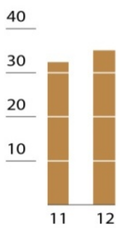
MANAGEMENT'S DISCUSSION AND ANALYSIS

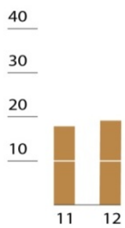
1.0 Financial Summary

1.1 Financial Position

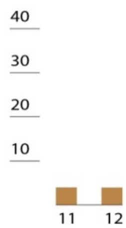
Total Assets
($ billions)



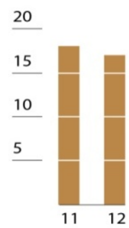
Total Equity
($ billions)



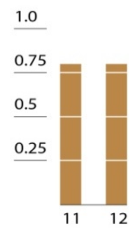
Total Long-term Debt
($ billions)



Debt to Capital Employed[1]
(%)

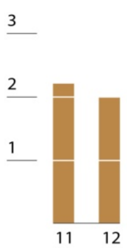


Debt to Cash Flow[1]
(times)

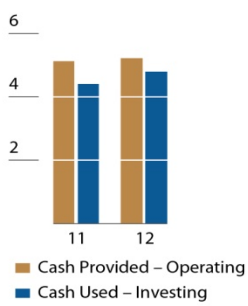


1.2 Financial Performance

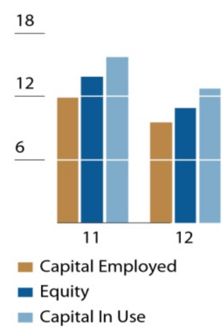
Net Earnings
($ billions)



Cash Flow
($ billions)



Return[1]
(%)

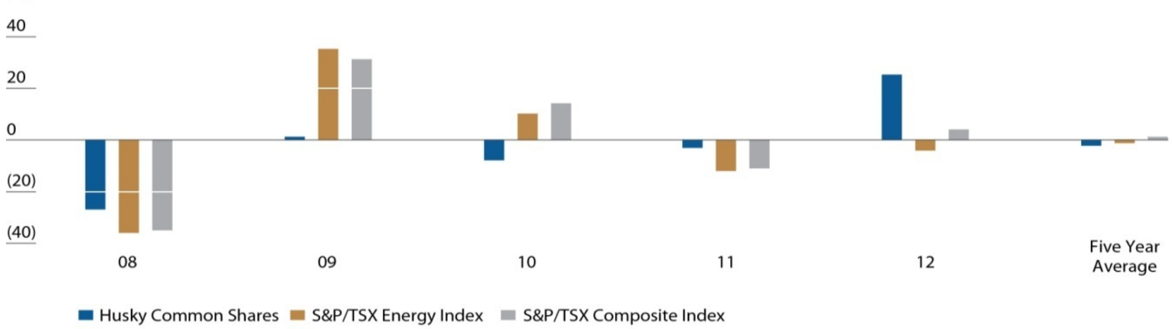


[1] *Debt to capital employed, debt to cash flow, return on equity, return on capital employed and return on capital in use constitute non-GAAP measures. (Refer to Section 11.3)*

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)	**2012**	2011	2010
Gross revenues	**23,128**	23,082	18,085
Net earnings by segment[1]			
Upstream	**1,320**	1,711	861
Midstream	**–**	–	160
Downstream	**895**	813	160
Corporate	**(193)**	(300)	(187)
Eliminations	**–**	–	(47)
Net earnings	**2,022**	2,224	947
Net earnings per share – basic	**2.06**	2.40	1.11
Net earnings per share – diluted	**2.06**	2.34	1.05
Ordinary dividends per common share	**1.20**	1.20	1.20
Dividends per cumulative redeemable preferred share, series 1	**1.11**	0.87	–
Cash flow from operations[2]	**5,010**	5,198	3,072
Total assets	**35,140**	32,426	28,050
Other long-term financial liabilities	**331**	342	102
Long-term debt including current portion	**3,918**	3,911	4,187
Total non-current financial liabilities	**12,886**	11,263	10,907
Cash and cash equivalents	**2,025**	1,841	252
Return on equity *(percent)*[2][3]	**10.9**	13.8	6.7
Return on capital in use (percent)[2][4]	**12.7**	15.6	8.4
Return on capital employed *(percent)*[2][5]	**9.5**	11.8	6.4

(1) During the first quarter of 2012, the Company completed an evaluation of the activities of the former Midstream segment as a service provider to the Upstream and Downstream operations. As a result, the segmented financial information for activities within the previously reported Midstream segment are presented under Upstream or Downstream segments to align with how the Company's results are assessed by management. Prior period information relating to 2011 has been restated to conform with current year presentation. The 2010 information has not been restated.

(2) Cash flow from operations and financial ratios constitute non-GAAP measures. (Refer to Section 11.3)

(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 equals net earnings plus after tax interest expense divided by the two-year average of capital employed less any capital invested in assets that are not generating cash flows.(Refer to Section 11.3)

(5) Return on capital employed equals net earnings plus after-tax finance expense divided by the two-year average of long-term debt including long-term debt due within one year plus total shareholders' equity.(Refer to Section 11.3)

2.0 Husky Business Overview

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

During 2012, the Company completed an evaluation of activities of the Company's former Midstream segment as a service provider to the Upstream or Downstream operations. As a result, and consistent with the Company's strategic view of its integrated business, the previously reported Midstream segment activities are aligned and reported within the Company's core exploration and production, or within upgrading and refining businesses. The Company believes this change in segment presentation allows management and third parties to more effectively assess the Company's performance. The current period and 2011 year results have been revised to conform to the new segment presentation.

2.1 Upstream

Profile and highlights of the Upstream segment include:

- Large base of crude oil producing properties in Western Canada that continue to produce with existing technology and have responded well to the application of increasingly sophisticated techniques such as horizontal drilling. Enhanced oil recovery ("EOR") techniques including thermal in-situ recovery methods have been extensively used in the mature Western Canada Sedimentary Basin to increase recovery rates and to stabilize decline rates of light and heavy crude oil. EOR techniques such as Alkaline Surfactant Polymer ("ASP") are being field tested and advanced, while techniques that have been in practice for several decades continue to be optimized;
- A large position in Western Canada gas resource plays with approximately 1,000,000 net acres associated with both liquids-rich and dry gas positions;
- Active oil resource play portfolio of approximately 800,000 net acres focusing in the Bakken, Viking, Cardium, Rainbow Muskwa and Canol shale formations;
- Expertise and experience exploring and developing the natural gas potential in the Alberta Deep Basin, Foothills, and northwest plains of Alberta and British Columbia;
- Husky and BP have advanced the development of the Sunrise Energy Project, which is a multiple stage, in-situ oil sands development with first production expected in 2014. Phase 1 is approximately 65% complete and is expected to produce approximately 60,000 bbls/day (30,000 bbls/day net Husky share). 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) and planning has advanced for the next phase of the project;
- In addition to Sunrise, Husky has an extensive portfolio of undeveloped oil sands leases, encompassing in excess of 550,000 acres in northern Alberta;
- Offshore China includes a production interest in the Wenchang oil field and significant natural gas discoveries at the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields within Block 29/26;
- The Liwan Gas Project development on Block 29/26 in the South China Sea has been approved by the Chinese Government and is now more than 80% complete and on track to achieve planned first production in late 2013/early 2014;
- Husky has a 40% interest in the Madura Strait Block covering approximately 622,000 acres, offshore East Java, south of Madura Island, Indonesia, and is focused on the development of the BD, MDA and MBH natural gas and natural gas liquids fields;
- In 2012, Husky signed a joint venture contract with CPC Corporation, Taiwan for an exploration block in the South China Sea covering approximately 10,000 square kilometers located 100 kilometers southwest of the island of Taiwan. Husky holds a 75% working interest during exploration while CPC Corporation has the right to participate in the development program up to a 50% interest;
- Husky is the operator of the White Rose field with a 72.5% working interest in the core field and a 68.9% working interest in satellite tiebacks, including the North Amethyst, West White Rose and South White Rose extensions. Development continues at White Rose and its three satellite extensions. Husky has a 13% non-operated interest in the Terra Nova oil field;
- Husky holds ownership interests in the producing oil fields at Terra Nova, White Rose and its satellites and North Amethyst. Husky also has a large portfolio of significant discovery and exploration licences offshore Newfoundland and Labrador and offshore Greenland (collectively referred to as the "Atlantic Region"). The offshore exploration and development program is focused in the Jeanne d'Arc Basin and the Flemish Pass.
- Integrated heavy oil pipeline systems in the Lloydminster producing region;
- The Infrastructure and Marketing business managed third-party commodity trading volumes of approximately 180 mboe/day in 2012 and managed access to capacity on third-party pipelines and storage facilities in both Canada and the United States and natural gas storage in excess of 45 bcf, owned and leased.

