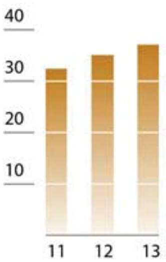
MANAGEMENT'S DISCUSSION AND ANALYSIS

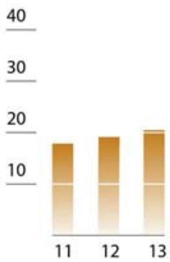
1.0 Financial Summary

1.1 Financial Position

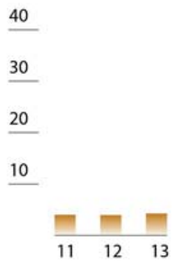
Total Assets
($ billions)



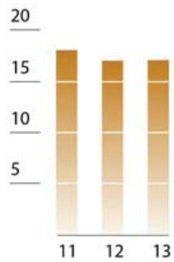
Total Equity
($ billions)



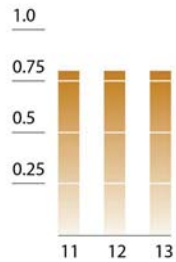
Total Long-term Debt
($ billions)



Debt to Capital Employed[(1)]
(%)

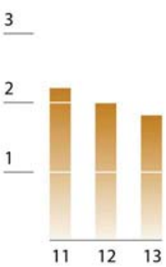


Debt to Cash Flow[(1)]
(times)

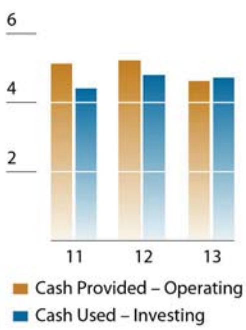


1.2 Financial Performance

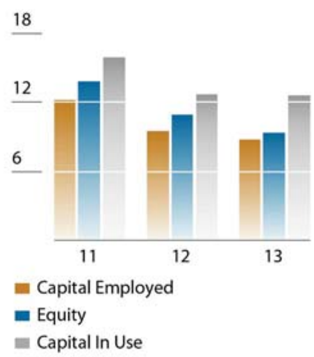
Net Earnings
($ billions)



Cash Flow
($ billions)



Return[(1)]
(%)

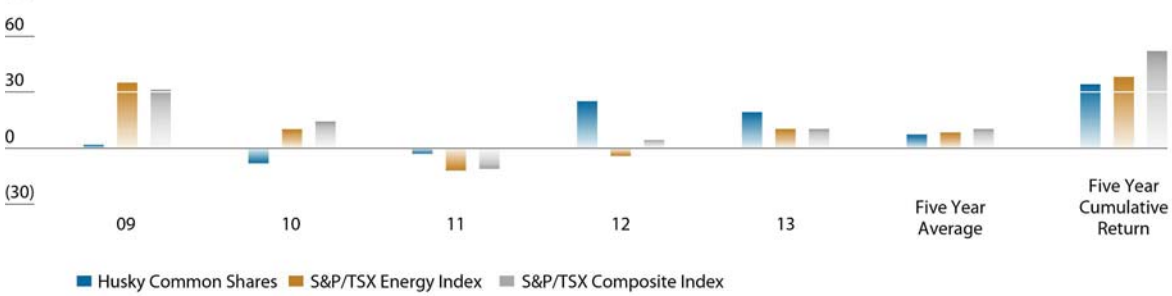


[(1)] *Debt to capital employed, debt to cash flow, return on capital employed, return on equity and return on capital in use constitute non-GAAP measures. (Refer to Section 11.3)*

1.3 Total Shareholder Returns

The following graph shows the total shareholder returns compared with the Standard and Poor's ("S&P") and the Toronto Stock Exchange ("TSX") energy and composite indices.

Total Shareholder Returns
(%)



1.4 Selected Annual Information

($ millions, except where indicated)	**2013**	2012	2011
Gross revenues[(1)]	**24,181**	22,948	22,829
Net earnings by segment[(1)]			
Upstream[(1)]	**1,244**	1,322	1,710
Downstream[(1)]	**830**	893	814
Corporate	**(245)**	(193)	(300)
Net earnings	**1,829**	2,022	2,224
Net earnings per share – basic	**1.85**	2.06	2.40
Net earnings per share – diluted	**1.85**	2.06	2.34
Ordinary dividends per common share	**1.20**	1.20	1.20
Dividends per cumulative redeemable preferred share, series 1	**1.11**	1.11	0.87
Cash flow from operations[(2)]	**5,222**	5,010	5,198
Total assets	**36,904**	35,161	32,426
Other long-term liabilities[(3)]	**271**	328	342
Long-term debt including current portion	**4,119**	3,918	3,911
Total non-current liabilities	**12,663**	12,908	11,263
Cash and cash equivalents	**1,097**	2,025	1,841
Return on equity *(percent)*[(2)(4)]	**9.3**	10.9	13.8
Return on capital in use (percent)[(2)(5)]	**12.6**	12.7	15.9
Return on capital employed *(percent)*[(2)(6)]	**8.7**	9.5	12.1

(1) *Gross revenues, marketing and other and purchases have been recast for the comparative periods to reflect a change in the classification of certain trading transactions.*
(2) *Cash flow from operations and financial ratios constitute non-GAAP measures. (Refer to Section 11.3)*
(3) *As at December 31, 2013, 2012 or 2011, the Company did not have long-term financial liabilities.*
(4) *Return on equity equals net earnings divided by the two-year average shareholder's equity. (Refer to Section 11.3)*
(5) *Return on capital in use for the years ended December 31, 2013 and 2011 was adjusted for after-tax impairments on property, plant and equipment of $204 million and $52 million, respectively. Return on capital in use, based on the calculation used in prior periods for the years ended December 31, 2013 and 2011, was 11.3% and 15.6%, respectively. (Refer to Section 11.3)*
(6) *Return on capital employed for the years ended December 31, 2013 and 2011 was adjusted for after-tax impairments on property, plant and equipment of $204 million and $52 million, respectively. Return on capital employed, based on the calculation used in prior periods for the years ended December 31, 2013 and 2011, was 7.9% and 11.8%, respectively. (Refer to Section 11.3)*

2.0 Husky Business Overview

Husky Energy Inc. ("Husky" or the "Company") is one of Canada's largest integrated energy companies. It is based in Calgary, Alberta, and is publicly traded on the TSX under the symbols HSE and HSE.PR.A. The Company operates in Western Canada, the United States, the Asia Pacific Region and the Atlantic Region with Upstream and Downstream business segments. Husky's balanced growth strategy focuses on consistent execution, disciplined financial management and safe and reliable operations.

2.1 Upstream

Profile and highlights of the Upstream segment include:

- Large base of crude oil producing properties in Western Canada that continue to produce with existing technology and have responded well to the application of increasingly sophisticated techniques, such as horizontal drilling. Enhanced oil recovery ("EOR") techniques, including thermal in-situ recovery methods, have been extensively used in the mature Western Canada Sedimentary Basin to increase recovery rates and to stabilize decline rates of light and heavy crude oil. EOR techniques, such as Alkaline Surfactant Polymer, are being field tested and advanced, while techniques that have been in practice for several decades continue to be optimized;
- Large position in Western Canada oil and liquids-rich natural gas resource plays of approximately 1,800,000 net acres;
- Thermal production for Heavy Oil grew from 17,000 boe/day in 2010 to approximately 37,000 boe/day in 2013, due to the addition of two new steam-assisted gravity drainage ("SAGD") projects, Pikes Peak South and Paradise Hills. Production is expected to be over 55,000 boe/day by 2016 from thermal projects such as the 3,500 boe/day project at Sandall, which achieved first oil in early 2014, the Rush Lake thermal project, with planned production in the second half of 2015, and the recently sanctioned Edam and Vawn SAGD projects;
- Expertise and experience exploring and developing the natural gas potential in the Alberta Deep Basin, Foothills, and northwest plains of Alberta and British Columbia;

- Husky and BP have advanced the development of the Sunrise Energy Project, which is a multiple stage, in-situ oil sands development, with start up of Phase 1 of the project expected in the second half of 2014. Phase 1 is expected to produce approximately 60,000 bbls/day (30,000 bbls/day net Husky share). Sunrise will use proven SAGD technology, keeping site disturbance to a minimum. Regulatory approval is in place to expand the project to 200,000 bbls/day (100,000 bbls/day net Husky share), and planning has advanced for this next phase of the project;
- In addition to Sunrise, Husky has an extensive portfolio of undeveloped oil sands leases, encompassing in excess of 550,000 acres in northern Alberta;
- Offshore China includes a production interest in the Wenchang oil field and the significant natural gas discoveries at the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields within Block 29/26 ("the Liwan Gas Project development"). The Liwan Gas Project development on Block 29/26 in the South China Sea is substantially complete, with first production expected in the latter part of the first quarter of 2014;
- Husky has a 40% interest in the Madura Strait Block covering approximately 622,000 acres, offshore East Java, south of Madura Island, Indonesia, and is focused on the development of the BD, MDA and MBH and five discovered natural gas fields;
- Husky and its joint venture partner CPC Corporation have rights to an exploration block in the South China Sea covering approximately 10,000 square kilometers located 100 kilometers southwest of the island of Taiwan. Husky holds a 75% working interest during exploration, while CPC Corporation has the right to participate in the development program up to a 50% interest;
- Husky is the operator of the White Rose field with a 72.5% working interest in the core field and a 68.875% working interest in satellite tiebacks, including the North Amethyst, West White Rose and South White Rose extensions. Development continues at White Rose and its three satellite extensions. Husky has a 13% non-operated interest in the Terra Nova oil field. The offshore exploration and development program in the Atlantic Region is focused on the Jeanne d'Arc Basin and the Flemish Pass Basin;
- Husky has a 35% interest in each of the three Flemish Pass Basin discoveries: Bay Du Nord, Mizzen and Harpoon;
- Extensive integrated heavy oil pipeline systems in the Lloydminster producing region; and
- The Infrastructure and Marketing business manages the sale and transportation of the Company's Upstream and Downstream production and managed third-party commodity trading volumes of approximately 175 mboe/day in 2013 through access to capacity on third-party pipelines and storage facilities in both Canada and the United States and natural gas storage of 43 bcf, owned and leased.

2.2 Downstream

Profile and highlights of the Downstream segment include:

- Heavy oil upgrading facility located in the Lloydminster, Saskatchewan heavy oil producing region with a throughput capacity of 82 mbbls/day;
- A refinery at Lima, Ohio with a gross crude oil throughput capacity of 160 mbbls/day and a 50% interest in the BP-Husky Refinery in Toledo, Ohio with a name plate capacity of 160 mbbls/day and operating capacity of 135 - 145 mbbls/day on its current crude slate;
- Refinery at Prince George, British Columbia with throughput capacity of 12 mbbls/day producing low sulphur gasoline and ultra low sulphur diesel;
- Largest marketer of paving asphalt in Western Canada, with a 29 mbbls/day capacity asphalt refinery located at Lloydminster, Alberta integrated with the local heavy oil production, transportation and upgrading infrastructure;
- Largest producer of ethanol in Western Canada with a combined 260 million litre per year of capacity at plants located in Lloydminster, Saskatchewan and Minnedosa, Manitoba; and
- Major regional motor fuel marketer with 503 retail marketing locations as at December 31, 2013, including bulk plants and travel centres with strategic land positions in Western Canada and Ontario.

3.0 The 2013 Business Environment

Husky's operations are significantly influenced by domestic and international business environment factors. The global crude oil and liquid fuel industry is impacted by various factors, including those encountered during 2013, that are anticipated to continue to impact the industry to varying degrees into 2014 and beyond. Business factors impacting Husky's industry during 2013 include, but are not limited, to the following:

- Pricing benchmarks for crude oil and natural gas and underlying market supply and demand drivers;
- Industry advancement in alternative and improved extraction methods have rapidly evolved North American and international on-shore and offshore activity;
- Growing domestic production of natural gas and crude oil continues to reshape the U.S. energy economy, with U.S. crude oil production approaching the historical high achieved in 1970;
- Increased production from U.S. shale gas and liquids-rich gas plays continues to assert downward pressure on North American natural gas pricing;
- Key takeaway capacity constraints for Western Canadian crude oil in North America causing a widening of differentials of crude oil relative to key benchmarks, such as West Texas Intermediate ("WTI");
- Political unrest in the Middle East has caused continued unplanned production outages having an impact on crude oil benchmark pricing;
- Expected continued production growth from the Western Canadian oil sands, which is expected to grow to approximately 3.2 million bbls/day by 2020 from approximately 1.8 million bbls/day in 2012;
- Economic conditions remain uncertain as national indebtedness among countries continues to impact global GDP growth;
- Continued global economic uncertainty has led to a tightening of investment from historical norms, creating greater competition among companies within capital markets;
- Increasing globalization, larger projects with major partners, and economies of scale;
- Strong demand for natural gas in Asian markets has led to robust gas pricing in the region;
- Domestic and international political, regulatory and tax system changes; and
- A continuing emphasis on environmental, health and safety, enterprise risk management, resource sustainability and corporate social responsibility.

Major business factors are considered in the formulation of Husky's short and longer term business strategy.

The Company is exposed to a number of risks inherent to the exploration, development, production, marketing, transportation, storage and sale of crude oil, liquids-rich natural gas and related products. For a discussion on Risk and Risk Management, see Section 7.0 and the 2013 Annual Information Form.

Commodity prices, foreign exchange rates and refining crack spreads are some of the most significant factors that affect the results of Husky's operations.

Average Benchmarks		2013	2012
WTI crude oil[1]	*(U.S. $/bbl)*	**97.97**	94.21
Brent crude oil[2]	*(U.S. $/bbl)*	**107.91**	111.54
Canadian light crude 0.3% sulphur	*($/bbl)*	**93.85**	86.57
Western Canada Select @ Hardisty[3]	*(U.S. $/bbl)*	**72.77**	73.18
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**64.41**	62.89
NYMEX natural gas[4]	*(U.S. $/mmbtu)*	**3.65**	2.79
NIT natural gas	*($/GJ)*	**3.00**	2.28
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**25.33**	21.46
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**22.21**	31.36
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**21.30**	27.63
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.971**	1.001
Canadian Equivalents[5]			
WTI crude oil	*($/bbl)*	**100.90**	94.12
Brent crude oil	*($/bbl)*	**111.13**	111.43
Western Canada Select @ Hardisty	*($/bbl)*	**74.94**	73.11
WTI/Lloyd crude blend differential	*($/bbl)*	**26.08**	21.44
NYMEX natural gas	*($/mmbtu)*	**3.76**	2.79

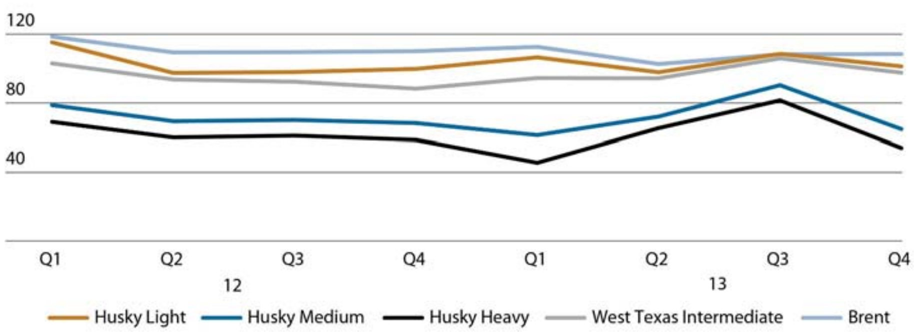
(1) Prices quoted are near-month contract prices for settlement during the next month.
(2) Quoted Brent prices are dated less than 15 days prior to loading for delivery.
(3) Western Canadian Select is a heavy crude blend primarily based on existing Canadian heavy conventional and bitumen crude oils and 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.

As an integrated producer, Husky's profitability is largely determined by realized prices for crude oil and natural gas, marketing margins on committed pipeline capacity and refinery processing margins, as well as the effect of changes in the U.S./Canadian dollar exchange rate. All of Husky's crude oil production and the majority of its natural gas production receives the prevailing market price. The market price for crude oil is determined largely by North American and global factors and is beyond the Company's control. The price for natural gas is determined more by North American fundamentals since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. Weather conditions also exert a significant effect on short-term supply and demand. Starting in 2014, natural gas produced from the Company's Liwan Gas Project in the Asia Pacific Region will supply the Guangdong Province and will receive a fixed price for five years in line with the current Guangdong gate station price set by the Chinese Government.

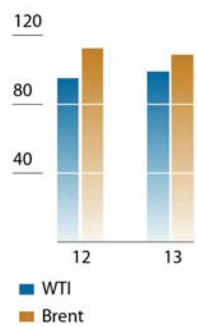
The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil. In the upgrading business segment, heavy crude oil feedstock is processed into light synthetic crude oil. Husky's U.S. refining operations process a mix of different types of crude oil from various sources, but the mix is primarily light sweet crude oil at the Lima Refinery and approximately 50% heavy crude oil feedstock at the BP-Husky Toledo Refinery. The Company's refined products business in Canada relies primarily on purchased refined products for resale in the retail distribution network. Refined products are acquired, under supply contracts, from other Canadian refiners at rack prices or exchanged with production from the Husky Prince George Refinery.

