	28	**141**	107
Asphalt	**76**	72	**195**	155
Ancillary	**14**	17	**39**	43
	167	152	**468**	400
Production, operating and transportation expenses	**66**	63	**198**	190
Selling, general and administrative expenses	**12**	12	**36**	34
Depletion, depreciation, amortization and impairment	**29**	27	**86**	83
Gain on sale of assets	**(2)**	(5)	**(2)**	(5)
Financial items	**3**	3	**9**	9
Provisions for income taxes	**16**	14	**38**	24
Net earnings	**43**	38	**103**	65
Number of fuel outlets[(1)]	**558**	557	**558**	504
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*	**7.7**	8.1	**7.5**	7.0
Fuel sales per retail outlet *(thousands of litres/day)*	**12.4**	12.4	**12.1**	11.9
Refinery throughput				
Prince George Refinery *(mbbls/day)*[(2)]	**11.5**	11.9	**10.7**	11.1
Lloydminster Refinery *(mbbls/day)*[(2)]	**27.8**	30.0	**27.8**	25.7
Ethanol production *(thousands of litres/day)*	**772.3**	845.9	**800.9**	798.5

(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.*

Third Quarter

Canadian Refined Products gross revenues increased by $199 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher product prices partially offset by lower fuel sales volumes in the third quarter of 2018.

Canadian Refined Products purchases of crude oil and products increased by $184 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher commodity prices.

Nine Months

Canadian Refined Products gross revenues increased by $619 million compared to the same period in 2017, primarily due to higher product prices and higher fuel sales volumes from the consolidation of a single expanded truck transport network.

Canadian Refined Products purchases of crude oil and products increased by $551 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter combined with higher throughput volumes at the Lloydminster Refinery resulting from a planned turnaround in the second quarter of 2017.

Refining gross margin increased by $34 million compared to the same period in 2017, primarily due to higher product prices.

Asphalt gross margin increased by $40 million compared to the same period in 2017, primarily due to higher sales prices and higher sales volume at the Lloydminster Refinery resulting from a planned turnaround in the second quarter of 2017.

U.S. Refining and Marketing

U.S. Refining and Marketing Loss Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2018**	2017	**2018**	2017
Gross revenues	**3,198**	2,292	**9,004**	6,600
Purchases of crude oil and products	**2,741**	1,876	**7,811**	5,743
Gross margin	**457**	416	**1,193**	857
Production, operating and transportation expenses	**222**	135	**602**	412
Selling, general and administrative expenses	**5**	4	**17**	11
Depletion, depreciation, amortization and impairment	**129**	82	**348**	264
Other – net	**(107)**	10	**(130)**	(7)
Financial items	**4**	4	**11**	10
Provisions for income taxes	**46**	67	**77**	62
Net earnings	**158**	114	**268**	105
Select operating data:				
Lima Refinery throughput *(mbbls/day)*[1]	**163.3**	178.3	**166.3**	174.8
BP-Husky Toledo Refinery throughput *(mbbls/day)*[1]	**70.8**	77.3	**70.4**	75.1
Superior Refinery throughput *(mbbls/day)*[1]	**—**	—	**15.6**	—
Refining and marketing margin *(US$/bbl crude throughput)*[2]	**17.52**	14.98	**13.99**	10.20
Refinery inventory *(mmbbls)*[3]	**9.5**	8.4	**9.5**	8.4

(1) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(2) *Prior period has been restated to include impact of U.S. product marketing margin.*
(3) *Feedstock and refined products are included in refinery inventory.*

Third Quarter

U.S. Refining and Marketing gross revenues increased by $906 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher refined product prices partially offset by lower sales volumes as the Lima Refinery entered into a major planned turnaround in the third quarter of 2018.

U.S. Refining and Marketing purchases of crude oil and products increased by $865 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to higher commodity prices partially offset by lower throughput volumes as the Lima Refinery entered into a major planned turnaround in the third quarter of 2018.

