MANAGEMENT'S DISCUSSION AND ANALYSIS

February 11, 2014

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1. Summary of Quarterly Results

	Three months ended								Year ended	
Quarterly Summary	**Dec. 31**	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	**Dec. 31**	Dec. 31
($ millions, except where indicated)	**2013**	2013	2013	2013	2012	2012	2012	2012	**2013**	2012
Production *(mboe/day)*	**308.3**	308.5	309.9	321.3	319.3	285.0	281.9	319.9	**312.0**	301.5
Gross revenues[(1)]	**6,132**	6,036	6,206	5,807	5,889	5,410	5,715	5,934	**24,181**	22,948
Net earnings	**177**	512	605	535	474	526	431	591	**1,829**	2,022
Per share – Basic	**0.18**	0.52	0.61	0.54	0.48	0.53	0.44	0.61	**1.85**	2.06
Per share – Diluted	**0.18**	0.52	0.59	0.54	0.48	0.53	0.43	0.60	**1.85**	2.06
Cash flow from operations[(2)]	**1,143**	1,347	1,449	1,283	1,414	1,271	1,153	1,172	**5,222**	5,010
Per share – Basic	**1.16**	1.37	1.47	1.31	1.44	1.29	1.18	1.21	**5.31**	5.13
Per share – Diluted	**1.16**	1.37	1.47	1.30	1.44	1.29	1.17	1.20	**5.31**	5.13

(1) *Gross revenues have been recast to reflect a change in presentation of trading activities and a change in the classification of certain trading transactions.*
(2) *Cash flow from operations is a non-GAAP measure. Refer to Section 11 for a reconciliation to the GAAP measure.*

Performance

- Production decreased by 11.0 mboe/day to 308.3 mboe/day in the fourth quarter of 2013 compared to the fourth quarter of 2012 as a result of:
    - Decreased crude oil production in the Atlantic Region due to the tie-in of equipment for the South White Rose Extension;
    - Natural reservoir declines at maturing White Rose fields; and
    - Decreased natural gas production in Western Canada 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 of $177 million included an after-tax impairment of $204 million related to Western Canada natural gas properties.
- Net operating earnings of $381 million in the fourth quarter of 2013 decreased by 20% when compared to the fourth quarter of 2012 due to:
    - Lower U.S. Refining and Marketing margins resulting from significantly lower market crack spreads;
    - Lower realized prices for Western Canadian crude oil as wider differentials offset higher West Texas Intermediate ("WTI") prices;
    - Lower crude oil production in the Atlantic Region; and
    - Higher stock-based compensation expense due to an increase in the Company's share price;
    - Partially offset by lower exploration and evaluation expenses as a result of successful results in the Atlantic Region offshore exploration campaign.

- Cash flow from operations in the fourth quarter of 2013 decreased compared to the fourth quarter of 2012 due to the same factors which impacted net earnings.

Key Projects

- At the Liwan Gas Project, testing and commissioning is underway. First production is expected in the latter part of the first quarter of 2014, seven years after initial discovery.
- The Sunrise Energy Project remains on track for start up in the second half of 2014. The Central Processing Facility ("CPF") is more than 75% complete with major equipment installed and field tanks and buildings for Plant 1A in place. Commissioning of the first six well pads commenced with the remaining two well pads expected to be turned over in the first quarter of 2014.
- Husky and its joint venture partners have concluded a benefits agreement with the Government of Newfoundland and Labrador for the West White Rose Extension project and a Development Application to the Canada-Newfoundland and Labrador Offshore Petroleum Board has been submitted. Construction of a dry-dock commenced in Argentia, Newfoundland and detailed engineering and design in advance of a final investment decision is ongoing.
- The North Amethyst G-25-9 multilateral well was completed and brought online in late November, with average gross production of 20,000 bbls/day (14,000 bbls/day net production to Husky). In addition, drilling commenced on the North Amethyst Hibernia well in the fourth quarter of 2013, which will target a secondary deeper zone below the main North Amethyst field and is scheduled to be brought on production later in 2014.
- The 3,500 bbls/day Sandall heavy oil thermal development project achieved first oil in the first quarter of 2014 and production is currently ramping up.
- Construction work continued at the 10,000 bbls/day Rush Lake commercial project with first production expected in the second half of 2015.
- Two 10,000 bbls/day thermal developments were sanctioned at Edam East and Vawn both located in Saskatchewan. Construction is scheduled to begin in 2014 with the projects expected to deliver a total of 20,000 bbls/day of production in 2016.
- Resource play development progressed in Western Canada with 16 oil wells (gross) and 12 liquids-rich natural gas wells (gross) drilled and 39 oil wells (gross) and 16 liquids-rich natural gas wells (gross) completed.

Financial

- Dividends on common shares of $295 million for the third quarter of 2013 were declared during the fourth quarter of 2013, of which $291 million and $4 million were paid in cash and common shares, respectively, on January 2, 2014.
- The stock dividend program has been discontinued and the fourth quarter 2013 dividend payable in April 2014 will be paid wholly in cash.

2. Business Environment

Average Benchmarks		Three months ended Dec. 31, 2013	Sept. 30, 2013	Jun. 30, 2013	Mar. 31, 2013	Dec. 31, 2012	Year ended Dec. 31, 2013	Dec. 31, 2012
WTI crude oil[1]	*(U.S. $/bbl)*	**97.46**	105.83	94.22	94.37	88.18	**97.97**	94.21
Brent crude oil[2]	*(U.S. $/bbl)*	**108.34**	108.21	102.52	112.55	110.00	**107.91**	111.54
Canadian light crude 0.3% sulphur	*($/bbl)*	**88.29**	104.91	93.78	88.42	84.43	**93.85**	86.57
Western Canadian Select[3]	*(U.S. $/bbl)*	**65.26**	88.35	75.06	62.41	70.07	**72.77**	73.18
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**57.70**	86.26	67.24	46.44	59.55	**64.41**	62.89
NYMEX natural gas[4]	*(U.S. $/mmbtu)*	**3.61**	3.58	4.09	3.34	3.40	**3.65**	2.79
NIT natural gas	*($/GJ)*	**2.99**	2.67	3.40	2.92	2.90	**3.00**	2.28
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**32.42**	17.50	19.21	32.18	18.29	**25.33**	21.46
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**18.90**	17.32	22.49	30.61	35.06	**22.21**	31.36
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**11.91**	15.86	30.78	26.87	28.00	**21.30**	27.63
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.953**	0.963	0.977	0.991	1.009	**0.971**	1.001
Canadian $ Equivalents								
WTI crude oil[5]	*($/bbl)*	**102.26**	109.90	96.44	95.23	87.39	**100.90**	94.12
Brent crude oil[5]	*($/bbl)*	**113.68**	112.37	104.93	113.57	109.02	**111.13**	111.43
WTI/Lloyd crude blend differential[5]	*($/bbl)*	**34.02**	18.17	19.66	32.47	18.13	**26.08**	21.44
NYMEX natural gas[5]	*($/mmbtu)*	**3.79**	3.72	4.19	3.37	3.37	**3.76**	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 was U.S. $98.42/bbl at the end of 2013, increasing from U.S. $94.19/bbl on December 31, 2012. The price of WTI averaged U.S. $97.46/bbl in the fourth quarter of 2013 compared to U.S. $88.18/bbl in the fourth quarter of 2012. The price of WTI averaged U.S. $97.97/bbl in 2013 compared to U.S. $94.21/bbl in 2012. The price of Brent was U.S. $110.28/bbl at the end of 2013, decreasing from U.S. $111.66/bbl on December 31, 2012. The price of Brent averaged U.S. $108.34/bbl in the fourth quarter of 2013 compared to U.S. $110.00/bbl in the fourth quarter of 2012. The price of Brent averaged U.S. $107.91/bbl in 2013 compared to U.S. $111.54/bbl in 2012.

