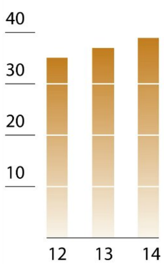
MANAGEMENT'S DISCUSSION AND ANALYSIS

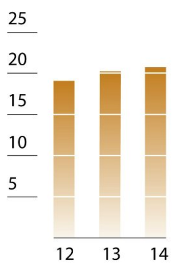
1.0 Financial Summary

1.1 Financial Position

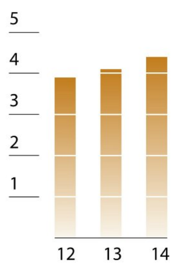
Total Assets
($ billions)



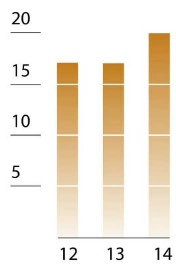
Total Equity
($ billions)



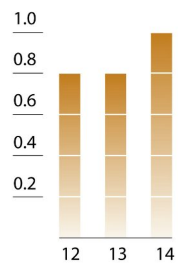
Total Long-term Debt *($ billions)*



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

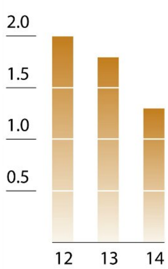


Debt to Cash Flow from Operations[1]
(times)

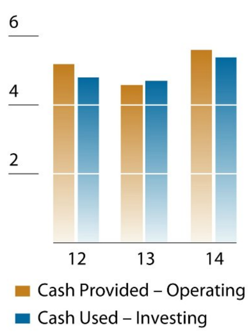


1.2 Financial Performance

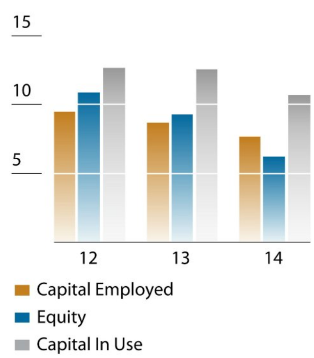
Net Earnings
($ billions)



Cash Flow
($ billions)



Return[1]
(%)

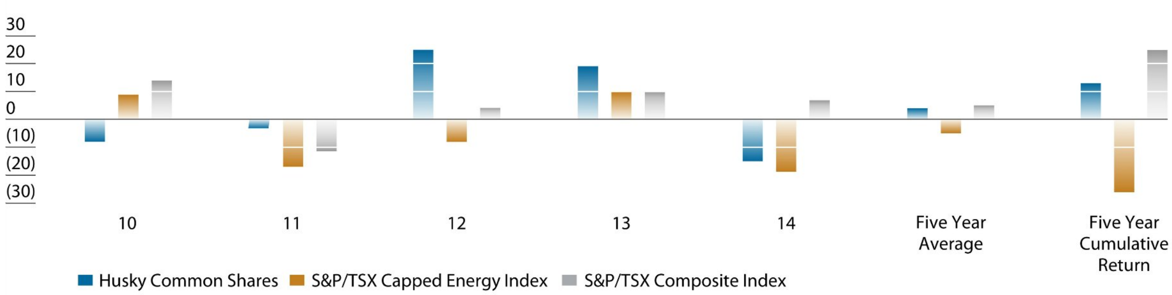


[1] *Debt to capital employed, debt to cash flow, return on capital employed, return on equity and return on capital in use constitute non-GAAP measures. (Refer to Section 11.3)*

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)	**2014**	2013	2012
Gross revenues	**25,122**	24,181	22,948
Net earnings (loss) by segment			
Upstream	**1,106**	1,244	1,322
Downstream	**363**	830	893
Corporate	**(211)**	(245)	(193)
Net earnings	**1,258**	1,829	2,022
Net earnings per share – basic	**1.26**	1.85	2.06
Net earnings per share – diluted	**1.20**	1.85	2.06
Ordinary dividends per common share	**1.20**	1.20	1.20
Dividends per cumulative redeemable preferred share, series 1	**1.11**	1.11	1.11
Cash flow from operations[(1)]	**5,535**	5,222	5,010
Total assets	**38,848**	36,904	35,161
Other long-term liabilities[(2)]	**585**	271	328
Long-term debt including current portion	**4,397**	4,119	3,918
Total non-current liabilities	**12,464**	12,663	12,908
Commercial paper	**895**	–	–
Cash and cash equivalents	**1,267**	1,097	2,025
Return on equity *(percent)*[(1)(3)]	**6.2**	9.3	10.9
Return on capital in use (percent)[(1)(4)]	**10.7**	12.6	12.7
Return on capital employed *(percent)*[(1)(5)]	**7.7**	8.7	9.5

(1) *Cash flow from operations and financial ratios constitute non-GAAP measures. (Refer to Section 11.3)*
(2) *As at December 31, 2014, 2013 or 2012, the Company did not have long-term financial liabilities.*
(3) *Return on equity equals net earnings divided by the two-year average shareholder's equity. (Refer to Section 11.3)*
(4) *Return on capital in use for the years ended December 31, 2014 and 2013 was adjusted for after-tax impairment charges on property, plant and equipment of $622 million and $204 million, respectively. Return on capital in use, including impairment charges, for the years ended December 31, 2014 and 2013 was 7.5 percent and 11.3 percent, respectively. (Refer to Section 11.3)*
(5) *Return on capital employed for the years ended December 31, 2014 and 2013 was adjusted for after-tax impairment charges on property, plant and equipment of $622 million and $204 million, respectively. Return on capital employed, including impairment charges, for the years ended December 31, 2014 and 2013 was 5.3 percent and 7.9 percent 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 and is based in Calgary, Alberta. The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and the Cumulative Redeemable Preferred Shares, Series 1 and Cumulative Redeemable Preferred Shares, Series 3 are listed under the symbols, "HSE.PR.A" and "HSE.PR.C", respectively. 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

Upstream includes exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids ("NGL") (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, pipeline transportation and blending of crude oil and natural gas and storage of crude oil, diluent and natural gas (Infrastructure and Marketing). The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada, offshore China and offshore Indonesia.

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;

- Heavy oil thermal portfolio with production of approximately 44,000 bbls/day in 2014 increasing to approximately 80,000 bbls/day by the end of 2016 with planned first production in the third quarter of 2015 from the 10,000 bbls/day Rush Lake thermal project and planned first production in the second half of 2016 from the two 10,000 bbls/day Edam East and Vawn thermal development projects and the 3,500 bbls/day Edam West thermal development project;
- Expertise and experience exploring and developing the natural gas potential in the Alberta Deep Basin, Foothills and northwest plains of Alberta and British Columbia;
- Sunrise Energy Project, a multiple stage in-situ oil sands development, with Phase 1 expected to commence production towards the end of the first quarter of 2015 ramping up to approximately 60,000 bbls/day (30,000 bbls/day net Husky share) around the end of 2016. Sunrise will use proven steam-assisted gravity drainage ("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);
- 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"). First production was achieved from the Liwan 3-1 gas field in March 2014 and from the Liuhua 34-2 gas field in December 2014;
- Husky has a 40 percent 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 fields and five discovered natural gas fields;
- Husky has a 100 percent interest in the rights to the Anugerah exploration block covering approximately 2,030,000 acres, which is located in the East Java Basin, Indonesia approximately 150 kilometres east of the Madura Straight block;
- Husky and its joint venture partner CPC Corporation have rights to an exploration block in the South China Sea covering approximately 10,000 square kilometres located 100 kilometres southwest of the island of Taiwan. Husky holds a 75 percent working interest during exploration, while CPC Corporation has the right to participate in the development program up to a 50 percent interest;
- Husky is the operator of the White Rose field with a 72.5 percent working interest in the core field and a 68.875 percent working interest in satellite tiebacks, including the North Amethyst, West White Rose and South White Rose extensions. Development continued at White Rose and its three satellite extensions in 2014. Husky has a 13 percent 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 percent 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 third-party commodity trading volumes through access to capacity on third-party pipelines and storage facilities in both Canada and the United States and natural gas storage of 29 bcf, owned and leased.

2.2 Downstream

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading), refining in Canada of crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products and production of ethanol (Canadian Refined Products) and refining in the U.S. of primarily crude oil to produce and market gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards (U.S. Refining and Marketing).

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 percent 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 490 retail marketing locations as at December 31, 2014, including bulk plants and travel centres with strategic land positions in Western Canada and Ontario.

3.0 The 2014 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 2014, that are anticipated to continue to impact the industry to varying degrees into 2015 and beyond. Business factors impacting Husky's industry during 2014 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 averaging an estimated 9.2 million bbls/day at the end of 2014, approaching the historical high achieved in 1970 of 9.6 million bbls/day;
- Accelerated growth of global crude oil production and inventory supplies relative to demand led to a sharp decline in key benchmarks such as West Texas Intermediate ("WTI") and Brent in the second half of 2014;
- Increased transportation of Western Canadian crude oil by rail which narrowed differentials relative to WTI and other key benchmarks;
- Expected continued production growth from the Western Canadian oil sands;
- 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 2014 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		2014	2013
WTI crude oil[1]	*(U.S. $/bbl)*	**93.00**	97.97
Brent crude oil[2]	*(U.S. $/bbl)*	**98.99**	107.91
Canadian light crude 0.3% sulphur	*($/bbl)*	**85.08**	93.85
Western Canada Select @ Hardisty[3]	*(U.S. $/bbl)*	**73.60**	72.77
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**73.28**	64.41
NYMEX natural gas[4]	*(U.S. $/mmbtu)*	**4.42**	3.65
NIT natural gas	*($/GJ)*	**4.19**	3.00
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**19.41**	25.33
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**18.61**	22.21
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**17.28**	21.30
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.906**	0.971
Canadian Equivalents[5]			
WTI crude oil	*($/bbl)*	**102.65**	100.90
Brent crude oil	*($/bbl)*	**109.26**	111.13
Western Canada Select @ Hardisty	*($/bbl)*	**81.24**	74.94
WTI/Lloyd crude blend differential	*($/bbl)*	**21.42**	26.08
NYMEX natural gas	*($/mmbtu)*	**4.88**	3.76

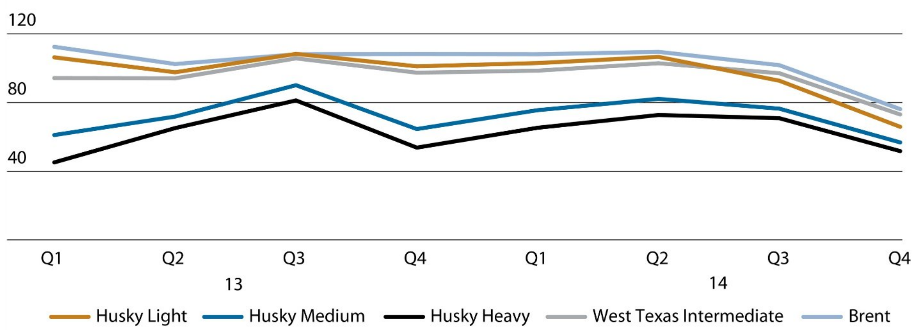
(1) Prices quoted are near-month contract prices for settlement during the next month.
(2) Quoted Brent prices are dated less than 15 days prior to loading for delivery.
(3) Western Canadian Select is a heavy crude blend primarily based on existing Canadian heavy conventional and bitumen crude oils and 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 price realized for crude oil is determined by North American and global factors and is beyond the Company's control. The price realized for natural gas production from Western Canada is determined primarily by North American fundamentals since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. In the Asia Pacific Region, natural gas is sold to specific buyers with long-term contracts. For the Liwan 3-1 gas field, the price is fixed for the initial five years and then will be linked to local benchmark pricing for the years following. For the Liuhua 34-2 field, the price is fixed during the contract delivery period.

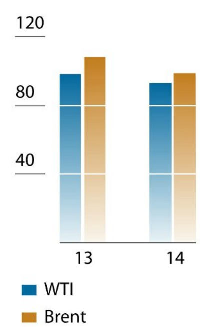
The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil. In the upgrading business segment, heavy crude oil feedstock is processed into light synthetic crude 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 percent 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)



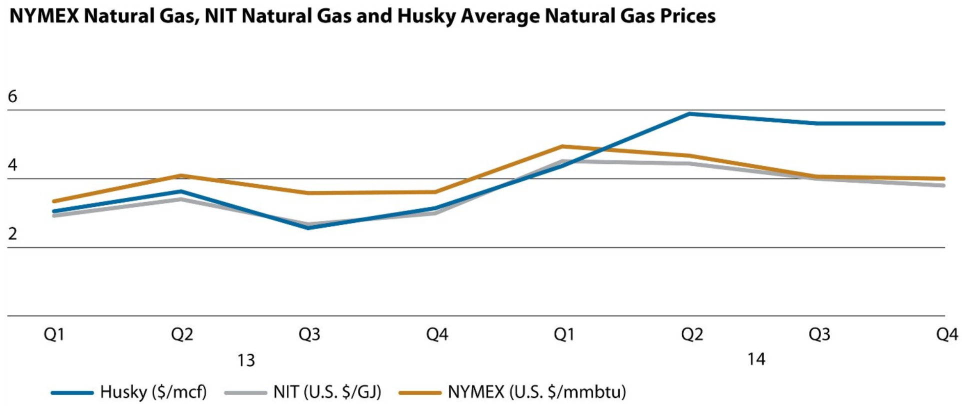
Average WTI and Brent
(U.S. $/bbl)

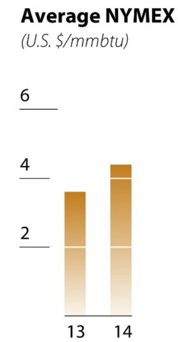


The price Husky receives for production from Western Canada is primarily driven by changes in the price of WTI and discounts or premiums to Western Canadian crude prices, while the majority of the Company's production in the Atlantic Region and the Asia Pacific Region is referenced to the price of Brent, a light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2014 at U.S. $53.27/bbl compared to U.S. $98.42/bbl on December 31, 2013 and averaged U.S. $93.00/bbl in 2014 compared to U.S. $97.97/bbl in 2013. The price of Canadian light crude ended 2014 at $51.15/bbl compared to $97.49/bbl on December 31, 2013 and averaged $85.08/bbl in 2014 compared to $93.85/bbl in 2013. The price of Brent ended 2014 at U.S. $54.98/bbl, compared to U.S. $110.28/bbl on December 31, 2013 and averaged U.S. $98.99/bbl in 2014 compared to U.S. $107.91/bbl in 2013.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2014, 56 percent of Husky's crude oil and NGL production was heavy crude oil or bitumen compared to 54 percent in 2013. The light/heavy crude oil differential averaged U.S. $19.41/bbl or 21 percent of WTI in 2014 compared to U.S. $25.33/bbl or 26 percent of WTI in 2013.

