MANAGEMENT'S DISCUSSION AND ANALYSIS

October 27, 2016

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1. 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)	**2016**	2016	2016	2015	2015	2015	2015	2014
Production *(mboe/day)*	**301.0**	315.8	341.3	357.0	333.0	336.9	356.0	359.6
Gross revenues and marketing and other	**3,520**	3,261	2,578	3,903	4,286	4,526	4,086	5,875
Net earnings (loss)	**1,390**	(196)	(458)	(69)	(4,092)	120	191	(603)
Per share – Basic	**1.37**	(0.20)	(0.47)	(0.08)	(4.17)	0.11	0.19	(0.62)
Per share – Diluted	**1.37**	(0.20)	(0.47)	(0.09)	(4.19)	0.10	0.17	(0.65)
Adjusted net earnings (loss)[(1)]	**(100)**	(91)	(458)	(49)	(101)	124	191	148
Cash flow from operations[(1)]	**484**	488	434	640	674	1,177	838	1,145
Per share – Basic	**0.48**	0.49	0.43	0.65	0.68	1.20	0.85	1.16
Per share – Diluted	**0.48**	0.49	0.43	0.65	0.68	1.20	0.85	1.16

[(1)] *Adjusted net earnings (loss) and cash flow from operations are non-GAAP measures. Refer to Section 11 for a reconciliation to the GAAP measures.*

Performance

- Net earnings of $1,390 million in the third quarter of 2016 compared to net loss of $4,092 million in the third quarter of 2015 with the increase primarily due to:
  - An after-tax gain on sale of assets of approximately $1.49 billion in the third quarter of 2016 which is mainly related to the sale of ownership in select midstream assets for an after-tax gain of $1.32 billion and the sale of select legacy Western Canada crude oil and natural gas assets for an after-tax gain of $167 million;
  - An increase in production volumes from the Company's heavy oil thermal developments;
  - Lower operating costs, royalties and depletion, depreciation and amortization ("DD&A"); and
  - Lower earnings in the third quarter of 2015 due to an after-tax asset and goodwill impairment of $3,824 million and an after-tax exploration and evaluation asset write-down of $167 million related to crude oil and natural gas assets located in Western Canada.

  Partially offset by:
  - Lower realized crude oil and North American natural gas prices; and
  - Lower natural gas and natural gas liquids ("NGLs") production from the Liwan Gas Project in the Asia Pacific Region.
- Cash flow from operations of $484 million in the third quarter of 2016 compared to $674 million in the third quarter of 2015 with the decrease primarily due to lower realized crude oil and North American natural gas prices, lower crude oil, natural gas and NGL production from the Asia Pacific Region and Western Canada and lower U.S. Refining margins. The decrease was partially offset by lower royalties and operating costs.

- Production decreased by 32.0 mboe/day or ten percent to 301.0 mboe/day in the third quarter of 2016 compared to the third quarter of 2015 as a result of:
  - Lower natural gas and NGLs production from the Liwan Gas Project in the Asia Pacific Region;
  - Disposition of select legacy Western Canada crude oil and natural gas assets; and
  - Natural reservoir declines at mature properties in Western Canada and the Atlantic Region with limited sustaining capital investment in a low commodity price environment.

  Partially offset by:
  - Increased thermal production driven by the Rush Lake ramp up, strong production performance from Tucker, and new production from Edam East, Vawn and Edam West; and
  - The production ramp up from the Sunrise Energy Project.

Key Projects

- First oil was achieved at the 10,000 bbls/day Edam East heavy oil thermal development on April 18, 2016. Production from the development averaged 14,500 bbls/day in the month of September exceeding its design capacity.
- First oil was achieved at the Vawn heavy oil thermal development on June 16, 2016 and production from the development reached its nameplate capacity of 10,000 bbls/day.
- First oil was achieved at the 4,500 bbls/day Edam West heavy oil thermal development on August 29, 2016 and production is ramping up as expected.
- First oil was achieved from the Colony formation at the Tucker Thermal Project in the Cold Lake region of Alberta on April 19, 2016. Total production from the Tucker Thermal Project is now averaging more than 20,000 bbls/day.
- Production from the Sunrise Energy Project has been fully restored to pre-wildfire levels and is now averaging approximately 33,000 bbls/day (16,500 bbls/day net Husky share). Production from the Sunrise Energy Project is expected to increase to approximately 60,000 bbls/day (30,000 bbls/day net Husky share) in early 2017.
- In the Atlantic Region, first oil was achieved from the North Amethyst Hibernia well on September 15, 2016 with peak production of approximately 5,000 bbls/day net Husky share.
- Husky and its partner continue to assess the commercial potential of the discoveries at Bay du Nord, Mizzen, Harpoon, Bay de Verde and Baccalieu.
- In Indonesia, progress continued on the BD, MDA, MBH and MDK shallow water gas developments in the Madura Strait Block. At the liquids-rich BD field, pipeline construction is ongoing and the project is approximately 92 percent complete. The installation and testing of the subsea pipeline has been completed. The construction of the onshore gas metering station is nearing completion. Construction of a floating production, storage and offloading ("FPSO") vessel to process the gas and liquids production is approximately 94 percent complete and preparations are underway for the transportation and installation of the vessel at the field location. Development well drilling continued in the third quarter of 2016. Production from the BD development is expected to commence in 2017. Production from the MDA, MBH and MDK fields is expected in the 2018 - 2019 timeframe. Combined net sales volumes from the BD, MDA, MBH and MDK fields are expected to be approximately 100 mmcf/day of natural gas and 2,400 bbls/day of associated NGLs once production is fully ramped up.
- Husky and Imperial Oil entered into a contractual agreement in the second half of 2015 to create a single expanded truck transport network of approximately 160 sites. The agreement received regulatory approval by Canada's Competition Bureau during the second quarter of 2016. Progress continues to be made on the implementation of the agreement and the consolidation of the two networks is expected in the first half of 2017.
- The Company continued work on a crude oil flexibility project at the Lima Refinery. The project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada. The project will provide the Refinery with the ability to swing between light and heavy crude oil feedstock. Current heavy crude oil feedstock capability is 5,000 bbls/day and is expected to increase to 8,000 bbls/day in the fourth quarter of 2016. The full scope of the project is expected to be completed in 2018. The Refinery's overall nameplate capacity will remain at 160,000 bbls/day.
- The Company and its partner completed the feedstock optimization project at the BP-Husky Toledo Refinery in mid-July. The Refinery is now able to process approximately 65,000 bbls/day of crude oil with a high content of naphthenic acids ("Hi-TAN") to support production from the Sunrise Energy Project. The Refinery's overall nameplate capacity remains unchanged at 160,000 bbls/day.
- Husky is continuing pre front-end engineering and design ("FEED") work on a potential 30,000 bbls/day expansion of its asphalt processing capacity in Lloydminster. This business continues to show strong returns through the cycle and its expansion would provide an additional outlet for the Company's growing heavy oil thermal production.

Divestitures

- On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The assets include approximately 1,900 kilometres of pipeline in the Lloydminster region, 4.1 mmbbls of storage capacity at Hardisty and Lloydminster and other ancillary assets. The assets are held by a newly-formed limited partnership, of which Husky owns 35 percent, Power Assets Holdings Limited ("PAH") owns 48.75 percent and Cheung Kong Infrastructure Holdings Limited ("CKI") owns 16.25 percent. The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets. Proceeds from the transaction were received in the third quarter of 2016.
- During the third quarter of 2016, the Company completed the sale of of its southeast Saskatchewan, Redwater, Pembina, Abbey, Rosevear and Orloff assets representing approximately 5,000 boe/day for total gross proceeds of approximately $299 million, resulting in a pre-tax gain of $229 million and an after-tax gain of $167 million.
- Additionally, during the third quarter of 2016, the Company signed a purchase and sale agreement with a third party for the sale of select assets in Southern Alberta for total gross proceeds of approximately $23 million. As at September 30, 2016, the assets and related liabilities have been classified as held for sale.

Financial

- Dividends on preferred shares of $8 million were declared and paid in the third quarter of 2016.

Saskatchewan Pipeline Spill Recovery Efforts

- During the third quarter of 2016, a pipeline leak occurred on the south shore of the North Saskatchewan River, spilling approximately 225 m^3 (+/- 10%) of heavy oil and diluent. To date, approximately 210 m^3 has been recovered and cleanup efforts are complete.
- As at September 30, 2016, total costs incurred in response to the spill are approximately $90 million, which have been incurred by Husky Midstream Limited Partnership ("HMLP"). Husky is the operator of the assets within HMLP, and also holds a 35% interest in the partnership. The Company expects to recover the costs associated with the spill.
- Management believes the costs incurred properly reflect the costs of the incident at this time, however, the overall impact of the incident is subject to estimate.

2. Business Environment

Average Benchmarks

Average Benchmarks Summary		Three months ended Sept. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sept. 30, 2015	Nine months ended Sept. 30, 2016	Sept. 30, 2015
West Texas Intermediate ("WTI") crude oil[(1)]	*(U.S. $/bbl)*	**44.94**	45.59	33.45	42.18	46.43	**41.33**	51.00
Brent crude oil[(2)]	*(U.S. $/bbl)*	**45.85**	45.57	33.89	43.69	50.26	**41.77**	55.38
Light sweet at Edmonton	*($/bbl)*	**54.80**	54.78	40.81	52.95	56.23	**50.13**	58.63
Daqing[(3)]	*(U.S. $/bbl)*	**42.19**	43.18	30.15	39.57	46.04	**38.51**	52.49
Western Canadian Select at Hardisty[(4)]	*(U.S. $/bbl)*	**31.44**	32.29	19.21	27.69	33.16	**27.65**	37.80
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**36.10**	35.81	18.49	30.23	38.66	**30.13**	42.12
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**13.42**	13.17	14.04	14.37	13.24	**13.54**	13.12
Condensate at Edmonton	*(U.S. $/bbl)*	**43.07**	44.07	34.40	41.67	44.21	**40.51**	49.26
NYMEX natural gas[(5)]	*(U.S. $/mmbtu)*	**2.81**	1.95	2.09	2.27	2.77	**2.29**	2.80
NOVA Inventory Transfer ("NIT") natural gas	*($/GJ)*	**2.09**	1.18	2.00	2.51	2.65	**1.76**	2.66
Chicago Regular Unleaded Gasoline	*(U.S. $/bbl)*	**58.90**	63.80	41.88	54.77	72.02	**55.06**	71.24
Chicago Ultra-low Sulphur Diesel	*(U.S. $/bbl)*	**59.88**	59.34	44.81	58.97	67.08	**54.81**	71.05
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**14.29**	16.67	9.23	14.00	23.87	**13.46**	20.17
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.766**	0.776	0.728	0.749	0.764	**0.757**	0.794
Canadian $ Equivalents[(6)]								
WTI crude oil	*($/bbl)*	**58.67**	58.75	45.95	56.32	60.77	**54.60**	64.23
Brent crude oil	*($/bbl)*	**59.86**	58.72	46.55	58.33	65.79	**55.18**	69.75
Daqing	*($/bbl)*	**55.08**	55.64	41.41	52.83	60.26	**50.87**	66.11
Western Canadian Select at Hardisty	*($/bbl)*	**41.04**	41.61	26.39	36.97	43.40	**36.53**	47.61
WTI/Lloyd crude blend differential	*($/bbl)*	**17.52**	16.97	19.29	19.19	17.33	**17.89**	16.52
NYMEX natural gas	*($/mmbtu)*	**3.67**	2.51	2.87	3.03	3.63	**3.03**	3.53

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

Crude Oil Benchmarks

Global crude oil benchmarks remained weak during the third quarter of 2016 due to continued market imbalance between supply and demand. WTI reached a low of U.S. $26.21/bbl on February 11, 2016 and subsequently increased to an average of U.S. $44.94/bbl during the third quarter of 2016, which was slightly weaker compared to the third quarter of 2015 when WTI averaged U.S. $46.43/bbl. Brent averaged U.S. $45.85/bbl in the third quarter of 2016 compared to U.S. $50.26/bbl the third quarter of 2015.

