MANAGEMENT'S DISCUSSION AND ANALYSIS

October 23, 2013

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1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Sept. 30**	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31
($ millions, except where indicated)	**2013**	2013	2013	2012	2012	2012	2012	2011
Production *(mboe/day)*	**308.5**	309.9	321.3	319.3	285.0	281.9	319.9	318.9
Gross revenues(1)	**6,036**	6,206	5,807	5,945	5,451	5,748	5,984	5,888
Net earnings	**512**	605	535	474	526	431	591	408
Per share – Basic	**0.52**	0.61	0.54	0.48	0.53	0.44	0.61	0.42
Per share – Diluted	**0.52**	0.59	0.54	0.48	0.53	0.43	0.60	0.42
Cash flow from operations(2)	**1,347**	1,449	1,283	1,414	1,271	1,153	1,172	1,197
Per share – Basic	**1.37**	1.47	1.31	1.44	1.29	1.18	1.21	1.25
Per share – Diluted	**1.37**	1.47	1.30	1.44	1.29	1.17	1.20	1.24

(1) *Gross revenues have been recast to reflect a change in presentation for trading activities. Refer to Note 3 of the 2012 Consolidated Financial Statements.*
(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 23.5 mboe/day to 308.5 mboe/day in the third quarter of 2013 compared to the third quarter of 2012 as a result of:
  - Increased crude oil production from heavy oil thermal projects in Western Canada;
  - Higher production in the Atlantic Region compared to the third quarter of 2012, which was impacted last year by the two major planned turnarounds of the SeaRose and Terra Nova floating, production, storage and offloading vessels ("FPSO");
  - Partially offset by decreased dry natural gas production due to natural reservoir declines and limited re-investment as capital is being directed to higher return oil and liquids-rich natural gas developments.
- Net earnings in the third quarter of 2013 were comparable to the third quarter of 2012:
  - Higher average commodity prices and a weaker Canadian dollar combined with higher crude oil production in the Atlantic Region and in Western Canada from heavy oil thermal projects were offset by;
  - Decreased Downstream margins resulting from significantly lower market crack spreads and a major turnaround initiated at the Company's Upgrading facility in the current quarter; and
  - Decreased Infrastructure and Marketing margins as Western Canadian location differentials continued to narrow.
- Cash flow from operations in the third quarter of 2013 were comparable to the third quarter of 2012.

Key Projects

- Husky Energy Inc. ("Husky" or "the Company") and its partner confirmed a significant discovery of light, sweet crude oil at the Bay du Nord prospect in the Flemish Pass Basin offshore East Coast Canada. The evaluation of well results to date have confirmed significant quantities of hydrocarbons with best estimate contingent resources estimated by Husky at 400 million barrels on a 100% working interest basis as at September 23, 2013. Husky also confirmed the Mizzen prospect, drilled in 2009, had best estimate contingent resources of 130 million barrels on a 100% working interest basis as at December 31, 2012. Husky holds a 35% working interest in both wells.
- The White Rose H-70 delineation well, which is part of a near-field drilling program northwest of the main White Rose field, was spud on August 19, 2013. Hydrocarbons were encountered and the evaluation of results is ongoing.
- Key milestones were met for the White Rose Extension Program including approval of the benefits agreement, release of the environmental impact assessment for further regulatory approval, and submission of the Development Plan Amendment.
- At the Liwan Gas Project in the South China Sea, the central platform, shallow water pipeline and onshore gas plant are mechanically complete with commissioning efforts ongoing. The project is more than 95% complete and remains on track with first production planned in the coming months.
- At the Sunrise Energy Project, work continues on the Central Processing Facility ("CPF") and field facilities with all module fabrication complete and major equipment installed. The project is on track at approximately 80% complete at the end of the third quarter with first production scheduled for the second half of 2014.
- At the 3,500 bbls/day Sandall heavy oil thermal development, construction is approximately 95% complete. The project is expected to be commissioned in the first quarter of 2014 with first production scheduled for the first half of 2014.
- At the Rush Lake thermal development, design and construction work continued and production performance from the two-well pair pilot is in line with expectations. Commissioning of the 10,000 bbls/day commercial project is expected in mid-2015.
- Resource play development progressed in Western Canada with 37 oil wells (gross) and two liquids-rich natural gas wells (gross) drilled and 19 oil wells (gross) and two liquids-rich natural gas wells (gross) completed.

Financial

- Dividends on common shares of $295 million for the second quarter of 2013 were declared during the third quarter of 2013, of which $292 million and $3 million were paid in cash and common shares, respectively, on October 1, 2013.

2. Business Environment

Average Benchmarks		Three months ended Sept. 30, 2013	Jun. 30, 2013	Mar. 31, 2013	Dec. 31, 2012	Sept. 30, 2012
WTI crude oil[(1)]	*(U.S. $/bbl)*	**105.83**	94.22	94.37	88.18	92.22
Brent crude oil[(2)]	*(U.S. $/bbl)*	**108.21**	102.52	112.55	110.00	109.48
Canadian light crude 0.3% sulphur	*($/bbl)*	**104.91**	93.78	88.42	84.43	84.89
Western Canadian Select[(3)]	*(U.S. $/bbl)*	**88.35**	75.06	62.41	70.07	70.49
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**86.26**	67.24	46.44	59.55	61.91
NYMEX natural gas[(4)]	*(U.S. $/mmbtu)*	**3.58**	4.09	3.34	3.40	2.81
NIT natural gas	*($/GJ)*	**2.67**	3.40	2.92	2.90	2.08
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**17.50**	19.21	32.18	18.29	21.94
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**17.32**	22.49	30.61	35.06	34.77
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**15.86**	30.78	26.87	28.00	35.18
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.963**	0.977	0.991	1.009	1.005
Canadian $ Equivalents						
WTI crude oil[(5)]	*($/bbl)*	**109.90**	96.44	95.23	87.39	91.76
Brent crude oil[(5)]	*($/bbl)*	**112.37**	104.93	113.57	109.02	108.94
WTI/Lloyd crude blend differential[(5)]	*($/bbl)*	**18.17**	19.66	32.47	18.13	21.83
NYMEX natural gas[(5)]	*($/mmbtu)*	**3.72**	4.19	3.37	3.37	2.79

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

The price the Company receives for production from Western Canada is primarily driven by the price of 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. $105.83/bbl in the third quarter of 2013 compared to U.S. $92.22/bbl in the third quarter of 2012. The price of WTI averaged U.S. $98.14/bbl in the first nine months of 2013 compared to U.S. $96.21/bbl in the first nine months of 2012. The price of Brent averaged U.S. $108.21/bbl in the third quarter of 2013 compared to U.S. $109.48/bbl in the third quarter of 2012. The price of Brent averaged U.S. $107.76/bbl in the first nine months of 2013 compared to U.S. $113.89/bbl in the first nine months of 2012.

Canadian crude oil prices in the third quarter of 2013 and in the first nine months of 2013 benefited from the weakening of the Canadian dollar against the U.S. dollar when compared to the same periods in 2012. In the third quarter of 2013, the price of WTI in U.S. dollars increased 15% compared to an increase of 20% in Canadian dollars and in the first nine months of 2013, the price of WTI in U.S. dollars increased 2% compared to an increase of 4% in Canadian dollars when compared to the same periods in 2012.

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. $17.50/bbl or 17% of WTI in the third quarter of 2013 compared to U.S. $21.94/bbl or 24% of WTI in the third quarter of 2012. The light/heavy crude oil differential averaged U.S. $22.95/bbl or 23% of WTI in the first nine months of 2013 compared to $22.51/bbl or 23% of WTI in the first nine months of 2012.

During the third quarter of 2013, the NYMEX near-month contract price of natural gas averaged U.S. $3.58/mmbtu compared to U.S. $2.81/mmbtu in the third quarter of 2012, an increase of 27%. During the first nine months of 2013, the NYMEX near-month contract price of natural gas averaged U.S. $3.67/mmbtu compared to U.S. $2.59/mmbtu during the first nine months of 2012, an increase of 42%.