2.2 Downstream

Profile and highlights of the Downstream segment include:

- Heavy oil upgrading facility located in the Lloydminster, Saskatchewan heavy oil producing region with a throughput capacity of 82 mbbls/day;
- Refinery at Lima, Ohio and a 50% interest in the BP-Husky Refinery in Toledo, Ohio, each with a gross crude oil throughput capacity of 160 mbbls/day;
- 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 capacity at plants located in Lloydminster, Saskatchewan and Minnedosa, Manitoba; and
- Major regional motor fuel marketer with 512 retail marketing locations as at December 31, 2012 including bulk plants and travel centres with strategic land positions in Western Canada and Ontario.

3.0 The 2012 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 2012, that are anticipated to continue to impact the industry to varying degrees into 2013 and beyond. Business factors impacting Husky's industry during 2012 include but are not limited to the following:

- The proliferation of shale oil plays in the Bakken, the Permian and the Eagle Ford have outpaced EIA production forecasts for the U.S.;
- Key takeaway capacity constraints still exist for Western Canadian crudes in North America causing a widening of differentials of these crudes relative to key benchmarks such as West Texas Intermediate ("WTI");
- Pricing benchmarks for crude oil and natural gas and underlying market supply and demand drivers;
- Political unrest in the Middle East have caused continued unplanned production outages having an impact on crude oil benchmark pricing;
- Expected continued production growth in both U.S. shale oil formations and from the Western Canadian oil sands with approximately 260 bitumen projects in progress at various stages from research to exploration, development and completion;
- Industry advancement in alternate and improved extraction methods have rapidly evolved North American and international on-shore and offshore activity;
- All-time high U.S. natural gas inventories with increased production from shale gas and liquids-rich gas plays have resulted in downward pressure on North American natural gas pricing;
- 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, 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 gas and natural gas and related products. For a discussion on Risks and Risk Management see Section 7.0 and the 2012 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.

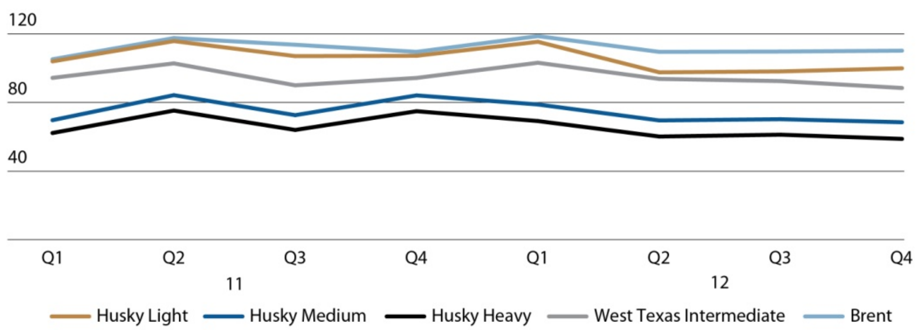
Average Benchmarks		2012	2011
WTI crude oil	*(U.S. $/bbl)*	**94.21**	95.12
Brent crude oil	*(U.S. $/bbl)*	**111.54**	111.27
Canadian light crude 0.3% sulphur	*($/bbl)*	**86.57**	95.32
Western Canada Select @ Hardisty	*(U.S. $/bbl)*	**73.18**	77.97
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**62.89**	67.61
NYMEX natural gas	*(U.S. $/mmbtu)*	**2.79**	4.04
NIT natural gas	*($/GJ)*	**2.28**	3.48
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**21.46**	17.44
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**31.36**	25.26
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**27.63**	24.65
U.S./Canadian dollar exchange rate	*(U.S. $)*	**1.001**	1.011
Canadian Equivalents			
WTI crude oil	*($/bbl)*	**94.12**	94.09
Brent crude oil	*($/bbl)*	**111.43**	110.06
WTI/Lloyd crude blend differential	*($/bbl)*	**21.44**	17.25
NYMEX natural gas	*($/mmbtu)*	**2.79**	4.00

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, including 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 receive the prevailing market price. The market price for crude oil is determined largely by North American and global factors and is beyond the Company's control. The price for natural gas is determined more by North American fundamentals since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. Weather conditions also exert a significant effect on short-term supply and demand.

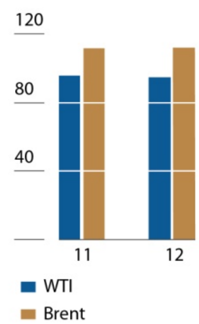
The Downstream segment is heavily impacted by the price of crude oil and natural gas. The largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil. In the upgrading business segment, heavy crude oil feedstock is processed into light synthetic crude oil.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



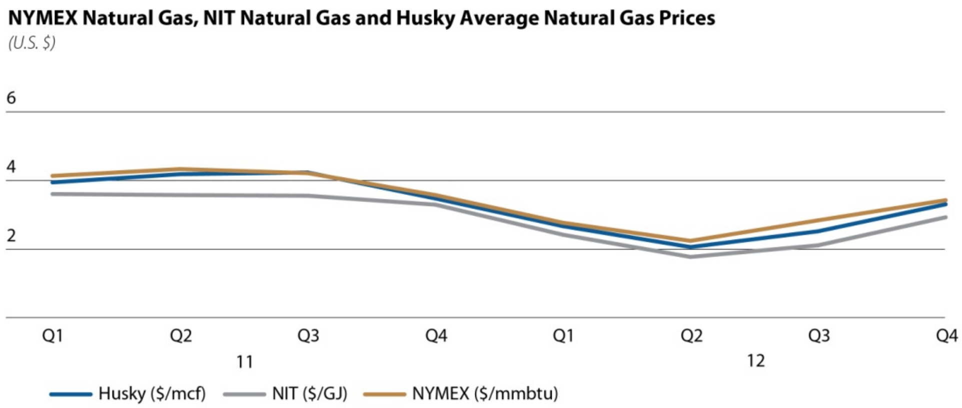
Average WTI and Brent
(U.S. $/bbl)

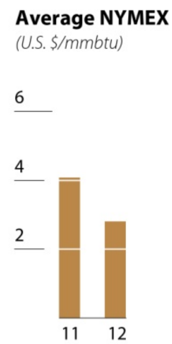


The price Husky receives for production from Western Canada is primarily driven by changes in the price of WTI and discounts or premiums to Western Canadian crude prices while the majority of the Company's production in the Atlantic Region and the Asia Pacific Region is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2012 at U.S. $94.19/bbl compared to U.S. $98.83/bbl on December 31, 2011, and averaged U.S. $94.21/bbl in 2012 compared with U.S. $95.12/bbl in 2011. The price of Canadian light crude ended 2012 at $74.32/bbl compared to $98.19/bbl on December 31, 2011 and averaged $86.57/bbl in 2012 compared with $95.32/bbl in 2011. The price of Brent ended 2012 at U.S. $111.66/bbl, compared to U.S. $106.51/bbl on December 31, 2011, and averaged U.S. $111.54/bbl in 2012 compared with U.S. $111.27/bbl in 2011.