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 for crude oil production from the Atlantic Region is primarily driven by Brent and the price received for crude oil and NGLs production from the Asia Pacific Region is primarily driven by Daqing. A portion of Husky's crude oil and NGLs production from Western Canada is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In the third quarter of 2016, 72 percent of Husky's crude oil and NGLs production was heavy crude oil or bitumen compared to 60 percent in the third quarter of 2015.

Husky'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.

Natural Gas Benchmarks

North American natural gas benchmarks recovered in the third quarter of 2016 from a temporary decline due to reduced demand from Canadian oil sands operations, which resulted from wildfires in the Fort McMurray region of Alberta in the second quarter of the year. North American natural gas benchmarks continued to be weak in the third quarter of 2016 due to an oversupply of natural gas in North America, which is largely the result of technological advances in horizontal drilling and hydraulic fracturing that have unlocked significant reserves.

The price realized by the Company for natural gas production from Western Canada is determined primarily by North American fundamentals since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. In the Asia Pacific Region, natural gas is sold to a specific buyer with long-term contracts. For the Liwan 3-1 gas field, a price profile has been fixed for five years and then will be linked to local benchmark pricing for the years following subject to a floor and ceiling. For the Liuhua 34-2 field, the price is fixed with a single escalation step during the contract delivery period.

Natural gas is consumed internally by the Company's Upstream and Downstream operations which reduces the impact of weak North American natural gas benchmark prices on the Company's results.

Refining Benchmarks

The 3:2:1 crack spread is the key indicator for refining margins and reflects refinery gasoline output that is approximately twice the distillate output. This crack spread 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 nor 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 market crack spread benchmark.

Husky's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil. The product slates produced at the Lima and BP-Husky Toledo Refineries contain approximately 10 to 15 percent of other products that are sold at discounted market prices compared to gasoline and distillate. Husky'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 Region operations and U.S. dollar denominated debt. The Canadian dollar remained weak in the third quarter of 2016 which averaged U.S. $0.766 compared to U.S. $0.764 in the third quarter of 2015.

The Company’s fixed long-term sales contracts in the Asia Pacific Region are priced in Chinese Yuan (“RMB”) and therefore, an increase in the value of RMB relative to the Canadian dollar will increase the revenues received in Canadian dollars from the sale of oil and gas commodities in the region. The Canadian dollar averaged RMB 5.108 in the third quarter of 2016 compared to RMB 4.817 in the third quarter of 2015.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in the third quarter of 2016 on earnings before income taxes and net earnings. The table below reflects what the effect would have been on the financial results for the third quarter of 2016 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the third quarter of 2016. 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	**2016 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)	**44.94**	*U.S. $1.00/bbl*	**94**	**0.09**	**69**	**0.07**
NYMEX benchmark natural gas price(5)	**2.81**	*U.S. $0.20/mmbtu*	**13**	**0.01**	**9**	**0.01**
WTI/Lloyd crude blend differential(6)	**13.42**	*U.S. $1.00/bbl*	**(48)**	**(0.05)**	**(36)**	**(0.04)**
Canadian light oil margins	**0.055**	*Cdn $0.005/litre*	**12**	**0.01**	**9**	**0.01**
Asphalt margins	**22.99**	*Cdn $1.00/bbl*	**12**	**0.01**	**9**	**0.01**
Chicago 3:2:1 crack spread	**14.29**	*U.S. $1.00/bbl*	**63**	**0.06**	**41**	**0.04**
Exchange rate (U.S. $ per Cdn $)(3)(7)	**0.766**	*U.S. $0.01*	**(44)**	**(0.04)**	**(32)**	**(0.03)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.5 million common shares outstanding as at September 30, 2016.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent based production.*
(5) *Includes impact of natural gas consumption.*
(6) *Excludes impact on 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.*

3. Strategic Plan

Husky's strategy is to remain diversified, physically integrated and to continue its transition into a low sustaining capital business. Husky will enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward low sustaining capital thermal developments and resource plays, while advancing growth in the Asia Pacific Region, the Oil Sands and the Atlantic Region. The Company's Downstream assets provide specialized support to its Upstream operations to enhance efficiency and extract additional value from production.

Upstream includes exploration for, and development and production of, crude oil, bitumen, natural gas and NGLs (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, NGLs, 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 primarily in Western Canada, offshore East Coast of Canada, offshore China and offshore Indonesia.

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading) in Canada, refining in Canada of crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol (Canadian Refined Products) and refining in the U.S. of primarily crude oil to produce and market gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards (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 therefore, were grouped together as the Downstream business segment due to the similar nature of their products and services.

4. Key Growth Highlights

The 2016 capital program enables Husky to advance its near-term profitable growth projects while maintaining prudent capital management in a weak commodity price environment.

4.1 Upstream

Heavy Oil

Heavy Oil Thermal Developments

The Company continued to advance its inventory of heavy oil thermal developments in the third quarter of 2016. These long-life developments are being built with modular, repeatable designs and will require low sustaining capital once brought online. Total heavy oil thermal production, including the Tucker Thermal Project, averaged 88,300 bbls/day in the third quarter of 2016 and is expected to reach approximately 100,000 bbls/day in the fourth quarter of 2016.

The following table lists the design capacity, percentage completion and status for the Company's near-term heavy oil thermal developments:

Heavy Oil Thermal Developments

Development	Design Capacity (bbls/day)	Percentage Completion	Status
Edam East	10,000	100%	On production
Vawn	10,000	100%	On production
Edam West	4,500	100%	On production

First oil was achieved at the 10,000 bbls/day Edam East heavy oil thermal development on April 18, 2016. Production from the development averaged 14,500 bbls/day in the month of September exceeding its design capacity.

First oil was achieved at the Vawn heavy oil thermal development on June 16, 2016 and production from the development reached its nameplate capacity of 10,000 bbls/day.

First oil was achieved at the 4,500 bbls/day Edam West heavy oil thermal development on August 29, 2016. Production is ramping up as expected.

First oil was achieved from the Colony formation at the Tucker Thermal Project in the Cold Lake region of Alberta on April 19, 2016. Total production from the Tucker Thermal Project is now averaging more than 20,000 bbls/day.

Site preparation work has commenced and long lead equipment was ordered at the 10,000 bbls/day Rush Lake 2 heavy oil thermal development.

Three additional 10,000 bbls/day heavy oil thermal projects are being progressed towards a sanction decision.

Oil Sands

Sunrise Energy Project

Production from the Sunrise Energy Project averaged 30,600 bbls/day (15,300 bbls/day net Husky share) in the third quarter of 2016. Operations were successfully restarted during the second quarter with all 55 well pairs back online and the plant is fully operational. Production has been restored to pre-wildfire levels and is now averaging approximately 33,000 bbls/day (16,500 bbls/day net Husky share). During the quarter, the steam-oil ratio ("SOR") continued to be impacted by the wildfire related shut-in and is expected to recover and continue to improve towards the design SOR of 3.0. The water-oil ratio has also been impacted by the wildfire shut-in, with the current ratio at 4.2. The water-oil ratio is also expected to recover and come in line with expectations at this stage of ramp up of between 3.4 - 3.6. Production from the Sunrise Energy Project is expected to increase to approximately 60,000 bbls/day (30,000 bbls/day net Husky share) in early 2017.

Asia Pacific Region

Indonesia

Madura Strait

Progress continued on the shallow water gas developments in the Madura Strait Block in the third quarter of 2016.

At the liquids-rich BD field, pipeline construction is ongoing and the project is approximately 92 percent complete. The installation and testing of the subsea pipeline has been completed. The construction of the onshore gas metering station is nearing completion. Construction of a FPSO vessel to process the gas and liquids production is approximately 94 percent complete and preparations are underway for the transportation and installation of the vessel at the field location. Development well drilling continued in the third quarter of 2016. All four wells have been drilled and cased to target depth and are now being completed. Production from the BD development is expected to commence in 2017.

At the MDA, MBH and MDK gas fields a re-tendering process is underway for a floating production vessel, for which bid documents have been received and are undergoing technical evaluation. Tendering is also underway for related engineering, procurement, construction and installation contracts. The Company has secured a gas sales agreement for the first tranche of gas from the MDA and MBH fields, which will be developed in tandem. Negotiations of gas sales agreements for the remaining available tranches of gas sales from the MDA, MBH and MDK gas fields are in progress. Production from the MDA, MBH and MDK fields is expected in the 2018 - 2019 timeframe. Combined net sales volumes from the BD, MDA, MBH and MDK fields are expected to be approximately 100 mmcf/day of natural gas and 2,400 bbls/day of associated NGLs once production is fully ramped up.

Anugerah

During 2015, Husky acquired two-dimensional and three-dimensional seismic survey data on the contract area. Results from analysis of this and other data will be evaluated to determine the potential for future drilling opportunities.

China

Block 29/26

The second 22-inch subsea pipeline connecting the deepwater pipeline end manifold to the central platform has been completed, tested and placed in service. This pipeline provides operating flexibility and redundancy for the deepwater infrastructure and completes the Liwan project development to its full design specification.

Negotiations for the sale of gas and liquids from Liuhua 29-1, the third deepwater field, are ongoing.

Offshore Taiwan

Analysis of the two-dimensional seismic survey data acquired in 2014 on the Company's offshore Taiwan block has been completed and a number of significant structures have been identified on the block. The Company plans to acquire three-dimensional seismic survey data on the most attractive structures during 2017.