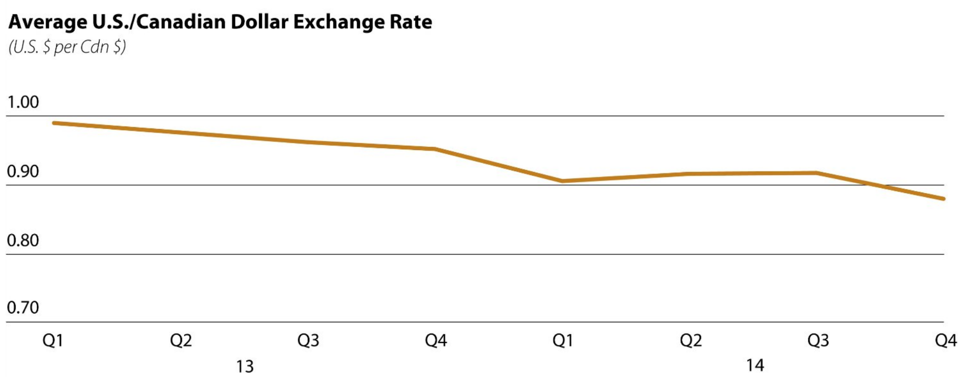
Natural Gas

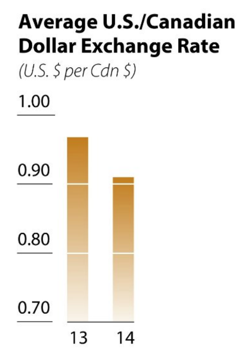




In 2014, 30 percent of Husky's total oil and gas production was natural gas compared with 27 percent in 2013, reflecting new production from the Liwan Gas Project, partially offset by a shift in investment in Western Canada from dry gas development to higher netback liquids-rich natural gas and crude oil production. The near-month natural gas price quoted on the NYMEX ended 2014 at U.S. $2.89/mmbtu compared with U.S. $4.23/mmbtu at December 31, 2013. During 2014, the NYMEX near-month contract price of natural gas averaged U.S. $4.42/mmbtu compared with U.S. $3.65/bbl in 2013. The near-month natural gas contract price for NOVA Inventory Transfer ("NIT"), which is a Canadian natural gas benchmark, was $2.64/mmbtu at the end of 2014 compared with $3.73/mmbtu at December 31, 2013. During 2014, the NIT near-month contract price of natural gas averaged $4.19/mmbtu compared to $3.00/mmbtu in 2013.

Foreign Exchange



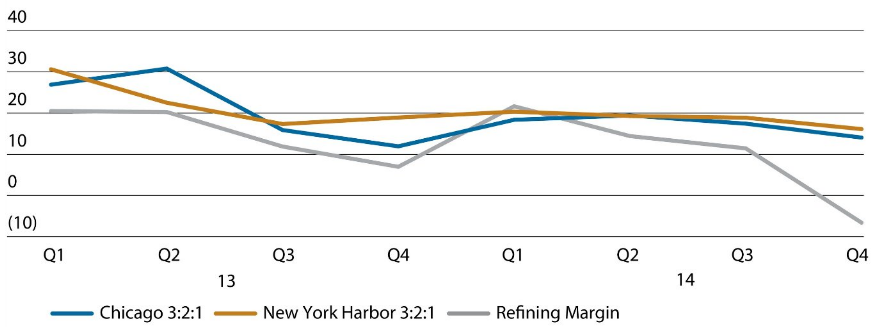


The majority of the Company's revenues from the sale of oil and gas commodities receive prices determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the revenues received from the sale of oil and gas commodities. Correspondingly, 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 U.S. Downstream and international Upstream operations.

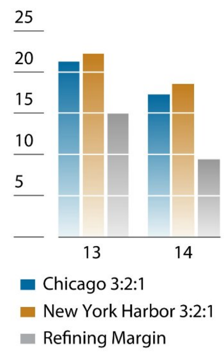
The Canadian dollar ended 2014 at U.S. $0.862 on December 31, 2014 compared to U.S. $0.940 on December 31, 2013. In 2014, the Canadian dollar averaged U.S. $0.906, weakening by 7 percent compared with U.S. $0.971 during 2013. Crude oil prices realized by Husky in 2014 benefited from the weakening of the Canadian dollar against the U.S. dollar compared to 2013. In 2014, the price of WTI in U.S. dollars decreased by 5 percent while the price of WTI in Canadian dollars increased by 2 percent when compared to 2013.

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 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. $18.61/bbl in 2014 compared to U.S. $22.21/bbl in 2013, and the Chicago 3:2:1 refining crack spread averaged U.S. $17.28/bbl in 2014 compared to U.S. $21.30/bbl in 2013.

The following table is indicative of the relative annualized effect on pre-tax earnings and net earnings from changes in certain key variables in 2014. The table below shows what the effect would have been on 2014 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2014. 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 when greater magnitudes of change are occurring.

Sensitivity Analysis	2014 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]	**93.00**	*U.S. $1.00/bbl*	**83**	**0.08**	**61**	**0.06**
NYMEX benchmark natural gas price[5]	**4.42**	*U.S. $0.20/mmbtu*	**33**	**0.03**	**24**	**0.02**
WTI/Lloyd crude blend differential[6]	**19.41**	*U.S. $1.00/bbl*	**(27)**	**(0.03)**	**(21)**	**(0.02)**
Canadian light oil margins	**0.050**	*Cdn $0.005/litre*	**14**	**0.01**	**11**	**0.01**
Asphalt margins	**22.12**	*Cdn $1.00/bbl*	**11**	**0.01**	**8**	**0.01**
New York Harbor 3:2:1 crack spread	**18.61**	*U.S. $1.00/bbl*	**48**	**0.05**	**29**	**0.03**
Exchange rate (U.S. $ per Cdn $)[3][7]	**0.906**	*U.S. $0.01*	**(82)**	**(0.08)**	**(60)**	**(0.06)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 983.7 million common shares outstanding as of December 31, 2014.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent based production.*
(5) *Includes impact of natural gas consumption.*
(6) *Excludes impact on asphalt operations.*
(7) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

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 growth in the Asia Pacific Region, the Oil Sands and in the Atlantic Region. The Company's Downstream assets provide specialized support to its Upstream operations to enhance efficiency and extract additional value from production.

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 2014 with development activities ongoing in the Bakken, Cardium, Duvernay, Falher, Lower Shaunavon, Montney, Muskwa, Second White Specks, Viking and Wilrich formations.

Husky has an extensive portfolio of oil sands leases, encompassing approximately 2,500 square kilometres in northern Alberta. During 2014, Husky advanced the development of the Sunrise Energy Project, a multiple stage in-situ oil sands development, where first steam was achieved on Phase 1 of the project in December 2014 and first oil is anticipated towards the end of the first quarter of 2015. The first phase 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 the next phase of the project.

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 and MBH development fields, five discoveries offshore Indonesia and rights to additional exploration blocks in the South China Sea located offshore Taiwan and in the East Java Basin, Indonesia. The Liwan Gas Project, located approximately 300 kilometres 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, and its partner China National Offshore Oil Corporation, achieved first gas production from the Liwan 3-1 gas field in March 2014 and from the Liuhua 34-2 gas field in December 2014.

In the Atlantic Region, the Company holds interests in eight Production Licences, 11 Exploration Licences (including two from Greenland) 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 2014, the Company and its partner began an 18-month appraisal drilling program around the Bay du Nord discovery in the Northern Flemish Pass. The Company has a 35 percent working interest at Bay du Nord as well as the Mizzen and Harpoon 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 supports Upstream production while providing integration with the Company's Downstream assets through optimization of market access. 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.

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 percent, 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 in 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 2014 Capital Program built on the momentum achieved over the past three years, repositioning the Heavy Oil and Western Canada foundation by accelerating heavy oil production growth and repositioning Western Canada to focus on oil and liquids-rich natural gas resource plays and advancing three major growth areas 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 2014 was approximately 34,000 boe/day, representing a more than one-third increase when compared to 2013.

Liquids-Rich Natural Gas Resource Plays

During 2014, the Company continued to advance exploration and development projects on its extensive liquids-rich natural gas resource land base. A total of 51 wells (gross) were drilled and 45 wells (gross) were completed in 2014 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, 2014:

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

Project	Location	Year ended December 31, 2014 Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	**31**	**23**
Duvernay	Kaybob, Alberta	–	**2**
Wilrich	Kakwa, Alberta	**10**	**7**
Strachan Cardium	Rocky Mountain House, Alberta	**9**	**11**
Bivouac Muskwa	Bivouac, B.C.	**1**	**2**
Total Gross		**51**	**45**
Total Net		**41**	**36**

(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 31 wells (gross) drilled and 23 wells (gross) completed in 2014. To date, the Company has drilled and completed over 350 (gross) wells at the play with average production of 17,500 boe/day in 2014, an increase of 27 percent when compared to 2013.

Husky completed a two-well pad in 2014 at the Duvernay liquids-rich natural gas resource play at Kaybob, Alberta. Results from the four-well pad drilled and completed in 2013 and the two-well pad completed in 2014 continue to be in line with expectations.

Drilling commenced in the year at the Wilrich Kakwa liquids-rich natural gas resource play. The Company drilled ten wells (gross) and completed seven wells (gross) in the year and production is in line with expectations.

At the Strachan Cardium liquids-rich natural gas resource play, development continued in the year with nine wells (gross) drilled and 11 wells (gross) completed. Production continues to be in line with expectations.

Oil Resource Plays

During 2014, the Company advanced exploration and development projects on its extensive oil resource land base. A total of 41 horizontal wells (gross) were drilled and 49 horizontal wells (gross) were completed in 2014.

The following table summarizes the key oil resource play drilling and completion activity for the year ended December 31, 2014:

Oil Resource Plays - Drilling and Completion Activity[1]		Year ended December 31, 2014	
Project	Location	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	7	7
Lower Shaunavon	S.W. Saskatchewan	–	2
Viking[2]	Alberta and S.W. Saskatchewan	27	25
N.Cardium	Wapiti, Alberta	6	13
Muskwa	Rainbow, Northern Alberta	1	2
Total Gross		**41**	**49**
Total Net		**36**	**44**

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*
(2) *Viking is comprised of project activity at Redwater in central Alberta, Alliance in Southeastern Alberta and drilling in Southwestern Saskatchewan.*

In the Northwest Territories, construction of the all-season road at the Slater River Canol shale play was completed in 2014. During the second quarter of 2014, Husky withdrew its application to drill four horizontal wells.

Heavy Oil

Production commenced in early 2014 ahead of schedule at the Sandall heavy oil development with rates exceeding the 3,500 bbls/day design rate capacity throughout the year. Production at the end of 2014 was approximately 5,700 bbls/day.

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

Site clearing, detailed engineering and module fabrication commenced at the two 10,000 bbls/day Edam East and Vawn developments in 2014 with first production expected in the second half of 2016.

The Company sanctioned a 3,500 bbls/day thermal project at Edam West in early 2014. Site clearing, detailed engineering and module fabrication commenced in the year with first production expected in the second half of 2016.

Total production from the Company's existing heavy oil thermal developments averaged approximately 44,000 bbls/day in 2014.

Husky completed a successful 2013/2014 winter delineation program at the McMullen thermal development property including the drilling of 40 stratigraphic wells, the acquisition of 25 square kilometers of three-dimensional ("3-D") seismic survey data and the completion of environmental field study work. Additional drilling commenced in December 2014 which will continue into the first quarter of 2015 to further progress the play.

Ninety-four horizontal heavy oil wells (gross) and 153 cold heavy oil production with sand ("CHOPS") wells (gross) were drilled in 2014.

Asia Pacific Region

China

Block 29/26

At the Liwan Gas Project, first gas from the deepwater wells from the Liwan 3-1 gas field was achieved on March 30, 2014 and gas sales into the Guangdong market natural gas grid commenced on April 24, 2014. In addition, the tie-in of the Liuhua 34-2 gas field single production well into the Liwan 3-1 field deepwater infrastructure was completed and commissioned with first production achieved in December 2014. Production from the Liwan Gas Project continues to increase with natural gas production averaging 114.2 mmcf/day and NGL production averaging 4.2 mbbls/day in 2014. Market opportunities for the sale of gas and liquids from the third deepwater field, Liuhua 29-1, continue to be assessed.

Offshore Taiwan

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

Indonesia

Madura Strait

Progress continued on the shallow water gas developments in the Madura Strait Block during 2014. Work related to the BD field engineering, procurement, installation and construction contract is ongoing and approximately 29 percent complete with construction moving forward on the wellhead platform and pipeline infrastructure in preparation for planned first production in 2017. The contract for the construction and lease of a floating production, storage and offloading ("FPSO") vessel received final approval in the second quarter of 2014 and was signed in December 2014.

Tender plans for the MDA and MBH development projects were approved by SKK Migas, the Indonesia oil and gas regulator, and the tendering process is in progress. The Gas Sales Agreement for the first tranche of gas from this development is complete and awaiting final approval from the regulator. The development plan for the MDK field to tie into the MDA/MBH combined development was approved by SKK Migas in July.

