

MANAGEMENT'S DISCUSSION AND ANALYSIS

July 23, 2014

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1. Summary of Quarterly Results

Quarterly Summary (\$ millions, except where indicated)	Three months ended							
	Jun. 30 2014	Mar. 31 2014	Dec. 31 2013	Sept. 30 2013	Jun. 30 2013	Mar. 31 2013	Dec. 31 2012	Sept. 30 2012
Production (mboe/day)	333.6	325.9	308.3	308.5	309.9	321.3	319.3	285.0
Gross revenues ⁽¹⁾	6,614	5,943	6,132	6,036	6,206	5,807	5,889	5,410
Net earnings	628	662	177	512	605	535	474	526
Per share – Basic	0.63	0.67	0.18	0.52	0.61	0.54	0.48	0.53
Per share – Diluted	0.63	0.66	0.18	0.52	0.59	0.54	0.48	0.53
Cash flow from operations ⁽²⁾	1,504	1,536	1,143	1,347	1,449	1,283	1,414	1,271
Per share – Basic	1.53	1.56	1.16	1.37	1.47	1.31	1.44	1.29
Per share – Diluted	1.52	1.56	1.16	1.37	1.47	1.30	1.44	1.29

⁽¹⁾ Gross revenues have been recast to reflect a change in the classification of certain trading transactions.

⁽²⁾ Cash flow from operations is a non-GAAP measure. Refer to Section 11 for a reconciliation to the GAAP measure.

Performance

- Production increased by 23.7 mboe/day or 8 percent to 333.6 mboe/day in the second quarter of 2014 compared to the second quarter of 2013 as a result of:
 - The Liwan Gas Project which achieved first gas at the end of the first quarter;
 - Strong production performance from heavy oil thermal developments, including the Sandall project which began producing crude oil in the first quarter;
 - Increased production from the Ansell multi-zone liquids-rich natural gas resource play;
 - Partially offset by lower production at the Wenchang field due to the planned floating production, storage and offloading ("FPSO") vessel offstation; and
 - Decreased natural gas production in Western Canada due to a planned turnaround at the Company's Rainbow oil and gas facility and natural reservoir declines combined with limited re-investment as capital is being directed to higher return oil and liquids-rich natural gas developments.
- Net earnings increased by \$23 million or 4 percent to \$628 million in the second quarter of 2014 compared to \$605 million in the second quarter of 2013 due to:
 - Increased crude oil and natural gas production;
 - Higher average realized crude oil and natural gas commodity prices combined with a weaker Canadian dollar;
 - Partially offset by a decrease in Upgrading margins due to lower average upgrading differentials and lower throughput;
 - U.S. Refining and Marketing margins due to lower market crack spreads and lower throughput; and
 - Higher stock-based compensation expense due to the increase in the Company's share price.

- Cash flow from operations of \$1,504 million in the second quarter of 2014 was comparable to the second quarter of 2013.

Key Projects

- At the Liwan Gas Project, gas from the Liwan 3-1 gas field is now being sold on a continuous basis into the Guangdong natural gas market. The 2014 construction season to finalize the deepwater development scope of the Liwan 3-1 gas field has commenced with tie-in of the Liuhua 34-2 field expected later in the year, subject to final approvals.
- Regulatory approval of the contract award for an FPSO vessel to develop the BD field in the Madura Strait offshore Indonesia was received.
- Phase 1 of the Sunrise Energy Project remains on track for start up by the end of 2014. Hydro testing of piping and the completion of electrical and instrumentation work continues for Plant 1A. Priority systems for Plant 1A are currently being turned over for commissioning.
- The public review process for the West White Rose Extension project commenced in the second quarter of 2014 and construction continued on the dry-dock in Argentiia, Newfoundland with a final investment decision expected in the fourth quarter of 2014.
- At the Sandall heavy oil thermal development, production response continues to be strong with oil rates averaging 5,300 bbls/day in the second quarter of 2014.
- Construction work continued at the 10,000 bbls/day Rush Lake heavy oil thermal development with first production expected in the second half of 2015.
- Resource play development progressed in Western Canada with three oil wells (gross) and 14 liquids-rich natural gas wells (gross) drilled and three oil wells (gross) and 10 liquids-rich natural gas wells (gross) completed.
- Front-end engineering design ("FEED") on the Lima feedstock flexibility project is approximately 95 percent complete.

Financial

- Dividends on common shares of \$295 million for the first quarter of 2014 were declared during the second quarter of 2014, of which \$291 million and \$4 million were paid in cash and common shares, respectively, on July 2, 2014.

2. Business Environment

		Three months ended				
		Jun. 30, 2014	Mar. 31, 2014	Dec. 31, 2013	Sept. 30, 2013	Jun. 30, 2013
Average Benchmarks						
WTI crude oil ⁽¹⁾	(U.S. \$/bbl)	102.99	98.68	97.46	105.83	94.22
Brent crude oil ⁽²⁾	(U.S. \$/bbl)	109.61	108.22	108.34	108.21	102.52
Canadian light crude 0.3 percent sulphur	(\$/bbl)	96.29	89.60	88.29	104.91	93.78
Western Canadian Select ⁽³⁾	(U.S. \$/bbl)	82.95	75.55	65.26	88.35	75.06
Lloyd heavy crude oil @ Lloydminster	(\$/bbl)	80.98	72.42	57.70	86.26	67.24
NYMEX natural gas ⁽⁴⁾	(U.S. \$/mmbtu)	4.67	4.94	3.61	3.58	4.09
NIT natural gas	(\$/GJ)	4.44	4.51	2.99	2.67	3.40
WTI/Lloyd crude blend differential	(U.S. \$/bbl)	20.17	23.09	32.42	17.50	19.21
New York Harbour 3:2:1 crack spread	(U.S. \$/bbl)	19.27	20.32	18.90	17.32	22.49
Chicago 3:2:1 crack spread	(U.S. \$/bbl)	19.40	18.35	11.91	15.86	30.78
U.S./Canadian dollar exchange rate	(U.S. \$)	0.917	0.906	0.953	0.963	0.977
Canadian \$ Equivalent⁽⁵⁾						
WTI crude oil	(\$/bbl)	112.31	108.92	102.26	109.90	96.44
Brent crude oil	(\$/bbl)	119.53	119.45	113.68	112.37	104.93
WTI/Lloyd crude blend differential	(\$/bbl)	22.00	25.49	34.02	18.17	19.66
NYMEX natural gas	(\$/mmbtu)	5.09	5.45	3.79	3.72	4.19

⁽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.

⁽⁴⁾ Quoted prices are based on the average price during the month.

⁽⁵⁾ Prices quoted are average settlement prices for deliveries during the period.

⁽⁶⁾ 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 WTI, adjusted to Western Canada, while the majority of the Company's production in the Atlantic and Asia Pacific regions is referenced to the price of Brent. The price of WTI averaged U.S. \$102.99/bbl in the second quarter of 2014 compared to U.S. \$94.22/bbl in the second quarter of 2013. The price of WTI averaged U.S. \$100.84/bbl in the first six months of 2014 compared to U.S. \$94.30/bbl in first six months of 2013. The price of Brent averaged U.S. \$109.61/bbl in the second quarter of 2014 compared to U.S. \$102.52/bbl in the second quarter of 2013. The price of Brent averaged U.S. \$108.91/bbl in the first six months of 2014 compared to U.S. \$107.54/bbl in first six months of 2013.

Crude oil prices in the second quarter and first six months of 2014 benefited from the weakening of the Canadian dollar against the U.S. dollar as compared to the same periods in 2013. In the second quarter of 2014, the price of WTI in U.S. dollars increased 9 percent compared to an increase of 16 percent in Canadian dollars. In the first six months of 2014, the price of WTI in U.S. dollars increased 7 percent compared to an increase of 15 percent in Canadian dollars when compared to the same periods in 2013.