Atlantic Region

White Rose Field and Satellite Extensions

During the third quarter of 2016, the Henry Goodrich rig continued operations at North Amethyst. First oil was achieved from the North Amethyst Hibernia well on September 15, 2016 with peak production of approximately 5,000 bbls/day net Husky share. The rig has since started drilling a third production well from the South White Rose Extension drill centre.

The Company continues to assess potential development options for the West White Rose satellite extension. One of the two concepts being assessed, a fixed wellhead platform, received government and regulatory approvals in 2015. A subsea option to develop the field is also being evaluated.

Atlantic Exploration

In the Flemish Pass, Husky holds a 35 percent working interest in the Bay du Nord, Mizzen, Harpoon, Bay de Verde and Baccalieu discoveries. Husky and its partner continue to assess the commercial potential of these discoveries.

Western Canada Resource Play Development

Oil and Natural Gas Resource Plays

Overall resource play production in Western Canada averaged approximately 31,100 boe/day in the third quarter of 2016, with current development primarily focused on the Ansell multi-zone natural gas resource play. Production from Ansell was approximately 18,400 boe/day in the quarter. Lower resource oil production reflects the sale of assets in the Bakken, Lower Shaunavon, and Viking plays.

Husky has identified 350 Wilrich locations and 300 Cardium locations for future development.

During the third quarter of 2016, Husky completed the sale of several packages of select legacy Western Canada crude oil and natural gas assets in Alberta and Saskatchewan representing approximately 5,000 boe/day. Husky has now completed the sale of approximately 27,200 boe/day of legacy crude oil and natural gas assets in Western Canada. In addition, the Company signed a purchase and sale agreement with a third party to sell select assets in Southern Alberta, which is expected to close in the fourth quarter of 2016. These transactions will allow future capital to be focused on fewer, more material plays and allow the Company to further drive operating and capital efficiencies.

Infrastructure and Marketing

Pipelines and Terminals

On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The Company retains a 35 percent ownership interest and remains the operator. The new limited partnership will provide the midstream takeaway capacity for another eight heavy oil thermal developments. Strategically, the deal facilitates both the expansion of Husky Lloydminster area production and expansion of third-party tariff business.

4.2 Downstream

Canadian Refined Products

Husky and Imperial Oil entered into a contractual agreement in the second half of 2015 to create a single expanded truck transport network of approximately 160 sites. The agreement received regulatory approval from the Canadian Competition Bureau during the second quarter of 2016. Progress continues to be made on the implementation of the agreement and the consolidation of the two networks is expected in the first half of 2017.

Lima Refinery

The Company continued work on a crude oil flexibility project in the third quarter of 2016. 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 Refinery with the ability to swing between light and heavy crude oil feedstock. The first stage of the project is now complete and the Refinery can currently process 5,000 bbls/day of heavy crude oil feedstock with capacity expected to increase to 8,000 bbls/day in the fourth quarter of 2016. The full scope of the project is expected to be completed in 2018. The Refinery's overall nameplate capacity will remain at 160,000 bbls/day.

BP-Husky Toledo, Ohio Refinery

The Company and its partner completed the feedstock optimization project at the BP-Husky Toledo Refinery in mid-July 2016. The Refinery is now able to process approximately 65,000 bbls/day of Hi-TAN crude oil to support production from the Sunrise Energy Project. The Refinery's overall nameplate capacity remains unchanged at 160,000 bbls/day.

Lloydminster Asphalt Expansion

Husky has started pre-FEED work on a potential 30,000 bbls/day expansion of its asphalt processing capacity in Lloydminster. This business continues to show strong returns through the cycle and its expansion would provide an additional outlet for the Company's growing heavy oil thermal production.

5. Results of Operations

5.1 Upstream

Exploration and Production

Exploration and Production Earnings (Loss) Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2016**	2015	**2016**	2015
Gross revenues	**941**	1,253	**2,821**	4,185
Royalties	**(56)**	(83)	**(200)**	(347)
Net revenues	**885**	1,170	**2,621**	3,838
Purchases of crude oil and products	**6**	8	**32**	34
Production, operating and transportation expenses	**429**	519	**1,322**	1,552
Selling, general and administrative expenses	**57**	51	**151**	180
Depletion, depreciation, amortization and impairment	**474**	5,920	**1,578**	7,352
Exploration and evaluation expenses	**17**	308	**110**	408
Loss (gain) on sale of assets	**(236)**	(15)	**(137)**	(13)
Other – net	**18**	(33)	**24**	(17)
Share of equity investment	**1**	1	**3**	1
Financial items	**32**	34	**108**	103
Provisions for (recovery of) income taxes	**24**	(1,520)	**(155)**	(1,558)
Net earnings (loss)	**63**	(4,103)	**(415)**	(4,204)

Third Quarter

Exploration and Production net revenues decreased by $285 million in the third quarter of 2016 compared to the third quarter of 2015, primarily due to lower global crude oil benchmark prices combined with lower oil and natural gas production in North America due to the disposition of select legacy Western Canada crude oil and natural gas assets in Alberta and Saskatchewan, and lower natural gas production in the Asia Pacific Region. The decline in Exploration and Production net revenues was partially offset by lower royalties.

Operating costs decreased by $90 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to cost savings initiatives and lower energy costs.

DD&A expense decreased by $5,446 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to the recognition of a pre-tax impairment charge of $5,181 million on crude oil and natural gas assets, including associated goodwill, located in Western Canada during the third quarter of 2015. The impairment charge reduced the carrying value of the Company's depletable asset base and resulted in a lower DD&A expense per unit of production in the third quarter of 2016. In addition, production was lower from the Liwan Gas Project which carries a higher per unit of production DD&A expense. In the third quarter of 2016, total DD&A excluding impairment averaged $17.11/boe compared to $24.13/boe in the third quarter of 2015.

Exploration and evaluation expenses decreased by $291 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to a $277 million write-down of certain Western Canada resource play assets including associated unfulfilled work commitment penalties during the third quarter of 2015.

Gain on sale of assets increased by $221 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to the sale of select legacy Western Canada crude oil and natural gas assets during the third quarter of 2016.

Nine Months

In the first nine months of 2016, Exploration and Production net revenues decreased by $1,217 million, operating costs decreased by $230 million, DD&A expense decreased by $5,774 million, exploration and evaluation expenses decreased by $298 million, and gain on sale of assets increased by $124 million compared to the same period in 2015, primarily due to the same factors which impacted the third quarter.

Average Sales Prices Realized

Average Sales Prices Realized	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Crude oil and NGLs *($/bbl)*				
Light and Medium crude oil	**54.91**	54.23	**49.11**	60.33
NGLs	**35.62**	43.18	**34.66**	46.93
Heavy crude oil	**35.04**	36.51	**28.80**	39.86
Bitumen	**29.53**	33.86	**25.02**	38.50
Total crude oil and NGLs average	**36.83**	41.92	**33.53**	47.21
Natural gas average *($/mcf)*	**3.99**	5.76	**3.98**	5.94
Total average *($/boe)*	**33.11**	39.45	**30.73**	43.23

Third Quarter

The average sales prices realized by the Company for crude oil and NGLs production decreased by 12 percent in the third quarter of 2016 compared to the same period in 2015 primarily due to lower crude oil benchmarks.

The average sales prices realized by the Company for natural gas production decreased by 31 percent in the third quarter of 2016 compared to the same period in 2015. The decrease in realized natural gas pricing was primarily due to lower fixed priced natural gas production from the Liwan Gas Project relative to total natural gas production and a price adjustment for natural gas from the Liwan 3-1 and Liuhua 34-2 fields, per the Heads of Agreement ("HOA") signed by the Company with CNOOC Limited in the third quarter of 2016. The price adjustment under the HOA is effective as of November 2015 and a retroactive adjustment was recognized in the third quarter of 2016.

Nine Months

In the first nine months of 2016, the average sales prices realized by the Company for crude oil and NGLs production decreased by 29 percent and the average sales prices realized by the Company for natural gas production decreased by 33 percent compared to the same period in 2015 primarily due to the same factors which impacted the third quarter.

Daily Gross Production

Daily Gross Production	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Crude Oil and NGLs *(mbbls/day)*				
Western Canada				
Light and Medium crude oil	**16.5**	35.0	**26.4**	37.2
NGLs	**7.9**	8.4	**8.2**	8.8
Heavy crude oil	**49.5**	67.9	**56.1**	70.0
Bitumen[(1)]	**88.3**	63.0	**79.8**	55.6
	162.2	174.3	**170.5**	171.6
Oil Sands				
Sunrise – bitumen	**15.3**	3.7	**11.4**	1.9
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**19.7**	26.1	**28.9**	29.8
Terra Nova – light crude oil	**5.1**	3.5	**3.7**	4.8
	24.8	29.6	**32.6**	34.6
Asia Pacific Region				
Wenchang – light crude oil	**6.3**	7.5	**6.9**	7.6
Liwan and Wenchang – NGLs[(2)]	**5.5**	8.3	**5.2**	9.8
	11.8	15.8	**12.1**	17.4
	214.1	223.4	**226.6**	225.5
Natural gas *(mmcf/day)*				
Western Canada	**414.2**	505.0	**454.7**	515.9
Asia Pacific Region[(2)]	**107.1**	152.7	**101.4**	182.6
	521.3	657.7	**556.1**	698.5
Total *(mboe/day)*	**301.0**	333.0	**319.3**	341.9

(1) *Bitumen consists of production from heavy oil thermal developments in Lloydminster and the Tucker Thermal Project located near Cold Lake, Alberta. Heavy oil thermal average daily gross production was 68.4 mbbls/day for the three months ended September 30, 2016 compared to 50.0 mbbls/day for the three months ended September 30, 2015.*

(2) *Reported production volumes for the nine months ended September 30, 2015 include an incremental share of production volumes allocated to Husky for exploration cost recoveries where applicable. The incremental share of production volumes ceased during the second quarter of 2015 reflecting the completion of cost recoveries from the Liwan 3-1 field.*

Crude Oil and NGLs Production

Third Quarter

Crude oil and NGLs production decreased in the third quarter of 2016 compared to the third quarter of 2015 primarily due to divestitures of select legacy Western Canada crude oil and natural gas assets in 2016 and natural reservoir declines from mature properties in Western Canada and the Atlantic Region. The decreases were partially offset by new production from the Edam East, Vawn and Edam West heavy oil thermal developments, the Rush Lake heavy oil thermal development being fully ramped up in 2016, the production ramp-up from the Sunrise Energy Project and strong performance from the Tucker Thermal Project including new production from the Colony formation. In addition, NGLs production decreased in the Asia Pacific Region in association with Liwan 3-1 gas production and minor maintenance at Wenchang.

Nine Months

Crude oil and NGLs production increased in the first nine months of 2016 compared to the same period in 2015 primarily due to the new thermal developments in 2016 and production ramp-up from Sunrise Energy Project, which were partially offset by the lower production due to the sale of select legacy Western Canada crude oil and natural gas assets in 2016.