Crude oil prices realized by the Company in 2013 benefited from the weakening of the Canadian dollar when compared to 2012. In the fourth quarter of 2013, the price of WTI in U.S. dollars increased 11% compared to an increase of 17% in Canadian dollars when compared to the same period in 2012. In 2013, the price of WTI in U.S. dollars increased 4% compared to an increase of 7% in Canadian dollars when compared to 2012. However, differentials for Western Canadian heavy crude oil widened significantly in the fourth quarter of 2013 offsetting the increase in WTI.

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. $32.42/bbl or 33% of WTI in the fourth quarter of 2013 compared to U.S. $18.29/bbl or 21% of WTI in the fourth quarter of 2012. The light/heavy crude oil differential averaged U.S. $25.33/bbl or 26% of WTI in 2013 compared to $21.46/bbl or 23% of WTI in 2012.

The near-month natural gas contract price quoted on the NYMEX was U.S. $4.23/mmbtu at the end of 2013 compared with U.S. $3.35/mmbtu at December 31, 2012. During the fourth quarter of 2013, the NYMEX near-month contract price of natural gas averaged U.S. $3.61/mmbtu compared to U.S. $3.40/mmbtu in the fourth quarter of 2012, an increase of 6%. During 2013, the NYMEX near-month contract price of natural gas averaged U.S. $3.65/mmbtu compared to U.S. $2.79/mmbtu during 2012, an increase of 31%. The near-month natural gas contract price for NOVA Inventory Transfer ("NIT"), which is a Canadian natural gas benchmark, was $3.73/GJ at the end of 2013 compared with $2.87/GJ at December 31, 2012. During the fourth quarter of 2013, the NIT near-month contract price of natural gas averaged $2.99/GJ compared to $2.90/GJ in the fourth quarter of 2012, an increase of 3%. During 2013, the NIT near-month contract price of natural gas averaged $3.00/GJ compared to $2.28/GJ during 2012, an increase of 32%.

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.

The Canadian dollar was U.S. $0.940 at the end of 2013, weakening from U.S. $1.005 on December 31, 2012. In the fourth quarter of 2013, the Canadian dollar averaged U.S. $0.953, weakening by 6% compared to U.S. $1.009 during the fourth quarter of 2012. In 2013, the Canadian dollar averaged U.S. $0.971, weakening by 3% compared to U.S. $1.001 during 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 fourth quarter of 2013, the Chicago 3:2:1 crack spread averaged U.S. $11.91/bbl compared to U.S. $28.00/bbl in the fourth quarter of 2012. In 2013, the Chicago 3:2:1 crack spread averaged U.S. $21.30/bbl compared to U.S. $27.63/bbl in 2012. During the fourth quarter of 2013, the New York Harbour 3:2:1 crack spread averaged U.S. $18.90/bbl compared to U.S. $35.06/bbl in the fourth quarter of 2012. In 2013, the New York Harbour 3:2:1 crack spread averaged U.S. $22.21/bbl compared to U.S. $31.36/bbl in 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 fourth quarter of 2013. The table below reflects what the effect would have been on the financial results for the fourth quarter of 2013 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the fourth 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 Fourth 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)]	**97.46**	*U.S. $1.00/bbl*	**75**	**0.08**	**55**	**0.06**
NYMEX benchmark natural gas price[(5)]	**3.61**	*U.S. $0.20/mmbtu*	**26**	**0.03**	**19**	**0.02**
WTI/Lloyd crude blend differential[(6)]	**32.42**	*U.S. $1.00/bbl*	**(24)**	**(0.03)**	**(18)**	**(0.02)**
Canadian light oil margins	**0.043**	*Cdn $0.005/litre*	**14**	**0.02**	**11**	**0.01**
Asphalt margins	**18.44**	*Cdn $1.00/bbl*	**10**	**0.01**	**8**	**0.01**
New York Harbour 3:2:1 crack spread	**18.90**	*U.S. $1.00/bbl*	**57**	**0.06**	**36**	**0.04**
Exchange rate (U.S. $ per Cdn $)[(3)(7)]	**0.953**	*U.S. $0.01*	**(15)**	**(0.02)**	**(11)**	**(0.01)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 983.4 million common shares outstanding as of December 31, 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 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 built 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 fourth quarter of 2013, a total of 16 wells (gross) were drilled and 39 wells (gross) were completed across the oil resource project portfolio.

Oil Resource Plays - Drilling and Completion Activity[1][2]		Three months ended Dec. 31, 2013		Year ended Dec. 31, 2013	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	3	4	14	12
Lower Shaunavon	S.W. Saskatchewan	2	1	9	7
Viking[3]	Alberta and S.W. Saskatchewan	7	30	59	64
N.Cardium	Wapiti, Alberta	4	4	13	9
Muskwa	Rainbow, Northern Alberta	—	—	6	2
Canol Shale	Northwest Territories	—	—	—	2
Total Gross		16	39	101	96
Total Net		15	36	96	92

(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 the Company plans to drill and complete two horizontal wells in 2015.

Liquids-Rich Natural Gas Resource Plays

In the fourth quarter of 2013, a total of 12 wells (gross) were drilled and 16 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)(2)]		Three months ended Dec. 31, 2013		Year ended Dec. 31, 2013	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	**10**	**10**	**25**	**30**
Duvernay	Kaybob, Alberta	**2**	**6**	**6**	**6**
Total Gross		**12**	**16**	**31**	**36**
Total Net		**11**	**15**	**29**	**34**

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

The four rig drilling program continued through the fourth quarter of 2013 at the Ansell Multi-Zone play with 10 liquids-rich horizontal natural gas wells drilled (gross) and nine horizontal wells (gross) and one vertical well (gross) completed.

Drilling and completion activities concluded on the first four well pad in the Duvernay play during the quarter. The first four well pad came on stream during the fourth quarter and the second well pad is expected to come on stream during the first quarter of 2014.

Conventional Oil and Gas

During the fourth quarter of 2013, 66 wells (gross) were drilled and 68 wells (gross) were completed in the conventional oil and gas portfolio.

Heavy Oil

The 3,500 bbls/day Sandall thermal development project achieved first oil in the first quarter of 2014 and production is currently ramping up.

Construction work continued at the 10,000 bbls/day Rush Lake commercial project with first production expected in the second half of 2015. Production performance from the two well pair pilot is in line with expectations.

Two 10,000 bbls/day thermal developments were sanctioned at Edam East and Vawn both located in Saskatchewan. Construction is scheduled to begin in 2014 and these projects are expected to deliver a total of 20,000 bbls/day of production once operations commence in 2016.

Forty-nine horizontal heavy oil wells (gross) were drilled during the fourth quarter of 2013 bringing the total number of wells (gross) drilled in the year to 140.

Seventy-six Cold Heavy Oil Production with Sand ("CHOPS") wells (gross) were drilled during the fourth quarter of 2013 bringing the total number of wells (gross) drilled in the year to 228.

Asia Pacific Region

China

Block 29/26

At the Liwan Gas Project development on Block 29/26 in the South China Sea, testing and commissioning is underway. First production is expected in the latter part of the first quarter of 2014.

Five major construction vessels and their support vessels were in operation in the quarter encountering unusually difficult weather conditions during an extended typhoon season to complete all final installation of deep water facilities. All remaining piping to connect the individual wells to the manifolds and the manifolds to the connecting infield production flow lines are now installed. Final testing and commissioning of the gas plant and offshore infrastructure is now underway and the Company is preparing to run test gas through the gas plant and shallow water pipelines.

The single development well of the Liuhua 34-2 field is expected to be tied into the Liwan 3-1 field deep water facilities with production expected later in the second half of 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 two-dimensional seismic survey data on the Company's offshore Taiwan block commenced in September 2013 and approximately half of the minimum committed survey distance was completed with the remainder planned for 2014.