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. The light/heavy crude oil differential averaged U.S. \$20.17/bbl or 20 percent of WTI in the second quarter of 2014 compared to U.S. \$19.21/bbl or 20 percent of WTI in the second quarter of 2013. The light/heavy crude oil differential averaged U.S. \$21.63/bbl or 21 percent of WTI in the first six months of 2014 compared to \$25.68/bbl or 27 percent of WTI in the first six months of 2013.

During the second quarter of 2014, the NYMEX near-month contract price of natural gas averaged U.S. \$4.67/mmbtu compared to U.S. \$4.09/mmbtu in the second quarter of 2013, an increase of 14 percent. During the first six months of 2014, the NYMEX near-month contract price of natural gas averaged U.S. \$4.81/mmbtu compared to U.S. \$3.72/mmbtu during the first six months of 2013, an increase of 29 percent. During the second quarter of 2014, the NOVA Inventory Transfer ("NIT") near-month contract price of natural gas averaged \$4.44/GJ compared to \$3.40/GJ in the same period in 2013, an increase of 31 percent. During the first six months of 2014, the NIT near-month contract price of natural gas averaged \$4.47/GJ compared to \$3.16/GJ in the same period in 2013, an increase of 41 percent.

Foreign Exchange

The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are 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 2014, the Canadian dollar averaged U.S. \$0.917, weakening by 6 percent compared to U.S. \$0.977 during the second quarter of 2013. In the first six months of 2014, the Canadian dollar averaged U.S. \$0.912, weakening by 7 percent compared to U.S. \$0.984 during the first six months of 2013.

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 equal to 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 or product configuration of a specific refinery.

During the second quarter of 2014, the Chicago 3:2:1 crack spread averaged U.S. \$19.40/bbl compared to U.S. \$30.78/bbl in the second quarter of 2013. In the first six months of 2014, the Chicago 3:2:1 crack spread averaged U.S. \$18.88/bbl compared to U.S. \$28.89/bbl in the first six months of 2013. During the second quarter of 2014, the New York Harbour 3:2:1 crack spread averaged U.S. \$19.27/bbl compared to U.S. \$22.49/bbl in the second quarter of 2013. In the first six months of 2013, the New York Harbour 3:2:1 crack spread averaged U.S. \$19.79/bbl compared to U.S. \$26.42/bbl in the first six months of 2013.

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 by 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 on earnings before income taxes and net earnings from changes in certain key variables in the second quarter of 2014. The table below reflects what the effect would have been on the financial results for the second quarter of 2014 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the second quarter of 2014. 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	2014	Increase	Effect on Earnings		Effect on	
	Second Quarter		before Income Taxes ⁽¹⁾		Net Earnings ⁽¹⁾	
	Average		(\$ millions)	(\$/share) ⁽²⁾	(\$ millions)	(\$/share) ⁽²⁾
WTI benchmark crude oil price ⁽³⁾⁽⁴⁾	102.99	U.S. \$1.00/bbl	79	0.08	59	0.06
NYMEX benchmark natural gas price ⁽⁵⁾	4.67	U.S. \$0.20/mmbtu	31	0.03	22	0.02
WTI/Lloyd crude blend differential ⁽⁶⁾	20.17	U.S. \$1.00/bbl	(29)	(0.03)	(22)	(0.02)
Canadian light oil margins	0.047	Cdn \$0.005/litre	14	0.01	10	0.01
Asphalt margins	22.45	Cdn \$1.00/bbl	10	0.01	7	0.01
New York Harbour 3:2:1 crack spread	19.27	U.S. \$1.00/bbl	47	0.05	28	0.03
Exchange rate (U.S. \$ per Cdn \$) ⁽³⁾⁽⁷⁾	0.917	U.S. \$0.01	(88)	(0.09)	(65)	(0.07)

⁽¹⁾ Excludes mark to market accounting impacts.

⁽²⁾ Based on 983.5 million common shares outstanding as of June 30, 2014.

⁽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 its three major growth pillars in the Asia Pacific Region, the Oil Sands and in 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 ("NGL") (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). The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada, offshore China and offshore Indonesia.

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading), 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).

4. Key Growth Highlights

The 2014 Capital Program builds on the momentum achieved over the past three years with respect to repositioning the Heavy Oil and Western Canada foundation by accelerating production growth and repositioning Western Canada to focus on oil and liquids-rich natural gas resource plays and advancing Husky's three major growth pillars in the Asia Pacific Region, the Oil Sands and the Atlantic Region.

4.1 Upstream

Western Canada (Excluding Heavy Oil and Oil Sands)

Oil Resource Plays

In the second quarter of 2014, three horizontal wells (gross) were drilled and three horizontal wells (gross) were completed across key plays in the oil resource project portfolio.

<i>Oil Resource Plays - Drilling and Completion Activity⁽¹⁾</i>		Three months ended June 30, 2014		Six months ended June 30, 2014	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	—	—	4	5
Lower Shaunavon	S.W. Saskatchewan	—	—	—	2
Viking ⁽²⁾	Alberta and S.W. Saskatchewan	3	—	13	8
N.Cardium	Wapiti, Alberta	—	3	4	8
Muskwa	Rainbow Region	—	—	—	2
Total Gross		3	3	21	25
Total Net		1	3	19	25

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

⁽²⁾ Viking is comprised of project activity at Redwater in central Alberta, Alliance in southeast Alberta and drilling in southwest Saskatchewan.

Construction of the all-season road at the Slater River Canol shale play in the Northwest Territories is expected to be completed in the third quarter of 2014. During the second quarter of 2014, Husky withdrew its application to drill four horizontal wells and anticipates that activity will resume in the 2016/2017 time frame.

Liquids-Rich Natural Gas Resource Plays

In the second quarter of 2014, 14 wells (gross) were drilled and 10 wells (gross) were completed in key plays across the liquids-rich natural gas portfolio.

Liquids-Rich Natural Gas Plays - Drilling and Completion Activity⁽¹⁾⁽²⁾		Three months ended June 30, 2014		Six months ended June 30, 2014	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	11	5	19	8
Duvernay	Kaybob, Alberta	—	—	—	2
Wilrich	Kakwa, Alberta	3	3	6	3
Strachan Cardium	Rocky Mountain House, Alberta	—	2	4	6
Total Gross		14	10	29	19
Total Net		9	8	22	17

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

⁽²⁾ Drilling activity includes operated and non-operated wells.

The liquids-rich natural gas formations in west central Alberta continue to be an area of focus for the Company.

In the Ansell multi-zone liquids-rich natural gas resource play, 11 liquids-rich horizontal natural gas wells (gross) were drilled and five horizontal wells (gross) were completed in the second quarter of 2014. Average production from the play was approximately 17,000 boe/day in the second quarter of 2014.

In the Duvernay liquids-rich natural gas resource play at Kaybob, production results from the four-well and two-well pads have been encouraging with higher than expected condensate yields at this stage of the extended production test.

At the Wilrich Kakwa liquids-rich natural gas resource play, three liquids-rich horizontal natural gas wells (gross) were drilled and three liquids-rich horizontal natural gas wells (gross) were completed in the second quarter of 2014. The Company and its partner plan to drill a total of five wells (gross) in 2014.

In the Strachan area located near Rocky Mountain House, Alberta, two liquids-rich horizontal natural gas wells (gross) were completed. Further development drilling is scheduled in 2014.

Conventional Oil and Gas

Approximately 15 wells (gross) were drilled and 17 wells (gross) were completed in the second quarter of 2014 in the conventional oil and gas portfolio.

Heavy Oil

The 3,500 bbls/day Sandall heavy oil thermal development began producing crude oil in the first quarter of 2014 ahead of schedule. Production response continues to be strong with oil rates averaging 5,300 bbls/day in the second quarter of 2014.

Construction work continued at the 10,000 bbls/day Rush Lake heavy oil thermal development with first production expected in the second half of 2015.

Site clearing, detailed engineering and module fabrication continued at the two 10,000 bbls/day Edam East and Vawn thermal development projects with first production expected in 2016. Work also commenced on the 3,500 bbls/day Edam West project with first production expected in 2016.

Husky completed a successful winter delineation program at the McMullen property which consisted of drilling 40 stratigraphic wells, the acquisition of 25 square kilometers of three-dimensional ("3-D") seismic survey data and the completion of environmental field study work.