Natural Gas Production

Third Quarter

Natural gas production decreased in the third quarter of 2016 compared to the third quarter of 2015. In the Asia Pacific Region, natural gas production decreased by 45.6 mmcf/day due to lower off-take by the buyer, shut-in for the connection of a second deepwater pipeline and typhoon related impacts. In Western Canada, natural gas production decreased by 90.8 mmcf/day primarily due to divestitures of select legacy Western Canada crude oil and natural gas assets, natural reservoir declines from mature properties, strategic shut-ins due to unfavourable economics and third-party pipeline restrictions.

Nine Months

Natural gas production decreased by 142.4 mmcf/day in the first nine months of 2016 compared to the same period in 2015. In addition to the factors impacting the third quarter, natural gas production in the Asia Pacific Region was impacted by lower sales volumes at the Liwan 3-1 field due to the unscheduled isolation and temporary repair in the gas buyer's onshore gas pipeline infrastructure in the first quarter of 2016 and the Company's entitlement share of production volumes reverted back to 49 percent in late May 2015 following the completion of exploration cost recoveries from the Liwan 3-1 field. In Western Canada, natural gas production decreased primarily due to the same factors which impacted the third quarter.

2016 Production Guidance

The following table shows actual daily production for the nine months ended September 30, 2016 and the year ended December 31, 2015, as well as the previously issued production guidance for 2016. The strong performance from the Company’s heavy oil thermal developments are expected to be partially offset by select asset dispositions in Western Canada combined with lower production from the Liwan Gas Project. As a result, annual production for 2016 is expected to be at the lower end of previously stated guidance.

		Actual Production	
	Guidance[(1)] 2016	**Nine months ended September 30, 2016**	Year ended December 31, 2015
Canada			
Light and Medium crude oil *(mbbls/day)*	66 - 68	**59**	73
NGLs *(mbbls/day)*	7 - 8	**8**	9
Heavy crude oil & bitumen *(mbbls/day)*	142 - 157	**147**	132
Natural gas *(mmcf/day)*	380 - 430	**455**	514
Canada total *(mboe/day)*	279 - 305	**290**	300
Asia Pacific			
Light crude oil *(mbbls/day)*	6 - 7	**7**	8
NGLs *(mbbls/day)*	7 - 8	**5**	9
Natural gas *(mmcf/day)*	140 - 150	**101**	175
Asia Pacific total *(mboe/day)*	36 - 40	**29**	46
Total *(mboe/day)*	315 - 345	**319**	346

(1) *Production guidance does not reflect the impact of asset dispositions in Western Canada.*

Royalties

Third Quarter

Royalty rates as a percentage of gross revenues averaged six percent in the third quarter of 2016 compared to seven percent in the same period in 2015. Royalty rates in Western Canada averaged five percent in the third quarter of 2016 compared to eight percent in the same period in 2015 due to a higher percentage of production from thermal projects, which are at a lower royalty rate. Royalty rates for the Atlantic Region averaged 12 percent in the third quarter of 2016 compared to seven percent in the same period in 2015 primarily due to lower eligible royalty costs. Royalty rates in the Asia Pacific Region averaged six percent in the third quarter of 2016 compared to five percent in the same period in 2015.

Nine Months

In the first nine months of 2016, royalty rates as a percentage of gross revenues averaged seven percent compared to eight percent in the same period in 2015. Royalty rates in Western Canada averaged six percent in the first nine months of 2016 compared to nine percent in the same period in 2015 primarily due to the same factors which impacted the third quarter combined with lower commodity prices with a sliding scale price sensitivity rate. Royalty rates for the Atlantic Region averaged 13 percent and 12 percent in the first nine months of 2016 and 2015, respectively. Royalty rates in the Asia Pacific Region averaged six percent and five percent in the first nine months of 2016 and 2015, respectively.

Operating Costs

($ millions)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Western Canada	**336**	422	**1,052**	1,269
Atlantic Region	**64**	57	**177**	164
Asia Pacific Region	**22**	25	**69**	74
Total operating costs	**422**	504	**1,298**	1,507
Unit operating costs ($/boe)	**15.15**	15.52	**14.09**	15.36

Third Quarter

Total Exploration and Production operating costs were $422 million in the third quarter of 2016 compared to $504 million in the same period in 2015. Total unit operating costs averaged $15.15/boe in the third quarter of 2016 compared to $15.52/boe in the same period in 2015 with the decrease primarily attributable to lower unit operating costs in Western Canada.

Unit operating costs in Western Canada averaged $14.72/boe in the third quarter of 2016 compared to $16.33/boe in the same period in 2015. The decrease in unit operating costs per boe was primarily attributable to cost savings initiatives and lower energy costs.

Unit operating costs in the Atlantic Region averaged $28.07/bbl in the third quarter of 2016 compared to $20.94/bbl in the same period in 2015. The increase in unit operating costs per boe was primarily attributable to higher subsea maintenance costs combined with a decrease in production.

Unit operating costs in the Asia Pacific Region averaged $7.89/boe in the third quarter of 2016 compared to $6.52/boe in the same period in 2015. The increase in unit operating costs per boe was primarily attributable to lower production at the Liwan Gas Project, partially offset by cost saving initiatives.

Nine Months

Total Exploration and Production operating costs were $1,298 million in the first nine months of 2016 compared to $1,507 million in the same period in 2015. Total unit operating costs averaged $14.09/boe in the first nine months of 2016 compared to $15.36/boe in the same period in 2015 with the decrease primarily attributable to lower unit operating costs in Western Canada.

Unit operating costs in Western Canada averaged $13.97/boe in the first nine months of 2016 compared to $16.89/boe in the same period in 2015. The decrease in unit operating costs per boe was primarily due to the same factors which impacted the third quarter.

Unit operating costs in the Atlantic Region averaged $19.76/bbl in the first nine months of 2016 compared to $17.38/bbl in the same period in 2015. The increase in unit operating costs per boe was primarily attributable to the same factors which impacted the third quarter combined with higher logistics costs.

Unit operating costs in the Asia Pacific Region averaged $8.67/boe in the first nine months of 2016 compared to $5.66/boe in the same period in 2015. The increase in unit operating costs per boe was primarily attributable to the same factors which impacted the third quarter.

Exploration and Evaluation Expenses

($ millions)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Seismic, geological and geophysical	**15**	27	**46**	78
Expensed drilling	**—**	246	**59**	285
Expensed land	**2**	35	**5**	45
Total exploration and evaluation expenses	**17**	308	**110**	408

Third Quarter

Exploration and evaluation expenses in the third quarter of 2016 were $17 million compared to $308 million in the third quarter of 2015. The decrease in expense drilling is primarily attributable to a $277 million write-down of certain Western Canada resource play assets including associated unfulfilled work commitment penalties in the third quarter of 2015. The write-down was the result of management's plan to withdraw from further exploration and evaluation due to lower estimated short and long-term crude oil and natural gas prices. The decrease in seismic, geological and geophysical costs resulted from lower seismic activity across the portfolio.

Nine Months

Exploration and evaluation expenses in the first nine months of 2016 were $110 million compared to $408 million in the same period in 2015. The decrease in exploration and evaluation expenses was primarily attributable to the same factors which impacted the third quarter.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were lower in the third quarter of 2016 compared to the third quarter of 2015 and reflect the Company's prudent capital management in a low commodity price environment.

Exploration and Production Capital Expenditures[1]	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2016**	2015	**2016**	2015
Exploration				
Western Canada conventional and resource plays	**6**	9	**10**	22
Heavy Oil	**1**	—	**5**	8
Atlantic Region	**(3)**	51	**16**	155
Asia Pacific Region[2]	**1**	—	**1**	—
	5	60	**32**	185
Development				
Western Canada conventional and resource plays	**10**	87	**92**	314
Heavy Oil	**72**	212	**206**	701
Oil Sands	**(7)**	54	**7**	237
Atlantic Region	**52**	125	**156**	355
Asia Pacific Region[2]	**36**	8	**98**	46
	163	486	**559**	1,653
Acquisitions				
Western Canada conventional and resource plays	**—**	1	**—**	2
Heavy Oil	**5**	50	**7**	51
	173	597	**598**	1,891

[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
[2] *Capital expenditures in the Asia Pacific Region exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture which is accounted for under the equity method.*

Western Canada Conventional and Resource Plays

During the first nine months of 2016, $102 million (17 percent) was invested in Western Canada conventional and resource plays, compared to $338 million (18 percent) in the same period in 2015. Capital expenditures in 2016 relate primarily to sustainment activities. The decrease in capital expenditures in the first nine months of 2016 compared to the same period in 2015 reflects an overall reduction in Western Canada conventional and resource play activity.

Heavy Oil

During the first nine months of 2016, $218 million (36 percent) was invested in Heavy Oil, compared to $760 million (40 percent) in the same period in 2015. Capital expenditures in 2016 relates primarily to the development of the Edam East, Edam West and Vawn heavy oil thermal developments in addition to the Colony formation at the Tucker Thermal Project. The decrease in capital expenditures in the first nine months of 2016 compared to the same period in 2015 reflects the Company's prudent capital management in a low commodity price environment.

Oil Sands

During the first nine months of 2016, $7 million (one percent) was invested in Oil Sands, compared to $237 million (13 percent) in the same period in 2015. Capital expenditures in 2016 and 2015 relate primarily to the Sunrise Energy Project. The decrease in capital expenditures in the first nine months of 2016 compared to the same period in 2015 reflects the completion of Phase 1 of the Sunrise Energy Project in the third quarter of 2015.

Atlantic Region

During the first nine months of 2016, $172 million (29 percent) was invested in the Atlantic Region, compared to $510 million (27 percent) in the same period in 2015. Capital expenditures in 2016 relates primarily to the development of the White Rose extension projects, including the North Amethyst Hibernia and South White Rose extension satellite fields and on further exploration and appraisal drilling in the Flemish Pass Basin. The decrease in capital expenditures in the first nine months of 2016 compared to the same period in 2015 reflects reduced drilling days in the Flemish Pass Basin and White Rose extension projects.

Asia Pacific Region

During the first nine months of 2016, $99 million (17 percent) was invested in the Asia Pacific Region, compared to $46 million (two percent) in the same period in 2015. The increase in capital expenditures in 2016 relate primarily to the planned installation of a second subsea pipeline at the Liwan Gas Project.

