MANAGEMENT'S DISCUSSION AND ANALYSIS

July 22, 2016

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1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Jun. 30**	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30
($ millions, except where indicated)	**2016**	2016	2015	2015	2015	2015	2014	2014
Production *(mboe/day)*	**315.8**	341.3	357.0	333.0	336.9	356.0	359.6	341.1
Gross revenues and marketing and other	**3,261**	2,578	3,903	4,286	4,526	4,086	5,875	6,690
Net earnings (loss)	**(196)**	(458)	(69)	(4,092)	120	191	(603)	571
Per share – Basic	**(0.20)**	(0.47)	(0.08)	(4.17)	0.11	0.19	(0.62)	0.58
Per share – Diluted	**(0.20)**	(0.47)	(0.09)	(4.19)	0.10	0.17	(0.65)	0.52
Adjusted net earnings (loss)[(1)]	**(91)**	(458)	(49)	(101)	124	191	148	572
Cash flow from operations[(1)]	**488**	434	640	674	1,177	838	1,145	1,341
Per share – Basic	**0.49**	0.43	0.65	0.68	1.20	0.85	1.16	1.36
Per share – Diluted	**0.49**	0.43	0.65	0.68	1.20	0.85	1.16	1.36

(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 loss of $196 million in the second quarter of 2016 compared to net earnings of $120 million in the second quarter of 2015 with the decrease primarily due to:
  - Lower realized crude oil and North American natural gas prices;
  - Lower U.S. Refining and Marketing throughput and sales volumes due to major planned turnarounds at both the Lima and BP-Husky Toledo Refineries;
  - Lower natural gas and natural gas liquids ("NGLs") production from the Asia Pacific Region; and
  - An after-tax loss of $71 million primarily associated with the disposition of select legacy crude oil and natural gas assets in Western Canada;

  Partially offset by:
  - Lower operating costs, royalties and depletion, depreciation and amortization ("DD&A");
  - An increase in production volumes from the Company's heavy oil thermal developments;
  - A deferred tax expense of $157 million recognized in the second quarter of 2015 related to an increase in Alberta provincial corporate tax rates; and
  - A weaker Canadian dollar.
- Cash flow from operations of $488 million in the second quarter of 2016 compared to $1,177 million in the second quarter of 2015 with the decrease primarily due to lower realized crude oil and North American natural gas prices, lower natural gas and natural gas liquids ("NGLs") production from the Asia Pacific Region and lower sales volumes in U.S. Refining and Marketing. The decreases were partially offset by a weaker Canadian dollar and lower royalties and operating costs.

- Production decreased by 21.1 mboe/day or six percent to 315.8 mboe/day in the second quarter of 2016 compared to the second quarter of 2015 as a result of:
    - Lower natural gas and NGLs production from the Liwan Gas Project in the Asia Pacific Region; 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:
    - New production from the Rush Lake heavy oil thermal development, the Edam East heavy oil thermal development and the South White Rose extension, production ramp-up from the Sunrise Energy Project and strong production performance from the Tucker Thermal Project.

Key Projects

- Production from the Sunrise Energy Project was negatively impacted during the second quarter by wildfires in the Fort McMurray region of Alberta. As a precautionary measure, production was temporarily shut-in during May 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 fully restored to pre-fire levels and is now averaging approximately 30,000 bbls/day (15,000 bbls/day net Husky share). Production from the Sunrise Energy Project is now expected to increase to approximately 60,000 bbls/day (30,000 bbls/day net Husky share) in early 2017.
- 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 11,100 bbls/day in June exceeding its design capacity.
- First oil was achieved at the 10,000 bbls/day Vawn heavy oil thermal development on June 16, 2016 and production is ramping up as expected.
- Construction work was completed and first steam was achieved at the 4,500 bbls/day Edam West heavy oil thermal development during the second quarter of 2016. First oil is expected in the third quarter of 2016.
- 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.
- In the Atlantic Region, the Henry Goodrich rig resumed operations at the White Rose field and satellite extensions.
- Husky and its partner announced two new discoveries from an exploration program in the Flemish Pass Basin. The discoveries at Bay de Verde and Baccalieu add to the resource base for a potential development at the Bay du Nord discovery.
- 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, wellhead platform and pipeline infrastructure construction is approximately 76 percent complete and construction of a floating production, storage and offloading ("FPSO") vessel is approximately 85 percent complete. The vessel has left the dry dock and the remaining processing modules are planned to be installed in the next few months. Development well drilling continued in the second quarter of 2016. Production from the BD field is expected to commence in the 2017 timeframe. 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 fully ramped up.
- Construction is approximately 90 percent complete on the expansion of the Saskatchewan Gathering System which will accommodate production from the Company's heavy oil thermal developments. Production from the Rush Lake, Edam East and Vawn heavy oil thermal developments is flowing in a completed section of the newly expanded pipeline system into Lloydminster.
- 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.
- The Company continued work on the initial stages of a crude oil flexibility project at the Lima Refinery designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada. The crude oil flexibility project will allow the Refinery to swing between light and heavy crude oil feedstock. Initial capacity of 8,000 bbls/day of heavy crude oil feedstock capability is expected to be available in the fourth quarter of 2016 with the full scope of the project 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 will remain at 160,000 bbls/day.
- Husky has started 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 April 25, 2016, the Company reached an agreement to sell 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.7 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 will enable 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. The transaction is effective July 1, 2016, received regulatory approval on July 13, 2016 and closed on July 15, 2016.
- On May 25, 2016, the Company completed the sale of royalty interests representing approximately 1,700 boe/day of Western Canada production. The sale proceeds include $165 million in cash and other considerations, including the transfer to Husky of royalty and working interests in select heavy oil properties in the Lloydminster area. Proceeds from the transaction were received in the second quarter of 2016.
- During the second quarter of 2016, the Company completed the sale of several packages of select legacy Western Canada crude oil and natural gas assets in Saskatchewan and Alberta representing approximately 20,500 boe/day for total gross proceeds of approximately $791 million. As a part of one of the transactions, the Company obtained interests in lands with thermal development potential in the Lloydminster region. Proceeds from the transactions were received during the second quarter of 2016.
- In addition, the Company signed purchase and sale agreements in the second quarter of 2016 with third parties for the sale of its southeast Saskatchewan, Redwater, Pembina and Orloff assets representing approximately 3,500 boe/day for total gross proceeds of approximately $295 million, which are expected to close in the third quarter of 2016.

Financial

- Dividends on preferred shares of $9 million were declared and paid in the second quarter of 2016.