Four horizontal heavy oil wells (gross) were drilled during the second quarter of 2014. Twenty-seven horizontal wells have been drilled to date.

Two Cold Heavy Oil Production with Sand ("CHOPS") wells (gross) were drilled during the second quarter of 2014. Seventy-five CHOPS wells have been drilled to date.

Asia Pacific Region

China

Block 29/26

Production at the Liwan Gas Project from the Liwan 3-1 gas field is now being sold into the Guangdong natural gas market. Short-term customer offtake delays, due to delay in commissioning of several new gas-fired power plants, have resulted in a portion of production volumes being deferred. Natural gas liquids that are separated from the gas sales at the Gaolan Gas plant are now also being sold into the Guangdong market.

The 2014 construction season to finalize the deepwater development of the Liwan 3-1 gas field has commenced. Two deepwater pipelay vessels are currently in operation to complete the laying of the second 22 inch deepwater production pipeline running from the Liwan 3-1 field to the central platform. The Liuhua 34-2 production well is expected to be tied into the Liwan 3-1 deepwater infrastructure later this year, subject to final approvals.

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

Offshore Taiwan

The acquisition of the second phase of two-dimensional seismic survey data on the Company's offshore Taiwan block was completed in the second quarter of 2014.

Indonesia

Progress continued on the shallow water gas developments in the Madura Strait Block. Work related to the BD field engineering, procurement, installation and construction contract is ongoing and approximately 20 percent complete. The contract award for the FPSO vessel has received final regulatory approval. Tender plans for the MDA and MBH development projects have been approved by SKK Migas, the Indonesia oil and gas regulator and the tendering process has commenced. The Gas Sales Agreement for the first tranche of gas sales is being negotiated following the signing of a corresponding Heads of Agreement in the first quarter of 2014.

Planning for exploration work, including a 3-D seismic survey, on the Anugerah contract area is in progress.

Oil Sands

Sunrise Energy Project

Phase 1 of the Sunrise Energy Project remains on track for start up by the end of 2014. Hydro testing of piping and the completion of electrical and instrumentation work continues for Plant 1A. Priority systems for Plant 1A are currently being turned over for commissioning. All well pads, diluent, diluted bitumen and gathering pipelines are complete and progressing through the commissioning phase. In addition, the Sunrise Energy Project also received its Maximum Operating Pressure Approval for the initial development area of Phase 1.

Atlantic Region

White Rose Field and Satellite Extensions

The public review process for the West White Rose Extension project commenced in the second quarter of 2014. Construction continued on the dry-dock in Argentia, Newfoundland and a final investment decision is expected in the fourth quarter of 2014.

Gas injection continued at the South White Rose Extension during the second quarter of 2014 and the installation of oil production equipment is scheduled for the third quarter of 2014. First production is anticipated around the end of 2014.

Drilling has resumed on the North Amethyst Hibernia formation well that will target a deeper zone beneath the main North Amethyst field. First production is planned later in 2014.

Atlantic Exploration

Husky and its partner commenced a 3-D seismic acquisition program over the Bay du Nord prospect area of the Flemish Pass Basin. An 18-month long drilling program at the Bay du Nord discovery is also scheduled to begin in the third quarter of 2014 and will utilize the West Hercules drilling rig. The drilling program will involve the appraisal and delineation of the Bay du Nord discovery as well as exploration of other potential targets. Husky holds a 35 percent working interest in the Bay du Nord discovery.

Infrastructure and Marketing

The Hardisty terminal expansion project includes multiple initiatives intended to increase pipeline connectivity and blending capacity that would expand Husky's terminalling business, support upstream production growth and provide additional flexibility through the inclusion of the Company's production in various crude streams. Construction is progressing on two 300,000-barrel tanks and additional piping interconnections and is anticipated to be complete in 2015. The project is expected to add approximately 20 percent to Husky's existing tank capacity at Hardisty.

The Saskatchewan Gathering System is undergoing an extension and capacity expansion into Lloydminster in order to accommodate the anticipated Rush Lake, Edam East, Vawn, and Edam West thermal development projects.

4.2 Downstream

Husky Lima, Ohio Refinery

FEED on the Company's feedstock flexibility project is approximately 95 percent complete. The project is expected to give the refinery flexibility to take up to 40,000 bbls/day of Western Canadian heavy oil while overall nameplate capacity remains unchanged at 160,000 bbls/day. Enhanced feedstock and product slate flexibility would allow the refinery to take advantage of heavy/light price and end product margin differentials while supporting anticipated production growth.

BP-Husky Toledo, Ohio Refinery

Work continued on the Hydrotreater Recycle Gas Compressor Project during the second quarter of 2014 which is scheduled to be completed towards the end of 2014. The project is intended to improve operational integrity and plant performance.

5. Results of Operations

5.1 Upstream

Total Second Quarter Upstream Earnings 2014 - \$570 million , 2013 - \$344 million.

Total Upstream net earnings include results from both the Exploration and Production operations and the Infrastructure and Marketing operations. Net earnings on a combined basis reflected stronger Exploration and Production earnings compared to the same period in 2013 due to increased crude oil and natural gas production and higher average realized commodity prices combined with a weaker Canadian dollar. The increase in Upstream earnings was partially offset by lower Infrastructure and Marketing earnings due to a decrease in realized marketing margins resulting from narrower product and location differentials between Canada and the United States compared to the same period in 2013. The shift in earnings between the two operations reflects the Company's integration strategy and the ability to capture value as it moves along the value chain.

Exploration and Production

<i>Exploration and Production Earnings Summary</i> (\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Gross revenues	2,352	1,843	4,534	3,488
Royalties	(302)	(208)	(592)	(412)
Net revenues	2,050	1,635	3,942	3,076
Purchases, operating, transportation and administrative expenses	630	608	1,276	1,167
Depletion, depreciation and amortization	637	568	1,210	1,130
Exploration and evaluation expenses	19	74	59	162
Other expenses	17	3	143	73
Income taxes	193	99	324	140
Net earnings	554	283	930	404

Second Quarter

Exploration and Production net earnings in the second quarter of 2014 increased by \$271 million compared to the second quarter of 2013 due to higher realized crude oil and natural gas prices and increased crude oil and natural gas production, partially offset by higher royalty expense and increased depletion, depreciation and amortization expense.

Production increased by 23.7 mboe/day in the second quarter of 2014 compared to the same period in 2013. The increase in production was primarily due to higher natural gas production from the Liwan Gas Project which came on stream at the end of the first quarter and heavy crude oil production from the Sandall heavy oil thermal development. The increase in production was partially offset by a planned turnaround at the Company's Rainbow oil and gas facility, natural reservoir declines in Western Canada natural gas properties as capital investment is being directed to higher return oil and liquids-rich natural gas developments and lower production at the Wenchang field due to the planned FPSO vessel offstation.

The average realized price for crude oil, NGL and bitumen in the second quarter of 2014 was \$90.33/bbl compared to \$77.98/bbl during the same period in 2013, a 16 percent increase, due to higher Brent, WTI and heavy crude oil and bitumen market prices combined with a weaker Canadian dollar. Realized natural gas prices averaged \$6.42/mcf in the second quarter of 2014 compared to \$3.72/mcf in the same period in 2013, an increase of 73 percent, primarily due to higher realized prices on production from the Liwan Gas Project and stronger North American supply and demand fundamentals compared to 2013.

Six Months

Exploration and Production net earnings in the first six months of 2014 were \$526 million higher compared to the same period in 2013 primarily due to higher realized crude oil and natural gas prices and increased production from the Liwan Gas Project and heavy oil thermal developments, partially offset by higher royalty expense and increased operating costs in Western Canada. During the first six months of 2014, the average realized price for crude oil, NGL and bitumen was \$88.79/bbl compared to \$73.11/bbl in the same period in 2013, an increase of 21 percent. During the first six months of 2014, the average realized natural gas price was \$5.67/mcf compared to \$3.39/mcf in the same period in 2013, an increase of 67 percent.

