MANAGEMENT'S DISCUSSION AND ANALYSIS

July 27, 2015

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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)	**2015**	2015	2014	2014	2014	2014	2013	2013
Production *(mboe/day)*	**336.9**	356.0	359.6	341.1	333.6	325.9	308.3	308.5
Gross revenues and marketing and other	**4,526**	4,086	5,875	6,690	6,614	5,943	6,132	6,036
Net earnings (loss)	**120**	191	(603)	571	628	662	177	512
Per share – Basic	**0.11**	0.19	(0.62)	0.58	0.63	0.67	0.18	0.52
Per share – Diluted	**0.10**	0.17	(0.65)	0.52	0.63	0.66	0.18	0.52
Adjusted net earnings(1)	**120**	191	147	571	628	669	375	517
Cash flow from operations(1)	**1,177**	838	1,145	1,341	1,504	1,545	1,143	1,347
Per share – Basic	**1.20**	0.85	1.16	1.36	1.53	1.57	1.16	1.37
Per share – Diluted	**1.20**	0.85	1.16	1.36	1.52	1.57	1.16	1.37

(1) *Adjusted net earnings and cash flow from operations are non-GAAP measures. Adjusted net earnings was redefined in the first quarter of 2015 to equal net earnings before after-tax property, plant and equipment impairment and after-tax inventory write-downs. Refer to Section 11 for a reconciliation to the GAAP measures.*

Performance

- Production increased by 3.3 mboe/day or one percent to 336.9 mboe/day in the second quarter of 2015 compared to the second quarter of 2014 as a result of:
  - Increased production from the Asia Pacific Region due to the ramp-up of the Liwan Gas Project as well as higher production at Wenchang due to a planned turnaround completed in the second quarter of 2014; and
  - Increased Western Canada resource play production;
  - Partially offset by natural reservoir declines in Western Canada and the Atlantic Region; and
  - Increased scheduled maintenance activities in Heavy Oil in the second quarter of 2015 compared to the second quarter of 2014.
- Cash flow from operations decreased by $327 million to $1,177 million in the second quarter of 2015 compared to $1,504 million in the second quarter of 2014 primarily due to the same factors noted below which impacted net earnings partially offset by higher non-cash depletion, depreciation and amortization expense.
- Net earnings decreased by $508 million or 81 percent to $120 million in the second quarter of 2015 compared to $628 million in the second quarter of 2014 due to:
  - Lower realized crude oil and North American natural gas prices resulting from a significant decrease in market benchmarks; and
  - Recognition of a deferred income tax expense of $157 million related to an increase in Alberta provincial tax rates;
  - Partially offset by stronger U.S. Refining and Marketing margins and higher throughput at the BP-Husky Toledo Refinery; and
  - A weaker Canadian dollar.

Key Projects

- Production continued to ramp up at the Sunrise Energy Project. Production in June averaged approximately 5,000 bbls/day (2,500 bbls/day net to Husky). The project is expected to increase production to 60,000 bbls/day (30,000 bbls/day net to Husky) around the end of 2016.
- First oil was achieved at the 10,000 bbls/day Rush Lake heavy oil thermal development on July 16 and is expected to reach its nameplate capacity around the end of 2015.
- Construction continued at the two 10,000 bbls/day Edam East and Vawn and the 4,500 bbls/day Edam West heavy oil thermal developments with first production from all three expected in the second half of 2016.
- In the Atlantic Region, first oil was achieved on the first production well at the South White Rose extension in June 2015. Drilling continues on the second production well with first oil anticipated in late summer of 2015. Production from the South White Rose extension is expected to increase to approximately 15,000 bbls/day net to Husky.
- Drilling of the Hibernia-formation well at the North Amethyst field will resume after the second production well at the South White Rose extension is completed.
- At the Liwan Gas Project, combined gross production and sales from the Liwan 3-1 and Liuhua 34-2 gas fields continued to increase during the second quarter of 2015. Negotiations for the sale of gas and liquids from Liuhua 29-1, the third deepwater field, continued in the quarter.
- In Indonesia, progress continued on the shallow water gas developments in the Madura Strait Block. Wellhead platform and pipeline infrastructure construction at the liquids-rich BD field is ongoing and approximately 45 percent complete, and construction of the FPSO vessel is now approximately 16 percent complete. The amended BD field gas sales agreements were approved by the regulator in the second quarter of 2015.
- Western Canada liquids-rich gas resource play development progressed in the second quarter of 2015 with eight wells (gross) drilled and 15 wells (gross) completed at key plays including continued development of the Ansell liquids-rich natural gas resource play.
- Construction is ongoing for the expansion of the South Saskatchewan Gathering System which will create incremental capacity to accommodate planned production from the Rush Lake, Edam East, Vawn and Edam West thermal developments. Construction is approximately 50 percent complete.

Financial

- Dividends on common shares of $295 million for the first quarter of 2015 were declared during the second quarter of 2015, of which $291 million and $4 million were paid in cash and common shares, respectively, on July 2, 2015.
- Dividends on preferred shares of $16 million were declared and paid in the second quarter of 2015.

2. Business Environment

Average Benchmarks		Three months ended Jun. 30, 2015	Mar. 30, 2015	Dec. 31, 2014	Sept. 30, 2014	Jun. 30, 2014
WTI crude oil[(1)]	*(U.S. $/bbl)*	**57.94**	48.63	73.15	97.17	102.99
Brent crude oil[(2)]	*(U.S. $/bbl)*	**61.92**	53.97	76.27	101.85	109.61
Canadian light crude 0.3 percent sulphur	*($/bbl)*	**54.39**	40.19	65.90	88.53	96.29
Western Canadian Select[(3)]	*(U.S. $/bbl)*	**46.35**	33.90	58.90	76.99	82.95
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**51.31**	36.41	61.77	77.96	80.98
NYMEX natural gas[(4)]	*(U.S. $/mmbtu)*	**2.64**	2.98	4.00	4.06	4.67
NIT natural gas	*($/GJ)*	**2.53**	2.80	3.80	4.00	4.44
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**11.49**	14.63	14.14	20.23	20.17
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**21.70**	19.33	16.09	18.86	19.27
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**20.30**	16.14	14.04	17.41	19.40
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.813**	0.806	0.881	0.918	0.917
Canadian $ Equivalents[(5)]						
WTI crude oil	*($/bbl)*	**71.27**	60.33	83.03	105.85	112.31
Brent crude oil	*($/bbl)*	**76.16**	66.96	86.57	110.95	119.53
WTI/Lloyd crude blend differential	*($/bbl)*	**14.13**	18.15	16.05	22.04	22.00
NYMEX natural gas	*($/mmbtu)*	**3.25**	3.70	4.54	4.42	5.09

(1) *Prices quoted are near-month contract prices for settlement during the next month.*
(2) *Dated Brent prices are dated less than 15 days prior to loading for delivery.*
(3) *Western Canadian Select is a heavy crude blend primarily based on existing Canadian heavy conventional and bitumen crude oils and is traded at Hardisty, Alberta. Quoted prices are based on the average price during the month.*
(4) *Prices quoted are average settlement prices for deliveries during the period.*
(5) *Prices quoted are calculated using U.S. benchmark commodity prices and U.S./Canadian dollar exchange rates.*

The price the Company receives for production from Western Canada is primarily driven by the price of West Texas Intermediate ("WTI"), adjusted to Western Canada, while the majority of the Company's production in the Atlantic Region and Asia Pacific Region is referenced to the price of Brent. Crude oil prices dropped by more than 50 percent at the end of 2014 and continued to be significantly weaker in the second quarter of 2015 when compared to the second quarter of 2014. The price of WTI averaged U.S. $57.94/bbl in the second quarter of 2015 compared to U.S. $102.99/bbl in the same period of 2014. The price of WTI averaged U.S. $53.29/bbl in the first six months of 2015 compared to U.S. $100.84/bbl in first six months of 2014. The price of Brent averaged U.S. $61.92/bbl in the second quarter of 2015 compared to U.S. $109.61/bbl in the same period of 2014. The price of Brent averaged U.S. $57.95/bbl in the first six months of 2015 compared to U.S. $108.91/bbl in first six months of 2014.

Crude oil prices realized by the Company in the second quarter of 2015 benefited significantly from the weakening of the Canadian dollar when compared to the second quarter of 2014. In the second quarter of 2015, the price of WTI in U.S. dollars decreased 44 percent compared to a decrease of 37 percent in Canadian dollars when compared to the second quarter of 2014. In the second quarter of 2015, the price of Brent in U.S. dollars decreased 44 percent compared to a decrease of 36 percent in Canadian dollars when compared to the second quarter of 2014.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In the second quarter of 2015, 56 percent of Husky's crude oil production was heavy oil or bitumen compared with 57 percent in the second quarter of 2014. The light/heavy crude oil differential averaged U.S. $11.49/bbl or 20 percent of WTI in the second quarter of 2015 compared to U.S. $20.17/bbl or 20 percent of WTI in the second quarter of 2014. The light/heavy crude oil differential averaged U.S. $13.06/bbl or 25 percent of WTI in the first six months of 2015 compared to $21.63/bbl or 21 percent of WTI in the first six months of 2014.