Indonesia

Progress continued on the shallow water gas developments in the Madura Strait Block during the fourth quarter of 2013. The BD field engineering and construction has commenced. The last outstanding tender for the BD field floating production, storage and offloading vessel ("FPSO") is awaiting government approval and the tender plans for the combined MDA and MBH development projects are under final review by Indonesia's regulatory authority. The Government of Indonesia appointed a lead distributor for the majority of the gas to be produced from the MDA and MBH fields and the negotiation of a gas sales contract is in progress. Exploration drilling on the block resulted in an additional discovery, the MBF field, located west of the MBH field.

Oil Sands

Sunrise Energy Project

Phase 1 of the Sunrise Energy Project remains on track for start up in the second half of 2014. The CPF is more than 75% complete with major equipment installed and field tanks and buildings for Plant 1A now in place. In addition, all modules have been delivered and major equipment installation has been completed for Plant 1B. Field facilities are substantially complete. The main power line to the plant is now energized and the testing of piping and the completion of remaining electrical and instrumentation work is an area of focus in advance of the planned systems turn over. Six well pads have been turned over with commissioning underway. The remaining two well pads are targeted to be turned over in the first quarter of 2014. To date, approximately 90% of the project's total cost estimate has been spent.

Early engineering is underway for the next phase of the Sunrise Energy Project.

McMullen

During the fourth quarter of 2013, 16 wells (gross) were drilled and 16 wells (gross) were completed at the conventional portion of the Company's McMullen play. CHOPS production from 27 wells (gross) located on three well pads commenced during the quarter and at the air injection pilot, three additional horizontal production wells (gross) were placed on production.

Atlantic Region

White Rose Field and Satellite Extensions

In the fourth quarter of 2013, Husky and its joint venture partners concluded a benefits agreement with the Government of Newfoundland and Labrador for the West White Rose Extension project and a Development Application to the Canada-Newfoundland and Labrador Offshore Petroleum Board was submitted. Construction of a dry-dock for the project commenced in Argentia, Newfoundland and detailed engineering and design in advance of a final investment decision is ongoing.

Installation of gas injection equipment to support the South White Rose Extension was completed at the end of 2013, with gas injection scheduled to commence in the first quarter of 2014. Installation of oil production equipment is scheduled in 2014 with first oil anticipated by the end of 2014.

The North Amethyst G-25-9 multilateral well was completed and brought online in late November, with average net production of 14,000 bbls/day. This concludes the wells proposed as part of the base plan for the North Amethyst field and the Company continues to examine additional oil recovery improvement opportunities. Drilling has commenced on the North Amethyst Hibernia formation well, which will target a secondary deeper zone below the main North Amethyst field. The well is expected to be brought on production later in 2014.

The Company continued to evaluate the results of a hydrocarbon discovery at 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.

Atlantic Exploration

Husky and its partner continue to assess the recent discoveries at the Bay Du Nord and Harpoon prospects in the Flemish Pass Basin offshore Newfoundland, and will work to identify ways to accelerate development in the region. The companies have announced a seismic survey for spring 2014 and an 18-month long exploration and delineation drilling program. A rig has been secured and is expected to begin operations offshore Newfoundland in fall 2014.

Infrastructure and Marketing

The Hardisty terminal expansion project includes multiple initiatives intended to increase pipeline connectivity and re-configure the existing terminal facility to accommodate the expansion and inclusion of the Company as a Western Canadian Select stream participant by 2015. During the fourth quarter, detailed engineering, procurement and construction progressed on the two 300,000 barrel tanks and procurement of long lead equipment continued for the required terminal reconfigurations in order to accommodate Western Canadian Select.

In order to accommodate the anticipated increase in production from heavy oil thermal development projects, the Company has undertaken initiatives related to the extension of pipeline systems from the Sandall thermal development project to Lloydminster and expansion of the South Saskatchewan Gathering System for the Rush Lake commercial project. Both initiatives are on track to align with anticipated production from these projects.

4.2 Downstream

Husky Lima, Ohio Refinery

As part of an initiative to improve feedstock flexibility, front end engineering design continued in the fourth 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 while maintaining the capability and flexibility to refine existing light crude oil. The project was sanctioned by the Company and regulatory approval was granted by the U.S. Environmental Protection Agency. The capability to refine heavy oil at the Husky Lima Refinery is anticipated by 2017.

BP-Husky Toledo, Ohio Refinery

Work progressed on the Hydrotreater Recycle Gas Compressor Project during the fourth 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 Fourth Quarter Upstream Earnings 2013 - $185 million ($389 million before impairment), 2012 - $309 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 excluding an after-tax impairment charge of $204 million related to Western Canada natural gas properties were $389 million, $80 million higher in the fourth quarter of 2013 compared to the same period in 2012.

Exploration and Production

Exploration and Production Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)	**2013**	2012	**2013**	2012
Gross revenues[(1)(2)]	**1,734**	1,773	**7,333**	6,581
Royalties	**(215)**	(189)	**(864)**	(693)
Net revenues	**1,519**	1,584	**6,469**	5,888
Purchases, operating, transportation and administrative expenses[(2)]	**575**	551	**2,347**	2,123
Depletion, depreciation, amortization and impairment	**791**	614	**2,515**	2,121
Exploration and evaluation expenses	**28**	157	**246**	344
Other expenses (income)	**(34)**	(42)	**78**	(21)
Income taxes	**41**	78	**331**	345
Net earnings	**118**	226	**952**	976

(1) *Gross revenues have been recast to reflect a change in the classification of certain trading transactions.*
(2) *In 2013, the Company reclassified its processing facilities from Infrastructure and Marketing to Exploration and Production. Prior period amounts have been adjusted to conform with current presentation.*

Fourth Quarter

Exploration and Production net earnings in the fourth quarter of 2013, excluding an after-tax impairment charge of $204 million related to Western Canada natural gas properties, increased by $96 million compared to the fourth quarter of 2012 primarily due to exploration drilling success resulting in lower exploration expense and reduced depletion expense as a result of higher reserve additions which more than offset the impact of lower production.

Production decreased by 11.0 mboe/day in the fourth quarter of 2013 compared to the same period in 2012 as a result of lower crude oil production in the Atlantic Region due to the tie-in of equipment for the South White Rose Extension and decreased natural gas production in Western Canada from 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 fourth quarter of 2013 was $73.06/bbl compared to $72.17/bbl during the same period in 2012 as higher Brent and Western Canadian light crude oil prices offset the widening of Western Canada heavy crude oil differentials. Realized natural gas prices averaged $3.30/mcf in the fourth quarter of 2013 compared to $3.25/mcf in the same period in 2012, an increase of 2%.

Twelve Months

Exploration and Production net earnings in 2013, excluding an after-tax impairment charge of $204 million, increased by $180 million compared to 2012. The increase in net earnings was primarily due to higher average realized commodity prices, higher production from the Atlantic Region where the Company completed two major turnarounds in 2012, increased production from heavy oil thermal projects in Western Canada, and lower exploration and evaluation expenses. The increase in net earnings was partially offset by higher depletion expense and increased operating costs in Western Canada. Other expenses in 2013 were higher compared to 2012 due to an increase in accretion expense associated with increased remediation cost estimates and a decrease in realized profits due to period changes in inventory balances.

In 2013, average realized prices for crude oil, NGL and bitumen increased by 3% to $78.12/bbl compared to $75.50/bbl in 2012. Average realized natural gas prices were $3.19/mcf in 2013 compared to $2.60/mcf in 2012, an increase of 23%.