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.

In the third quarter of 2013, the Canadian dollar averaged U.S. $0.963, weakening by 4% compared to U.S. $1.005 during the third quarter of 2012. In the first nine months of 2013, the Canadian dollar averaged U.S. $0.977, weakening by 2% compared to U.S. $0.998 during the first nine months of 2012.

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 third quarter of 2013, the Chicago 3:2:1 crack spread averaged U.S. $15.86/bbl compared to U.S. $35.18/bbl in the third quarter of 2012. In the first nine months of 2013, the Chicago 3:2:1 crack spread averaged U.S. $24.45/bbl compared to U.S. $27.50/bbl in the first nine months of 2012. During the third quarter of 2013, the New York Harbour 3:2:1 crack spread averaged U.S. $17.32/bbl compared to U.S. $34.77/bbl in the third quarter of 2012. In the first nine months of 2013, the New York Harbour 3:2:1 crack spread averaged U.S. $23.32/bbl compared to U.S. $27.77/bbl in the first nine months of 2012.

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 relative annualized effect on earnings before income taxes and net earnings from changes in certain key variables in the third quarter of 2013. The table below reflects what the effect would have been on the financial results for the third quarter of 2013 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the third quarter of 2013. 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	2013 Third Quarter Average	Increase	Effect on Earnings before Income Taxes[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	105.83	*U.S. $1.00/bbl*	75	0.08	56	0.06
NYMEX benchmark natural gas price[5]	3.58	*U.S. $0.20/mmbtu*	23	0.02	17	0.02
WTI/Lloyd crude blend differential[6]	17.50	*U.S. $1.00/bbl*	(34)	(0.03)	(25)	(0.03)
Canadian light oil margins	0.039	*Cdn $0.005/litre*	15	0.02	11	0.01
Asphalt margins	11.70	*Cdn $1.00/bbl*	14	0.01	10	0.01
New York Harbour 3:2:1 crack spread	17.32	*U.S. $1.00/bbl*	48	0.05	30	0.03
Exchange rate (U.S. $ per Cdn $)[3][7]	0.963	*U.S. $0.01*	(79)	(0.08)	(58)	(0.06)

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 983.3 million common shares outstanding as of September 30, 2013.*
(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 Greenland, offshore China, offshore Indonesia and offshore Taiwan.

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 2013 Capital Program builds on the momentum achieved over the past two years with respect to repositioning the Heavy Oil and Western Canada foundation by accelerating near-term production growth and advancing Husky's three major growth pillars in the Asia Pacific Region, the Oil Sands and in the Atlantic Region.

4.1 Upstream

Western Canada (Excluding Heavy Oil and Oil Sands)

Oil Resource Plays

In the third quarter of 2013, a total of 37 wells (gross) were drilled and 19 wells (gross) were completed across the oil resource project portfolio.

Oil Resource Plays - Drilling and Completion Activity[1][2]		Three months ended Sept. 30, 2013		Nine months ended Sept. 30, 2013	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	5	3	11	8
Lower Shaunavon	S.W. Saskatchewan	3	5	7	6
Viking[3]	Alberta and S.W. Saskatchewan	24	10	52	34
N.Cardium	Wapiti, Alberta	5	1	9	5
Muskwa	Rainbow, Northern Alberta	—	—	6	2
Canol Shale	Northwest Territories	—	—	—	2
Total Gross		37	19	85	57
Total Net		34	19	81	56

[1] Excludes service/stratigraphic test wells for evaluation purposes.
[2] Drilling activity includes operated and non-operated wells.
[3] Viking is comprised of project activity at Redwater in central Alberta, Alliance in southeast Alberta and drilling in southwest Saskatchewan.

In the Northwest Territories, the Slater River Canol Shale play all-season road construction is substantially complete and approval was received from the Sahtu Land and Water Board for the summer 2014 two vertical well program with authorization pending from the National Energy Board.

Liquids-Rich Natural Gas Resource Plays

In the third quarter of 2013, a total of two wells (gross) were drilled and two wells (gross) were completed in key plays across the liquids-rich natural gas resource portfolio.

Liquids-Rich Natural Gas Plays - Drilling and Completion Activity[1]		Three months ended Sept. 30, 2013		Nine months ended Sept. 30, 2013	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	2	2	15	20
Duvernay	Kaybob, Alberta	—	—	4	—
Total Gross		2	2	19	20
Total Net		2	2	18	19

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

In the third quarter of 2013, one liquids-rich horizontal natural gas well was drilled and one horizontal and one vertical well were completed at the Ansell Multi-Zone play. A four-rig well drilling program commenced during the quarter.

Completion activities commenced on the first four-well pad at Kaybob in the Duvernay play during the third quarter of 2013 and have continued into the fourth quarter with production anticipated early 2014. Drilling of two additional wells on a second well pad commenced in the third quarter.

Conventional Oil and Gas

During the third quarter of 2013, 71 wells (gross) were drilled and 63 wells (gross) were completed in the conventional oil and gas portfolio.

Heavy Oil

Construction is approximately 95% complete at the 3,500 bbls/day Sandall thermal development project. The project is expected to be commissioned in the first quarter of 2014 with first production scheduled for the first half of 2014.

Design and construction work continued at the 10,000 bbls/day Rush Lake commercial project with commissioning expected in mid-2015. Production performance from the two-well pair pilot is in line with expectations.

Forty-five horizontal heavy oil wells were drilled during the third quarter of 2013. Ninety-one horizontal wells have been drilled to date, out of the 140 well program for 2013.

Ninety-three Cold Heavy Oil Production with Sand ("CHOPS") wells were drilled during the third quarter of 2013. One hundred fifty-two CHOPS wells have been drilled to date, out of the 200 well program for 2013.

Asia Pacific Region

China

Block 29/26

The Liwan Gas Project development on Block 29/26 in the South China Sea is more than 95% complete and remains on track to achieve planned first production in the coming months.

Five major construction vessels and their support vessels are in operation and construction continues on the deep water facilities to connect the wells and the pipeline to the shallow water platform. All three production manifolds have been installed and the connecting infield production flow lines have been laid. Jumper and tie-in spools to connect the individual wells to the manifolds and the manifolds to the connecting infield production flow lines are currently being installed. The first of two pipelines from the deep water fields to the shallow water central platform has been cleaned and gauged and is being prepared for connection to the central platform. The platform has been declared mechanically complete and commissioning efforts are ongoing. The 261 kilometers of shallow water pipeline from the central platform to the gas plant is mechanically complete. The onshore gas plant has been declared mechanically complete and will now undergo testing and commissioning processes.

The single development well of the Liuhua 34-2 field is expected to be tied into the Liwan 3-1 field deep water facilities in mid-2014 with production expected to commence in late 2014.

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

Offshore Taiwan
The acquisition of a two-dimensional ("2-D") seismic survey on the Company's offshore Taiwan block commenced in September 2013.

Indonesia
Progress continued on the shallow water gas developments in the Madura Strait Block during the third quarter of 2013. The last outstanding BD field tender for the FPSO is under final review by Indonesia's regulatory authority. In addition, the tender plans for the combined MDA and MBH development projects are under review by Indonesia's regulatory authority for approval.

Oil Sands

Sunrise Energy Project
Phase 1 of the Sunrise Energy Project is approximately 80% complete and remains on track for first production in the second half of 2014.

The CPF is approximately 70% complete with all module fabrication complete and major equipment installed. Field tank construction in plant 1A is underway and on target for completion in the fourth quarter of 2013. The main power line work is complete and medium voltage cable pulling is progressing. Installation of the operations control center building is now complete with internal work expected to be wrapped up in early 2014. Field facilities are nearing completion and pre-winter work has advanced in the third quarter of 2013. The first two well pads have been turned over and commissioning activities are in progress with the remaining well pads targeted to be completed by the end of 2013. To date, 80% of the project's total cost estimate has been spent.