During the second quarter of 2015, the NYMEX near-month contract price of natural gas averaged U.S. $2.64/mmbtu compared to U.S. $4.67/mmbtu in the same period of 2014, a decrease of 43 percent. During the first six months of 2015, the NYMEX near-month contract price of natural gas averaged U.S. $2.81/mmbtu compared to U.S. $4.81/mmbtu during the first six months of 2014, a decrease of 42 percent. During the second quarter of 2015, the NOVA Inventory Transfer ("NIT") near-month contract price of natural gas averaged $2.53/GJ compared to $4.44/GJ in the same period in 2014, a decrease of 43 percent. During the first six months of 2015, the NIT near-month contract price of natural gas averaged $2.66/GJ compared to $4.47/GJ in the same period in 2014, a decrease of 40 percent.

Increasing supply of global crude oil and natural gas production, primarily led by growth in U.S. unconventional production, led to the sharp decline in key crude oil and natural gas benchmarks in the second half of 2014. These benchmarks continue to be significantly weaker in the second quarter of 2015 compared to the second quarter of 2014.

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 International Upstream operations and U.S. dollar denominated debt.

In the second quarter of 2015, the Canadian dollar averaged U.S. $0.813, weakening by 11 percent compared to U.S. $0.917 in the second quarter of 2014. In the first six months of 2015, the Canadian dollar averaged U.S. $0.810, weakening by 11 percent compared to U.S. $0.912 in the first six months of 2014.

Refining Crack Spreads

The 3:2:1 crack spread is the key indicator for refining margins as refinery gasoline output 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 fuel oil (distillate) 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.

In the second quarter of 2015, the Chicago 3:2:1 crack spread averaged U.S. $20.30/bbl compared to U.S. $19.40/bbl in the second quarter of 2014. In the first six months of 2015, the Chicago 3:2:1 crack spread averaged U.S. $18.26/bbl compared to U.S. $18.88/bbl in the first six months of 2014. In the second quarter of 2015, the New York Harbour 3:2:1 crack spread averaged U.S. $21.70/bbl compared to U.S. $19.27/bbl in the second quarter of 2014. In the first six months of 2015, the New York Harbour 3:2:1 crack spread averaged U.S. $20.53/bbl compared to U.S. $19.79/bbl in the first six months of 2014.

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. Husky's realized refining margins are accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in the second quarter of 2015 on earnings before income taxes and net earnings. The table below reflects what the effect would have been on the financial results for the second quarter of 2015 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the second quarter of 2015. 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 applicable 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	**2015 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)	**57.94**	*U.S. $1.00/bbl*	**87**	**0.09**	**64**	**0.06**
NYMEX benchmark natural gas price(5)	**2.64**	*U.S. $0.20/mmbtu*	**26**	**0.03**	**18**	**0.02**
WTI/Lloyd crude blend differential(6)	**11.49**	*U.S. $1.00/bbl*	**(53)**	**(0.05)**	**(38)**	**(0.04)**
Canadian light oil margins	**0.047**	*Cdn $0.005/litre*	**4**	**0.00**	**3**	**0.00**
Asphalt margins	**20.89**	*Cdn $1.00/bbl*	**3**	**0.00**	**2**	**0.00**
New York Harbour 3:2:1 crack spread	**21.70**	*U.S. $1.00/bbl*	**48**	**0.05**	**31**	**0.03**
Exchange rate (U.S. $ per Cdn $)(3)(7)	**0.813**	*U.S. $0.01*	**(58)**	**(0.06)**	**(43)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 984.0 million common shares outstanding as of June 30, 2015.*
(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 maintain and enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward 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 natural gas liquids (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, pipeline transportation and 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 the East Coast of Canada, offshore China and offshore Indonesia.

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading), 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 process and refine natural resources into marketable products and therefore, were grouped together as the Downstream business segment due to the similar nature of products and services.

4. Key Growth Highlights

The 2015 Capital Program enables Husky to build on the momentum achieved over the past five years while maintaining prudent capital management and pacing the Company's growth projects and exploration plans 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. These long-life developments are being built with modular, repeatable designs and are expected to require low sustaining capital once brought online. Total heavy oil thermal production in the second quarter averaged 41,100 bbls/day reflecting some planned maintenance activity during the quarter.

Heavy Oil Thermal Developments

Development	Design Capacity (bbls/day)	Percentage Completion	First Production Expected
Rush Lake	10,000	100%	On production
Edam East	10,000	62%	Q3 2016
Vawn	10,000	52%	Q4 2016
Edam West	4,500	36%	Q4 2016

First oil was achieved at the 10,000 bbls/day Rush Lake heavy oil thermal development on July 16 and is expected to reach its nameplate capacity around the end of 2015.

At the 10,000 bbls/day Edam East and 10,000 bbls/day Vawn heavy oil thermal developments, construction is approximately 62 and 52 percent complete, respectively. Major equipment is being delivered and mechanical and electrical central processing facility construction is progressing at both projects with first production expected in the third quarter of 2016 at Edam East and in the fourth quarter of 2016 at Vawn.

At the 4,500 bbls/day Edam West heavy oil thermal development construction is approximately 36 percent complete. Detailed engineering and civil construction continued in the second quarter of 2015. First production is expected in the fourth quarter of 2016.

Several other Heavy Oil Thermal projects are in the pre-development phase.

Emerging Heavy Oil Thermal Development

Early engineering work is ongoing at the McMullen thermal development to define the scope for a commercial demonstration project.

Asia Pacific Region

China

Block 29/26

Combined gross production from the Liwan 3-1 and Liuhua 34-2 gas fields increased from 262 mmcf/day in the first quarter of 2015 to 295 mmcf/day in the second quarter. Gross sales of associated natural gas liquids increased from approximately 13.6 mboe/day to 15.1 mboe/day over the same period. The Company's entitlement to Liwan gas and liquids sales reduced from approximately 76 percent up until late May to its equity interest of 49 percent, reflecting the completion of exploration cost recoveries which were originally funded solely by the Company. Negotiations for the sale of gas and liquids from Liuhua 29-1, the third deepwater field, continue to be pursued together with CNOOC Limited.

Offshore Taiwan

Analysis of the two-dimensional seismic survey data acquired in 2014 on the Company's offshore Taiwan block is ongoing.

Indonesia

Madura Strait

Progress continued on the shallow water gas developments in the Madura Strait Block. Wellhead platform and pipeline infrastructure construction at the liquids-rich BD field is ongoing and approximately 45 percent complete, and construction of the FPSO vessel is now approximately 16 percent complete. The amended BD field gas sales agreements were approved by the regulator in the second quarter of 2015.

Tender plans for the MDA and MBH development projects were approved by SKK Migas, the Indonesia oil and gas regulator, and the tendering process is in progress. The Gas Sales Agreement for the first tranche of gas from this development was signed in the second quarter.

Anugerah

Two-dimensional and three-dimensional seismic survey data was acquired during the quarter on the Anugerah contract area. The data is being evaluated to determine the potential for future drilling activity.

Oil Sands

Sunrise Energy Project

First oil was achieved on phase 1 at the Sunrise Energy Project in March 2015. Production from the project is expected to ramp up to 60,000 bbls/day (30,000 bbls/day net to Husky) around the end of 2016. Sales from production volumes commenced in the second quarter of 2015 with production from the project averaging approximately 5,000 bbls/day (2,500 mbbls/day net to Husky) in the month of June.

Atlantic Region

White Rose Field and Satellite Extensions

Production commenced from the South White Rose extension late in the second quarter of 2015. Drilling is continuing on a second production well, which is scheduled to come online in late summer of 2015.

Drilling of the Hibernia formation well at the North Amethyst field will resume after the second production well is completed for the South White Rose extension.

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

Atlantic Exploration

An exploration and appraisal drilling program continues at the Bay du Nord discovery in the Flemish Pass Basin. Evaluation of initial results is ongoing.

Western Canada Resource Play Development

Liquids-Rich Natural Gas Resource Plays

In the second quarter of 2015, eight wells (gross) were drilled and 15 wells (gross) were completed in key plays across the liquids-rich natural gas portfolio.