Anugerah

During 2014, Husky signed a production Production Sharing Contract ("PSC") for the Anugerah contract area. The contract area covers approximately 8,215 square kilometres and is primarily offshore East Java, Indonesia, with water depths of up to 1,400 metres. The main prospective locations are in water depths of 800 to 1,300 metres. The contract area is located approximately 150 kilometres east of the Madura Strait Block. Under the PSC, Husky has an obligation to carry out seismic surveys to assess the petroleum potential of the exploration block within the first three years. Exploration work, including planning for a 3-D seismic survey covering the contract area, is in progress.

Oil Sands

Sunrise Energy Project

The Company completed all remaining work and commissioning on Plant 1A, the first of two 30,000 bbls/day plants, at the Sunrise Energy Project. Steam injection into the reservoir commenced in December 2014, with first oil anticipated towards the end of the first quarter of 2015.

At Plant 1B, all welding is substantially completed, and construction activities are focused on completing electrical, instrumentation and insulation work. Plant 1B is on track to begin steaming in mid-2015.

In early 2014, an additional 38 square kilometers of 3-D seismic survey data was acquired and 12 stratigraphic wells were drilled to support continued field development of the Sunrise Energy Project.

Emerging Oil Sands

The Company completed a successful winter delineation program in the first quarter of 2014 at the Caribou and Cadotte North emerging oil sands properties.

Atlantic Region

White Rose Field and Satellite Extensions

At the South White Rose Extension project, gas injection commenced in early 2014 which is expected to increase reservoir pressure and oil recovery. Fabrication of production equipment was completed and installed in the second half of the year with development drilling commencing on the first production wells in late 2014. First oil is anticipated in mid-2015.

Drilling continued in 2014 at the Hibernia-formation well at the North Amethyst field which targeted a deeper zone beneath the main North Amethyst field. Production from the well, originally planned to commence in late 2014, has been delayed due to rig scheduling and is now expected to commence producing in the second half of 2015.

Hearings for the public review of the application for a wellhead platform to facilitate full field development at West White Rose were held during 2014. Construction continued on the dry-dock in Argentia, Newfoundland and early site preparation was advanced, including construction of a graving dock. Husky has deferred a final investment decision on the project.

Atlantic Exploration

The Company and its partner commenced an 18-month appraisal and exploration drilling program in November 2014 in the Bay du Nord discovery area in the Flemish Pass basin offshore Newfoundland and Labrador. The drilling program will involve the appraisal and delineation of the Bay du Nord discovery. The Company holds a 35 percent working interest in the Bay du Nord discovery.

Drilling of an exploration well on the Aster prospect in the Flemish Pass Basin commenced on December 19, 2014, and results are being evaluated.

In addition, a 3-D seismic program over the Bay du Nord discovery was completed in 2014.

Infrastructure and Marketing

The Hardisty terminal expansion project includes multiple initiatives intended to increase pipeline connectivity and blending capacity that would expand Husky's terminalling business, support Upstream production growth and provide additional flexibility through the inclusion of the Company's production in various crude streams. Construction of the two 300,000-barrel storage tanks and the expanded piping and blending infrastructure is complete. The project is now in the commissioning phase with start up expected in the first quarter of 2015.

The Company completed an expansion of its pipeline system from the Sandall heavy oil thermal development to the existing gathering system that leads to Hardisty, Alberta. In addition, the Saskatchewan Gathering System is undergoing an extension and capacity expansion into Lloydminster in order to accommodate the anticipated production from the Rush Lake, Edam East, Vawn and Edam West thermal developments.

5.2 Downstream

Lima Refinery

Front-end engineering design ("FEED") on the Company's feedstock flexibility project was completed in 2014. The project is expected to give the refinery flexibility to take up to 40,000 bbls/day of Western Canadian heavy oil while overall nameplate capacity would remain unchanged at 160,000 bbls/day. The initial planned completion date has been deferred with the project now expected to be completed in the 2018-2019 time frame.

BP-Husky Toledo Refinery

The Hydrotreater Recycle Gas Compressor Project was completed and became operational in late 2014. The project is expected to improve operational integrity and plant performance.

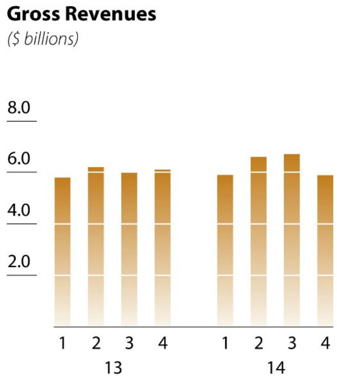
6.0 Results of Operations

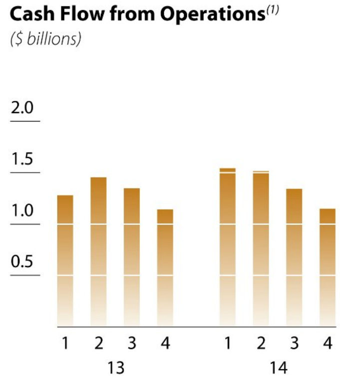
6.1 Segment Earnings

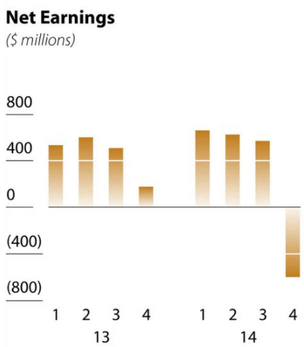
	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[1]	
($ millions)	**2014**	2013	**2014**	2013	**2014**	2013
Upstream						
Exploration and Production	**1,337**	1,283	**992**	952	**4,189**	4,264
Infrastructure and Marketing	**153**	392	**114**	292	**211**	96
Downstream						
Upgrading	**227**	401	**168**	297	**50**	205
Canadian Refined Products	**287**	260	**214**	194	**86**	109
U.S. Refining and Marketing	**(30)**	522	**(19)**	339	**374**	220
Corporate	**(190)**	(230)	**(211)**	(245)	**113**	134
Total	**1,784**	2,628	**1,258**	1,829	**5,023**	5,028

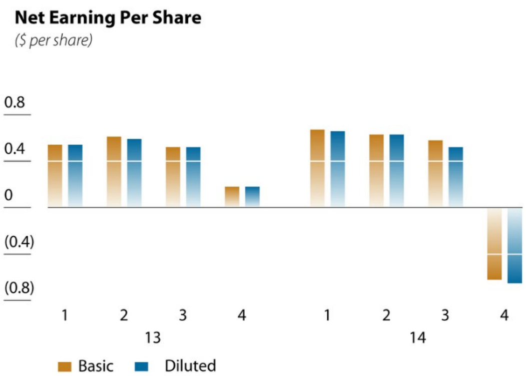
(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

6.2 Summary of Quarterly Results





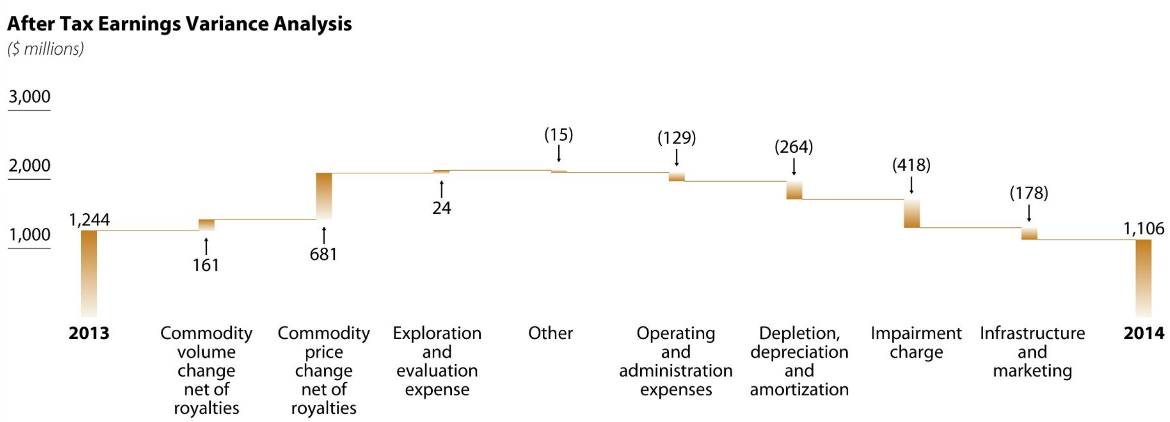




[(1)] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*

6.3 Upstream

2014 Total Upstream Earnings $1,106 million

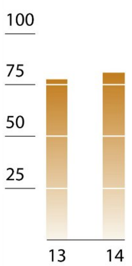


Exploration and Production

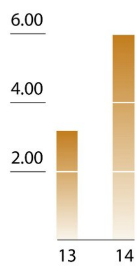
Exploration and Production Earnings Summary *($ millions)*	**2014**	2013
Gross revenues	**8,634**	7,333
Royalties	**(1,030)**	(864)
Net revenues	**7,604**	6,469
Purchases, operating, transportation and administrative expenses	**2,521**	2,347
Depletion, depreciation, amortization and impairment	**3,434**	2,515
Exploration and evaluation expenses	**214**	246
Other expenses	**98**	78
Income taxes	**345**	331
Net earnings	**992**	952

Excluding an after-tax impairment charge of $622 million and $204 million recognized in 2014 and 2013, respectively, Exploration and Production net earnings in 2014 were $1,614 million, an increase of $458 million compared to 2013 primarily due to new natural gas and NGL production from the Liwan Gas Project and new heavy crude oil production at the Sandall heavy oil thermal development, higher realized commodity prices in the first half of 2014 and lower exploration and evaluation expenses partially offset by lower realized crude oil prices due to declines in market benchmarks in the second half of 2014.

Average Price Realized
Crude Oil
($/bbl)

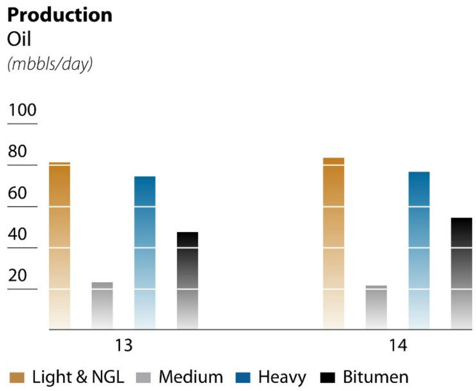


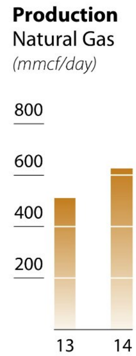
Average Price Realized
Natural Gas
($/mcf)

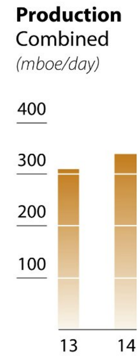


Average Sales Prices Realized	**2014**	2013
Crude oil and NGL *($/bbl)*		
Light crude oil & NGL	**96.70**	102.35
Medium crude oil	**80.69**	74.29
Heavy crude oil	**71.91**	63.44
Bitumen	**70.57**	61.68
Total crude oil and NGL average	**81.10**	78.12
Natural gas average *($/mcf)*	**5.99**	3.19
Total average *($/boe)*	**67.38**	61.96

During 2014, the average realized price for crude oil, NGL and bitumen was $81.10/bbl compared to $78.12/bbl in 2013, an increase of 4 percent. Lower average realized Brent and WTI market prices during 2014 were offset by a weaker Canadian dollar and narrower heavy crude oil and bitumen differentials. During 2014, the average realized natural gas price was $5.99/mcf compared to $3.19/mcf in 2013, an increase of 88 percent primarily due to higher realized fixed prices on production from the Liwan Gas Project and higher natural gas benchmark prices in Canada.







Daily Gross Production	2014	2013
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**30.1**	29.7
Medium crude oil	**21.5**	23.2
Heavy crude oil	**76.8**	74.5
Bitumen[1]	**54.6**	47.7
	183.0	175.1
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**38.6**	39.3
Terra Nova – light crude oil	**6.0**	4.8
	44.6	44.1
Asia Pacific Region		
Light crude oil & NGL[2]	**9.0**	7.3
Crude oil *(mbbls/day)*	**236.6**	226.5
Natural gas *(mmcf/day)*		
Western Canada	**506.8**	512.7
Asia Pacific Region[2]	**114.2**	–
	621.0	512.7
Total *(mboe/day)*	**340.1**	312.0

[1] *Bitumen production included heavy oil thermal average daily gross production of 43.8 mbbls/day and 37.4 mbbls/day for the years ended December 31, 2014 and 2013, respectively.*
[2] *Reported production volumes include Husky's net working interest production from the Liwan Gas Project (49 percent) and an incremental share of production volumes which are allocated to Husky until full project exploration cost recovery is attained.*

Total production increased 9 percent in 2014 when compared to 2013.

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	2014	2013
Crude oil		
Light crude oil & NGL	**36%**	43%
Medium crude oil	**7%**	9%
Heavy crude oil	**24%**	25%
Bitumen	**17%**	15%
Crude oil	**84%**	92%
Natural gas	**16%**	8%
Total	**100%**	100%

During 2014, crude oil, bitumen and NGL production increased by 10.1 bbls/day or 4 percent compared to 2013, primarily due to new heavy oil thermal production at the Sandall heavy oil thermal development, new NGL production from the Liwan Gas Project, increased production at the Ansell liquids-rich natural gas resource play and higher production from Terra Nova where turnaround activity was lower in 2014 compared to 2013. Production increases were partially offset by natural reservoir declines from mature properties in Western Canada. Production from the White Rose and satellite fields in the Atlantic Region in 2014 was comparable to 2013 with new production from the multilateral well at North Amethyst offsetting natural declines at the mature main field.

Natural gas production increased by 108.3 mmcf/day or 21 percent in 2014 compared to 2013 due to new production from the Liwan Gas Project and increased production at the Ansell liquids-rich natural gas resource play, partially offset by natural reservoir declines in Western Canada mature properties.