A Design Basis Memorandum has been completed for the next phase of the Sunrise Energy Project. Project development continues toward the Front End Engineering Design ("FEED") phase.

McMullen
During the third quarter of 2013, seventeen wells were drilled and nine wells were completed at the conventional portion of the Company's McMullen play with CHOPS production from the first well pad expected by the end of 2013. Completions on the second well pad commenced in the third quarter of 2013 and are expected to be finished in the fourth quarter of 2013. At the air injection pilot, three additional horizontal production wells were tied-in and approval was received from the Alberta Energy Regulator to allow the horizontal wells to be brought on to production.

Atlantic Region

White Rose Field and Satellite Extensions
A number of key milestones were met for the West White Rose Extension project including approval of the benefits agreement by the Government of Newfoundland and Labrador, release of the environmental impact assessment for further federal and provincial approval, and submission of the Development Plan Amendment to the Canada-Newfoundland and Labrador Offshore Petroleum Board. Husky and its partners progressed detailed engineering and design and due diligence in anticipation of a final investment decision.

Installation of gas injection equipment commenced to support the South White Rose Extension and is expected to be completed in the fourth quarter of 2013. The project is being developed in two phases with the installation of gas injection equipment in 2013 and oil production equipment in 2014 with first oil anticipated by the end of 2014.

The North Amethyst G-25-8 water injection well was completed and brought online in August 2013 bringing the total number of producing wells at the field to eight, including four production wells and four water injection wells. Drilling is currently underway on the G-25-9 multilateral production well.

Atlantic Exploration
Husky and its partner have confirmed a third discovery of a high-quality, light, sweet crude oil resource on the Bay du Nord prospect in the Flemish Pass Basin approximately 500 kilometres offshore Newfoundland. The evaluation of well results to date have confirmed significant quantities of hydrocarbons with best estimate contingent resources estimated by Husky at 400 million barrels on a 100% working interest basis as at September 23, 2013. Husky and its partner plan to perform further delineation work to assess the potential for additional resources at the prospect. The Bay du Nord prospect is south of the Mizzen discovery and west of the Harpoon discovery made in the second quarter of 2013. In addition, the evaluation of well results at the Harpoon discovery is ongoing with further appraisal drilling required to assess the potential of the prospect. The 2009 Mizzen discovery of slightly heavier oil had best estimate contingent resources estimated by Husky at 130 million barrels on a 100% working interest basis as at December 31, 2012. Husky holds a 35% working interest in all three wells.

The Husky-operated White Rose H-70 delineation well, which is part of a near-field drilling program northwest of the main White Rose field, was spud on August 19, 2013. Hydrocarbons were encountered and the evaluation of results is ongoing.

The non-operated Federation well in the southern Jeanne d'Arc Basin was drilled in the third quarter of 2013. The well did not encounter commercial quantities of hydrocarbons and was expensed in the quarter. Husky holds a 35% working interest in the well.

4.2 Downstream

Lima, Ohio Refinery

As part of an initiative to improve feedstock flexibility, FEED commenced in the third quarter of 2013 to revamp existing refinery process units and add new equipment to allow the refinery to process up to 40,000 bbls/day of Western Canadian heavy oil by 2017 while maintaining the capability to refine existing light crude oil. An environmental permit for the project is anticipated to be approved by the Ohio Environmental Protection Agency in the fourth quarter of 2013.

BP-Husky Toledo, Ohio Refinery

Work progressed on the Hydrotreater Recycle Gas Compressor Project during the third quarter of 2013 and is scheduled to be completed in 2014. The installation of a new recycle gas compressor in the existing hydrotreater is intended to improve operational integrity and plant performance.

5. Results of Operations

5.1 Upstream

Total Third Quarter Upstream Earnings 2013 - $460 million, 2012 - $211 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 were higher in the third quarter of 2013 compared to the same period in 2012 due to an increase in realized commodity prices and higher crude oil production. Realized prices in Western Canada reflect narrower location differentials to WTI benchmark prices, which drove improved Exploration and Production results, partially offset by a decrease in margins in Infrastructure and Marketing. The shift in earnings between the two operations reflects the Company's integration strategy and the ability to capture differentials as they move along the value chain.

Exploration and Production

Exploration and Production Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2013**	2012	**2013**	2012
Gross revenues	**2,111**	1,430	**5,599**	4,783
Royalties	**(237)**	(145)	**(649)**	(504)
Net revenues	**1,874**	1,285	**4,950**	4,279
Purchases, operating, transportation and administrative expenses	**605**	516	**1,772**	1,542
Depletion, depreciation and amortization	**594**	515	**1,724**	1,507
Exploration and evaluation expenses	**56**	59	**218**	187
Other expenses	**39**	44	**112**	21
Income taxes	**150**	41	**290**	267
Net earnings	**430**	110	**834**	755

Third Quarter

Exploration and Production net earnings in the third quarter of 2013 increased by $320 million compared with the third quarter of 2012 primarily due to stronger realized commodity prices combined with higher production from the Atlantic Region and Western Canada heavy oil thermal projects, partially offset by increased operating costs and higher depletion, depreciation and amortization resulting from increased production and a higher capital base.

Production increased by 23.5 mboe/day in the third quarter of 2013 compared to the same period in 2012 as a result of higher production from the Atlantic Region, where the Company had two major planned turnarounds ongoing in the prior year, and increased production in Western Canada at the Pikes Peak South and Paradise Hill heavy oil thermal projects. Natural gas production in mature fields decreased in the third quarter of 2013 compared to the same period in 2012 due to natural reservoir declines as capital investment is being directed to higher return oil and liquids-rich natural gas developments.

The average realized price for crude oil, NGL and bitumen in the third quarter of 2013 was $93.23/bbl compared to $70.14/bbl during the same period in 2012, an increase of 33%, due to higher WTI crude oil market prices combined with improved Western Canada crude oil differentials. Realized natural gas prices averaged $2.66/mcf in the third quarter of 2013 compared with $2.48/mcf in the same period in 2012, an increase of 7%.

Nine Months

Exploration and Production net earnings in the first nine months of 2013 increased by $79 million compared to the same period in 2012 primarily due to the same factors impacting the third quarter. During the first nine months of 2013, average realized prices for crude oil, NGL and bitumen increased by 4% to $79.80/bbl compared with $76.80/bbl during the same period in 2012. Average realized natural gas prices were $3.15/mcf during the first nine months of 2013 compared with $2.39/mcf in the same period in 2012, an increase of 32%.

Average Sales Prices Realized	Three months ended Sept. 30, 2013	2012	Nine months ended Sept. 30, 2013	2012
Crude oil and NGL *($/bbl)*				
Light crude oil & NGL	**107.83**	90.50	**102.48**	101.06
Medium crude oil	**93.67**	69.59	**76.50**	72.78
Heavy crude oil	**84.45**	60.58	**65.83**	63.24
Bitumen	**83.17**	60.10	**64.17**	61.30
Total average	**93.23**	70.14	**79.80**	76.80
Natural gas average *($/mcf)*	**2.66**	2.48	**3.15**	2.39
Total average *($/boe)*	**72.13**	52.52	**63.09**	56.93

The price realized for Western Canada crude oil in the third quarter of 2013 reflects the narrowing of Western Canada light and heavy crude oil and bitumen differentials. The premium to WTI realized for offshore production reflects Brent prices.