2. Business Environment

Average Benchmarks

Average Benchmarks Summary		Three months ended Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sept. 30, 2015	Jun. 30, 2015	Six months ended Jun. 30, 2016	Jun. 30, 2015
West Texas Intermediate ("WTI") crude oil(1)	*(U.S. $/bbl)*	**45.59**	33.45	42.18	46.43	57.94	**39.52**	53.29
Brent crude oil(2)	*(U.S. $/bbl)*	**45.57**	33.89	43.69	50.26	61.92	**39.73**	57.95
Light sweet at Edmonton	*($/bbl)*	**54.78**	40.81	52.95	56.23	67.72	**47.79**	59.83
Daqing(3)	*(U.S. $/bbl)*	**43.18**	30.15	39.57	46.04	60.01	**36.67**	55.71
Western Canadian Select at Hardisty(4)	*(U.S. $/bbl)*	**32.29**	19.21	27.69	33.16	46.35	**25.75**	40.13
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**35.81**	18.49	30.23	38.66	51.31	**27.15**	43.86
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**13.17**	14.04	14.37	13.24	11.49	**13.60**	13.06
Condensate at Edmonton	*(U.S. $/bbl)*	**44.07**	34.40	41.67	44.21	57.94	**39.24**	51.78
NYMEX natural gas(5)	*(U.S. $/mmbtu)*	**1.95**	2.09	2.27	2.77	2.64	**2.02**	2.81
NOVA Inventory Transfer ("NIT") natural gas	*($/GJ)*	**1.18**	2.00	2.51	2.65	2.53	**1.59**	2.66
Chicago Regular Unleaded Gasoline	*(U.S. $/bbl)*	**63.80**	41.88	54.77	72.02	79.43	**53.10**	70.84
Chicago Ultra-low Sulphur Diesel	*(U.S. $/bbl)*	**59.34**	44.81	58.97	67.08	75.89	**52.25**	73.10
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**16.67**	9.23	14.00	23.87	20.30	**13.04**	18.26
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.776**	0.728	0.749	0.764	0.813	**0.752**	0.810
Canadian $ Equivalents(6)								
WTI crude oil	*($/bbl)*	**58.75**	45.95	56.32	60.77	71.27	**52.55**	65.79
Brent crude oil	*($/bbl)*	**58.72**	46.55	58.33	65.79	76.16	**52.83**	71.54
Daqing	*($/bbl)*	**55.64**	41.41	52.83	60.26	73.81	**48.76**	68.78
Western Canadian Select at Hardisty	*($/bbl)*	**41.61**	26.39	36.97	43.40	57.01	**34.24**	49.54
WTI/Lloyd crude blend differential	*($/bbl)*	**16.97**	19.29	19.19	17.33	14.13	**18.09**	16.12
NYMEX natural gas	*($/mmbtu)*	**2.51**	2.87	3.03	3.63	3.25	**2.69**	3.47

(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 of 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 improved during the second quarter of 2016 resulting primarily from increasing global demand, disruptions in global supply and falling U.S. crude oil production. WTI reached a low of US $26.21/bbl on February 11, 2016 and subsequently increased resulting in an average of US $45.59/bbl during the second quarter of 2016. Notwithstanding the increase, global crude oil benchmarks remained significantly weaker compared to the second quarter of 2015 when WTI averaged US $57.94/bbl.

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 second quarter of 2016, 64 percent of Husky's crude oil and NGLs production was heavy crude oil or bitumen compared to 56 percent in the second 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 continued to be weak in the second quarter of 2016 primarily due to the substantial supply of natural gas in North America resulting largely from technological advances in horizontal drilling and hydraulic fracturing which have unlocked significant reserves that were not economical under previously applied extraction methods. In addition, demand for natural gas in North America was lower due to unseasonably mild weather conditions coupled with a temporary decline in natural gas demand from Canadian oil sands operations due to the wildfires in the Fort McMurray region of Alberta.

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 percent 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 Company's earnings benefited from the weakening of the Canadian dollar in the second quarter of 2016 which averaged U.S. $0.776 compared to U.S. $0.813 in the second 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 $5.070 in the second quarter of 2016 compared to RMB $5.045 in the second quarter of 2015.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in the second quarter of 2016 on earnings before income taxes and net earnings (loss). The table below reflects what the effect would have been on the financial results for the second quarter of 2016 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the second 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 Second Quarter Average**	Increase	Effect on Earnings before Income Taxes[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)[2]*	*($ millions)*	*($/share)[2]*
WTI benchmark crude oil price[3][4]	**45.59**	*U.S. $1.00/bbl*	**97**	**0.10**	**70**	**0.07**
NYMEX benchmark natural gas price[5]	**1.95**	*U.S. $0.20/mmbtu*	**16**	**0.02**	**12**	**0.01**
WTI/Lloyd crude blend differential[6]	**13.17**	*U.S. $1.00/bbl*	**(48)**	**(0.05)**	**(37)**	**(0.04)**
Canadian light oil margins	**0.054**	*Cdn $0.005/litre*	**12**	**0.01**	**11**	**0.01**
Asphalt margins	**21.99**	*Cdn $1.00/bbl*	**10**	**0.01**	**9**	**0.01**
Chicago 3:2:1 crack spread	**16.67**	*U.S. $1.00/bbl*	**61**	**0.06**	**38**	**0.04**
Exchange rate (U.S. $ per Cdn $)[3][7]	**0.776**	*U.S. $0.01*	**(42)**	**(0.04)**	**(31)**	**(0.03)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.5 million common shares outstanding as at June 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 second 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 78,500 bbls/day in the second quarter of 2016 and is expected to reach approximately 100,000 bbls/day during the second half of 2016.

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

Heavy Oil Thermal Developments

Development	Design Capacity (bbls/day)	Percentage Completion	First Production Expected
Edam East	10,000	100%	On production
Vawn	10,000	100%	On production
Edam West	4,500	100%	Q3 2016

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 11,100 bbls/day in the month of June exceeding its design capacity.

First oil was achieved at the 10,000 bbls/day Vawn heavy oil thermal development on June 16, 2016 and production is ramping up as expected.

Construction work was completed and first steam was achieved at the 4,500 bbls/day Edam West heavy oil thermal development. First oil is expected in the third quarter of 2016.

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

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.

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

Asia Pacific Region

Indonesia

Madura Strait

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

At the liquids-rich BD field, wellhead platform and pipeline infrastructure construction is ongoing and approximately 76 percent complete. Construction of an FPSO vessel to process gas and liquids production from the BD field is approximately 85 percent complete. The vessel has left the dry dock and the remaining processing modules are planned to be installed in the next few months. Development well drilling continued in the second quarter of 2016. The first of four wells being drilled in batch mode has reached target depth and the drilling of the remaining three is ongoing. Production from the development is expected to commence in the 2017 timeframe.

At the MDA, MBH and MDK gas fields, the tendering process for a floating production vessel has been reviewed for consistency with government tender guidelines and the operating company is awaiting feedback from the industry regulator for any necessary further actions. Tendering is 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 fully ramped up.

Anugerah

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

China

Block 29/26

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.

Oil Sands

Sunrise Energy Project

Production from the Sunrise Energy Project averaged 19,000 bbls/day (9,500 bbls/day net Husky share) in the second quarter of 2016 and was negatively impacted by wildfires in the Fort McMurray region of Alberta. 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-fire levels and is now averaging approximately 30,000 bbls/day (15,000 bbls/day net Husky share). During the quarter, the steam-oil ratio (“SOR”) continued to improve towards the design SOR of 3.0 while the water-oil ratio is in line with expectations at this stage of ramp up at 3.6 - 3.8. Production from the Sunrise Energy Project is now expected to increase to approximately 60,000 bbls/day (30,000 bbls/day net Husky share) in early 2017.