2015 Production Guidance and 2014 Actual

Gross Production	Guidance 2015	Year ended December 31 2014	Guidance 2014
Canada			
Light / Medium crude oil & NGL *(mbbls/day)*	87 - 92	**96**	100 - 103
Heavy crude oil & bitumen *(mbbls/day)*	125 - 135	**131**	125 - 130
Natural gas *(mmcf/day)*	440 - 480	**507**	420 - 480
Canada total *(mboe/day)*	285 - 307	**312**	295 - 313
Asia Pacific			
Light crude oil & NGL *(mbbls/day)*	13 - 15	**9**	10 - 12
Natural gas *(mmcf/day)*	160 - 195	**114**	150 - 180
Asia Pacific total *(mboe/day)*	40 - 48	**28**	35 - 42
Total *(mboe/day)*	325 - 355	**340**	330 - 355

The Company's total production for the year ended December 31, 2014 was within production guidance. Husky expects that production levels in 2015 will be comparable to 2014 as increasing production from the Liwan Gas Project in the Asia Pacific Region and new production at the Sunrise Energy Project will be offset by decreasing production from natural gas properties in Western Canada due to natural reservoir declines.

Factors that could potentially impact Husky's production performance for 2015 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 or delay capital expenditures;
- defaults by contracting parties whose services or facilities are necessary for the Company's 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 percent of gross revenues in both 2014 and 2013. Royalty rates in Western Canada averaged 12 percent in both 2014 and 2013. Royalty rates in the Atlantic Region averaged 17 percent in 2014 compared to 13 percent in 2013 due to Tier 1 and super royalty rates being reached at the North Amethyst and West White Rose Satellite Extensions. Royalty rates in the Asia Pacific Region averaged 8 percent in 2014 compared to 24 percent in 2013 due to lower royalty rates associated with production from the Liwan Gas Project which started producing late in March 2014.

Operating Costs

($ millions)	2014	2013
Western Canada	**1,819**	1,745
Atlantic Region	**218**	201
Asia Pacific	**82**	31
Total	**2,119**	1,977
Unit operating costs *($/boe)*	**16.12**	16.28

Total Exploration and Production operating costs were $2,119 million in 2014 compared to $1,977 million in 2013. Total Upstream unit operating costs in 2014 averaged $16.12/boe compared to $16.28/boe in 2013 primarily due to lower per unit operating costs on production from the Liwan Gas Project, which started producing in late March 2014, and lower unit operating costs on production from thermal projects. The decrease was partially offset by increased natural gas prices and maintenance activities in Western Canada and higher logistics and ice management costs and the completion of maintenance turnarounds on the SeaRose FPSO in the Atlantic Region.

Operating costs in Western Canada increased to $17.39/boe in 2014 compared to $17.05/boe in 2013 primarily due to increased natural gas prices and maintenance activities partially offset by the impact of production from lower unit operating cost thermal projects.

Operating costs in the Atlantic Region averaged $13.38/boe in 2014 compared to $12.47/boe in 2013 primarily due to higher logistics and ice management costs and the completion of maintenance turnarounds on the SeaRose FPSO.

Operating costs in the Asia Pacific Region averaged $8.06/boe in 2014 compared to $11.39/boe in 2013 primarily due to lower unit cost production from the Liwan Gas Project which commenced in late March 2014.

Exploration and Evaluation Expenses

($ millions)	**2014**	2013
Seismic, geological and geophysical	**111**	133
Expensed drilling	**45**	102
Expensed land	**58**	11
Total	**214**	246

Exploration and evaluation expenses in 2014 were $214 million compared to $246 million in 2013. Expensed land in 2014 was primarily in Western Canada. Expensed drilling in 2013 included costs related to the winter program at the Slater River Canol shale project, as well as drilling costs associated with activities in the Atlantic Region. Seismic, geological and geophysical costs in 2013 included a one-time work commitment penalty in the Atlantic Region.

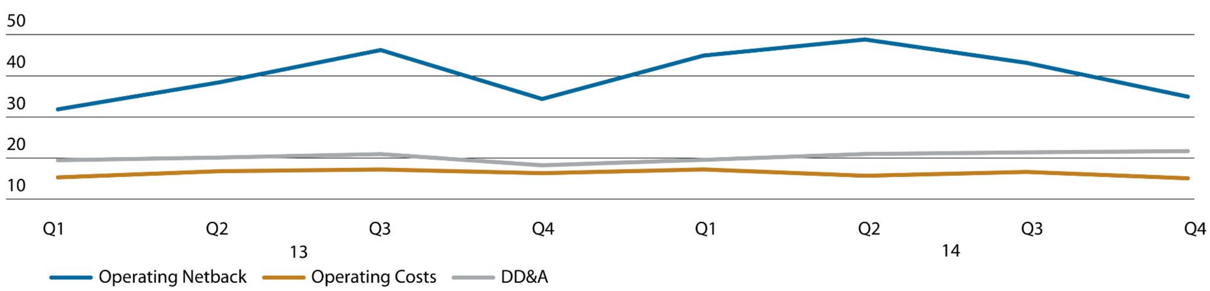
Depletion, Depreciation, Amortization ("DD&A") and Impairment

During 2014, the Company recognized a pre-tax impairment charge of $838 million on certain conventional crude oil and natural gas assets located in Western Canada compared to a pre-tax impairment charge of $275 million in 2013. The impairment charge was the result of lower estimated short and long-term crude oil and natural gas prices.

During 2014, total DD&A was $20.92/boe compared to $19.67/boe in 2013, both excluding impairment charges. The increase in DD&A in 2014 was primarily attributable to higher depletion rates per boe on production from the Liwan Gas Project.

At December 31, 2014, capital costs in respect of assets under construction and major development projects were $6.9 billion compared to $8.3 billion at the end of 2013. These costs are excluded from the Company's DD&A calculation until the properties are developed and have started producing 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 2014, Upstream Exploration and Production capital expenditures were $4,189 million. Capital expenditures were $2,334 million (56%) in Western Canada including Heavy Oil, $713 million (17%) in Oil Sands, $746 million (18%) in the Atlantic Region and $396 million (9%) in the Asia Pacific Region.

Exploration and Production Capital Expenditures[1] *($ millions)*	2014	2013
Exploration		
Western Canada	209	353
Oil Sands	5	–
Atlantic Region	96	201
Asia Pacific Region	16	21
	326	575
Development		
Western Canada	2,074	2,029
Oil Sands	708	552
Atlantic Region	650	437
Asia Pacific Region	380	633
	3,812	3,651
Acquisitions		
Western Canada	51	38
	4,189	4,264

[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:

	2014		2013	
Wells Drilled *(wells)*[1]	Gross	Net	Gross	Net
Exploration				
Oil	53	45	39	24
Gas	9	5	19	14
Dry	3	3	–	–
	65	53	58	38
Development				
Oil	469	419	768	709
Gas	78	68	68	41
Dry	3	3	1	–
	550	490	837	750
Total	615	543	895	788

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

The Company drilled 543 net wells in the Western Canada, Heavy Oil and Oil Sands business units in 2014 resulting in 464 net oil wells and 73 net natural gas wells compared to 788 net wells resulting in 733 net oil wells and 55 net natural gas wells in 2013.

During 2014, Husky invested $2,334 million on exploration, development and acquisitions, including Heavy Oil, throughout the Western Canada Sedimentary Basin compared to $2,420 million in 2013. Property acquisitions totalling $51 million were completed in 2014 compared to $38 million in 2013. Oil related exploration and development in 2014 was $392 million compared to $576 million in 2013. Investment in natural gas related exploration and development, primarily liquids-rich, was $502 million in 2014 compared to $596 million in 2013.

In addition, $829 million was spent on production optimization, cost reduction initiatives, facilities, land acquisition and retention and environmental protection in 2014 compared to $581 million in 2013.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling were $560 million in 2014 compared to $629 million in 2013.

Oil Sands

During 2014, $713 million was invested in Oil Sands projects, compared to $552 million in 2013, primarily for Phase 1 of the Sunrise Energy Project.

Atlantic Region

The following table discloses Husky's offshore Atlantic Region drilling activity during 2014:

Atlantic Region Offshore Drilling Activity

Well	Working Interest	Well Type
Terra Nova L-98-1Y	WI 13%	Development (Producer)
South White Rose J-05-1	WI 68.875%	Development (Gas Injector)
Terra Nova L-98-13	WI 13%	Development (Water Injector)
North Amethyst E-18-12A	WI 68.875%	Delineation
Bay de Verde F-67	WI 35%	Exploration

During 2014, $746 million was invested in Atlantic Region projects compared to $638 million in 2013, primarily on the continued development of the White Rose Extension projects, including the North Amethyst, West White Rose and South White Rose Extensions.

Asia Pacific Region

During 2014, $396 million was invested in the Asia Pacific Region projects, compared to $654 million in 2013, primarily on the continued development of the Liwan Gas Project.

2015 Upstream Capital Program

($ millions)	
Western Canada	**1,500**
Oil Sands	**200**
Atlantic Region	**600**
Asia Pacific Region	**200**
Total Upstream capital expenditures(1)	**2,500**

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

The 2015 Capital Program enables Husky to build on the momentum achieved over the past four years while maintaining prudent capital management and pacing of the Company's growth projects and exploration plans in a weak commodity price environment.

The Company has budgeted $200 million for the Asia Pacific Region in 2015, primarily for the continued development of the Liwan Gas Project and the development of the Madura Strait block in Indonesia.

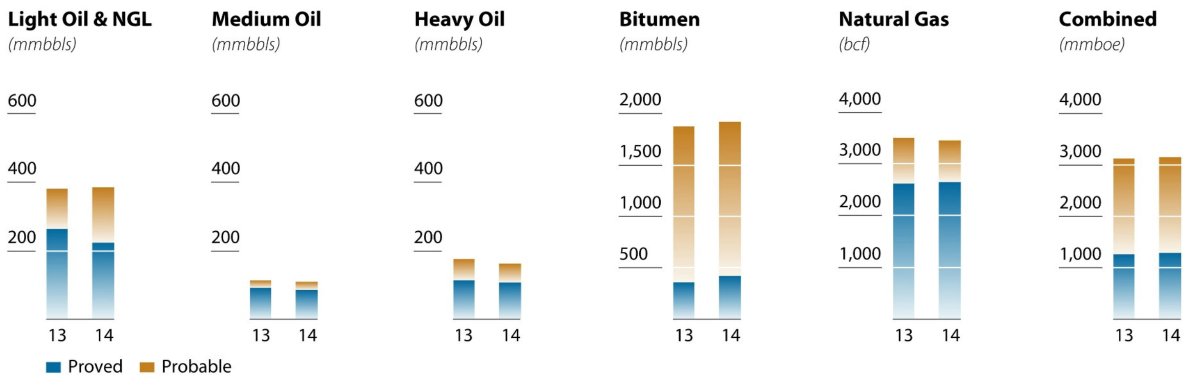
The Company has budgeted $200 million in Oil Sands in 2015, primarily for the continued development of Phase 1 of the Sunrise Energy Project.

The Company has budgeted $600 million in the Atlantic Region in 2015, primarily for continued development of the White Rose fields and extensions. The Company has commenced an 18-month exploration and appraisal program in the Bay du Nord discovery area offshore Newfoundland and Labrador.

In addition to advancing mid and long-term growth, the 2015 Capital Program provides support to the Company’s efforts to continue to reinvigorate and transform its foundation in Western Canada. The Company is making progress in its strategy to transition a greater percentage of its heavy oil production to long-life thermal. Husky will continue its development of the 10,000 bbls/day Rush Lake thermal project, with expected first production in the third quarter of 2015 and the two 10,000 bbls/day Edam East and Vawn and the 3,500 bbls/day Edam West thermal developments, with first production from all three projects expected in the second half of 2016.

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, 2014. 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.

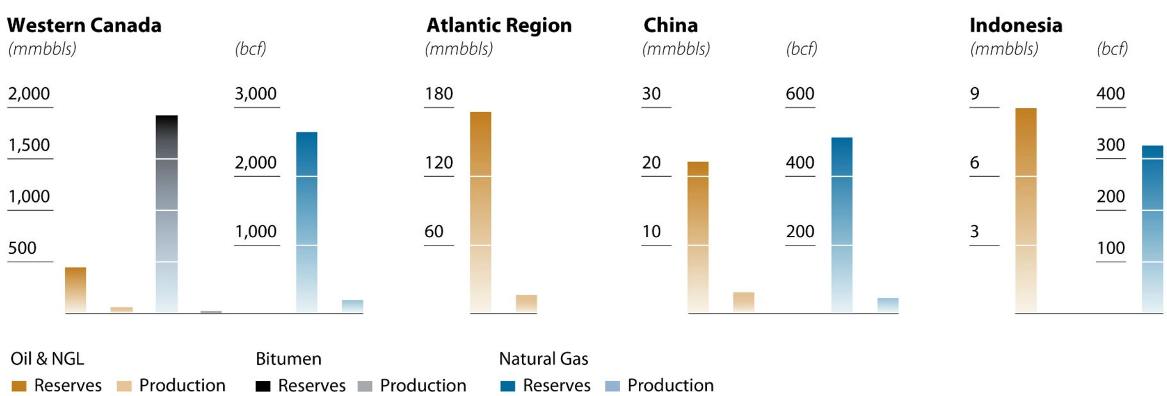
The Company's complete Oil and Gas Reserves Disclosure, prepared in accordance with NI 51-101, is contained in Husky's Annual Information Form, which is available at www.sedar.com, or Husky's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com.

McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit of the Company's internally evaluated crude oil, natural gas, NGL and the Tucker property reserves estimates, other than for the Company's Heavy Oil and Gas business unit. McDaniel issued an audit opinion stating that the Company's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions 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.

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 Company's Heavy Oil and Gas business unit, excluding the Tucker property.