Daily Gross Production	Three months ended Sept. 30, 2013	2012	Nine months ended Sept. 30, 2013	2012
Crude oil and NGL *(mbbls/day)*				
Western Canada				
Light crude oil & NGL	**29.2**	29.0	**29.5**	29.6
Medium crude oil	**23.2**	23.9	**23.1**	24.3
Heavy crude oil	**75.3**	77.1	**74.0**	77.1
Bitumen[(1)]	**48.0**	37.8	**48.0**	32.3
	175.7	167.8	**174.6**	163.3
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**34.5**	18.5	**39.3**	26.1
Terra Nova – light crude oil	**7.2**	—	**5.9**	3.8
	41.7	18.5	**45.2**	29.9
China				
Wenchang – light crude oil & NGL	**6.8**	7.9	**7.4**	8.3
	224.2	194.2	**227.2**	201.5
Natural gas *(mmcf/day)*	**505.5**	544.9	**515.8**	564.4
Total *(mboe/day)*	**308.5**	285.0	**313.2**	295.6

(1) Bitumen production includes heavy oil thermal average daily gross production of 38.8 boe/day and 38.0 boe/day for the three and nine months ended September 30, 2013, respectively. Heavy oil thermal production typically receives a higher price than bitumen production.

Crude Oil and NGL Production

Third Quarter

Crude oil and NGL production in the third quarter of 2013 increased by 30.0 mbbls/day or 15% compared with the same period in 2012 due to increased production in Western Canada at the Pikes Peak South and Paradise Hill heavy oil thermal projects combined with higher production in the Atlantic Region, where the SeaRose and Terra Nova FPSO planned turnarounds were ongoing in the third quarter of 2012, partially offset by lower production at maturing fields due to natural reservoir declines.

Nine Months

In the first nine months of 2013, crude oil and NGL production increased by 13% compared to the same period in 2012 primarily due to the same factors impacting the third quarter.

Natural Gas Production

Third Quarter

Natural gas production in the third quarter of 2013 decreased by 39.4 mmcf/day or 7% compared to the same period in 2012 due to natural reservoir declines in mature properties as capital investment is being directed to higher return oil and liquids-rich natural gas developments.

Nine Months

In the first nine months of 2013, natural gas production decreased 9% compared to the same period in 2012 primarily due to the same factors impacting the third quarter.

2013 Production Guidance

The following table shows actual daily production for the nine months ended September 30, 2013 and the year ended December 31, 2012, as well as the previously issued production guidance for 2013.

		Actual Production	
	2013 Guidance	Nine months ended September 30, 2013	Year ended December 31, 2012
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	85 – 90	82	72
Medium crude oil	25 – 30	23	24
Heavy crude oil & bitumen	110 – 120	122	113
	220 – 240	227	209
Natural gas *(mmcf/day)*	540 – 580	516	554
Total *(mboe/day)*	310 – 330	313	302

Royalties

Third Quarter

In the third quarter of 2013, royalty rates as a percentage of gross revenues averaged 12% compared to 11% in the same period in 2012. Royalty rates in Western Canada averaged 11% in the third quarter of 2013 compared to 10% in the same period of 2012. Royalty rates for the Atlantic Region averaged 12% in the third quarter of 2013 compared to 8% in the same period in 2012 when low rates reflected the ongoing planned SeaRose and Terra Nova FPSO turnarounds. Royalty rates in the Asia Pacific Region averaged 24% in the third quarter of 2013 compared to 23% in the same period in 2012.

Nine Months

In the first nine months of 2013, royalty rates as a percentage of gross revenues averaged 12% compared to 11% in the same period in 2012. Royalty rates in Western Canada averaged 11% in the first nine months of 2013 compared to 10% in the same period in 2012 due to a royalty credit adjustment received during the second quarter of 2012. Royalty rates for the Atlantic Region averaged 13% in the first nine months of 2013 compared to 11% in the same period in 2012 due to the same factors impacting the third quarter. Royalty rates in the Asia Pacific Region averaged 25% in the first nine months of 2013 compared to 24% in the same period in 2012.

Operating Costs

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	2013	2012	2013	2012
Western Canada	456	378	1,317	1,126
Atlantic Region	51	57	144	167
Asia Pacific	8	6	21	21
Total	515	441	1,482	1,314
Unit operating costs *($/boe)*	17.20	16.69	16.27	15.65

Third Quarter

Total Exploration and Production operating costs increased by $74 million in the third quarter of 2013 compared to the same period in 2012 primarily due to increased crude oil production in Western Canada. Total operating costs averaged $17.20/boe in the third quarter of 2013 compared to $16.69/boe in the same period in 2012 primarily due to higher energy consumption and increased natural gas and electricity prices associated with Western Canada thermal crude oil production.

Operating costs in Western Canada averaged $17.98/boe in the third quarter of 2013 compared to $16.40/boe in the same period in 2012 primarily due to increased electricity, licensing, taxes, maintenance and environmental costs combined with higher natural gas prices and energy consumption associated with thermal production, partially offset by lower treating and servicing costs.

Operating costs in the Atlantic Region averaged $13.31/boe in the third quarter of 2013 compared to $33.36/boe in the same period in 2012. The decrease in operating costs was attributable to higher production and lower maintenance and supply costs compared to the same period in 2012 when the planned SeaRose and Terra Nova FPSOs turnarounds were underway.

Operating costs in the Asia Pacific Region averaged $12.72/boe in the third quarter of 2013 compared to $9.10/boe in the same period in 2012. The increase was due to higher costs for health, safety and environment, maintenance and support combined with lower production associated with typhoon-related shut-ins compared to the same period in 2012.

Nine Months

Total Exploration and Production operating costs in the first nine months of 2013 were $1,482 million compared to $1,314 million in the same period in 2012. Operating costs in the first nine months of 2013 compared to the same period in 2012 averaged $17.22/boe and $16.10/boe, respectively, in Western Canada, $11.64/boe and $20.42/boe, respectively, in the Atlantic Region, and $10.64/boe and $9.42/boe, respectively, in the Asia Pacific Region. Operating costs in the first nine months of 2013 were primarily impacted by the same factors affecting the third quarter of 2013.

Exploration and Evaluation Expenses

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2013**	2012	**2013**	2012
Seismic, geological and geophysical	**25**	34	**102**	112
Expensed drilling	**28**	21	**107**	62
Expensed land	**3**	4	**9**	13
Exploration and evaluation expenses	**56**	59	**218**	187

Third Quarter

Exploration and evaluation expenses in the third quarter of 2013 were $56 million compared to $59 million in the third quarter of 2012. The decrease in seismic, geological and geophysical expenses was due to reduced exploration activity on the Madura Strait block in the third quarter of 2013 compared to the same period in 2012. Expensed drilling includes costs associated with the Federation well in the Atlantic Region which did not encounter commercial quantities of hydrocarbons.

Nine Months

Exploration and evaluation expenses for the first nine months of 2013 were $218 million compared to $187 million in the same period of 2012 primarily due to the same factors impacting the third quarter, as well as costs related to the winter program at the Slater River Canol Shale play where the Company completed drilling and testing of two vertical wells and completed the baseline groundwater study in the first quarter of 2013.

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

Third Quarter

In the third quarter of 2013, total DD&A averaged $20.93/boe compared to $19.64/boe in the third quarter of 2012 as the Company continues to shift focus to investments in oil and liquids-rich natural gas properties with offsetting higher netbacks.

Nine Months

For the first nine months of 2013, total DD&A averaged $20.16/boe compared to $18.61/boe during the same period in 2012 due to the same factors impacting the third quarter.

Exploration and Production Capital Expenditures

In the first nine months of 2013, Upstream Exploration and Production capital expenditures were $2,984 million. Capital expenditures were $1,569 million (53%) in Western Canada including Heavy Oil, $441 million (15%) in Oil Sands, $549 million (18%) in the Atlantic Region and $425 million (14%) in the Asia Pacific Region. Husky's major projects remain on budget and on schedule.