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 2012, 54% of Husky's crude oil production was heavy crude oil or bitumen compared with 47% in 2011. The increase in the 2012 heavy oil to total crude oil production weighting was due to lower light crude oil production from the Atlantic Region where two planned offstation turnarounds for the SeaRose and Terra Nova floating, production, storage and offloading vessels ("FPSO") were completed combined with increased production from new heavy oil thermal projects. The light/heavy crude oil differential averaged U.S. $21.46/bbl or 23% of WTI in 2012 compared to U.S. $17.44/bbl or 18% of WTI in 2011.

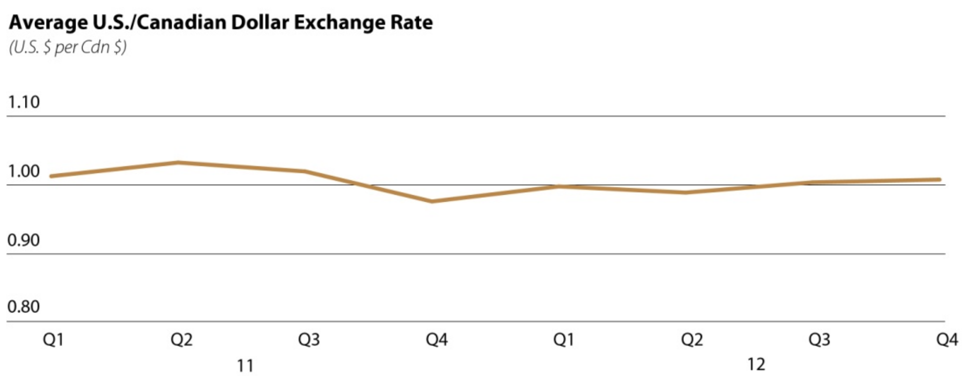
Natural Gas

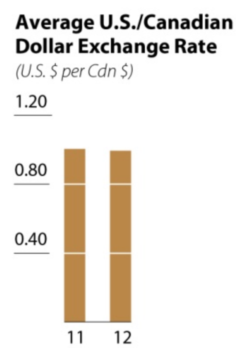




In 2012, 31% of Husky's total oil and gas production was natural gas compared with 32% in 2011. The near-month natural gas price quoted on the NYMEX ended 2012 at U.S. $3.35/mmbtu compared with U.S. $2.99/mmbtu at December 31, 2011. During 2012, the NYMEX near-month contract price of natural gas averaged U.S. $2.79/mmbtu compared with U.S. $4.04/mmbtu in 2011.

Foreign Exchange



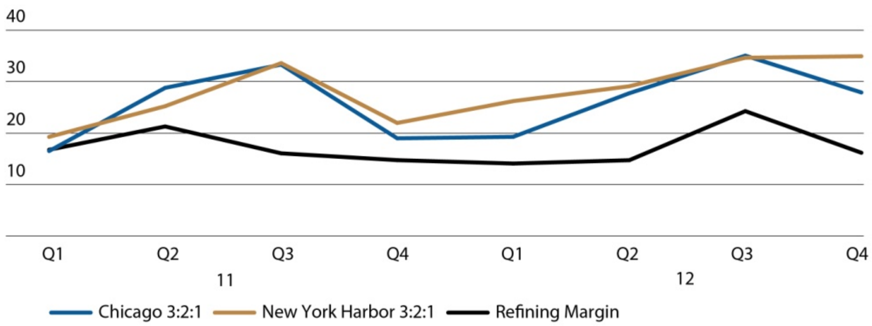


The majority of the Company's revenues from the sale of oil and gas commodities receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are in Canadian dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the 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. In addition, changes in foreign exchange rates impact the translation of the foreign operations of the U.S. Downstream segment and the Asia Pacific Region.

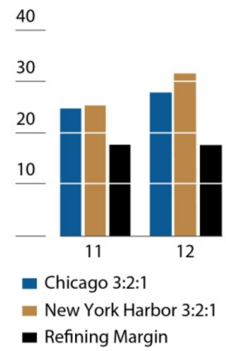
The Canadian dollar ended 2011 at U.S. $0.983 and closed at U.S. $1.005 on December 31, 2012. In 2012, the Canadian dollar averaged U.S. $1.001 weakening by 1% compared with U.S. $1.011 during 2011. In 2012, the price of WTI in U.S. dollars decreased by 1% and nil in Canadian dollars when compared to 2011 with the weakening of the Canadian dollar versus the U.S. dollar offsetting the movement in crude oil prices.

Refining Crack Spreads

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



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



The 3:2:1 refining crack spread is the key indicator for refining margins as refinery gasoline output is approximately twice the distillate output. This crack spread is equal to the price of two-thirds of a barrel of gasoline plus one-third of a barrel of fuel oil (distillate) less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel, and do not necessarily reflect the actual crude oil purchase costs or product configuration of a specific refinery. Each refinery has a unique crack spread depending on several variables. Realized refining margins are affected by the product configuration of each refinery, crude oil feedstock, product slates, transportation costs to benchmark hubs and by the time lag between the purchase and delivery of crude oil, which is accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

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

During 2012, the New York Harbor 3:2:1 refining crack spread averaged U.S. $31.36/bbl compared with U.S. $25.26/bbl in 2011 and the Chicago 3:2:1 crack spread averaged U.S. $27.63/bbl in 2012 compared with U.S. $24.65/bbl in 2011.

The following table is indicative of the relative annualized effect on pre-tax earnings and net earnings from changes in certain key variables in 2012. The table below shows what the effect would have been on 2012 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2012. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis	2012 Average	Increase	Effect on Pre-tax Earnings[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	94.21	*U.S. $1.00/bbl*	66	0.07	49	0.05
NYMEX benchmark natural gas price[5]	2.79	*U.S. $0.20/mmbtu*	24	0.02	18	0.02
WTI/Lloyd crude blend differential[6]	62.89	*U.S. $1.00/bbl*	(16)	(0.02)	(12)	(0.01)
Canadian light oil margins	0.044	*Cdn $0.005/litre*	16	0.02	12	0.01
Asphalt margins	22.90	*Cdn $1.00/bbl*	9	0.01	7	0.01
New York Harbor 3:2:1 crack spread[7]	31.36	*U.S. $1.00/bbl*	53	0.05	34	0.03
Exchange rate (U.S. $ per Cdn $)[3][8]	1.001	*U.S. $0.01*	(55)	(0.06)	(41)	(0.04)

(1) Excludes mark to market accounting impacts.
(2) Based on 982.2 million common shares outstanding as of December 31, 2012.
(3) Does not include gains or losses on inventory.
(4) Includes impacts related to Brent-based production.
(5) Includes impact of natural gas consumption.
(6) Excludes impact on asphalt operations.
(7) Relates to U.S. Refining & Marketing.
(8) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.