Average Sales Prices Realized	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Crude oil and NGL (\$/bbl)				
Light crude oil & NGL	110.29	96.22	110.40	99.97
Medium crude oil	89.67	73.62	86.49	67.68
Heavy crude oil	79.45	66.77	75.90	56.12
Bitumen	77.97	65.71	74.48	54.52
Total crude oil and NGL average	90.33	77.98	88.79	73.11
Natural gas average (\$/mcf)	6.42	3.72	5.67	3.39
Total average (\$/boe)	74.70	62.88	73.48	58.60

The price realized for Western Canada crude oil reflected higher WTI and heavy crude oil and bitumen prices combined with a weaker Canadian dollar. The premium to WTI realized for offshore production reflects Brent prices.

Daily Gross Production	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Crude Oil and NGL (mbbls/day)				
Western Canada				
Light crude oil & NGL	27.7	28.6	29.6	29.6
Medium crude oil	22.4	22.9	23.1	23.0
Heavy crude oil	78.1	72.3	76.8	73.4
Bitumen ⁽¹⁾	54.6	48.3	53.2	48.0
	182.8	172.1	182.7	174.0
Atlantic Region				
White Rose and Satellite Fields – light crude oil	42.4	40.4	43.0	41.8
Terra Nova – light crude oil	5.2	5.7	5.9	5.3
	47.6	46.1	48.9	47.1
Asia Pacific Region				
Light crude oil & NGL	2.6	7.6	5.7	7.7
	233.0	225.8	237.3	228.8
Natural gas (mmcf/day)				
Western Canada	490.6	504.7	498.2	521.0
Asia Pacific Region	113.0	—	56.8	—
	603.6	504.7	555.0	521.0
Total (mboe/day)	333.6	309.9	329.8	315.6

⁽¹⁾ Bitumen production includes heavy oil thermal average daily gross production of 43.4 mbbls/day and 42.2 mbbls/day for the three months and six months ended June 30, 2014, respectively.

Crude Oil and NGL Production

Second Quarter

Crude oil and NGL production in the second quarter of 2014 increased by 7.2 mbbls/day or 3 percent compared to the same period in 2013. The increase in production was primarily due to production from the Sandall heavy oil thermal development which came on stream in the first quarter of 2014, higher production at the Ansell multi-zone liquids-rich natural gas resource play and increased production in the Atlantic Region from the North Amethyst multilateral well which was brought on stream in late 2013. The increase in crude oil and NGL production was partially offset by lower production at the Wenchang field due to the planned FPSO vessel offstation and natural reservoir declines at maturing White Rose fields.

Six Months

In the first six months of 2014, crude oil and NGL production increased by 8.5 mbbls/day or 4 percent compared to the same period in 2013 primarily due to the same factors which impacted the second quarter.

Natural Gas Production

Second Quarter

Natural gas production in the second quarter of 2014 increased by 98.9 mmcf/day or 20 percent compared to the same period in 2013 primarily due to production from the Liwan Gas Project, partially offset by a planned turnaround at the Company's Rainbow oil and gas facility and natural reservoir declines in Western Canada mature properties as capital investment is being directed to higher return oil and liquids-rich natural gas developments.

Six Months

In the first six months of 2014, natural gas production increased by 34.0 mmcf/day or 7 percent compared to the same period in 2013 primarily due to the same factors which impacted the second quarter.

2014 Production Guidance

The following table shows actual daily production for the six months ended June 30, 2014 and the year ended December 31, 2013, as well as the previously issued production guidance for 2014.

	2014 Guidance	Actual Production	
		Six months ended June 30, 2014	Year ended December 31, 2013
Crude oil, NGL and Asia Pacific Gas (mbbls/day)			
Light / Medium crude oil & NGL	110 – 115	106	104
Heavy crude oil	125 – 130	130	122
Natural Gas & NGL Asia Pacific Region (mboe/day)	25 – 30	11	—
	260 – 275	247	226
Natural Gas Canada (mmcf/day)	420 – 480	498	513
Total (mboe/day)	330 – 355	330	312

Royalties

Second Quarter

In the second quarter of 2014, royalty rates as a percentage of gross revenues averaged 14 percent compared to 12 percent in the same period in 2013. Royalty rates in Western Canada averaged 12 percent in the second quarter of 2014 compared to 11 percent in the same period in 2013. Royalty rates for the Atlantic Region averaged 21 percent in the second quarter of 2014 compared to 12 percent in the same period in 2013 due to Tier 1 and super royalty rates being reached at the North Amethyst and West White Rose Satellite Extensions. Royalty rates in the Asia Pacific Region averaged 6 percent in the second quarter of 2014 compared to 23 percent in the same period in 2013 due to lower royalty rates associated with production from the Liwan Gas Project combined with the Wenchang field planned FPSO vessel offstation that started in early April.

Six Months

Royalty rates averaged 14 percent of gross revenues in the first six months of 2014 compared to 13 percent in the same period in 2013. Royalty rates in Western Canada averaged 12 percent in both of the first six months of 2014 and 2013. Royalty rates for the Atlantic Region averaged 20 percent in the first six months of 2014 compared to 13 percent in the same period in 2013 due to the same factors which impacted the second quarter of 2014. Royalty rates in the Asia Pacific Region averaged 12 percent in the first six months of 2014 compared to 25 percent in the same period in 2013 due to the same factors which impacted the second quarter of 2014.

Operating Costs

(\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Western Canada	456	438	926	861
Atlantic Region	45	50	102	93
Asia Pacific	10	6	18	13
Total	511	494	1,046	967
Unit operating costs (\$/boe)	15.68	16.79	16.44	15.80

Second Quarter

Total Exploration and Production operating costs were \$511 million in the second quarter of 2014 compared to \$494 million in the same period in 2013. Total operating costs averaged \$15.68/boe in the second quarter of 2014 compared to \$16.79/boe in the same period in 2013.

Operating costs in Western Canada averaged \$17.44/boe in the second quarter of 2014, which was comparable to \$17.76/boe in the same period in 2013.

Operating costs in the Atlantic Region averaged \$10.52/boe in the second quarter of 2014 compared to \$12.16/boe in the same period in 2013 primarily due to an insurance recovery received in the second quarter, partially offset by higher fuel and logistics costs.

Operating costs in the Asia Pacific Region averaged \$4.99/boe in the second quarter of 2014 compared to \$10.28/boe in the same period in 2013. The decrease was primarily attributable to lower operating costs on a per barrel basis associated with the Liwan Gas Project which came on stream at the end of the first quarter of 2014.

Six Months

Total Exploration and Production operating costs in the first six months of 2014 were \$1,046 million compared to \$967 million in the same period in 2013. Operating costs in Western Canada averaged \$17.85/boe in the first six months of 2014 compared to \$16.83/boe in the same period in 2013 primarily due to increased natural gas prices and higher energy consumption related to new heavy oil thermal projects. Operating costs in the Atlantic Region averaged \$11.57/boe in the first six months of 2014 compared to \$10.89/boe in the same period in 2013 primarily due to higher ice management costs, partially offset by an insurance recovery. Operating costs in the Asia Pacific Region averaged \$6.59/boe in the first six months of 2014 compared to \$9.71/boe in the same period in 2013 primarily due to the same factors which impacted the second quarter.

Exploration and Evaluation Expenses

(\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Seismic, geological and geophysical	17	44	42	77
Expensed drilling	1	27	13	79
Expensed land	1	3	4	6
Exploration and evaluation expenses	19	74	59	162

Second Quarter

Exploration and evaluation expenses in the second quarter of 2014 were \$19 million compared to \$74 million in the second quarter of 2013. Higher expensed drilling costs were incurred in the second quarter of 2013 due to adjustments made to drilling rig cost allocations on previously drilled wells. The decrease of \$27 million in seismic, geological and geophysical costs was primarily due to a one time work commitment penalty in the second quarter of 2013 in the Atlantic Region.