Liquids-Rich Natural Gas Resource Plays - Drilling and Completion Activity in Key Plays[(1)(2)]

		Three months ended June 30, 2015		Six months ended June 30, 2015	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	4	12	12	20
Wilrich	Kakwa, Alberta	3	1	4	2
Strachan Cardium	Rocky Mountain House, Alberta	1	2	4	2
Total Gross		8	15	20	24
Total Net		4	11	12	19

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*
(2) *Drilling activity includes operated and non-operated wells.*

In the Ansell multi-zone liquids-rich natural gas resource play, four horizontal wells (gross) were drilled and 12 horizontal wells (gross) were completed in the second quarter of 2015. Average production from the play was approximately 19,100 boe/day in the second quarter of 2015.

Development continued on the Strachan liquids-rich natural gas resource play near Rocky Mountain house with one well (gross) drilled and two wells (gross) completed in the second quarter of 2015. Production results from the play are in line with expectations.

Oil Resource Plays and Conventional

Oil related drilling and completion activity in Western Canada has been substantially curtailed and is not expected to resume for the balance of the year.

Infrastructure and Marketing

Construction is ongoing for the expansion of the South Saskatchewan Gathering System which will create incremental capacity to accommodate planned production from the Rush Lake, Edam East, Vawn and Edam West thermal developments. Construction is approximately 50 percent complete.

Husky is also expanding its pumping capacity at the Hardisty terminal to meet the new requirements of the Enbridge Clipper pipeline to maintain market access.

4.2 Downstream

BP-Husky Toledo, Ohio Refinery

The Company continued construction to address updated flare stack regulatory monitoring and emission standards coming into effect during the fourth quarter of 2015. Husky expects the work to be completed by the fourth quarter of 2015.

5. Results of Operations

5.1 Upstream

Total Upstream net earnings (loss) include results from both the Exploration and Production and Infrastructure and Marketing operations. Net earnings (loss) on a combined basis reflect weaker Exploration and Production earnings compared to the same period in 2014 primarily due to lower realized crude oil prices and North American natural gas prices resulting from significantly lower market benchmarks and lower crude oil production in Canada. The decreases were partially offset by a weaker Canadian dollar and higher realized contracted prices on production from the Liwan Gas Project in the Asia Pacific Region.

Exploration and Production

Exploration and Production Earnings (Loss) Summary	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Gross revenues	**1,577**	2,352	**2,932**	4,534
Royalties	**(134)**	(302)	**(264)**	(592)
Revenues, net of royalties	**1,443**	2,050	**2,668**	3,942
Purchases, operating, transportation and administrative expenses	**598**	630	**1,188**	1,276
Depletion, depreciation and amortization	**713**	637	**1,432**	1,210
Exploration and evaluation expenses	**43**	19	**100**	59
Other expenses	**67**	17	**87**	143
Provisions for (recovery of) income taxes	**4**	193	**(38)**	324
Net earnings (loss)	**18**	554	**(101)**	930

Second Quarter

Exploration and Production net earnings decreased by $536 million in the second quarter of 2015 compared to the second quarter of 2014 primarily due to lower realized crude oil and North American natural gas prices resulting from significant declines in market benchmarks and lower crude oil production in Canada. The decreases were partially offset by higher NGL and natural gas production, higher realized contract prices on production from the Liwan Gas Project and a weaker Canadian dollar.

Production increased by 3.3 mboe/day to 336.9 mboe/day in the second quarter of 2015 compared to 333.6 mboe/day in the second quarter of 2014. The increase in production was primarily due to higher NGL and natural gas production from the Liwan Gas Project, higher production from the Wenchang field where a planned turnaround on the FPSO vessel offstation was ongoing in the second quarter of 2014 and increased Western Canada resource play production. The increases were partially offset by lower heavy crude oil and bitumen production due to scheduled maintenance activities in Heavy Oil and natural reservoir declines at mature properties in Western Canada and the Atlantic Region.

The average realized price for crude oil, NGL and bitumen in the second quarter of 2015 was $56.79/bbl compared to $90.33/bbl during the same period in 2014, a 37 percent decrease, due to lower crude oil benchmark prices prices partially offset by a weaker Canadian dollar and narrower heavy crude oil and bitumen differentials. Realized natural gas prices averaged $6.09/mcf in the second quarter of 2015 compared to $6.42/mcf in the same period in 2014, a decrease of five percent, primarily due to lower realized natural gas benchmarks in North America partially offset by higher contract prices on production from the Liwan Gas Project.

Six Months

Exploration and Production net earnings decreased by $1,031 million in the first six months of 2015 compared to the same period in 2014 primarily due to the same factors which impacted the second quarter. During the first six months of 2015, the average realized price for crude oil, NGL and bitumen was $49.85/bbl compared to $88.79/bbl in the same period in 2014, a decrease of 44 percent. During the first six months of 2015, the average realized natural gas price was $6.03/mcf compared to $5.67/mcf in the same period in 2014, an increase of six percent.

Average Sales Prices Realized	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Crude oil and NGL *($/bbl)*				
Light crude oil & NGL	68.40	110.29	62.88	110.40
Medium crude oil	58.46	89.67	48.62	86.49
Heavy crude oil	50.21	79.45	41.52	75.90
Bitumen	48.45	77.97	41.42	74.48
Total crude oil and NGL average	56.79	90.33	49.85	88.79
Natural gas average *($/mcf)*	6.09	6.42	6.03	5.67
Total average *($/boe)*	49.50	74.70	45.08	73.48

The price realized for Western Canada crude oil reflected lower WTI prices partially offset by a weaker Canadian dollar and narrower heavy crude oil and bitumen differentials. The premium to WTI realized for offshore production reflects Brent prices. Realized natural gas prices reflect favourable prices received at the Liwan Gas Project offset by lower natural gas benchmark prices in North America.

Daily Gross Production	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Crude Oil and NGL *(mbbls/day)*				
Western Canada				
Light crude oil & NGL	28.0	27.7	28.9	29.6
Medium crude oil	18.0	22.4	18.4	23.1
Heavy crude oil	70.0	78.1	71.0	76.8
Bitumen(1)	48.5	54.6	52.0	53.2
	164.5	182.8	170.3	182.7
Oil Sands				
Sunrise - bitumen	1.8	—	0.9	—
Atlantic Region				
White Rose and Satellite Fields – light crude oil	29.9	42.4	31.8	43.0
Terra Nova – light crude oil	2.7	5.2	5.4	5.9
	32.6	47.6	37.2	48.9
Asia Pacific Region				
Wenchang – light crude oil & NGL	7.4	0.3	7.7	4.5
Liwan - NGL(2)	10.3	2.3	10.4	1.2
	17.7	2.6	18.1	5.7
	216.6	233.0	226.5	237.3
Natural gas *(mmcf/day)*				
Western Canada	518.8	490.6	521.5	498.2
Asia Pacific Region(2)	202.8	113.0	197.9	56.8
	721.6	603.6	719.4	555.0
Total *(mboe/day)*	336.9	333.6	346.4	329.8

(1) *Bitumen production includes heavy oil thermal average daily gross production of 41.2 mbbls/day for the three months ended June 30, 2015 compared to 43.4 mbbls/day for the three months ended June 30, 2014.*

(2) *Reported production volumes include Husky's net working interest production from the Liwan Gas Project (49 percent) and an incremental share of production volumes allocated to Husky for exploration cost recoveries.*

Crude Oil and NGL Production

Second Quarter

Crude oil and NGL production in the second quarter of 2015 decreased by 16.4 mbbls/day compared to the same period in 2014 primarily due to lower heavy crude oil and bitumen production in Western Canada due to scheduled maintenance activities in Heavy Oil and natural reservoir declines at mature properties in Western Canada and the Atlantic Region. These decreases were partially offset by higher NGL production from the Liwan Gas Project and higher production from the Wenchang field where a planned turnaround on the FPSO vessel offstation was ongoing in the second quarter of 2014.

Six Months

Crude oil and NGL production in the first six months of 2015 decreased by 10.8 mbbls/day or five percent compared to the same period in 2014 primarily due to the same factors which impacted the second quarter.

Natural Gas Production

Second Quarter

Natural gas production in the second quarter of 2015 increased by 118.0 mmcf/day or 20 percent compared to the same period in 2014 primarily due to higher production from the Liwan Gas Project and higher resource play production in Western Canada combined with a planned turnaround completed at the Company's Rainbow oil and gas facility in the second quarter of 2014.

Six Months

Natural gas production in the first six months of 2015 increased by 164.4 mmcf/day or 30 percent compared to the same period in 2014 primarily due to the same factors impacting the second quarter.

2015 Production Guidance

The following table shows actual daily production for the six months ended June 30, 2015 and the year ended December 31, 2014, as well as the previously issued production guidance for 2015.