Average Sales Prices Realized	Three months ended Dec. 31, 2013	2012	Year ended Dec. 31, 2013	2012
Crude oil and NGL *($/bbl)*				
Light crude oil & NGL	**101.95**	94.91	**102.35**	99.22
Medium crude oil	**67.86**	67.55	**74.29**	71.51
Heavy crude oil	**56.51**	57.90	**63.44**	61.91
Bitumen	**54.08**	55.74	**61.68**	59.49
Total crude oil and NGL average	**73.06**	72.17	**78.12**	75.50
Natural gas average *($/mcf)*	**3.30**	3.25	**3.19**	2.60
Total average *($/boe)*	**58.55**	57.77	**61.96**	57.16

The price realized for Western Canada crude oil in the fourth quarter of 2013 reflects the widening 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 Dec. 31, 2013	2012	Year ended Dec. 31, 2013	2012
Crude Oil and NGL *(mbbls/day)*				
Western Canada				
Light crude oil & NGL	**30.2**	31.9	**29.7**	30.1
Medium crude oil	**23.4**	23.2	**23.2**	24.1
Heavy crude oil	**75.9**	76.0	**74.5**	76.9
Bitumen[(1)]	**46.7**	46.7	**47.7**	35.9
	176.2	177.8	**175.1**	167.0
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**39.2**	44.9	**39.3**	30.8
Terra Nova – light crude oil	**1.6**	0.8	**4.8**	3.0
	40.8	45.7	**44.1**	33.8
China				
Wenchang – light crude oil & NGL	**7.3**	8.5	**7.3**	8.4
	224.3	232.0	**226.5**	209.2
Natural gas *(mmcf/day)*	**503.8**	523.7	**512.7**	554.0
Total *(mboe/day)*	**308.3**	319.3	**312.0**	301.5

(1) *Bitumen production includes heavy oil thermal average daily gross production of 35.6 mbbls/day and 37.4 mbbls/day for the three and twelve months ended December 31, 2013, respectively. Heavy oil thermal production typically receives a higher price than bitumen production.*

Crude Oil and NGL Production

Fourth Quarter

Crude oil and NGL production in the fourth quarter of 2013 decreased by 7.7 mbbls/day or 3% compared to the same period in 2012 primarily due to lower production from the Atlantic Region resulting from the tie-in of equipment for the South White Rose Extension and natural reservoir declines at maturing White Rose fields. Natural reservoir declines in the Atlantic Region were partially offset by production from the North Amethyst G-25-9 multilateral well which was brought online in late November, with average net production of 14,000 bbls/day.

Twelve Months

Crude oil and NGL production in 2013 increased by 8% compared to 2012 primarily 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 performed during 2012.

Natural Gas Production

Fourth Quarter

Natural gas production in the fourth quarter of 2013 decreased by 19.9 mmcf/day or 4% 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.

Twelve Months

Natural gas production in 2013 decreased by 7% compared to 2012 primarily due to the same factors impacting the fourth quarter.

2013 Production Guidance

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

	2013 Guidance	Actual Production: Year ended December 31, 2013	Actual Production: Year ended December 31, 2012
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	85 – 90	**81**	72
Medium crude oil	25 – 30	**23**	24
Heavy crude oil & bitumen	110 – 120	**122**	113
	220 – 240	**226**	209
Natural gas *(mmcf/day)*	540 – 580	**513**	554
Total *(mboe/day)*	310 – 330	**312**	302

Royalties

Fourth Quarter

In the fourth quarter of 2013, royalty rates as a percentage of gross revenues averaged 13% compared to 11% in the same period in 2012. Royalty rates in Western Canada averaged 12% in the fourth quarter of 2013 compared to 11% in the same period of 2012. Royalty rates for the Atlantic Region averaged 14% in the fourth quarter of 2013 compared to 10% in the same period in 2012 due to higher royalty rates in effect for the White Rose Extension project and the absence of eligible costs from the SeaRose FPSO off-station and Terra Nova FPSO turnaround in 2012. Royalty rates in the Asia Pacific Region averaged 24% in the fourth quarter of 2013 compared to 22% in the same period in 2012.

Twelve Months

In 2013, royalty rates as a percentage of gross revenues averaged 12% compared to 11% in 2012. Royalty rates in Western Canada averaged 12% in 2013 compared to 10% in 2012 due to a royalty credit adjustment received during the second quarter of 2012. Royalty rates for the Atlantic Region averaged 13% in 2013 compared to 11% in 2012 when lower rates reflected the planned SeaRose and Terra Nova FPSO turnarounds completed in the second and third quarters of 2012. Royalty rates in the Asia Pacific Region averaged 24% in 2013 and 2012.

Operating Costs

($ millions)	Three months ended Dec. 31, 2013	Three months ended Dec. 31, 2012	Year ended Dec. 31, 2013	Year ended Dec. 31, 2012
Western Canada	**428**	445	**1,745**	1,571
Atlantic Region	**57**	45	**201**	212
Asia Pacific	**10**	10	**31**	31
Total	**495**	500	**1,977**	1,814
Unit operating costs *($/boe)*	**16.31**	15.05	**16.28**	15.49

Fourth Quarter

Total Exploration and Production operating costs were $495 million in the fourth quarter of 2013 compared to $500 million in the same period in 2012. Total operating costs averaged $16.31/boe in the fourth quarter of 2013 compared to $15.05/boe in the same period in 2012 primarily due to lower production volumes and higher costs resulting from the Terra Nova FPSO turnaround.

Operating costs in Western Canada averaged $16.55/boe in the fourth quarter of 2013 compared to $15.90/boe in the same period in 2012. The increase was due to lower production volumes and increased energy, land, maintenance and servicing costs at maturing fields, partially offset by lower operating costs per barrel at the new heavy oil thermal projects.

Operating costs in the Atlantic Region averaged $15.19/boe in the fourth quarter of 2013 compared to $10.73/boe in the same period in 2012. The increase was due to lower production volumes and increased costs from the Terra Nova FPSO turnaround.

Operating costs in the Asia Pacific Region averaged $13.63/boe in the fourth quarter of 2013 compared to $12.01/boe in the same period in 2012. The increase was due to lower production volumes compared to the fourth quarter of 2012.

Twelve Months

Total Exploration and Production operating costs in 2013 were $1,977 million compared to $1,814 million in 2012. Operating costs in Western Canada averaged $17.05/boe in 2013 compared to $15.45/boe in 2012 primarily due to higher energy consumption and increased natural gas and electricity prices. Operating costs in the Atlantic Region averaged $12.47/boe in 2013 compared to $17.12/boe in 2012 primarily due to higher production and lower maintenance and supply costs compared to 2012 when the planned SeaRose and Terra Nova FPSO turnarounds were underway. Operating costs in the Asia Pacific Region averaged $11.39/boe in 2013 compared to $10.08/boe in 2012 and were primarily impacted by the same factors which impacted the fourth quarter.

Exploration and Evaluation Expenses

	Three months ended Dec. 31,		*Year ended Dec. 31,*	
($ millions)	**2013**	2012	**2013**	2012
Seismic, geological and geophysical	**31**	28	**133**	140
Expensed drilling[1]	**(5)**	126	**102**	188
Expensed land	**2**	3	**11**	16
Exploration and evaluation expenses	**28**	157	**246**	344

[1] *Expensed drilling in the fourth quarter of 2013 included a recovery of Atlantic Region drilling costs previously written-off in 2012.*

Fourth Quarter

Exploration and evaluation expenses in the fourth quarter of 2013 were $28 million compared to $157 million in the fourth quarter of 2012 primarily due to high drilling success rates which resulted in more capitalized exploration costs. Expensed drilling in the fourth quarter of 2012 included costs related to the Searcher well in the Atlantic Region and the Liuhua 32-1-1 well in the Asia Pacific Region.

Twelve Months

Exploration and evaluation expenses were $246 million in 2013 compared to $344 million in 2012 primarily due to the same factors impacting the fourth quarter.

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

Fourth Quarter

During the fourth quarter of 2013, the Company recognized a pre-tax impairment charge of $275 million on certain conventional natural gas assets located in Western Canada. The impairment charge was the result of low estimated long-term future natural gas prices and the redirection of capital investments to higher yield oil and liquids-rich natural gas opportunities.