At December 31, 2014, Husky's proved oil and gas reserves were 1,279 mmboe, up from 1,265 mmboe at the end of 2013. Additions to proved reserves, including acquisitions and divestitures, represent 115 percent excluding economic revisions (111 percent including economic revisions) of 2014 production. Major additions to proved reserves in 2014 included:

- The extension through additional drilling locations at the Sunrise Energy Project that resulted in the booking of an additional 40 mmbbls of bitumen in proved undeveloped reserves;
- Extensions, improved recovery and strong performance in Heavy Oil and Gas thermal projects that resulted in the booking of an additional 36 mmbbls of Bitumen in proved reserves;
- Strong performance from Liwan 3-1 that resulted in the booking of an additional 19 mmboe of natural gas and natural gas liquids in proved developed producing reserves; and
- The extension through additional drilling locations at the Ansell liquids-rich natural gas resource play that resulted in the booking of an additional 10 mmboe of natural gas and natural gas liquids in proved undeveloped reserves.



Note: Reserves reported represent proved plus probable reserves.

Reconciliation of Proved Reserves

(forecast prices and costs before royalties)	Canada						International		Total		
	Western Canada					Atlantic Region					
	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, 2013	167	91	113	359	2,175	74	23	452	827	2,627	1,265
Revision of previous estimate	(31)	–	23	(6)	65	5	3	98	(6)	163	21
Purchase of reserves in place	–	–	2	1	–	–	–	–	3	–	3
Sale of reserves in place	–	–	(7)	–	(1)	–	–	–	(7)	(1)	(7)
Discoveries, extensions and improved recovery	12	2	20	70	123	–	1	–	105	123	125
Economic revision	–	–	(1)	–	(23)	–	–	–	(1)	(23)	(4)
Production	(11)	(8)	(44)	(4)	(185)	(16)	(3)	(42)	(86)	(227)	(124)
Proved reserves December 31, 2014	**137**	**85**	**106**	**420**	**2,154**	**63**	**24**	**508**	**835**	**2,662**	**1,279**
Proved and probable reserves December 31, 2014	**176**	**107**	**162**	**1,917**	**2,637**	**177**	**31**	**836**	**2,570**	**3,473**	**3,149**
December 31, 2013	223	112	176	1,870	2,669	125	33	859	2,539	3,528	3,127

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

Reconciliation of Proved Developed Reserves

(forecast prices and costs before royalties)	Canada						International		Total		
	Western Canada					Atlantic Region					
	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 developed reserves											
December 31, 2013	146	85	92	66	1,702	60	15	267	464	1,969	792
Revision of previous estimate	(29)	1	23	(8)	97	6	4	116	(3)	213	33
Transfer from proved undeveloped	4	1	9	66	63	–	–	–	80	63	90
Purchase of reserves in place	–	–	1	–	–	–	–	–	1	–	1
Sale of reserves in place	–	–	(3)	–	(1)	–	–	–	(3)	(1)	(3)
Discoveries, extensions and improved recovery	4	1	12	1	19	–	1	–	19	19	22
Economic revision	–	–	(1)	–	(23)	–	–	–	(1)	(23)	(4)
Production	(11)	(8)	(44)	(4)	(185)	(16)	(3)	(42)	(86)	(227)	(124)
Proved developed reserves December 31, 2014	**114**	**80**	**89**	**121**	**1,672**	**50**	**17**	**341**	**471**	**2,013**	**807**

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

Planned Turnarounds

- Planned turnarounds at the Ansell liquids-rich gas resource play and Ram River plant in Western Canada are expected to have an impact of about 4,700 boe/day in the second quarter of 2015.
- Other scheduled third-party shutdowns are expected to impact Western Canada production by approximately 3,300 boe/day in the third quarter of 2015.
- A three-week maintenance shutdown is planned at the Tucker heavy oil thermal project in the second quarter of 2015.
- Partial shut-downs are scheduled at several heavy oil thermal projects to perform routine maintenance, with an estimated aggregate impact of 8,000 bbls/day in June 2015.
- An 18-day turnaround on the SeaRose FPSO vessel is scheduled for the third quarter of 2015.
- A planned ten-week maintenance event at Terra Nova has been scheduled to commence in the second quarter of 2015.

Infrastructure and Marketing

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

Infrastructure and Marketing Earnings Summary *($ millions, except where indicated)*	**2014**	2013
Infrastructure gross margin	**146**	130
Marketing and other gross margin	**70**	312
Gross margin	**216**	442
Operating and administrative expenses	**40**	33
Depletion, depreciation and amortization	**25**	20
Other expenses	**(2)**	(3)
Income taxes	**39**	100
Net earnings	**114**	292
Commodity trading volumes managed (mboe/day)	**252.3**	174.5

Infrastructure and Marketing net earnings decreased by $178 million in 2014 compared with 2013 primarily due to the narrowing product price differentials between Canada and the United States. The Company is able to capture differences between the two markets by utilizing infrastructure capacity to deliver feedstock acquired in Canada to the U.S. market. The increase to commodity trading volumes managed relates primarily to additional pipeline capacity.

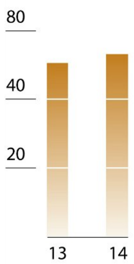
Infrastructure and Marketing capital expenditures totalled $211 million in 2014 compared with $96 million in 2013 primarily related to the Hardisty terminal expansion project and the extension and capacity expansion of the Saskatchewan Gathering System into Lloydminster.

6.4 Downstream

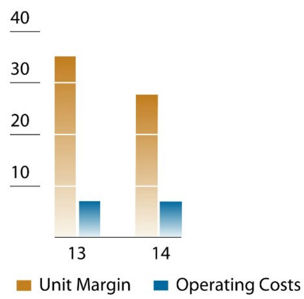
2014 Total Downstream Earnings $363 million

Upgrader

Upgrader
Synthetic Crude Sales
(mbbls/day)



Upgrader
Unit Margin & Operating Costs
($/bbl)



Upgrader Earnings Summary *($ millions, except where indicated)*	2014	2013
Gross revenues	**2,212**	2,023
Gross margin	**536**	645
Operating and administrative expenses	**189**	168
Depreciation and amortization	**108**	96
Other income (expense)	**12**	(20)
Income taxes	**59**	104
Net earnings	**168**	297
Upgrader throughput[1] *(mbbls/day)*	**72.7**	66.1
Synthetic crude oil sales *(mbbls/day)*	**53.3**	50.5
Upgrading differential *($/bbl)*	**21.80**	29.14
Unit margin ($/bbl)	**27.55**	34.99
Unit operating cost[2] ($/bbl)	**6.78**	6.96

(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.

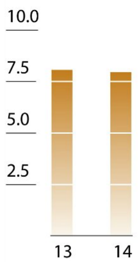
Upgrader net earnings in 2014 decreased by $129 million compared with 2013. The decrease in net earnings was primarily due to lower realized upgrading differentials as slightly higher realized prices for Husky Synthetic Blend were offset by higher feedstock costs.

During 2014, the price of Husky Synthetic Blend averaged $101.38/bbl compared to the average cost of blended heavy crude oil from the Lloydminster area of $79.58/bbl. During 2013, the price of Husky Synthetic Blend averaged $100.57/bbl compared to an average cost of blended heavy crude oil from the Lloydminster area of $71.43/bbl. This resulted in an average synthetic/heavy crude oil differential of $21.80/bbl in 2014 compared to $29.14/bbl in 2013 and a gross unit margin of $27.55/bbl in 2014 compared to $34.99/bbl in 2013.

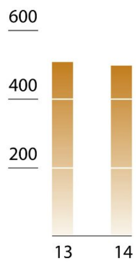
The operating cost of upgrading averaged $6.78/bbl in 2014 compared to $6.96/bbl in 2013 which resulted in a net margin for upgrading heavy crude of $20.77/bbl, down 26 percent compared to $28.03/bbl in 2013. Higher energy costs and maintenance contributed to the increase in operating and administrative expenses and a recovery of upside interest, associated with the remaining payment obligation to Natural Resources Canada and the Alberta Department of Energy, recognized in 2013 contributed to the increase in other expenses in 2014 compared to 2013.

Canadian Refined Products

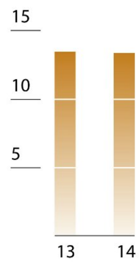
Canadian Refined Products
Volume
(millions of litres/day)



Outlets



Volume per Outlet
(thousands of litres/day)



Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	2014	2013
Gross revenues	**4,020**	3,737
Gross margin		
Fuel	**147**	140
Refining	**251**	175
Asphalt	**246**	233
Ancillary	**57**	55
	701	603
Operating and administrative expenses	**307**	253
Depreciation and amortization	**102**	90
Other expense	**5**	–
Income taxes	**73**	66
Net earnings	**214**	194
Number of fuel outlets[(1)]	**497**	509
Fuel sales volume, including wholesale		
Fuel sales *(million of litres/day)*	**8.0**	8.1
Fuel sales per outlet *(thousand of litres/day)*	**13.4**	13.5
Refinery throughput		
Prince George refinery *(mbbls/day)*	**11.7**	10.3
Lloydminster refinery *(mbbls/day)*	**28.8**	26.4
Ethanol production *(thousand of litres/day)*	**780.7**	742.4

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

Fuel gross margins increased in 2014 compared to 2013 primarily due to higher realized gasoline margins.

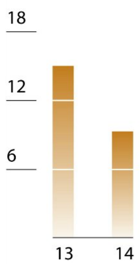
Refining gross margins increased in 2014 compared to 2013 primarily due to higher refinery throughput and lower feedstock costs at the ethanol plants.

Asphalt gross margins increased in 2014 compared to 2013 primarily due to higher asphalt throughput resulting from a scheduled refinery turnaround completed in 2013.

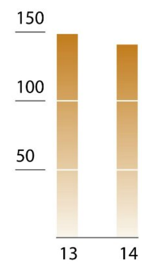
Higher energy costs contributed to the increase in operating and administrative expenses in 2014 when compared to 2013.

U.S. Refining and Marketing

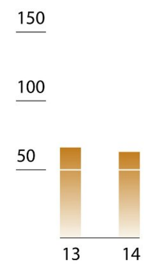
Refining Margin
U.S.
(U.S. $/bbl crude throughput)



Throughput
Lima Refinery
(mbbls/day)



Toledo Refinery
(mbbls/day)



U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	2014	2013
Gross revenues	**10,663**	10,728
Gross refining margin	**722**	1,182
Operating and administrative expenses	**481**	424
Depreciation and amortization	**268**	233
Other expenses	**3**	3
Income taxes	**(11)**	183
Net earnings (loss)	**(19)**	339
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**141.6**	149.4
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**63.2**	65.0
Refining margin *(U.S. $/bbl crude throughput)*	**9.37**	15.06
Refinery inventory (feedstocks and refined products) *(mmbbls)*[(1)]	**10.8**	10.3

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

U.S. Refining and Marketing net earnings decreased by $358 million in 2014 compared with 2013 primarily due to lower market crack spreads combined with FIFO losses and provisions booked to reduce inventory to net realizable value resulting from falling crack spreads and crude oil prices at year end.

The after-tax impact from provisions booked to reduce inventories to net realizable value was $128 million in 2014. Excluding this provision, the Company's U.S. refining margin for 2014 was U.S. $11.83/bbl. In addition, lower refinery throughput resulting from planned maintenance at the Lima Refinery contributed to the decrease in net earnings.

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 in the previous year when crude oil prices were higher. The estimated FIFO impact was a reduction in net earnings of approximately $108 million in 2014 compared to a reduction in net earnings of $18 million in 2013.

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

Downstream Capital Expenditures

In 2014, Downstream capital expenditures totalled $510 million compared to $534 million in 2013. In Canada, capital expenditures of $136 million were primarily related to upgrades at retail stations and projects at the Upgrader and Prince George Refinery. In the United States, capital expenditures totalled $374 million for 2014 compared to $220 million in 2013. At the Lima Refinery, $260 million was spent primarily on the feedstock flexibility project and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $114 million (Husky's 50 percent share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

A turnaround at the partner-operated refinery in Toledo is scheduled to commence in the third quarter of 2015.

6.5 Corporate

2014 Loss $211 million

Corporate Summary *($ millions) income (expense)*	2014	2013
Selling, general and administration expenses	**(139)**	(217)
Depreciation and amortization	**(73)**	(51)
Other income	**5**	17
Foreign exchange gains	**81**	21
Interest expense	**(64)**	–
Income taxes	**(21)**	(15)
Net loss	**(211)**	(245)

The Corporate segment reported a loss of $211 million in 2014 compared to a loss of $245 million in 2013. Selling, general, and administrative expenses decreased in 2014 compared to 2013 primarily due to lower stock-based compensation expense associated with a decrease in the Company's share price in 2014. Other income decreased by $12 million in 2014 compared to 2013 primarily due to the recovery of an insurance provision in 2013. Foreign exchange gains increased by $60 million in 2014 compared to 2013 due to the weakening of the Canadian dollar against the U.S. dollar which positively impacted the translation of the Company's foreign currency denominated working capital. Interest expense increased by $64 million in 2014 compared to 2013 due to a decrease in the amount of capitalized interest related to production being achieved at the Liwan Gas Project and a decrease in interest income associated with the Sunrise Oil Sands Partnership contribution receivable which was paid in full in the second quarter of 2014.

Foreign Exchange Summary *($ millions, except exchange rate amounts)*	2014	2013
Gains (losses) on translation of U.S. dollar denominated long-term debt	**7**	(11)
Gains on contribution receivable	**6**	27
Gains on non-cash working capital	**42**	33
Other foreign exchange gains (losses)	**26**	(28)
Foreign exchange gains	**81**	21
U.S./Canadian dollar exchange rates:		
At beginning of year	**U.S. $0.940**	U.S. $1.005
At end of year	**U.S. $0.862**	U.S. $0.940

Consolidated Income Taxes

Consolidated income taxes decreased in 2014 to $526 million from $799 million in 2013, resulting in an effective tax rate of 29 percent in 2014 compared to 30 percent in 2013. The decrease was primarily due to a recovery of non-deductible stock-based compensation recorded in 2014 compared to an expense recorded in 2013.

($ millions)	2014	2013
Income taxes as reported	**526**	799
Cash taxes paid	**661**	433

Corporate Capital Expenditures

Corporate capital expenditures were $113 million in 2014 compared to $134 million in 2013 and were primarily related to computer hardware and software and leasehold improvements.