		Actual Production	
	2015 Guidance	**Six months ended June 30, 2015**	Year ended December 31, 2014
Canada			
Light / Medium crude oil & NGL *(mbbls/day)*	87 - 92	**84**	96
Heavy crude oil & bitumen *(mbbls/day)*	125 - 135	**124**	131
Natural gas *(mmcf/day)*	440 - 480	**522**	507
Canada total *(mboe/day)*	285 - 307	**295**	312
Asia Pacific			
Light crude oil & NGL *(mbbls/day)*	13 - 15	**18**	9
Natural gas *(mmcf/day)*	160 - 195	**198**	114
Asia Pacific total *(mboe/day)*	40 - 48	**51**	28
Total *(mboe/day)*	325 - 355	**346**	340

Royalties

Second Quarter

In the second quarter of 2015, royalty rates as a percentage of gross revenues averaged nine percent compared to 14 percent in the same period in 2014. Royalty rates in Western Canada averaged nine percent in the second quarter of 2015 compared to 12 percent in the same period in 2014 primarily due to lower commodity prices. Royalty rates for the Atlantic Region averaged 13 percent in the second quarter of 2015 compared to 21 percent in the same period in 2014 due to higher eligible royalty costs and lower revenue at White Rose in the second quarter of 2015 combined with the turnaround completed at the Terra Nova FPSO. Royalty rates in the Asia Pacific Region averaged five percent in the second quarter of 2015 comparable to six percent in the same period in 2014.

Six Months

Royalty rates averaged nine percent of gross revenues in the first six months of 2015 compared to 14 percent in the same period in 2014. Royalty rates in Western Canada averaged 10 percent in the first six months of 2015 compared to 12 percent in the first six months of 2014 due to the same factors which impacted the second quarter of 2015. Royalty rates for the Atlantic Region averaged 14 percent in the first six months of 2015 compared to 20 percent in the same period in 2014 due to the same factors which impacted the second quarter of 2015. Royalty rates in the Asia Pacific Region averaged five percent in the first six months of 2015 compared to 12 percent in the same period in 2014 due to lower royalty rates associated with production from the Liwan Gas Project which started producing at the end of the first quarter of 2014.

Operating Costs

($ millions)	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Western Canada	421	456	847	926
Atlantic Region	57	45	107	102
Asia Pacific	28	10	49	18
Total	506	511	1,003	1,046
Unit operating costs ($/boe)	15.72	15.68	15.28	16.44

Second Quarter

Total Exploration and Production operating costs in the second quarter of 2015 were $506 million compared to $511 million in the same period in 2014. Total unit operating costs averaged $15.72/boe in the second quarter of 2015, comparable to $15.68/boe in the same period in 2014.

Operating costs in Western Canada averaged $17.23/boe in the second quarter of 2015 comparable to $17.44/boe in the same period in 2014. The decrease in operating costs was primarily attributable to lower energy costs and cost savings initiatives.

Operating costs in the Atlantic Region averaged $19.20/boe in the second quarter of 2015 compared to $10.52/boe in the same period in 2014. The increase in operating costs was primarily attributable to insurance recoveries received in the second quarter of 2014 combined with lower production volumes in the second quarter of 2015.

Operating costs in the Asia Pacific Region averaged $6.09/boe in the second quarter of 2015 compared to $4.99/boe in the same period in 2014. The increase in operating costs was primarily attributable to a decrease in the Company's entitlement share of production volumes from approximately 76 percent up until late May to its equity interest of 49 percent at the Liwan development which was not accompanied by a corresponding reduction in total operating costs.

Six Months

Total Exploration and Production operating costs in the first six months of 2015 were $1,003 million compared to $1,046 million in the same period in 2014. Total unit operating costs in the first six months of 2015 averaged $15.28/boe compared to $16.44/boe in the same period in 2014.

Operating costs in Western Canada averaged $17.17/boe in the first six months of 2015 compared to $17.85/boe in the same period in 2014. The decrease in operating costs was primarily attributable to the same factors which impacted the second quarter.

Operating costs in the Atlantic Region averaged $15.93/boe in the first six months of 2015 compared to $11.57/boe in the same period in 2014. The increase in operating costs was primarily attributable to the same factors which impacted the second quarter.

Operating costs in the Asia Pacific Region averaged $5.31/boe in the first six months of 2015 compared to $6.59/boe in the same period in 2014. The decrease was primarily attributable to lower unit cost production from the Liwan Gas Project which commenced at the end of the first quarter of 2014 partially offset by the factors which impacted the second quarter.

Exploration and Evaluation Expenses

($ millions)	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Seismic, geological and geophysical	30	17	51	42
Expensed drilling	7	1	39	13
Expensed land	6	1	10	4
Exploration and evaluation expenses	43	19	100	59

Second Quarter

Exploration and evaluation expenses in the second quarter of 2015 were $43 million compared to $19 million in the second quarter of 2014. The increase in seismic, geological and geophysical costs resulted from higher activity in the Asia Pacific and Atlantic Regions.

Six Months

Exploration and evaluation expenses in the first six months of 2015 were $100 million compared to $59 million in the same period of 2014. The increase in seismic, geological and geophysical costs in the first six months of 2015 was primarily attributable to the same factors which impacted the second quarter of 2015. The increase in expensed drilling costs was primarily attributable to the expensed Aster exploration well in the Atlantic Region during the first quarter of 2015.

Depletion, Depreciation and Amortization ("DD&A")

Second Quarter

In the second quarter of 2015, total DD&A averaged $23.21/boe compared to $20.95/boe in the second quarter of 2014. The increase was primarily attributable to higher depletion rates on production from the Liwan Gas Project.

Six Months

For the first six months of 2015, total DD&A averaged $22.82/boe compared to $20.26/boe in the same period of 2014. The increase was primarily attributable to the same factor which impacted the second quarter.

Exploration and Production Capital Expenditures

In the first six months of 2015, Upstream Exploration and Production capital expenditures were $1,303 million. Capital expenditures were $241 million (18 percent) in Western Canada conventional and resource plays, $498 million (38 percent) in Heavy Oil, $183 million (14 percent) in Oil Sands, $334 million (26 percent) in the Atlantic Region and $47 million (four percent) in the Asia Pacific Region.

Exploration and Production Capital Expenditures[(1)]	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Exploration				
Western Canada[(2)]	**8**	54	**13**	105
Heavy Oil[(2)]	**1**	2	**8**	25
Oil Sands[(2)]	**—**	—	**—**	5
Atlantic Region	**44**	15	**104**	22
Asia Pacific Region	**—**	—	**1**	9
	53	71	**126**	166
Development				
Western Canada[(2)]	**65**	255	**227**	568
Heavy Oil[(2)]	**232**	239	**489**	524
Oil Sands[(2)]	**100**	121	**183**	247
Atlantic Region	**103**	90	**230**	244
Asia Pacific Region	**25**	80	**46**	229
	525	785	**1,175**	1,812
Acquisitions				
Western Canada[(2)]	**1**	—	**1**	1
Heavy Oil[(2)]	**—**	3	**1**	4
	579	859	**1,303**	1,983

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(2) *During the second quarter of 2015, the Company reclassified capital expenditures to Heavy Oil, previously classified as part of Western Canada and Oil Sands.*

Western Canada

During the first six months of 2015, $241 million was invested in Western Canada conventional and resource plays, compared to $674 million in the same period in 2014, primarily on the development of the Company's liquids-rich natural gas resource plays.

Heavy Oil

During the first six months of 2015, $498 million was invested in Heavy Oil, compared to $553 million in the same period in 2014, primarily on the development of the Company's heavy oil thermal developments.

Oil Sands

During the first six months of 2015, $183 million was invested in Oil Sands projects, compared to $252 million in the same period in 2014, primarily on development of Phase 1 of the Sunrise Energy Project.

Atlantic Region

During the first six months of 2015, $334 million was invested in Atlantic Region projects, compared to $266 million in the same period in 2014, primarily on the continued development of the White Rose extension projects, including the North Amethyst, West White Rose and South White Rose extension satellite fields.

Asia Pacific Region

During the first six months of 2015, $47 million was invested in Asia Pacific Region projects, compared to $238 million in the same period of 2014. Development of the Liwan Gas Project was substantially completed in 2014.