Exploration and Production Wells Drilled

Onshore drilling activity

The following table discloses the number of wells drilled in Heavy Oil, Oil Sands and Western Canada conventional and resource plays during the three and nine months ended September 30, 2016 and 2015:

	Three months ended September 30,				Nine months ended September 30,			
	2016		2015		**2016**		2015	
Wells Drilled [1]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Heavy Oil	**27**	**27**	8	8	**70**	**70**	74	73
Oil Sands	**—**	**—**	14	7	**—**	**—**	28	14
Western Canada conventional and resource plays	**—**	**—**	7	10	**2**	**1**	43	29
	27	**27**	29	25	**72**	**71**	145	116

[1] *Excludes Service/Stratigraphic test wells for evaluation purposes.*

During the third quarter of 2016, the Company's onshore drilling was focused primarily on Heavy Oil thermal developments. Oil Sands and Western Canada conventional and resource plays related drilling and completion activity has been curtailed due to limited capital investment in a low commodity price environment.

Offshore drilling activity

The following table discloses Husky's offshore Atlantic drilling activity during the nine months ended September 30, 2016:

Region	***Well***	***Working Interest***	***Well Type***
Atlantic Region	Bay d'Espoir B-09 [1]	WI 35 percent	Exploration
Atlantic Region	Bay du Loup M-62 [1]	WI 35 percent	Exploration
Atlantic Region	Baccalieu F-89	WI 35 percent	Exploration
Atlantic Region	North Amethyst E-18 12Y	WI 68.875 percent	Development

[1] *The Bay d'Espoir B-09 and Bay du Loup M-62 exploration wells were fully written off in the second quarter of 2016 as the wells did not encounter economic quantities of hydrocarbons.*

Infrastructure and Marketing

The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGLs, sulphur and petroleum coke production. The Company owns infrastructure in Western Canada, including pipeline and storage facilities, and has access to capacity on third party pipelines and storage facilities in both Canada and the U.S. The Company is able to capture differences between the two markets by utilizing infrastructure capacity to deliver feedstock acquired in Canada to the U.S. market.

Infrastructure and Marketing Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2016**	2015	**2016**	2015
Gross revenues	**275**	250	**760**	953
Purchases of crude oil and products	**273**	217	**671**	854
Infrastructure gross margin	**2**	33	**89**	99
Marketing and other	**5**	23	**(79)**	48
Total Infrastructure and Marketing gross margin	**7**	56	**10**	147
Production, operating and transportation expenses	**2**	7	**17**	25
Selling, general and administrative expenses	**1**	2	**3**	5
Depletion, depreciation, amortization and impairment	**1**	6	**13**	17
Loss (gain) on sale of assets	**(1,442)**	—	**(1,442)**	—
Other – net	**(3)**	(4)	**(7)**	(2)
Share of equity investment loss (gain)	**20**	—	**20**	—
Provisions for (recovery of) income taxes	**122**	13	**116**	28
Net earnings	**1,306**	32	**1,290**	74

Third Quarter

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $25 million and $56 million, respectively, in the third quarter of 2016 compared to the third quarter of 2015 primarily due to higher volumes.

Infrastructure gross margin decreased by $31 million due to the sale of ownership interest in select midstream assets in the third quarter of 2016.

Marketing and other decreased by $18 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to crude oil marketing losses from narrowing price differentials between Canada and the United States in the third quarter of 2016. This was partially offset by unrealized gas storage mark-to-market gains in the third quarter of 2016 as a result of rising forward North American natural gas prices.

Gain on sale of assets increased by $1,442 million in the third quarter of 2016 compared to the third quarter of 2015 due to the sale of ownership interest in select midstream assets in the third quarter of 2016.

Share of equity investment loss increased by $20 million in the third quarter of 2016 compared to the third quarter of 2015 due to the formation of HMLP. Refer to Note 7 of the Condensed Interim Consolidated Financial Statements. Reflected in the share of equity investment in the third quarter of 2016 is Husky's 35% share of the Saskatchewan pipeline spill recovery costs.

Nine Months

Infrastructure and Marketing gross revenues and purchases of crude oil and products decreased by $193 million and $183 million, respectively, in the first nine months of 2016 compared to the same period in 2015 primarily due to lower commodity prices.

Marketing and other decreased by $127 million in the first nine months of 2016 compared to the the same period in 2015 primarily due to the same factors which impacted the third quarter.

Gain on sale of assets increased by $1,442 million in the first nine months of 2016 compared to the the same period in 2015 due to the same factor which impacted the third quarter.

Share of equity investment loss increased by $20 million in the first nine months of 2016 compared to the the same period in 2015 due to the same factor which impacted the third quarter.

5.2 Downstream

Upgrader

Upgrader Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2016**	2015	**2016**	2015
Gross revenues	**334**	190	**984**	955
Purchases of crude oil and products	**225**	162	**584**	710
Gross margin	**109**	28	**400**	245
Production, operating and transportation expenses	**43**	40	**119**	125
Selling, general and administrative expenses	**—**	1	**2**	3
Depletion, depreciation, amortization and impairment	**27**	26	**82**	78
Other – net	**—**	—	**(1)**	(11)
Financial items	**1**	—	**1**	—
Provisions for (recovery of) income taxes	**11**	(10)	**54**	14
Net earnings (loss)	**27**	(29)	**143**	36
Upgrader throughput *(mbbls/day)*[(1)]	**69.2**	44.2	**74.6**	66.0
Total sales *(mbbls/day)*	**69.7**	42.5	**74.9**	65.4
Synthetic crude oil sales *(mbbls/day)*	**53.3**	31.6	**57.0**	48.3
Upgrading differential *($/bbl)*	**19.45**	17.58	**20.82**	17.47
Unit margin *($/bbl)*	**17.00**	7.16	**19.49**	13.72
Unit operating cost *($/bbl)*[(2)]	**6.75**	9.84	**5.82**	6.94

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

Third Quarter

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

Upgrader gross revenues increased by $144 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to higher throughput and sales volumes, combined with unplanned maintenance to the facility's coke drums that suspended operations for approximately six weeks during the third quarter of 2015. Production throughput increased by 25.0 mbbls/day, or 57 percent, and sales volumes increased by 27.2 mbbls/day, or 64 percent, compared to the third quarter of 2015.

Upgrader gross margin increased by $81 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to higher average upgrading differentials and higher sales volumes. During the third quarter of 2016, the upgrading differential averaged $19.45/bbl, an increase of $1.87/bbl, or 11 percent compared to the third quarter of 2015. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The increase in upgrading differential was attributable to significantly lower heavy crude oil feedstock costs partially offset by lower realized prices for Husky Synthetic Blend. During the third quarter of 2016, the price of Husky Synthetic Blend averaged $58.97/bbl compared to $59.40/bbl in the third quarter of 2015.

Nine Months

Upgrader gross revenues increased by $29 million in the first nine months of 2016 compared to the same period in 2015 primarily due to higher throughput and sales volumes offset by lower realized prices for synthetic crude oil and low sulphur distillates.

Upgrader gross margin increased by $155 million in the first nine months of 2016 compared to the same period in 2015 primarily due to the same factors which impacted the third quarter. During the first nine months of 2016, the upgrading differential averaged $20.82/bbl, an increase of $3.35/bbl, or 19 percent compared to the same period in 2015.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2016**	2015	**2016**	2015
Gross revenues	**678**	839	**1,698**	2,187
Purchases of crude oil and products	**516**	655	**1,295**	1,737
Gross margin				
Fuel	**35**	40	**98**	106
Refining	**33**	36	**82**	102
Asphalt	**79**	92	**179**	198
Ancillary	**15**	16	**44**	44
	162	184	**403**	450
Production, operating and transportation expenses	**62**	57	**175**	183
Selling, general and administrative expenses	**6**	7	**20**	23
Depletion, depreciation, amortization and impairment	**26**	26	**75**	77
Loss (gain) on sale of assets	**(2)**	(1)	**(3)**	(3)
Other – net	**(8)**	—	**(9)**	1
Financial items	**2**	1	**5**	4
Provisions for income taxes	**21**	25	**38**	44
Net earnings	**55**	69	**102**	121
Number of fuel outlets[(1)]	**481**	486	**481**	487
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*	**6.8**	7.7	**6.6**	7.6
Fuel sales per retail outlet *(thousands of litres/day)*	**12.4**	13.2	**11.8**	12.7
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**9.7**	11.0	**8.6**	10.5
Lloydminster Refinery *(mbbls/day)*	**26.7**	26.4	**27.6**	28.0
Ethanol production *(thousands of litres/day)*	**796.3**	814.2	**805.4**	785.8

[(1)] *Average number of fuel outlets for period indicated.*

Third Quarter

Canadian Refined Products gross revenues decreased by $161 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to lower refined product prices, lower sales volumes at the Lloydminster Refinery, lower fuel sales volumes and demand resulting from a weak economic environment and lower throughput and sales volumes at the Prince George Refinery where a planned turnaround was completed. Throughput at the Prince George Refinery decreased by 1.3 mbbls/day, or 12 percent, and fuel sales per retail outlet decreased by 800 litres/day, or six percent, compared to the third quarter of 2015.

Fuel gross margins decreased by $5 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to lower sales volumes partially offset by widening rack to retail differentials.

Refining gross margins decreased by $3 million in the third quarter of 2016 compared to the third quarter of 2015. Gross margins were $1 million lower at the Prince George Refinery primarily due to the planned turnaround and $2 million lower at the Lloydminster and Minnedosa Ethanol plants primarily due to higher grain feedstock costs.

Asphalt margins decreased by $13 million in the third quarter of 2016 compared to the third quarter of 2015 due to weather related delays which hindered sales volumes and a higher supply of asphalt in the market which lowered asphalt prices.

Nine Months

Canadian Refined Products gross revenues decreased by $489 million in the first nine months of 2016 compared to the same period in 2015 primarily due to lower refined product prices and lower fuel sales volumes and demand resulting from a weak economic environment.

Fuel gross margins decreased by $8 million in the first nine months of 2016 compared to the same period in 2015 primarily due to the same factors which impacted the third quarter.

Refining gross margins decreased by $20 million in the first nine months of 2016 compared to the same period in 2015 primarily due to an unplanned outage at the Prince George Refinery, in 2016, which resulted in lower throughput and the need to purchase finished products from third parties to deliver on committed sales volumes, combined with the same factors which impacted the third quarter.

Asphalt gross margins decreased by $19 million in the first nine months of 2016 compared to the same period in 2015 primarily due to the same factors which impacted the third quarter.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2016**	2015	**2016**	2015
Gross revenues	**1,642**	1,973	**4,105**	5,653
Purchases of crude oil and products	**1,448**	1,784	**3,571**	4,872
Gross margin	**194**	189	**534**	781
Production, operating and transportation expenses	**127**	119	**391**	354
Selling, general and administrative expenses	**3**	3	**9**	8
Depletion, depreciation, amortization and impairment	**88**	74	**246**	257
Other – net	**—**	(65)	**(175)**	(156)
Financial items	**—**	—	**2**	2
Provisions for (recovery of) income taxes	**(8)**	22	**23**	(86)
Net earnings (loss)	**(16)**	36	**38**	402
Select operating data:				
Lima Refinery throughput *(mbbls/day)*	**155.6**	142.9	**129.1**	133.1
BP-Husky Toledo Refinery throughput *(mbbls/day)* [1]	**58.4**	68.0	**56.3**	64.6
Refining margin *(U.S. $/bbl crude throughput)*	**7.34**	8.10	**9.60**	12.10
Refinery inventory *(mmbbls)* [2]	**11.2**	12.5	**11.2**	12.5

(1) Prior period BP-Husky Toledo Refinery throughput was revised in the first quarter of 2016 to reflect total throughput. Prior periods reflected crude throughput.
(2) Included in refinery inventory is feedstock and refined products.