Atlantic Region

White Rose Field and Satellite Extensions

During the second quarter of 2016, the Henry Goodrich rig resumed operations at North Amethyst. First oil is anticipated in the third quarter of 2016 and is expected to produce 5,000 bbls/day net Husky share at peak production. In addition, the rig will be utilized for further development drilling at the White Rose field and satellite extensions as part of a two year drilling program.

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

The exploration and appraisal drilling program at the Bay du Nord discovery in the Flemish Pass Basin was completed in the second quarter of 2016. Since the program commenced in the fourth quarter of 2014, Husky has participated in three appraisal and four exploration wells in and around Bay du Nord, leading to two new oil discoveries at Bay de Verde and Baccalieu and two unsuccessful wells at Bay d'Espoir and Bay du Loup. The two new discoveries will add to the resource base for a potential development at Bay du Nord. Husky and its partner continue to evaluate the drilling results and assess the commercial potential of the Bay du Nord discovery. Husky holds a 35 percent working interest in Bay du Nord, Mizzen, Harpoon, Bay de Verde and Baccalieu.

Western Canada Resource Play Development

Oil and Natural Gas Resource Plays

Overall resource play production in Western Canada averaged approximately 37,100 boe/day in the second quarter of 2016, with current development primarily focused on the Ansell multi-zone natural gas resource play. Production from Ansell was approximately 20,800 boe/day in the quarter.

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

During the second quarter of 2016, Husky completed the sale of several packages of select legacy Western Canada crude oil and natural gas assets in Saskatchewan and Alberta and select royalty interests representing approximately 22,200 boe/day. In addition, Husky signed purchase and sale agreements in the second quarter of 2016 with third parties for the sale of its southeast Saskatchewan, Redwater, Pembina and Orloff assets representing approximately 3,500 boe/day which are expected to close in the third 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

Construction is approximately 90 percent complete on the expansion of the Saskatchewan Gathering System which will accommodate production from the Company's heavy oil thermal developments. Production from the Rush Lake, Edam East and Vawn heavy oil thermal developments is flowing in a completed section of the newly expanded pipeline system into Lloydminster. The expansion is expected to be completed in the third quarter of 2016.

On July 13, 2016, final regulatory approval was received on an agreement to sell 65 percent of Husky's ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross cash proceeds of $1.7 billion. The Company will retain a 35 percent interest in the assets and will remain 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. The transaction is effective July 1, 2016 and closed on July 15, 2016.

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 by Canada's Competition Bureau during the second quarter of 2016.

Lima Refinery

The Company continued work on the initial stages of a crude oil flexibility project in the second quarter of 2016. The crude oil flexibility project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada providing the Refinery with the ability to swing between light and heavy crude oil feedstock. Initial capacity of 8,000 bbls/day of heavy crude oil feedstock capability is expected to be available in the fourth quarter of 2016 with the full scope of the project 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. 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 will remain 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 June 30,		Six months ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Gross revenues	**1,044**	1,577	**1,880**	2,932
Royalties	**(90)**	(134)	**(144)**	(264)
Net revenues	**954**	1,443	**1,736**	2,668
Purchases of crude oil and products	**14**	17	**26**	26
Production, operating and transportation expenses	**442**	521	**893**	1,033
Selling, general and administrative expenses	**52**	60	**94**	129
Depletion, depreciation, amortization and impairment	**542**	713	**1,104**	1,432
Exploration and evaluation expenses	**76**	43	**93**	100
Other – net	**105**	33	**105**	18
Share of equity investment	**1**	—	**2**	—
Financial items	**36**	34	**76**	69
Provisions for (recovery of) income taxes	**(86)**	4	**(179)**	(38)
Net earnings (loss)	**(228)**	18	**(478)**	(101)

Second Quarter

Exploration and Production net revenues decreased by $489 million in the second quarter of 2016 compared to the second quarter of 2015, primarily due to lower global crude oil and North American natural gas benchmark prices combined with lower natural gas and NGLs production in the Asia Pacific Region. The decline in Exploration and Production net revenues was partially offset by higher production from the Company's heavy oil thermal developments, lower royalties and a weaker Canadian dollar.

Operating costs decreased by $79 million in the second quarter of 2016 compared to the second quarter of 2015 primarily due to cost savings initiatives and lower energy costs.

DD&A expense decreased by $171 million in the second quarter of 2016 compared to the second quarter of 2015 primarily due to a reduced depletion base resulting from an impairment charge recognized on certain crude oil and natural gas assets 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 second 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 second quarter of 2016, total DD&A averaged $18.81/boe compared to $23.21/boe in the second quarter of 2015.

Exploration and evaluation expenses increased by $33 million in the second quarter of 2016 compared to the second quarter of 2015 primarily due to two exploration wells drilled in the Flemish Pass Basin which did not encounter economic quantities of hydrocarbons and were expensed in the second quarter of 2016.

Other-net expense increased by $72 million in the second quarter of 2016 compared to the second quarter of 2015 primarily due to the loss recognized on the sale of select legacy Western Canada crude oil and natural gas assets.

Six Months

In the first six months of 2016, Exploration and Production net revenues decreased by $932 million, operating costs decreased by $140 million, DD&A expense decreased by $328 million and other-net expense increased by $87 million compared to the same period in 2015, primarily due to the same factors which impacted the second quarter.

Average Sales Prices Realized

Average Sales Prices Realized	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Crude oil and NGLs *($/bbl)*				
Light and Medium crude oil	**56.11**	69.99	**47.26**	63.03
NGLs	**36.68**	51.97	**34.18**	48.54
Heavy crude oil	**34.88**	50.21	**26.21**	41.52
Bitumen	**30.95**	48.45	**22.22**	41.42
Total crude oil and NGLs average	**39.94**	56.79	**32.00**	49.85
Natural gas average *($/mcf)*	**3.46**	6.09	**3.97**	6.03
Total average *($/boe)*	**34.59**	49.50	**29.62**	45.08

Second Quarter

The average sales prices realized by the Company for crude oil and NGLs production decreased by 30 percent in the second quarter of 2016 compared to the same period in 2015 primarily due to significantly lower crude oil benchmarks. The impact of weaker crude oil benchmarks, resulting from the supply and demand market imbalance, was partially mitigated by a weaker Canadian dollar.

The average sales prices realized by the Company for natural gas production decreased by 43 percent in the second 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 significantly lower North American natural gas benchmarks, partially mitigated by the weakening of the Canadian dollar relative to the U.S. dollar.

Six Months

In the first six months of 2016, the average sales prices realized by the Company for crude oil and NGLs production decreased by 36 percent and the average sales prices realized by the Company for natural gas production decreased by 34 percent compared to the same period in 2015 primarily due to the same factors which impacted the second quarter.