Production, operating and transportation expenses increased by $87 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to the incident at the Superior Refinery in the second quarter of 2018.

DD&A expense increased by $47 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to the derecognition of assets damaged during the incident at the Superior Refinery in the second quarter of 2018.

Other – net increased by $117 million in the third quarter of 2018 compared to the third quarter of 2017, primarily due to insurance recoveries for property damage and recovery costs associated with the incident at the Superior Refinery in the second quarter of 2018.

The Chicago 3:2:1 crack spread is based on LIFO accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while crude oil feedstock costs included in realized margins are based on FIFO accounting, which reflects purchases made in previous months. The estimated impact of FIFO accounting was a reduction in net earnings of approximately $7 million in the third quarter of 2018 compared to an increase in net earnings of approximately $31 million in the third quarter of 2017.

Nine Months

U.S. Refining and Marketing gross revenues increased by $2,404 million, purchases of crude oil and products increased by $2,068 million and production, operating and transportation expenses increased by $190 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter.

DD&A expense increased by $84 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter.

Other – net increased by $123 million compared to the same period in 2017, primarily due to the same factors which impacted the third quarter.

Downstream Capital Expenditures

In the first nine months of 2018, Downstream capital expenditures totalled $474 million compared to $469 million in the same period in 2017. In Canada, capital expenditures of $105 million in the first nine months of 2018 related primarily to the scheduled partial turnaround at the Lloydminster Upgrader in the second quarter of 2018, and various reliability and environmental activities at the Lloydminster and Prince George refineries. In the U.S., capital expenditures of $369 million in the first nine months of 2018 related primarily to the turnaround and crude oil flexibility project at the Lima Refinery, the turnaround at the Superior Refinery, and various reliability and environmental initiatives at the Lima and BP-Husky Toledo refineries.

4.3 Corporate

Corporate Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions) income (expense)	**2018**	2017	**2018**	2017
Selling, general and administrative expenses	**(96)**	(61)	**(256)**	(183)
Depletion, depreciation and amortization	**(23)**	(18)	**(65)**	(51)
Other – net	**—**	(12)	**9**	(9)
Net foreign exchange gain (loss)	**(9)**	2	**16**	(11)
Finance income	**13**	9	**36**	22
Finance expense	**(43)**	(58)	**(137)**	(175)
Recovery of income taxes	**51**	75	**116**	172
Net loss	**(107)**	(63)	**(281)**	(235)

Third Quarter

The Corporate segment reported a net loss of $107 million in the third quarter of 2018 compared to a net loss of $63 million in the third quarter of 2017. Selling, general and administrative expenses increased by $35 million in the third quarter of 2018, primarily due to the higher stock based compensation expenses.

Nine Months

In the first nine months of 2018, the Corporate segment reported a net loss of $281 million compared to a net loss of $235 million in the same period in 2017. Selling, general and administrative expenses increased by $73 million compared to the same period in 2017, primarily due to the same factors that impacted the third quarter.

Finance expense decreased by $38 million compared to the same period in 2017, primarily due to lower interest expense in 2018 from the repayment of long term debt in late 2017.

The net foreign exchange gain increased by $27 million due to items noted below.

Foreign Exchange Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2018**	2017	**2018**	2017
Non-cash working capital loss	**(12)**	(8)	**(12)**	(13)
Other foreign exchange gain	**3**	10	**28**	2
Net foreign exchange gain (loss)	**(9)**	2	**16**	(11)
U.S./Canadian dollar exchange rates:				
At beginning of period	**US$0.761**	US$0.770	**US$0.799**	US$0.745
At end of period	**US$0.774**	US$0.799	**US$0.774**	US$0.799

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	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2018**	2017	**2018**	2017
Provisions for (recovery of) income taxes	**169**	24	**420**	(18)
Cash income taxes recovered	**(70)**	(122)	**(10)**	(35)

Third Quarter

Consolidated income taxes were a provision of $169 million in the third quarter of 2018 compared to a provision of $24 million in the third quarter of 2017. The increase in consolidated income taxes was primarily due to the increase in earnings before income taxes in the third quarter of 2018 compared to the third quarter of 2017, which was partially offset by the U.S. tax reform changes enacted in December 2017.