Exploration and Production Capital Expenditures	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)[(1)]	**2013**	2012	**2013**	2012
Exploration				
Western Canada	**99**	43	**273**	159
Atlantic Region	**102**	35	**146**	41
Asia Pacific Region	**1**	17	**7**	17
	202	95	**426**	217
Development				
Western Canada	**505**	497	**1,285**	1,367
Oil Sands	**146**	152	**441**	438
Atlantic Region	**148**	150	**403**	309
Asia Pacific Region	**133**	175	**418**	512
	932	974	**2,547**	2,626
Acquisitions				
Western Canada	**1**	16	**11**	21
	1,135	1,085	**2,984**	2,864

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

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:

	Three months ended Sept. 30,				Nine months ended Sept. 30,			
Wells Drilled	**2013**		2012		**2013**		2012	
(wells)[(1)]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration								
Oil	**11**	**8**	2	1	**28**	**17**	32	22
Gas	**1**	**—**	4	2	**12**	**9**	15	12
Dry	**—**	**—**	—	—	**—**	**—**	—	—
	12	**8**	6	3	**40**	**26**	47	34
Development								
Oil	**269**	**249**	267	245	**551**	**508**	542	498
Gas	**15**	**12**	2	1	**53**	**29**	15	11
Dry	**—**	**—**	—	—	**1**	**—**	2	1
	284	**261**	269	246	**605**	**537**	559	510
Total	**296**	**269**	275	249	**645**	**563**	606	544

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

The Company drilled 563 net wells in the Western Canada, Heavy Oil and Oil Sands business units in the first nine months of 2013 consisting of 525 net oil wells and 38 net natural gas wells compared to 544 net wells in the same period of 2012 consisting of 520 net oil wells and 23 net natural gas wells.

During the first nine months of 2013, Husky invested $1,569 million in exploration, development and acquisitions, including heavy oil, throughout the Western Canada Sedimentary Basin compared to $1,547 million in the same period in 2012. Property acquisitions totalling $11 million were completed in the first nine months of 2013 compared to acquisitions of $21 million in the same period in 2012. Investment in oil related exploration and development was $404 million in the first nine months of 2013 compared to $388 million in the same period in 2012. Investment in natural gas related exploration and development, primarily liquids-rich, was $381 million in the first nine months of 2013 compared to $335 million in the same period in 2012.

In addition, $165 million was spent on production optimization and cost reduction initiatives and $234 million was spent on facilities, land acquisition and retention and environmental protection in the first nine months of 2013.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling were $374 million in the first nine months of 2013 compared to $401 million in the same period in 2012.

Oil Sands

During the first nine months of 2013, $441 million was invested in Oil Sands projects primarily for Phase 1 of the Sunrise Energy Project. In addition, the Company drilled 34 gross (17 net) evaluation wells for the next phase of the Sunrise Energy Project.

Atlantic Region

During the first nine months of 2013, $549 million was invested in Atlantic Region projects primarily on the continued development of the White Rose Extension projects, including the North Amethyst and South White Rose Extension satellite fields. In addition, the Company and its partner advanced the delineation of resources at the Bay Du Nord and Harpoon discoveries made during the year.

Asia Pacific Region

During the first nine months of 2013, $425 million was invested in Asia Pacific Region projects primarily for the continued development of the Liwan Gas Project.

Turnarounds

A planned maintenance turnaround was completed on the SeaRose FPSO during the third quarter of 2013. The six-day shutdown focused on annual regulatory inspections and maintenance, and tie-in of equipment for the South White Rose Extension.

An 11-week turnaround of the Terra Nova FPSO commenced on September 25, 2013. The planned maintenance shutdown has been extended to accommodate repair and replacement of nine mooring chains. The anticipated impact to Husky's production for the fourth quarter is forecasted to be approximately 5,500 bbls/day and together with the outages earlier in the year, the cumulative annual production impact is forecasted to be approximately 2,100 bbls/day.

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.

Infrastructure and Marketing Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Infrastructure gross margin	**37**	42	**111**	107
Marketing and other gross margin	**17**	120	**236**	311
Gross margin	**54**	162	**347**	418
Operating and administrative expenses	**7**	21	**28**	57
Depletion, depreciation and amortization	**6**	5	**18**	16
Other expenses (income)	**—**	—	**(1)**	—
Income taxes	**11**	35	**77**	88
Net earnings	**30**	101	**225**	257
Commodity trading volumes managed *(mboe/day)*	**165.8**	164.9	**171.2**	174.1

Third Quarter

Infrastructure and Marketing net earnings in the third quarter of 2013 decreased by $71 million compared to the same period in 2012 primarily due to lower marketing margins as a result of the narrowing of Western Canadian crude oil price differentials and fewer arbitrage opportunities available from utilizing the Company's access to infrastructure to move crude oil from Canada to the United States. The decrease in net earnings was partially offset by lower operating and administrative expenses due to lower processing facility costs and by higher realized prices in the Exploration and Production operations in the third quarter of 2013 when compared to the same period in 2012.

Nine Months

Infrastructure and Marketing net earnings in the first nine months of 2013 decreased by $32 million compared to the same period in 2012 as a result of the same factors which impacted the third quarter of 2013.

In the first nine months of 2013, Infrastructure and Marketing capital expenditures totalled $55 million and were primarily related to pipeline expenditures.

5.2 Downstream

Total Third Quarter Downstream Earnings 2013 - $89 million, 2012 - $366 million

Total Downstream net earnings include results from the Upgrader, Canadian Refined Products and U.S. Refining and Marketing. Net earnings on a combined basis reflect lower Upgrading net earnings due to a major planned turnaround initiated in the third quarter and decreased net earnings in U.S. Refining and Marketing where realized margins were impacted by significantly reduced market crack spreads. In addition, net earnings in Canadian Refined Products decreased due to lower realized asphalt and refining margins due to higher priced heavy oil feedstock.

Upgrader

Upgrader Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gross revenues	**437**	576	**1,539**	1,629
Gross margin	**96**	153	**523**	410
Operating and administrative expenses	**40**	33	**121**	112
Depreciation and amortization	**24**	25	**71**	75
Other expenses	**—**	3	**2**	9
Income taxes	**8**	24	**85**	56
Net earnings	**24**	68	**244**	158
Upgrader throughput *(mbbls/day)*[1]	**51.3**	81.6	**66.3**	76.2
Synthetic crude oil sales *(mbbls/day)*	**37.5**	64.1	**50.0**	59.4
Upgrading differential *($/bbl)*	**23.59**	22.04	**29.85**	21.69
Unit margin *($/bbl)*	**27.83**	25.94	**38.32**	25.28
Unit operating cost *($/bbl)*[2]	**8.48**	4.40	**6.69**	5.29

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

Third 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 in the third quarter of 2013 were $24 million compared to $68 million in the same period in 2012. The decrease was primarily due to lower throughput and synthetic crude oil sale volumes compared to the same period in 2012 resulting from a major planned turnaround initiated in the third quarter, partially offset by higher realized synthetic crude oil prices. The Upgrader returned to normal operations in mid-October after successful completion of the turnaround.

During the third quarter of 2013, the upgrading differential averaged $23.59/bbl, an increase of $1.55/bbl or 7%, compared to the same period in 2012. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The increase in the upgrading differential was attributable to higher realized synthetic crude oil prices in the third quarter of 2013 compared to the same period in 2012 partially offset by higher Lloyd Heavy Blend costs as Western Canada location differentials have narrowed. The average price for Husky Synthetic Blend in the third quarter of 2013 was $113.86/bbl compared to $90.00/bbl in the same period in 2012. The overall unit margin increased to $27.83/bbl in the third quarter of 2013 from $25.94/bbl in the same period in 2012.