7.0 Risk and Risk Management

7.1 Enterprise Risk Management

The Company'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. The Company 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 the Company and its operations.

7.2 Significant Risk Factors

Operational, Environmental and Safety Incidents

The Company's businesses are subject to inherent operational risks in respect to safety and the environment that require continuous vigilance. The Company seeks to minimize these operational risks by carefully designing and building its facilities and conducting its operations in a safe and reliable manner using its integrated management system that considers the environmental requirements and process and occupational safety (Husky Operational Integrity Management System). Failure to manage the risks effectively could result in potential fatalities, serious injury, asset damage or environmental impact. Enterprise risk management, emergency preparedness, business continuity and security policies and programs are in place for all operating areas and are adhered to on an ongoing basis. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

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 the Company's oil and gas reserves. The Company'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 the Company's 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 in Western Canada and Asia Pacific. Western Canada is 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 Asia or in North America, the crude oil price is based on the balance of supply and demand. Natural gas price in North America is affected primarily by supply and demand, as well as by prices for alternative energy sources. The natural gas Husky produces in the Asia Pacific Region is sold to specific buyers with long-term contracts. The price is fixed for the initial 5 years for the Liwan 3-1 gas field and then linked to city-gas pricing adjustment. For Liuhua 34-2, the price is fixed during the delivery period.

In certain instances, the Company uses derivative commodity instruments to manage exposure to price volatility on a portion of its crude 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 could have a material adverse effect on the Company's business, financial condition and cash flow. For information on 2014 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 negatively affect the Company's reputation, investor confidence and the Company's ability to deliver on its growth strategy.

In order to maintain the Company's future production of crude oil, natural gas and NGL 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. In order 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 developable 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 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 the Company's refineries and or upgrader may limit the Company's ability to deliver product with negative implications on sales and results from operating activities.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact the Company’s personnel, which could result in injury, death, extortion, hostage and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or activist incident targeted at a facility, office or offshore vessel/installation owned or operated by the Company could result in the interruption or cessation of key elements of the Company's operations. Outcomes of such incidents could have a material impact on the Company’s financial position, business strategy and cash flow.

A cyber incident may impact the operational state and/or cause physical damage to the Company's assets, along with potential health and safety risks or loss of intellectual property.

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 Storage

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, which may 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. A tight labour market, an insufficient number of qualified candidates and an aging workforce are factors that can precipitate a human resource risk for the Company if not properly managed. Failure to 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 oil and gas projects ranging from Upstream to Downstream assets. The risks associated with project development and execution, as well as the risks involved in commissioning and integration of new assets with existing facilities, can impact the economic feasibility of the Company’s projects. These risks can result in, among other things, cost overruns, schedule delays and a decline in the market value of the Company’s oil and gas products. These risks can also impact the Company’s safety and environmental performance, which could negatively affect the Company’s reputation.

Partner Misalignment

Joint venture partners operate a portion of the Company'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 project may be delayed and the Company may be partially or totally liable for its partner's share of the project.

Reserves Data and Future Net Revenue Estimates

The reserves data contained or referenced 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. For those reasons, estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom may differ substantially from actual results. The data may be prepared by different engineers or by the same engineers at different times. These factors may cause the estimates to vary substantially over time. All reserves estimates involve a degree of ambiguity and, 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 is 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, uncertain environmental and safety policies, penalties, taxes, royalties, government fees, 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

Changes in environmental regulation could have a material adverse effect on the Company's financial condition and results of operations by requiring increased capital expenditures and operating costs or by impacting the quality, formulation or demand of products, which may or may not be offset through market pricing. The scope and complexity of changes in environmental regulation make it challenging to forecast the potential impact on the Company. The Company engages in the dialogue on proposed changes, both directly and through industry associations, to ensure the Company's interests are recognized and the Company is sufficiently prepared to fully comply when new regulations come into force.

The Company anticipates further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, increased compliance costs and approval delays for critical licenses and permits, which could have a material adverse effect on the Company's financial condition and results of operations through increased capital and operating costs.

Some of the topics that are or could in the future be subject to new or enhanced environmental regulation include:

- water use, withdrawals and discharges;
- the use of hydraulic fracturing to aid in oil and gas production;
- targets for reduced purchases of unconventional oils, such as bitumen;
- new greenhouse gas ("GHG") regulations in jurisdictions where the Company has operations;
- jurisdictional calculation and regulation of fuel life-cycle carbon content;
- fuel reformulation to support reduced combustion emissions;
- new regulations for managing air pollutants at facility and equipment levels; and
- regulations affecting the transportation of product by rail.

Transportation of Dangerous Goods Regulation

The transportation of flammable liquids (crude, ethanol, gasoline, etc.) by rail is an emerging issue for the petroleum industry. Throughout 2014, Transport Canada and the Pipeline and Hazardous Materials Safety Administration ("PHMSA") in the United States have issued a series of orders and directives that are intended to enhance the safe transport of flammable liquids. Among these changes is greater oversight by the regulators, enhancements to emergency preparedness and response requirements, rail car design, testing and classification practices as well as discussions on a federal rail liability and compensation regime. Some of the enhancements came into effect in 2014; however the details of the other measures are still being worked on by the Canadian Association of Petroleum Producers, Canadian Fuels and other trade associations. On August 1, 2014, PHMSA published a Notice of Proposed Rulemaking concerning more stringent standards and operational controls for trains transporting high volumes of crude oil and other flammable materials and an Advance Notice of Proposed Rulemaking for oil spill response plans for these trains. If finalized, the rules would require the replacement of existing railcars and the implementation of other compliance measures. The final impact to the Company and the industry due to additional transportation costs imposed by the PHMSA rules and other developing standards has yet to be determined.

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 percent below an established baseline emissions intensity. These regulations currently affect the Company's Ram River Gas Plant and Tucker Thermal Facility and are expected to affect the Sunrise Energy Project when it starts production.

The Saskatchewan government is currently in the process of developing such regulations. These regulations may impact the Company's current and future operations in that province.

British Columbia currently has a $30 per tonne carbon tax that is placed on fuel the Company uses and purchases in that jurisdiction, which affects all of the Company's operations in British Columbia. Additionally, British Columbia has a Low Carbon Fuel Standard in place that requires a reduction in the allowable carbon intensities of all fuels, with penalties applied after 2016 for intensities that do not meet targets. Due to the geographical location of the Company's Prince George Refinery, the Company is already at the blend-wall as the cloud point of the Company's produced diesel has to meet the requirements for vehicle engines operating at low temperatures. These regulations may impact the Company's current and future operations in that province.

The Federal Government of Canada has announced its intention to take a sector based approach to future climate change regulations although it is not clear how new regulations will be structured or what compliance mechanisms will be available for the Company's affected operations. Climate change regulations may become more onerous over time as public and political pressures increase to implement initiatives that further reduce GHG emissions. Although the impact of emerging regulations is uncertain, they may have a material adverse effect on the Company's financial condition and results of operations through increased capital and operating costs.

The Company's U.S. refining business may be materially impacted by implementation of the Environmental Protection Agency ("EPA") climate change rules or by future U.S. GHG legislation that applies to the oil and gas industry or the consumption of petroleum products. Such legislation or regulation could require the Company's U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may have a material adverse effect on the Company's financial condition and results of operations through increased capital and operating costs.

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. The Company's 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 of the Company 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 the Company's debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in the Company's ratings outlook, could adversely affect the Company'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 availability of oil and gas field equipment may 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.

The Company operates in some of the harshest environments in the world, including offshore in the Atlantic Region. Climate change is expected to increase severe weather conditions in these locations including winds, flooding and variable temperatures, which are contributing to the melting of Northern ice and increased creation of icebergs. Icebergs off the coast of Newfoundland and Labrador may threaten offshore oil production facilities, causing damage to equipment and possible production disruptions, spills, asset damage and human impacts. The Company has in place a number of policies to protect people, equipment and the environment in the event of extreme weather conditions and ice melt conditions.

The Company's Atlantic Region business unit has a robust ice management program which uses a range of resources including a dedicated ice surveillance aircraft, as well as synergistic relationships with government agencies including Environment Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commence in February and continue until the threat has abated. In addition, Atlantic Region operators employ a series of supply and support vessels to actively manage ice and icebergs. These vessels are equipped with a variety of ice management tools including towing ropes, towing nets and water cannons. The Company also maintains a series of ad-hoc relationships with contractors, allowing the quick mobilization of additional resources as required.

7.3 Financial Risks

The Company'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.

Foreign Currency Risk

The Company's results are affected by the exchange rates between various currencies including the Canadian and U.S. dollars. The majority of the Company'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 the Company's U.S. dollar denominated debt and related interest expense, as expressed in Canadian dollars. The fluctuations in exchange rates are beyond the Company's control and 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. The Company 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, 2014, the amount that the Company designated was U.S. $2.9 billion (December 31, 2013 - U.S. $3.2 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, the Company 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. The Company 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. The Company actively manages this exposure to credit and contract execution risk from both a customer and a supplier perspective. Internal credit policies govern the Company's credit portfolio and limit transactions according to a counterparty's and a supplier's credit quality. Counterparties for all financial derivatives transacted by the Company 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.

The Company is committed to retaining investment grade credit ratings to support access to 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)
Series 3 Preferred Shares	Stable	P-2 (low)
Dominion Bond Rating Service:		
Senior Unsecured Debt	Stable	A (low)
Series 1 Preferred Shares	Stable	Pfd-2 (low)
Series 3 Preferred Shares	Stable	Pfd-2 (low)
Commercial Paper	Stable	R-1 (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, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, inventories measured at fair value, 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, 2014**	As at December 31, 2013
Commodity contracts – FVTPL		
Natural gas[(1)]	**(5)**	32
Crude oil[(2)]	**4**	41
Foreign currency contracts – FVTPL		
Foreign currency forwards	**(1)**	–
Other assets – FVTPL	**2**	2
Contingent consideration	**(40)**	(60)
Hedging instruments[(3)]		
Derivatives designated as a cash flow hedge[(4)]	–	37
Hedge of net investment[(5)]	**(353)**	(93)
	(393)	(41)

(1) Natural gas contracts include a $12 million decrease as at December 31, 2014 (December 31, 2013 – $27 million increase) to the fair value of held-for-trading inventory, recognized in the Condensed Consolidated Balance Sheets, related to third party physical purchase and sale contracts for natural gas held in storage. Total fair value of the related natural gas storage inventory was $87 million at December 31, 2014.

(2) Crude oil contracts include a $21 million decrease as at December 31, 2014 (December 31, 2013 – $49 million increase) to the fair value of held-for-trading inventory, recognized in the condensed consolidated balance sheets, related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory was $199 million at December 31, 2014.

(3) Hedging instruments are presented net of tax.

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

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

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

In 2014, the Company funded its capital programs and dividend payments through cash generated from operating activities, cash on hand, the issuance of commercial paper and the issuance of preferred shares. At December 31, 2014, the Company had total debt of $5,292 million, partially offset by cash on hand of $1,267 million for $4,025 million of net debt compared to $3,022 million of net debt as at December 31, 2013. At December 31, 2014, the Company had $2,792 million of unused credit facilities of which $2,335 million are long-term committed credit facilities and $457 million are short-term uncommitted credit facilities. In addition, the Company had $2.75 billion in unused capacity under its December 31, 2012 Canadian universal short form base shelf prospectus (the "2012 Canadian Shelf Prospectus") and U.S. $2.25 billion in unused capacity under its 2013 U.S. universal short form base shelf prospectus (the "U.S. Shelf Prospectus"). The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions. Refer to Section 8.2.

Cash Flow Summary *($ millions, except ratios)*	**2014**	2013
Cash flow		
Operating activities	**5,585**	4,645
Financing activities	**(6)**	(846)
Investing activities	**(5,423)**	(4,722)
Financial Ratios[(1)]		
Debt to capital employed *(percent)*[(2)]	**20.5**	17.0
Debt to cash flow *(times)*[(3)(4)]	**1.0**	0.8
Corporate reinvestment ratio *(percent)*[(3)(5)]	**101**	108
Interest coverage on long-term debt only[(3)(6)]		
Earnings	**6.7**	11.2
Cash flow	**23.6**	22.4
Interest coverage on total debt[(3)(7)]		
Earnings	**6.6**	11.3
Cash flow	**23.2**	22.6

(1) *Financial ratios constitute non-GAAP measures. (Refer to Section 11.3)*
(2) *Debt to capital employed is equal to long-term debt, long-term debt due within one year and commercial paper 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, long-term debt due within one year and commercial paper 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 long-term debt, the current portion of long-term debt and commercial paper.*

Cash Flow from Operating Activities

Cash generated from operating activities was $5,585 million in 2014 compared to $4,645 million in 2013. The increase in cash flow generated from operating activities resulted from a decrease in non-cash working capital primarily due to the timing of accounts receivable and accounts payable settlements and lower investments in inventory due to falling commodity prices.

Cash Flow used for Financing Activities

Cash used for financing activities was $6 million in 2014 compared to $846 million in 2013. The decrease in cash flow used for financing activities was primarily resulting from the issuance of Cumulative Redeemable Preferred Shares, Series 3 and proceeds from the issuance of commercial paper.

Cash Flow used for Investing Activities

Cash used for investing activities was $5,423 million in 2014 compared to $4,722 million in 2013. 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, 2014, Husky's working capital deficiency was $1,314 million compared to working capital of $754 million at December 31, 2013.