Crude Oil

WTI, Brent and Husky Average Crude Oil Prices
(U.S. $/bbl)



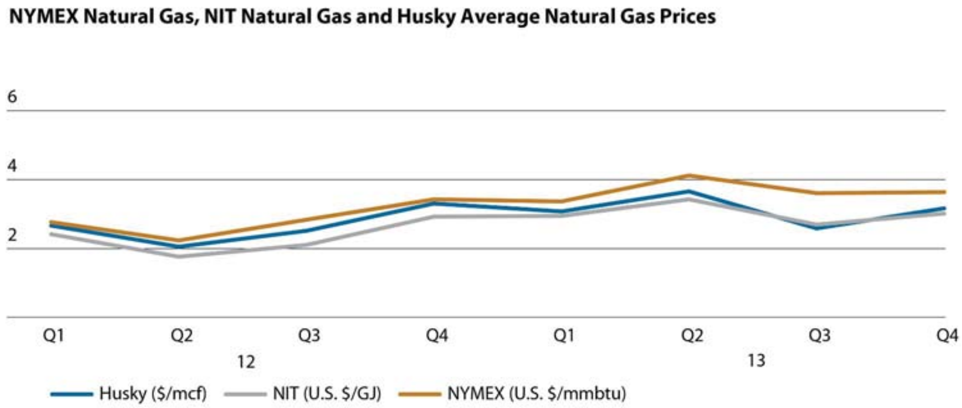
Average WTI and Brent
(U.S. $/bbl)

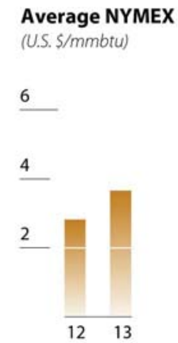


The price Husky receives for production from Western Canada is primarily driven by changes in the price of WTI and discounts or premiums to Western Canadian crude prices, while the majority of the Company's production in the Atlantic Region and the Asia Pacific Region is referenced to the price of Brent, a light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2013 at U.S. $98.42/bbl compared to U.S. $94.19/bbl on December 31, 2012, and averaged U.S. $97.97/bbl in 2013 compared with U.S. $94.21/bbl in 2012. The price of Canadian light crude ended 2013 at $97.49/bbl compared to $74.32/bbl on December 31, 2012 and averaged $93.85/bbl in 2013 compared with $86.57/bbl in 2012. The price of Brent ended 2013 at U.S. $110.28/bbl, compared to U.S. $111.66/bbl on December 31, 2012, and averaged U.S. $107.91/bbl in 2013 compared with U.S. $111.54/bbl in 2012.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In both 2013 and 2012, 54% of Husky's crude oil production was heavy crude oil or bitumen. The light/heavy crude oil differential averaged U.S. $25.33/bbl or 26% of WTI in 2013 compared to U.S. $21.46/bbl or 23% of WTI in 2012.

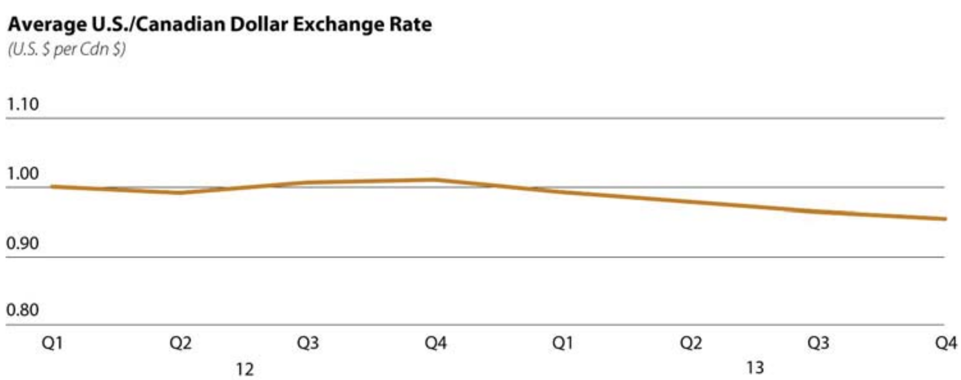
Natural Gas

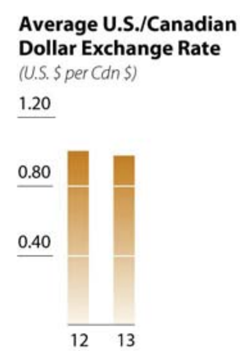




In 2013, 27% of Husky's total oil and gas production was natural gas compared with 31% in 2012, reflecting a shift in investment from dry gas development to higher netback liquids-rich natural gas and crude oil production. The near-month natural gas price quoted on the NYMEX ended 2013 at U.S. $4.23/mmbtu compared with U.S. $3.35/mmbtu at December 31, 2012. During 2013, the NYMEX near-month contract price of natural gas averaged U.S. $3.65/mmbtu compared with U.S. $2.79/mmbtu in 2012. The near-month natural gas contract price for NOVA Inventory Transfer ("NIT"), which is a Canadian natural gas benchmark, was $3.73/mmbtu at the end of 2013 compared with $2.87/mmbtu at December 31, 2012. During 2013, the NIT near-month contract price of natural gas averaged $3.00/mmbtu compared to $2.28/mmbtu in 2012.

Foreign Exchange



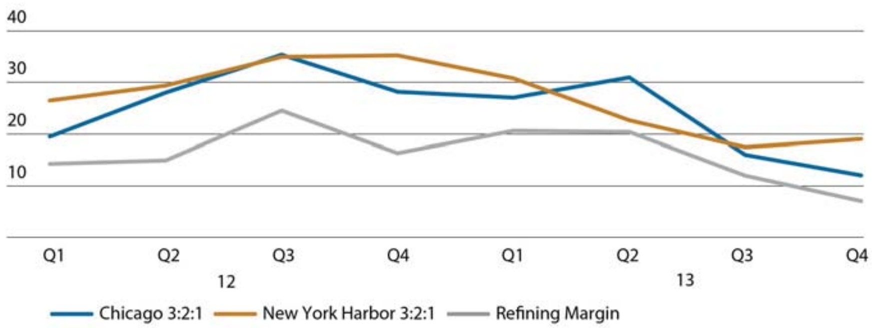


The majority of the Company's revenues from the sale of oil and gas commodities receive prices determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the revenues received from the sale of oil and gas commodities. Correspondingly, an increase in the value of the Canadian dollar relative to the U.S. dollar decreases the revenues received from the sale of oil and gas commodities. The majority of the Company's long-term debt is denominated in U.S. dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the principal amount owing on long-term debt at maturity and the associated interest payments. The majority of the Company's expenditures are in Canadian dollars. In addition, changes in foreign exchange rates impact the translation of the U.S. Downstream segment and the Asia Pacific Region.

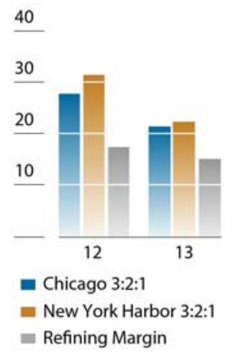
The Canadian dollar ended 2013 at U.S. $0.940 compared to U.S. $1.005 on December 31, 2012. In 2013, the Canadian dollar averaged U.S. $0.971, weakening by 3% compared with U.S. $1.001 during 2012. Crude oil prices realized by Husky in 2013 benefited from the weakening of the Canadian dollar against the U.S. dollar compared to 2012. In 2013, the price of WTI in U.S. dollars increased by 4% while the price of WTI in Canadian dollars increased by 7% when compared to 2012.

Refining Crack Spreads

Chicago and New York Harbor Average Crack Spread and Husky Realized U.S. Refining Margin
(U.S. $/bbl)



Average Crack Spread
(U.S. $/bbl)



The 3:2:1 refining 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 necessarily reflect the actual crude oil purchase costs or product configuration of a specific refinery. Each refinery has a unique crack spread depending on several variables. Realized refining margins are affected by the product configuration of each refinery, crude oil feedstock, product slates, transportation costs to benchmark hubs and by the time lag between the purchase and delivery of crude oil, which is accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

The New York Harbor 3:2:1 refining crack spread benchmark is calculated as the difference between the price of a barrel of WTI crude oil and the sum of the price of two-thirds of a barrel of reformulated gasoline and the price of one-third of a barrel of heating oil. The Chicago 3:2:1 refining crack spread benchmark is calculated based on WTI, regular unleaded gasoline and ultra low sulphur diesel.

The New York Harbor 3:2:1 refining crack spread averaged U.S. $22.21/bbl in 2013 compared to U.S. $31.36/bbl in 2012, and the Chicago 3:2:1 refining crack spread averaged U.S. $21.30/bbl in 2013 compared to U.S. $27.63/bbl in 2012.

The following table is indicative of the relative annualized effect on pre-tax earnings and net earnings from changes in certain key variables in 2013. The table below shows what the effect would have been on 2013 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2013. Each separate item in the sensitivity analysis shows the 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 greater magnitudes of change.

Sensitivity Analysis	2013 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]	**97.97**	*U.S. $1.00/bbl*	**74**	**0.08**	**55**	**0.06**
NYMEX benchmark natural gas price[5]	**3.65**	*U.S. $0.20/mmbtu*	**27**	**0.03**	**19**	**0.02**
WTI/Lloyd crude blend differential[6]	**25.33**	*U.S. $1.00/bbl*	**(23)**	**(0.02)**	**(17)**	**(0.02)**
Canadian light oil margins	**0.043**	*Cdn $0.005/litre*	**15**	**0.02**	**11**	**0.01**
Asphalt margins	**22.62**	*Cdn $1.00/bbl*	**10**	**0.01**	**7**	**0.01**
New York Harbor 3:2:1 crack spread[7]	**22.21**	*U.S. $1.00/bbl*	**55**	**0.06**	**35**	**0.04**
Exchange rate (U.S. $ per Cdn $)[3][8]	**0.971**	*U.S. $0.01*	**(54)**	**(0.06)**	**(40)**	**(0.04)**

(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) *Relates to U.S. Refining and Marketing.*
(8) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

4.0 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, 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.

Husky's strategic direction by business segment is summarized as follows:

4.1 Upstream

Husky has a substantial portfolio of assets in Western Canada. New technologies are making it possible to economically access new pools and recover more production from existing reservoirs. The Company is active in the exploration and production of heavy oil, light crude oil, natural gas and natural gas liquids. The Western Canada strategy is comprised of maintaining production while refocusing by growing oil and liquids-rich natural gas resource plays and expanding thermal and horizontal drilling in heavy oil. The Company advanced its oil and gas resource play positions in 2013 with development activities ongoing in the Bakken, Viking, Cardium, Lower Shaunavon, Muskwa, Canol, Duvernay, Spirit River, Montney, Second White Specs and Willrich formations.

Husky has an extensive portfolio of oil sands leases, encompassing 2,500 square kilometers in northern Alberta. Husky advanced the development of the Sunrise Energy Project in 2013, a multiple stage in-situ oil sands development. The first phase is expected to produce approximately 60,000 barrels per day, with start up expected in second half of 2014. Husky's working interest is 50%. Sunrise will use proven SAGD technology, keeping site disturbance to a minimum.

The Asia Pacific Region consists of the Wenchang oil field, the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields on Block 29/26 located offshore China, the Madura Strait block BD, MDA, MBH development fields, five discoveries offshore Indonesia, and the rights to an exploration block in the South China Sea located offshore Taiwan. The Liwan Gas Project development, located approximately 300 kilometers southeast of the Hong Kong Special Administrative Region, is an important component of the Company's near term production growth strategy and a key step in accessing the burgeoning energy markets in the Hong Kong Special Administrative Region and Mainland China. Husky has partnered with China National Offshore Oil Corporation ("CNOOC") on the development, with first gas production anticipated in the latter half of the first quarter of 2014.

In the Atlantic Region, the Company holds interests in eight Production Licences, 15 Exploration Licences and 23 Significant Discovery Areas. Development activity at the White Rose core field and its satellites, including North Amethyst and the West and South White Rose Extensions, continues to advance. In 2013, the Company made two significant discoveries in the Flemish Pass Basin at the Harpoon and Bay du Nord prospects. With the Mizzen discovery made in 2009, this brings the total number of discoveries in the Flemish Pass Basin to three, making long-term development a viable option subject to further delineation and review. The Company has a 35% working interest in each of these discoveries. The Company has significant exploration acreage in this region and continues to explore innovative ways to further develop the significant resources in the region.

The Infrastructure and Marketing business unit supports Upstream production while providing integration with the Company's Downstream assets through optimization of market access for Husky's Upstream production. The Company also plans to expand terminal pipeline access and product storage opportunities to enhance market access.

4.2 Downstream

Downstream supports heavy oil and oil sands production and makes prudent investments in respect of feedstock, product and market access flexibility. Husky plans to continue to pursue projects to optimize, integrate and reconfigure the Lima, Ohio Refinery for additional crude oil feedstock and product flexibility and reconfigure and increase capacity at the BP-Husky Toledo Refinery to accommodate Sunrise production as its primary feedstock. In support of the downstream strategy, the Company sanctioned a refinery reconfiguration project at the Lima, Ohio Refinery 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.

4.3 Financial

Husky is committed to ensuring sufficient liquidity, financial flexibility and access to long-term capital to fund the Company's growth and support dividend payments. Husky maintains undrawn committed term credit facilities with a portfolio of creditworthy financial institutions and other sources of liquidity to provide timely access to funding to supplement cash flow.

Husky intends to continue to maintain a strong balance sheet to provide financial flexibility. The Company's target is to maintain a debt to cash flow ratio of under 1.5 times and a debt to capital employed ratio of under 25%, which are both non-GAAP measures (refer to Section 11.3). Husky is committed to retaining its investment grade credit ratings to support access to debt capital markets.

The significant asset base in the Company's foundation businesses in Western Canada provides a steady source of cash flow to reinvest in its growth projects, including the Asia Pacific Region, the Oil Sands and the Atlantic Region. As these significant growth projects are developed, the Company expects that they will provide steady sources of cash for the Company.

5.0 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 the Atlantic Region.

5.1 Upstream

Western Canada (excluding Heavy Oil and Oil Sands)

Husky continued to progress crude oil and liquids-rich gas resource plays as a core element of its Western Canada foundation. Total production from these resource plays in 2013 was approximately 25,000 bbls/day, representing a 15% increase compared to 2012.

Oil Resource Plays
During 2013, the Company continued to advance exploration and development projects on its extensive oil resource land base. A total of 101 horizontal wells (gross) were drilled and two vertical and 94 horizontal wells (gross) were completed in 2013.

The following table summarizes the key oil resource play drilling and completion activity for the year ended December 31, 2013:

Oil Resource Plays - Drilling and Completion Activity(1)(2)

Project	Location	Year ended December 31, 2013 Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	14	12
Lower Shaunavon	S.W. Saskatchewan	9	7
Viking(3)	Alberta and S.W. Saskatchewan	59	64
N.Cardium	Wapiti, Alberta	13	9
Muskwa	Rainbow, Northern Alberta	6	2
Canol Shale	Northwest Territories	–	2
Total Gross		101	96
Total Net		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 Southeastern Alberta and drilling in Southwestern 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

During 2013, the Company continued to advance exploration and development projects on its extensive liquids-rich natural gas resource land base. A total of 31 wells (gross) were drilled and 36 wells (gross) were completed in 2013 in key plays across the liquids-rich natural gas resource plays .

The following table summarizes the key liquids-rich natural gas drilling and completion activity for the year ended December 31, 2013:

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

Project	Location	Year ended December 31, 2013 Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	25	30
Duvernay	Kaybob, Alberta	6	6
Total Gross		31	36
Total Net		29	34

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

The liquids-rich gas formations at Ansell in west central Alberta continue to be a key area of focus, with 25 wells (gross) drilled and 30 wells (gross) completed in 2013. To date, the Company has drilled and completed over 300 (gross) wells at the play with average production of 13,800 boe/day in 2013.

At the Duvernay play in Kaybob, Alberta, the Company drilled and completed the first four well pad, with production from the pad commencing in late 2013. The Company also drilled a second two well pad in the year, which is scheduled to be completed and brought on production in early 2014.

Heavy Oil

Production in 2013 at the Pikes Peak South and Paradise Hill heavy oil thermal projects continued to exceed the combined 11,500 bbls/day design rate capacity. Average 2013 production levels from the developments were approximately 11,400 bbls/day at Pikes Peak South and 4,900 bbls/day at Paradise Hill.

Production commenced at the 3,500 bbls/day Sandall thermal development project in early 2014.

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 in 2016.

The Company advanced its horizontal drilling program in 2013 drilling 140 wells. In 2014, the Company plans to carry out a 144 well program. The Company also drilled 228 gross cold heavy oil production with sand ("CHOPS") wells during 2013. In 2014, the Company plans to carry out a 177 CHOPS well program.

Asia Pacific Region

China

Block 29/26

At the Liwan Gas Project development, testing and commissioning is underway. All nine wells on the Liwan 3-1 gas field are complete and ready for production and first production is expected in the latter part of the first quarter of 2014.

The platform topsides were completed and transported approximately 2,500 kilometers from Qingdao, China to the South China Sea and successfully installed onto the jacket. In addition, the 261 kilometers of shallow water pipeline from the central platform to the gas plant and construction of the onshore gas plant was completed. Five major construction vessels and their support vessels were in operation during 2013 while construction continued on the deep water facilities. Despite encountering unusually difficult weather conditions during an extended typhoon season in late 2013, all piping to connect the individual wells to the manifolds and the manifolds to the connecting infield production flow lines was installed. Final testing and commissioning of the gas plant and offshore infrastructure is now underway.

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. 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.

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 the second half of 2014.

Indonesia

Progress continued on the shallow water gas developments in the Madura Strait Block during 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 Central Processing Facility 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 of the eight well pads have been turned over, with commissioning underway on four well pads. The remaining two well pads are targeted to be turned over in early 2014. To date, approximately 90% of the project's total cost estimate has been spent.

Development work continued on the next phase of the project with the Design Basis Memorandum completed in 2013. Early engineering is underway.