Nine Months

In the first nine months of 2018, consolidated income taxes were a provision of $420 million, compared to a recovery of $18 million in the same period in 2017. The increase in consolidated income taxes was primarily due to the same factors which impacted the third 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 March 1, 2018. 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, 2017, which were discussed in the Company's MD&A for the year ended December 31, 2017.

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 September 30, 2018, 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 14 of the condensed interim consolidated financial statements.

Foreign Exchange Risk Management

At September 30, 2018, Cdn $3.5 billion or 65 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. However, it 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 nine months ended September 30, 2018, the Company incurred an unrealized gain of $51 million and an unrealized loss of $94 million, respectively, arising from the translation of the debt, net of tax of $8 million and net of tax recovery of $15 million, respectively, which was recorded in hedge of net investment within other comprehensive income (loss).

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 September 30, 2018, the Company had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[(1)]	**900**	**476**
Syndicated credit facilities[(2)]	**4,000**	**3,800**
Total	**4,900**	**4,276**

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

At September 30, 2018, the Company had $4,276 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $476 million are short-term uncommitted credit facilities. A total of $424 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 September 30, 2018, the Company had no direct borrowing against committed credit facilities. The maturity dates for the Company's revolving syndicated credit facilities are March 9, 2020 and June 19, 2022, respectively. 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 September 30, 2018, and assessed the risk of non-compliance to be low.

Working capital is the amount by which current assets exceed current liabilities. At September 30, 2018, working capital was $2,445 million compared to $2,109 million at December 31, 2017.

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 September 30, 2018.

On March 30, 2017, the Company filed a universal short form base shelf prospectus (the "2017 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including April 30, 2019. The 2017 Canadian Shelf Prospectus replaced the Company's Canadian universal short form base shelf prospectus which expired on March 23, 2017. During the 25-month period that the 2017 Canadian Shelf Prospectus is in effect, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On 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. The 2018 U.S. Shelf Prospectus replaced the Company's U.S universal short form base shelf prospectus which expired on January 22, 2018. During the 25-month period that the 2018 U.S. Shelf Prospectus and the related U.S registration statement are effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

As at September 30, 2018, the Company has $3.0 billion in unused capacity under the 2017 Canadian Shelf Prospectus and US$3.0 billion in unused capacity under the 2018 U.S. Shelf Prospectus and related U.S. registration statement. The ability of the Company to utilize the capacity under the 2017 Canadian Shelf Prospectus and 2018 U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

6.2 Capital Structure

Capital Structure	September 30, 2018
($ millions)	**Outstanding**
Total debt[1]	**5,552**
Shareholders' equity	**19,106**

[1] *Total debt is defined as long-term debt including long-term debt due within one year and short-term debt.*

The Company considers its capital structure to include shareholders' equity and debt which totalled $24.7 billion as at September 30, 2018 (December 31, 2017 – $23.4 billion). To maintain or adjust the capital structure, the Company may, from time to time, sell assets, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to funds from operations (refer to Section 10.3). The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. At September 30, 2018, debt to capital employed was 22.5 percent (December 31, 2017 – 23.2 percent) and debt to funds from operations was 1.3 times (December 31, 2017 – 1.6 times), within the Company's targets.

To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

6.3 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, 2017 under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2017. During the three months ended September 30, 2018, 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 earns a management fee. The Company is also the contractor for HMLP and constructs its assets on a cost recovery basis with certain restrictions. HMLP charges an access fee to the Company for the use of its pipeline systems in performing the Company's blending business, and the Company also pays for transportation and storage services. These transactions are related party transactions, as the Company has a 35 percent ownership interest in HMLP and the remaining ownership interests in HMLP belong to Power Assets Holdings Limited and CK Infrastructure Holdings Limited, which are affiliates of one of the Company's principal shareholders. For the three and nine months ended September 30, 2018, the Company charged HMLP $103 million and $284 million, respectively, related to construction and management services. For the three and nine months ended September 30, 2018, the Company had purchases from HMLP of $51 million and $151 million, respectively, related to the use of the pipeline for the Company's blending, transportation and storage activities. As at September 30, 2018, the Company had $80 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, 2017, 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.