4.0 Strategic Plan

Husky's strategy is to maintain and enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward thermal developments and resource plays, while advancing its three major growth pillars in the Asia Pacific Region, Oil Sands and in the Atlantic Region. The Company's Downstream assets provide specialized support to its Upstream operations to enhance efficiency and extract additional value from production.

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

4.1 Upstream

Husky has a substantial portfolio of assets in Western Canada. New technologies are making it possible to economically access new pools and recover more production from existing reservoirs. The Company is active in the exploration and production of heavy oil, light crude oil, natural gas and natural gas liquids. The Western Canada strategy is comprised of maintaining production while refocusing by growing oil resource plays, directing capital into liquids-rich natural gas plays and expanding thermal and horizontal drilling in heavy oil. Approximately two-thirds of Upstream production is oil-weighted. Husky is advancing its oil resource play position with activities in the Bakken, Viking, Cardium, Lower Shaunavon, Muskwa and Canol formations, with approximately 800,000 net acres of oil resource play inventory. Husky also has a large position in Western Canada gas resource plays, with approximately 1,000,000 net acres associated with both liquids-rich and dry gas positions.

Husky has an extensive portfolio of oil sands leases, encompassing 2,500 square kilometers in northern Alberta. Husky has advanced the development of the Sunrise Energy Project, which is a multiple stage, in-situ oil sands development with first phase construction and drilling having commenced in 2011. The first phase, which represents a $2.7 billion investment, is expected to produce approximately 60,000 barrels per day with anticipated first production beginning in 2014. Husky's working interest is 50%. Sunrise will use proven steam-assisted gravity drainage ("SAGD") technology, keeping site disturbance to a minimum.

The Asia Pacific Region consists of the Wenchang oil field, the Liwan Gas Project ("Block 29/26") located offshore China and the Madura Strait block BD, MDA and MBH development fields offshore Indonesia. The Liwan 3-1 field in Block 29/26, located approximately 300 kilometers southeast of Hong Kong, is an important component of the Company's near term production growth strategy and a key step in accessing the burgeoning energy markets in Hong Kong and Mainland China. Husky has partnered with China National Offshore Oil Corporation ("CNOOC") on the development, with first gas production anticipated in late 2013/early 2014. In addition to the producing Wenchang oil field, the natural gas discoveries on Block 29/26 and growth opportunities in Indonesia, including the BD, MDA and MBH developments in the Madura Strait Production Sharing Contract ("PSC"), represent growth areas for Husky in the Asia Pacific Region.

The Atlantic Region continues to be a focus area with current production of approximately 48,000 bbls/day of crude oil. The Company holds interests in eight Production Licences, 17 Exploration Licences and 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. Husky also holds significant exploration acreage in the the Atlantic Region. Work is progressing to identify innovative ways to further develop the significant resources in the region.

The Infrastructure and Marketing business unit supports Upstream production while providing integration with the Company's Downstream assets through optimization of market access for Husky's upstream production.

4.2 Downstream

Downstream supports heavy oil and oil sands production and makes prudent reinvestments in respect of feedstock, product and market access feasibility. 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. The Company also plans to expand terminal pipeline access and product storage opportunities to enhance market access.

4.3 Financial

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

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

The significant asset base in the Company's foundational businesses in Western Canada provides a steady source of cash flow to reinvest in its growth projects, including the Asia Pacific Region, the Oil Sands and the Atlantic Region of Canada. 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 2012 Capital Program supported the repositioning of the Heavy Oil and Western Canada foundation by accelerating near-term production growth and advancing Husky's three major growth pillars in the Asia Pacific Region, the Oil Sands and the Atlantic Region.

5.1 Upstream

Western Canada (excluding Heavy Oil and Oil Sands)

Husky continued to progress crude oil and liquids-rich gas resource plays as a core element of its Western Canada foundation. Total production from these resource plays at the end of 2012 was approximately 20,000 bbls/day, representing a 70% increase compared to 2011.

Oil Resource Plays

During 2012, the Company continued to advance exploration and development projects on its extensive oil resource land base of approximately 800,000 net acres. A total of 93 horizontal wells and two vertical wells were drilled and 78 horizontal wells were completed in 2012. It is anticipated that up to 88 wells will be drilled during the 2013 oil resource drilling program.

The following table summarizes the oil resource play drilling and completion activity for the year ended December 31, 2012:

Oil Resource Plays[(1)]

		Year ended December 31, 2012	
Project	Location	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	22	21
Lower Shaunavon	S.W. Saskatchewan	4	4
Viking [(2)]	Alberta and S.W. Saskatchewan	50	45
N.Cardium	Wapiti, Alberta	5	5
Rainbow Muskwa	Northern Alberta	12	3
Slater River	Northwest Territories	2	–
Total Gross		95	78
Total Net		89	74

(1) *Excludes service/stratigraphic test wells for evaluation purposes. All activity was horizontal except Slater River N.W.T. , vertical wells.*
(2) *Viking is comprised of project activity at Redwater in central Alberta, Alliance in Southeastern Alberta and drilling in Southwestern Saskatchewan.*

At the Rainbow Muskwa play, the first horizontal shale oil well was placed on production to a single well battery and is being monitored.

At the Slater River Project in the Northwest Territories, the Company drilled two vertical wells and a 220 square kilometre three-dimensional ("3-D") seismic survey was completed.

Liquids-Rich Gas Resource Plays

The following table summarizes the liquids-rich gas drilling and completion activity for the year ended December 31, 2012:

Liquids-Rich Gas Resource Plays[1]		Year ended December 31, 2012	
Project	Location	Gross Wells Drilled	Gross Wells Completed
Ansell	West Central Alberta	**18**	**53**
Duvernay	West Central Alberta	**4**	**3**
Montney	West Central Alberta	**1**	**2**
Total Gross		**23**	**58**
Total Net		**21**	**56**

[1] *Excludes service/stratigraphic test wells for evaluation purposes. Liquids-rich gas drilling activity in 2012 was mainly horizontal wells. Completion activity includes legacy vertical wells. Types of drilling include Wilrich and Cardium horizontals and vertical single and multi-zone wells.*

The liquids-rich gas formations at Ansell in west central Alberta continue to be a key area of focus with 55 Cardium and three Wilrich wells on production at the end of 2012.

At the Duvernay play in Kaybob, Alberta, a third horizontal well was completed in 2012 and commenced production in January 2013. In December 2012, the first well on a four well pad of horizontal wells was spud and drilling continues in 2013. A previously completed well is expected to be tied-in during the first quarter of 2013.

Alkaline Surfactant Polymer Floods

Construction was completed on the Fosterton, Saskatchewan Alkaline Surfactant Polymer ("ASP") facility in 2012. Husky is the operator and holds a 62% working interest in this project. Chemical injection has commenced with initial production response expected in the second half of 2013.

Heavy Oil

Production commenced in the second quarter of 2012 ahead of schedule at both the Pikes Peak South and Paradise Hill heavy oil thermal projects and has ramped up to levels exceeding the combined 11,500 bbls/day design rate capacity. Average production levels of approximately 12,000 bbls/day at Pikes Peak South and 5,000 bbls/day at Paradise Hill heavy oil thermal projects were achieved during the fourth quarter of 2012.

Construction is approximately 40% complete at the 3,500 bbls/day Sandall thermal development project and initial drilling has commenced. First production is scheduled in 2014.