In the fourth quarter of 2013, total DD&A, excluding the impairment charge, averaged $18.22/boe compared to $20.81/boe in the fourth quarter of 2012. The decreased DD&A rate in the fourth quarter of 2013 was a result of higher reserve additions in 2013.

Twelve Months

In 2013, total DD&A, excluding the impairment charge, averaged $19.67/boe compared to $19.20/boe in 2012.

Exploration and Production Capital Expenditures

In 2013, Upstream Exploration and Production capital expenditures were $4,264 million. Capital expenditures were $2,420 million (57%) in Western Canada including Heavy Oil, $552 million (13%) in Oil Sands, $638 million (15%) in the Atlantic Region and $654 million (15%) in the Asia Pacific Region.

Exploration and Production Capital Expenditures	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)[1]	**2013**	2012	**2013**	2012
Exploration				
Western Canada	**80**	79	**353**	238
Atlantic Region[2]	**55**	(28)	**201**	13
Asia Pacific Region	**14**	5	**21**	22
	149	56	**575**	273
Development				
Western Canada	**744**	662	**2,029**	2,029
Oil Sands	**111**	220	**552**	658
Atlantic Region	**34**	91	**437**	400
Asia Pacific Region	**215**	213	**633**	725
	1,104	1,186	**3,651**	3,812
Acquisitions				
Western Canada	**27**	—	**38**	21
	1,280	1,242	**4,264**	4,106

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(2) *The Company wrote-off $79 million related to a Searcher well in the fourth quarter of 2012 of which $37 million had been capitalized at the end of the third quarter of 2012. Exploration capital expenditures in the Atlantic Region excluding this write-off were $9 million in the fourth quarter of 2012.*

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 Dec. 31,				Year ended Dec. 31,			
Wells Drilled	**2013**		2012		**2013**		2012	
(wells)[1]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration								
Oil	**11**	**7**	15	8	**39**	**24**	47	30
Gas	**7**	**5**	4	—	**19**	**14**	19	12
Dry	**—**	**—**	—	—	**—**	**—**	—	—
	18	**12**	19	8	**58**	**38**	66	42
Development								
Oil	**217**	**201**	233	217	**768**	**709**	775	715
Gas	**15**	**12**	8	6	**68**	**41**	23	17
Dry	**—**	**—**	3	3	**1**	**—**	5	4
	232	**213**	244	226	**837**	**750**	803	736
Total	**250**	**225**	263	234	**895**	**788**	869	778

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

The Company drilled 788 net wells in the Western Canada, Heavy Oil and Oil Sands business units in 2013 consisting of 733 net oil wells and 55 net natural gas wells compared to 778 net wells in 2012 consisting of 745 net oil wells and 29 net natural gas wells.

During 2013, Husky invested $2,420 million in exploration, development and acquisitions, including Heavy Oil, throughout the Western Canada Sedimentary Basin compared to $2,288 million in 2012. Property acquisitions totalling $38 million were completed in 2013 compared to acquisitions of $21 million in 2012. Investment in oil related exploration and development was $576 million in 2013 compared to $538 million in 2012. Investment in natural gas related exploration and development, primarily liquids-rich, was $596 million in 2013 compared to $500 million in 2012.

In addition, $232 million was spent on production optimization and cost reduction initiatives and $349 million was spent on facilities, land acquisition and retention and environmental protection in 2013.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling were $629 million in 2013 compared to $586 million in 2012.

Oil Sands

During 2013, $552 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 2013, $638 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 and exploration at the Bay Du Nord and Harpoon discoveries made during the year.

Asia Pacific Region

During 2013, $654 million was invested in Asia Pacific Region projects, primarily for the continued development of the Liwan Gas Project.

Turnarounds

2013 Turnarounds

An 11-week turnaround of the Terra Nova FPSO commenced on September 25, 2013 and concluded in the fourth quarter of 2013. The planned maintenance shutdown was extended to accommodate repair and replacement of nine mooring chains. The impact to Husky's production in the fourth quarter was approximately 5,900 bbls/day and, together with outages earlier in the year, the cumulative annual production impact was approximately 2,100 bbls/day.

Planned Turnarounds

Planned plant maintenance activities for Western Canada are scheduled in the second and third quarters of 2014 including the full shutdown and maintenance of the Rainbow oil and gas facility for approximately four weeks in the second quarter.

Production from the Liwan Gas Project is scheduled to go off-line in the second half of 2014 for approximately six to eight weeks to tie in the Liuhua 34-2 field.

In the Atlantic Region, the partner-operated Terra Nova FPSO is scheduled to undergo a 28-day turnaround in the third quarter of 2014.

Infrastructure and Marketing

The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke production. The Company owns extensive infrastructure in Western Canada, including pipeline and storage facilities, and has access to capacity on third party pipelines and storage facilities in both Canada and the United States.

Infrastructure and Marketing Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Infrastructure gross margin[1]	**19**	44	**130**	119
Marketing and other gross margin[2]	**76**	79	**312**	398
Gross margin	**95**	123	**442**	517
Operating and administrative expenses[1]	**5**	6	**33**	33
Depreciation and amortization	**2**	6	**20**	22
Other expenses (income)	**(2)**	—	**(3)**	—
Income taxes	**23**	28	**100**	116
Net earnings	**67**	83	**292**	346
Commodity trading volumes managed *(mboe/day)*	**184.5**	197.8	**174.5**	180.1

(1) *In 2013, the Company reclassified its processing facilities from Infrastructure and Marketing to Exploration and Production. Prior period amounts have been adjusted to conform with current presentation.*
(2) *Marketing and other gross margin has been recast to reflect a change in the classification of certain trading transactions.*

Fourth Quarter

Infrastructure and Marketing net earnings in the fourth quarter of 2013 decreased by $16 million compared to the same period in 2012. Lower infrastructure gross margins were driven by decreased pipeline throughput as shipping of heavy oil production shifted to rail transportation and by reduced margin from a fractionation facility that underwent turnaround activity during the quarter.

Twelve Months

Infrastructure and Marketing net earnings in 2013 decreased by $54 million compared to 2012 primarily due to lower marketing margins as a result of narrow crude oil price differentials in the second and third quarters of 2013 and fewer arbitrage opportunities available from utilizing the Company's access to infrastructure to move crude oil from Canada to the United States.

In 2013, Infrastructure and Marketing capital expenditures totalled $96 million and were primarily related to storage tank and pipeline expenditures.

5.2 Downstream

Total Fourth Quarter Downstream Earnings 2013 - $94 million, 2012 - $194 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 decreased Upgrading net earnings primarily due to lower throughput resulting from a major planned turnaround initiated in the third quarter and completed in the fourth quarter and decreased net earnings in U.S. Refining and Marketing where realized margins were impacted by significantly lower market crack spreads, partially offset by higher asphalt margins due to stronger sales volumes of drilling fluids and lower heavy crude oil feedstock costs.

Upgrader

Upgrader Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gross revenues	**484**	562	**2,023**	2,191
Gross margin	**122**	145	**645**	555
Operating and administrative expenses	**47**	41	**168**	153
Depreciation and amortization	**25**	27	**96**	102
Other income	**(22)**	(15)	**(20)**	(6)
Income taxes	**19**	24	**104**	80
Net earnings	**53**	68	**297**	226
Upgrader throughput *(mbbls/day)*[1]	**65.6**	81.1	**66.1**	77.4
Synthetic crude oil sales *(mbbls/day)*	**52.0**	63.4	**50.5**	60.4
Upgrading differential *($/bbl)*	**26.63**	24.27	**29.14**	22.34
Unit margin *($/bbl)*	**25.50**	24.86	**34.99**	25.17
Unit operating cost *($/bbl)*[2]	**7.79**	5.50	**6.96**	5.42

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

Fourth 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 fourth quarter of 2013 were $53 million compared to $68 million in the same period in 2012. The decrease in net earnings was primarily due to lower upgrader throughput compared to the same period in 2012 as operations ramped up to pre-turnaround levels in mid-October following the major turnaround initiated in the second quarter of 2013. The decrease in volumes was partially offset by higher upgrading differentials in the fourth quarter of 2013 compared to the same period in 2012.