McMullen

During 2013, 51 wells were drilled and 49 wells were placed on production in the conventional portion of the Company's McMullen play. CHOPS production from 27 wells drilled and completed on three well pads commenced in late 2013. In addition, at the air injection pilot, the Company received approval from the Alberta Energy Regulator in 2013 to allow an additional three horizontal wells to be brought on production, bringing the total number of producing wells to six at the pilot.

Atlantic Region

White Rose Field and Satellite Extensions

Government and regulatory approval was granted for a development plan amendment to include gas injection and storage at the South White Rose Extension. The development plan amendment will also enable the production of additional reserves from the main White Rose field. Installation of gas injection equipment to support the South White Rose Extension was completed at the end of 2013, with gas injection commencing in early 2014. Installation of oil production equipment is scheduled in 2014, with first oil anticipated by the end of 2014.

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

At North Amethyst, development continued with the drilling and completion of the North Amethyst G-25-8 water injection well. In addition, 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 Husky share). 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.

Atlantic Exploration

Husky and its partner made two significant discoveries in the year of a high-quality, light, sweet crude oil resource in the Flemish Pass Basin. The first discovery was made at the Harpoon O-85 well followed by a second discovery made at the Bay Du Nord prospect, both located approximately 500 kilometres offshore Newfoundland. The evaluation of well results at the Harpoon discovery is ongoing with further appraisal drilling required to assess the potential of the prospect. The evaluation of well results at the Bay Du Nord prospect has confirmed significant quantities of hydrocarbons with best estimate contingent resources estimated by Husky at 400 million barrels on a 100% working interest basis as at December 31, 2013. The two discoveries made in the year bring the total number of significant discoveries in the region to three with the 2009 Mizzen discovery of slightly heavier oil with best estimate contingent resources estimated by Husky at 130 million barrels on a 100% working interest basis as at December 31, 2013. Husky holds a 35% working interest in all three wells.

The Husky-operated White Rose H-70 delineation well, which is part of a near-field drilling program northwest of the main White Rose field, encountered hydrocarbons and the evaluation of results is ongoing. Husky holds a 68.875% working interest in the well. The non-operated Federation well in the southern Jeanne d'Arc Basin did not encounter commercial quantities of hydrocarbons and was expensed.

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. In 2013, detailed engineering, procurement and construction progressed on 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 commerical project. Both initiatives are on track to align with anticipated production from these projects.

5.2 Downstream

Lima Refinery

The Lima Refinery continues to progress reliability and profitability improvement projects. Construction of the 20 mbbls/day kerosene hydrotreater, which increased on-road diesel and jet fuel production volumes, was completed and brought on-line in early 2013. In addition, front-end engineering design commenced 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. 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 Refinery

The Continuous Catalyst Regeneration Reformer Project at the BP-Husky Toledo Refinery was completed and became operational in early 2013. Work progressed on the Hydrotreater Recycle Gas Compressor Project during 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. The refinery continues to advance a multi-year program to improve operational integrity and plant performance while reducing operating costs and environmental impacts.

6.0 Results of Operations

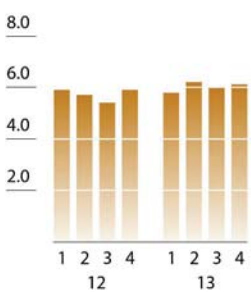
6.1 Segment Earnings

($ millions)	Earnings (Loss) before Income Taxes 2013	2012	Net Earnings (Loss) 2013	2012	Capital Expenditures[1] 2013	2012
Upstream[2]						
Exploration and Production[2]	**1,283**	1,321	**952**	976	**4,264**	4,106
Infrastructure and Marketing[2]	**392**	462	**292**	346	**96**	54
Downstream						
Upgrading	**401**	306	**297**	226	**205**	47
Canadian Refined Products	**260**	311	**194**	231	**109**	97
U.S. Refining and Marketing[2]	**522**	693	**339**	436	**220**	313
Corporate	**(230)**	(257)	**(245)**	(193)	**134**	84
Total	**2,628**	2,836	**1,829**	2,022	**5,028**	4,701

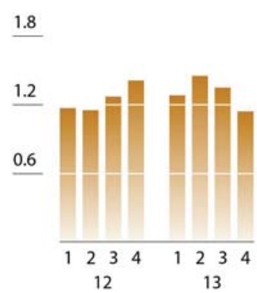
[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
[2] *Gross revenues, marketing and other and purchases have been recast for the comparative period to reflect a change in the classification of certain trading transactions.*

6.2 Summary of Quarterly Results

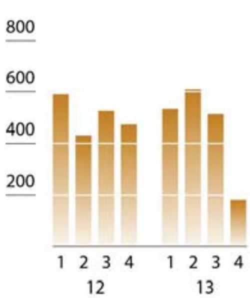
Gross Revenues
($ billions)



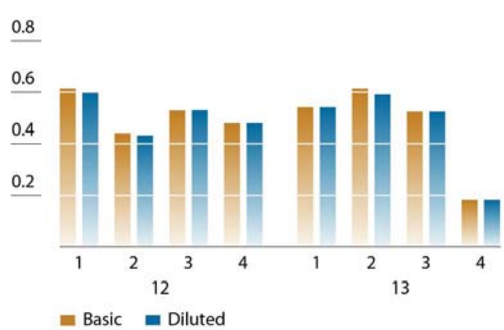
Cash Flow from Operations[1]
($ billions)



Net Earnings
($ millions)



Net Earning Per Share
($ per share)

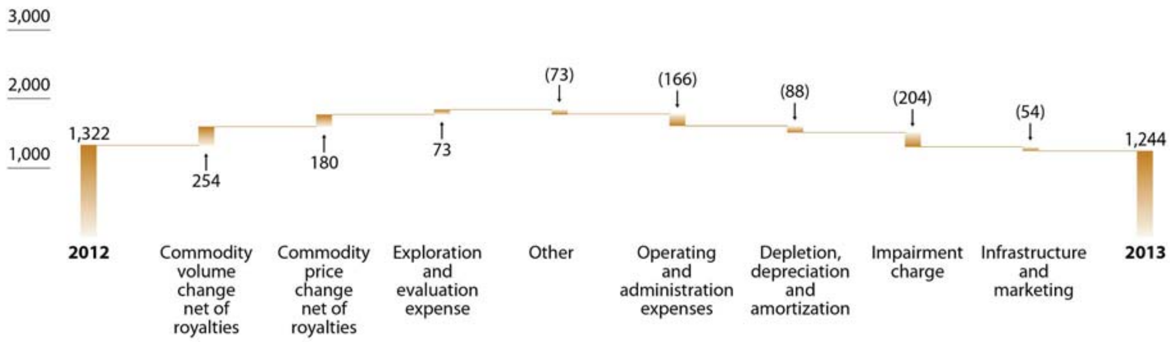


[1] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*

6.3 Upstream

2013 Total Upstream Earnings $1,244 million

After Tax Earnings Variance Analysis
($ millions)



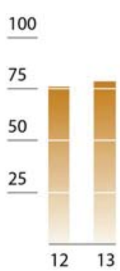
Exploration and Production

Exploration and Production Earnings Summary *($ millions)*	2013	2012
Gross revenues[1][2]	**7,333**	6,581
Royalties	**(864)**	(693)
Net revenues	**6,469**	5,888
Purchases, operating, transportation and administrative expenses	**2,347**	2,123
Depletion, depreciation, amortization and impairment	**2,515**	2,121
Exploration and evaluation expenses	**246**	344
Other expenses (income)	**78**	(21)
Income taxes	**331**	345
Net earnings	**952**	976

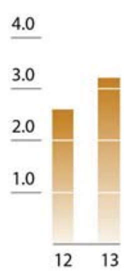
(1) *Gross revenues have been recast for the comparative period to reflect a change in the classification of certain trading transactions.*
(2) *In 2013, the Company reclassified its processing facilities from Infrastructure and Marketing to Exploration and Production. Prior period amounts have been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

Exploration and Production net earnings, excluding an after-tax impairment of $204 million on Western Canada natural gas properties, were $180 million higher in 2013 compared with 2012, 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. These were partially offset by higher depletion expense due to higher production 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 associated with the growing asset base and a decrease in realized profits due to period changes in inventory balances.

Average Price Realized
Crude Oil
($/bbl)



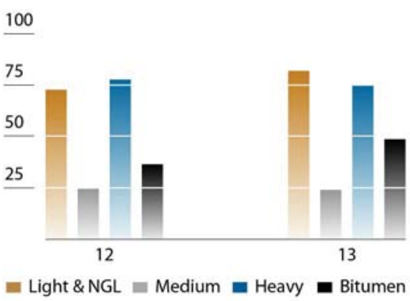
Average Price Realized
Natural Gas
($/mcf)



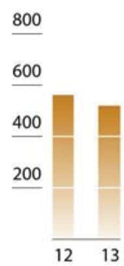
Average Sales Prices Realized	2013	2012
Crude oil and NGL *($/bbl)*		
Light crude oil & NGL	**102.35**	99.22
Medium crude oil	**74.29**	71.51
Heavy crude oil	**63.44**	61.91
Bitumen	**61.68**	59.49
Total crude oil and NGL average	**78.12**	75.50
Natural gas average *($/mcf)*	**3.19**	2.60
Total average *($/boe)*	**61.96**	57.16

During 2013, the average realized price for crude oil, NGL and bitumen increased 3% to $78.12/bbl compared with $75.50/bbl during 2012, primarily due to higher WTI prices combined with a weaker Canadian dollar partially offset by wider Western Canada crude oil differentials. Realized natural gas prices averaged $3.19/mcf during 2013 compared with $2.60/mcf in 2012, an increase of 23% as supply and demand fundamentals improved in 2013 compared to 2012.

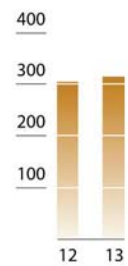
Production
Oil
(mbbls/day)



Production
Natural Gas
(mmcf/day)



Production
Combined
(mboe/day)



Daily Gross Production	2013	2012
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**29.7**	30.1
Medium crude oil	**23.2**	24.1
Heavy crude oil	**74.5**	76.9
Bitumen[(1)]	**47.7**	35.9
	175.1	167.0
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**39.3**	30.8
Terra Nova – light crude oil	**4.8**	3.0
	44.1	33.8
China		
Wenchang – light crude oil & NGL	**7.3**	8.4
Crude oil *(mbbls/day)*	**226.5**	209.2
Natural gas *(mmcf/day)*	**512.7**	554.0
Total *(mboe/day)*	**312.0**	301.5

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

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	2013	2012
Crude oil		
Light crude oil & NGL	**43%**	43%
Medium crude oil	**9%**	10%
Heavy crude oil	**25%**	28%
Bitumen	**15%**	12%
Crude oil	**92%**	93%
Natural gas	**8%**	7%
Total	**100%**	100%

During 2013, crude oil, bitumen and NGL production increased by 17.3 bbls/day or 8% compared with 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 in 2012, partially offset by lower production at Wenchang due to typhoon related shut-ins.

Production from dry natural gas decreased by 41.3 mmcf/day or 7% in 2013 compared with 2012 due to natural reservoir declines in mature properties as capital investment continues to be directed at higher return oil and liquids-rich natural gas developments.

2014 Production Guidance and 2013 Actual

Gross Production	Guidance 2014	Year ended December 31 2013	Guidance 2013
Crude oil, NGL and Asia Pacific Region *(mbbls/day)*			
Light / Medium crude oil & NGL	110 - 115	**104**	110 - 120
Heavy crude oil & bitumen	125 - 130	**122**	110 - 120
Natural gas Asia Pacific Region (mboe/day)	25 - 30	–	–
Crude oil, NGL and Asia Pacific Region *(mbbls/day)*	260 - 275	**226**	220 - 240
Natural gas *(mmcf/day)*	420 - 480	**513**	540 - 580
Total *(mboe/day)*	330 - 355	**312**	310 - 330

The Company's total production for the year ended December 31, 2013 was within production guidance. In 2012, the Company set a compound annual production growth rate of 5% to 8% through the plan period of 2012 to 2017, which it is on track to achieve. Husky expects that production levels in 2014 will be higher compared to 2013 due to new production from the Liwan Gas Project in the Asia Pacific Region and new production at North Amethyst in the Atlantic Region.

Factors that could potentially impact Husky's production performance for 2014 include, but are not limited to:

- performance on recently commissioned facilities, new wells brought onto production and unanticipated reservoir response from existing fields;
- unplanned or extended maintenance and turnarounds at any of the Company's operated or non-operated facilities, upgrading, refining, pipeline or offshore assets;
- business interruptions due to unexpected events, such as severe weather, fires, blowouts, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events;
- significant declines in crude oil and natural gas commodity prices, which may result in the decision to temporarily shut-in production; and
- foreign operations and related assets, which are subject to a number of political, economic and socio-economic risks.

Royalties

Royalty rates averaged 12% of gross revenues in 2013 compared with 11% in 2012. Royalty rates in Western Canada averaged 12% in 2013 compared with 10% in 2012 due to a royalty credit adjustment received in 2012. Royalty rates in the Atlantic Region averaged 13% in 2013 compared with 11% in 2012 when lower rates reflected the ongoing SeaRose and Terra Nova FPSO turnarounds. Royalty rates in the Asia Pacific Region averaged 24% in both 2013 and 2012.

Operating Costs

($ millions)	**2013**	2012
Western Canada	**1,745**	1,571
Atlantic Region	**201**	212
Asia Pacific	**31**	31
Total	**1,977**	1,814
Unit operating costs *($/boe)*	**16.28**	15.49

Total operating costs increased to $1,977 million in 2013 from $1,814 million in 2012. Total Upstream unit operating costs in 2013 averaged $16.28/boe compared with $15.49/boe in 2012 due to higher energy consumption and increased natural gas and electricity prices associated with Western Canada crude oil production.

Operating costs in Western Canada increased to $17.05/boe in 2013 compared with $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 with $17.12/boe in 2012. The decrease in operating costs was attributable to higher production and lower maintenance and supply costs compared to 2012 when the planned SeaRose and Terra Nova FPSO turnarounds were performed.

Operating costs in the Asia Pacific Region averaged $11.39/boe in 2013 compared with $10.08/boe in 2012. The increase was due to lower production associated with typhoon-related shut-ins in 2013.

Exploration and Evaluation Expenses

($ millions)	**2013**	2012
Seismic, geological and geophysical	**133**	140
Expensed drilling	**102**	188
Expensed land	**11**	16
Total	**246**	344

Total exploration and evaluation expenses decreased by $98 million in 2013 compared to 2012 primarily due to high drilling success rates, which resulted in more capitalized exploration costs. Expensed drilling in 2012 included costs related to the Searcher well in the Atlantic Region and the Liuhua 32-1-1 well in the Asia Pacific Region. The decrease in seismic, geological and geophysical expense in 2013 was primarily due to a shift from exploration to development activities in Western Canada and the Asia Pacific Region in 2013.

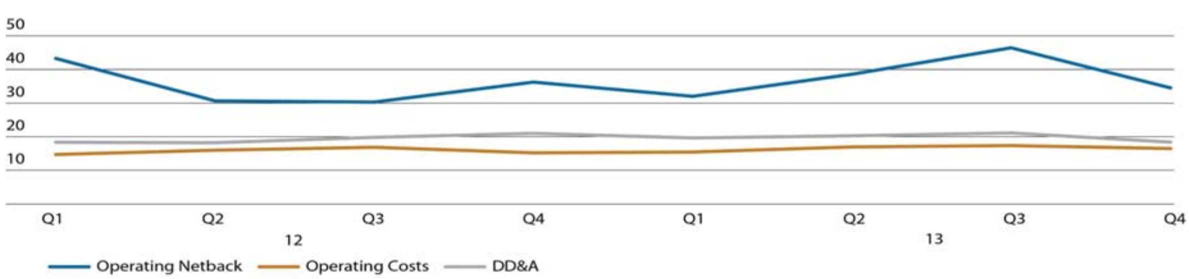
Depletion, Depreciation, Amortization ("DD&A") and Impairment

During 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.

During 2013, total unit DD&A, excluding the impairment charge, was $19.67/boe compared to $19.20/boe during 2012.

At December 31, 2013, capital costs in respect of unproved properties and major development projects were $8.3 billion compared with $6.1 billion at the end of 2012. These costs are excluded from the Company's DD&A calculation until the unproved properties are evaluated and developed, proved reserves are attributed to the project or the project is deemed to be impaired.

Operating Netback[1], Unit Operating Costs and DD&A
($/boe)



[1] *Operating netback is a non-GAAP measure and is equal to Husky's realized price less royalties, operating costs and transportation costs on a per unit basis. Refer to section 11.3*

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, $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[1] *($ millions)*	**2013**	2012
Exploration		
Western Canada	**353**	238
Atlantic Region	**201**	13
Asia Pacific Region	**21**	22
	575	273
Development		
Western Canada	**2,029**	2,029
Oil Sands	**552**	658
Atlantic Region	**437**	400
Asia Pacific Region	**633**	725
	3,651	3,812
Acquisitions		
Western Canada	**38**	21
	4,264	4,106

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

Western Canada, Heavy Oil & Oil Sands

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

	2013		2012	
Wells Drilled *(wells)*	**Gross**	**Net**	Gross	Net
Exploration				
Oil	**39**	**24**	47	30
Gas	**19**	**14**	19	12
Dry	–	–	–	–
	58	**38**	66	42
Development				
Oil	**768**	**709**	775	715
Gas	**68**	**41**	23	17
Dry	**1**	–	5	4
	837	**750**	803	736
Total	**895**	**788**	869	778

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

During 2013, Husky invested $2,420 million on 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 $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 in 2013. Capital expenditures on facilities, land acquisition and retention, and environmental protection totalled $349 million.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling were $629 million during 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

The following table discloses Husky's offshore Atlantic Region drilling activity during 2013:

Atlantic Region Offshore Drilling Activity

Well	Working Interest	Well Type
North Amethyst G-25 9	WI 68.875%	Development (Producer)
Terra Nova E-18-12Z	WI 13%	Development (Producer)
North Amethyst G-25-8	WI 68.875%	Development (Injector)
Harpoon 0-85	WI 35%	Exploration
Bay Du Nord C-78	WI 35%	Exploration
Federation K-78	WI 35%	Exploration
White Rose H-70	WI 68.875%	Delineation
White Rose H-70Z	WI 93.33%	Delineation
Terra Nova E-19	WI 13%	Delineation

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

Total capital expenditures of $654 million were invested in the Asia Pacific Region in 2013, primarily for development of the Liwan Gas Project. In addition, the Company drilled the MBF-1 exploration well (50% interest) and the MAX-3 appraisal well (40% interest) at the Madura Strait in Indonesia in 2013.