Leases

In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet while operating leases are recognized in the Consolidated Statements of Income when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expense upon implementation. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 Revenue from Contracts with Customers, has been applied, or is applied at the same date as IFRS 16.

The implementation of IFRS 16 consists of four phases:

- Project awareness and engagement – This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 16 to stakeholders, and creating a project steering committee.
- Scoping – This phase focuses on identifying and categorizing the Company's contracts, performing a high-level impact assessment and determining the adoption approach and which optional recognition exemptions will be applied by the Company. This phase also includes identifying the systems impacted by the new accounting standard and evaluating potential system solutions.
- Detailed analysis and solution development – This phase includes assessing which agreements contain leases and determining the expected conversion differences for leases currently accounted for as operating leases under the existing standard. This phase also includes selection of the system solution.
- Implementation – This phase includes implementing the changes required for compliance with IFRS 16. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the execution of customized training programs and preparation of disclosures under IFRS 16.

The Company is currently in the implementation phase of implementing IFRS 16. The impact on the Company's consolidated financial statements upon adoption of IFRS 16 is currently being assessed, but is expected to be material. The Company is adopting the transition to IFRS 16 using the modified retrospective approach.

Changes in Accounting Policies

Revenue from Contracts with Customers

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

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

Financial Instruments

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

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

Amendments to IFRS 2 Share-based payment

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

9.0 Outstanding Share Data

Authorized:

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

Issued and outstanding: October 19, 2018:

• common shares	1,005,121,738
• cumulative redeemable preferred shares, series 1	10,435,932
• cumulative redeemable preferred shares, series 2	1,564,068
• cumulative redeemable preferred shares, series 3	10,000,000
• cumulative redeemable preferred shares, series 5	8,000,000
• cumulative redeemable preferred shares, series 7	6,000,000
• stock options	19,871,753
• stock options exercisable	10,524,588

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 2018 production guidance, including guidance for specified areas and product types; expected strategic, financial and operational benefits that may result from a transaction with MEG; and the Company's objective of maintaining stated debt to capital employed and debt to funds from operations ratio targets;

- with respect to the Company's thermal developments: long-life thermal bitumen production expectations through to 2021; the expected timing of ramp-up to capacity at the Rush Lake 2 thermal development; the expected timing of first production at Dee Valley, Spruce Lake North and Spruce Lake Central; the expected timing of first production from, and design capacity of, two new Lloyd thermal projects; total production expectations for 2018, and the expected timing at the Tucker Thermal Project; and the expected timing to reach nameplate capacity, and timing for infill wells to come online, at the Sunrise Energy Project;

- with respect to the Company's Western Canada resource plays, 2018 drilling plans in the Ansell, Kakwa, Karr and Wembley areas;

- with respect to the Company's Offshore business in Asia Pacific: the expected timing of first gas production, and drilling of new wells, at Liuhua 29-1; target net production at Liuhua 29-1 when fully ramped up; drilling plans at Block 16/25 offshore China; the expected timing of drilling of five MDA field production wells and two MBH field production wells, and the expected timing of first gas therefrom; and the expected timing of tie-in of, and production from, the additional MDK shallow water field;

- with respect to the Company's Offshore business in Atlantic: the expected timing of the first round of slip forming, and first production, at the West White Rose Project; planned subsea program at the White Rose Field and satellite extensions and expected peak production therefrom; timing for infill wells to come online at White Rose; and evaluation of opportunities for further delineation in the area of the White Rose A-24 exploration well;