During the fourth quarter of 2013, the upgrading differential averaged $26.63/bbl, an increase of $2.36/bbl or 10%, 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 attributed to lower Lloyd Heavy Blend feedstock costs due to oversupply and export pipeline constraints in Western Canada and an increase in realized price for Husky Synthetic Blend. The average price for Husky Synthetic Blend in the fourth quarter of 2013 was $92.08/bbl compared to $89.65/bbl in the same period in 2012. The overall unit margin increased to $25.50/bbl in the fourth quarter of 2013 from $24.86/bbl in the same period in 2012.

Twelve Months

Upgrading net earnings in 2013 increased by $71 million compared to 2012. The increase was primarily due to higher upgrading differentials driven by a deep discount on Lloyd Heavy Blend feedstock in the first quarter of 2013 and higher realized prices for Husky Synthetic Blend in 2013 compared to 2012, partially offset by lower throughput which resulted from a major turnaround completed during the third and fourth quarters of 2013.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gross revenues	**1,288**	933	**3,737**	3,848
Gross margin				
Fuel	**34**	36	**140**	153
Refining	**54**	45	**175**	180
Asphalt	**58**	48	**233**	257
Ancillary	**13**	10	**55**	50
	159	139	**603**	640
Operating and administrative expenses	**65**	64	**253**	242
Depreciation and amortization	**23**	21	**90**	83
Other expenses (income)	**2**	1	**—**	4
Income taxes	**17**	14	**66**	80
Net earnings	**52**	39	**194**	231
Number of fuel outlets[(1)]	**504**	511	**509**	531
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*[(2)]	**7.9**	8.8	**8.1**	8.7
Fuel sales per retail outlet *(thousands of litres/day)*[(2)]	**13.8**	13.9	**13.5**	13.1
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**12.0**	11.4	**10.3**	11.1
Lloydminster Refinery *(mbbls/day)*	**28.4**	28.3	**26.4**	28.3
Ethanol production *(thousands of litres/day)*	**776.4**	746.4	**742.4**	721.2

(1) *Average number of fuel outlets for period indicated.*
(2) *Fuel sales have been recast to exclude non-retail products. Prior periods have been adjusted to conform with the current period presentation.*

Fourth Quarter

Higher refining gross margins in the fourth quarter of 2013 compared to the same period in 2012 were a result of lower cost feedstock and higher realized refined product prices at the Prince George Refinery.

Asphalt gross margins were higher in the fourth quarter of 2013 compared to the same period in 2012 due to stronger sales volumes of drilling fluids and lower heavy crude oil feedstock costs.

Twelve Months

During 2013, refined products net earnings were lower compared to 2012 primarily due to lower asphalt production as a result of a scheduled refinery turnaround in the year and lower fuel net earnings due to decreased diesel margins and lower sales volumes resulting from retail site construction and selected retail outlet closures.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gross revenues[(1)]	**2,690**	2,355	**10,728**	9,856
Gross refining margin[(1)]	**147**	309	**1,182**	1,312
Operating and administrative expenses	**102**	105	**424**	398
Depreciation and amortization	**60**	57	**233**	212
Other expenses	**1**	5	**3**	9
Income taxes	**(5)**	55	**183**	257
Net earnings (loss)	**(11)**	87	**339**	436
Selected operating data:				
Lima Refinery throughput *(mbbls/day)*	**151.8**	155.9	**149.4**	150.0
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**66.3**	58.1	**65.0**	60.6
Refining margin *(U.S. $/bbl crude throughput)*[(1)]	**6.94**	16.19	**15.06**	17.48
Refinery inventory *(mmbbls)*[(2)]	**10.3**	11.3	**10.3**	11.3

(1) *Gross revenues and purchases have been recast to reflect a change in the classification of certain trading transactions.*
(2) *Included in refinery inventory is feedstock and refined products.*

Fourth Quarter

U.S. Refining and Marketing net earnings decreased in the fourth quarter of 2013 compared to the same period in 2012 primarily due to significantly lower Chicago 3:2:1 market crack spread and declining crude oil prices earlier in the quarter, partially offset by higher throughput at the BP-Husky Toledo Refinery due to planned turnaround activity in the fourth quarter of 2012. The drop in Chicago 3:2:1 market crack spread resulted in an approximate reduction in realized margins of $200 million in the fourth quarter of 2013 compared with the same period in 2012.

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 higher. The estimated FIFO impact was a reduction in net earnings of approximately $94 million in the fourth quarter of 2013 compared to a reduction in net earnings of approximately $27 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.

Twelve Months

Net earnings in 2013 decreased compared to 2012 primarily due to a significant drop in Chicago 3:2:1 market crack spread in the second half of 2013, resulting in an annual decrease of approximately $300 million in gross refining margin, partially offset by increased throughput at the BP-Husky Toledo Refinery due to turnaround activity in 2012. The estimated FIFO impact was a reduction in net earnings of approximately $18 million in 2013 compared to a reduction in net earnings of approximately $28 million in 2012.

Downstream Capital Expenditures

In 2013, Downstream capital expenditures totalled $534 million compared to $457 million in 2012. In Canada, capital expenditures of $314 million were related to upgrades at the Upgrader, the Prince George Refinery and the Company's retail stations. At the Lima Refinery, $143 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $77 million (Husky's 50% share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

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

The Lima Refinery is scheduled to complete a major 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 2016. In addition, the Refinery is scheduled to undergo an 18-day outage in March 2014 for planned maintenance to prepare for the major turnaround in 2015. The Refinery is expected to operate at approximately 60% capacity during the outage.

The BP-Husky Toledo Refinery is scheduled to complete a turnaround in 2014 which will affect approximately 30% of its operating capacity. Refinery operations are expected to 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 Dec. 31,		Year ended Dec. 31,	
($ millions) income (expense)	**2013**	2012	**2013**	2012
Administrative expenses	**(17)**	(29)	**(112)**	(128)
Stock-based compensation	**(73)**	(33)	**(105)**	(54)
Depreciation and amortization	**(17)**	(13)	**(51)**	(40)
Other income	**—**	19	**17**	3
Foreign exchange gains	**12**	(1)	**21**	14
Interest income (expense)	**9**	(1)	**—**	(52)
Income taxes recovery (expense)	**(16)**	29	**(15)**	64
Net loss	**(102)**	(29)	**(245)**	(193)

Fourth Quarter

The Corporate segment reported a loss of $102 million in the fourth quarter of 2013 compared to a loss of $29 million in the same period in 2012. Stock-based compensation increased by $40 million in the fourth quarter of 2013 compared to the same period in 2012 due to an increase in the Company's share price. Interest expense decreased by $10 million in the fourth quarter of 2013 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.

Twelve Months

In 2013, the Corporate segment reported a loss of $245 million compared to a loss of $193 million in 2012. Stock-based compensation increased in 2013 compared to 2012 due to the same factors impacting the fourth quarter. Other income increased by $14 million in 2013 compared to 2012 primarily due to the recovery of an insurance provision from the prior year. Interest expense was lower in 2013 compared to 2012 due to the same factors impacting the fourth quarter.

Foreign Exchange Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gains (losses) on translation of U.S. dollar denominated long-term debt	**—**	(4)	**(11)**	43
Gains on cross currency swaps	**—**	—	**—**	2
Gains (losses) on contribution receivable	**6**	15	**27**	(7)
Other foreign exchange gains (losses)	**6**	(12)	**5**	(24)
Net foreign exchange gains (losses)	**12**	(1)	**21**	14
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.972**	U.S. $1.017	**U.S. $1.005**	U.S. $0.983
At end of period	**U.S. $0.940**	U.S. $1.005	**U.S. $0.940**	U.S. $1.005

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 fourth quarter of 2013 to $111 million from $170 million in the same period in 2012 resulting in an effective tax rate of 39% in the fourth quarter of 2013 and 26% in the same period in 2012. The effective tax rate was higher in the fourth quarter of 2013 compared to 2012 due to the increase in non-deductible stock-based compensation expense.