Six Months

Exploration and evaluation expenses in the first six months of 2014 were \$59 million compared to \$162 million in the same period of 2013 due to the same factors which impacted the second quarter, as well as higher expensed drilling costs in 2013 at the Slater River Canol Shale project where the Company completed the drilling and testing of two vertical wells and completed the baseline groundwater study.

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

Second Quarter

In the second quarter of 2014, total DD&A averaged \$20.95/boe, which was comparable to \$20.10/boe in the second quarter of 2013.

Six Months

For the first six months of 2014, total DD&A averaged \$20.26/boe, which was comparable to \$19.77/boe during the same period in 2013.

Exploration and Production Capital Expenditures

In the first six months of 2014, Upstream Exploration and Production capital expenditures were \$1,983 million. Capital expenditures were \$1,194 million (60%) in Western Canada including Heavy Oil, \$285 million (15%) in Oil Sands, \$266 million (13%) in the Atlantic Region and \$238 million (12%) in the Asia Pacific Region.

<i>Exploration and Production Capital Expenditures⁽¹⁾</i> (\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Exploration				
Western Canada ⁽²⁾	56	64	130	174
Oil Sands ⁽²⁾	—	—	5	—
Atlantic Region	15	39	22	44
Asia Pacific Region	—	—	9	6
	71	103	166	224
Development				
Western Canada	468	267	1,059	780
Oil Sands	147	137	280	295
Atlantic Region	90	116	244	255
Asia Pacific Region	80	156	229	285
	785	676	1,812	1,615
Acquisitions				
Western Canada	3	4	5	10
	859	783	1,983	1,849

⁽¹⁾ Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.

⁽²⁾ During the second quarter of 2014, the Company redefined its McMullen property as a Heavy Oil thermal project resulting in the reclassification of capital expenditures from Oil Sands to Western Canada including Heavy Oil.

Western Canada, Heavy Oil and Oil Sands

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

<i>Wells Drilled⁽¹⁾</i> (wells)	Three months ended June 30,				Six months ended June 30,			
	2014		2013		2014		2013	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration								
Oil	4	1	2	—	48	44	17	9
Gas	3	1	6	4	5	3	11	9
Dry	—	—	—	—	—	—	—	—
	7	2	8	4	53	47	28	18
Development								
Oil	14	7	34	30	217	194	282	259
Gas	29	24	3	2	42	35	38	17
Dry	—	—	1	—	—	—	1	—
	43	31	38	32	259	229	321	276
Total	50	33	46	36	312	276	349	294

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

The Company drilled 276 net wells in the Western Canada, Heavy Oil and Oil Sands business units in the first six months of 2014 resulting in 238 net oil wells and 38 net natural gas wells compared to 294 net wells resulting in 268 net oil wells and 26 net natural gas wells in the same period of 2013.

During the first six months of 2014, Husky invested \$1,194 million in exploration, development and acquisitions, including Heavy Oil, throughout the Western Canada Sedimentary Basin compared to \$964 million in the same period in 2013. Property acquisitions totalling \$5 million were completed in the first six months of 2014 compared to \$10 million in the same period in 2013. Oil related exploration and development in the first six months of 2014 was \$204 million compared to \$242 million in the same period in 2013. Investment in natural gas related exploration and development, primarily liquids-rich, was \$295 million in the first six months of 2014 compared to \$245 million in the same period in 2013.

In addition, \$113 million was spent on production optimization and cost reduction initiatives in the first six months of 2014 compared to \$102 million in the same period in 2013. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled \$314 million in the first six months of 2014 compared to \$148 million in the same period in 2013.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling were \$263 million in the first six months of 2014 compared to \$217 million in the same period in 2013.

Oil Sands

During the first six months of 2014, \$285 million was invested in Oil Sands projects, compared to \$295 million in the same period in 2013, primarily on Phase 1 of the Sunrise Energy Project.

Atlantic Region

During the first six months of 2014, \$266 million was invested in Atlantic Region projects, compared to \$299 million in the same period in 2013, 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 2014, \$238 million was invested in Asia Pacific Region projects, compared to \$291 million in the same period of 2013, primarily on the continued development of the Liwan Gas Project.

Upstream Planned Turnarounds

In the Atlantic Region, the partner-operated Terra Nova FPSO is scheduled to undergo a four-week turnaround and the SeaRose FPSO is scheduled to have a one-week turnaround during the third quarter of 2014.

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.

<i>Infrastructure and Marketing Earnings Summary</i>	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
<i>(\$ millions, except where indicated)</i>				
Infrastructure gross margin	32	42	76	74
Marketing and other gross margin	3	57	37	219
Gross margin	35	99	113	293
Operating and administrative expenses	7	12	17	21
Depreciation and amortization	6	6	13	12
Other income	—	(1)	—	(1)
Income taxes	6	21	21	66
Net earnings	16	61	62	195
Commodity trading volumes managed (mboe/day)	237.7	167.4	294.8	173.9

Second Quarter

Infrastructure and Marketing net earnings in the second quarter of 2014 decreased by \$45 million compared to the same period in 2013 as a result of narrower product and location differentials between Canada and the United States.

Six Months

Infrastructure and Marketing net earnings in the first six months of 2014 decreased by \$133 million compared to the same period in 2013 primarily due to the same factors which impacted the second quarter, in addition to increased volatility of market prices for natural gas in the first quarter of 2014 which resulted in higher losses on forward natural gas contracts.

5.2 Downstream

Total Second Quarter Downstream Earnings 2014 - \$153 million, 2013 - \$295 million

Total Downstream net earnings include results from the Upgrader, Canadian Refined Products and U.S. Refining and Marketing operations. Net earnings on a combined basis reflected a decrease in Upgrading net earnings primarily due to lower average upgrading differentials and lower throughput and a decrease in U.S. Refining and Marketing net earnings where realized margins were impacted by significantly lower market crack spreads and lower throughput resulting from a planned turnaround at the BP-Husky Toledo Refinery and scheduled downtime for maintenance at the Lima Refinery.

Upgrader

Upgrader Earnings Summary

(\$ millions, except where indicated)

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Gross revenues	560	573	1,133	1,102
Gross margin	139	185	328	427
Operating and administrative expenses	45	42	94	81
Depreciation and amortization	28	23	52	47
Other expenses	—	1	9	2
Income taxes	17	31	45	77
Net earnings	49	88	128	220
Upgrader throughput (mbbls/day) ⁽¹⁾	68.2	73.8	70.2	74.0
Synthetic crude oil sales (mbbls/day)	48.2	56.7	51.0	56.4
Upgrading differential (\$/bbl)	25.27	27.39	26.26	32.96
Unit margin (\$/bbl)	31.69	35.85	35.53	41.83
Unit operating cost (\$/bbl) ⁽²⁾	6.93	6.25	7.08	6.05

⁽¹⁾ Throughput includes diluent returned to the field.

⁽²⁾ 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.

Upgrading net earnings decreased by \$39 million in the second quarter of 2014 compared to the same period in 2013. The decrease in net earnings was primarily due to lower average upgrading differentials and lower throughput and sales volumes resulting from unplanned maintenance completed in the second quarter.

During the second quarter of 2014, the upgrading differential averaged \$25.27/bbl, a decrease of \$2.12/bbl or 8 percent, compared to the same period in 2013. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The decrease in the upgrading differential was attributable to higher heavy oil feedstock costs, which are captured in the Upstream Exploration and Production results, partially offset by higher prices for synthetic crude oil. The average price for Husky Synthetic Blend in the second quarter of 2014 was \$112.80/bbl compared to \$100.90/bbl in the same period in 2013. The overall unit margin decreased to \$31.69/bbl in the second quarter of 2014 from \$35.85/bbl in the same period in 2013.

Six Months

Upgrading net earnings for the first six months of 2014 decreased by \$92 million compared to the same period in 2013 primarily due to the same factors which impacted the second quarter.