Design and initial site work is continuing at the 10,000 bbls/day Rush Lake commercial project with first production anticipated in 2015. Production performance from the first single well pair pilot is in line with expectations and a second well pair pilot is planned to commence production in the second quarter of 2013. Initial planning is ongoing for three additional commercial thermal projects.

The Company advanced its horizontal drilling program in 2012 with the completion of 144 wells. Based on the positive performance of previous horizontal drilling programs, Husky is continuing this program by planning to drill approximately 140 wells in 2013. The Company also drilled 250 gross cold heavy oil production with sand ("CHOPS") wells during 2012. In 2013, 200 CHOPS wells are planned.

A carbon dioxide ("CO_2") capture and liquefaction plant at the Lloydminster Ethanol Plant was commissioned and started producing liquid CO_2 in March 2012. The liquefied CO_2 from this facility is used in the ongoing solvent EOR piloting program.

Asia Pacific Region

China

The Overall Development Plan ("ODP") for the Liwan Gas Project development on Block 29/26 in the South China Sea has been approved by the Chinese Government. The development project is now more than 80% complete and remains on track to achieve planned first production in late 2013/early 2014.

Two further upper completions in the Liwan 3-1 gas field were installed and flow tested successfully at the expected production rates bringing the total of fully ready production wells to seven. All nine subsea production trees have been installed on the wells and eight associated upper completions have also been installed.

At the end of 2012, approximately 90 kilometers of the two 79-kilometer deep water pipelines connecting the gas field to the central platform have been laid and approximately 190 kilometers out of 261 kilometers of shallow water pipeline have been laid from the central platform to the onshore gas plant. Pipe laying activity is planned to resume in 2013.

The completed jacket for the shallow water central platform was transported from the Qingdao construction yard in Eastern China to its final offshore location in the South China Sea and was successfully launched from the transport barge onto the ocean floor on August 30, 2012. Piling to anchor the feet of the jacket to the seabed has also been completed. Fabrication of the platform topsides is progressing and the floatover of the topsides for the central platform is planned for mid-2013.

The 850-tonne Monoethylene Glycol Recovery Unit has been delivered to the Qingdao, Eastern China topsides construction site and the approximately 850 tonne unit has been elevated and set into its final installation position on the upper deck. Generators and compressors have also been positioned on the deck. Construction of control rooms, living areas and other facilities are in their final stages.

The contract for the use of the West Hercules deepwater drilling rig expired in July 2012. The deepwater semi-submersible drilling rig, Hai Yang Shi You 981, has been contracted to continue the deepwater development project.

Construction of the onshore gas plant is also progressing on schedule. Site preparations and foundations are largely complete including the completion of a seawall on the eastern side of the site. Nine of ten spherical liquids storage tanks are in place and the construction of pipe racks for transporting gas through the site is progressing. Construction of control and administrative buildings as well as living areas has commenced.

Development of the single well Liuhua 34-2 field is planned to proceed in parallel with, and be tied into the development of, the Liwan 3-1 field. Front end engineering design ("FEED") for the development of the Liuhua 29-1 gas field has now been completed, and the ODP is being prepared. Negotiations for the sale of the gas from the Liuhua 34-2 and Liuhua 29-1 fields are ongoing.

On Block 63/05 in the Qiongdongnan Basin, Husky and CNOOC have agreed to the termination of the contract after completion of the first phase of the exploration period. Accordingly, the Company has no further obligation with respect to this block.

Taiwan

In December, Husky signed a joint venture contract with CPC Corporation, Taiwan for an exploration block in the South China Sea. The exploration block is located 100 kilometers southwest of the island of Taiwan and covers approximately 10,000 square kilometers. Husky holds a 75% working interest during exploration, while CPC Corporation has the right to participate in the development program up to a 50% interest. Under the joint venture contract, Husky has an obligation to carry out 2-D seismic surveys within the first two years, with options to carry out 3-D seismic surveys and to drill at least one exploration well in subsequent exploration periods.

Indonesia

The 2012 exploration drilling program on the Madura Strait Block concluded in October with four new discoveries made as a result of a five well exploration drilling program. These discoveries are now under evaluation for commercial development.

The development plan for a combined MDA and MBH development project was approved in 2013 by SKK Migas, the industry regulator. As agreed with the regulator, a re-tender process for the BD field FPSO was conducted and pre-qualification responses are being evaluated. First gas from the Madura Strait Block is anticipated in the 2015 time frame.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages. During 2012, drilling of the planned SAGD horizontal well pairs for Phase 1 was completed and site construction and equipment installations were substantially advanced. Phase 1 of the 60,000 bbls/day (30,000 bbls/day net) project remains on track for first production in 2014.

Substantial cost certainty on the first phase of the Sunrise Energy Project was achieved in 2012 with the conversion to a lump sum contract for the Central Processing Facility ("CPF"). Over 85% of the costs for Phase 1 are now fixed and incorporate all significant contract conversions and facility and efficiency design improvements. To date, approximately 65% of the project's total cost estimate has been spent.

The CPF is approaching 50% completion with piling substantially completed and foundation work proceeding at the site. Major equipment continues to be delivered and placed into position with approximately half of the modules fabricated and moved to the site. Construction for the field facilities is now more than 80% complete with significant activity currently underway, including pipelining in the field and fabrication in the module shops.

Development work continues on the next phase of the project with the Design Basis Memorandum expected to be completed in 2013. Regulatory approvals are in place for a total of 200,000 bbls/day (100,000 bbls/day net).

Tucker

Production rates at Husky's Tucker Oil Sands Project have remained stable at approximately 10,000 bbls/day in 2012. Production from the Grand Rapids pilot well pair commenced in the first quarter of 2012. Based on positive performance from the pilot, Husky initiated drilling of an additional five Grand Rapids well pairs in November 2012 with production expected in 2013.

Saleski

A regulatory application for the bitumen carbonates pilot is anticipated to be filed in 2013.

McMullen

During 2012, seven evaluation wells were drilled and 32 slant wells were drilled, equipped and placed on production in the cold production development project. At the end of 2012, production from McMullen was 4,600 bbls/day and development activity is continuing.

Atlantic Region

White Rose Field and Satellite Extensions

Development continued at the White Rose field with the addition of an infill production well which was brought online in August 2012. As at the end of 2012, a total of 22 wells, including nine producing wells, ten water injectors, and three gas injectors were in operation. Future infill wells are being evaluated.

The Husky-operated SeaRose FPSO completed its planned maintenance dry-docking in Belfast, Northern Ireland with zero lost-time incidents and ahead of schedule with production resuming on August 13, 2012 approximately three weeks ahead of plan. Production from the White Rose field and satellite extensions returned to expected levels by the end of the third quarter of 2012.

A development plan amendment was filed with the regulator in October 2012 to facilitate development of resources at the South White Rose Extension. This region will be developed via subsea tieback to the SeaRose FPSO, similar to the North Amethyst satellite extension. A new drill centre to support the development was excavated during the third quarter of 2012 and drilling of a gas injection well is scheduled to commence in 2013.

At North Amethyst, development continued in 2012 with the addition of the fourth production well. At the end of 2012, four production and three water injection wells were on-line. An additional water injector well is scheduled to be drilled in 2013. An application to develop the deeper Hibernia formation at North Amethyst is progressing through the regulatory review process.

A water injection well to support the existing producing well for the West White Rose pilot project was completed and brought online during 2012. Evaluation of a wellhead platform to facilitate future development continued during 2012 and supporting regulatory filings were submitted for an environmental assessment of the concept. A decision on a preferred development option is expected in 2013.

Drilling of the Searcher prospect in the southern Jeanne D'Arc Basin did not encounter commercial hydrocarbons and the well was expensed in 2012.