Daily Gross Production

	Three months ended June 30,		Six months ended June 30,	
Daily Gross Production	**2016**	2015	**2016**	2015
Crude Oil and NGLs *(mbbls/day)*				
Western Canada				
Light and Medium crude oil	**29.6**	37.4	**31.3**	38.2
NGLs	**8.0**	8.6	**8.4**	9.1
Heavy crude oil	**57.5**	70.0	**59.5**	71.0
Bitumen[(1)]	**78.5**	48.5	**75.5**	52.0
	173.6	164.5	**174.7**	170.3
Oil Sands				
Sunrise – bitumen	**9.5**	1.8	**9.4**	0.9
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**30.9**	29.9	**33.5**	31.8
Terra Nova – light crude oil	**1.8**	2.7	**3.1**	5.4
	32.7	32.6	**36.6**	37.2
Asia Pacific Region				
Wenchang – light crude oil	**7.1**	7.2	**7.2**	7.5
Liwan and Wenchang – NGLs[(2)]	**4.8**	10.5	**5.0**	10.6
	11.9	17.7	**12.2**	18.1
	227.7	216.6	**232.9**	226.5
Natural gas *(mmcf/day)*				
Western Canada	**441.5**	518.8	**475.2**	521.5
Asia Pacific Region[(2)]	**87.3**	202.8	**98.7**	197.9
	528.8	721.6	**573.9**	719.4
Total *(mboe/day)*	**315.8**	336.9	**328.6**	346.4

(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 59.1 mbbls/day for the three months ended June 30, 2016 compared to 41.2 mbbls/day for the three months ended June 30, 2015.*

(2) *Reported production volumes for the three and six months ended June 30, 2015 include an incremental share of production volumes allocated to Husky for exploration cost recoveries. 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

Second Quarter

Crude oil and NGLs production increased in the second quarter of 2016 compared to the second quarter of 2015 primarily due to new production from the Rush Lake and Edam East heavy oil thermal developments and the South White Rose extension, the production ramp-up from the Sunrise Energy Project and strong performance from the Tucker Thermal Project including new production from the Colony formation. The increases were partially offset by natural reservoir declines from mature properties in Western Canada and the Atlantic Region and the temporary shut-in of production at the Sunrise Energy Project during May in response to wildfires in the Fort McMurray region of Alberta. In addition, NGLs production was lower from the Liwan Gas Project in the Asia Pacific Region primarily due to a reversion of the Company's entitlement share of production at Liwan 3-1 to 49 percent, from approximately 76 percent, following the completion of Liwan 3-1 field exploration cost recoveries in May 2015.

Six Months

Crude oil and NGLs production increased in the first six months of 2016 compared to the same period in 2015 primarily due to the same factors which impacted the second quarter.

Natural Gas Production

Second Quarter

Natural gas production decreased in the second quarter of 2016 by 192.8 mmcf/day compared to the second quarter of 2015. In the Asia Pacific Region, natural gas production decreased by 115.5 mmcf/day primarily due to lower production from the Liwan Gas Project where 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 addition, production declined due to a planned partial shut-down at the Liwan Gas Project to install a second deepwater pipeline and lower demand. Discussions are continuing with CNOOC related to the Liwan take-or-pay contract. In Western Canada, natural gas production decreased by 77.3 mmcf/day primarily due to natural reservoir declines from mature properties, the completion of a planned three-week turnaround at the Ram River gas plant, strategic shut-ins due to unfavourable economics and third-party pipeline restrictions.

Six Months

Natural gas production decreased by 145.5 mmcf/day in the first six months of 2016 compared to the same period in 2015. In addition to the factors impacting the second 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. In Western Canada, natural gas production decreased primarily due to the same factors which impacted the second quarter.

2016 Production Guidance

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

		Actual Production	
	Guidance[1] 2016	**Six months ended June 30, 2016**	Year ended December 31, 2015
Canada			
Light and Medium crude oil *(mbbls/day)*	66 - 68	**68**	73
NGLs *(mbbls/day)*	7 - 8	**8**	9
Heavy crude oil & bitumen *(mbbls/day)*	142 - 157	**144**	132
Natural gas *(mmcf/day)*	380 - 430	**475**	514
Canada total *(mboe/day)*	279 - 305	**300**	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	**99**	175
Asia Pacific total *(mboe/day)*	36 - 40	**29**	46
Total *(mboe/day)*	315 - 345	**329**	346

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

Royalties

Second Quarter

Royalty rates as a percentage of gross revenues averaged nine percent in both the second quarter of 2016 and 2015. Royalty rates in Western Canada averaged eight percent in the second quarter of 2016 compared to nine percent in the same period in 2015. Royalty rates for the Atlantic Region averaged 17 percent in the second quarter of 2016 compared to 13 percent in the same period in 2015 primarily due to lower eligible royalty costs and a prior period adjustment. Royalty rates in the Asia Pacific Region averaged six percent in the second quarter of 2016 compared to five percent in the same period in 2015.

Six Months

In the first six months of 2016, royalty rates as a percentage of gross revenues averaged eight percent compared to nine percent in the same period in 2015. Royalty rates in Western Canada averaged seven percent in the first six months of 2016 compared to 10 percent in the same period in 2015 primarily due to lower commodity prices with a sliding scale price sensitivity rate. Royalty rates for the Atlantic Region averaged 14 percent in the first six months of 2016 and 2015 as lower production volumes and crude oil prices were offset by the same factors which impacted the second quarter. Royalty rates in the Asia Pacific Region averaged five percent in the first six months of 2016 and 2015.

Operating Costs

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Western Canada	**350**	421	**716**	847
Atlantic Region	**61**	57	**113**	107
Asia Pacific Region	**23**	28	**47**	49
Total operating costs	**434**	506	**876**	1,003
Unit operating costs ($/boe)	**13.90**	15.72	**13.59**	15.28

Second Quarter

Total Exploration and Production operating costs were $434 million in the second quarter of 2016 compared to $506 million in the same period in 2015. Total unit operating costs averaged $13.90/boe in the second quarter of 2016 compared to $15.72/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 $13.49/boe in the second quarter of 2016 compared to $17.23/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 $20.27/bbl in the second quarter of 2016 compared to $19.20/bbl in the same period in 2015. The increase in unit operating costs per boe was primarily attributable to higher subsea maintenance costs.

Unit operating costs in the Asia Pacific Region averaged $9.91/boe in the second quarter of 2016 compared to $6.09/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 combined with costs for a planned maintenance program at the Wenchang field in May 2016. The increases were partially offset by cost saving initiatives at the Liwan Gas Project.

Six Months

Total Exploration and Production operating costs were $876 million in the first six months of 2016 compared to $1,003 million in the same period in 2015. Total unit operating costs averaged $13.59/boe in the first six months of 2016 compared to $15.28/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 $13.62/boe in the first six months of 2016 compared to $17.17/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 second quarter.