Exploration and Production Wells Drilled

Onshore drilling activity

The following table discloses the number of gross and net exploration and development wells completed in Western Canada conventional and resource plays, Heavy Oil and Oil Sands during the periods indicated:

	Three months ended June 30,				Six months ended June 30,			
Wells Drilled [1]	**2015**		2014		**2015**		2014	
(wells)	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration								
Oil	—	—	4	1	**5**	**4**	48	44
Gas	—	—	3	1	**2**	—	5	3
Dry	—	—	—	—	—	—	—	—
	—	—	7	2	**7**	**4**	53	47
Development								
Oil	**44**	**35**	14	7	**87**	**72**	217	194
Gas	**8**	**5**	29	24	**22**	**15**	42	35
Dry	—	—	—	—	—	—	—	—
	52	**40**	43	31	**109**	**87**	259	229
Total	**52**	**40**	50	33	**116**	**91**	312	276

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

The Company drilled 91 net wells in the Western Canada conventional and resource plays, Heavy Oil and Oil Sands business units in the first six months of 2015 resulting in 76 net oil wells and 15 net natural gas wells compared to 276 net wells resulting in 238 net oil wells and 38 net natural gas wells in the same period of 2014.

Offshore drilling activity

The following table discloses Husky's offshore Atlantic and Asia Pacific Region drilling completions during the first six months of 2015:

Region	Well	Working Interest	Well Type
Atlantic Region	Bay du Nord P-78	WI 35 percent	Exploration
Atlantic Region	Bay du Nord L-76	WI 35 percent	Exploration
Atlantic Region	Aster C-93A[1]	WI 40 percent	Exploration
Atlantic Region	White Rose J-05 3	WI 68.875 percent	Development
Asia Pacific Region	Wenchang 13-1A4H2	WI 40 percent	Development

[1] *The Aster well was fully written off in the first quarter of 2015 as the well did not encounter economic quantities of hydrocarbons.*

Upstream Planned Turnarounds

- A planned turnaround at the Ram River plant has been deferred until 2016.
- Other scheduled third-party shutdowns are expected to impact Western Canada production by approximately 3,300 boe/day in the third quarter of 2015.
- An 18-day turnaround on the SeaRose FPSO vessel is expected to impact production by approximately 7,500 bbls/day in the third quarter of 2015.

Infrastructure and Marketing

The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGL, 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 United States. The Company is able to capture differences between the two markets by utilizing infrastructure capacity to deliver feedstock acquired in Canada to the United States market.

Infrastructure and Marketing Earnings (Loss) Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2015**	2014	**2015**	2014
Infrastructure gross margin	**35**	32	**66**	76
Marketing and other gross margin	**(44)**	3	**25**	37
Gross margin	**(9)**	35	**91**	113
Operating and administrative expenses	**10**	7	**21**	17
Depreciation and amortization	**6**	6	**11**	13
Other income	**3**	—	**2**	—
Provisions for (recovery of) income taxes	**(7)**	6	**15**	21
Net earnings (loss)	**(21)**	16	**42**	62
Commodity trading volumes managed *(mboe/day)*	**283.1**	237.7	**287.9**	260.7

Second Quarter

Infrastructure and Marketing net earnings (loss) in the second quarter of 2015 decreased by $37 million compared to the same period in 2014 resulting primarily from unrealized mark to market losses on the Company's risk management positions and the narrowing of product price differentials between Canada and the United States.

Six Months

Infrastructure and Marketing net earnings in the first six months of 2015 decreased by $20 million compared to the same period in 2014 primarily due to the same factors which impacted the second quarter of 2015.

Infrastructure and Marketing Capital Expenditures

In the first six months of 2015, Infrastructure and Marketing capital expenditures totalled $49 million compared to $54 million in 2014 primarily related to the expansion of the South Saskatchewan Gathering System into Lloydminster.

5.2 Downstream

Total Downstream net earnings include results from the Upgrader, Canadian Refined Products and U.S. Refining and Marketing. The increase in U.S. Refining and Marketing net earnings was primarily due to FIFO gains, higher Chicago 3:2:1 market crack spreads coupled with a weaker Canadian dollar and higher throughput at the BP-Husky Toledo Refinery. The decrease in Upgrader net earnings was primarily due to lower upgrading differentials attributable to narrower heavy crude oil and bitumen differentials. The decrease in Canadian Refined Products net earnings was primarily due to lower realized product pricing and higher feedstock costs at the Lloydminster and Minnedosa Ethanol plants and an unplanned outage at the Prince George Refinery.

Upgrader

Upgrader Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2015**	2014	**2015**	2014
Gross revenues	**418**	560	**765**	1,133
Gross margin	**108**	139	**217**	328
Operating and administrative expenses	**43**	45	**87**	94
Depreciation and amortization	**26**	28	**52**	52
Other expenses (income)	**—**	—	**(11)**	9
Provisions for income taxes	**11**	17	**24**	45
Net earnings	**28**	49	**65**	128
Upgrader throughput *(mbbls/day)*[(1)]	**70.6**	68.2	**77.1**	70.2
Total sales *(mbbls/day)*[(2)]	**73.2**	67.2	**77.1**	69.1
Synthetic crude oil sales *(mbbls/day)*	**55.0**	48.2	**56.8**	51.0
Upgrading differential *($/bbl)*	**18.93**	25.27	**17.38**	26.26
Unit margin *($/bbl)*[(2)]	**16.21**	22.73	**15.55**	26.23
Unit operating cost *($/bbl)*[(3)]	**6.54**	6.93	**6.09**	7.08

(1) *Throughput includes diluent returned to the field.*
(2) *Unit margin was revised in the first quarter of 2015 to reflect total sales volumes. Prior periods have been adjusted to conform with current period presentation.*
(3) *Based on throughput.*

Second Quarter

The Upgrading operations add value by processing heavy sour 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 net earnings decreased by $21 million in the second quarter of 2015 compared to the same period in 2014 primarily due to lower realized upgrading differentials partially offset by higher throughput and sales volumes compared to the same period in 2014 resulting from unplanned maintenance completed in the second quarter of 2014.

During the second quarter of 2015, the upgrading differential averaged $18.93/bbl, a decrease of $6.34/bbl or 25 percent compared to the same period in 2014. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The decrease in the upgrading differential was attributable to narrower heavy crude oil and bitumen differentials. The average price for Husky Synthetic Blend in the second quarter of 2015 was $73.90/bbl compared to $112.80/bbl in the same period in 2014.

Six Months

Upgrader net earnings for the first six months of 2015 decreased by $63 million compared to the same period in 2014 primarily due to the same factors which impacted the second quarter. The average price for Husky Synthetic Blend in the first six months of 2015 was $64.76/bbl compared to $109.55/bbl in the same period in 2014.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2015**	2014	**2015**	2014
Gross revenues	**747**	991	**1,348**	1,930
Gross margin				
Fuel	**33**	33	**66**	65
Refining	**38**	64	**66**	145
Asphalt	**62**	58	**106**	119
Ancillary	**15**	14	**28**	28
	148	169	**266**	357
Operating and administrative expenses	**69**	77	**142**	150
Depreciation and amortization	**26**	25	**51**	49
Other expenses	**—**	2	**2**	2
Provisions for income taxes	**14**	17	**19**	40
Net earnings	**39**	48	**52**	116
Number of fuel outlets[(1)]	**488**	502	**488**	502
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*	**7.6**	7.5	**7.6**	7.6
Fuel sales per retail outlet *(thousands of litres/day)*	**12.4**	12.8	**12.4**	13.0
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**8.5**	11.3	**9.9**	11.6
Lloydminster Refinery *(mbbls/day)*	**28.4**	29.0	**28.8**	29.0
Ethanol production *(thousands of litres/day)*	**767.9**	790.9	**771.4**	785.3

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

Second Quarter

Refining gross margins were lower in the second quarter of 2015 compared to the same period in 2014 primarily due to lower realized product pricing and higher feedstock costs at the Lloydminster and Minnedosa Ethanol plants. In addition, an unplanned outage at the Prince George Refinery resulted in lower throughput and the need to purchase finished products from third parties to deliver on committed sales volumes during the outage which resulted in lower realized margins.

Asphalt gross margins were higher in the second quarter of 2015 compared to the same period in 2014 primarily due to strong retail asphalt sales, strong contract pricing and lower feedstock costs.

Six Months

During the first six months of 2015, Canadian Refined Products earnings decreased by $64 million compared to the same period in 2014. The decrease was primarily due to lower realized sales prices and throughput at the Prince George Refinery and lower asphalt margins in the first quarter of 2015 due to reduced drilling activity in Western Canada which resulted in lower demand and sales prices for drilling fluids.