Husky and Seadrill entered into a five-year contract for the use of Seadrill's West Mira rig, a new harsh environment semi-submersible rig currently being built and expected to be completed in 2015.

Atlantic Exploration

The Company was awarded exploration rights to a 208,899 hectare parcel of land offshore Newfoundland during the November 2012 licencing round. The licence is located in the Flemish Pass and is east of and adjacent to existing land holdings in the Jeanne d'Arc Basin. Husky has a 40% working interest and future exploration is currently being evaluated.

The Company plans to participate in a number of operated and non-operated exploratory wells in the Atlantic Region during the 2013/2014 timeframe. The first well in this program is a partner-operated exploration well southeast of the Mizzen discovery located in the Flemish Pass.

Offshore Greenland
A two-year extension was received on the initial phase of the exploration program for two Husky-operated exploration licenses offshore Greenland. Geological and geophysical evaluations continued in 2012 and socio-economic study work is continuing.

Infrastructure and Marketing

Through the Company's continued development of both proprietary infrastructure and contracted pipeline commitments, it is able to access higher priced crude oil markets, partially offset Western Canadian differentials, and provide crude feedstock flexibility for the Lima Refinery, enabling the optimization of the crude slate in terms of quality, location and price.

A new 300,000 barrel tank at the Hardisty terminal was placed in service May 2012. The tank facilitates moving crude oil volumes to U.S. Petroleum Administration for Defense Districts ("PADD") II and III markets.

5.2 Downstream

Lima Refinery
The Lima Refinery continues to progress reliability and profitability improvement projects. Construction of the 20 mbbls/day kerosene hydrotreater, which will increase on-road diesel and jet fuel production volumes, is approximately 80% complete and is expected to be operational in the first quarter of 2013.

BP-Husky Toledo Refinery
The Continuous Catalyst Regeneration Reformer Project at the BP-Husky Toledo Refinery is progressing as planned. Mechanical completion was achieved in the fourth quarter of 2012 and start up is expected in the first quarter of 2013. The refinery continues to advance a multi-year program to improve operational integrity and plant performance while reducing operating costs and environmental impacts.

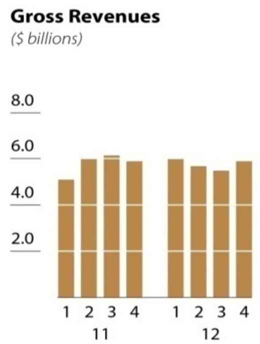
6.0 Results of Operations

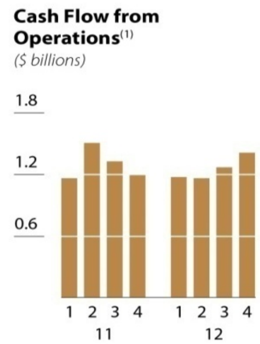
6.1 Segment Earnings

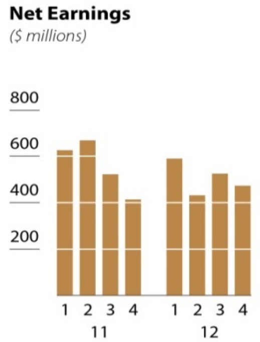
	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures(1)	
($ millions)	**2012**	2011	**2012**	2011	**2012**	2011
Upstream(2)						
Exploration and Production	**1,324**	2,137	**979**	1,581	**4,106**	4,131
Infrastructure and Marketing	**457**	174	**341**	130	**54**	43
Downstream(2)						
Upgrading	**306**	202	**226**	150	**47**	55
Canadian Refined Products	**311**	295	**231**	220	**97**	94
U.S. Refining and Marketing	**695**	697	**438**	443	**313**	224
Corporate	**(257)**	(365)	**(193)**	(300)	**84**	71
Total	**2,836**	3,140	**2,022**	2,224	**4,701**	4,618

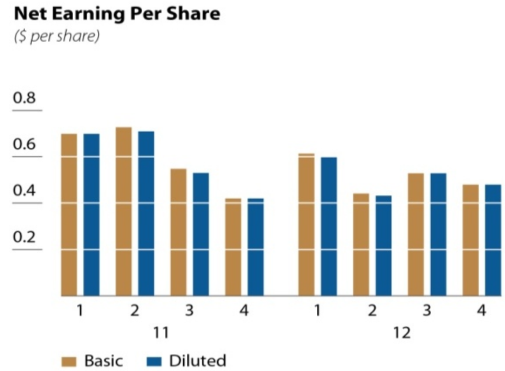
(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(2) *During the first quarter of 2012, the Company completed an evaluation of the activities of the former Midstream segment as a service provider to the Upstream and Downstream operations. As a result, the segmented financial information for activities within the previously reported Midstream segment are presented under Upstream or Downstream segments to align with how the Company's results are assessed by management. Prior period disclosures have been restated to conform with current year presentation.*

6.2 Summary of Quarterly Results





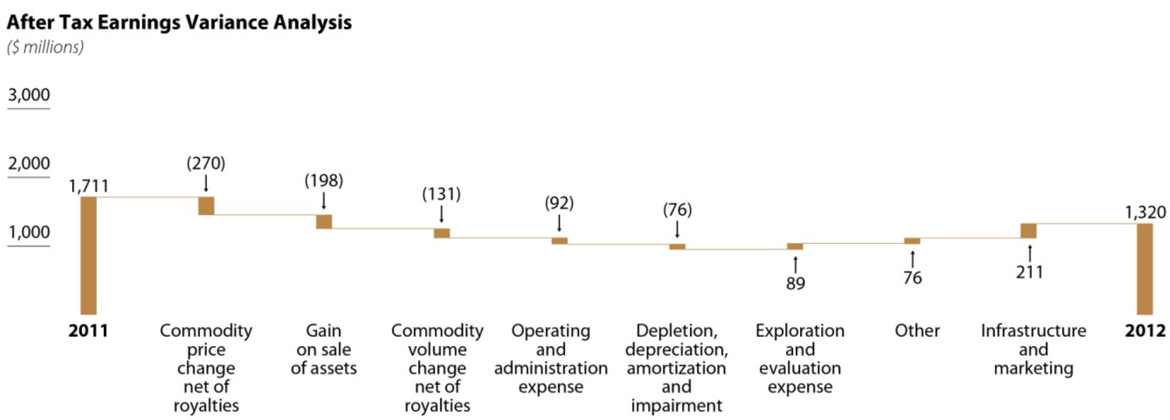




[(1)] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*

6.3 Upstream

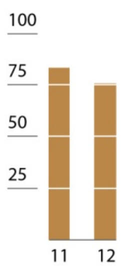
2012 Total Upstream Earnings $1,320 million



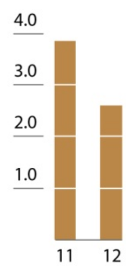
Exploration and Production Earnings Summary *($ millions)*	2012	2011
Gross revenues	**6,547**	7,519
Royalties	**(693)**	(1,125)
Net revenues	**5,854**	6,394
Purchases, operating, transportation and administration expenses	**2,091**	1,966
Depletion, depreciation, amortization and impairment	**2,121**	2,018
Exploration and evaluation expense	**350**	470
Other expenses (income)	**(32)**	(197)
Income taxes	**345**	556
Net earnings	**979**	1,581

Exploration and Production net earnings were $602 million lower in 2012 compared with 2011 primarily due to lower realized crude oil and natural gas prices and lower production in the Atlantic Region as a result of the planned maintenance of the SeaRose and Terra Nova FPSOs, partially offset by increased production in Western Canada from the new heavy oil thermal development projects at Paradise Hill and Pikes Peak South and lower exploration and evaluation expense. In addition, Husky realized after-tax gains on the sale of non-core assets and an asset swap of $198 million in 2011.