Nine Months

Upgrading net earnings for the first nine months of 2013 increased by $86 million compared to the same period in 2012. The increase was due to higher upgrading differentials primarily driven by a deep discount on Lloyd Heavy Blend feedstock in the first quarter of 2013 and higher realized prices for Husky Synthetic Blend feedstock in the second and third quarters of 2013 when compared to the same periods in 2012, partially offset by the major turnaround during the third quarter of 2013.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gross revenues	**993**	1,067	**2,449**	2,915
Gross margin				
Fuel	**32**	41	**106**	117
Refining	**28**	53	**121**	135
Asphalt	**42**	109	**175**	209
Ancillary	**16**	15	**42**	40
	118	218	**444**	501
Operating and administrative expenses	**66**	59	**188**	178
Depreciation and amortization	**23**	21	**67**	62
Other expenses (income)	**(2)**	—	**(2)**	3
Income taxes	**8**	35	**49**	66
Net earnings	**23**	103	**142**	192
Number of fuel outlets[(1)]	**507**	515	**511**	538
Refined products sales volume				
Light oil products *(millions of litres/day)*	**8.3**	9.9	**8.2**	9.4
Light oil products per outlet *(thousands of litres/day)*	**16.4**	19.2	**16.0**	18.3
Asphalt products *(mbbls/day)*	**39.4**	34.0	**28.1**	26.9
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**11.8**	11.3	**9.7**	11.0
Lloydminster Refinery *(mbbls/day)*	**28.7**	28.7	**25.4**	28.3
Ethanol production *(thousands of litres/day)*	**713.0**	683.0	**731.0**	711.0

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

Third Quarter

Lower fuel margins in the third quarter of 2013 compared to the same period in 2012 were primarily due to decreased diesel margins and lower sales volumes resulting from retail site construction and selected outlet closures.

Lower refining gross margins in the third quarter of 2013 compared to the same period in 2012 were a result of higher cost feedstock at the Prince George Refinery, partially offset by higher throughput and higher realized product prices.

Asphalt gross margins were lower in the third quarter of 2013 compared to the same period in 2012 due to higher heavy oil feedstock costs as a result of the tightening of heavy to light crude oil differentials, partially offset by higher sales volumes.

Nine Months

During the first nine months of 2013, refined products earnings were lower when compared to the same period in 2012 primarily due to the same factors which impacted the third quarter.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gross revenues	**2,405**	2,477	**8,038**	7,626
Gross refining margin	**231**	456	**1,035**	1,004
Operating and administrative expenses	**109**	95	**322**	293
Depreciation and amortization	**58**	52	**173**	155
Other expenses	**—**	1	**2**	4
Income taxes	**22**	113	**188**	202
Net earnings	**42**	195	**350**	350
Selected operating data:				
Lima Refinery throughput *(mbbls/day)*	**148.8**	153.9	**148.6**	148.0
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**59.1**	52.7	**64.4**	61.5
Refining margin *(U.S. $/bbl crude throughput)*	**11.86**	24.36	**17.57**	17.86
Refinery inventory *(mmbbls)*[1]	**11.3**	10.1	**11.3**	10.1

[1] *Included in refinery inventory is feedstock and refined products.*

Third Quarter

U.S. Refining and Marketing net earnings decreased in the third quarter of 2013 compared to the same period in 2012 primarily due to lower realized refining margins as a result of significantly lower market crack spreads.

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 an increase in net earnings of approximately $47 million in the third quarter of 2013 compared to an increase in net earnings of approximately $34 million in the same period in 2012.

In addition, the product slates produced at the Lima and BP-Husky Toledo Refineries contain approximately 10% to 15% 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.

Nine Months

Net earnings in the first nine months of 2013 were consistent with the same period in 2012 as favourable market crack spreads in the first half of 2013 were offset by a significant drop in market crack spreads in the third quarter of 2013. The estimated FIFO impact was an increase in net earnings of approximately $76 million in the first nine months of 2013 compared to a reduction in net earnings of $6 million in the same period in 2012.

Downstream Capital Expenditures

In the first nine months of 2013, Downstream capital expenditures totalled $360 million compared to $294 million in the same period in 2012. In Canada, capital expenditures of $239 million were related to upgrades at the Upgrader and the Prince George Refinery. At the Lima Refinery, $76 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $45 million (Husky's 50% share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

The Lima Refinery is scheduled to complete a turnaround in 2015 on 70% of its operating units. The Refinery is expected to be shut down for 45 days. The remaining 30% of the operating units are scheduled to be addressed in a turnaround planned for 2015.

The BP-Husky Toledo Refinery is scheduled to complete a turnaround in 2014 which will affect approximately 30% of its operating capacity. Refinery operations will be impacted for approximately 35 to 50 days depending on the unit. The remaining 70% of the operating units are scheduled to be addressed in a turnaround planned for 2015.

5.3 Corporate

Corporate Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions) income (expense)	**2013**	2012	**2013**	2012
Administrative expenses	**(25)**	(26)	**(95)**	(99)
Stock-based compensation	**(30)**	(9)	**(32)**	(21)
Depreciation and amortization	**(13)**	(11)	**(34)**	(27)
Other income (expenses)	**8**	(4)	**17**	(16)
Foreign exchange gains	**7**	16	**9**	15
Interest income (expense)	**1**	(11)	**(9)**	(51)
Income taxes recovery (expense)	**15**	(6)	**1**	35
Net loss	**(37)**	(51)	**(143)**	(164)

Third Quarter

The Corporate segment reported a loss of $37 million in the third quarter of 2013 compared to a loss of $51 million in the same period in 2012. Interest expense decreased by $12 million compared to the same period in 2012 due to an increase in the amount of capitalized interest related to projects in the Asia Pacific Region and the Sunrise Energy Project. Stock-based compensation increased by $21 million compared to the same period in 2012 due to an increase in the Company's share price from the second quarter of 2013.

Nine Months

In the first nine months of 2013, the Corporate segment reported a loss of $143 million compared to a loss of $164 million in the same period of 2012. Interest expense was lower in the first nine months of 2013 compared to the same period in 2012 due to the same factors impacting the third quarter. Stock-based compensation increased in the first nine months of 2013 compared to the same period in 2012 due to the same factors impacting the third quarter. Other income increased by $33 million in the first nine months of 2013 compared to the same period in 2012 primarily due to the recovery of an insurance provision from the prior year.

Foreign Exchange Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gains (losses) on translation of U.S. dollar denominated long-term debt	**10**	49	**(11)**	47
Gains on cross currency swaps	**—**	—	**—**	2
Gains (losses) on contribution receivable	**(9)**	(27)	**21**	(22)
Other foreign exchange gains (losses)	**6**	(6)	**(1)**	(12)
Net foreign exchange gains	**7**	16	**9**	15
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.951**	U.S. $0.981	**U.S. $1.005**	U.S. $0.983
At end of period	**U.S. $0.972**	U.S. $1.017	**U.S. $0.972**	U.S. $1.017

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 decreased in the third quarter of 2013 to $184 million from $254 million in the same period in 2012 resulting in an effective tax rate of 27% in the third quarter of 2013 and 33% in the same period in 2012. The effective tax rate was lower in the third quarter of 2013 compared to the same period in 2012 due to lower U.S. downstream earnings. Cash taxes in the quarter reflect lower U.S. downstream earnings and prepayments made in the second quarter of 2013.

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2013**	2012	**2013**	2012
Income taxes as reported	**184**	254	**688**	644
Cash taxes paid (recovered)	**(21)**	83	**352**	488

Corporate Capital Expenditures

In the first nine months of 2013, Corporate capital expenditures were $92 million compared to $35 million in the same period of 2012 primarily related to computer hardware and software and leasehold improvements.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the third quarter of 2013, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At September 30, 2013, Husky had total debt of $4,011 million, partially offset by cash on hand of $1,607 million, for $2,404 million of net debt compared to $1,893 million of net debt at December 31, 2012. At September 30, 2013, the Company had $3.5 billion of unused credit facilities of which $3.2 billion is long-term committed credit facilities and $305 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. The ability of the Company to utilize the capacity under its base shelf prospectus is subject to market conditions. Refer to Section 6.2.