Third Quarter

U.S. Refining and Marketing gross revenues decreased by $331 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to the lower Chicago 3:2:1 crack spread and lower realized refining margins, combined with the scheduled major turnaround at the BP-Husky Toledo Refinery, which was completed in July. Due to the scheduled turnaround, throughput at the BP-Husky Toledo Refinery decreased by 9.6 bbls/day when compared to the third quarter of 2015. Throughput at the Lima Refinery increased by 12.7 mbbls/day due to the unplanned outages in the coker unit in the third quarter of 2015.

U.S. Refining and Marketing purchases decreased by $336 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to the impact of the scheduled major turnaround at the BP-Husky Toledo Refinery, combined with lower crude oil feedstock costs.

Operating costs increased by $8 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to the completion of the scheduled major turnaround at the BP-Husky Toledo Refinery.

Other-net expense increased by $65 million in the third quarter of 2016 compared to the third quarter of 2015 primarily due to accrued business interruption and property damage insurance recoveries of $64 million in the third quarter of 2015 associated with the Company's isocracker unit fire at the Lima Refinery, compared to $nil in the third quarter of 2016.

The Chicago 3:2:1 market crack spread benchmark is based on last in first out (“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 FIFO impact was a decrease in net earnings of approximately $40 million in the third quarter of 2016 compared to $127 million in the third quarter of 2015.

Nine Months

U.S. Refining and Marketing gross revenues decreased by $1,548 million in the first nine months of 2016 compared to the same period in 2015. In addition to the factors that impacted the third quarter, the Lima Refinery was impacted by the scheduled major turnaround in the second quarter of 2016. In the first quarter of 2015, throughput was negatively impacted at the Lima Refinery by the isocracker unit fire and the BP-Husky Toledo Refinery was negatively impacted by unplanned maintenance to repair a damaged fluid catalytic cracking unit.

U.S. Refining and Marketing purchases decreased by $1,301 million in the first nine months of 2016 compared to the same period in 2015 primarily due to lower throughput and lower crude oil feedstock costs.

Operating costs increased by $37 million in the first nine months of 2016 compared to the same period in 2015 primarily due to the same factor which impacted the third quarter and additional costs associated with the major turnaround at the Lima Refinery in the second quarter of 2016.

In the first nine months of 2016, the Company accrued business interruption and property damage insurance recoveries of $175 million associated with the Company's isocracker unit fire at the Lima Refinery, compared to $156 million in the same period in 2015, which is reflected in other–net expense. To date, the Company has recorded $410 million in insurance recoveries.

In the first quarter of 2015, the Company recorded a deferred income tax recovery of $203 million related to the partial payment of the contribution payable to BP-Husky Refining LLC.

Downstream Capital Expenditures

In the first nine months of 2016, Downstream capital expenditures totalled $628 million compared to $293 million in the same period in 2015. In Canada, capital expenditures of $72 million were primarily related to the scheduled major turnaround at the Prince George Refinery and projects at the Upgrader. At the Lima Refinery, capital expenditures of $313 million were primarily related to the scheduled major turnaround, upgrades to the isocracker unit and various reliability and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures of $243 million (Husky's 50 percent share) were primarily related to the scheduled major turnaround, facility upgrades and environmental protection initiatives.

5.3 Corporate

Corporate Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions) income (expense)	**2016**	2015	**2016**	2015
Selling, general and administrative expenses	**(39)**	15	**(184)**	(21)
Depletion, depreciation, amortization and impairment	**(22)**	(22)	**(63)**	(62)
Other – net	**17**	3	**(114)**	3
Net foreign exchange gain (loss)	**1**	(14)	**5**	54
Finance income	**2**	3	**7**	5
Finance expense	**(60)**	(48)	**(182)**	(98)
Recovery of (provisions for) income taxes	**56**	(34)	**109**	(91)
Net earnings (loss)	**(45)**	(97)	**(422)**	(210)

Third Quarter

The Corporate segment reported a net loss of $45 million in the third quarter of 2016 compared to a net loss of $97 million in the third quarter of 2015. Selling, general and administrative expenses increased by $54 million primarily due to an increase in stock-based compensation expense in the third quarter of 2016 compared to the stock-based compensation recovery of $10 million in the third quarter of 2015 due to declines in the Company's share price in the third quarter of 2015 and re-organization costs recognized in the third quarter of 2016. The net foreign exchange gain of $1 million in the third quarter of 2016 compared to a loss of $14 million in the third quarter of 2015 is a result of the Canadian dollar weakening in the third quarter of 2015. Finance expense increased by $12 million primarily due to a decrease in the amount of capitalized interest in the third quarter of 2016 compared to the third quarter of 2015.

Nine Months

The Corporate segment reported a net loss of $422 million in the first nine months of 2016 compared to a net loss of $210 million in the same period in 2015. Selling, general and administrative expenses increased by $163 million primarily due to the same factors which impacted the third quarter. Other–net expense of $114 million related primarily to losses on the Company's short term hedging program which concluded in June 2016. Finance expense increased by $84 million primarily due to the same factors which impacted the third quarter. Foreign exchange gain decreased by $49 million due to the items noted below.

Foreign Exchange Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2016**	2015	**2016**	2015
Gain (loss) on translation of U.S. dollar denominated long-term debt	**—**	(12)	**—**	(34)
Gain (loss) on non-cash working capital	**—**	9	**(20)**	28
Other foreign exchange gain (loss)	**1**	(11)	**25**	60
Net foreign exchange gain (loss)	**1**	(14)	**5**	54
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.769**	U.S. $0.802	**U.S. $0.723**	U.S. $0.862
At end of period	**U.S. $0.762**	U.S. $0.747	**U.S. $0.762**	U.S. $0.747

Included in other foreign exchange gain (loss) are realized and unrealized foreign exchange gains and losses on working capital and intercompany financing. The foreign exchange gains and losses on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period. The Company manages its exposure to foreign currency fluctuations in order to minimize the impact of foreign exchange gains and losses on the Condensed Interim Consolidated Financial Statements.

Consolidated Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2016**	2015	**2016**	2015
Provisions for (recovery of) income taxes	**114**	(1,436)	**(33)**	(1,467)
Cash income taxes paid (recovered)	**47**	50	**(9)**	196

Third Quarter

Consolidated income taxes were an expense of $114 million in the third quarter of 2016 compared to a recovery of $1,436 million in the same period in 2015. The decrease in consolidated income tax recoveries was primarily due to the recognition of gains on the sale of Husky's ownership interest in select midstream assets and the sale of select Western Canada legacy oil and natural gas assets in the third quarter of 2016. The income tax recovery in the third quarter of 2015 was primarily associated with impairment charges recognized on crude oil and natural gas assets located in Western Canada.

Nine Months

Consolidated income taxes were a recovery of $33 million in the first nine months of 2016 compared to a recovery of $1,467 million in the same period in 2015. The decrease in consolidated income tax recoveries was primarily due to the same factors which impacted the third quarter.

6. Liquidity and Capital Resources

6.1 Sources of Liquidity

Liquidity describes a company's ability to access cash. Sources of liquidity include cash flow 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, 2016, Husky had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities [(1)]	**670**	**382**
Syndicated credit facilities [(2)]	**4,000**	**3,800**
	4,670	**4,182**

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

At September 30, 2016, Husky had $4,182 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $382 million are short-term uncommitted credit facilities. A total of $288 million of the Company's short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $200 million of the Company's long-term committed borrowing credit facilities was used in support of commercial paper. At September 30, 2016 the Company had no direct borrowings against committed credit facilities. The Company's ability to renew existing bank credit facilities and raise new debt on favourable terms is dependent upon maintaining investment grade credit ratings and conditions in the capital and credit markets. Credit ratings may be affected by the Company's level of debt, from time to time.

Working capital is the amount by which current assets exceed current liabilities. At September 30, 2016, working capital was $1,098 million compared to a working capital deficiency of $922 million at December 31, 2015.

The 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, 2016.

On February 23, 2015, the Company filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada (the "Canadian Shelf Prospectus") 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 March 23, 2017. During the 25-month period that the Canadian Shelf Prospectus is effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On December 22, 2015, the Company filed a universal short form base shelf prospectus (the "U.S. Shelf Prospectus") with the Alberta Securities Commission and a related U.S. registration statement containing the U.S. Shelf Prospectus with the SEC that enables the Company to offer up to U.S. $3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the United States up to and including January 22, 2018. During the 25-month period that the 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.

In March 2016, holders of 1,564,068 Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") exercised their option to convert their shares, on a one-for-one basis, to Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares") and receive a floating rate quarterly dividend. The dividend rate applicable to the Series 2 Preferred Shares for the three month period commencing June 30, 2016 to, but excluding, September 30, 2016 is equal to the sum of the Government of Canada 90 day treasury bill rate on May 31, 2016 plus 1.73 percent, being 2.269 percent. The floating rate quarterly dividend applicable to the Series 2 Preferred Shares will be reset every quarter. The dividend rate applicable to the Series 1 Preferred Shares for the five year period commencing March 31, 2016, to, but excluding, March 31, 2021 is equal to the sum of the Government of Canada five year bond yield on March 1, 2016 plus 1.73 percent, being 2.404 percent. Both rates were calculated in accordance with the articles of amendment of Husky creating the Series 1 Preferred Shares and Series 2 Preferred Shares dated March 11, 2011.

On March 9, 2016, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on December 14, 2016, was extended to March 9, 2020. In addition, the Company's leverage covenant was replaced by a debt to capital covenant calculated as total debt and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. The Company was in compliance with the syndicated credit facility covenants at September 30, 2016 and assesses the risk of non-compliance to be low. 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 has $1.9 billion in unused capacity under the Canadian Shelf Prospectus and U.S. $3.0 billion in unused capacity under the U.S. Shelf Prospectus and related U.S. registration statement as at September 30, 2016. The ability of the Company to utilize the capacity under its Canadian Shelf Prospectus and 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, 2016**	
($ millions)	**Outstanding**	**Available [1]**
Total debt [2]	**5,508**	**4,182**
Common shares, preferred shares, retained earnings and other reserves	**17,335**	

[1] *Total debt available includes committed and uncommitted credit facilities.*
[2] *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 (excluding non-controlling interest) and debt which was $22.8 billion as at September 30, 2016 (December 31, 2015 – $23.3 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to cash flow from operations (refer to section 11). The Company’s objective is to maintain a debt to capital employed target of less than 25 percent and a debt to cash flow from operations ratio of less than 1.5 times. At September 30, 2016, debt to capital employed was 24.1 percent (December 31, 2015 – 28.9 percent) which was under the Company's target and debt to cash flow from operations was 2.7 times (December 31, 2015 – 2.0 times), exceeding the Company's target.