- with respect to the Company's Infrastructure and Marketing business: the expected timing of completion of construction of HMLP's new 150-kilometre pipeline system; and the expected timing the Ansell Corser Plant will come online and expected process capacity of such plant; and

- with respect to the Company's Downstream operating segment: the expected timing of completion of the crude oil flexibility project at the Lima Refinery; and the expected timing of resumption of normal 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 that may prove to be inaccurate, including the timing of regulatory approvals, and in respect of a possible transaction with MEG, the ability to meet closing conditions and the ability to integrate the Company's and MEG's businesses and operations and realize financial, operational and other synergies from the proposed transaction. Those assumptions and factors are based on information currently available to the Company about itself (and in respect of a possible transaction with MEG, MEG) and the businesses in which they operate, as applicable. 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, 2017, offer documents (in respect of the offer to acquire MEG) 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, historical production volumes provided represent the Company's working interest share before 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: adjusted net earnings (loss), funds from operations, net debt, debt to capital employed, debt to funds from operations and LIFO. None of these measures are used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for debt to capital employed or debt to funds from operations. These are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity. The non-GAAP measures do not have a standardized meaning 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.

Adjusted Net Earnings (Loss)

Adjusted net earnings (loss) is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "net earnings (loss)" as determined in accordance with IFRS, as an indicator of financial performance. Adjusted net earnings (loss) is comprised of net earnings (loss) and excludes items such as after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on sale of assets which are not considered to be indicative of the Company's ongoing financial performance. Adjusted net earnings (loss) is a complementary measure used in assessing the Company's financial performance through providing comparability between periods.

The following table shows the reconciliation of net earnings (loss) to adjusted net earnings (loss) for the three months ended:

Adjusted Net Earnings (Loss)	Three months ended							
	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31
($ millions)	**2018**	2018	2018	2017	2017	2017	2017	2016
Net earnings (loss)	**545**	448	248	672	136	(93)	71	186
Impairment (impairment reversal) of property, plant and equipment, net of tax	**23**	21	—	3	—	123	—	(202)
Exploration and evaluation asset write-downs, net of tax	**—**	5	—	—	1	3	—	41
Inventory write-downs, net of tax	**—**	—	—	—	—	—	—	6
Loss (gain) on sale of assets, net of tax	**—**	—	(3)	(10)	(1)	(23)	2	(37)
Adjusted net earnings (loss)	**568**	474	245	665	136	10	73	(6)

Debt to Capital Employed

Debt to capital employed percentage is a non-GAAP measure and is equal to long-term debt, long-term debt due within one year, and short-term debt divided by capital employed. Capital employed is equal to long-term debt, long-term debt due within one year, short-term debt and shareholders' equity. Management believes this measure assists management and investors in evaluating the Company's financial strength.

Debt to Funds from Operations

Debt to funds from operations is a non-GAAP measure and is equal to long-term debt, long-term debt due within one year and short-term debt divided by funds from operations. Funds from operations is equal to cash flow – operating activities plus change in non-cash working capital. Management believes this measure assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of debt to funds from operations for the periods ended September 30, 2018, and December 31, 2017:

Debt to Funds from Operations *($ millions)*	**September 30, 2018**	December 31, 2017
Total debt	**5,552**	5,440
Funds from operations[1]	**4,435**	3,306
Debt to funds from operations	**1.3**	1.6

[1] *Annualized using 12 - month rolling figures.*

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 is presented to assist management and investors in analyzing operating performance of the Company in the stated period. Funds from operations equals cash flow – operating activities plus change in non-cash working capital.