($ millions)	Three months ended Dec. 31, 2013	2012	Year ended Dec. 31, 2013	2012
Income taxes as reported	111	170	799	814
Cash taxes paid (recovered)	81	87	433	575

Corporate Capital Expenditures

In 2013, Corporate capital expenditures were $134 million compared to $84 million in 2012 primarily related to computer hardware and software and leasehold improvements.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the fourth quarter of 2013, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At December 31, 2013, Husky had total debt of $4,119 million, partially offset by cash on hand of $1,097 million, for $3,022 million of net debt compared to $1,893 million of net debt at December 31, 2012. At December 31, 2013, the Company had $3.6 billion of unused credit facilities of which $3.2 billion is long-term committed credit facilities and $371 million is short-term uncommitted credit facilities. In addition, the Company had $3.0 billion in unused capacity under its December 2012 Canadian universal short form base shelf prospectus and U.S. $3.0 billion in unused capacity under its October 2013 U.S. universal short form base shelf prospectus. The ability of the Company to utilize the capacity under its base shelf prospectuses is dependent on market conditions at the time of sale. Refer to Section 6.2.

Cash Flow Summary *($ millions, except ratios)*	Three months ended Dec. 31, 2013	2012	Year ended Dec. 31, 2013	2012
Cash flow				
Operating activities	829	1,301	4,645	5,193
Financing activities	(257)	(184)	(846)	(162)
Investing activities	(1,084)	(1,357)	(4,722)	(4,834)
Financial Ratios(1)				
Debt to capital employed *(percent)*(2)			17.0	17.0
Debt to cash flow *(times)*(3)(4)			0.8	0.8
Corporate reinvestment ratio *(percent)*(3)(5)			108	106
Interest coverage ratios on long-term debt only(3)(6)				
Earnings			11.2	12.5
Cash flow			22.4	24.9
Interest coverage ratios on total debt(3)(7)				
Earnings			11.3	12.3
Cash flow			22.6	24.6

(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

Fourth Quarter

Cash flow generated from operating activities was $829 million in the fourth quarter of 2013 compared to $1.3 billion in the same period in 2012 primarily due to lower realized margins in U.S. Refining and Marketing and lower crude oil production, partially offset by a weaker Canadian dollar.

Twelve Months

Cash flow generated from operating activities was $4.6 billion in 2013 compared to $5.2 billion in 2012 primarily due to a decrease in non-cash working capital resulting from the timing of accounts payable settlements and inventory movement. The decrease in cash flow generated from operating activities was partially offset by higher crude oil production and realized commodity prices in Exploration and Production.

Cash Flow used for Financing Activities

Fourth Quarter

Cash flow used for financing activities was $257 million in the fourth quarter of 2013 compared to $184 million in the same period in 2012. The increase in cash flow used for financing activities compared to the same period in 2012 was primarily due to a lower contribution receivable payments received.

Twelve Months

Cash flow used for financing activities was $846 million in 2013 compared to $162 million in 2012. The increase in cash flow used for financing activities was primarily due to higher cash versus stock dividends paid in 2013 compared to 2012.

Cash Flow used for Investing Activities

Fourth Quarter

Cash flow used for investing activities was $1.1 billion in the fourth quarter of 2013 compared to $1.4 billion in the same period in 2012. Cash invested in both periods was primarily for capital expenditures.

Twelve Months

Cash flow used for investing activities was $4.7 billion in 2013 compared to $4.8 billion 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 December 31, 2013, working capital was $754 million compared to $2,401 million at December 31, 2012. The decrease in working capital is attributed to a reduction in the cash balance and long-term debt of $798 million maturing in 2014 being reclassified to current liabilities as at December 31, 2013.

At December 31, 2013, Husky had unused short and long-term credit facilities totalling $3.6 billion. A total of $224 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million.

On December 14, 2012, the Company amended and restated both of its revolving syndicated credit facilities to allow the Company to borrow up to $1.5 billion and $1.6 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The maturity date for the $1.5 billion facility was extended to December 14, 2016 and there was no change to the August 31, 2014 maturity date of the $1.6 billion facility. In February 2013, the limit on the $1.5 billion facility was increased to $1.6 billion. There continues to be no difference between the terms of these facilities, other than their maturity dates. As at December 31, 2013, there were no amounts drawn under the facilities.

On December 31, 2012, the Company filed a universal short form base shelf prospectus (the "Canadian Shelf 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 in Canada up to and including January 30, 2015. As at December 31, 2013, the Company had not issued securities under the Canadian Shelf Prospectus. The ability of the Company to raise capital utilizing the Canadian Shelf Prospectus is dependent on market conditions at the time of sale.

On October 31, 2013 and November 1, 2013, the Company filed a universal short form base shelf prospectus (the "U.S. Shelf Prospectus") with the Alberta Securities Commission and the U.S. Securities and Exchange Commission, respectively, that enables the Company to offer up to U.S. $3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the United States up to and including November 30, 2015. As at December 31, 2013, the Company had not issued securities under the U.S. Shelf Prospectus. The ability of the Company to raise capital utilizing the U.S. Shelf Prospectus is dependent on market conditions at the time of sale.

Capital Structure	December 31, 2013	
($ millions)	Outstanding	Available[(1)]
Total debt	4,119	3,571
Common shares, preferred shares, retained earnings and other reserves	20,078	

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

6.3 Contractual Obligations and Commercial Commitments

In the normal course of business, the Company is obligated to make future payments. The following summarizes known non-cancellable contracts and other commercial commitments:

($ millions)	Within 1 year	After 1 year but not more than 5 years	More than 5 years	Total
Long-term debt and interest on fixed rate debt	1,015	1,514	3,163	5,692
Operating leases	155	958	367	1,480
Firm transportation agreements	289	1,073	2,702	4,064
Unconditional purchase obligations[(1)]	2,287	2,028	71	4,386
Lease rentals and exploration work agreements	107	431	1,208	1,746
Asset retirement obligations[(2)]	132	447	11,666	12,245
Total	3,985	6,451	19,177	29,613

[(1)] *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases.*
[(2)] *Asset retirement obligation amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets.*

The Company updated its estimates for Asset Retirement Obligations as outlined in Note 9 of the Condensed Interim Consolidated Financial Statements. On an undiscounted basis, the ARO increased from $10.3 billion as at December 31, 2012 to $12.3 billion as at December 31, 2013 due to increased cost estimates and asset growth in both the Upstream and Downstream segments.

The Company is in the process of renegotiating certain purchase, distribution and terminal commitments related to light oil and asphalt products as the existing contracts are approaching expiration.

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay would have a material adverse impact on its financial position, results of operations or liquidity.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time and management believes that it has adequately provided for current and deferred income taxes.

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 twelve months ended December 31, 2013, the amounts of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $14 million and $55 million, respectively. For the three and twelve months ended December 31, 2013, the amounts of steam purchased by the Company from Meridian totalled $5 million and $17 million, respectively. In addition, the Company provides cogeneration and facility support services to Meridian, measured on a cost recovery basis. For the three and twelve months ended December 31, 2013, the total cost recovery for these services was $3 million and $9 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 December 31, 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 December 31, 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. The effective portion of these contracts has been recorded at fair value in other assets; there was no ineffective portion at December 31, 2013. The weighted average swap rate for these forward starting swaps range from 2.24% to 2.25%.

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

Foreign Currency Risk Management

At December 31, 2013, $3.4 billion or 82% of Husky's outstanding debt was denominated in U.S. dollars. No long-term debt, including amounts due within one year, is exposed to changes in the Canadian/U.S. exchange rate, as all U.S. denominated debt has been designated as a hedge of the Company's net investment in its U.S. refining operations.