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)	**2015**	2014	**2015**	2014
Gross revenues	**1,955**	2,928	**3,680**	5,348
Gross refining margin	**406**	269	**592**	633
Operating and administrative expenses	**109**	118	**240**	242
Depreciation and amortization	**114**	62	**183**	123
Other expenses (income)	**(90)**	—	**(89)**	1
Provisions for (recovery of) income taxes	**101**	33	**(108)**	99
Net earnings	**172**	56	**366**	168
Select operating data:				
Lima Refinery throughput *(mbbls/day)*	**136.1**	135.9	**127.6**	123.3
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**69.7**	59.4	**60.9**	62.3
Refining margin *(U.S. $/bbl crude throughput)*	**17.88**	14.40	**14.37**	17.81
Refinery inventory *(mmbbls)*[(1)]	**10.4**	10.7	**10.4**	10.7

(1) *Included in refinery inventory is feedstock and refined products.*

Second Quarter

U.S. Refining and Marketing net earnings increased in the second quarter of 2015 compared to the same period in 2014 primarily due to FIFO gains, higher Chicago 3:2:1 market crack spreads coupled with a weaker Canadian dollar and higher throughput at the BP-Husky Toledo Refinery where a planned turnaround was ongoing in the second quarter of 2014.

Included in depreciation and amortization in the second quarter of 2015 was a $46 million write-off of the carrying value of the isocracker unit at Lima which was damaged by a fire during the first quarter of 2015. In addition, the Company accrued business interruption insurance recoveries associated with the fire of $92 million which is reflected in other expenses (income).

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 on a FIFO basis crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter. The FIFO impact was an increase in net earnings of approximately $78 million in the second quarter of 2015 compared to a decrease in net earnings of approximately $13 million in the same period in 2014. In addition, the product slates produced at the Lima and BP-Husky Toledo Refineries contain approximately 10 percent to 15 percent of other products which are sold at discounted market prices compared to gasoline and distillate, which are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

Six Months

Net earnings in the first six months of 2015 increased by $198 million compared to the same period in 2014 primarily due to a $203 million deferred income tax recovery recognized in the first quarter of 2015 related to the partial payment of the contribution payable to BP-Husky Refining LLC partially offset by the impact from falling commodity prices in the first quarter of 2015 which resulted in FIFO losses in realized refining margins.

Downstream Capital Expenditures

In the first six months of 2015, Downstream capital expenditures totalled $168 million compared to $210 million in the same period in 2014. In Canada, capital expenditures of $25 million were primarily related to upgrades at retail stations and projects at the Upgrader and Prince George Refinery. At the Lima Refinery, $107 million was spent primarily on various reliability and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $36 million (Husky's 50 percent share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Turnarounds

- Unplanned maintenance commenced at the Lloydminster Upgrader in late June to address repairs to the facility's coke drums. The Upgrader will see operations suspended for an estimated period of six to eight weeks while the repairs are completed.
- A six to eight week maintenance turnaround has been scheduled at the Lima Refinery starting in March 2016. As a result, the isocracker is expected to resume operations at the same time as the refinery start up.

5.3 Corporate

Corporate Summary	Three months ended June 30,		Six months ended June 30,	
($ millions) income (expense)	**2015**	2014	**2015**	2014
Administrative expenses	**(20)**	(12)	**(50)**	(30)
Stock-based compensation	**4**	(47)	**14**	(53)
Depreciation and amortization	**(20)**	(18)	**(40)**	(34)
Other - net	**—**	9	**—**	9
Foreign exchange gain (loss)	**6**	(3)	**68**	15
Interest expense	**(35)**	(34)	**(48)**	(27)
Provisions for (recovery of) income taxes	**(51)**	10	**(57)**	6
Net loss	**(116)**	(95)	**(113)**	(114)

Second Quarter

The Corporate segment reported a net loss of $116 million in the second quarter of 2015 compared to a loss of $95 million in the same period in 2014. Administrative expenses increased by $8 million in the second quarter of 2015 compared to the same period in 2014 primarily due to a reclassification of early invoice payment discounts to the Company's Upstream and Downstream segments. Stock-based compensation expense decreased by $51 million in the second quarter of 2015 compared to the same period in 2014 due to a decline in the Company's share price.

Six Months

In the first six months of 2015, the Corporate segment reported a loss of $113 million compared to a loss of $114 million in the same period of 2014. Stock-based compensation expense decreased in the first six months of 2015 primarily due to the same factors which impacted the second quarter of 2015. Administrative expenses increased in the first six months of 2015 compared to the same period in 2014 primarily due to the same factors which impacted the second quarter of 2015. Foreign exchange gain increased by $53 million in the first six months of 2015 due to a weakening of the Canadian dollar against the U.S. dollar which impacted the translation of the Company's foreign currency denominated working capital. Interest expense increased by $21 million due to higher debt and a decrease in the amount of capitalized interest related to production being achieved at the Liwan Gas Project late in the first quarter of 2014 and production being achieved at the Sunrise Energy Project in the first quarter of 2015.

Foreign Exchange Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2015**	2014	**2015**	2014
Gain (loss) on translation of U.S. dollar denominated long-term debt	**5**	28	**(22)**	28
Gain on contribution receivable	**—**	—	**—**	7
Gain (loss) on non-cash working capital	**(36)**	—	**19**	—
Other foreign exchange gain (loss)	**37**	(31)	**71**	(20)
Net foreign exchange gain (loss)	**6**	(3)	**68**	15
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S $0.788**	U.S. $0.905	**U.S $0.862**	U.S. $0.940
At end of period	**U.S $0.802**	U.S. $0.937	**U.S $0.802**	U.S. $0.937

Included in other foreign exchange gain (loss) are realized and unrealized foreign exchange gains and losses on working capital and intercompany financing. The foreign exchange on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period.

Corporate Capital Expenditures

In the first six months of 2015, Corporate capital expenditures were $36 million compared to $78 million in the same period of 2014 and were primarily related to computer hardware and software and leasehold improvements.

Consolidated Income Taxes

($ millions)	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Provisions for (recovery of) income taxes	**174**	256	**(31)**	523
Income taxes paid	**150**	285	**146**	381

Second Quarter

Consolidated income taxes decreased in the second quarter of 2015 to $174 million from $256 million in the same period in 2014 primarily due to lower net earnings. The decrease in consolidated income taxes was partially offset by the recognition of a $157 million deferred income tax expense related to the increase in Alberta provincial tax rates.

Six Months

Consolidated income taxes were a recovery $31 million in the first six months of 2015 compared to income tax expense of $523 million in the same period in 2014. The decrease in consolidated income taxes was primarily due to a future income tax recovery from the distribution of U.S. $1.0 billion by BP-Husky Refining LLC to each member following the partial payment of the contribution payable by the Company in the first quarter of 2015 in addition to factors which impacted the second quarter.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the second quarter of 2015, Husky funded its capital programs and dividend payments through cash generated from operating activities, cash on hand, the issuance of commercial paper, direct borrowings against committed credit facilities and the issuance of preferred shares. At June 30, 2015, Husky had total debt of $6,176 million, partially offset by cash on hand of $177 million, for $5,999 million of net debt compared to $4,025 million of net debt at December 31, 2014. At June 30, 2015, the Company had $3,373 million of unused credit facilities of which $2,934 million are long-term committed credit facilities and $439 million are short-term uncommitted credit facilities. In addition, the Company had $1.90 billion in unused capacity under its February 2015 Canadian universal short form base shelf prospectus (the "Canadian Shelf Prospectus") and U.S. $2.25 billion in unused capacity under its October 2013 U.S. universal short form base shelf prospectus (the "U.S. Shelf Prospectus"). The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions. Refer to Section 6.2.

Cash Flow Summary ($ millions, except ratios)	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Cash flow				
Operating activities	**902**	1,147	**1,766**	2,483
Financing activities	**40**	(1,158)	**282**	(503)
Investing activities	**(911)**	(1,438)	**(3,213)**	(3,011)

Cash Flow from Operating Activities

Second Quarter

In the second quarter of 2015, cash flow generated from operating activities was $902 million compared to $1,147 million in the same period in 2014. The decrease in cash flow generated from operating activities was primarily due to lower realized crude oil and North American natural gas prices and an increase in non-cash working capital in the second quarter of 2015 partially offset by lower cash taxes paid and higher non-cash depletion, depreciation and amortization expense.

Six Months

In the first six months of 2015, cash flow generated from operating activities was $1,766 million compared to $2,483 million in the same period in 2014 primarily due to the same factors which impacted the second quarter coupled with lower realized refining margins in the U.S. Refining and Marketing segment during the first quarter of 2015.

Cash Flow from (used for) Financing Activities

Second Quarter

In the second quarter of 2015, cash flow generated from financing activities was $40 million compared to cash flow used for financing activities of $1,158 million in the same period in 2014. The increase in cash flow generated from financing activities resulted primarily from proceeds received from the issuance of $361 million of commercial paper and from the issuance of $150 million of Cumulative Redeemable Preferred Shares, Series 7 (the "Series 7 Preferred Shares") in the second quarter of 2015 and from the repayment of $814 million in senior unsecured notes in the second quarter of 2014.