Movement in Working Capital

($ millions)	December 31, 2014	December 31, 2013	Change
Cash and cash equivalents	**1,267**	1,097	170
Accounts receivable	**1,324**	1,458	(134)
Income taxes receivable	**353**	461	(108)
Inventories	**1,385**	1,812	(427)
Prepaid expenses	**166**	89	77
Accounts payable and accrued liabilities	**(2,989)**	(3,155)	166
Asset retirement obligations	**(97)**	(210)	113
Short-term debt	**(895)**	–	(895)
Contribution payable	**(1,528)**	–	(1,528)
Long-term debt due within one year	**(300)**	(798)	498
Net working capital (deficiency)	**(1,314)**	754	(2,068)

The increase in cash was primarily due to higher cash flow from operating activities in the year, proceeds from the issuance of commercial paper and proceeds from the issuance of the Series 3 Shares. Movements in accounts receivable and accounts payable were due to the timing of settlements compared to 2013. The decrease in inventories was primarily due to lower investments in inventory due to falling commodity prices. The increase in short-term debt resulted from the issuance of commercial paper. The increase in contribution payable resulted from the reclassification of the BP-Husky Toledo contribution payable from long-term to short-term to reflect the repayment scheduled in 2015. The decrease in long-term debt due within one year was due to repayment of the maturing U.S. $750 million 5.90 percent notes issued under a trust indenture dated September 11, 2007, partially offset by the reclassification of the $300 million 3.75 percent medium-term notes maturing in 2015.

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. The Company 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 and short-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, the Company frequently evaluates 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, 2014, no production was hedged.

At December 31, 2014, Husky had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[1]	**645**	**457**
Syndicated bank facilities	**3,230**	**2,335**
	3,875	**2,792**

[1] *Consists of demand credit facilities.*

Cash and cash equivalents at December 31, 2014 totalled $1,267 million compared to $1,097 million at the beginning of the year.

At December 31, 2014, Husky had unused short and long-term borrowing credit facilities totalling $2.8 billion. A total of $188 million of the Company's short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $895 million of the Company's long-term committed borrowing credit facilities was used in support of commercial paper.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. There were no amounts drawn on this demand credit facility at December 31, 2014.

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, 2014, the Company declared dividends payable of $1.20 per common share, resulting in dividends of $1,180 million. An aggregate of $1,169 million was paid in cash during 2014. At December 31, 2014, $295 million, including $292 million in cash and $3 million in common shares, was payable to shareholders on account of dividends declared on October 23, 2014.

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 in February 2013, the limit on the $1.5 billion facility was increased to $1.6 billion. On June 19, 2014, the $1.6 billion revolving syndicated credit facility previously set to expire on August 31, 2014 was increased to $1.63 billion, and its maturity was extended to June 19, 2018. The Company also increased the limit on one of the operating facilities from $50 million to $100 million.

On December 31, 2012, the Company filed the 2012 Canadian Shelf Prospectus with applicable securities regulators in each of the provinces of Canada, other than Quebec, that enabled 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. During 2014, the Company issued $250 million of Cumulative Redeemable Preferred Shares, Series 3 (the "Series 3 Preferred Shares"), resulting in unused capacity of $2.75 billion under the 2012 Canadian Shelf Prospectus as at December 31, 2014.

On October 31, 2013 and November 1, 2013, the Company filed 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.

On March 17, 2014, the Company issued U.S. $750 million of 4 percent notes due April 15, 2024 pursuant to the U.S. Shelf Prospectus. The notes are redeemable at the option of the Company at any time, subject to a make-whole premium if the notes are redeemed prior to the three month period prior to maturity. Interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness. As at December 31, 2014, the Company had U.S. $2.25 billion in unused capacity under its U.S. Shelf Prospectus.

On June 15, 2014, the Company repaid the maturing 5.9 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to noteholders was U.S. $772 million, including U.S. $22 million of interest, equivalent to $839 million in Canadian dollars, including interest of $25 million.

On September 15, 2014, the Company launched a commercial paper program in Canada. The program is supported by the Company's syndicated credit facilities and the Company is authorized to issue commercial paper up to a maximum of $1.0 billion having a term not to exceed 365 days. The weighted average interest rate for commercial paper outstanding as at December 31, 2014 was 1.24 percent.

On December 9, 2014, the Company issued 10 million Series 3 Preferred Shares at a price of $25.00 per share for aggregate gross proceeds of $250 million under the 2012 Canadian Shelf Prospectus. Holders of the Series 3 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.5 percent annually for the initial period ending December 31, 2019 as declared by the Company. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.13 percent. Holders of Series 3 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 4 (the "Series 4 Preferred Shares"), subject to certain conditions, on December 31, 2019 and on December 31 every five years thereafter. Holders of the Series 4 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.13 percent.

Subsequent to December 31, 2014, on February 23, 2015, the Company filed a short form base shelf prospectus (the "2015 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including March 22, 2017.

The ability of the Company to raise capital utilizing the 2015 Canadian Shelf Prospectus or U.S. Shelf Prospectus is dependent on market conditions at the time of sale.

Capital Structure	December 31, 2014	
($ millions)	**Outstanding**	**Available**[(1)]
Total debt	**5,292**	**2,792**
Common shares, retained earnings and other reserves	**20,575**	

(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, the Company is obligated to make future payments. The following summarizes known non-cancellable contracts and other commercial commitments:

Contractual Obligations

Payments due by period ($ millions)	**2015**	**2016-2017**	**2018-2019**	**Thereafter**	**Total**
Long-term debt and interest on fixed rate debt	537	1,026	1,593	3,065	6,221
Operating leases	115	478	440	1,019	2,052
Firm transportation agreements	351	669	648	3,275	4,943
Unconditional purchase obligations[(1)]	2,495	750	468	329	4,042
Lease rentals and exploration work agreements	321	292	176	1,219	2,008
Asset retirement obligations[(2)]	95	315	243	14,920	15,573
	3,914	3,530	3,568	23,827	34,839

(1) *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases. Unconditional purchase obligations have been updated for changes to commitments subsequent to the release of the Company's 2014 fourth quarter Management's Discussion and Analysis.*

(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 ("ARO") as outlined in Note 16 to the 2014 Consolidated Financial Statements. On an undiscounted basis, the ARO increased from $12.3 billion as at December 31, 2013 to $15.5 billion as at December 31, 2014, due to increased cost estimates and asset growth in both the Upstream and Downstream segments an increased estimated time to retirement in the Upstream segment.

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

The Company has entered into new firm transportation agreements in 2014, and future payments on transportation agreements settled in U.S. dollars have been impacted by a weaker Canadian dollar.

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 79 active employees, 89 participants with deferred benefits and 539 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 completed the full wind up of the defined benefit pension plan in the United States effective May 2014. 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 2014 Consolidated Financial Statements).

The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery (Refer to Note 8 to the 2014 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, 2014, Husky's share of this obligation was U.S. $1.3 billion, including accrued interest.

Subsequent to December 31, 2014, the Company amended the terms of repayment of the Company's contribution payable with BP-Husky Refining LLC. In accordance with the amendment, U.S. $1 billion of the net contribution payable was paid on February 2, 2015. As a result of prepayment, the accretion rate has been reduced from 6 percent to 2.5 percent for the future term of the agreement. The remaining amount of approximately U.S. $300 million will be paid by way of funding all capital contributions of the BP- Husky Refining LLC joint operation with full payment required on or before December 31, 2017.

The Company 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

The Company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the Company's financial condition, results of operations, liquidity or capital expenditures.

Standby Letters of Credit

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

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.

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, 2014, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $78 million. For the year ended December 31, 2014, the amount of steam purchased by the Company from Meridian totalled $25 million. In addition, the Company provides facility services to Meridian which are measured and reimbursed at cost. For the year ended December 31, 2014, 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 23, 2015

• common shares	983,840,282
• cumulative redeemable preferred shares, series 1	12,000,000
• cumulative redeemable preferred shares, series 3	10,000,000
• stock options	25,994,288
• stock options exercisable	13,285,074

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 2014 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 and impairment, ARO, 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 defined benefit pension plan and the other post-retirement benefit plans 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, 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.

Exploration and Evaluation Costs

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. Drilling results, required operating costs and capital expenditure and estimated reserves are important judgments when making this determination 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 any indications of impairment requires significant judgment of external factors, such as an extended decrease in prices or margins for oil and gas commodities or products, a significant decline in an asset's market value, a significant downward revision of estimated volumes, an upward revision of future development costs, a decline in the entity's market capitalization or significant changes in the technological, market, economic or legal environment that would have an adverse impact on the entity. 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 judgment 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

Financial Instruments

In July 2014, the IASB issued IFRS 9 "Financial Instruments" to replace IAS 39 which provides a logical model for classification and measurement, a single, forward-looking 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The standard is effective for the Company for annual periods beginning on January 1, 2018, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the standard on January 1, 2018. The adoption of the standard is not expected to have a material impact on the Company's Consolidated Financial Statements.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to replace IAS 18 which establishes principles for reporting useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. The standard is effective for the Company for annual periods beginning on January 1, 2017, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the standard on January 1, 2017. The company is assessing the impact of this standard and does not expect it to have a material impact on the Company's Consolidated Financial Statements.

Change in Accounting Policy

Impairment of Assets

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

Levies

The IASB issued International Financial Reporting Interpretations Committee Interpretation ("IFRIC") 21, "Levies" which was adopted by the Company on January 1, 2014. The IFRIC clarifies that an entity should recognize a liability for a levy when the activity that triggers payment occurs. The adoption of this interpretation had no impact on the Company's 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; the Company's 2015 production guidance, including weighting of production among product types; and the Company's 2015 Upstream capital program;
- with respect to the Company's Asia Pacific Region: planned timing of first gas from the Madura Strait BD field;
- with respect to the Company's Atlantic Region: expected benefits of gas injection at the Company's South White Rose Extension project; anticipated timing of first production at the Company's South White Rose Extension project; scheduled timing of first production from the North Amethyst Hibernia-formation well; the scheduled duration and timing of a turnaround for the SeaRose FPSO; and the scheduled timing and duration of a maintenance event at Terra Nova;
- with respect to the Company's Oil Sands properties: anticipated timing of first oil at the Company's Sunrise Energy Project Phase 1; anticipated timing of, and volume of production from, the Company's Sunrise Energy Project; and anticipated timing of first steam at Plant 1B at the Company's Sunrise Energy Project;
- with respect to the Company's Heavy Oil properties: anticipated future volume of production for the Company's Heavy Oil business segment; expected timing of first production and anticipated volumes of production at the Company's Rush Lake, Edam East, Edam West and Vawn heavy oil thermal developments; the scheduled timing and duration of a turnaround at the Tucker heavy oil thermal project; and the scheduled timing and anticipated impact of partial shut-downs at several heavy oil thermal projects;
- with respect to the Company's Western Canadian oil and gas resource plays: scheduled timing and anticipated impact of turnarounds at the Ansell liquids-rich natural gas resource play and Ram River plant; and scheduled timing and anticipated impact of third-party shutdowns in Western Canada;
- with respect to the Company's Infrastructure and Marketing operating segment: scheduled timing of completion of, and anticipated outcome of, the Hardisty terminal expansion project; and
- with respect to the Company's Downstream operating segment: the anticipated timing of completion and benefits from the Lima, Ohio Refinery feedstock flexibility project and the anticipated processing capacity of Western Canadian heavy oil once reconfiguration is complete; the anticipated benefits of the Hydrotreater Recycle Gas Compressor Project at the BP-Husky Toledo Refinery; and the scheduled timing of a turnaround at the BP-Husky Toledo Refinery.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves 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 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, 2014 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe 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 estimates in this document have an effective date of December 31, 2014 and represent Husky's share. Unless otherwise noted, historical production numbers given represent Husky's share.

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

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.

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 $622 million and $204 million for the years ended December 31, 2014 and 2013, respectively. Return on capital employed including impairment for the years ended December 31, 2014 and 2013 was 5.3 percent and 7.9 percent, respectively. Return on capital in use including impairment for the years ended December 31, 2013 and 2012 was 7.5 percent and 11.3 percent, 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 the Company'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 property, plant and equipment impairment charges and inventory write-downs 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)		**2014**	2013	2012
GAAP	Net earnings	**1,258**	1,829	2,022
	Impairment of property, plant and equipment, net of tax	**622**	204	–
	Inventory write-downs, net of tax	**135**	1	1
Non-GAAP	Net operating earnings(1)	**2,015**	2,034	2,023

(1) *Net Operating Earnings were redefined in 2014 to include after-tax inventory write-downs. Prior periods have been adjusted to conform with current period presentation.*

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 property, plant, and equipment and other non-cash items.

The following table shows the reconciliation of cash flow – operating activities to cash flow from operations and related per share amounts for the years ended December 31:

($ millions)	**2014**	2013	2012
GAAP cash flow – operating activities	**5,585**	4,645	5,193
Settlement of asset retirement obligations	**167**	142	123
Income taxes paid	**661**	433	575
Interest received	**(7)**	(19)	(34)
Change in non-cash working capital	**(871)**	21	(847)
Non-GAAP cash flow from operations	**5,535**	5,222	5,010
Cash flow from operations – basic	**5.63**	5.31	5.13
Cash flow from operations – diluted	**5.62**	5.31	5.13

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 as realized price less royalties, operating costs and transportation on a per unit basis.

11.4 Additional Reader Advisories

Intention of Management's Discussion and Analysis

This Management's Discussion and Analysis 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 Management's Discussion and Analysis was reviewed by the Audit Committee and approved by Husky's Board of Directors on February 23, 2015. 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 Management's Discussion and Analysis should be read in conjunction with the 2014 Consolidated Financial Statements and related notes. The readers are also encouraged to refer to Husky's interim reports filed for 2014, which contain the Management's Discussion and Analysis and Consolidated Financial Statements, and Husky's 2014 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. Husky's Management's Discussion and Analysis for the interim period ended December 31, 2014 is incorporated herein by reference.

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, 2014 and 2013 and Husky's financial position as at December 31, 2014 and at December 31, 2013. All currency is expressed in Canadian dollars unless otherwise directed.