2014 Upstream Capital Program

($ millions)	
Western Canada	**2,500**
Oil sands	**400**
Atlantic Region	**600**
Asia Pacific Region	**500**
Total Upstream capital expenditures[1]	**4,000**

[1] *Capital program excludes capitalized administration costs, capitalized interest and asset retirement obligations incurred.*

The 2014 Capital Program will enable Husky to build on the momentum achieved over the past three years and will support the acceleration of near-term production and the continued execution of the Company's mid and long-term growth initiatives.

The Company has budgeted $500 million for the Asia Pacific Region in 2014, mainly for the completion of the Liwan Gas Project including the tie-in of the Liuhua 34-2 field into the Liwan deep water infrastructure and development of the Madura Strait block in Indonesia.

Oil Sands capital for 2014 will primarily be for completing the development of Phase 1 of the Sunrise Energy Project as well as planning, design and engineering for the next phase of the project.

Budgeted investment in the Atlantic Region of $600 million is for continued development of the White Rose fields and extensions. The Company plans to conduct additional drilling in 2014 in the Flemish Pass Basin to further assess the economic potential of oil development following the three major discoveries.

In addition to advancing mid and long-term growth pillars, the 2014 Capital Program provides support to the Company's efforts to continue to reinvigorate and transform its foundation in Western Canada. A substantial oil and liquids-rich natural gas resource play portfolio has been acquired and further drilling is scheduled to take place across the portfolio in 2014. The Company is making progress in its strategy to transition a greater percentage of its heavy oil production to long-life thermal. The Company will continue its development of the 10,000 bbls/day Rush Lake thermal project, with expected first production in the second half of 2015. In addition, two 10,000 bbls/day thermal developments were sanctioned in late 2013 at Edam East and Vawn, both located in Saskatchewan, with construction scheduled to begin in 2014.

Upstream Turnarounds

2013 Turnarounds

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

An 11-week turnaround of the Terra Nova FPSO was completed in 2013. The planned maintenance shutdown was extended to accommodate repair and replacement of nine mooring chains. The impact to Husky's 2013 annual production was approximately 2,100 bbls/day.

Planned Turnarounds

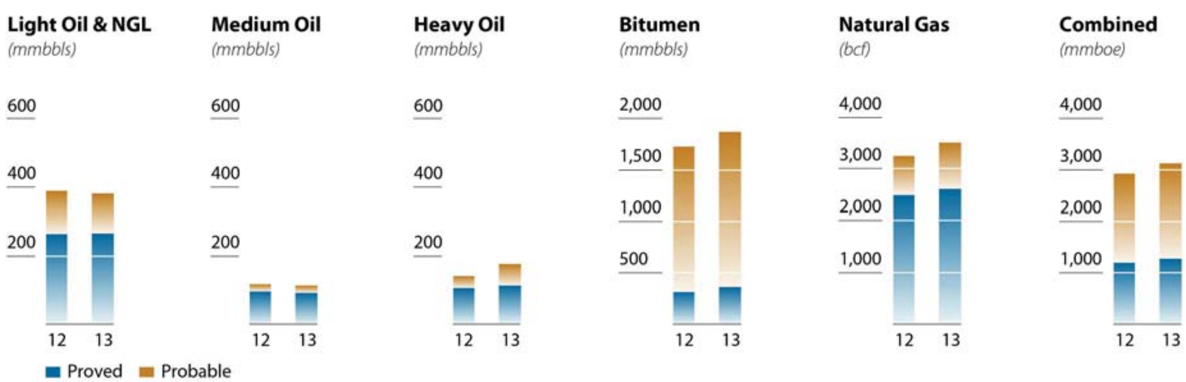
Planned plant maintenance activities for Western Canada are scheduled in the second and third quarters of 2014, including the full shutdown and maintenance of the Rainbow oil and gas facility for approximately four weeks in the second quarter.

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

A planned offstation for the Wenchang FPSO is scheduled for approximately five months in 2014. The offstation is intended to address dry dock maintenance and mooring line replacement.

Oil and Gas Reserves

The following oil and gas reserves disclosure has been prepared in accordance with Canadian Securities Administrators' National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") effective December 31, 2013. Husky received approval from the Canadian Securities Administrators to also disclose its reserves using U.S. disclosure requirements as supplementary disclosure to the reserves and oil and gas activities disclosure required by NI 51-101. The reserves information prepared in accordance with the U.S. disclosure requirements is included in the Company's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com .



Note: All heavy oil thermal reserves are classified as bitumen.

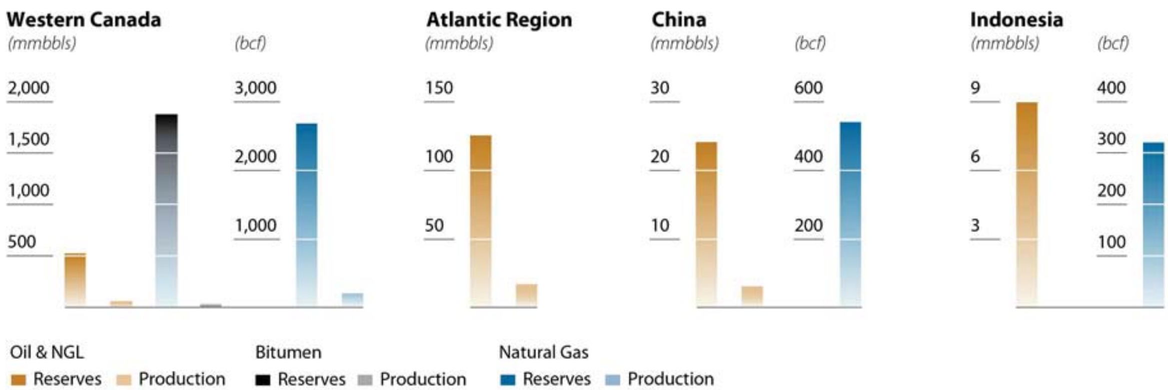
The Company's complete Oil and Gas Reserves Disclosure, prepared in accordance with NI 51-101, is contained in Husky's Annual Information Form, which is available at www.sedar.com, or Husky's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com.

Sproule Unconventional Limited ("Sproule"), an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct a full evaluation of Husky's crude oil, natural gas and natural gas products reserves for the Heavy Oil and Gas business unit, excluding the Tucker property.

McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and natural gas products reserves, excluding those estimated by Sproule. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally evaluated proved and probable reserves and net present values are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the Canadian Oil and Gas Evaluation Handbook.

At December 31, 2013, Husky's proved oil and gas reserves were 1,265 mmboe, up from 1,192 mmboe at the end of 2012. Additions to proved reserves, including acquisitions and divestitures, represent 166% excluding economic revisions (164% including economic revisions) of 2013 production. Major additions to proved reserves in 2013 included:

- The extension through additional drilling locations at the Sunrise Energy Project in the Oil Sands that resulted in the booking of an additional 39 mmbbls of bitumen in proved undeveloped reserves;
- The project sanction at the South White Rose Extension in the Atlantic Region that resulted in the booking of an additional 7 mmbbls of light oil in proved undeveloped reserves; and
- The extension through additional drilling locations at the Ansell liquids-rich natural gas resource play in the Alberta Deep Basin that resulted in the booking of an additional 32 mmboe of natural gas and NGL in proved undeveloped reserves.



Note: Reserves reported represent proved plus probable reserves.

Reconciliation of Proved Reserves

	Canada						International		Total		
	Western Canada					Atlantic Region					
(forecast prices and costs before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)* [(1)]	Bitumen *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL (mmbbls)	Natural Gas *(bcf)*	Crude Oil & NGL *(mmbbls)*	Natural Gas (bcf)	Equivalent Units *(mmboe)*
Proved reserves											
December 31, 2012	173	95	105	311	2,073	68	22	434	774	2,507	1,192
Revision of previous estimate	(10)	(3)	7	24	79	13	3	–	34	79	48
Purchase of reserves in place	–	–	–	1	1	–	–	–	1	1	1
Sale of reserves in place	–	–	–	–	(3)	–	–	–	–	(3)	(1)
Discoveries, extensions and improved recovery	15	7	28	40	232	9	1	18	100	250	142
Economic revision	1	–	–	–	(20)	–	–	–	1	(20)	(3)
Production	(12)	(8)	(27)	(17)	(187)	(16)	(3)	–	(83)	(187)	(114)
Proved reserves December 31, 2013	**167**	**91**	**113**	**359**	**2,175**	**74**	**23**	**452**	**827**	**2,627**	**1,265**
Proved and probable reserves December 31, 2013	**223**	**112**	**176**	**1,870**	**2,669**	**125**	**33**	**859**	**2,539**	**3,528**	**3,127**
December 31, 2012	229	117	140	1,725	2,547	130	30	718	2,371	3,265	2,915

[(1)] *Heavy oil thermal property reserves are classified as bitumen.*

Reconciliation of Proved Developed Reserves

(forecast prices and costs before royalties)	Canada – Western Canada – Light Crude Oil & NGL (mmbbls)	Canada – Western Canada – Medium Crude Oil (mmbbls)	Canada – Western Canada – Heavy Crude Oil (mmbbls)[1]	Canada – Western Canada – Bitumen (mmbbls)	Canada – Western Canada – Natural Gas (bcf)	Canada – Atlantic Region – Light Crude Oil (mmbbls)	International – Light Crude Oil & NGL (mmbbls)	International – Natural Gas (bcf)	Total – Crude Oil & NGL (mmbbls)	Total – Natural Gas (bcf)	Total – Equivalent Units (mmboe)
Proved developed reserves											
December 31, 2012	149	88	84	59	1,714	56	8	–	444	1,714	729
Revision of previous estimate	(6)	(2)	14	11	106	12	2	–	31	106	50
Transfer from proved undeveloped	4	3	6	13	58	8	8	267	42	325	97
Purchase of reserves in place	–	–	–	–	1	–	–	–	–	1	–
Sale of reserves in place	–	–	–	–	(3)	–	–	–	–	(3)	(1)
Discoveries, extensions and improved recovery	10	4	15	–	33	–	–	–	29	33	34
Economic revision	1	–	–	–	(20)	–	–	–	1	(20)	(3)
Production	(12)	(8)	(27)	(17)	(187)	(16)	(3)	–	(83)	(187)	(114)
Proved developed reserves December 31, 2013	**146**	**85**	**92**	**66**	**1,702**	**60**	**15**	**267**	**464**	**1,969**	**792**

[1] *Heavy oil thermal property reserves are classified as bitumen.*

Infrastructure and Marketing

The Company is engaged in the marketing of 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 *($ millions, except where indicated)*	**2013**	2012
Infrastructure gross margin[1]	**130**	119
Marketing and other gross margin[2]	**312**	398
Gross margin	**442**	517
Operating and administrative expenses	**33**	33
Depletion, depreciation and amortization	**20**	22
Other expenses	**(3)**	–
Income taxes	**100**	116
Net earnings	**292**	346
Commodity trading volumes managed (mboe/day)	**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.*

Infrastructure and Marketing net earnings decreased by $54 million in 2013 compared to 2012 due to lower marketing margins as a result of the narrowing of WTI to Brent 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.

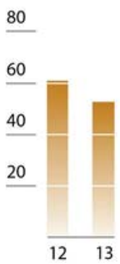
Infrastructure and Marketing capital expenditures totalled $96 million in 2013 compared to $54 million in 2012. The majority of Infrastructure and Marketing capital expenditures during the year related to pipeline maintenance and storage tank expenditures.

6.4 Downstream

2013 Total Downstream Earnings $830 million

Upgrader

Upgrader
Synthetic Crude Sales
(mbbls/day)



Upgrader
Unit Margin & Operating Costs
($/bbl)

Upgrader Earnings Summary *($ millions, except where indicated)*	2013	2012
Gross revenues	**2,023**	2,191
Gross margin	**645**	555
Operating and administrative expenses	**168**	153
Depreciation and amortization	**96**	102
Other income	**(20)**	(6)
Income taxes	**104**	80
Net earnings	**297**	226
Upgrader throughput[(1)] *(mbbls/day)*	**66.1**	77.4
Synthetic crude oil sales *(mbbls/day)*	**50.5**	60.4
Upgrading differential *($/bbl)*	**29.14**	22.34
Unit margin ($/bbl)	**34.99**	25.17
Unit operating cost[(2)] ($/bbl)	**6.96**	5.42

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

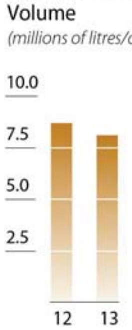
The Upgrading operations add value by processing heavy sour crude oil into high value synthetic crude oil and low sulphur distillates. The Upgrader profitability is primarily dependent on the differential between the cost of heavy crude oil feedstock and the sales price of synthetic crude oil.

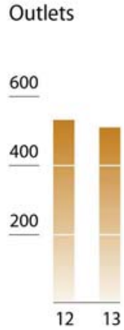
The increase in Upgrader earnings in 2013 compared to 2012 was primarily due to higher upgrading differentials that resulted from a deep discount on Lloyd Heavy Blend feedstock in early and late 2013 and higher realized prices for Husky Synthetic Blend crude oil, partially offset by lower throughput due to a major planned turnaround completed in the year.

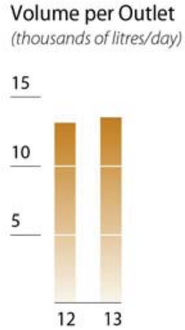
During 2013, the price of Husky's synthetic crude oil averaged $100.57/bbl compared with the average cost of blended heavy crude oil from the Lloydminster area of $71.43/bbl. During 2012, the price of Husky's synthetic crude oil averaged $91.90/bbl compared with an average cost of blended heavy crude oil from the Lloydminster area of $69.56/bbl. This resulted in an average synthetic/heavy crude oil differential of $29.14/bbl in 2013 compared to $22.34/bbl in 2012 and a gross unit margin of $34.99/bbl in 2013 compared to $25.17/bbl in 2012. The cost of upgrading averaged $6.96/bbl in 2013 compared to $5.42/bbl in 2012, due to the major planned turnaround in 2013, which resulted in a net margin for upgrading heavy crude of $28.03/bbl, up 42% compared with $19.75/bbl in 2012.

Canadian Refined Products

Fuel Sales Volumes







Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	**2013**	2012
Gross revenues	**3,737**	3,848
Gross margin		
Fuel	**140**	153
Refining	**175**	180
Asphalt	**233**	257
Ancillary	**55**	50
	603	640
Operating and administrative expenses	**253**	242
Depreciation and amortization	**90**	83
Other expense	**–**	4
Income taxes	**66**	80
Net earnings	**194**	231
Number of fuel outlets[(1)]	**509**	531
Fuel sales volume, including wholesale		
Fuel sales *(million of litres/day)*[(2)]	**8.1**	8.7
Fuel sales per outlet *(thousand of litres/day)*[(2)]	**13.5**	13.1
Refinery throughput		
Prince George refinery *(mbbls/day)*	**10.3**	11.1
Lloydminster refinery *(mbbls/day)*	**26.4**	28.3
Ethanol production *(thousand of litres/day)*	**742.4**	721.2

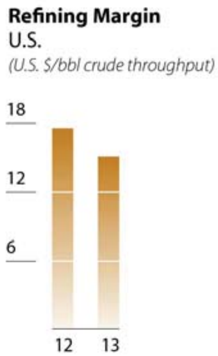
(1) *Average number of fuel outlets for period indicated.*
(2) *Fuel sales have been recast to exclude non-retail products. Prior periods have been adjusted to conform with the current period presentation.*

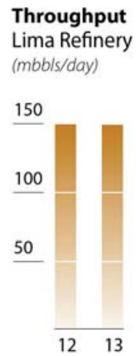
Fuel margins decreased in 2013 compared to 2012 primarily due to lower diesel margins, decreased wholesale sales volumes and lower fuel sales resulting from retail site construction and selected outlet closures.

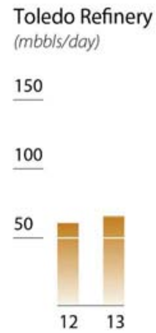
Refining gross margins decreased slightly in 2013 compared to 2012 primarily due to higher priced feedstock costs and lower throughput and sales volumes, partially offset by higher realized prices for refined products.

Asphalt gross margins decreased compared to the same period in 2012 primarily due to lower asphalt production as a result of a scheduled refinery turnaround in the year.