Canadian Refined Products

Canadian Refined Products Earnings Summary

(\$ millions, except where indicated)	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Gross revenues	991	613	1,930	1,456
Gross margin				
Fuel	33	38	65	74
Refining	64	45	145	93
Asphalt	58	49	119	133
Ancillary	14	13	28	26
	169	145	357	326
Operating and administrative expenses	77	64	150	122
Depreciation and amortization	25	22	49	44
Other expenses	2	—	2	—
Income taxes	17	15	40	41
Net earnings	48	44	116	119
Number of fuel outlets ⁽¹⁾	502	513	502	513
Fuel sales volume, including wholesale				
Fuel sales (millions of litres/day) ⁽²⁾	7.5	8.0	7.6	8.1
Fuel sales per retail outlet (thousands of litres/day) ⁽²⁾	12.8	13.0	13.0	13.2
Refinery throughput				
Prince George Refinery (mbbls/day)	11.3	6.3	11.6	8.7
Lloydminster Refinery (mbbls/day)	29.0	18.7	29.0	23.4
Ethanol production (thousands of litres/day)	790.9	698.7	785.3	740.8

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

⁽²⁾ Prior periods have been adjusted to reflect a change in classification of certain retail sales volumes.

Second Quarter

Lower fuel gross margins in the second quarter of 2014 compared to the same period in 2013 were primarily due to lower gasoline margins and lower sales volumes resulting from select outlet closures.

Higher refining gross margins in the second quarter of 2014 compared to the same period in 2013 were primarily due to lower feedstock costs at the Lloydminster and Minnedosa Ethanol plants. Higher feedstock costs at the Prince George Refinery were offset by higher throughput, sales volumes and Canadian crack spreads compared to the same period in 2013 when the refinery completed a turnaround.

Higher asphalt gross margins in the second quarter of 2014 compared to the same period in 2013 were primarily due to higher throughput as the Lloydminster Refinery completed a turnaround in the second quarter of 2013.

Higher energy costs contributed to the increase in operating and administrative expenses during the second quarter of 2014 compared to the same period in 2013.

Six Months

During the first six months of 2014, Canadian Refined Products earnings were comparable to the same period in 2013. Higher refining margins resulting from higher refinery throughput at the Prince George Refinery and lower feedstock costs at the ethanol plants were offset by higher operating costs, lower fuel sales and higher feedstock costs at the Prince George and Lloydminster Refineries.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary <i>(\$ millions, except where indicated)</i>	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Gross revenues	2,928	2,922	5,348	5,633
Gross refining margin	269	418	633	804
Operating and administrative expenses	118	108	242	213
Depreciation and amortization	62	58	123	115
Other expenses	—	1	1	2
Income taxes	33	88	99	166
Net earnings	56	163	168	308
Select operating data:				
Lima Refinery throughput (mbbls/day)	135.9	149.8	123.3	148.3
BP-Husky Toledo Refinery throughput (mbbls/day)	59.4	68.1	62.3	67.2
Refining margin (U.S. \$/bbl crude throughput)	14.40	20.24	17.81	20.36
Refinery inventory (mmbbls) ⁽¹⁾	10.7	10.9	10.7	10.9

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

Second Quarter

U.S. Refining and Marketing net earnings decreased in the second quarter of 2014 compared to the same period in 2013 primarily due to significantly lower Chicago 3:2:1 market crack spreads and lower throughput at the BP-Husky Toledo Refinery due to a planned turnaround. In addition, the Company's Lima Refinery underwent scheduled downtime for maintenance which resulted in higher operating costs, lower throughput and the need to purchase refined products to deliver on committed sales volumes which impacted realized margins.

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 when crude oil prices were lower. The estimated FIFO impact was a decrease in net earnings of approximately \$13 million in the second quarter of 2014 compared to an increase in net earnings of approximately \$19 million in the same period in 2013.

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 2014 decreased by \$140 million compared to the same period in 2013 primarily due to the same factors affecting the second quarter.

Downstream Capital Expenditures

In the first six months of 2014, Downstream capital expenditures totalled \$264 million compared to \$155 million in the same period in 2013. In Canada, capital expenditures of \$97 million were related to projects at the Upgrader and the Prince George Refinery. At the Lima Refinery, \$99 million was spent primarily on the feedstock flexibility project and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled \$68 million (Husky's 50 percent share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

The Lloydminster Upgrader is scheduled to undergo a partial outage in the fall of 2014 for planned maintenance. Plant rates are expected to remain at approximately 80 percent during the planned 42-day turnaround.

5.3 Corporate

Corporate Summary

(\$ millions) income (expense)	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Administrative	(12)	(27)	(30)	(70)
Stock-based compensation	(47)	7	(53)	(2)
Depreciation and amortization	(18)	(11)	(34)	(21)
Other income (expense)	9	(5)	9	9
Foreign exchange gains (losses)	(3)	10	15	2
Interest expense	(34)	(1)	(27)	(10)
Income tax recovery (expense)	10	(7)	6	(14)
Net loss	(95)	(34)	(114)	(106)

Second Quarter

The Corporate segment reported a loss of \$95 million in the second quarter of 2014 compared to a loss of \$34 million in the same period in 2013. Administrative expenses decreased by \$15 million in the second quarter of 2014 compared to the same period in 2013 primarily due to lower personnel costs. Stock-based compensation increased by \$54 million in the second quarter of 2014 compared to the same period in 2013 due to the increase in the Company's share price. Interest expense increased by \$33 million in the second quarter of 2014 compared to the same period in 2013 due to a decrease in the amount of capitalized interest related to production being achieved at the Liwan Gas Project.

Six Months

In the first six months of 2014, the Corporate segment reported a loss of \$114 million compared to a loss of \$106 million in the same period of 2013. Administrative expenses decreased in the first six months of 2014 compared to the same period in 2013 primarily due to the same factors which impacted the second quarter of 2014. Interest expense and stock-based compensation increased in the first six months of 2014 compared to the same period in 2013 primarily due to the same factors which impacted the second quarter of 2014.

Foreign Exchange Summary

(\$ millions, except where indicated)	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Gains (losses) on translation of U.S. dollar denominated long-term debt	28	(13)	28	(21)
Gains on contribution receivable	—	16	7	30
Other foreign exchange gains (losses)	(31)	7	(20)	(7)
Net foreign exchange gains (losses)	(3)	10	15	2
U.S./Canadian dollar exchange rates:				
At beginning of period	U.S. \$0.905	U.S. \$0.985	U.S. \$0.940	U.S. \$1.005
At end of period	U.S. \$0.937	U.S. \$0.951	U.S. \$0.937	U.S. \$0.951

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

Consolidated Income Taxes

Consolidated income taxes in the second quarter of 2014 was \$256 million compared to \$261 million in the same period in 2013 resulting in an effective tax rate of 29 percent in the second quarter of 2014 compared to 30 percent in the same period in 2013.

(\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Income taxes as reported	256	261	523	504
Cash taxes paid	285	232	381	373

Corporate Capital Expenditures

In the first six months of 2014, Corporate capital expenditures were \$78 million compared to \$52 million in the same period of 2013 and were primarily related to computer hardware and software and leasehold improvements.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the second quarter of 2014, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At June 30, 2014, Husky had total debt of \$4,113 million, partially offset by cash on hand of \$48 million, for \$4,065 million of net debt compared to \$3,022 million of net debt at December 31, 2013. At June 30, 2014, the Company had \$3.7 billion of unused credit facilities of which \$3.2 billion is long-term committed credit facilities and \$434 million is short-term uncommitted credit facilities. In addition, the Company had \$3.0 billion in unused capacity under its December 2012 Canadian universal short form base shelf prospectus and U.S. \$2.25 billion in unused capacity under its October 2013 U.S. universal short form base 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,		Six months ended June 30,	
	2014	2013	2014	2013
Cash flow				
Operating activities	1,147	1,225	2,483	2,540
Financing activities	(1,158)	(230)	(503)	(435)
Investing activities	(1,438)	(1,124)	(3,011)	(2,358)
Financial Ratios⁽¹⁾				
Debt to capital employed (percent) ⁽²⁾			16.5	17.0
Debt to cash flow (times) ⁽³⁾⁽⁴⁾			0.7	0.8
Corporate reinvestment ratio (percent) ⁽³⁾⁽⁵⁾			105	101
Interest coverage ratios on long-term debt only ⁽³⁾⁽⁶⁾				
Earnings			11.0	13.7
Cash flow			20.7	25.7
Interest coverage ratios on total debt ⁽³⁾⁽⁷⁾				
Earnings			11.0	13.7
Cash flow			20.7	25.8

⁽¹⁾ Financial ratios constitute non-GAAP measures. Refer to Section 11.