Average Price Realized
Crude Oil
($/bbl)

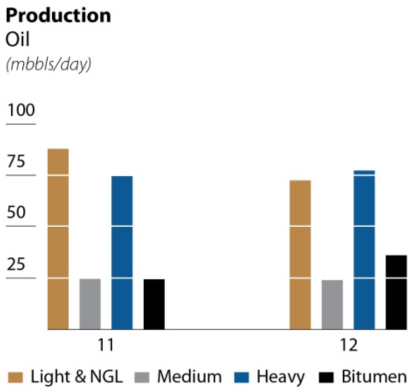


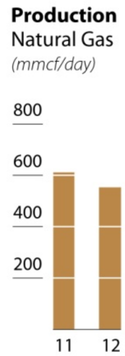
Average Price Realized
Natural Gas
($/mcf)

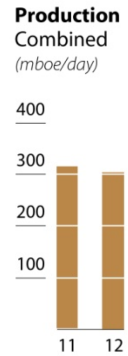


Average Sales Prices Realized	2012	2011
Crude oil *($/bbl)*		
Light crude oil & NGL	**99.22**	104.06
Medium crude oil	**71.51**	76.59
Heavy crude oil	**61.91**	68.13
Bitumen	**59.49**	65.75
Total average	**75.50**	83.73
Natural gas average *($/mcf)*	**2.60**	3.89
Total average *($/boe)*	**57.16**	64.17

During 2012, the average realized price decreased 10% to $75.50/bbl for crude oil, NGL and bitumen compared with $83.73/bbl during 2011 primarily due to lower Brent-based production from the Atlantic Region and wider Western Canada crude oil price differentials to WTI. Realized natural gas prices averaged $2.60/mcf during 2012 compared with $3.89/mcf in 2011, a decline of 33%.







Daily Gross Production	2012	2011
Crude oil *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**30.1**	24.8
Medium crude oil	**24.1**	24.5
Heavy crude oil	**76.9**	74.5
Bitumen	**35.9**	24.7
	167.0	148.5
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**30.8**	48.7
Terra Nova – light crude oil	**3.0**	5.6
	33.8	54.3
China		
Wenchang – light crude oil & NGL	**8.4**	8.5
Crude oil *(mbbls/day)*	**209.2**	211.3
Natural gas *(mmcf/day)*	**554.0**	607.0
Total *(mboe/day)*	**301.5**	312.5

Upstream Revenue Mix *(Percentage of Upstream Net Revenues)*	2012	2011
Crude oil		
Light crude oil & NGL	**43 %**	44 %
Medium crude oil	**10 %**	9 %
Heavy crude oil	**28 %**	26 %
Bitumen	**12 %**	8 %
Crude oil	**93 %**	87 %
Natural gas	**7 %**	13 %
Total	**100 %**	100 %

During 2012, crude oil, bitumen and NGL production decreased by 2.1 boe/day or 1% compared with 2011, primarily due to lower production in the Atlantic Region as a result of the planned maintenance of the SeaRose and Terra Nova FPSOs, largely offset by increased production in Western Canada from the new heavy oil thermal development projects at Paradise Hill and Pikes Peak South.

Production from natural gas decreased by 53.0 mmcf/day or 9% in 2012 compared with 2011 due to natural reservoir declines in mature properties as capital investment is being directed to higher return oil and liquids-rich developments.

2013 Production Guidance and 2012 Actual

Gross Production	Guidance 2013	Year ended December 31, 2012	Guidance 2012
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	85 – 90	**72**	70 – 75
Medium crude oil	25 – 30	**24**	25 – 30
Heavy crude oil & bitumen	110 – 120	**113**	100 – 110
Crude oil & NGL *(mbbls/day)*	220 – 240	**209**	195 – 215
Natural gas *(mmcf/day)*	540 – 580	**554**	560 – 610
Total *(mboe/day)*	310 – 330	**302**	290 – 315

The Company's total production for the year ended December 31, 2012 was within production guidance set by the Company in 2011. Husky expects that production levels in 2013 will be higher compared to 2012 due to a full year of production from the Atlantic Region where the Company and its partners executed two major maintenance turnarounds of the SeaRose and Terra Nova FPSOs. In 2010, the Company set a compound annual production growth target of 3% to 5% through the plan period 2010-2015 and is on track to achieve that goal. In 2012, a new target was set for the plan period of 2012 to 2017 at an increased compound annual production growth rate of 5% to 8%.

Factors that could potentially impact Husky's production performance for 2013 include, but are not limited to:

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

Royalties

Royalty rates averaged 11% of gross revenues in 2012 compared with 16% in 2011. Royalty rates in Western Canada averaged 10% in 2012 compared with 14% in 2011 due to lower natural gas prices and royalty credit adjustments. In the Atlantic Region, the average rate was 11% in 2012 compared with 17% in 2011 due to higher eligible costs associated with the SeaRose FPSO offstation and lower Terra Nova production which is subject to higher royalty rates. Royalty rates in the Asia Pacific Region averaged 24% in 2012 compared with 30% in 2011 mainly due to reductions in windfall profit taxes that became effective in November of 2011.

Operating Costs

($ millions)	2012	2011
Western Canada	**1,571**	1,485
Atlantic Region	**212**	174
Asia Pacific	**31**	25
Total	**1,814**	1,684
Unit operating costs *($/boe)*	**15.49**	14.01

Total operating costs increased to $1,814 million in 2012 from $1,684 million in 2011. Total Upstream unit operating costs in 2012 averaged $15.49/boe compared with $14.01/boe in 2011.

Operating costs in Western Canada increased to $15.45/boe in 2012 compared with $15.35/boe in 2011 primarily due to higher fuel and labour costs offset by higher heavy oil production, lower treating costs and decreased maintenance costs.

Operating costs in the Atlantic Region averaged $17.12/boe in 2012 compared with $8.75/boe in 2011. The increase was mainly due to higher maintenance costs and lower production as a result of the planned maintenance of the SeaRose and Terra Nova FPSOs.

Operating costs in the Asia Pacific Region averaged $10.08/boe in 2012 compared with $8.08/boe in 2011 due to higher maintenance, fuel, workover and helicopter costs.

Exploration and Evaluation Expenses

($ millions)	2012	2011
Seismic, geological and geophysical	146	170
Expensed drilling	188	245
Expensed land	16	55
Total	350	470

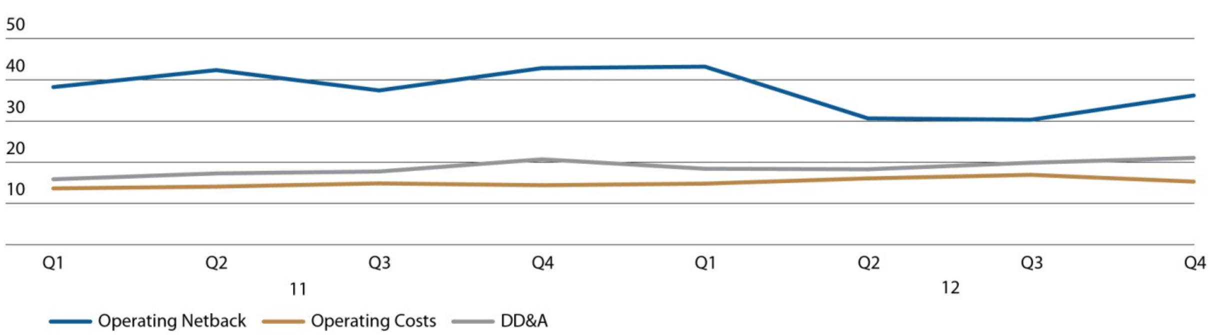
Total exploration and evaluation expenses decreased in 2012 to $350 million from $470 million in 2011. The decrease in seismic, geological and geophysical expense was primarily due to a shift in focus in 2012 to more development activities in Western Canada compared with 2011. Expensed drilling in 2012 primarily consisted of drilling in the Northwest Territories to gain a general understanding of geological formations, and costs related to the Searcher well in the Atlantic Region and the MAQ-1 well in the Madura Strait of Indonesia, neither of which encountered economic quantities of hydrocarbons. Expensed drilling and land costs in 2011 included acquisition and drilling costs expensed for properties in the Columbia River Basin located in the states of Washington and Oregon.