U.S. Refining and Marketing







U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	**2013**	2012
Gross revenues[(1)]	**10,728**	9,856
Gross refining margin[(1)]	**1,182**	1,312
Operating and administrative expenses	**424**	398
Depreciation and amortization	**233**	212
Other expenses	**3**	9
Income taxes	**183**	257
Net earnings	**339**	436
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**149.4**	150.0
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**65.0**	60.6
Refining margin *(U.S. $/bbl crude throughput)*[(1)]	**15.06**	17.48
Refinery inventory (feedstocks and refined products) *(mmbbls)*[(2)]	**10.3**	11.3

(1) *Gross revenues and purchases have been recast for the comparative period to reflect a change in the classification of certain trading transactions.*
(2) *Refinery inventory includes feedstock and refined products.*

U.S. Refining and Marketing net earnings in 2013 decreased compared to 2012 primarily due to a significant drop in the 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 Chicago 3:2:1 market crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while crude oil feedstock costs included in realized margins are based on FIFO accounting, which reflects purchases made earlier in the previous year when crude oil prices were lower. The estimated FIFO impact was a reduction in net earnings of approximately $18 million in 2013 compared to a reduction in net earnings of $28 million in 2012.

In addition, the product slates produced at the Lima and Toledo refineries contain approximately 10% to 15% of other products that are sold at discounted market prices compared with gasoline and distillate, which are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

Downstream Capital Expenditures

Downstream capital expenditures totalled $534 million for 2013 compared to $457 million in 2012. In Canada, capital expenditures were $314 million related to upgrades at the Prince George Refinery, the Upgrader and at retail stations. In the United States, capital expenditures totalled $220 million. At the Lima Refinery, $143 million was spent on various process improvement 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 the 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 currently 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 that will affect approximately 30% of its operating capacity. Refinery operations will be impacted for approximately 35 to 50 days depending on the unit. The remaining 70% of the operating units are scheduled to be addressed in a turnaround planned for 2015.

6.5 Corporate

2013 Loss $245 million

Corporate Summary *($ millions) income (expense)*	**2013**	2012
Administration expenses	**(112)**	(128)
Stock-based compensation	**(105)**	(54)
Depreciation and amortization	**(51)**	(40)
Other income	**17**	3
Foreign exchange gains	**21**	14
Interest - net	**–**	(52)
Income taxes	**(15)**	64
Net loss	**(245)**	(193)

The Corporate segment reported a loss in 2013 of $245 million compared to a loss of $193 million in 2012. Stock-based compensation expense increased by $51 million in 2013 due to a higher share price at the end of 2013 compared to 2012. Interest - net decreased by $52 million in 2013 compared to 2012 due to increases in amounts of capitalized interest related to projects in the Asia Pacific Region and the Sunrise Energy Project. Other income increased by $14 million in 2013 compared to 2012 primarily due to the recovery of an insurance provision from the prior year.

Foreign Exchange Summary *($ millions, except exchange rate amounts)*	**2013**	2012
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(11)**	43
Gains on cross currency swaps	**–**	2
Gains (losses) on contribution receivable	**27**	(7)
Other foreign exchange gains (losses)	**5**	(24)
Foreign exchange gains	**21**	14
U.S./Canadian dollar exchange rates:		
At beginning of year	**U.S. $1.005**	U.S. $0.983
At end of year	**U.S. $0.940**	U.S. $1.005

Consolidated Income Taxes

Consolidated income taxes decreased in 2013 to $799 million from $814 million in 2012, resulting in an effective tax rate of 30% in 2013 compared to 29% in 2012. The increase in the effective tax rate was attributable to the increase in non-deductible stock-based compensation expense.

($ millions)	**2013**	2012
Income taxes as reported	**799**	814
Cash taxes paid	**433**	575

Taxable income from Canadian operations is primarily generated through partnerships. This structure previously allowed a deferral of taxable income and related taxes to a future period. Starting in 2012, the Canadian government has removed this deferral, and any income taxes related to previously deferred taxable income are now payable over a five-year period that commenced in 2013.

Corporate Capital Expenditures

Corporate capital expenditures of $134 million in 2013 were primarily related to computer hardware and software and leasehold improvements.

7.0 Risk and Risk Management

7.1 Enterprise Risk Management

Husky's enterprise risk management program supports decision-making via comprehensive and systematic identification and assessment of risks that could materially impact the results of the Company. Through this framework, the Company builds risk management and mitigation into strategic planning and operational processes for its business units through the adoption of standards and best practices. Husky has developed an enterprise risk matrix to identify risks to its people, the environment, its assets and its reputation, and to systematically mitigate these risks to an acceptable level.

The Company attempts to mitigate its financial, operational and strategic risks to an acceptable level through a variety of policies, systems and processes. The following provides a list of the most significant risks relating to Husky and its operations.

7.2 Significant Risk Factors

Operational, Environmental and Safety Incidents

The Company's businesses are subject to inherent operational risks and hazards in respect to safety and the environment that require continuous vigilance. The Company seeks to minimize these operational risks and hazards by carefully designing and building its facilities and conducting its operations in a safe and reliable manner. However, failure to manage these operational risks and hazards effectively could result in unexpected incidents, including the release of restricted substances, fires, explosions, well blow-outs, marine catastrophe or mechanical failures and pipeline failures. The consequences of such events include personal injuries, loss of life, environmental damage, property damage, loss of revenues, fines, penalties, legal liabilities, disruption to operations, asset repair costs, remediation and reclamation costs, monitoring post-cleanup and/or reputational impacts that may affect the Company's license to operate. Remediation may be complicated by a number of factors including shortages of specialized equipment or personnel, extreme operating environments and the absence of appropriate or proven countermeasures to effectively remedy such consequences. Enterprise risk management, emergency preparedness, business continuity and security policies and programs are in place for all operating areas, and are routinely exercised. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks and hazards. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks and hazards.

Commodity Price Volatility

The Company's results of operations and financial condition are dependent on the prices received for its crude oil and natural gas production. Lower prices for crude oil and natural gas could adversely affect the value and quantity of Husky's oil and gas reserves. Husky's reserves include significant quantities of heavier grades of crude oil that trade at a discount to light crude oil. Heavier grades of crude oil are typically more expensive to produce, process, transport and refine into high value refined products. Refining and transportation capacity for heavy crude oil is limited and planned increases of North American heavy crude oil production may create the need for additional heavy oil refining and transportation capacity. As a result, wider price differentials could have adverse effects on the Company's financial performance and condition, reduce the value and quantities of heavier crude oil reserves and delay or cancel projects that involve the development of heavier crude oil resources. There is no guarantee that planned pipeline development projects will provide sufficient transportation capacity and access to refining capacity to accommodate expected increases in North American heavy crude oil production.

Prices for crude oil are based on world supply and demand. Supply and demand can be affected by a number of factors including, but not limited to, actions taken by OPEC, non-OPEC crude oil supply, social conditions in oil producing countries, the occurrence of natural disasters, general and specific economic conditions, prevailing weather patterns and the availability of alternate sources of energy.

The Company's natural gas production is currently located entirely in Western Canada and is, therefore, subject to North American market forces. North American natural gas supply and demand is affected by a number of factors including, but not limited to, the amount of natural gas available to specific market areas either from the well head or from storage facilities, prevailing weather patterns, the price of crude oil, the U.S. and Canadian economies, the occurrence of natural disasters and pipeline restrictions.

In certain instances, the Company uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

The fluctuations in crude oil and natural gas prices are beyond the Company's control and accordingly, could have a material adverse effect on the Company's business, financial condition and cash flow.

For information on 2013 commodity price sensitivities, refer to Section 3.0 within this Management's Discussion and Analysis.

Reservoir Performance Risk

Lower than projected reservoir performance on the Company's key growth projects could have a material impact on the Company's financial position, medium to long-term business strategy and cash flow. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets, and could negatively affect the Company's reputation, investor confidence and the Company's ability to deliver on its growth strategy.

To maintain the Company's future production of crude oil, natural gas and natural gas liquids and maintain the value of the reserves portfolio, additional reserves must be added through discoveries, extensions, improved recovery, performance related revisions and acquisitions. The production rate of oil and gas properties tends to decline as reserves are depleted, while the associated unit operating costs increase. To mitigate the effects of this, the Company must undertake successful exploration and development programs, increase the recovery factor from existing properties through applied technology, and identify and execute strategic acquisitions of proved developed and undeveloped properties and unproved prospects. Maintaining an inventory of potential development projects depends on, among other things, obtaining and renewing rights to explore, develop and produce oil and natural gas, drilling success, completing long-lead time capital intensive projects on budget and on schedule and the application of successful exploitation techniques on mature properties.

Restricted Market Access and Pipeline Interruptions

The Company's results depend upon the Company's ability to deliver products to the most attractive markets. The Company's results could be impacted by restricted market access resulting from a lack of pipeline or other transportation alternatives to attractive markets, as well as by regulatory and/or other marketplace barriers. The interruptions and restrictions may be caused by the inability of a pipeline to operate, or they can be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. With growing conventional and oil sands production across North America and limited availability of infrastructure to carry the Company's products to the marketplace, oil and natural gas transportation capacity is expected to be restricted in the next few years. Restricted market access may potentially have a material impact on the Company's financial position, medium to long-term business strategy, cash flow and corporate reputation. Unplanned shutdowns and closures of our refineries or upgrader may limit our ability to deliver product with negative implications on sales from operating activities.

Security and Terrorist Threats

A security threat or terrorist attack on a facility owned or operated by the Company could result in the interruption or cessation of key elements of its operations. Security and terrorist threats may also impact the Company’s personnel, which could result in death, injury, hostage taking and/or kidnapping. This could have a material impact on the Company's financial position, business strategy and cash flow.

International Operations

International operations can expose the Company to uncertain political, economic and other risks. The Company's operations in certain jurisdictions may be adversely affected by political, economic or social instability or events. These events may include, but are not limited to, onerous fiscal policy, renegotiation or nullification of agreements, imposition of onerous regulation, changes in laws governing existing operations, financial constraints, including currency and exchange rate fluctuations, and unreasonable taxation. This could adversely affect the Company's interest in its foreign operations and future profitability.

Gas Offtake

The potential inability to deliver an effective gas storage solution as inventories grow over the life of the White Rose field may potentially result in prolonged shutdown of these operations. This could have a material impact on the Company's financial position, medium to long-term business strategy and cash flow.

Skills and Human Resource Shortage

The Company recognizes that a robust, productive, and healthy workforce drives efficiency, effectiveness, and financial performance. Attracting and retaining qualified and skilled labour is critical to the successful execution of the Company's current and future business strategies. However, a tight labour market, an insufficient number of qualified candidates, and an aging workforce are factors that could precipitate a human resource risk for the Company. Failure to manage any of the foregoing developments, retain current employees and attract new skilled employees could materially affect the Company's ability to conduct its business.

Major Project Execution

The Company manages a variety of major projects relating to oil and gas exploration, development and production. Risks associated with the execution of the Company's major projects, as well as the commissioning and integration of new assets into its existing infrastructure, may result in cost overruns, project or production delays, and missed financial targets, thereby eroding project economics. Typical project execution risks include: the availability and cost of capital, inability to find mutually agreeable parameters with key project partners for large growth projects, availability of manufacturing and processing capacity, faulty construction and design errors, labour disruptions, bankruptcies, productivity issues affecting the Company directly or indirectly, unexpected changes in the scope of a project, health and safety incidents, need for government approvals or permits, unexpected cost increases, availability of qualified and skilled labour, availability of critical equipment, severe weather, and availability and proximity of pipeline capacity.

Partner Misalignment

Joint venture partners operate a portion of Husky's assets in which the Company has an ownership interest. The Company is at times dependent upon its partners for the successful execution of various projects. If a dispute with partners were to occur over the development and operation of a project, or if partners were unable to fund their contractual share of the capital expenditures, a Husky project may be delayed and the Company may be partially or totally liable for its partner's share of the project.

Reserves Data, Future Net Revenue and Resource Estimates

The reserves data in this Management's Discussion and Analysis represent estimates only. The accurate assessment of oil and gas reserves is critical to the continuous and effective management of the Company's Upstream assets. Reserves estimates support various investment decisions about the development and management of resource plays. In general, estimates of economically recoverable crude oil and gas reserves and the future net cash flow therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties, and the assumed effects of regulation by governmental agencies, including with respect to royalty payments, all of which may vary considerably from actual results. All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. Estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, prepared by different engineers or by the same engineers at different times, may vary substantially. All reserves estimates at times, rely on indirect measurement techniques to estimate the size and recoverability of the resource. While new technologies have increased the accuracy and efficacy of these techniques, there remains the potential for human or systemic error in recording and reporting the magnitude of the Company's oil and gas reserves. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets, and could negatively affect the Company's reputation, investor confidence, and the Company's ability to deliver on its growth strategy.

Government Regulation

Given the scope and complexity of the Company's operations, the Company may be subject to regulation and intervention by governments at the federal, provincial, state and municipal levels in the countries in which it conducts its operations or exploratory activities. As these governments continually balance competing demands from different interest groups and stakeholders, the Company recognizes that the magnitude of regulatory risks has the potential to change over time. Changes in government policy, legislation or regulation could impact the Company's existing and planned projects as well as impose costs of compliance, increase capital expenditures and operating expenses, and expose the Company to other risks including environmental and safety risks. Examples of the Company's regulatory risks include, but are not limited to, uncertain or negative interactions with governments, uncertain energy policies, environmental and safety controls related to the reduction of greenhouse gasses and other emissions, penalties, taxes, royalties, government fees, anti-corruption laws, reserves access, limitations or increases in costs relating to the exportation of commodities, restrictions on the acquisition of exploration and production rights and land tenure, expropriation or cancellation of contract rights, limitations on control over the development and abandonment of fields, and loss of licenses to operate.

Environmental Regulation

The Company anticipates that changes in environmental legislation may require reductions in emissions from its operations and result in increased capital expenditures. Further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, and increased capital expenditures and operating costs, which could have a material adverse effect on the Company's financial condition and results of operations.

Following the 2010 Deepwater Horizon oil spill in the Gulf of Mexico, the United States implemented stricter regulation of offshore oil and gas operations with respect to operations in the Outer Continental Shelf, including in the Gulf of Mexico. Further regulation, increased financial assurance requirements and increased caps on liability are likely to be applied to offshore oil and gas operations in these areas. In the event that similar changes in environmental regulation occur with respect to the Company's operations in the Atlantic or Asia Pacific Regions, such changes could increase the cost of complying with environmental regulation in connection with these operations and have a material adverse impact on Husky's operations.

The transportation of crude oil by rail is an emerging issue for the petroleum industry. There have been four major incidents in the past eight months involving Bakken crude oil transported on rail, and federal and industry reviews of regulations and equipment standards are underway. In early 2014, Transport Canada announced proposed regulatory amendments to further improve the safety of the transportation of dangerous goods by rail. This may result in stricter standards, larger fines and liabilities, and increased capital expenditures for the petroleum industry.

Climate Change Regulation

The Company continues to monitor the international and domestic efforts to address climate change, including international low carbon fuel standards and regulations and emerging regulations in the jurisdictions in which the Company operates. Existing regulations in Alberta require facilities that emit more than 100,000 tonnes of carbon dioxide equivalent in a year to reduce their emissions intensity by up to 12% below an established baseline emissions intensity. These regulations currently affect the Company's Ram River Gas Plant and Tucker Thermal Oil Facility and are anticipated to affect the Sunrise Energy Project when it begins to produce oil. British Columbia currently has a $30 per tonne carbon tax that is placed on fuel the Company uses in that jurisdiction, which affects all of the Company's operations in British Columbia. The Saskatchewan government is anticipated to release regulations similar to Alberta's and the Federal Government of Canada has announced pending regulations for the oil and gas sector. Climate change regulations may become more onerous over time as public and political pressures increase to implement initiatives that further reduce the emissions of greenhouse gases. Although the impact of emerging regulation is uncertain, they may adversely affect the Company's operations and increase costs.

In addition, the Company's operations may be materially impacted by application of the EPA'sclimate change rules or by future U.S. greenhouse gas legislation that applies to the oil and gas industry or the consumption of petroleum products or by these or any further restrictive regulations issued by the EPA. Such legislation or regulation could require U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

Competition

The energy industry is highly competitive with respect to gaining access to the resources required to increase oil and gas reserves and production and gain access to markets. The Company competes with others to acquire prospective lands, retain drilling capacity and field operating and construction services, obtain sufficient pipeline and other transportation capacity, gain access to and retain adequate markets for its products and services, and gain access to capital markets. The Company's ability to successfully complete development projects could be adversely affected if it is unable to acquire economic supplies and services due to competition. Subsequent increases in the cost of or delays in acquiring supplies and services could result in uneconomic projects. Competitors comprise all types of energy companies, some of which have greater resources.

Internal Credit Risk

Credit ratings affect the Company's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability to engage in ordinary course derivative or hedging transactions and maintain ordinary course contracts with customers and suppliers on acceptable terms depends on the Company's credit ratings. A reduction in the current rating on debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings or a negative change in ratings outlook, could adversely affect Husky's cost of financing and its access to sources of liquidity and capital. Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to the Company's securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

General Economic Conditions

General economic conditions may have a material adverse effect on the Company's results of operations, liquidity and financial condition. A decline in economic activity will reduce demand for petroleum products and adversely affect the price the Company receives for its commodities. The Company's cash flow could decline, assets could be impaired, future access to capital could be restricted, and major development projects could be delayed or abandoned.

Cost or Availability of Oil and Gas Field Equipment

The cost or lack of availability of oil and gas field equipment could adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including land and offshore drilling rigs, land and offshore geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available, when required, at reasonable prices.