At December 31, 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. For the three and twelve months ended December 31, 2013, the Company incurred an unrealized loss of $97 million and $180 million, respectively, arising from the translation of the debt, net of tax of $15 million and $27 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 December 31, 2013, Husky's share of this receivable was U.S. $128 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 December 31, 2013, Husky's share of this obligation was U.S. $1.3 billion including accrued interest. At December 31, 2013, the cost of a Canadian dollar in U.S. currency was $0.940.

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 December 31, 2013**	As at December 31, 2012
Derivatives – fair value through profit or loss ("FVTPL")		
Accounts receivable	**18**	13
Accounts payable and accrued liabilities	**(19)**	(5)
Other assets, including derivatives	**2**	1
Other – FVTPL(1)		
Accounts payable and accrued liabilities	**(29)**	(27)
Other long-term liabilities	**(31)**	(78)
Hedging instruments (2)		
Derivatives designated as cash flow hedge	**37**	1
Hedge of net investment(3)	**(93)**	88
	(115)	(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.

During the fourth quarter of 2013, the Company updated its estimates for Asset Retirement Obligations as outlined in Note 9 of the Condensed Interim Consolidated Financial Statements.

During the fourth quarter of 2013, the Company completed an evaluation of its cash generating units with natural gas properties and concluded that the carrying amount of certain conventional natural gas assets was in excess of the estimated recoverable amount due to low estimated long-term future natural gas prices and a reduction of natural gas property development. See Note 5 of the Condensed Interim Consolidated Financial Statements.

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 is no longer accounted for using proportionate consolidation. It is now 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 did 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 effective for 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: February 7, 2014

• common shares	983,491,183
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	28,048,882
• stock options exercisable	12,773,423

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 U.S. Securities and Exchange Commission for additional information relating to the Company. These documents are available at *www.sedar.com*, at *www.sec.gov* and at *www.huskyenergy.com*.

Use of Pronouns and Other Terms Denoting Husky

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended December 31, 2013 are compared to the results for the three months ended December 31, 2012 and the results for the twelve months ended December 31, 2013 are compared to the results for the twelve months ended December 31, 2012. Discussions with respect to Husky's financial position as at December 31, 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 December 31, 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, net operating 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 adjusted net earnings, net operating earnings and cash flow from operations, 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 months and year ended December 31, 2013:

		Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)		**2013**	2012	**2013**	2012
GAAP	Net earnings	**177**	474	**1,829**	2,022
	Foreign exchange	**(4)**	—	**(14)**	(16)
	Financial instruments	**(36)**	(12)	**(7)**	(37)
	Stock-based compensation	**77**	24	**100**	40
	Inventory net realizable value adjustments	**(6)**	1	**1**	1
	Impairment of property, plant and equipment	**204**	—	**204**	—
Non-GAAP	Adjusted net earnings	**412**	487	**2,113**	2,010
	Adjusted net earnings – basic	**0.42**	0.50	**2.15**	2.06
	Adjusted net earnings – diluted	**0.42**	0.50	**2.15**	2.06

Disclosure of Net Operating Earnings

The term "Net Operating Earnings" is a non-GAAP measure comprised of net earnings excluding extraordinary and non-recurring items such as impairment charges not considered indicative of the Company's on-going financial performance. Net operating 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 net operating earnings and related per share amounts for the three months and year ended December 31, 2013:

		Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)		**2013**	2012	**2013**	2012
GAAP	Net earnings	**177**	474	**1,829**	2,022
	Impairment of property, plant and equipment, net of tax	**204**	—	**204**	—
Non-GAAP	Net operating earnings	**381**	474	**2,033**	2,022
	Net operating earnings – basic	**0.39**	0.48	**2.07**	2.07
	Net operating earnings – diluted	**0.39**	0.48	**2.07**	2.07

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, amortization and impairment, 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 months and year ended December 31, 2013:

		Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)		**2013**	2012	**2013**	2012
GAAP	Cash flow – operating activities	**829**	1,301	**4,645**	5,193
	Settlement of asset retirement obligations	**50**	38	**142**	123
	Income taxes paid	**81**	87	**433**	575
	Interest received	**(5)**	(10)	**(19)**	(34)
	Change in non-cash working capital	**188**	(2)	**21**	(847)
Non-GAAP	Cash flow from operations	**1,143**	1,414	**5,222**	5,010
	Cash flow from operations – basic	**1.16**	1.44	**5.31**	5.13
	Cash flow from operations – diluted	**1.16**	1.44	**5.31**	5.13

Cautionary Note Required by National Instrument 51-101

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

Terms

Adjusted Net Earnings	*Net earnings plus after-tax foreign exchange gains and losses, gains and losses from the use of financial instruments, stock-based compensation expense or recovery and any asset impairments and write-downs*
Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
Capital Employed	*Long-term debt including current portion and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Net earnings plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, exploration and evaluation 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*
Net operating earnings	*Net earnings before impairment charge*
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/day*	*thousand barrels per day*
boe	*barrels of oil equivalent*	*mboe*	*thousand barrels of oil equivalent*
CHOPS	*cold heavy oil production with sand*	*mboe/day*	*thousand barrels of oil equivalent per day*
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*
mbbls	*thousand barrels*		

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.

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;
- with respect to the Company's Asia Pacific Region: expected timing of first production at the Company's Liwan Gas Project; expected timing of tie-in and production at the Company's Liuhua 34-2 field; expected timing of completion of the acquisition of a seismic survey at the Company's offshore Taiwan exploration block; planned testing of the gas plant and shallow water pipelines for the Liwan Gas Project; and scheduled timing and duration of the Liwan Gas Project production going off-line;
- with respect to the Company's Atlantic Region: scheduled timing of gas injection and expected timing of installation of oil production equipment at the Company's South White Rose Extension project; scheduled timing of first production at the Company's South White Rose Extension project; scheduled timing and duration of a planned turnaround of the Terra Nova FPSO; planned drilling activities at and scheduled timing of first production from the North Amethyst Hibernia formation well; and anticipated timing of a seismic survey, anticipated duration of a delineation drilling program and expected timing of commencement of rig operations at the Company's Bay du Nord and Harpoon prospects in the Flemish Pass Basin;
- with respect to the Company's Oil Sands properties: scheduled timing of start up at the Company's Sunrise Energy Project; and targeted timing of turn over of well pads at the Company's Sunrise Energy Project;
- with respect to the Company's Heavy Oil properties: anticipated volumes of production at the Company's Sandall heavy oil thermal development project; expected timing of first production and anticipated volumes of production at the Company's Rush Lake heavy oil thermal development project; and scheduled timing of construction and first production, and anticipated volumes of production, at the Company's Edam East and Vawn heavy oil thermal developments;
- with respect to the Company's Western Canadian oil and gas resource plays: the Company's drilling plans for its Canol Shale project in the Northwest Territories; anticipated timing of completion activities and production from the Company's Kaybob project in the Duvernay play; and planned maintenance activities for Western Canada, including scheduled timing and duration of a shutdown at the Rainbow oil and gas facility; and

- with respect to the Company's Downstream operating segment: plans to increase pipeline connectivity and re-configure the terminal facility at the Hardisty terminal; the anticipated benefits from and scheduled timing of completion of the Lima, Ohio refinery reconfiguration and the anticipated processing capacity once reconfiguration is complete; scheduled timing, duration and expected impact of a partial outage of the Lloydminster Upgrader for planned maintenance; scheduled timing and intended impact of completion of a Hydrotreater Recycle Gas Compressor Project at the BP-Husky Toledo Refinery; scheduled timing, duration and expected impact of turnarounds at the BP-Husky Toledo Refinery; and scheduled timing, duration and expected impact of an outage for planned maintenance and turnarounds at the Lima Refinery.

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.