Unit operating costs in the Atlantic Region averaged $16.92/bbl in the first six months of 2016 compared to $15.93/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 second quarter combined with higher logistic costs.

Unit operating costs in the Asia Pacific Region averaged $9.09/boe in the first six months of 2016 compared to $5.31/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.

Exploration and Evaluation Expenses

($ millions)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Seismic, geological and geophysical	15	30	31	51
Expensed drilling	59	7	59	39
Expensed land	2	6	3	10
Total exploration and evaluation expenses	76	43	93	100

Second Quarter

Exploration and evaluation expenses in the second quarter of 2016 were $76 million compared to $43 million in the second quarter of 2015. The increase in expensed drilling related primarily to two exploration wells drilled in the Flemish Pass which did not encounter economic quantities of hydrocarbons. The decrease in seismic, geological and geophysical costs resulted from lower seismic activity across the portfolio.

Six Months

Exploration and evaluation expenses in the first six months of 2016 were $93 million compared to $100 million in the same period in 2015. The decrease in seismic, geological and geophysical costs was primarily attributable to the same factors which impacted the second quarter. The increase in expensed drilling costs was primarily attributable to the same factors which impacted the second quarter. Expensed drilling in the first quarter of 2015 reflected the write-off of the Aster exploration well.

Exploration and Production Capital Expenditures

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

Exploration and Production Capital Expenditures[1] ($ millions)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Exploration				
Western Canada conventional and resource plays	2	8	4	13
Heavy Oil	1	1	4	8
Atlantic Region	8	44	19	104
	11	53	27	125
Development				
Western Canada conventional and resource plays	37	65	82	227
Heavy Oil	59	232	134	489
Oil Sands	3	100	14	183
Atlantic Region	87	103	104	230
Asia Pacific Region[2]	51	17	62	38
	237	517	396	1,167
Acquisitions				
Western Canada conventional and resource plays	—	1	—	1
Heavy Oil	2	—	2	1
	250	571	425	1,294

[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 six months of 2016, $86 million (20 percent) was invested in Western Canada conventional and resource plays, compared to $241 million (19 percent) in the same period in 2015. Capital expenditures in 2016 relate primarily to maintenance activities. The decrease in capital expenditures in the first six 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 six months of 2016, $140 million (33 percent) was invested in Heavy Oil, compared to $498 million (38 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 six 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 six months of 2016, $14 million (three percent) was invested in Oil Sands, compared to $183 million (14 percent) in the same period in 2015. Capital expenditures in 2016 and 2015 relates primarily to the Sunrise Energy Project. The decrease in capital expenditures in the first six 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 six months of 2016, $123 million (29 percent) was invested in the Atlantic Region, compared to $334 million (26 percent) in the same period in 2015. Capital expenditures in 2016 relates primarily to the development of the White Rose extension projects, including the West White Rose and South White Rose extension satellite fields and on further exploration and appraisal in and around the Bay du Nord discovery in the Flemish Pass Basin. The decrease in capital expenditures in the first six 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 six months of 2016, $62 million (15 percent) was invested in the Asia Pacific Region, compared to $38 million (three percent) in the same period in 2015. Capital expenditures in 2016 relates primarily to the Liwan Gas Project. The increase in capital expenditures in the first six months of 2016 compared to the same period in 2015 was primarily due to the installation of a second deepwater production pipeline at Liwan 3-1.

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 six months ended June 30, 2016 and 2015:

	Three months ended June 30,				Six months ended June 30,			
	2016		2015		2016		2015	
Wells Drilled[1]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy Oil	7	7	31	31	43	43	66	65
Oil Sands	—	—	8	4	—	—	14	7
Western Canada conventional and resource plays	—	—	13	5	2	1	36	19
	7	7	52	40	45	44	116	91

(1) *Excludes Service/Stratigraphic test wells for evaluation purposes.*

During the second quarter of 2016, the Company's onshore drilling was focused primarily on the development of Heavy Oil. 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 and Asia Pacific Region drilling activity during six months ended June 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

[(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 extensive 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 June 30,		Six months ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Gross revenues	**270**	337	**485**	703
Purchases of crude oil and products	**227**	302	**398**	637
Infrastructure gross margin	**43**	35	**87**	66
Marketing and other	**18**	(44)	**(84)**	25
Total Infrastructure and Marketing gross margin	**61**	(9)	**3**	91
Production, operating and transportation expenses	**7**	9	**15**	18
Selling, general and administrative expenses	**1**	1	**2**	3
Depletion, depreciation, amortization and impairment	**6**	6	**12**	11
Other – net	**(1)**	3	**(4)**	2
Provisions for (recovery of) income taxes	**13**	(7)	**(6)**	15
Net earnings (loss)	**35**	(21)	**(16)**	42

Second Quarter

Infrastructure and Marketing gross revenues and purchases of crude oil and products decreased by $67 million and $75 million, respectively, in the second quarter of 2016 compared to the second quarter of 2015 primarily due to significantly lower commodity prices.

Marketing and other increased by $62 million in the second quarter of 2016 compared to the second quarter of 2015 primarily due to unrealized mark-to-market losses recognized on the Company's risk management positions and the narrowing of product price differentials between Canada and the United States in the second quarter of 2015. The decreases were partially offset by unrealized gas storage mark-to-market gains in the second quarter of 2016 as a result of rising forward North American natural gas prices.

Six Months

Infrastructure and Marketing gross revenues and purchases of crude oil and products decreased by $218 million and $239 million, respectively, in the first six months of 2016 compared to the same period in 2015 primarily due to the same factor which impacted the second quarter.

Marketing and other decreased by $109 million in the first six months of 2016 compared to the the same period in 2015 primarily due to narrower product and location differentials between Canada and the U.S. which resulted in fewer arbitrage opportunities and unrealized mark-to-market losses recognized in the first quarter of 2016 partially offset by the factors which impacted the second quarter.

Infrastructure and Marketing Capital Expenditures

In the first six months of 2016, Infrastructure and Marketing capital expenditures totalled $56 million compared to $49 million in the same period in 2015. Capital expenditures in both periods relates primarily to the expansion of the Saskatchewan Gathering System into Lloydminster.

5.2 Downstream

Upgrader

Upgrader Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2016**	2015	**2016**	2015
Gross revenues	**369**	418	**650**	765
Purchases of crude oil and products	**222**	310	**359**	548
Gross margin	**147**	108	**291**	217
Production, operating and transportation expenses	**40**	42	**76**	85
Selling, general and administrative expenses	**1**	1	**2**	2
Depletion, depreciation, amortization and impairment	**27**	26	**55**	52
Other – net	**(1)**	—	**(1)**	(11)
Provisions for income taxes	**22**	11	**43**	24
Net earnings	**58**	28	**116**	65
Upgrader throughput *(mbbls/day)*(1)	**76.9**	70.6	**77.3**	77.1
Total sales *(mbbls/day)*	**76.5**	73.2	**77.4**	77.1
Synthetic crude oil sales *(mbbls/day)*	**59.8**	55.0	**58.8**	56.8
Upgrading differential *($/bbl)*	**20.85**	18.93	**21.55**	17.38
Unit margin *($/bbl)*	**21.12**	16.21	**20.66**	15.55
Unit operating cost *($/bbl)*(2)	**5.72**	6.54	**5.40**	6.09

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

Second 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 decreased by $49 million in the second quarter of 2016 compared to the second quarter of 2015 primarily due to lower realized prices for synthetic crude oil and low sulphur distillates partially offset by higher throughput and sales volumes. Throughput increased by 6.3 mbbls/day, or nine percent, and sales volumes increased by 3.3 mbbls/day, or five percent, compared to the second quarter of 2015.