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 31° API and above;
- Medium crude oil is 22° API and above but below 31° API;
- Heavy crude oil is above 10° API but below 22° 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	*Long-term debt including current portion, commercial paper and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses, but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Net earnings plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, exploration and evaluation expenses, deferred income taxes, foreign exchange, stock-based compensation, gains or losses on sale of property, plant and equipment and other non-cash items*
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, long-term debt due within one year and commercial paper divided by capital employed*
Debt to Cash Flow	*Long-term debt, long-term debt due within one year and commercial paper divided by cash flow from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
Feedstock	*Raw materials that are processed into petroleum products*
Front-End Engineering Design ("FEED")	*Preliminary engineering and design planning which, among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Interest Coverage on Long-term Debt	*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.*
Interest Coverage on Total Debt	*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 long-term debt, the current portion of long-term debt and commercial paper.*
Interest Coverage Ratio	*A calculation of a company's ability to meet its interest payment obligation. It is equal to net earnings or cash flow – operating activities before finance expense divided by finance expense and capitalized interest*
Net Operating Earnings	*Net earnings before property, plant and equipment impairment charges and inventory write-downs*
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 long-term debt due within one year, commercial paper 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

3-D	*three-dimensional*
ARO	*asset retirement obligations*
bbls	*barrels*
bbls/day	*barrels per day*
bcf	*billion cubic feet*
boe	*barrels of oil equivalent*
boe/day	*barrels of oil equivalent per day*
bps	*basis points*
CGUs	*cash generating units*
CHOPS	*cold heavy oil production with sand*
CSA	*Canadian Securities Administrators*
DD&A	*depletion, depreciation and amortization*
EOR	*enhanced oil recovery*
EPA	*Environmental Protection Agency*
FIFO	*first in first out*
FPSO	*floating production, storage and offloading vessel*
FVTPL	*fair value through profit or loss*
GAAP	*Generally Accepted Accounting Principles*
GHG	*greenhouse gas*
GJ	*gigajoule*
IASB	*International Accounting Standards Board*
IFRIC	*International Financial Reporting Interpretations Committee Interpretation*
IFRS	*International Financial Reporting Standards*
LIFO	*last in first out*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mcf	*thousand cubic feet*
mcfge	*thousand cubic feet of gas equivalent*
MD&A	*Management's Discussion and Analysis*
mmbbls	*million barrels*
mmboe	*million barrels of oil equivalent*
mmbtu	*million British Thermal Units*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
NGL	*natural gas liquids*
NIT	*NOVA Inventory Transfer*
NYMEX	*New York Mercantile Exchange*
OPEC	*Organization of Petroleum Exporting Countries*
PHMSA	*Pipeline and Hazardous Materials Safety Administration*
PSC	*production sharing contract*
S&P	*Standard and Poor's*
SAGD	*Steam assisted gravity drainage*
SEC	*U.S. Securities and Exchange Commission*
SEDAR	*System for Electronic Document Analysis and Retrieval*
TSX	*Toronto Stock Exchange*
WI	*working interest*
WTI	*West Texas Intermediate*

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, 2014, 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 framework to evaluate the effectiveness of Husky's internal control over financial reporting.
3) As at December 31, 2014, 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, 2014, 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, 2014, 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

	2014				2013			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream								
Daily production, before royalties								
Light crude oil & NGL *(mbbls/day)*	**89.8**	**76.9**	**77.9**	**90.4**	78.3	77.7	82.3	86.4
Medium crude oil *(mbbls/day)*	**19.7**	**20.2**	**22.4**	**23.7**	23.4	23.2	22.9	23.0
Heavy crude oil *(mbbls/day)*	**77.5**	**76.1**	**78.1**	**75.5**	75.9	75.3	72.3	74.4
Bitumen *(mbbls/day)*	**55.7**	**56.2**	**54.6**	**52.0**	46.7	48.0	48.3	47.9
Total crude oil production *(mboe/day)*	**242.7**	**229.4**	**233.0**	**241.6**	224.3	224.2	225.8	231.7
Natural gas *(mmcf/day)*	**701.5**	**670.3**	**603.6**	**505.9**	503.8	505.5	504.7	537.3
Total production *(mboe/day)*	**359.6**	**341.1**	**333.6**	**325.9**	308.3	308.5	309.9	321.3
Average sales prices								
Light crude oil & NGL *($/bbl)*	**71.77**	**96.47**	**110.29**	**110.48**	101.95	107.83	96.22	103.59
Medium crude oil *($/bbl)*	**64.60**	**83.35**	**89.67**	**83.47**	67.86	93.67	73.62	61.74
Heavy crude oil *($/bbl)*	**58.86**	**77.29**	**79.45**	**72.18**	56.51	84.45	66.77	45.67
Bitumen *($/bbl)*	**58.21**	**75.50**	**77.87**	**70.78**	54.08	83.17	65.71	43.12
Natural gas *($/mcf)*	**6.37**	**6.11**	**6.42**	**4.82**	3.30	2.66	3.72	3.08
Operating costs *($/boe)*	**15.07**	**16.61**	**15.68**	**17.21**	16.31	17.20	16.79	15.29
Operating netbacks[1]								
Lloydminster – Thermal Oil *($/boe)*[2]	**43.73**	**58.92**	**61.67**	**53.32**	38.76	67.57	50.57	32.55
Lloydminster – Non-Thermal Oil *($/boe)*[2]	**30.54**	**45.50**	**48.81**	**40.29**	27.32	49.69	37.70	19.06
Oil Sands – Bitumen *($/boe)*[2]	**27.75**	**43.68**	**45.29**	**35.99**	21.45	52.68	35.30	12.32
Western Canada – Crude Oil *($/boe)*[2]	**31.84**	**44.04**	**49.42**	**45.39**	37.60	54.41	39.24	31.17
Western Canada – Natural gas *($/mcf)*[3]	**2.16**	**2.29**	**2.90**	**3.40**	1.93	1.21	1.81	1.68
Atlantic – Light Oil *($/boe)*[2]	**55.50**	**65.78**	**84.47**	**83.74**	83.90	87.14	78.66	89.37
Asia Pacific – Light Oil & NGL *($/boe)*[2]	**55.10**	**67.21**	**76.56**	**78.41**	70.35	74.60	62.52	73.46
Total *($/boe)*[2]	**34.84**	**43.05**	**48.70**	**44.81**	34.29	46.15	38.32	31.78
Net wells drilled[4]								
Exploration Oil	**–**	**1**	**1**	**43**	7	8	–	9
Gas	**1**	**1**	**1**	**2**	5	–	4	5
Dry	**3**	**–**	**–**	**–**	–	–	–	–
	4	**2**	**2**	**45**	12	8	4	14
Development Oil	**93**	**132**	**7**	**187**	201	249	30	229
Gas	**8**	**25**	**24**	**11**	12	12	2	15
Dry	**2**	**1**	**–**	**–**	–	–	–	–
	103	**158**	**31**	**198**	213	261	32	244
Total net wells drilled	**107**	**160**	**33**	**243**	225	269	36	258
Success ratio *(percent)*	**95**	**99**	**100**	**100**	100	100	100	100
Upgrader								
Synthetic crude oil sales *(mbbls/day)*	**54.8**	**56.1**	**48.2**	**56.1**	52.0	37.5	56.7	56.1
Upgrading differential *($/bbl)*	**14.96**	**19.98**	**25.27**	**38.51**	26.63	23.59	27.39	38.51
Canadian Refined Products								
Fuel sales *(million litres/day)*	**8.1**	**8.5**	**7.5**	**7.7**	7.9	8.3	8.0	8.2
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	**29.0**	**28.3**	**29.0**	**29.0**	28.4	28.7	18.7	28.3
Prince George refinery *(mbbls/day)*	**11.7**	**11.7**	**11.3**	**12.0**	12.0	11.8	6.3	11.2
Refinery utilization *(percent)*	**99**	**98**	**97**	**99**	96	61	100	100
U.S. Refining and Marketing								
Refinery throughput								
Lima refinery *(mbbls/day)*	**162.8**	**156.0**	**135.9**	**110.5**	151.8	148.8	149.8	146.9
BP-Husky Toledo refinery *(mbbls/day)*	**63.8**	**64.2**	**59.4**	**65.5**	66.3	59.1	68.1	66.3

(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.*

Segmented Capital Expenditures[1]

($ millions)	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Q4	2013 Q3	2013 Q2	2013 Q1
Upstream								
Exploration								
Western Canada	37	42	56	74	80	99	64	110
Oil Sands	–	–	–	5	–	–	–	–
Atlantic Region	62	12	15	7	55	102	39	5
Asia Pacific Region	5	2	–	9	14	1	–	6
	104	56	71	95	149	202	103	121
Development								
Western Canada	559	456	468	591	744	505	267	513
Oil Sands	225	203	147	133	111	146	137	158
Atlantic Region	205	201	90	154	34	148	116	139
Asia Pacific Region	12	139	80	149	215	133	156	129
	1,001	999	785	1,027	1,104	932	676	939
Acquisitions								
Western Canada	31	15	3	2	27	1	4	6
Total Exploration and Production	1,136	1,070	859	1,124	1,280	1,135	783	1,066
Infrastructure and Marketing	98	59	30	24	41	27	17	11
Total Upstream	1,234	1,129	889	1,148	1,321	1,162	800	1,077
Downstream								
Upgrader	14	23	9	4	43	129	20	13
Canadian Refined Products	31	25	19	11	32	24	41	12
U.S. Refining and Marketing	118	89	92	75	99	52	42	27
	163	137	120	90	174	205	103	52
Corporate	22	13	47	31	42	40	29	23
	1,419	1,279	1,056	1,269	1,537	1,407	932	1,152

[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			
2014 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	1,890	2,210	2,352	2,182	638	647	458	459	475	604	560	573
Royalties	(178)	(260)	(302)	(290)	–	–	–	–	–	–	–	–
Marketing and other	–	–	–	–	22	11	3	34	–	–	–	–
Revenues, net of royalties	1,712	1,950	2,050	1,892	660	658	461	493	475	604	560	573
Expenses												
Purchases of crude oil and products	20	23	31	22	604	611	426	415	380	491	421	384
Production and operating expenses	540	562	525	545	10	9	5	8	48	42	43	47
Selling, general and administrative expenses	22	78	74	79	3	1	2	2	2	3	2	2
Depletion, depreciation, amortization and impairment	1,553	671	637	573	6	6	6	7	29	27	28	24
Exploration and evaluation expenses	113	42	19	40	–	–	–	–	–	–	–	–
Other – net	(71)	(60)	(22)	93	(1)	(1)	–	–	3	–	–	8
Earnings from operating activities	(465)	634	786	540	38	32	22	61	13	41	66	108
Share of equity investment	8	(10)	(2)	(2)	–	–	–	–	–	–	–	–
Net foreign exchange gains (losses)	–	–	–	–	–	–	–	–	–	–	–	–
Finance income	(2)	(1)	1	1	–	–	–	–	–	–	–	–
Finance expenses	(40)	(41)	(38)	(32)	–	–	–	–	–	–	–	(1)
	(42)	(42)	(37)	(31)	–	–	–	–	–	–	–	(1)
Earnings (loss) before income tax	(499)	582	747	507	38	32	22	61	13	41	66	107
Provisions for (recovery of) income taxes												
Current	52	156	112	66	36	1	(13)	75	1	19	17	10
Deferred	(177)	(10)	81	65	(26)	7	19	(60)	3	(9)	–	18
	(125)	146	193	131	10	8	6	15	4	10	17	28
Net earnings (loss)	(374)	436	554	376	28	24	16	46	9	31	49	79
Capital expenditures[3]	1,136	1,070	859	1,124	98	59	30	24	14	23	9	4
Total assets	26,035	26,283	25,667	25,525	1,969	1,907	2,001	1,978	1,243	1,244	1,372	1,330

(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
945	1,145	991	939	2,504	2,811	2,928	2,420	(599)	(738)	(678)	(664)	5,853	6,679	6,611	5,909
–	–	–	–	–	–	–	–	–	–	–	–	(178)	(260)	(302)	(290)
–	–	–	–	–	–	–	–	–	–	–	–	22	11	3	34
945	1,145	991	939	2,504	2,811	2,928	2,420	(599)	(738)	(678)	(664)	5,697	6,430	6,312	5,653
782	964	822	751	2,655	2,571	2,659	2,056	(599)	(738)	(678)	(664)	3,842	3,922	3,681	2,964
67	65	68	63	121	113	116	122	–	–	–	–	786	791	757	785
14	11	9	10	2	3	2	2	91	(35)	59	24	134	61	148	119
27	26	25	24	68	77	62	61	21	18	18	16	1,704	825	776	705
–	–	–	–	–	–	–	–	–	–	–	–	113	42	19	40
–	1	–	(1)	–	–	–	–	–	4	(9)	–	(69)	(56)	(31)	100
55	78	67	92	(342)	47	89	179	(112)	13	(68)	(40)	(813)	845	962	940
–	–	–	–	–	–	–	–	–	–	–	–	8	(10)	(2)	(2)
–	–	–	–	–	–	–	–	35	31	(3)	18	35	31	(3)	18
–	–	–	–	–	–	–	–	1	1	3	4	(1)	–	4	5
(1)	(1)	(2)	(1)	(1)	(1)	–	(1)	(17)	(22)	(37)	3	(59)	(65)	(77)	(32)
(1)	(1)	(2)	(1)	(1)	(1)	–	(1)	19	10	(37)	25	(25)	(34)	(76)	(9)
54	77	65	91	(343)	46	89	178	(93)	23	(105)	(15)	(830)	801	884	929
18	18	17	27	(77)	2	15	61	25	27	30	22	55	223	178	261
(5)	2	–	(4)	(50)	15	18	5	(27)	2	(40)	(18)	(282)	7	78	6
13	20	17	23	(127)	17	33	66	(2)	29	(10)	4	(227)	230	256	267
41	57	48	68	(216)	29	56	112	(91)	(6)	(95)	(19)	(603)	571	628	662
31	25	19	11	118	89	92	75	22	13	47	31	1,419	1,279	1,056	1,269
1,676	1,746	1,839	1,842	5,788	6,133	5,891	5,980	2,137	1,737	883	2,022	38,848	39,050	37,653	38,677

	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	503	483	2	3	9	7	45	39	40	37
Selling, general and administrative expenses	44	60	85	51	3	4	3	2	2	1	2	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 taxes	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 the 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
59	57	57	54	102	109	107	102	–	–	–	–	710	736	716	683
6	9	7	4	–	–	1	3	90	55	20	52	145	129	118	114
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