Cash Flow Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except ratios)	**2013**	2012	**2013**	2012
Cash flow				
Operating activities	**1,276**	1,353	**3,816**	3,892
Financing activities	**(154)**	30	**(589)**	22
Investing activities	**(1,280)**	(1,187)	**(3,638)**	(3,477)
Financial Ratios[(1)]				
Debt to capital employed *(percent)*[(2)]			**16.7**	17.0
Debt to cash flow *(times)*[(3)(4)]			**0.7**	0.8
Corporate reinvestment ratio *(percent)*[(3)(5)]			**103**	109
Interest coverage ratios on long-term debt only[(3)(6)]				
Earnings			**12.9**	12.3
Cash flow			**24.6**	24.4
Interest coverage ratios on total debt[(3)(7)]				
Earnings			**13.0**	12.0
Cash flow			**24.8**	23.9

(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

Third Quarter

Cash flow generated from operating activities was $1.3 billion in the third quarter of 2013 compared to $1.4 billion in the same period in 2012 primarily due to lower realized margins in Upgrading and U.S. Refining and Marketing offset by higher realized commodity prices and production in Exploration and Production.

Nine Months

Cash flow generated from operating activities was $3.8 billion in the first nine months of 2013 compared to $3.9 billion in the same period in 2012.

Cash Flow used for Financing Activities

Third Quarter

Cash flow used for financing activities was $154 million in the third quarter of 2013 compared to cash flow from financing activities of $30 million in the same period in 2012. The increase in cash flow used for financing activities was primarily due to higher cash versus stock dividends paid in the third quarter of 2013 when compared to the same period in 2012.

Nine Months

Cash flow used for financing activities was $589 million in the first nine months of 2013 compared to cash flow from financing activities of $22 million in the same period of 2012. The increase in cash flow used for financing activities was primarily due to the same factors impacting the third quarter of 2013.

Cash Flow used for Investing Activities

Third Quarter

Cash flow used for investing activities was $1.3 billion in the third quarter of 2013 compared to $1.2 billion in the same period in 2012. Cash invested in both periods was primarily for capital expenditures.

Nine Months

Cash flow used for investing activities was $3.6 billion in the first nine months of 2013 compared to $3.5 billion in the same period in 2012. 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 equity, 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 September 30, 2013, working capital was $1,327 million compared to $2,401 million at December 31, 2012.

At September 30, 2013, Husky had unused short and long-term credit facilities totalling $3.5 billion. A total of $211 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

Husky Energy (HK) Limited and Husky Oil China Ltd., subsidiaries of Husky, each have an uncommitted demand revolving facility of U.S. $10 million available for general purposes.

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.

In December 2012, the Company amended and restated both of its revolving syndicated credit facilities to allow the Company to borrow up to $3.1 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. In February 2013, this amount was increased to $3.2 billion. One facility matures in August 2014 and the other facility was extended to December 2016.

On December 31, 2012, the Company filed a universal short form base shelf prospectus (the "Canadian Base Prospectus") with applicable securities regulators in each of the provinces of Canada, other than Quebec, that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada up to and including January 30, 2015. As of September 30, 2013, the Company had not issued Securities under the Canadian Base Prospectus. The ability of the Company to raise capital utilizing its Canadian Base Prospectus is dependent on market conditions at the time of sale.

Capital Structure	September 30, 2013	
($ millions)	Outstanding	Available[(1)]
Total debt	4,011	3,505
Common shares, preferred shares, retained earnings and other reserves	20,074	

[(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 2012 Annual MD&A under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2012. There were no material changes to commitments noted during the third quarter of 2013.

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

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 nine months ended September 30, 2013, the amounts of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $11 million and $41 million, respectively. For the three and nine months ended September 30, 2013, the amounts of steam purchased by the Company from Meridian totalled $3 million and $12 million, respectively. In addition, the Company provides cogeneration and facility support services to Meridian, measured on a cost recovery basis. For the three and nine months ended September 30, 2013, the total cost recovery for these services was $2 million and $6 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 2012 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 changed since December 31, 2012, as discussed in Husky's 2012 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 September 30, 2013, 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

At September 30, 2013, the Company had designated a cash flow hedge using forward starting interest rate swap arrangements whereby the Company fixed the underlying U.S. 10-year Treasury Bond rate on U.S. $500 million to June 16, 2014, which is the Company's forecasted debt issuance on the same date. The effective portion of these contracts has been recorded at fair value in other assets; there was no ineffective portion at September 30, 2013. The weighted average swap rate for these forward starting swaps is 2.24%.

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

Foreign Currency Risk Management

At September 30, 2013, 82% or $3.3 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, no long-term debt is exposed to changes in the Canadian/U.S. exchange rate.

At September 30, 2013, the Company had designated all of its U.S. $3.2 billion denominated debt as a hedge of the Company's net investment in its U.S. refining operations. Of this amount, U.S. $400 million was designated in the third quarter of 2013. For the three and nine months ended September 30, 2013, the Company incurred an unrealized gain of $54 million and loss of $83 million, respectively, arising from the translation of the debt, net of tax of $8 million and $12 million, respectively, which was recorded in net investment hedge within other comprehensive income ("OCI").

Husky holds 50% of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and is denominated in U.S. dollars. Related gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in foreign exchange in current period earnings. At September 30, 2013, Husky's share of this receivable was U.S. $239 million including accrued interest. The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a U.S. dollar functional currency foreign operation. At September 30, 2013, Husky's share of this obligation was U.S. $1.3 billion including accrued interest. At September 30, 2013, the cost of a Canadian dollar in U.S. currency was $0.972.

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

Financial Instruments at Fair Value ($ millions)	As at September 30, 2013	As at December 31, 2012
Derivatives – fair value through profit or loss ("FVTPL")		
Accounts receivable	36	13
Accounts payable and accrued liabilities	(11)	(5)
Other assets, including derivatives	3	1
Other – FVTPL[(1)]		
Accounts payable and accrued liabilities	(51)	(27)
Other long-term liabilities	(31)	(78)
Hedging instruments [(2)]		
Derivatives designated as cash flow hedge	27	1
Hedge of net investment[(3)]	4	88
	(23)	(7)

(1) Non-derivative items related to contingent consideration recognized as part of a business acquisition.
(2) Hedging instruments are presented net of tax.
(3) Represents the translation of the Company's U.S. 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 2012 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 and Recent Accounting Standards

9.1 Change in Accounting Policies

The following new accounting standards and amendments to existing standards, as issued by the International Accounting Standards Board ("IASB"), have been adopted by the Company effective January 1, 2013.

New Accounting Standards

IFRS 10, "Consolidated Financial Statements" provides a single control model to be applied in the assessment of control for all entities in which the Company has an investment. The adoption of this standard had no impact on the Company's consolidated financial statements.

IFRS 11, "Joint Arrangements" classifies joint arrangements as either joint operations or joint ventures. Parties to a joint operation retain the rights and obligations to individual assets and liabilities of the operation and apply proportionate consolidation, while parties to a joint venture have rights to the net assets of the venture and apply equity accounting. As a result of identifying and analyzing the applicability of these new standards, the Company's Madura joint arrangement will no longer be accounted for using proportionate consolidation. It will now be accounted for on an equity basis as it meets the IFRS 11 definition of a joint venture. The Company's share of income or loss in the Madura joint arrangement is included as share of equity investment on the consolidated statements of income. The adoption of this standard resulted in the following cumulative balance sheet impact, applied prospectively from January 1, 2012.

	December 31, 2012	January 1, 2012
Accounts receivable	(4)	(4)
Exploration and evaluation assets	(37)	(14)
Property, plant and equipment, net	(45)	(42)
Investment in joint ventures	132	91
Other assets	(25)	—
Accounts payable and accrued liabilities	1	18
Other long-term liabilities	3	(24)
Deferred tax liabilities	(25)	(25)
Total Balance Sheet Impact	—	—

IFRS 12, "Disclosure of Interests in Other Entities" contains new annual disclosure requirements for interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. The adoption of this standard will not have a material impact on the Company's annual consolidated financial statement disclosures.

IFRS 13, "Fair Value Measurement" establishes a single source of guidance for fair value measurement and disclosure of financial and non-financial items under IFRS. The adoption of this standard had an immaterial impact on the Company's consolidated financial statements.