Upgrader gross margin increased by $39 million in the second quarter of 2016 compared to the second quarter of 2015 primarily due to higher average upgrading differentials. During the second quarter of 2016, the upgrading differential averaged $20.85/bbl, an increase of $1.92/bbl, or 10 percent compared to the second 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 second quarter of 2016, the price of Husky Synthetic Blend averaged $45.99/bbl compared to $73.90/bbl in the second quarter of 2015.

Six Months

Upgrader gross revenues decreased by $115 million in the first six months of 2016 compared to the same period in 2015 primarily due to lower realized prices for synthetic crude oil and low sulphur distillates.

Upgrader gross margin increased by $74 million in the first six months of 2016 compared to the same period in 2015 primarily due to the same factors which impacted the second quarter. During the first six months of 2016, the upgrading differential averaged $21.55/bbl, an increase of $4.17/bbl, or 24 percent compared to the same period in 2015.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2016**	2015	**2016**	2015
Gross revenues	**585**	747	**1,020**	1,348
Purchases of crude oil and products	**440**	599	**779**	1,082
Gross margin				
Fuel	**37**	33	**63**	66
Refining	**32**	38	**49**	66
Asphalt	**61**	62	**100**	106
Ancillary	**15**	15	**29**	28
	145	148	**241**	266
Production, operating and transportation expenses	**64**	63	**113**	126
Selling, general and administrative expenses	**7**	6	**14**	16
Depletion, depreciation, amortization and impairment	**25**	26	**49**	51
Other – net	**(1)**	(2)	**(2)**	(1)
Financial items	**1**	2	**3**	3
Provisions for income taxes	**13**	14	**17**	19
Net earnings	**36**	39	**47**	52
Number of fuel outlets[(1)]	**482**	488	**482**	488
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*	**6.8**	7.6	**6.5**	7.6
Fuel sales per retail outlet *(thousands of litres/day)*	**11.6**	12.4	**11.3**	12.4
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**5.1**	8.5	**8.1**	9.9
Lloydminster Refinery *(mbbls/day)*	**28.2**	28.4	**28.1**	28.8
Ethanol production *(thousands of litres/day)*	**809.2**	767.9	**810.0**	771.4

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

Second Quarter

Canadian Refined Products gross revenues decreased by $162 million in the second quarter of 2016 compared to the second 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 3.4 mbbls/day, or 40 percent, and fuel sales per retail outlet decreased by 800 litres/day, or six percent, compared to the second quarter of 2015.

Fuel gross margins increased by $4 million in the second quarter of 2016 compared to the second quarter of 2015 primarily due to widening rack to retail differentials partially offset by lower sales volumes.

Refining gross margins decreased by $6 million in the second quarter of 2016 compared to the second quarter of 2015. Gross margins were $2 million lower at the Prince George Refinery primarily due to the planned turnaround and $4 million lower at the Lloydminster and Minnedosa Ethanol plants primarily due to higher grain feedstock costs.

Six Months

Canadian Refined Products gross revenues decreased by $328 million in the first six 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.

Refining gross margins decreased by $17 million in the first six months of 2016 compared to the same period in 2015 primarily due to the same factors which impacted the second quarter.

Asphalt gross margins decreased by $6 million in the first six months of 2016 compared to the same period in 2015 primarily due to lower refined product prices partially offset by lower heavy crude oil feedstock costs.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2016**	2015	**2016**	2015
Gross revenues	**1,337**	1,955	**2,463**	3,680
Purchases of crude oil and products	**1,083**	1,549	**2,123**	3,088
Gross margin	**254**	406	**340**	592
Production, operating and transportation expenses	**127**	107	**264**	235
Selling, general and administrative expenses	**3**	2	**6**	5
Depletion, depreciation, amortization and impairment	**77**	114	**158**	183
Other – net	**(50)**	(91)	**(175)**	(91)
Financial items	**1**	1	**2**	2
Provisions for (recovery of) income taxes	**35**	101	**31**	(108)
Net earnings	**61**	172	**54**	366
Select operating data:				
Lima Refinery throughput *(mbbls/day)*	**103.9**	136.1	**115.7**	127.6
BP-Husky Toledo Refinery throughput *(mbbls/day)*[(1)]	**41.2**	75.5	**55.1**	66.0
Refining margin *(U.S. $/bbl crude throughput)*	**16.46**	17.88	**9.00**	14.37
Refinery inventory *(mmbbls)*[(2)]	**11.1**	10.4	**11.1**	10.4

(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.*

Second Quarter

U.S. Refining and Marketing gross revenues decreased by $618 million in the second quarter of 2016 compared to the second quarter of 2015 primarily due to lower throughput and sales volumes at the Lima and BP-Husky Toledo Refineries where scheduled major turnarounds were completed in May and July, respectively, combined with lower realized refined product prices. The decreases were partially offset by a weaker Canadian dollar. Throughputs at the Lima and BP-Husky Toledo Refineries decreased by 32.2 mbbls/day and 34.3 mbbls/day, respectively, when compared to the second quarter of 2015.

U.S. Refining and Marketing purchases decreased by $466 million in the second quarter of 2016 compared to the second quarter of 2015 primarily due to the impact of the scheduled major turnaround combined with lower crude oil feedstock costs.

U.S. Refining and Marketing gross margin decreased by $152 million in the second quarter of 2016 compared with the second quarter of 2015 primarily due to lower throughput and sales volumes combined with lower Chicago 3:2:1 crack spreads which is reflected in refining margins.

Operating costs increased by $20 million primarily due to the scheduled major turnarounds and a weaker Canadian dollar.

In the second quarter of 2016, the Company accrued business interruption and property damage insurance recoveries of $52 million associated with the Company's isocracker unit fire at Lima, compared to $92 million in the second quarter of 2015, bringing total insurance recoveries to date of $410 million up to June 30, 2016. The insurance recoveries are reflected in other – net. Included in depletion, depreciation, amortization and impairment in the second quarter of 2015 was a $46 million write-off of the carrying value of the isocracker unit.

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 an increase in net earnings of approximately $88 million in the second quarter of 2016 compared to $78 million the second quarter of 2015.

Six Months

U.S. Refining and Marketing gross revenues decreased by $1,217 million in the first six months of 2016 compared to the same period in 2015 primarily due to the same factors which impacted the second quarter. In the first quarter of 2015, throughput was negatively impacted at the Lima Refinery by the isocracker unit fire and at the BP-Husky Toledo Refinery by unplanned maintenance to repair a damaged fluid catalytic cracking unit.