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

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

Funds from Operations	Three months ended							
	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31
($ millions)	**2018**	2018	2018	2017	2017	2017	2017	2016
Net earnings (loss)	**545**	448	248	672	136	(93)	71	186
Items not affecting cash:								
Accretion	**23**	25	24	28	27	29	28	30
Depletion, depreciation, amortization and impairment	**672**	639	618	647	673	862	700	405
Inventory write-down to net realizable value	**—**	—	—	—	—	—	—	9
Exploration and evaluation expenses	**—**	7	—	—	1	4	1	56
Deferred income taxes	**156**	138	77	(360)	52	(57)	6	45
Foreign exchange loss (gain)	**(6)**	(2)	1	1	(3)	15	(17)	(29)
Stock-based compensation	**40**	33	21	25	11	8	1	3
Loss (gain) on sale of assets	**—**	—	(4)	(13)	(2)	(33)	2	(52)
Unrealized mark to market loss (gain)	**(22)**	(26)	(86)	57	31	18	(50)	26
Share of equity investment income	**(18)**	(26)	(9)	(1)	(12)	(23)	(25)	(38)
Other	**(2)**	19	2	8	9	5	(6)	29
Settlement of asset retirement obligations	**(45)**	(22)	(49)	(45)	(23)	(20)	(48)	(31)
Deferred revenue	**(25)**	(25)	(20)	(5)	(9)	—	(2)	23
Distribution from joint ventures	**—**	—	72	—	—	—	25	—
Change in non-cash working capital	**(35)**	(199)	(366)	337	3	98	(40)	(18)
Cash flow – operating activities	**1,283**	1,009	529	1,351	894	813	646	644
Change in non-cash working capital	**35**	199	366	(337)	(3)	(98)	40	18
Funds from operations	**1,318**	1,208	895	1,014	891	715	686	662
Funds from operations – basic	**1.31**	1.20	0.89	1.01	0.89	0.71	0.68	0.66
Funds from operations – diluted	**1.31**	1.20	0.89	1.01	0.89	0.71	0.68	0.66

LIFO

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

Net Debt

Net debt is a non-GAAP measure that equals total debt less cash and cash equivalents. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt. Management believes this measurement assists management and investors in evaluating the Company’s financial strength.

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, 2017, the 2017 consolidated financial statements, the Annual Information Form dated March 1, 2018 filed with Canadian securities regulatory authorities and the 2017 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 September 30, 2018 and the nine months ended September 30, 2018 are compared to the results for the three months ended September 30, 2017 and the nine months ended September 30, 2017. Discussions with respect to the Company's financial position as at September 30, 2018 are compared to its financial position as at December 31, 2017. 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.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- 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 September 30, 2018 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

Terms

Adjusted Net Earnings (Loss)	*Net earnings (loss) before after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on the sale of assets*
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	*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'soriginal temperature in the reservoir and at atmospheric pressure on a gas-free basis, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods*
Capital Employed	*Long-term debt, long-term debt due within one year, short-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and short-term debt divided by capital employed*
Debt to Funds from Operations	*Long-term debt, long-term debt due within one year and short-term debt divided by funds from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil and bitumen to facilitate transmissibility of the oil through a pipeline*
Feedstock	*Raw materials which are processed into petroleum products*
Funds from Operations	*Cash flow – operating activities plus change in non-cash working capital*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/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*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
Light crude oil	*Crude oil with a relative density greater than 31.1 degrees API gravity*
Medium crude oil	*Crude oil with a relative density that is greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity*
Net Debt	*Total debt less cash and cash equivalents*
Net Revenue	*Gross revenue 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 associated mineral substances*
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 Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Thermal	*Use of steam injection into the reservoir in order to enable heavy oil and bitumen to flow to the well bore*
Total Debt	*Long-term debt, including long-term debt due within one year, and short-term debt*
Turnaround	*Performance of scheduled plant or facility maintenance requiring the complete or partial shutdown of the plant or facility operations*
Western Canada	*Includes Upstream oil and gas exploration and development activities located in Alberta, Saskatchewan and British Columbia*

Units of Measure

bbls	*barrels*
bbls/day	*barrels per day*
boe	*barrels of oil equivalent*
boe/day	*barrels of oil equivalent per day*
GJ	*gigajoule*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mcf	*thousand cubic feet*
mmbbls	*million barrels*
mmboe	*million barrels of oil equivalent*
mmbtu	*million British Thermal Units*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*