Six Months

Cash flow generated from financing activities was $282 million in the first six months of 2015 compared to cash flow used of $503 million in the same period in 2014. The increase in cash flow generated from financing activities was primarily due to the same factors which impacted the second quarter of 2015 in addition to the issuance of $750 million of unsecured notes and the issuance of $200 million of Cumulative Redeemable Preferred Shares, Series 5 (the "Series 5 Preferred Shares") in the first quarter of 2015.

Cash Flow used for Investing Activities

Second Quarter

In the second quarter of 2015, cash flow used for investing activities was $911 million compared to $1,438 million in the same period in 2014. The decrease was primarily due to a reduction in capital expenditures during the second quarter of 2015.

Six Months

Cash flow used for investing activities was $3,213 million in the first six months of 2015 compared to $3,011 million in the first six months of 2014. The increase was primarily due to the payment of $1.3 billion of the Company's BP-Husky Refining LLC contribution payable in the first quarter of 2015 partially offset by a reduction in capital expenditures in the first six months of 2015.

6.2 Sources of Capital

Husky funds its capital programs, non-cancellable contractual obligations and other commercial commitments principally by cash generated from operating activities, cash on hand, the issuance of long-term debt, borrowings under committed and uncommitted credit facilities, the issuance of short-term commercial paper and the issuance of equity. The Company also maintains access to sufficient capital via debt and equity markets commensurate with its balance sheet. 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, 2015, the Company's debt to capital employed was 22.8 percent (December 31, 2014 - 19.8 percent). Debt to capital employed constitutes a non-GAAP measure. Refer to Section 11.

Working capital is the amount by which current assets exceed current liabilities. At June 30, 2015, working capital was nil compared to a working capital deficiency of $1,314 million at December 31, 2014. The increase in working capital was mainly attributable to the payment of $1.3 billion of the Company's BP-Husky Refining LLC contribution payable in the first quarter of 2015.

At June 30, 2015, Husky had unused short and long-term credit facilities totalling $3.4 billion. A total of $206 million of the Company's short-term credit facilities was used in support of outstanding letters of credit, and $866 million of the Company's long-term borrowing credit facilities was used in support of commercial paper. At June 30, 2015 the Company had direct borrowings of $200 million against committed credit facilities.

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, 2015.

On October 31, 2013 and November 1, 2013, Husky filed the U.S. Shelf Prospectus with the Alberta Securities Commission and the U.S. Securities and Exchange Commission, respectively, 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 November 30, 2015. At June 30, 2015, the Company had unused capacity of $2.25 billion under its U.S. Shelf Prospectus.

On March 17, 2014, the Company issued U.S. $750 million of 4.00 percent notes due April 15, 2024 pursuant to the U.S. Shelf Prospectus. The notes are redeemable at the option of the Company at any time, subject to a make whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On February 23, 2015, the Company filed the Canadian Shelf Prospectus with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including March 22, 2017. At June 30, 2015, the Company had unused capacity of $1.90 billion under its Canadian Shelf Prospectus.

On March 6, 2015, the Company's $1.63 billion and the $1.60 billion revolving syndicated credit facilities were each increased to $2.0 billion. The terms of the revolving syndicated credit facilities remain unchanged.

On March 12, 2015, the Company issued eight million Series 5 Preferred Shares at a price of $25.00 per share for aggregate gross proceeds of $200 million, by way of a prospectus supplement dated March 5, 2015 to the Canadian Shelf Prospectus. Net proceeds after share issue costs were $195 million. Holders of the Series 5 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending March 31, 2020 as declared by the board of directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.57 percent. Holders of Series 5 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 6 (the "Series 6 Preferred Shares"), subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Holders of the Series 6 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.57 percent.

On March 12, 2015, the Company issued $750 million of 3.55 percent notes due March 12, 2025 by way of a prospectus supplement dated March 9, 2015 to the Canadian Shelf Prospectus. The notes are redeemable at the option of the Company at any time, subject to a make whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 12 and September 12 of each year, beginning September 12, 2015. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On June 17, 2015, the Company issued six million Series 7 Preferred Shares at a price of $25.00 per share for aggregate gross proceeds of $150 million, by way of a prospectus supplement dated June 10, 2015 to the Canadian Shelf Prospectus. Net proceeds after share issue costs were $145 million. Holders of the Series 7 Preferred Shares are entitled to receive a cumulative fixed dividend yielding 4.60 percent annually for the initial period ending June 30, 2020 as declared by the board of directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.52 percent. Holders of the Series 7 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 8 (the "Series 8 Preferred Shares"), subject to certain conditions, on June 30, 2020 and on June 30 every five years thereafter. Holders of the Series 8 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.52 percent.

The ability of the Company to raise capital utilizing the Canadian Shelf Prospectus or the U.S. Shelf Prospectus is dependent on market conditions at the time of sale.

Capital Structure	June 30, 2015	
($ millions)	**Outstanding**	**Available[(1)]**
Total debt	**6,176**	**3,373**
Common shares, preferred shares, retained earnings and other reserves	**20,864**	

[(1)] *Available long-term debt includes committed and uncommitted credit facilities.*

6.3 Contractual Obligations and 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 2014 Annual MD&A under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2014. During the three months ended June 30, 2015, there were no material changes to contractual obligations and commercial commitments.

6.4 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.

6.5 Transactions with Related Parties and Major Customers

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 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, 2015, the amount of natural gas sales to Meridian totalled $11 million and $25 million, respectively. For the three and six months ended June 30, 2015, the amount of steam purchased by the Company from Meridian totalled $3 million and $8 million, respectively. For the three and six months ended June 30, 2015, the total cost recovery by the Company for facilities services was $7 million and $9 million, respectively.

At June 30, 2015, U.S. $27 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 U.S. $2 million of the senior notes. Ace Dimension Limited subscribed for U.S. $25 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.

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 2014 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, 2014, as discussed in Husky's 2014 Annual MD&A.

7.2 Financial Risks

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

Commodity Price Risk Management

Husky uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its crude oil and natural gas production and firm commitments for the purchase or sale of crude oil and natural gas. These contracts are recorded at fair value.

At June 30, 2015, 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. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities.

Interest Rate Risk Management

During 2014, the Company discontinued its cash flow hedge with respect to forward starting interest rate swaps. Accordingly, the accrued gain in other reserves is being amortized into net earnings over the remaining life of the underlying long-term debt to which the hedging relationship was originally designated. The amortization period is ten years. At June 30, 2015, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was $22 million (December 31, 2014 – $23 million), net of tax of $7 million (December 31, 2014 – net of tax of $8 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in offsets to finance expenses of less than $1 million and $1 million for the three and six months ended June 30, 2015, respectively.

Refer to the interest rate swaps disclosure within Note 13 of the Condensed Interim Consolidated Financial Statements.

Foreign Currency Risk Management

At June 30, 2015, 75 percent or $4.0 billion of Husky's outstanding long-term debt was denominated in U.S. dollars. Including the debt that has been designated as a hedge of a net investment, six percent of long-term debt is exposed to changes in the Canadian/U.S. exchange rate.

At June 30, 2015, the Company had designated U.S. $2.9 billion denominated debt as a hedge of the Company's net investment in its U.S. refining operations. For the three and six months ended June 30, 2015, the Company incurred an unrealized gain of $56 million and loss of $221 million, respectively, arising from the translation of the debt, net of tax of $6 million and $35 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, 2015, Husky's share of this obligation was U.S. $293 million including accrued interest. At June 30, 2015, the cost of a Canadian dollar in U.S. currency was $0.802.

The following table summarizes the Company's financial instruments that are carried at fair value in the consolidated balance sheets:

Financial Instruments at Fair Value *($ millions)*	**June 30, 2015**	December 31, 2014
Commodity contracts – fair value through profit or loss ("FVTPL")		
Natural gas[(1)]	**(5)**	(5)
Crude oil[(2)]	**(21)**	4
Foreign currency contracts – FVTPL		
Foreign currency forwards	**(3)**	(1)
Other assets – FVTPL	**2**	2
Contingent consideration	**—**	(40)
Hedge of net investment[(3)(4)]	**(574)**	(353)
	(601)	(393)

(1) *Natural gas contracts includes a $8 million decrease at June 30, 2015 (December 31, 2014 – $12 million decrease) to the fair value of held-for-trading inventory, recognized in the Condensed Interim Consolidated Balance Sheets, related to third party physical purchase and sale contracts for natural gas held in storage. Total fair value of the related natural gas storage inventory was $64 million at June 30, 2015.*

(2) *Crude oil contracts includes a $17 million decrease at June 30, 2015 (December 31, 2014 – $21 million decrease) to the fair value of held-for-trading inventory, recognized in the Condensed Interim Consolidated Balance Sheets, related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory was $292 million at June 30, 2015.*

(3) *Hedging instruments are presented net of tax.*

(4) *Represents the translation of the Company's U.S. dollar denominated long-term debt designated as a hedge of the Company's net investment in its U.S. refining operations.*

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 2014 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. Changes in Accounting Policies

Effective January 1, 2015, the Company adopted the following new accounting standards issued by the IASB:

IFRS 8 Operating Segments

The amendments are applied retrospectively and clarify that an entity must disclose the judgments made by management in applying the aggregation criteria in paragraph 12 of IFRS 8, including a brief description of operating segments that have been aggregated and the economic characteristics used to assess whether the segments are 'similar'. The reconciliation of segment assets to total assets is only required to be disclosed if the reconciliation is reported to the chief operating decision maker, similar to the required disclosure for segment liabilities. The adoption of this amended standard has no material impact on the Company's Consolidated Financial Statements.