⁽²⁾ Debt to capital employed is equal to long-term debt and long-term debt due within one year divided by capital employed.

⁽³⁾ Calculated for the 12 months ended for the dates shown.

⁽⁴⁾ Debt to cash flow (times) is equal to long-term debt and long-term debt due within one year divided by cash flow from operations.

⁽⁵⁾ Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations.

⁽⁶⁾ Interest coverage on long-term debt on a net earnings basis is equal to net earnings before finance expense on long-term debt and income taxes divided by finance expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow – operating activities before finance expense on long-term debt and current income taxes divided by finance expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.

⁽⁷⁾ Interest coverage on total debt on a net earnings basis is equal to net earnings before finance expense on total debt and income taxes divided by finance expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow – operating activities before finance expense on total debt and current income taxes divided by finance expense on total debt and capitalized interest. Total debt includes short and long-term debt.

Cash Flow from Operating Activities

Second Quarter

In the second quarter of 2014, cash flow generated from operating activities was \$1,147 million compared to \$1,225 million in the same period in 2013 due to increased cash taxes paid during the period and a decrease in changes in non-cash working capital.

Six Months

In the first six months of 2014, cash flow generated from operating activities was \$2,483 million compared to \$2,540 million in the same period in 2013.

Cash Flow used for Financing Activities

Second Quarter

In the second quarter of 2014, cash flow used for financing activities was \$1,158 million compared to \$230 million in the same period in 2013. The increase in cash flow used for financing activities was due to the repayment of U.S. \$750 million, equivalent to \$814 million in Canadian dollars, in senior unsecured notes which matured in June 2014 and the final settlement of the Sunrise Energy Project contribution receivable during the quarter.

Six Months

Cash flow used for financing activities was \$503 million in the first six months of 2014 compared to \$435 million in the same period in 2013.

Cash Flow used for Investing Activities

Second Quarter

In the second quarter of 2014, cash flow used for investing activities was \$1,438 million compared to \$1,124 million in the same period in 2013. Cash invested in both periods was primarily for capital expenditures.

Six Months

Cash flow used for investing activities was \$3,011 million for the first six months of 2014 compared to \$2,358 million in the first six months of 2013. Cash invested in both periods was primarily for capital expenditures.

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 and borrowings under committed and uncommitted credit facilities. The Company also maintains access to sufficient capital via debt 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.

Working capital is the amount by which current assets exceed current liabilities. At June 30, 2014, working capital was \$1,102 million compared to \$754 million at December 31, 2013 due to repayment of debt, partially offset by reclassification of debt due within one year.

During the three months ended June 30, 2014 the Company increased the limit of one of its operating lines from \$50 million to \$100 million. At June 30, 2014, Husky had unused short and long-term credit facilities totalling \$3.7 billion. A total of \$211 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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.

On October 31, 2013 and November 1, 2013, Husky filed a universal short form base shelf prospectus (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.

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 if the notes are redeemed prior to 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 June 15, 2014, the Company repaid the maturing 5.90 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to noteholders was U.S. \$772 million, including U.S. \$22 million of interest, equivalent to \$839 million in Canadian dollars, including interest of \$25 million.

On June 19, 2014, the maturity of the \$1.6 billion revolving syndicated credit facility previously set to expire on August 31, 2014 was extended to June 19, 2018.

Capital Structure

(\$ millions)

	Outstanding	June 30, 2014 Available ⁽¹⁾
Total debt	4,113	3,664
Common shares, preferred shares, retained earnings and other reserves	20,743	

⁽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 2013 Annual MD&A under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2013.

During the three months ended June 30, 2014, the Company had the following material change to non-cancellable commitments:

- On June 15, 2014, the Company repaid U.S. \$772 million, including U.S. \$22 million of interest, equivalent to \$839 million in Canadian dollars, including interest of \$25 million, of maturing 5.90 percent notes issued under a trust indenture dated September 11, 2007.

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 material effect on the Company's financial condition, results of operations, liquidity or capital expenditures.

6.5 Transactions with Related Parties and Major Customers

On May 11, 2009, the Company issued U.S. \$251 million aggregate principal amount of 5-year 5.90 percent senior notes to certain management, shareholders, affiliates and directors. Subsequent to this offering, U.S. \$122 million of the 5.90 percent notes issued to related parties were sold to third parties. On June 15, 2014, the Company repaid the maturing 5.90 percent notes. As a result, U.S. \$133 million was repaid to related parties which included interest of U.S. \$4 million. These transactions were measured at fair market value at the date of the transaction and have been carried out on the same terms as applied to unrelated parties.

The Company sells natural gas to and purchases steam from the Meridian cogeneration facility and other cogeneration facilities owned by a related party. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the three and six months ended June 30, 2014, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled \$21 million and \$43 million, respectively. For the three and six months ended June 30, 2014, the amount of steam purchased by the Company from Meridian totalled \$6 million and \$14 million, respectively. In addition, the Company provides facility services to Meridian which are measured at cost. For the three and six months ended June 30, 2014, the total cost recovery for these services was \$3 million and \$5 million, respectively.

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 2013 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, 2013, as discussed in Husky's 2013 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, 2014, 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 the first quarter of 2014, the Company discontinued its cash flow hedge with respect to the forward starting interest rate swaps. These forward interest rate swaps were settled and derecognized. Accordingly, the accrued gain in other reserves-hedging, within the Condensed Consolidated Statement of Changes in Shareholders' Equity, 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, 2014, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was \$25 million (December 31, 2013 – \$37 million), net of tax of \$8 million (December 31, 2013 – net of tax of \$13 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in an addition to finance income of \$1 million for the three and six months ended June 30, 2014.

Refer to Note 11 of the Condensed Interim Consolidated Financial Statements.

Foreign Currency Risk Management

At June 30, 2014, 83 percent or \$3.4 billion of Husky's outstanding debt was denominated in U.S. dollars. Including the debt that has been designated as a hedge of a net investment, 19 percent of long-term debt is exposed to changes in the Canadian/U.S. exchange rate.

At June 30, 2014, the Company had designated U.S. \$2.4 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, 2014, the Company incurred an unrealized gain of \$94 million and loss of \$22 million, respectively, arising from the translation of the debt, net of tax of \$14 million and \$3 million, respectively, which was recorded in net investment hedge within other comprehensive income ("OCI").

During the second quarter of 2014, the balance of Husky's 50 percent contribution receivable, representing BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership, was fully repaid. The contribution receivable was denominated in U.S. dollars, and related gains and losses incurred from changes in the value of the Canadian dollar versus the U.S. dollar were recorded in foreign exchange in current period earnings. 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, 2014, Husky's share of this obligation was U.S. \$1.3 billion including accrued interest. At June 30, 2014, the cost of a Canadian dollar in U.S. currency was \$0.937.

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

<i>Financial Instruments at Fair Value</i> (\$ millions)	As at June 30, 2014	As at December 31, 2013
Commodity contracts – fair value through profit or loss ("FVTPL")		
Natural gas ⁽¹⁾	1	32
Crude oil ⁽²⁾	(5)	41
Foreign currency contracts – FVTPL		
Foreign currency forwards	(1)	—
Other assets – FVTPL	2	2
Contingent consideration	(37)	(60)
Hedging instruments ⁽³⁾		
Derivatives designated as a cash flow hedge ⁽⁴⁾	—	37
Hedge of net investment ⁽⁵⁾	(115)	(93)
	(155)	(41)

⁽¹⁾ Natural gas contracts includes a \$2 million increase as at June 30, 2014 (December 31, 2013 – \$27 million increase) 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 \$101 million at June 30, 2014.