Climatic Conditions

Extreme climatic conditions may have significant adverse effects on operations. The predictability of the demand for energy is affected to a large degree by the predictability of weather and climate. In addition, the Company's exploration, production and construction operations, or disruptions to the operations of major customers or suppliers, can be affected by extreme weather. This may result in cessation or diminishment of production, delay of exploration and development activities or delay of plant construction. All of these could potentially cause adverse financial impacts.

7.3 Financial Risks

Husky's financial risks are largely related to commodity price risk, foreign currency risk, interest rate risk, credit risk, and liquidity risk. From time to time, the Company uses derivative financial instruments to manage its exposure to these risks. These derivative financial instruments are not intended for trading or speculative purposes. For further details on the Company's derivative financial instruments, including assumptions made in the calculation of fair value and additional discussion of exposure to risks and mitigation activities, see Note 22 Financial Instrument and Risk Management within the Company's 2013 Consolidated Financial Statements and Section 3.0 of this Management's Discussion and Analysis. For a discussion on commodity price risk, refer to the Commodity Price Volatility section above.

Foreign Currency Risk

The Company's results are affected by the exchange rates between various currencies including the Canadian and U.S. dollar. The majority of Husky's expenditures are in Canadian dollars while the majority of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. 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, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt and related interest expense, as expressed in Canadian dollars. The fluctuations in exchange rates are beyond Husky's control and, accordingly, could have a material adverse effect on the Company's business, financial condition and cash flow.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. revenue dollars to hedge against these potential fluctuations. Husky also designates a portion of its U.S debt as a hedge of the Company's net investment in the U.S. refining operations, which are considered as a foreign functional currency. At December 31, 2013, the amount that the Company designated was U.S. $3.2 billion (December 31, 2012 - U.S. $2.8 billion).

Interest Rate Risk

Interest rate risk is the impact of fluctuating interest rates on earnings, cash flows and valuations. In order to manage interest rate risk and the resulting interest expense, Husky mitigates some of its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of its credit facilities and various financial instruments. The optimal mix maintained will depend on market conditions. Husky may also enter into interest rate swaps from time to time as an additional means of managing current and future interest rate risk.

Credit Risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties in a transaction fail to meet or discharge their obligation to the Company. Husky actively manages this exposure to credit and contract execution risk from both a customer and a supplier perspective. Internal credit policies govern Husky's credit portfolio and limit transactions according to a counterparty's and a supplier's credit quality. Counterparties for all financial derivatives transacted by Husky are major financial institutions or counterparties with investment grade credit ratings.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company's process for managing liquidity risk includes ensuring, to the extent possible, that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, and the availability to raise capital from various debt capital markets, including under its shelf prospectuses. The availability of capital under its shelf prospectuses is dependent on market conditions.

Husky is committed to retaining investment grade credit ratings to support access to debt capital markets and currently has the following credit ratings:

	Outlook	Rating
Moody's:		
Senior Unsecured Debt	Stable	Baa2
Standard and Poor's:		
Senior Unsecured Debt	Stable	BBB+
Series 1 Preferred Shares	Stable	P-2 (low)
Dominion Bond Rating Service:		
Senior Unsecured Debt	Stable	A (low)
Series 1 Preferred Shares	Stable	Pfd-2 (low)

Fair Value of Financial Instruments

The Company's financial assets and liabilities that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon the fair value hierarchy. Level 1 fair value measurements are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair value measurements of assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 fair value measurements are based on inputs that are unobservable and significant to the overall fair value measurement.

The Company's financial instruments include cash and cash equivalents, accounts receivable, contribution receivable, accounts payable and accrued liabilities, long-term debt, contribution payable, and portions of other assets and other long-term liabilities.

The following table summarizes by measurement classification, derivatives, contingent consideration and hedging instruments that are carried at fair value through profit or loss ("FVTPL") 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)
Net gains (losses) for the year related to financial instruments held at fair value	**(111)**	122
Included in net earnings	**33**	104
Included in OCI	**(144)**	18

(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.

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

In 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 as at December 31, 2012. At December 31, 2013, the Company had $3.6 billion of unused credit facilities of which $3.2 billion was long-term committed credit facilities and $371 million was 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 8.2.

	2013	2012
Cash flow		
Operating activities *($ millions)*	**4,645**	5,193
Financing activities *($ millions)*	**(846)**	(162)
Investing activities *($ millions)*	**(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 on long-term debt only[3][6]		
Earnings	**11.2**	12.5
Cash flow	**22.4**	24.9
Interest coverage 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 11.3)*
(2) *Debt to capital employed is equal to long-term debt and long-term debt due within one year divided by capital employed. (Refer to Section 11.3)*
(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. (Refer to Section 11.3)*
(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. (Refer to Section 11.3)*
(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

Cash generated from operating activities was $4,645 million in 2013 compared to $5,193 million 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

Cash 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

Cash used for investing activities was $4,722 million in 2013 compared to $4,834 million in 2012. Cash invested in both periods was primarily for capital expenditures.

8.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2013, Husky's working capital was $754 million compared with $2,401 million at December 31, 2012.

Movement in Working Capital

($ millions)	**December 31, 2013**	December 31, 2012	Increase/ (Decrease)
Cash and cash equivalents	**1,097**	2,025	(928)
Accounts receivable	**1,458**	1,345	113
Income taxes receivable	**461**	323	138
Inventories	**1,812**	1,736	76
Prepaid expenses	**89**	64	25
Accounts payable and accrued liabilities	**(3,155)**	(2,985)	(170)
Asset retirement obligations	**(210)**	(107)	(103)
Long-term debt due within one year	**(798)**	–	(798)
Net working capital	**754**	2,401	(1,647)

The decrease in cash was primarily due to lower cash flow from operations in the year and higher cash versus stock dividends paid in 2013 compared to 2012. Movements in accounts receivable, income taxes receivable and accounts payable were due to the timing of settlements compared to 2012. The increase in long-term debt due within one year was due to the reclassification of long-term debt maturing in 2014 to current liabilities as at December 31, 2013.

Sources and Uses of Cash

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and develop reserves, to acquire strategic oil and gas assets, and to repay maturing debt and pay dividends. Husky is currently able to fund its capital programs principally by cash generated from operating activities, cash on hand, issuances of equity, issuances of long-term debt and borrowings under committed and uncommitted credit facilities. During times of low oil and gas prices, a portion of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, Husky frequently evaluates the options with respect to sources of short and long-term capital resources. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines. At December 31, 2013, no production was hedged.

At December 31, 2013, Husky had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[(1)]	**595**	**371**
Syndicated bank facilities	**3,200**	**3,200**
	3,795	**3,571**

[(1)] *Consists of demand credit facilities.*

Cash and cash equivalents at December 31, 2013 totalled $1,097 million compared to $2,025 million at the beginning of the year.

At December 31, 2013, Husky had unused short and long-term borrowing 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.

At the special meeting of shareholders held on February 28, 2011, the Company's shareholders approved amendments to the common share terms, which provide shareholders with the ability to receive dividends in common shares or in cash. Under the amended terms, quarterly dividends may be declared in an amount expressed in dollars per common share and paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares is calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares. During the year ended December 31, 2013, the Company declared dividends payable of $1.20 per common share, resulting in dividends of $1,180 million. An aggregate of $1,171 million was paid in cash during 2013. At December 31, 2013, $295 million, including $291 million in cash and $4 million in common shares, was payable to shareholders on account of dividends declared on October 24, 2013. Commencing in the fourth quarter of 2013, the Board of Directors discontinued the payment of dividends by way of the issuance of common shares. The change became effective with the dividend declaration in February 2014.

On March 22, 2012, the Company issued U.S. $500 million of 3.95% senior unsecured notes due April 15, 2022 pursuant to a universal short form base shelf prospectus filed with the Alberta Securities Commission and the U.S. Securities and Exchange Commission ("SEC") on June 13, 2011 and an accompanying prospectus supplement. The notes are redeemable at the option of the Company at a make-whole premium and interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On June 15, 2012, the Company repaid the maturing 6.25% notes issued under a trust indenture dated June 14, 2002. The amount paid to note holders was U.S. $413 million, including U.S. $13 million of interest.

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.

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 SEC, 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. During the 25-month period that the U.S. Shelf Prospectus is effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement. 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 the Canadian Shelf Prospectus or U.S. Shelf Prospectus is dependent on market conditions at the time of sale.

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

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

8.3 Cash Requirements

Contractual Obligations and Other Commercial Commitments

In the normal course of business, Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

Contractual Obligations

Payments due by period ($ millions)	2014	2015-2016	2017-2018	Thereafter	Total
Long-term debt and interest on fixed rate debt	1,015	882	632	3,163	5,692
Operating leases	155	526	432	367	1,480
Firm transportation agreements	289	548	525	2,702	4,064
Unconditional purchase obligations(1)	2,287	1,977	51	71	4,386
Lease rentals and exploration work agreements	107	251	180	1,208	1,746
Asset retirement obligations(2)	132	226	221	11,666	12,245
	3,985	4,410	2,041	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 16 to the 2013 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.

Other Obligations

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.

Husky provides a defined contribution plan and a post-retirement health and dental plan for all qualified employees in Canada. The Company also provides a defined benefit pension plan for approximately 86 active employees, 97 participants with deferred benefits and 532 participants or joint survivors receiving benefits in Canada. This plan was closed to new entrants in 1991 after the majority of employees transferred to the defined contribution pension plan. Husky provides a defined benefit pension plan for approximately 210 active union represented employees in the United States, which was curtailed effective July 31, 2013. A defined benefit pension plan for 175 active non-represented employees in the United States was curtailed effective April 1, 2011. Approximately 10 participants in both U.S. plans have deferred benefits and no participants were receiving benefits at year end. These pension plans were established effective July 1, 2007 in conjunction with the acquisition of the Lima Refinery. Husky also assumed a post-retirement welfare plan covering all qualified employees at the Lima Refinery and contributes to a 401(k) plan (Refer to Note 19 to the 2013 Consolidated Financial Statements).

Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery (Refer to Note 8 to the 2013 Consolidated Financial Statements), which is payable between December 31, 2011 and December 31, 2015 with the final balance due and payable by December 31, 2015. The timing of payments during this period will be determined by the capital expenditures made at the refinery during this same period. At December 31, 2013, Husky's share of this obligation was U.S. $1.3 billion, including accrued interest.

Husky is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess their impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

The Company has a number of contingent environmental liabilities, which individually have been estimated to be immaterial and have not been reflected in the Company's financial statements beyond the associated ARO. These contingent environmental liabilities are primarily related to the migration of contamination at fuel outlets and certain legacy sites where Husky had previously conducted operations. The contingent environmental liabilities involved have been considered in aggregate and based on reasonable estimates the Company does not believe they will result, in aggregate, in a material adverse effect on its financial position, results of operations or liquidity.

8.4 Off-Balance Sheet Arrangements

Husky does not believe that it has any 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.

Standby Letters of Credit

On occasion, Husky issues letters of credit in connection with transactions in which the counterparty requires such security.

8.5 Transactions with Related Parties

On May 11, 2009, the Company issued 5-year and 10-year senior notes of U.S. $251 million and U.S. $107 million, respectively, to certain management, shareholders, affiliates and directors. The coupon rates offered were 5.90% and 7.25% for the 5-year and 10-year tranches, respectively. Subsequent to this offering, U.S. $122 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. These transactions were measured at fair market value at the date of the transaction and have been carried out on the same terms as would have applied with unrelated parties. At December 31, 2013, the senior notes are included in long-term debt in the Company's consolidated balance sheets.

On December 7, 2010, the Company issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million in a private placement to its then principal shareholders, L.F. Management and Investment S.à r.l (formerly L.F. Investments (Barbados) Limited) and Hutchison Whampoa Luxembourg Holdings S.à r.l.

On June 29, 2011, the Company issued 7.4 million common shares at a price of $27.05 per share for total gross proceeds of $200 million in a private placement to its then principal shareholders, L.F. Management and Investment S.à r.l and Hutchison Whampoa Luxembourg Holdings S.à r.l.

In April 2011, the Company sold its 50% interest in the Meridian cogeneration facility ("Meridian") to a related party. The consideration for the Company's share of Meridian was $61 million, resulting in no net gain or loss on the transaction.

The Company sells natural gas to and purchases steam from Meridian 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 year ended December 31, 2013, the amounts of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $55 million. For the year ended December 31, 2013, the amounts of steam purchased by the Company from Meridian totalled $17 million. In addition, the Company provides cogeneration and facility support services to Meridian, measured on a cost recovery basis. For the year ended December 31, 2013, the total cost recovery for these services was $9 million.

8.6 Outstanding Share Data

Authorized:
- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 25, 2014

• common shares	983,491,183
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	27,548,178
• stock options exercisable	12,311,092

9.0 Critical Accounting Estimates and Key Judgments

Husky's consolidated financial statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Significant accounting policies are disclosed in Note 3 to the 2013 Consolidated Financial Statements. Certain of the Company's accounting policies require subjective judgment and estimation about uncertain circumstances.

9.1 Accounting Estimates

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and on a prospective basis. By their nature, estimates are subject to measurement uncertainty, and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as the Company's operating environment changes. Specifically, amounts recorded for depletion, depreciation, amortization, impairment, asset retirement obligations, assets and liabilities measured at fair value, employee future benefits, income taxes, and contingencies are based on estimates.

Depletion, Depreciation and Amortization

Eligible costs associated with oil and gas activities are capitalized on a unit of measure basis. Depletion expense is subject to estimates including petroleum and natural gas reserves, future petroleum and natural gas prices, estimated future remediation costs, future interest rates as well as other fair value assumptions. The aggregate of capitalized costs, net of accumulated DD&A, less estimated salvage values, is charged to DD&A over the life of the proved developed reserves using the unit of production method.

Asset Retirement Obligations

Estimating ARO requires that Husky estimates costs that are many years in the future. Restoration technologies and costs are constantly changing, as are regulatory, political, environment, safety and public relations considerations. Inherent in the calculation of ARO are numerous assumptions and estimates, including the ultimate settlement amounts, future third-party pricing, inflation factors, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in changes to the ARO.

Fair Value of Financial Instruments

The fair values of derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. These estimates are also subject to change with fluctuations in commodity prices, interest rates, foreign currency exchange rates and estimates of non-performance. The actual settlement of a derivative instrument could differ materially from the fair value recorded and could impact future results.

Employee Future Benefits

The determination of the cost of the post-retirement health and dental care plan and the defined benefit pension plan reflects a number of estimates that affect expected future benefit payments. These estimates include, but are not limited to, attrition, mortality, the rate of return on pension plan assets and salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The fair value of the plan assets is used for the purposes of calculating the expected return on plan assets.

Income Taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Estimates that require significant judgments are also are made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where the transaction and calculations for which the ultimate tax determination are uncertain. All tax filings are subject to audit and potential reassessment, often after the passage of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Legal, Environmental Remediation and Other Contingent Matters

Husky is required to determine both whether a loss is probable based on judgment and interpretation of laws and regulations and whether the loss can be reasonably estimated. When a loss is determined it is charged to net earnings. Husky must continually monitor known and potential contingent matters and make appropriate provisions by charges to net earnings when warranted by circumstances.

9.2 Key Judgments

Management makes judgments regarding the application of IFRS for each accounting policy. Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include successful efforts and impairment assessments, the determination of cash generating units ("CGUs"), the determination of a joint arrangement and the designation of the Company's functional currency.

Successful Efforts Assessments

Costs directly associated with an exploration well are initially capitalized as exploration and evaluation assets. Expenditures related to wells that do not find reserves or where no future activity is planned are expensed as exploration and evaluation expenses. Exploration and evaluation costs are excluded from costs subject to depletion until technical feasibility and commercial viability is assessed or production commences. At that time, costs are either transferred to property, plant and equipment or their value is impaired. Impairment is charged directly to net earnings. Successful efforts assessments require significant judgment and may change as new information becomes available.

Impairment of Non-Financial Assets and Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment. Determining whether there are indications of impairment requires significant judgment of internal and external indicators. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to net earnings. The determination of the recoverable amount for impairment purposes involves the use of numerous assumptions and estimates including future net cash flows from oil and gas reserves, future third-party pricing, inflation factors, discount rates and other uncertainties. Future revisions to these assumptions impact the recoverable amount.

A financial asset is assessed at the end of each reporting period to determine whether it is impaired based on objective evidence indicating that one or more events have had a negative effect on the estimated future cash flows of that asset. Objective evidence used by the Company to assess impairment of financial assets includes quoted market prices for similar financial assets and historical collection rates for loans and receivables. The calculations for the net present value of estimated future cash flows related to derivative financial assets requires the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and expected production volumes, and it is possible that the assumptions may change, which may require a material adjustment to the carrying value of financial assets.

Cash Generating Units

The Company's assets are grouped into respective CGUs, which is the smallest identifiable group of assets, liabilities and associated goodwill that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The determination of the Company's CGUs is subject to management's judgment.

Joint Arrangements

Joint arrangements represent activities where the Company has joint control established by a contractual agreement. Joint control requires unanimous consent for financial and operational decisions. A joint arrangement is either a joint operation whereby the parties have rights to the assets and obligations for the liabilities, or a joint venture whereby the parties have rights to the net assets.

Determining the type of joint arrangement as either joint operation or joint venture is based on management's assumptions of whether it has joint control over another entity. The considerations include, but are not limited to, determining if the arrangement is structured through a separate vehicle, and whether the legal form and contractual arrangements give the entity direct rights to the assets and obligations for the liabilities within the normal course of business. Other facts and circumstances are also assessed by management, including the entity's rights to the economic benefits and its involvement and responsibility for settling liabilities associated with the arrangement.

Functional and Presentation Currency

Functional currency is the currency of the primary economic environment in which the Company and its subsidiaries operate and is normally the currency in which the entity primarily generates and expends cash. The designation of the Company's functional currency is a management judgement based on the composition of revenues and costs in the locations in which it operates.