IFRS 2 Share-based Payment

This improvement is applied prospectively and clarifies various issues relating to the definitions of performance and service conditions which are vesting conditions, including:

- A performance condition must contain a service condition;
- A performance target must be met while the counterparty is rendering service;
- A performance target may relate to the operations or activities of an entity, or to those of another entity in the same group; and
- A performance condition may be a market or non-market condition.

The adoption of this amended standard has no impact on the Company's Consolidated Financial Statements.

IFRS 3 Business Combinations

The amendment is applied prospectively and clarifies that all contingent consideration arrangements classified as liabilities (or assets) arising from a business combination should be subsequently measured at fair value through profit or loss whether or not they fall within the scope of IFRS 9 (or International Accounting Standard ("IAS") 39, as applicable). 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 23, 2015	
• common shares	984,130,971
• cumulative redeemable preferred shares, series 1	12,000,000
• 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	28,466,930
• stock options exercisable	17,008,029

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 2014 Annual MD&A, the 2014 Consolidated Financial Statements and the 2014 Annual Information Form filed with Canadian securities regulatory authorities and the 2014 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, 2015 are compared to the results for the three months ended June 30, 2014 and the results for the six months ended June 30, 2015 are compared to the results for the six months ended June 30, 2014. Discussions with respect to Husky's financial position as at June 30, 2015 are compared to its financial position at June 30, 2014. 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 International Accounting Standards Board.
- 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 quoted include or exclude the effect of hedging as indicated.
- There have been no changes to the Company's internal controls over financial reporting ("ICFR") for the three months ended June 30, 2015 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, cash flow from operations, operating netback, debt to capital employed 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 or debt to capital employed. These are useful complementary measurements 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 users. They are common in the reports of other companies but may differ by definition and application. All non-GAAP measures are defined below.

Disclosure of Adjusted Net Earnings

The term "Adjusted Net Earnings" is a non-GAAP measure comprised of net earnings excluding extraordinary and non-recurring items such as after-tax property, plant and equipment impairment charges and after-tax inventory write-downs not considered to be indicative of the Company's on going financial performance. Adjusted net earnings is a complementary measure used in assessing Husky's financial performance through providing comparability between periods. Adjusted net earnings was redefined in the first quarter of 2015. Previously, adjusted net earnings was defined as net earnings plus after-tax foreign exchange gains and losses, gains and losses from the use of financial instruments, stock based compensation expense or recovery and any asset impairments and write-downs.

The following table shows the reconciliation of net earnings to adjusted net earnings for the three and six months ended June 30, 2015 and 2014:

		Three months ended June 30,		Six months ended June 30,	
($ millions)		2015	2014	2015	2014
GAAP	Net earnings	120	628	311	1,290
	Inventory write-downs, net of tax	—	—	—	7
Non-GAAP	Adjusted net earnings	120	628	311	1,297

Disclosure of Cash Flow from Operations

Husky uses the term "Cash Flow From Operations," 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 plus items not affecting cash which include accretion, depletion, depreciation and amortization, inventory write-down 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 and other non-cash items.

The following table shows the reconciliation of net earnings to cash flow from operations and related per share amounts for the three and six months ended June 30, 2015 and 2014:

		Three months ended June 30,		Six months ended June 30,	
($ millions)		**2015**	2014	**2015**	2014
GAAP	Net earnings	**120**	628	**311**	1,290
	Items not affecting cash:				
	Accretion	**31**	34	**61**	68
	Depletion, depreciation and amortization	**905**	776	**1,769**	1,481
	Inventory write-down to net realizable value	**—**	—	**—**	9
	Exploration and evaluation expenses	**6**	1	**6**	3
	Deferred income taxes	**79**	78	**(180)**	84
	Foreign exchange (gain) loss	**(7)**	(58)	**21**	(45)
	Stock-based compensation	**(4)**	47	**(14)**	53
	Loss (gain) on sale of assets	**(2)**	(16)	**6**	(17)
	Other	**49**	14	**35**	123
Non-GAAP	Cash flow from operations	**1,177**	1,504	**2,015**	3,049
	Cash flow from operations – basic	**1.20**	1.53	**2.05**	3.10
	Cash flow from operations – diluted	**1.20**	1.52	**2.05**	3.09

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 commercial paper divided by capital employed. Capital employed is equal to long-term debt, long-term debt due within one year, commercial paper and shareholders' equity. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

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

The Company uses the terms barrels of oil equivalent ("boe"), which is consistent with other oil and gas producers' disclosures, and is calculated on an energy equivalence basis 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 producers but does not represent value equivalence.

Terms

Adjusted Net Earnings	*Net earnings before after-tax property, plant and equipment impairment charges and after-tax inventory write-downs*
Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
Capital Employed	*Long-term debt, long-term debt due within one year, commercial paper 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 plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, exploration and evaluation expenses, deferred income taxes, foreign exchange, stock-based compensation, gain or loss on sale of property, plant, and equipment and other non-cash items*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and commercial paper divided by capital employed*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
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 Production	*A company's working interest share of production before deduction of royalties*
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*
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*
Seismic	*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*
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, commercial paper and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

Abbreviations

bbls	*barrels*	*mbbls/day*	*thousand barrels per day*
bbls/day	*barrels per day*	*mboe*	*thousand barrels of oil equivalent*
boe	*barrels of oil equivalent*	*mboe/day*	*thousand barrels of oil equivalent per day*
boe/day	*barrels of oil equivalent per day*	*mcf*	*thousand cubic feet*
CHOPS	*cold heavy oil production with sand*	*MD&A*	*Management's Discussion and Analysis*
EDGAR	*Electronic Data Gathering, Analysis and Retrieval (U.S.A.)*	*mmbbls*	*million barrels*
FIFO	*first in first out*	*mmboe*	*million barrels of oil equivalent*
FPSO	*Floating production, storage and offloading vessel*	*mmbtu*	*million British Thermal Units*
FVTPL	*fair value through profit or loss*	*mmcf*	*million cubic feet*
GAAP	*Generally Accepted Accounting Principles*	*mmcf/day*	*million cubic feet per day*
GJ	*gigajoule*	*NGL*	*natural gas liquids*
IAS	*International Accounting Standard*	*NYMEX*	*New York Mercantile Exchange*
ICFR	*Internal Controls over Financial Reporting*	*OCI*	*other comprehensive income*
IFRS	*International Financial Reporting Standards*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
LIFO	*Last in first out*	*WTI*	*West Texas Intermediate*
mbbls	*thousand barrels*		

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 production guidance range for the year;
- with respect to the Company's Atlantic Region: anticipated timing of first production from the second production well at the South White Rose extension; anticipated increase in production volumes from the South White Rose extension; planned timing of resumption of drilling at the Hibernia-formation well at the North Amethyst field; expected timing, duration, and impact on production of a planned turnaround on the SeaRose FPSO;
- with respect to the Company's Oil Sands properties: expected timing and volume of ramp up to peak production at phase 1 of the Sunrise Energy Project;
- with respect to the Company's Heavy Oil properties: expected timing of achievement of nameplate capacity production from the Company's Rush Lake heavy oil thermal development; anticipated timing of first production from, and design capacity of, the Company's Edam East, Edam West and Vawn heavy oil thermal projects; expected sustaining capital requirements of the Company's heavy oil thermal projects once brought online;
- with respect to the Company's Western Canadian oil and gas resource plays: drilling and completions plans for 2015; planned timing of a turnaround at the Ram River plant; expected timing and impact on production of scheduled third-party shutdowns in the region; and
- with respect to the Company's Downstream operating segment: anticipated impact on capacity of expansions to the South Saskatchewan Gathering System; anticipated timing of completion of work at the BP-Husky Toledo Refinery to address updated flare stack regulatory monitoring and emission standards; expected duration of suspension of operations at the Lloydminster Upgrader; and scheduled timing of a turnaround, and expected timing of resumption of operations of the isocracker, at the Lima Refinery.

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, 2014 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.