⁽²⁾ Crude oil contracts includes a \$2 million increase as at June 30, 2014 (December 31, 2013 – \$49 million increase) 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 \$322 million at June 30, 2014.

⁽³⁾ Hedging instruments are presented net of tax.

⁽⁴⁾ Forward starting swaps previously designated as a cash flow hedge were discontinued during the first quarter of 2014.

⁽⁵⁾ 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 2013 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. Change in Accounting Policies

The International Accounting Standards Board ("IASB") issued amendments to International Accounting Standards 36, "Impairment of Assets" which was adopted by the Company on January 1, 2014. The amendments require disclosure of information about the recoverable amount of impaired assets. The adoption of this amended standard had no impact on the Company's Condensed Interim Consolidated Financial Statements.

The IASB issued International Financial Reporting Interpretations Committee Interpretation ("IFRIC") 21, "Levies" which was adopted by the Company on January 1, 2014. The IFRIC clarifies that an entity should recognize a liability for a levy when the activity that triggers payment occurs. The adoption of this interpretation had no impact on the Company's Condensed Interim Consolidated Financial Statements.

10. Outstanding Share Data

Authorized:

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

Issued and outstanding: July 21, 2014

• common shares	983,626,639
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	27,916,418
• stock options exercisable	14,107,545

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 2013 Annual MD&A, the 2013 Consolidated Financial Statements and the 2013 Annual Information Form filed with Canadian securities regulatory authorities and the 2013 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, 2014 are compared to the results for the three months ended June 30, 2013 and the results for the six months ended June 30, 2014 are compared to the results for the six months ended June 30, 2013. Discussions with respect to Husky's financial position as at June 30, 2014 are compared to its financial position at December 31, 2013. 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 International Accounting Standard ("IAS") 34, "Interim Financial Reporting" as issued by the IASB.
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices 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, 2014 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 cash flow from operations, adjusted net earnings, operating netback, debt to capital employed, debt to cash flow, corporate reinvestment ratio, interest coverage on long-term debt and interest coverage on total debt. None of these measurements are used to enhance the Company's reported financial performance or position. These are useful complementary measurements in assessing Husky's financial performance, efficiency and liquidity. With the exception of adjusted net earnings and cash flow from operations, there are no comparable measures in accordance with IFRS. 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. Except as described below, the definitions of these measurements are found in Section 6.1.

Disclosure of Adjusted Net Earnings

The term "Adjusted Net Earnings" is a non-GAAP measure comprised of net earnings adjusted for certain items not considered 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.

The following table shows the reconciliation of net earnings to adjusted net earnings and related per share amounts for the three and six months ended June 30, 2014 and 2013:

(\$ millions)		Three months ended June 30,		Six months ended June 30,	
		2014	2013	2014	2013
GAAP	Net earnings	628	605	1,290	1,140
	Foreign exchange	(1)	(3)	(11)	3
	Financial instruments	8	12	59	11
	Stock-based compensation	47	(6)	53	1
	Inventory write downs	—	2	7	2
Non-GAAP	Adjusted net earnings	682	610	1,398	1,157
	Adjusted net earnings – basic	0.69	0.62	1.42	1.18
	Adjusted net earnings – diluted	0.69	0.62	1.42	1.18

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, 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 cash flow – operating activities to cash flow from operations and related per share amounts for the three and six months ended June 30, 2014 and 2013:

(\$ millions)		Three months ended June 30,		Six months ended June 30,	
		2014	2013	2014	2013
GAAP	Cash flow – operating activities	1,147	1,225	2,483	2,540
	Settlement of asset retirement obligations	23	20	72	63
	Income taxes paid	285	232	381	373
	Interest received	(3)	(5)	(6)	(8)
	Change in non-cash working capital	52	(23)	110	(236)
Non-GAAP	Cash flow from operations	1,504	1,449	3,040	2,732
	Cash flow from operations – basic	1.53	1.47	3.09	2.78
	Cash flow from operations – diluted	1.52	1.47	3.08	2.78

Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. 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.

Cautionary Note Required by National Instrument 51-101

The Company uses the term barrels of oil equivalent ("boe"), which is calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

Terms

Adjusted Net Earnings	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
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 including current portion 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
Corporate Reinvestment Ratio	Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations
Debt to Capital Employed	Long-term debt and long-term debt due within one year divided by capital employed
Debt to Cash Flow	Long-term debt and long-term debt due within one year divided by cash flow from operations
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
Front-End Engineering Design ("FEED")	Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics
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
Interest Coverage Ratio	A calculation of a company's ability to meet its interest payment obligation. It is equal to net earnings or cash flow – operating activities before finance expense and income taxes divided by finance expense and capitalized interest
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	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 and bank operating loans
Turnaround	Scheduled performance of plant or facility maintenance

Abbreviations

bbbls	barrels	mmbbls/day	thousand barrels per day
boe	barrels of oil equivalent	mboe	thousand barrels of oil equivalent
CHOPS	cold heavy oil production with sand	mboe/day	thousand barrels of oil equivalent per day
EDGAR	Electronic Data Gathering, Analysis and Retrieval (U.S.A.)	mcf	thousand cubic feet
FEED	Front-end engineering design	MD&A	Management's Discussion and Analysis
FIFO	first in first out	mmbbls	million barrels
FPSO	Floating production, storage and offloading vessel	mmbboe	million barrels of oil equivalent
FVTPL	fair value through profit or loss	mmbtu	million British Thermal Units
GAAP	Generally Accepted Accounting Principles	mmcf	million cubic feet
GJ	gigajoule	mmcf/day	million cubic feet per day
IAS	International Accounting Standard	NGL	natural gas liquids
IASB	International Accounting Standards Board	NYMEX	New York Mercantile Exchange
ICFR	Internal Controls over Financial Reporting	OCI	other comprehensive income
IFRIC	International Financial Reporting Interpretations Committee	SEDAR	System for Electronic Document Analysis and Retrieval
IFRS	International Financial Reporting Standards	WTI	West Texas Intermediate
mmbbls	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; and the Company’s 2014 production guidance, including weighting of production among product types;
- with respect to the Company’s Asia Pacific Region: expected timing of tie-in of the Company’s Lihua 34-2 field to the Liwan 3-1 field;
- with respect to the Company’s Atlantic Region: anticipated timing of a final investment decision with respect to the Company’s West White Rose Extension project; scheduled timing of installation of oil production equipment and anticipated timing of first production at the Company’s South White Rose Extension project; scheduled timing and duration of planned turnarounds of the Terra Nova FPSO and the SeaRose FPSO; planned drilling targets and timing of first production from the North Amethyst Hibernia formation well; and scheduled timing, duration and objectives for a drilling program at the Bay du Nord discovery;
- with respect to the Company’s Oil Sands properties: scheduled timing of start up at the Company’s Sunrise Energy Project;
- with respect to the Company’s Heavy Oil properties: expected timing of first production at the Company’s Rush Lake heavy oil thermal development project; and expected timing of first production at the Company’s Edam East, Edam West and Vawn heavy oil thermal and development projects;
- with respect to the Company’s Western Canadian oil and gas resource plays: expected timing of completion of an all-season road at the Company’s Slater River Canol shale play; anticipated timing of resumption of activity by the Company at the Slater River Canol shale play; and drilling and development plans at the Company’s Wilrich Kakwa play and Strachan area;
- with respect to the Company’s Infrastructure and Marketing operating segment: scheduled timing of completion of, and anticipated outcome of, plans to increase pipeline connectivity and re-configure the terminal facility at the Hardisty terminal and construct two 300,000 barrel tanks; and
- with respect to the Company’s Downstream operating segment: the anticipated benefits from and scheduled timing of completion of the Lima, Ohio refinery reconfiguration and the anticipated processing capacity of Western Canadian heavy oil once reconfiguration is complete; scheduled timing, duration and impact of a partial outage of the Lloydminster Upgrader for planned maintenance; and the anticipated benefits from and scheduled timing of completion of a Hydrotreater Recycle Gas Compressor Project at the BP-Husky Toledo 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, 2013 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe the 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.