10.0 Recent Accounting Standards and Changes in Accounting Policies

Recent Accounting Standards

Impairment of Assets

In May 2013, the IASB published narrow-scope amendments to IAS 36, "Impairment of Assets," which requires the disclosure of information about the recoverable amount of impaired assets, particularly if that amount is based on fair value less costs of disposal. Amendments to IAS 36 are effective for the Company on January 1, 2014, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the amendments on January 1, 2014. The adoption of the standard is not expected to have a material impact on the Company's annual consolidated financial statements.

Change in Accounting Policy

Consolidated Financial Statements

In May 2011, the IASB published IFRS 10, "Consolidated Financial Statements," which provides a single model to be applied in the assessment of control for all entities in which the Company has an investment including special purpose entities currently in the scope of Standing Interpretations Committee ("SIC") 12. Under the new control model, the Company has control over an investment if the Company has the ability to direct the activities of the investment, is exposed to the variability of returns from the investment and there is a link between the ability to direct activities and the variability of returns. IFRS 10 was effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. The Company retrospectively adopted IFRS 10 on January 1, 2013. The adoption of the standard had no impact on the Company's annual consolidated financial statements.

Joint Arrangements

In May 2011, the IASB published IFRS 11, "Joint Arrangements," whereby joint arrangements are classified 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, while parties to a joint venture have rights to the net assets of the venture. Joint operations shall be accounted for in a manner consistent with jointly controlled assets and operations whereby the Company's contractual share of the arrangement's assets, liabilities, revenues and expenses is included in the consolidated financial statements. Any arrangement structured through a separate vehicle that does effectively result in separation between the Company and the joint arrangement shall be classified as a joint venture and accounted for using the equity method of accounting. Under the previous standard, the Company had the option to account for any interests in joint arrangements using either proportionate consolidation or equity accounting. IFRS 11 was effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company retrospectively adopted IFRS 11 on January 1, 2013. The adoption of the standard resulted in the following cumulative balance sheet impact related to the Madura joint arrangement, applied prospectively from January 1, 2012:

Balance Sheet Impact *($ millions)*	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	–	–

Disclosure of Interests in Other Entities

In May 2011, the IASB published IFRS 12, "Disclosure of Interests in Other Entities," which contains new annual disclosure requirements for interests the Company has in subsidiaries, joint arrangements, associates and unconsolidated structured entities. Required disclosures aim to provide readers of the financial statements with information to evaluate the nature of and risks associated with the Company's interests in other entities and the effects of those interests on the Company's consolidated financial statements. IFRS 12 was effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company retrospectively adopted IFRS 12 on January 1, 2013. The adoption of the standard did not have a material impact on the Company's annual consolidated financial statements.

Investments in Associates and Joint Ventures

In May 2011, the IASB issued amendments to IAS 28, "Investments in Associates and Joint Ventures," which provides additional guidance applicable to accounting for interests in joint ventures or associates when a portion of an interest is classified as held for sale or when the Company ceases to have joint control or significant influence over an associate or joint venture. When joint control or significant influence over an associate or joint venture ceases, the Company will no longer be required to remeasure the investment at that date. When a portion of an interest in a joint venture or associate is classified as held for sale, the portion not classified as held for sale shall be accounted for using the equity method of accounting until the sale is completed at which time the interest is reassessed for prospective accounting treatment. Amendments to IAS 28 were effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. The Company retrospectively adopted these amendments on January 1, 2013. The adoption of the amendments had no impact on the Company's annual consolidated financial statements.

Fair Value Measurement

In May 2011, the IASB published IFRS 13, "Fair Value Measurement," which provides a single source of fair value measurement guidance and replaces the guidance contained in individual IFRSs. The standard provides a framework for measuring fair value and establishes new disclosure requirements to enable readers to assess the methods and inputs used to develop fair value measurements, for recurring valuations that are subject to measurement uncertainty, and for the effect of those measurements on the financial statements. IFRS 13 was effective for the Company on January 1, 2013, with required prospective application and early adoption permitted. The Company adopted IFRS 13 on January 1, 2013. The adoption of the standard did not have a material impact on the Company's annual consolidated financial statements.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19, "Employee Benefits" to eliminate the corridor method that permits the deferral of actuarial gains and losses, to revise the presentation requirements for changes in defined benefit plan assets and liabilities and to enhance the required disclosures for defined benefit plans. Amendments to IAS 19 were effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company retrospectively adopted these amendments on January 1, 2013.

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	–	–	–	–

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IFRS 7, "Financial Instruments: Disclosures" and IAS 32, "Financial Instruments: Presentation" to clarify the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Amendments to IFRS 7 were effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. Amendments to IAS 32 were effective for the Company for reporting periods ending after January 1, 2014, with required retrospective application and early adoption permitted. The Company retrospectively adopted both IFRS 7 and IAS 32 amendments on January 1, 2013. The adoption of the amendments did not have a material impact on the Company's consolidated financial statements (refer to note 22 of the Consolidated Financial Statements).

11.0 Reader Advisories

11.1 Forward-Looking Statements

Certain statements in this document are forward-looking statements and information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this document are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result","are expected to","will continue","is anticipated","is targeting","estimated","intend","plan","projection","could", "aim","vision", "goals", "objective", "target", "schedules" and "outlook"). In particular, forward-looking statements in this document include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; target debt to cash flow and debt to capital employed ratios; the Company's 2014 production guidance, including weighting of production among product types; target compound annual production growth rate for 2012-2017; and the Company's 2014 Upstream capital program;
- 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 of 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; scheduled timing and duration of the Liwan Gas Project production going off-line; and scheduled timing, duration and expected impact of the planned offstation for the Wenchang FPSO;
- with respect to the Company's Atlantic Region: expected timing of installation of oil production equipment and anticipated timing of first production at the Company's South White Rose Extension project; scheduled timing and duration of a planned turnaround of the Terra Nova FPSO; scheduled timing of first production from the North Amethyst Hibernia formation well; and plans for further drilling in the Flemish Pass Basin;
- with respect to the Company's Oil Sands properties: scheduled timing of start up and anticipated volumes of production 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; estimated timing and volume of production growth from the Company's thermal projects; expected timing of first production and anticipated volumes of production at the Company's Rush Lake heavy oil thermal development project; scheduled timing of construction and first production, and anticipated volumes of production, at the Company's Edam East and Vawn heavy oil thermal developments; and the Company's horizontal and CHOPS drilling program for 2014;
- with respect to the Company's Western Canadian oil and gas resource plays: the Company's drilling and completion plans for its Slater River Canol shale play 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;
- with respect to the Company's Infrastructure and Marketing operations: plans to increase pipeline connectivity and re-configure the terminal facility at the Hardisty terminal; anticipated timing of the extension of pipeline systems from the Sandall thermal development to Lloydminster; and the expansion of the South Saskatchewan Gathering System for the Rush Lake commercial project; and
- with respect to the Company's Downstream operating segment: the anticipated benefits from and scheduled timing of completion of the Lima, Ohio refinery reconfiguration and the anticipated processing capacity once reconfiguration is complete; scheduled timing and duration of a partial outage of the Lloydminster Upgrader for planned maintenance; the anticipated benefits from and scheduled timing of completion of a Hydrotreater Recycle Gas Compressor Project at the BP-Husky Toledo Refinery; plans to reconfigure and increase capacity at the BP-Husky Toledo Ohio 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.

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

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources including third-party consultants, suppliers, regulators and other sources.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to Husky.

The Company's Annual Information Form for the year ended December 31, 2013 and other documents filed with securities regulatory authorities (accessible through the SEDAR website (www.sedar.com) and the EDGAR website (www.sec.gov)) describe the risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty, as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

11.2 Oil and Gas Reserves Reporting

Disclosure of Oil and Gas Reserves and Other Oil and Gas Information

Unless otherwise stated, reserve and resource estimates in this document have an effective date of December 31, 2013 and represent Husky's share. Unless otherwise noted, historical production numbers given represent Husky's share.

The Company uses the terms 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.

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

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

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

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

Note to U.S. Readers

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

11.3 Non-GAAP Measures

Disclosure of non-GAAP Measurements

Husky uses measurements primarily based on IFRS as issued by the IASB and also certain secondary non-GAAP measurements. The non-GAAP measurements included in this Management's Discussion and Analysis are net operating earnings, cash flow from operations, operating netback, debt to capital employed, debt to cash flow, corporate reinvestment ratio, interest coverage on long-term debt, interest coverage on total debt, return on equity, return on capital employed and return on capital in use. Return on capital employed and return on capital in use were adjusted for an after-tax impairment charge on property, plant and equipment of $204 million and $52 million for the years ended December 31, 2013 and 2011, respectively. Return on capital employed based on the calculation used in prior periods for the years ended December 31, 2013 and 2011 was 7.9% and 11.8%, respectively. Return on capital in use based on the calculation used in prior periods for the years ended December 31, 2013 and 2011 was 11.3% and 15.6%, respectively. None of these measurements are used to enhance the Company's reported financial performance or position. With the exception of net operating earnings and cash flow from operations, there are no comparable measures to these non-GAAP measures in accordance with IFRS. These non-GAAP measurements are considered to be useful as 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 by definition to similar measures presented by other companies. Except as described below, the definitions of these measurements are found in Section 11.4, "Additional Reader Advisories."

Disclosure of Net Operating Earnings

The metric "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 ongoing 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 the related per share amounts for the years ended December 31:

($ millions)		2013	2012	2011
GAAP	Net earnings	**1,829**	2,022	2,224
	Impairment of property, plant and equipment, net of tax	**204**	–	52
Non-GAAP	Net operating earnings	**2,033**	2,022	2,276
	Net operating earnings – basic	**2.07**	2.07	2.44
	Net operating earnings – diluted	**2.07**	2.07	2.37

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. Husky's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash, which include accretion, depletion, depreciation, amortization and impairment, exploration and evaluation expenses, deferred income taxes, foreign exchange, stock-based compensation, gain or loss on sale of assets, 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 years ended December 31:

($ millions)	2013	2012	2011
GAAP cash flow – operating activities	**4,645**	5,193	5,092
Settlement of asset retirement obligations	**142**	123	105
Income taxes paid	**433**	575	282
Interest received	**(19)**	(34)	(12)
Change in non-cash working capital	**21**	(847)	(269)
Non-GAAP cash flow from operations	**5,222**	5,010	5,198
Cash flow from operations – basic	**5.31**	5.13	5.63
Cash flow from operations – diluted	**5.31**	5.13	5.58

Disclosure of Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. This measurement assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. The Operating netback was determined by taking upstream netback (gross revenues less operating costs less royalties) divided by upstream gross production.

11.4 Additional Reader Advisories

Intention of Management's Discussion and Analysis ("MD&A")

This MD&A is intended to provide an explanation of financial and operational performance compared with prior periods and the Company's prospects and plans. It provides additional information that is not contained in the Company's consolidated financial statements.

Review by the Audit Committee

This MD&A was reviewed by the Audit Committee and approved by Husky's Board of Directors on February 25, 2014. Any events subsequent to that date could materially alter the veracity and usefulness of the information contained in this document.

Additional Husky Documents Filed with Securities Commissions

This MD&A should be read in conjunction with the Consolidated Financial Statements and related notes. The readers are also encouraged to refer to Husky's interim reports filed in 2013, which contain the Management's Discussion and Analysis and Consolidated Financial Statements, and Husky's 2013 Annual Information Form filed separately with Canadian regulatory agencies and Form 40-F filed with the SEC, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and www.huskyenergy.com.

Use of Pronouns and Other Terms

"Husky" and "the Company" refer to Husky Energy Inc. on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, comparisons of results are for the years ended December 31, 2013 and 2012 and Husky's financial position as at December 31, 2013 and at December 31, 2012.

Reclassifications and Materiality for Disclosures

Certain prior year amounts have been reclassified to conform to current year presentation. Materiality for disclosures is determined on the basis of whether the information omitted or misstated would cause a reasonable investor to change their decision to buy, sell or hold Husky's securities.

Additional Reader Guidance

Unless otherwise indicated:

- Financial information is presented in accordance with IFRS as issued by the IASB;
- Currency is presented in millions of Canadian dollars ("$ millions");
- Gross production and reserves are Husky's working interest prior to deduction of royalty volume;
- Prices are presented before the effect of hedging;
- Light crude oil is 30° API and above;
- Medium crude oil is 21° API and above but below 30° API;
- Heavy crude oil is above 10° API but below 21° API; and
- Bitumen is solid or semi-solid with a viscosity greater than 10,000 centipoise at original temperature in the deposit and atmospheric pressure.

Terms

Brent Crude Oil	*Brent Crude is a major trading classification of sweet light crude oil that serves as a major benchmark price for purchases of oil worldwide. Brent Crude is sourced from the North Sea and is dated less than 15 days prior to loading for delivery*
Capital Employed	*Short and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses, but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations, income taxes paid, interest received and changes in non-cash working capital*
Corporate Reinvestment Ratio	*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*
Feedstock	*Raw materials that are processed into petroleum products*
Front-End Engineering Design	*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 Reserves/Production	*A company's working interest share of reserves/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*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Operating Netback	*Net revenues after deduction of operating costs, transportation and royalty payments*
Return on Capital Employed	*Non-GAAP measure used to assist in analyzing shareholder value and return on average capital. Net earnings plus after tax interest expense divided by the two-year average capital employed*
Return on Capital in Use	*Non-GAAP measure used to assist in analyzing shareholder value and return on capital. Net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not generating cash flows*
Return on Equity	*Non-GAAP measure used to assist in analyzing shareholder value. Net earnings divided by the two-year average shareholders' equity*
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*
Total Debt	*Long-term debt, including current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

"Proved reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"Proved developed reserves" are those reserves that are expected to be recovered from existing wells and installed facilities or , if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production.

"Proved undeveloped reserves" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"Probable reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Abbreviations

bbls	barrels
bpd	barrels per day
EOR	enhanced oil recovery
bps	basis points
mbbls	thousand barrels
mbbls/day	thousand barrels per day
mmbbls	million barrels
mcf	thousand cubic feet
mmcf	million cubic feet
mmcf/day	million cubic feet per day
bcf	billion cubic feet
tcf	trillion cubic feet
boe	barrels of oil equivalent
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per day
mmboe	million barrels of oil equivalent
mcfge	thousand cubic feet of gas equivalent
mmbtu	million British Thermal Units
mmlt	million long tons
tcfe	trillion cubic feet equivalent
tgal	thousand gallons
ASP	alkali surfactant polymer
CHOPS	cold heavy oil production with sand
CNOOC	China National Offshore Oil Corporation
CSA	Canadian Securities Administrators
FPSO	Floating production, storage and offloading vessel
GAAP	Generally Accepted Accounting Principles
GJ	gigajoule
LIBOR	London Interbank Offered Rate
MD&A	Management's Discussion and Analysis
MW	megawatt
NGL	natural gas liquids
NIT	NOVA Inventory Transfer
NYMEX	New York Mercantile Exchange
OPEC	Organization of Petroleum Exporting Countries
PSC	production sharing contract
SAGD	Steam assisted gravity drainage
SEC	U.S. Securities and Exchange Commission
SEDAR	System for Electronic Document Analysis and Retrieval
WI	working interest
WTI	West Texas Intermediate
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
IFRS	International Financial Reporting Standards

11.5 Disclosure Controls and Procedures

Disclosure Controls and Procedures

Husky's management, under supervision of the Chief Executive Officer and the Chief Financial Officer, have evaluated the effectiveness of Husky's disclosure controls and procedures (as defined in the rules of the SEC and the Canadian Securities Administrators ("CSA")) as at December 31, 2013, and have concluded that such disclosure controls and procedures are effective.

Management's Annual Report on Internal Control over Financial Reporting

The following report is provided by management in respect of Husky's internal controls over financial reporting (as defined in the rules of the SEC and the CSA):

1) Husky's management, under the supervision of the Chief Executive Officer and Chief Financial Officer, is responsible for designing, establishing and maintaining adequate internal control over financial reporting for Husky. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.
2) Husky's management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework to evaluate the effectiveness of Husky's internal control over financial reporting.
3) As at December 31, 2013, management, under the supervision of the Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective.
4) KPMG LLP, who has audited the Consolidated Financial Statements of Husky for the year ended December 31, 2013, has also issued a report on internal controls over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States) that attests to management's assessment of Husky's internal controls over financial reporting.

Changes in Internal Control over Financial Reporting

There have been no changes in Husky's internal control over financial reporting during the year ended December 31, 2013, that have materially affected or are reasonably likely to materially affect its internal control over financial reporting.