U.S. Refining and Marketing purchases decreased by $965 million and gross margin decreased by $252 million in the first six months of 2016 compared to the same period in 2015 primarily due to the same factors which impacted the second quarter.

In the first six 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 Lima compared to $92 million in the same period in 2015.

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 six months of 2016, Downstream capital expenditures totalled $505 million compared to $168 million in the same period in 2015. In Canada, capital expenditures of $56 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 $286 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 $163 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 June 30,		Six months ended June 30,	
($ millions) income (expense)	**2016**	2015	**2016**	2015
Selling, general and administrative expenses	**(82)**	(16)	**(145)**	(36)
Depletion, depreciation, amortization and impairment	**(20)**	(20)	**(41)**	(40)
Other – net	**(65)**	—	**(131)**	—
Net foreign exchange gain (loss)	**(9)**	6	**4**	68
Finance income	**—**	1	**5**	2
Finance expense	**(58)**	(36)	**(122)**	(50)
Recovery of (provisions for) income taxes	**76**	(51)	**53**	(57)
Net loss	**(158)**	(116)	**(377)**	(113)

Second Quarter

The Corporate segment reported a net loss of $158 million in the second quarter of 2016 compared to $116 million in the second quarter of 2015. Selling, general and administrative expenses increased by $66 million primarily due to an increase in stock-based compensation expense and re-organization costs recognized in the second quarter of 2016. Other – net expense of $65 million in the second quarter of 2016 related primarily to losses on the Company's short term hedging program which concluded in June 2016. The Canadian dollar weakened relative to the U.S. dollar in the second quarter of 2016 which resulted in a foreign exchange loss of $9 million compared to a $6 million gain in the second quarter of 2015 when the Canadian dollar strengthened. Foreign currency fluctuations impact the translation of the Company's foreign currency denominated non-cash working capital. Finance expense increased by $22 million primarily due to higher debt and a decrease in the amount of capitalized interest.

Six Months

The Corporate segment reported a net loss of $377 million in the first six months of 2016 compared to $113 million in the same period in 2015. Selling, general and administrative expenses increased by $109 million primarily due to the same factors which impacted the second quarter. Other – net expense of $131 million related primarily to losses on the Company's short term hedging program which concluded in June 2016. Finance expense increased by $72 million primarily due to the same factors which impacted the second quarter. Foreign exchange gain decreased by $64 million due to the items noted below.

Foreign Exchange Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2016**	2015	**2016**	2015
Gain (loss) on translation of U.S. dollar denominated long-term debt	**—**	5	**—**	(22)
Gain (loss) on non-cash working capital	**(7)**	(36)	**(20)**	19
Other foreign exchange gain (loss)	**(2)**	37	**24**	71
Net foreign exchange gain (loss)	**(9)**	6	**4**	68
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S $0.771**	U.S $0.788	**U.S $0.723**	U.S $0.862
At end of period	**U.S $0.769**	U.S $0.802	**U.S $0.769**	U.S $0.802

Included in other foreign exchange gain 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 June 30,		Six months ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Provisions for (recovery of) income taxes	**(79)**	174	**(147)**	(31)
Cash income taxes paid (recovered)	**(21)**	150	**(56)**	146

Second Quarter

Consolidated income taxes were a recovery of $79 million in the second quarter of 2016 compared to an expense of $174 million in the same period in 2015. The decrease in consolidated income taxes was primarily due to the recognition of a $157 million deferred income tax expense related to the increase in Alberta provincial corporate tax rates in the second quarter of 2015 and lower net earnings before income taxes in the second quarter of 2016.

Six Months

Consolidated income taxes were a recovery of $147 million in the first six months of 2016 compared $31 million in the same period in 2015. The decrease in consolidated income taxes was primarily due to lower net earnings before income taxes in the first six months of 2016.

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 continues to believe that it has sufficient liquidity to sustain its operations, fund capital programs and meet non-cancellable contractual obligations and commitments, including any working capital deficiencies, in the short and long-term principally by cash generated from operating activities, cash on hand, the issuance of equity, the issuance of debt, borrowings under committed and uncommitted credit facilities and cash proceeds from asset sales. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

At June 30, 2016, Husky had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[1]	**670**	**355**
Syndicated credit facilities[2]	**4,000**	**2,940**
	4,670	**3,295**

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

At June 30, 2016, Husky had $3,295 million of unused credit facilities of which $2,940 million are long-term committed credit facilities and $355 million are short-term uncommitted credit facilities. A total of $315 million of the Company's short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $860 million of the Company's long-term committed borrowing credit facilities was used in support of commercial paper. At June 30, 2016 the Company had direct borrowings of $200 million 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 an investment grade credit rating 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 June 30, 2016, working capital deficiency was $524 million compared to a working capital deficiency of $922 million at December 31, 2015. The Company had sufficient sources of liquidity to supplement the working capital deficiency as at June 30, 2016.

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 June 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.

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 March 31, 2016 to, but excluding, June 30, 2016 is equal to the sum of the Government of Canada 90 day treasury bill rate on March 1, 2016 plus 1.73 percent, being 2.192 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 June 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 June 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		June 30, 2016
($ millions)	**Outstanding**	**Available[(1)]**
Total debt[(2)]	**6,333**	**3,295**
Common shares, preferred shares, retained earnings and other reserves	**15,915**	

(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 and debt which was $22.2 billion as at June 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 June 30, 2016, debt to capital employed was 28.5 percent (December 31, 2015 – 28.9 percent) and debt to cash flow from operations was 2.8 times (December 31, 2015 – 2.0 times), exceeding the Company's targets.

The increase in the Company's debt to capital employed and debt to cash flow from operations ratios as at June 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, the continued transition to low sustaining capital projects, the disposition of 65 percent of Husky's ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan and the disposition of select legacy crude oil and natural gas assets in Western Canada.

Divestitures

Pipeline and Terminals

On April 25, 2016, the Company reached an agreement to sell 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.7 billion in cash, with the sale price representing approximately 13 times the expected 2016 earnings before interest, tax, depreciation and amortization ("EBITDA") of the select midstream assets. EBITDA is a non-GAAP measure, refer to section 11. 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 will enable 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. The transaction is effective July 1, 2016, received regulatory approval on July 13, 2016 and closed on July 15, 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 $184 million. The proceeds were received in the second quarter of 2016.

In addition, the Company signed purchase and sale agreements in the second quarter of 2016 with third parties to sell its southeast Saskatchewan, Redwater, Pembina and Orloff assets for gross proceeds of $295 million, which are expected to close in the third quarter of 2016.

Cash proceeds generated from the Western Canada legacy oil and natural gas asset dispositions 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. The dispositions noted above have received the required regulatory approvals.