The decrease in the Company's debt to capital employed as at September 30, 2016 is due to the proceeds received from the sale of its ownership interest in select midstream assets in the third quarter of 2016 and the disposition of select legacy Western Canada crude oil and natural gas assets in 2016. The higher debt to cash flow from operations ratio as at September 30, 2016 reflects the impact of lower global crude oil and North American natural gas benchmark pricing which resulted in significantly lower cash flow from operations. 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.

The Company has taken measures to strengthen its financial position and navigate through this commodity down cycle including but not limited to a reduction of budgeted capital spending, the suspension of the quarterly common share dividend and the continued transition to low sustaining capital projects.

Divestitures

Pipeline and Terminals

On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The assets include approximately 1,900 kilometres of pipeline in the Lloydminster region, 4.1 mmbbls of storage capacity at Hardisty and Lloydminster and other ancillary assets. The assets are held by a newly-formed limited partnership, of which Husky owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent. The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets. Proceeds from the transaction were received in the third quarter of 2016.

Upstream Exploration and Production - Western Canada

On May 25, 2016, the Company completed the sale of royalty interests to a third party for gross proceeds of $165 million, resulting in a pre-tax gain of $163 million and an after-tax gain of $119 million.

In June 2016, the Company completed the sale of select assets in southwest Saskatchewan, the Taber area, and Dodsland near Kindersley, Saskatchewan to third parties for gross proceeds of $791 million, resulting in a pre-tax loss of $253 million and an after-tax loss of $187 million. The proceeds were received in the second quarter of 2016.

During the third quarter of 2016, the Company completed the sale of its southeast Saskatchewan, Redwater, Pembina, Abbey, Rosevear and Orloff assets representing approximately 5,000 boe/day for total gross proceeds of approximately $299 million, resulting in a pre-tax gain of $229 million and an after tax gain of $167 million. The proceeds were received in the third quarter of 2016.

In September 2016, the Company signed a purchase and sale agreement with a third party for the sale of select assets in Southern Alberta for total gross proceeds of approximately $23 million, which is expected to close in the fourth quarter of 2016.

Use of Proceeds

Cash proceeds from the dispositions will allow the Company to pay down debt which serves to strengthen the Company's balance sheet. This will also enable the Company to focus on fewer, more material plays while providing for a more capital efficient business with reduced sustaining capital requirements.

6.3 Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Other Commercial Commitments

In the normal course of business, Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable. Refer to Husky's 2015 Annual MD&A under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2015.

During the third quarter of 2016, the Company's firm transportation agreements increased by $2.77 billion, resulting in total transportation commitments of $6.76 billion. These agreements, some of which are subject to regulatory approval, are for terms of up to 20 years subsequent to the date of commencement.

In addition, the Company signed related blending and storage agreements, increasing operating leases by $955 million, resulting in total operating lease commitments of $2.70 billion. These agreements are for terms of up to 20 years subsequent to the date of commencement.

The majority of the increases in the Company's commitments relates to contracts with HMLP.

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

On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The assets include approximately 1,900 kilometres of pipeline in the Lloydminster region, 4.1 mmbbls of storage capacity at Hardisty and Lloydminster and other ancillary assets. The assets are held by a newly-formed limited partnership, of which Husky owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent. This transaction is a related party transaction, as PAH and CKI are affiliates of one of the Company's principal shareholders, and has been measured at fair value. The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets. Subsequent to the sale of its ownership interest, the Company performs management services as the operator of the pipeline for which it earns a management fee from HMLP. 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 its blending business and the Company also pays for transportation and storage services. For the three and nine months ended September 30, 2016 the Company charged HMLP $22 million related to management services, and the Company had purchases from HMLP of $8 million related to the use of the pipeline for its blending activities and $22 million related to transportation and storage. As at September 30, 2016, the Company had $42 million due from HMLP and $11 million due to HMLP related to these transactions. All transactions with HMLP have been measured at fair value.

The Company sells natural gas to and purchases steam from the Meridian Limited Partnership ("Meridian"), owner of the Meridian cogeneration facility, for use at the facility, Upgrader and Lloydminster ethanol plant. In addition, the Company provides facilities services and personnel for the operations of the Meridian cogeneration facility, which are primarily measured and reimbursed at cost. These transactions are related party transactions, as Meridian is an affiliate of one of the Company's principal shareholders, and have been measured at fair value. For the three and nine months ended September 30, 2016, the amount of natural gas sales to Meridian totalled $11 million and $28 million, respectively, the amount of steam purchased by the Company from Meridian totalled $3 million and $8 million, respectively, and the total cost recovery by the Company for facilities services was $2 million and $10 million, respectively. At September 30, 2016, the Company had under $1 million due from Meridian with respect to these transactions.

At September 30, 2016, $33 million of the May 11, 2009 7.25% senior notes were held by a related party, Ace Dimension Limited, and are included in long-term debt in the Company's consolidated balance sheet. The related party transaction was measured at fair market value at the date of the transaction and has been carried out on the same terms as applied with unrelated parties.

On December 7, 2010, the Company issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million in a private placement to its then principal shareholders, L.F. Management and Investment S.à r.l (formerly L.F. Investments (Barbados) Limited) and Hutchison Whampoa Luxembourg Holdings S.à r.l, which was completed in conjunction with a public offering by the Company of common shares in Canada.

On June 29, 2011, the Company issued 7.4 million common shares at a price of $27.05 per share for total gross proceeds of $200 million in a private placement to its then principal shareholders, L.F. Management and Investment S.à r.l (formerly L.F. Investments (Barbados) Limited) and Hutchison Whampoa Luxembourg Holdings S.à r.l, which was completed in conjunction with a public offering by the Company of common shares.

7. Risk Management and Financial Risks

7.1 Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's 2015 Annual Information Form. The Company has processes in place to identify the principal risks of the business and put in place appropriate mitigation to manage such risks where possible. The Company's exposure to operational, political, environmental, financial, liquidity and contract and credit risk has not materially changed since December 31, 2015, as discussed in Husky's 2015 Annual MD&A.

7.2 Financial Risks

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

Commodity Price Risk Management

Husky uses derivative commodity instruments, including commodity put and call options under a short term hedging program, from time to time to manage exposure to price volatility on a portion of its crude oil and natural gas production and 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 liabilities.

At September 30, 2016, 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 16 of the Condensed Interim Consolidated Financial Statements.

Interest Rate Risk Management

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

During 2014, the Company discontinued its cash flow hedge with respect to forward starting interest rate swaps. These forward starting interest rate swaps were settled and derecognized. Accordingly, the accrued gain in other reserves is being amortized into net earnings over the remaining life of the underlying long-term debt to which the hedging relationship was originally designated. The amortization period is ten years. At September 30, 2016, the balance in other reserves related to the accrued gain was $18 million (December 31, 2015 – $20 million), net of tax of $6 million (December 31, 2015 – net of tax of $7 million). The amortization of the accrued gain resulted in a reduction to finance expenses of $1 million and $2 million for the three and nine months ended September 30, 2016, respectively. Refer to the Interest Rate Risk Management disclosure within Note 16 of the Condensed Interim Consolidated Financial Statements.

Foreign Currency Risk Management

At September 30, 2016, 79 percent or CDN $4.2 billion of Husky's outstanding long-term debt was denominated in U.S. dollars. No long-term debt, including amounts due within one year, is exposed to changes in the Canadian/U.S. exchange rate, as all U.S. denominated debt has been designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency. In addition, the Company has fixed the exchange rate on a portion of the U.S. $200 million, 7.55% notes due in the fourth quarter of 2016.

At September 30, 2016, the Company had designated all of its U.S. $3.2 billion denominated debt 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, 2016, the Company incurred an unrealized loss of $29 million and gain of $199 million, respectively, arising from the translation of the debt, net of tax of $5 million and $31 million, respectively, which was recorded in hedge of net investment within other comprehensive income ("OCI").

The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a U.S. dollar functional currency foreign operation. At September 30, 2016, Husky's share of this obligation was U.S. $126 million including accrued interest. At September 30, 2016, the cost of a Canadian dollar in U.S. currency was $0.762.

8. Critical Accounting Estimates and Key Judgments

The application of some of the Company's accounting policies require subjective judgment about uncertain circumstances. The potential effects of these estimates, as described in Husky’s 2015 Annual MD&A, as well as critical areas of judgments 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.

9. Recent Accounting Standards and Changes in Accounting Policies

Recent Accounting Standards

IFRS 16 Leases

In January 2016, the IASB issued IFRS 16 Leases. 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 Company is currently evaluating the impact of adopting IFRS 16 on the consolidated financial statements.

Amendments to IAS 7 Statement of Cash Flows

In January 2016, the IASB issued amendments to IAS 7 to be applied prospectively for annual periods beginning on or after January 1, 2017 with early adoption permitted. The amendments require disclosure of information enabling users of financial statements to evaluate changes in liabilities arising from financing activities. The Company is currently evaluating the impact of adopting the amendments on the consolidated financial statements.

IFRS 15 Revenue from Contracts with Customers

In April 2016, the IASB issued amendments to IFRS 15. The amendments have the same effective date as the standard and will be applied to annual periods beginning on or after January 1, 2018. Early adoption is permitted. The Company is currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

Amendments to IFRS 2 Share-based Payment

In June 2016, the IASB issued amendments to IFRS 2 to be applied for annual periods beginning on or after January 1, 2018 with early adoption permitted. The amendments clarify how to account for certain types of share-based payment transactions. The Company is currently evaluating the impact of adopting the amendments on the consolidated financial statements.

Changes in Accounting Policies

Effective January 1, 2016, the Company adopted the following new accounting standards issued by the IASB:

Amendments to IAS 1 Presentation of Financial Statements

The amendments clarify guidance on materiality and aggregation, use of subtotals, aggregation and disaggregation of financial statement line items, the order of the notes to the financial statements and disclosure of significant accounting policies. The adoption of this amended standard has no material impact on the Company's consolidated financial statements.

Amendments to IFRS 7 Financial Instrument: Disclosures

The amendments clarify:

- whether a servicing contract is continuing involvement in a transferred asset for the purpose of determining the disclosures required; and
- the applicability of the amendments to IFRS 7 on offsetting disclosures to condensed interim financial statements.

The adoption of this amended standard has no impact on the Company's consolidated financial statements.