12.0 Selected Quarterly Financial & Operating Information

Segmented Operational Information

	2013				2012			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Upstream								
Daily production, before royalties								
Light crude oil & NGL *(mbbls/day)*	**78.3**	**77.7**	**82.3**	**86.4**	86.1	55.4	56.8	91.2
Medium crude oil *(mbbls/day)*	**23.4**	**23.2**	**22.9**	**23.0**	23.2	23.9	24.1	24.9
Heavy crude oil *(mbbls/day)*	**75.9**	**75.3**	**72.3**	**74.4**	76.0	77.1	78.1	76.2
Bitumen *(mbbls/day)*	**46.7**	**48.0**	**48.3**	**47.9**	46.7	37.8	29.6	29.6
Total crude oil production *(mboe/day)*	**224.3**	**224.2**	**225.8**	**231.7**	232.0	194.2	188.6	221.9
Natural gas *(mmcf/day)*	**503.8**	**505.5**	**504.7**	**537.3**	523.7	544.9	559.5	588.3
Total production *(mboe/day)*	**308.3**	**308.5**	**309.9**	**321.3**	319.3	285.0	281.9	319.9
Average sales prices								
Light crude oil & NGL *($/bbl)*	**101.95**	**107.83**	**96.22**	**103.59**	94.91	90.50	94.71	111.53
Medium crude oil *($/bbl)*	**67.86**	**93.67**	**73.62**	**61.74**	67.55	69.59	69.92	78.63
Heavy crude oil *($/bbl)*	**56.51**	**84.45**	**66.77**	**45.67**	57.90	60.58	60.42	68.93
Bitumen *($/bbl)*	**54.08**	**83.17**	**65.71**	**43.12**	55.74	60.10	58.09	65.83
Natural gas *($/mcf)*	**3.30**	**2.66**	**3.72**	**3.08**	3.25	2.48	2.05	2.64
Operating costs *($/boe)*	**16.31**	**17.20**	**16.79**	**15.29**	15.05	16.69	15.83	14.56
Operating netbacks[(1)]								
Lloydminster – Thermal Oil *($/boe)*[(2)]	**38.76**	**67.57**	**50.57**	**32.55**	45.47	48.42	43.42	50.25
Lloydminster – Non-Thermal Oil *($/boe)*[(2)]	**27.32**	**49.69**	**37.70**	**19.06**	30.09	33.35	37.07	47.94
Oil Sands – Bitumen *($/boe)*[(2)]	**21.45**	**52.68**	**35.30**	**12.32**	19.49	33.91	30.05	35.88
Western Canada – Crude Oil *($/boe)*[(2)]	**37.60**	**54.41**	**39.24**	**31.17**	38.31	37.12	38.52	43.67
Western Canada – Natural gas *($/mcf)*[(3)]	**1.93**	**1.21**	**1.81**	**1.68**	1.49	1.16	1.11	1.52
Atlantic – Light Oil *($/boe)*[(2)]	**83.90**	**87.14**	**78.66**	**89.37**	85.05	66.97	70.99	94.34
Asia Pacific – Light Oil & NGL *($/boe)*[(2)]	**70.35**	**74.60**	**62.52**	**73.46**	69.28	72.97	73.54	88.16
Total *($/boe)*[(2)]	**34.29**	**46.15**	**38.32**	**31.78**	35.99	30.08	30.43	43.00
Net wells drilled[(4)]								
Exploration Oil	**7**	**8**	–	**9**	8	1	3	18
Gas	**5**	–	**4**	**5**	–	2	–	10
Dry	–	–	–	–	–	–	–	–
	12	**8**	**4**	**14**	8	3	3	28
Development Oil	**201**	**249**	**30**	**229**	217	245	56	197
Gas	**12**	**12**	**2**	**15**	6	1	2	8
Dry	–	–	–	–	3	–	–	1
	213	**261**	**32**	**244**	226	246	58	206
Total net wells drilled	**225**	**269**	**36**	**258**	234	249	61	234
Success ratio *(percent)*	**100**	**100**	**100**	**100**	99	100	100	100
Upgrader								
Synthetic crude oil sales *(mbbls/day)*	**52.0**	**37.5**	**56.7**	**56.1**	63.4	64.1	53.1	61.1
Upgrading differential *($/bbl)*	**26.63**	**23.59**	**27.39**	**38.51**	24.27	22.04	22.64	20.38
Canadian Refined Products								
Fuel sales *(million litres/day)*[(5)]	**7.9**	**8.3**	**8.0**	**8.2**	8.8	9.0	8.4	8.3
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	**28.4**	**28.7**	**18.7**	**28.3**	28.3	28.7	29.1	27.2
Prince George refinery *(mbbls/day)*	**12.0**	**11.8**	**6.3**	**11.2**	11.4	11.3	10.4	11.1
Refinery utilization *(percent)*	**96**	**61**	**100**	**100**	97	97	96	93
U.S. Refining and Marketing								
Refinery throughput								
Lima refinery *(mbbls/day)*	**151.8**	**148.8**	**149.8**	**146.9**	155.9	153.9	150.7	139.4
BP-Husky Toledo refinery *(mbbls/day)*	**66.3**	**59.1**	**68.1**	**66.3**	58.1	52.7	64.9	67.3

(1) *Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.*
(2) *Includes associated co-products converted to boe.*
(3) *Includes associated co-products converted to mcfge.*
(4) *Includes Western Canada, Heavy Oil and Oil Sands.*
(5) *Fuel sales have been recast to exclude non-retail products. Prior periods have been adjusted to conform with the current period presentation.*

Segmented Capital Expenditures[1]

($ millions)	2013 Q4	2013 Q3	2013 Q2	2013 Q1	2012 Q4	2012 Q3	2012 Q2	2012 Q1
Upstream								
Exploration								
Western Canada	**80**	**99**	**64**	**110**	79	43	29	87
Atlantic Region	**55**	**102**	**39**	**5**	(28)	35	6	–
Asia Pacific Region	**14**	**1**	**–**	**6**	5	17	–	–
	149	**202**	**103**	**121**	56	95	35	87
Development								
Western Canada	**744**	**505**	**267**	**513**	662	497	293	577
Oil Sands	**111**	**146**	**137**	**158**	220	152	132	154
Atlantic Region	**34**	**148**	**116**	**139**	91	150	101	58
Asia Pacific Region	**215**	**133**	**156**	**129**	213	175	203	134
	1,104	**932**	**676**	**939**	1,186	974	729	923
Acquisitions								
Western Canada	**27**	**1**	**4**	**6**	–	16	–	5
Total Exploration and Production	**1,280**	**1,135**	**783**	**1,066**	1,242	1,085	764	1,015
Infrastructure and Marketing	**41**	**27**	**17**	**11**	19	14	11	10
Total Upstream	**1,321**	**1,162**	**800**	**1,077**	1,261	1,099	775	1,025
Downstream								
Upgrader	**43**	**129**	**20**	**13**	17	13	9	8
Canadian Refined Products	**32**	**24**	**41**	**12**	33	32	19	13
U.S. Refining and Marketing	**99**	**52**	**42**	**27**	113	92	65	43
	174	**205**	**103**	**52**	163	137	93	64
Corporate	**42**	**40**	**29**	**23**	49	16	14	5
	1,537	**1,407**	**932**	**1,152**	1,473	1,252	882	1,094

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

Segmented Financial Information

	Upstream								Downstream			
	Exploration and Production[1]				Infrastructure and Marketing				Upgrading			
2013 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	1,734	2,111	1,843	1,645	457	646	664	367	484	437	573	529
Royalties	(215)	(237)	(208)	(204)	–	–	–	–	–	–	–	–
Marketing and other	–	–	–	–	76	17	57	162	–	–	–	–
Revenues, net of royalties	1,519	1,874	1,635	1,441	533	663	721	529	484	437	573	529
Expenses												
Purchases of crude oil and products	29	17	20	25	438	609	622	335	362	341	388	287
Production and operating expenses	502	528	504	482	1	3	7	3	45	38	41	37
Selling, general and administrative expenses	44	60	84	52	4	4	5	6	2	2	1	2
Depletion, depreciation, amortization and impairment	791	594	568	562	2	6	6	6	25	24	23	24
Exploration and evaluation expenses	28	56	74	88	–	–	–	–	–	–	–	–
Other – net	(63)	11	(24)	41	(2)	–	(1)	–	(23)	(2)	(1)	(1)
Earnings from operating activities	188	608	409	191	90	41	82	179	73	34	121	180
Share of equity investment	(5)	1	(6)	–	–	–	–	–	–	–	–	–
Net foreign exchange gains (losses)	1	(1)	–	–	–	–	–	–	–	–	–	–
Finance income	2	–	2	–	–	–	–	–	–	–	–	–
Finance expenses	(27)	(28)	(23)	(29)	–	–	–	–	(1)	(2)	(2)	(2)
	(24)	(29)	(21)	(29)	–	–	–	–	(1)	(2)	(2)	(2)
Earnings (loss) before income tax	159	580	382	162	90	41	82	179	72	32	119	178
Provisions for (recovery of) income taxes												
Current	54	86	(30)	52	43	(3)	90	92	6	6	1	6
Deferred	(13)	64	129	(11)	(20)	14	(69)	(47)	13	2	30	40
	41	150	99	41	23	11	21	45	19	8	31	46
Net earnings (loss)	118	430	283	121	67	30	61	134	53	24	88	132
Capital expenditures[3]	1,280	1,135	783	1,066	41	27	17	11	43	129	20	13
Total assets	24,653	24,058	23,603	23,250	1,670	1,766	1,554	1,476	1,355	1,214	1,217	1,214

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*

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

Downstream (continued)								Corporate and Eliminations[2]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
1,288	**993**	**613**	**843**	**2,690**	**2,405**	**2,922**	**2,711**	**(597)**	**(573)**	**(466)**	**(450)**	**6,056**	**6,019**	**6,149**	**5,645**
–	–	–	–	–	–	–	–	–	–	–	–	**(215)**	**(237)**	**(208)**	**(204)**
–	–	–	–	–	–	–	–	–	–	–	–	**76**	**17**	**57**	**162**
1,288	**993**	**613**	**843**	**2,690**	**2,405**	**2,922**	**2,711**	**(597)**	**(573)**	**(466)**	**(450)**	**5,917**	**5,799**	**5,998**	**5,603**
1,129	**875**	**468**	**662**	**2,543**	**2,174**	**2,504**	**2,325**	**(597)**	**(573)**	**(466)**	**(450)**	**3,904**	**3,443**	**3,536**	**3,184**
49	**50**	**50**	**44**	**99**	**105**	**104**	**101**	–	–	–	–	**696**	**724**	**706**	**667**
16	**16**	**14**	**14**	**3**	**4**	**4**	**4**	**90**	**55**	**20**	**52**	**159**	**141**	**128**	**130**
23	**23**	**22**	**22**	**60**	**58**	**58**	**57**	**17**	**13**	**11**	**10**	**918**	**718**	**688**	**681**
–	–	–	–	–	–	–	–	–	–	–	–	**28**	**56**	**74**	**88**
1	**(3)**	**(2)**	**(1)**	–	**(1)**	**1**	–	–	**(8)**	**5**	**(14)**	**(87)**	**(3)**	**(22)**	**25**
70	**32**	**61**	**102**	**(15)**	**65**	**251**	**224**	**(107)**	**(60)**	**(36)**	**(48)**	**299**	**720**	**888**	**828**
–	–	–	–	–	–	–	–	–	–	–	–	**(5)**	**1**	**(6)**	–
–	–	–	–	–	–	–	–	**12**	**7**	**10**	**(8)**	**13**	**6**	**10**	**(8)**
–	–	–	–	–	–	–	–	**13**	**11**	**12**	**11**	**15**	**11**	**14**	**11**
(1)	**(1)**	**(2)**	**(1)**	**(1)**	**(1)**	–	**(1)**	**(4)**	**(10)**	**(13)**	**(20)**	**(34)**	**(42)**	**(40)**	**(53)**
(1)	**(1)**	**(2)**	**(1)**	**(1)**	**(1)**	–	**(1)**	**21**	**8**	**9**	**(17)**	**(6)**	**(25)**	**(16)**	**(50)**
69	**31**	**59**	**101**	**(16)**	**64**	**251**	**223**	**(86)**	**(52)**	**(27)**	**(65)**	**288**	**696**	**866**	**778**
11	**17**	**7**	**30**	**(43)**	**(25)**	**44**	**42**	**22**	**33**	**62**	**(14)**	**93**	**114**	**174**	**208**
6	**(9)**	**8**	**(4)**	**38**	**47**	**44**	**36**	**(6)**	**(48)**	**(55)**	**21**	**18**	**70**	**87**	**35**
17	**8**	**15**	**26**	**(5)**	**22**	**88**	**78**	**16**	**(15)**	**7**	**7**	**111**	**184**	**261**	**243**
52	**23**	**44**	**75**	**(11)**	**42**	**163**	**145**	**(102)**	**(37)**	**(34)**	**(72)**	**177**	**512**	**605**	**535**
32	**24**	**41**	**12**	**99**	**52**	**42**	**27**	**42**	**40**	**29**	**23**	**1,537**	**1,407**	**932**	**1,152**
1,788	**1,704**	**1,656**	**1,714**	**5,537**	**5,665**	**5,525**	**5,397**	**1,901**	**2,193**	**2,439**	**2,468**	**36,904**	**36,600**	**35,994**	**35,519**

	Upstream								Downstream			
	Exploration and Production[1]				Infrastructure and Marketing				Upgrading			
2012 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues[3][4]	1,773	1,440	1,389	1,979	785	365	623	604	562	576	472	581
Royalties	(189)	(145)	(140)	(219)	–	–	–	–	–	–	–	–
Marketing and other[3]	–	–	–	–	79	122	124	73	–	–	–	–
Revenues, net of royalties	1,584	1,295	1,249	1,760	864	487	747	677	562	576	472	581
Expenses												
Purchases of crude oil and products[3][5]	20	15	13	25	741	335	591	591	417	423	344	452
Production and operating expenses[4][5]	513	456	441	465	–	6	4	2	40	33	42	35
Selling, general and administrative expenses	18	55	66	36	6	5	6	4	1	–	1	1
Depletion, depreciation, amortization and impairment	614	515	463	529	6	5	6	5	27	25	25	25
Exploration and evaluation expenses	157	59	53	75	–	–	–	–	–	–	–	–
Other – net	(72)	28	(60)	(1)	–	–	1	(1)	(17)	–	–	–
Earnings from operating activities	334	167	273	631	111	136	139	76	94	95	60	68
Share of equity investment	(11)	–	–	–	–	–	–	–	–	–	–	–
Net foreign exchange gains (losses)	–	–	–	–	–	–	–	–	–	–	–	–
Finance income	–	5	–	–	–	–	–	–	–	–	–	–
Finance expenses	(19)	(21)	(19)	(19)	–	–	–	–	(2)	(3)	(3)	(3)
	(19)	(16)	(19)	(19)	–	–	–	–	(2)	(3)	(3)	(3)
Earnings (loss) before income taxes	304	151	254	612	111	136	139	76	92	92	57	65
Provisions for (recovery of) income taxes												
Current	16	(44)	(47)	209	50	54	62	5	(1)	24	(11)	19
Deferred	62	85	114	(50)	(22)	(19)	(27)	13	25	–	26	(2)
	78	41	67	159	28	35	35	18	24	24	15	17
Net earnings (loss)	226	110	187	453	83	101	104	58	68	68	42	48
Capital expenditures[6]	1,242	1,085	764	1,015	19	14	11	10	17	13	9	8
Total assets	22,774	21,175	20,819	20,548	1,506	1,400	1,143	1,434	1,242	1,271	1,295	1,252

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to the Exploration and Production.*

(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*

(3) *Gross revenues, marketing and other and purchases of crude oil products have been recast to reflect a change in the classification of certain trading transactions.*

(4) *In 2013, the Company reclassified its processing facilities from Infrastructure and Marketing to Exploration and Production. 2012 amounts have been adjusted to conform with current presentation.*

(5) *Certain hydrogen feedstock costs were reclassified in 2012 from production and operating expenses to purchases of of crude oil products.*

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

Downstream (continued)								Corporate and Eliminations[(2)]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
933	1,067	968	880	2,355	2,436	2,623	2,442	(598)	(596)	(484)	(625)	5,810	5,288	5,591	5,861
–	–	–	–	–	–	–	–	–	–	–	–	(189)	(145)	(140)	(219)
–	–	–	–	–	–	–	–	–	–	–	–	79	122	124	73
933	1,067	968	880	2,355	2,436	2,623	2,442	(598)	(596)	(484)	(625)	5,700	5,265	5,575	5,715
794	849	802	763	2,046	1,980	2,335	2,183	(598)	(596)	(484)	(625)	3,420	3,006	3,601	3,389
49	45	50	40	102	91	100	92	(1)	1	1	3	703	632	638	637
15	14	15	14	3	4	3	3	63	34	40	41	106	112	131	99
21	21	21	20	57	52	52	51	13	11	9	7	738	629	576	637
–	–	–	–	–	–	–	–	–	–	–	–	157	59	53	75
–	(2)	–	–	4	–	–	–	(19)	4	7	5	(104)	30	(52)	3
54	140	80	43	143	309	133	113	(56)	(50)	(57)	(56)	680	797	628	875
–	–	–	–	–	–	–	–	–	–	–	–	(11)	–	–	–
–	–	–	–	–	–	–	–	(1)	16	–	(1)	(1)	16	–	(1)
–	–	–	–	–	–	–	–	21	17	23	27	21	22	23	27
(1)	(2)	(2)	(1)	(1)	(1)	(2)	(1)	(22)	(28)	(43)	(47)	(45)	(55)	(69)	(71)
(1)	(2)	(2)	(1)	(1)	(1)	(2)	(1)	(2)	5	(20)	(21)	(25)	(17)	(46)	(45)
53	138	78	42	142	308	131	112	(58)	(45)	(77)	(77)	644	780	582	830
16	32	23	18	(49)	48	–	–	29	35	16	32	61	149	43	283
(2)	3	(3)	(7)	104	65	48	41	(58)	(29)	(50)	(39)	109	105	108	(44)
14	35	20	11	55	113	48	41	(29)	6	(34)	(7)	170	254	151	239
39	103	58	31	87	195	83	71	(29)	(51)	(43)	(70)	474	526	431	591
33	32	19	13	113	92	65	43	49	16	14	5	1,473	1,252	882	1,094
1,646	1,658	1,656	1,625	5,326	5,160	5,260	5,334	2,667	2,802	2,669	3,093	35,161	33,466	32,842	33,286