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 second quarter of 2016, the Company reached agreements for the sale of several packages of select legacy Western Canada crude oil and natural gas assets in Saskatchewan and Alberta. As a result, commitments related to lease rentals and asset retirement obligations have decreased by approximately $2 billion.

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 April 25, 2016, the Company reached an agreement to sell 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.7 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 proceeds from the transaction will allow the Company to pay down debt to enable the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets. In addition, the partners are aligned with expanding Husky's heavy oil business and have the funding capacity to build the midstream infrastructure requirements associated with the planned construction of additional Lloydminster thermal projects in Saskatchewan and Alberta. The transaction is effective July 1, 2016, received regulatory approval on July 13, 2016 and closed on July 15, 2016.

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 six months ended June 30, 2016, the amount of natural gas sales to Meridian totalled $6 million and $17 million, respectively, the amount of steam purchased by the Company from Meridian totalled $2 million and $5 million, respectively, and the total cost recovery by the Company for facilities services was $2 million and $8 million, respectively. At June 30, 2016, the Company had under $1 million due from Meridian with respect to these transactions.

At June 30, 2016, $36 million of the May 11, 2009 7.25% senior notes were held by related parties and are included in long-term debt in the Company's consolidated balance sheet. Mr. Canning Fok, co-chair and a director of the Company, indirectly subscribed for $3 million of the senior notes. Ace Dimension Limited subscribed for $33 million of the senior notes. These related party transactions were measured at fair market value at the date of the transactions and have 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 June 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 15 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 were originally designated. The amortization period is ten years. At June 30, 2016, the balance in other reserves related to the accrued gain was $19 million (December 31, 2015 – $20 million), net of tax of $7 million (December 31, 2015 – net of tax of $7 million). The amortization of the accrued gain resulted in an offset to finance expenses of less than $1 million and $1 million for the three and six months ended June 30, 2016, respectively. Refer to the Interest Rate Risk Management disclosure within Note 15 of the Condensed Interim Consolidated Financial Statements.

Foreign Currency Risk Management

At June 30, 2016, 76 percent or $4.1 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 investments in selected foreign operations with a U.S. dollar functional currency.

At June 30, 2016, the Company had designated all of its U.S. $3.2 billion denominated debt as a hedge of the Company's net investments in selected foreign operations with a U.S. dollar functional currency. For the three and six months ended June 30, 2016, the Company incurred an unrealized loss of $11 million and gain of $228 million, respectively, arising from the translation of the debt, net of tax of $2 million and $36 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 June 30, 2016, Husky's share of this obligation was U.S. $170 million including accrued interest. At June 30, 2016, the cost of a Canadian dollar in U.S. currency was $0.769.

8. Critical Accounting Estimates and Key Judgments

Certain 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: July 18, 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	27,012,353
• stock options exercisable	16,423,449

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 June 30, 2016 and the six months ended June 30, 2016 are compared to the results for the three months ended June 30, 2015 and the six months ended June 30, 2015. Discussions with respect to Husky's financial position as at June 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 June 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, operating netback, debt to capital employed, earnings coverage, EBITDA, 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 six months ended June 30, 2016 and 2015:

		Three months ended June 30,		Six months ended June 30,	
($ millions)		**2016**	2015	**2016**	2015
GAAP	Net earnings (loss)	**(196)**	120	**(654)**	311
	Impairment of property, plant and equipment, net of tax	**12**	—	**12**	—
	Exploration and evaluation asset write-downs, net of tax	**22**	4	**22**	4
	Loss on sale of assets	**71**	—	**71**	—
Non-GAAP	Adjusted net earnings (loss)	**(91)**	124	**(549)**	315

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 gains and losses 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 six months ended June 30, 2016 and 2015:

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Net earnings (loss)	**(196)**	120	**(654)**	311
Items not affecting cash:				
Accretion	**33**	31	**67**	61
Depletion, depreciation, amortization and impairment	**697**	905	**1,419**	1,769
Exploration and evaluation expenses	**30**	6	**30**	6
Deferred income taxes	**(108)**	79	**(115)**	(180)
Foreign exchange	**12**	(7)	**13**	21
Stock-based compensation	**8**	(4)	**25**	(14)
Loss (gain) on sale of assets	**96**	(2)	**98**	6
Unrealized mark to market	**(83)**	79	**40**	45
Other	**(1)**	(30)	**(1)**	(10)
Cash flow from operations	**488**	1,177	**922**	2,015
Cash flow from operations – basic	**0.49**	1.20	**0.92**	2.05
Cash flow from operations – diluted	**0.49**	1.20	**0.92**	2.05

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 negative 16.7 times for the twelve month period ended June 30, 2016.

EBITDA

EBITDA is a non-GAAP measure and is equal to net earnings (loss) plus finance income (expense), income taxes and depletion, depreciation and amortization. Management believes that in addition to net earnings (loss), EBITDA is a useful supplemental measure as it provides an indication of the results generated by business activities prior to financing and investing activities and income taxes.

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, foreign exchange, stock-based compensation, gain or loss on sale of property, plant, and equipment, unrealized mark to market gains or losses 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*
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*
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*	*NGLs*	*natural gas liquids*
GJ	*gigajoule*	*NIT*	*NOVA Inventory Transfer*
IAS	*International Accounting Standard*	*NYMEX*	*New York Mercantile Exchange*
IASB	*International Accounting Standards Board*	*OCI*	*other comprehensive income*
ICFR	*Internal Controls over Financial Reporting*	*RMB*	*Chinese Yuan*
IFRS	*International Financial Reporting Standards*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
LIFO	*Last in first out*	*SOR*	*steam-oil ratio*
mbbls	*thousand barrels*	*WTI*	*West Texas Intermediate*
mbbls/day	*thousand barrels per day*		

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; planned use of midstream, royalty and Western Canada disposition proceeds; multiple of the expected 2016 EBITDA from the select midstream assets subject to the sale represented by the sale price of such assets;
- 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 Atlantic Region: anticipated timing of first oil and anticipated net peak daily production from the Company's North Amethyst Hibernia well project; drilling plans for the Henry Goodrich associated with the 2 year White Rose field and satellite extensions drilling program;
- with respect to the Company's Oil Sands properties: the Company's forecasted steam-oil ratio for the Sunrise Energy Project; and forecast daily production from the Company's Sunrise Energy Project by early 2017;
- with respect to the Company's Heavy Oil properties: anticipated timing of first production from, and forecast design capacity of, the Company's Edam West heavy oil thermal project; forecasted thermal production from Tucker and Lloyd for year-end 2016; and forecasted design capacity of the Company's Edam East, Vawn, Rush Lake 2 and three additional heavy oil thermal projects;
- 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 closings of the southeast Saskatchewan, Redwater, Pembina and Orloff asset sales;
- with respect to the Company's Infrastructure and Marketing segment: expected timing of completion, and the anticipated benefits, of the expansion of the Saskatchewan Gathering System; and

- with respect to the Company's Downstream operating segment: anticipated timing and benefits of the crude oil flexibility project at the Lima Refinery; and the potential expansion of the Company's Lloyd asphalt 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.