Amendments to Standards

Amendments to IFRS 7, "Financial Instruments Disclosures" require additional disclosures regarding the Company's financial assets and financial liabilities that are subject to set-off rights and related arrangements. Refer to Note 11 of the Condensed Interim Consolidated Financial Statements for the additional disclosure required.

Amendments to IAS 28, "Investments in Associates and Joint Ventures" provide additional guidance applicable to accounting for interests in joint ventures or associates using the equity method of accounting. The adoption of this amended standard had no impact on the Company's consolidated financial statements.

Amendments to IAS 19, "Employee Benefits" replaced the corridor approach with immediate recognition of actuarial re-measurements and past service costs, modified the calculation of benefit costs and eliminated the expected returns on plan assets through profit or loss. Additional disclosures regarding risk, judgments and assumptions are required.

The adoption of this amended standard resulted in the following balance sheet impact, applied retrospectively to January 1, 2010.

(millions of Canadian dollars) (unaudited)	2012	2011	2010	Total
Increase/(decrease) in net defined benefit liability	1	2	(12)	(9)
Increase/(decrease) in retained earnings	(1)	(2)	12	9
Total balance sheet impact	—	—	—	—

9.2 Recent Accounting Standards

The IASB issued amendments to IAS 36, "Impairment of Assets" which require retrospective application and will be adopted by the Company on January 1, 2014. The adoption of these amended standards is not expected to have a material impact on the Company's consolidated financial statements.

10. Outstanding Share Data

Authorized:

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

Issued and outstanding: October 21, 2013

• common shares	983,374,075
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	30,553,438
• stock options exercisable	14,853,879

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 2012 Annual MD&A, the 2012 Consolidated Financial Statements and the 2012 Annual Information Form filed with Canadian securities regulatory authorities and the 2012 Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency, for additional information relating to the Company. These documents are available at *www.sedar.com*, at *www.sec.gov* and at *www.huskyenergy.com*.

Use of Pronouns and Other Terms Denoting Husky

In this MD&A, the terms "Husky" and "the Company" denote the corporate entity Husky Energy Inc. and its subsidiaries on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended September 30, 2013 are compared to the results for the three months ended September 30, 2012 and the results for the nine months ended September 30, 2013 are compared to the results for the nine months ended September 30, 2012. Discussions with respect to Husky's financial position as at September 30, 2013 are compared to its financial position at December 31, 2012. 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 September 30, 2013 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, 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. With the exception of cash flow from operations and adjusted net earnings, there are no comparable measures in accordance with IFRS. These are useful complementary measurements in assessing Husky's financial performance, efficiency and liquidity. The non-GAAP measurements do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other users. They are common in the reports of other companies but may differ by definition and application. 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 nine months ended September 30, 2013:

		Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)		**2013**	2012	**2013**	2012
GAAP	Net earnings	**512**	526	**1,652**	1,548
	Foreign exchange	**(13)**	(16)	**(10)**	(16)
	Financial instruments	**18**	(5)	**29**	(25)
	Stock-based compensation	**22**	7	**23**	16
	Inventory net realizable value adjustments	**5**	—	**7**	—
Non-GAAP	Adjusted net earnings	**544**	512	**1,701**	1,523
	Adjusted net earnings – basic	**0.55**	0.52	**1.73**	1.56
	Adjusted net earnings – diluted	**0.55**	0.52	**1.73**	1.56

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 expense, 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 nine months ended September 30, 2013:

		Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)		**2013**	2012	**2013**	2012
GAAP	Cash flow – operating activities	**1,276**	1,353	**3,816**	3,892
	Settlement of asset retirement obligations	**29**	28	**92**	85
	Income taxes paid (received)	**(21)**	83	**352**	488
	Interest received	**(6)**	(5)	**(14)**	(24)
	Change in non-cash working capital	**69**	(188)	**(167)**	(845)
Non-GAAP	Cash flow from operations	**1,347**	1,271	**4,079**	3,596
	Cash flow from operations – basic	**1.37**	1.29	**4.15**	3.69
	Cash flow from operations – diluted	**1.37**	1.29	**4.15**	3.69

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 and amortization, exploration and evaluation expense, 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 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 current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

Abbreviations

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

12. Forward-Looking Statements and Information

Certain statements in this interim report 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 interim report are forward-looking and not historical facts. Such forward-looking statements are based on the Company's current expectations, estimates, projections and assumptions that were made by the Company in light of its experience and its perception of historical trends. Further, such forward-looking statements are subject to risks, uncertainties and other factors, some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed or projected in the forward-looking statements.

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 interim report include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company’s general strategic plans and growth strategies; the Company’s 2013 production guidance; the anticipated impact to the Company’s production of a planned turnaround of the Terra Nova FPSO; the forecasted cumulative annual production impact of the planned turnarounds of the Terra Nova FPSO together with previous outages; and anticipated timing of a forecasted debt issuance;
- with respect to the Company's Asia Pacific region: planned timing of first production at the Company’s Liwan Gas Project; testing and commissioning plans at the Company’s Liwan Gas Project; and expected timing of tie-in and production at the Company’s Liuhua 34-2 field;
- with respect to the Company's Atlantic region: expected timing of completion of installation of gas injection equipment and oil production equipment at the Company’s South White Rose Extension project; anticipated timing of first production at the Company’s South White Rose Extension project; and the duration and anticipated impact of the Terra Nova FPSO turnaround;
- with respect to the Company's Oil Sands properties: scheduled timing of first production at the Company’s Sunrise Energy Project; scheduled timing of completion of construction of field and control facilities at the Company’s Sunrise Energy Project; targeted timing of completion of well pads at the Company’s Sunrise Energy Project; and expected timing of completions and production at the Company’s McMullen play;
- with respect to the Company's Heavy Oil properties: scheduled timing of commissioning and first production, and anticipated volumes of production, at the Company’s Sandall heavy oil thermal development project; expected timing

of commissioning and volumes of production for the Company's Rush Lake thermal development project; and the Company's horizontal and CHOPS drilling programs for 2013;

- with respect to the Company's Western Canadian oil and gas resource plays: the Company's 2014 drilling program at its Slater River Canol Shale project in the Northwest Territories; and anticipated timing of completion activities and production from the Company's Kaybob project in the Duvernay play; and
- with respect to the Company's Downstream operating segment: plans to increase the processing capability of the Lima, Ohio refinery by 2017; anticipated timing of approval of an environmental permit for increased operations at the Lima, Ohio refinery; scheduled timing of completion and anticipated benefits of a Hydrotreater Recycle Gas Compressor Project at the BP-Husky Toledo Refinery; and expected timing, duration and impact of turnarounds at the Lima and BP-Husky Toledo refineries.

In addition, statements relating to "reserves" and "resources" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves or resources described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and resources and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserve, resource and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this interim report 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, 2012 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.

Disclosure of Oil and Gas Information

The Company has disclosed best-estimate contingent resources in this interim report. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Best estimate as it relates to resources is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Estimates of contingent resources have not been adjusted for risk based on the chance of development. There is no certainty as to the timing of such development. For movement of resources to reserves categories, all projects must have an economic depletion plan and may require, among other things: (i) additional delineation drilling for unrisked contingent resources; (ii) regulatory approvals; and (iii) Company and partner approvals to proceed with development.

Specific contingencies preventing the classification of contingent resources at the Company's Atlantic Region discoveries as reserves include additional delineation drilling, well testing, facility design, preparation of firm development plans, regulatory applications, Company and partner approvals.

Positive and negative factors relevant to the estimate of Atlantic Region resources include water depth and distance from existing infrastructure.

Note to U.S. Readers

The Company reports its reserves and resources information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101, "Standards of Disclosure for Oil and Gas Disclosure", adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves and resources information in accordance with Canadian disclosure requirements, it uses certain terms in this interim report, such as "best estimate contingent resources" that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the SEC.