Amendments to IAS 34 Interim Financial Reporting

The amendments clarify the requirements relating to information required by IAS 34 that is presented elsewhere within the interim financial report but outside the interim financial statements. The adoption of this amended standard has no impact on the Company's consolidated financial statements.

10. Outstanding Share Data

Authorized:
- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: October 24, 2016:

• common shares	1,005,451,854
• 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	26,301,399
• stock options exercisable	15,845,094

11. 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 Husky's 2015 Annual MD&A, the 2015 Consolidated Financial Statements and the 2015 Annual Information Form filed with Canadian securities regulatory authorities and the 2015 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, 2016 and the nine months ended September 30, 2016 are compared to the results for the three months ended September 30, 2015 and the nine months ended September 30, 2015. Discussions with respect to Husky's financial position as at September 30, 2016 are compared to its financial position as at December 31, 2015. 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 millions of 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, 2016 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

Non-GAAP Measures

Disclosure of non-GAAP Measurements

Husky uses measurements primarily based on IFRS and also on secondary non-GAAP measurements. The non-GAAP measurements included in this MD&A and related disclosures are: adjusted net earnings (loss), cash flow from operations, free cash flow, operating netback, debt to capital employed, earnings coverage, debt to cash flow from operations and LIFO. None of these measurements are used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for operating netback, debt to capital employed, earnings coverage or debt to cash flow from operations. These are useful complementary measures in assessing Husky's financial performance, efficiency and liquidity. The non-GAAP measurements 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 are defined below.

Adjusted Net Earnings (Loss)

The term "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, goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and gains or losses on the sale of assets not considered to be indicative of the Company's ongoing financial performance. Adjusted net earnings (loss) is a complementary measure used in assessing Husky'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 and nine months ended September 30, 2016 and 2015:

		Three months ended September 30,		Nine months ended September 30,	
($ millions)		**2016**	2015	**2016**	2015
GAAP	Net earnings (loss)	**1,390**	(4,092)	**736**	(3,781)
	Impairment of property, plant and equipment, net of tax	**—**	3,664	**12**	3,664
	Impairment of goodwill	**—**	160	**—**	160
	Exploration and evaluation asset write-downs, net of tax	**—**	167	**22**	171
	Loss (gain) on sale of assets, net of tax	**(1,490)**	—	**(1,419)**	—
Non-GAAP	Adjusted net earnings (loss)	**(100)**	(101)	**(649)**	214

Cash Flow from Operations

The term "cash flow 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. Cash flow from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Cash flow from operations equals net earnings (loss) plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, loss (gain) on sale of property, plant, and equipment, unrealized mark to market (gain) loss and other non-cash items.

The following table shows the reconciliation of net earnings (loss) to cash flow from operations and related per share amounts for the three and nine months ended September 30, 2016 and 2015:

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2016**	2015	**2016**	2015
Net earnings (loss)	**1,390**	(4,092)	**736**	(3,781)
Items not affecting cash:				
Accretion	**29**	30	**96**	91
Depletion, depreciation, amortization and impairment	**638**	6,074	**2,057**	7,843
Exploration and evaluation expenses	**—**	229	**30**	235
Deferred income taxes (recoveries)	**99**	(1,510)	**(16)**	(1,690)
Foreign exchange	**12**	14	**25**	35
Stock-based compensation	**5**	(10)	**30**	(24)
Loss (gain) on sale of assets	**(1,680)**	(16)	**(1,582)**	(16)
Unrealized mark to market loss (gain)	**(28)**	(56)	**12**	(11)
Other	**19**	11	**18**	7
Cash flow from operations	**484**	674	**1,406**	2,689
Cash flow from operations – basic	**0.48**	0.68	**1.40**	2.73
Cash flow from operations – diluted	**0.48**	0.68	**1.40**	2.73

Free Cash Flow

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

The following table shows the reconciliation of cash flow from operations to free cash flow for the three and nine months ended September 30, 2016 and 2015:

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2016**	2015	**2016**	2015
Cash flow from operations	**484**	674	**1,406**	2,689
Capital expenditures	**(309)**	(817)	**(1,314)**	(2,364)
Free cash flow	**175**	(143)	**92**	325

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

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

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

Debt to Cash Flow from Operations
Debt to cash flow from operations is a non-GAAP measure and is equal to total debt divided by cash flow from operations. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

Earnings Coverage
Earnings coverage is a non-GAAP measure and is equal to net earnings (loss) before finance expense on long-term debt, capitalized interest and income taxes divided by finance expense on long-term debt, dividends on preferred shares and capitalized interest. Long-term debt includes the current portion of long-term debt. The Company's earnings coverage on long-term debt was 2.2 times for the twelve month period ended September 30, 2016.

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 earlier in the quarter. 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.

Cautionary Note Required by National Instrument 51-101
Unless otherwise noted, historical production numbers given represent Husky’s share.

The Company uses the term barrels of oil equivalent ("boe"), which is consistent with other oil and gas producers' 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 and does not represent value equivalency at the wellhead.

Steam-oil ratio measures the average volume of steam required to produce a barrel of oil. Water-oil ratio measures the average volume of water produced per a barrel of oil. These measures do not have any standardized meanings and should not be used to make comparisons to similar measures presented by other issuers.

Terms

Adjusted Net Earnings (Loss)	*Net earnings (loss) before after-tax property, plant and equipment impairment charges, goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs*
Bitumen	*Bitumen is a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds or 10,000 centipoise measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods*
Capital Employed	*Long-term debt, long-term debt due within one year, short-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Net earnings (loss) plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, (gain) loss on sale of property, plant, and equipment, unrealized mark to market (gain) loss and other non-cash items*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and short-term debt divided by capital employed*
Debt to Cash Flow from Operations	*Long-term debt, long-term debt due within one year and short-term debt divided by cash flow 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*
Earnings Coverage	*Net earnings (loss) before finance expense on long-term debt, capitalized interest and income taxes divided by finance expense on long-term debt, dividends on preferred shares and capitalized interest. Long-term debt includes the current portion of long-term debt*
Feedstock	*Raw materials which are processed into petroleum products*
Free Cash Flow	*Cash flow from operations less capital expenditures*
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*
Hi-TAN	*A measure of acidity. Crude oils with a high content of naphthenic acids are referred to as high total acid number (TAN) crude oils or high acid crude oil. The TAN value is defined as the milligrams of Potassium Hydroxide required to neutralize the acidic group of one gram of the oil sample. Crude oils in the industry with a TAN value greater than 1 are referred to as Hi-TAN crudes*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
Light crude oil	*Crude oil with a relative density greater than 31.1 degrees API gravity*
Medium crude oil	*Crude oil with a relative density that is greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity*
Net Debt	*Total debt less cash and cash equivalents*
NOVA Inventory Transfer ("NIT")	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Oil sands	*Sands and other rock materials that contain crude bitumen and include all other mineral substances in association therewith*
Operating Netback	*Net revenues after deduction of operating costs, transportation and royalty payments*
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, retained earnings and other reserves*
Steam-oil ratio	*The steam-oil ratio measures the volume of steam used to produce one unit volume of oil*
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*
Total Debt	*Long-term debt including long-term debt due within one year and short-term debt*
Turnaround	*Performance of plant or facility maintenance*

Abbreviations

bbls	*barrels*	*mboe*	*thousand barrels of oil equivalent*
bbls/day	*barrels per day*	*mboe/day*	*thousand barrels of oil equivalent per day*
boe	*barrels of oil equivalent*	*mcf*	*thousand cubic feet*
boe/day	*barrels of oil equivalent per day*	*MD&A*	*Management's Discussion and Analysis*
DD&A	*depletion, depreciation and amortization*	*mmbbls*	*million barrels*
EDGAR	*Electronic Data Gathering, Analysis and Retrieval (U.S.A.)*	*mmboe*	*million barrels of oil equivalent*
FEED	*front end engineering and design*	*mmbtu*	*million British Thermal Units*
FIFO	*first in first out*	*mmcf*	*million cubic feet*
FPSO	*Floating production, storage and offloading vessel*	*mmcf/day*	*million cubic feet per day*
GAAP	*Generally Accepted Accounting Principles*	m^3	*cubic meter*
GJ	*gigajoule*	*NGLs*	*natural gas liquids*
IAS	*International Accounting Standard*	*NIT*	*NOVA Inventory Transfer*
IASB	*International Accounting Standards Board*	*NYMEX*	*New York Mercantile Exchange*
ICFR	*Internal Controls over Financial Reporting*	*OCI*	*other comprehensive income*
IFRS	*International Financial Reporting Standards*	*RMB*	*Chinese Yuan*
LIFO	*Last in first out*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
mbbls	*thousand barrels*	*SOR*	*steam-oil ratio*
mbbls/day	*thousand barrels per day*	*WTI*	*West Texas Intermediate*

12. Forward-Looking Statements and Information

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", "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; anticipated benefits to the Company resulting from the disposition of select midstream and Western Canada legacy assets; the Company's 2016 production guidance, including guidance for specified areas and product types and the expectation that annual production will be at the lower end of previously stated guidance; the Company's objective of maintaining stated debt to capital employed and debt to cash flow from operations ratio targets; management's plan to withdraw from further exploration and evaluation due to lower estimated short and long-term crude oil and natural gas prices; the Company's belief 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; planned use of midstream, and Western Canada disposition proceeds; and expectations with respect to the recovery of costs associated with the Saskatchewan pipeline spill;
- with respect to the Company's Asia Pacific Region: planned timing of first gas from the Madura Strait MDA, MBH, MDK and BD fields; targeted combined daily net sales volumes from the Madura Strait developments; timing of installation of remaining processing modules on the FPSO vessel to process gas and liquids production from the BD field; the Company's plan and anticipated timing for acquiring three-dimensional seismic survey data for offshore Taiwan;
- with respect to the Company's Oil Sands properties: the Company's forecasted steam-oil and water-oil ratios for the Sunrise Energy Project; and forecast daily production from the Company's Sunrise Energy Project in early 2017;
- with respect to the Company's Heavy Oil properties: forecasted design capacity of the Company's Edam East, Vawn, Edam West, Rush Lake 2 and three additional heavy oil thermal projects; the Company's forecasted total heavy oil thermal production for the fourth quarter of 2016;
- with respect to the Company's Western Canadian oil and gas resource plays: the Company's strategic plans for its Western Canada portfolio; and anticipated timing of the closing of the select assets in Southern Alberta; and

- with respect to the Company's Downstream operating segment: anticipated timing and benefits of the crude oil flexibility project at the Lima Refinery; anticipated timing of the consolidation of Husky and Imperial Oil's truck networks; anticipated benefits of expansion of the Company's Lloyd asphalt refinery; and nameplate capacity for the Lima Refinery and the BP-Husky Toledo, Ohio 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. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources.

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 Husky.

The Company's Annual Information Form for the year ended December 31, 2015 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.

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. 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 its assessment of the future considering all information then available.