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

During 2012, total unit DD&A was $19.20/boe compared with $17.69/boe during 2011. The higher DD&A rate in 2012 was primarily due to a shift in focus by the Company to higher capital investments in oil and liquids-rich natural gas properties with higher netbacks than natural gas developments.

At December 31, 2012, capital costs in respect of unproved properties and major development projects were $6.1 billion compared with $5.3 billion at the end of 2011. These costs are excluded from the Company's DD&A calculation until the unproved properties are evaluated and developed, proved reserves are attributed to the project or the project is deemed to be impaired.

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



[1] Operating netback is a non-GAAP measure and constitues Husky's average price less royalties and operating costs on a per unit basis. Refer to Section 11.3.

Upstream Capital Expenditures

In 2012, Upstream Exploration and Production capital expenditures were $4,106 million. Capital expenditures were $2,288 million (56%) in Western Canada, $658 million (16%) in Oil Sands, $413 million (10%) in the Atlantic Region and $747 million (18%) in the Asia Pacific Region. Husky's major projects remain on budget and on schedule.

Upstream Capital Expenditures[1] *($ millions)*	2012	2011
Exploration		
Western Canada	**238**	233
Atlantic Region	**13**	2
Asia Pacific	**22**	168
	273	403
Development		
Western Canada	**2,029**	1,787
Oil Sands	**658**	263
Atlantic Region	**400**	258
Asia Pacific	**725**	546
	3,812	2,854
Acquisitions		
Western Canada	**21**	874
	4,106	4,131

(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:

	2012		2011	
Wells Drilled *(wells)*	Gross	Net	Gross	Net
Exploration				
Oil	**47**	**30**	50	40
Gas	**19**	**12**	24	24
Dry	**–**	**–**	3	3
	66	**42**	77	67
Development				
Oil	**775**	**715**	880	765
Gas	**23**	**17**	57	42
Dry	**5**	**4**	4	4
	803	**736**	941	811
Total	**869**	**778**	1,018	878

The Company drilled 778 net wells in the Western Canada, Heavy Oil and Oil Sands business units in 2012 resulting in 745 net oil wells and 29 net natural gas wells compared with 878 net wells resulting in 805 net oil wells and 66 net natural gas wells in 2011.

Capital expenditures for wells drilled in Western Canada increased substantially in 2012 compared with 2011 due to the increased focus on resource play development drilling in areas such as the liquids-rich gas resource play in Ansell, a larger number of horizontal wells drilled and more multi-stage fracture completions performed.

During 2012, Husky invested $2,288 million on exploration, development and acquisitions, including heavy oil, throughout the Western Canada Sedimentary Basin compared with $2,894 million in 2011. Property acquisitions totalling $21 million were completed in 2012 compared with $874 million in 2011. Investment in oil related exploration and development was $538 million and $500 million was invested in natural gas resource plays during 2012 compared with $591 million for oil and $359 million in natural gas in 2011.

In addition, $245 million was spent on production optimization and cost reduction initiatives in 2012. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $398 million.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling, were $586 million during 2012 compared to $587 million in 2011.

Oil Sands

During 2012, capital expenditures on Oil Sands projects increased to $658 million compared to $263 million in the same period in 2011 as Sunrise Phase 1 progressed and activity at the central processing facility and field facilities accelerated. In addition, the Company drilled 29 gross (15 net) evaluation wells for Phase 2 at the Sunrise Energy Project during 2012.

Atlantic Region

The following table discloses Husky's offshore Atlantic Region drilling activity during 2012:

Atlantic Region Offshore Drilling Activity

White Rose E-18-11	WI 68.875%	Development	Service/injector
North Amethyst G-25 7	WI 68.875%	Development	Production
White Rose B-07 11	WI 72.5%	Development	Production
Searcher C-87	WI 100%	Exploration	Stratigraphic

During 2012, $413 million was invested in Atlantic Region projects primarily on the continued development of the White Rose Extension Project including the West White Rose and North Amethyst satellite fields. A drill center was excavated at the South White Rose Extension and a temporary guide base was installed in 2012. In addition, one infill oil well was drilled in the White Rose field during 2012.

Asia Pacific Region

The following table discloses Husky's offshore China and Indonesia drilling activity completed during 2012:

Asia Pacific Region Offshore Drilling Activity

MBJ-1, Madura Strait Block	WI 40%	Exploration	Stratigraphic test
MDK-1, Madura Strait Block	WI 40%	Exploration	Stratigraphic test
MAC-1, Madura Strait Block	WI 40%	Exploration	Stratigraphic test
MAX-1, Madura Strait Block	WI 40%	Exploration	Stratigraphic test
MAQ-1, Madura Strait Block	WI 40%	Exploration	Stratigraphic test

Total capital expenditures of $747 million were invested in the Asia Pacific Region in 2012 primarily for development of the Liwan Gas Project. Five exploration wells were drilled at the Madura Strait in Indonesia during 2012, resulting in four discoveries under evaluation for commercial development.

2013 Upstream Capital Program

($ millions)

Western Canada	**2,100**
Oil sands	**500**
Atlantic Region	**600**
Asia Pacific Region	**800**
Total Upstream capital expenditures[(1)]	**4,000**

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

The 2013 Capital Program will enable Husky to build on the momentum achieved over the past two years and will support the acceleration of near-term production and the continued execution of the Company's mid and long-term growth initiatives.

The Company has budgeted $800 million for the Asia Pacific Region in 2013, mainly for the Liwan Gas Project to complete the construction of the shallow water pipeline installations, the onshore gas plant and the topsides portion of the platform with planned first production in late 2013/early 2014. Oil Sands capital for 2013 will primarily be for the continued development of Phase 1 of the Sunrise Energy Project as well as planning, design and engineering for the next phase of the project. Investment in the Atlantic Region of $600 million is for continued development of the White Rose fields and extensions and evaluation of the feasibility of a concrete wellhead and drilling platform for the development of future resources, including the full development of West White Rose.

In addition to advancing mid and long-term growth pillars, the 2013 Capital Program provides support to the Company's efforts to continue to reinvigorate and transform its foundation in Western Canada. A substantial oil and liquids-rich natural gas resource play portfolio has been acquired and further drilling is scheduled to take place across the portfolio in 2013. The Company is making progress in its strategy to transition a greater percentage of its heavy oil production to long-life thermal. The Company will continue its development of the 3,500 bbls/day Sandall thermal project with expected first production in 2014 and the 10,000 bbls/day Rush Lake thermal project with expected first production in 2015.

Upstream Turnarounds

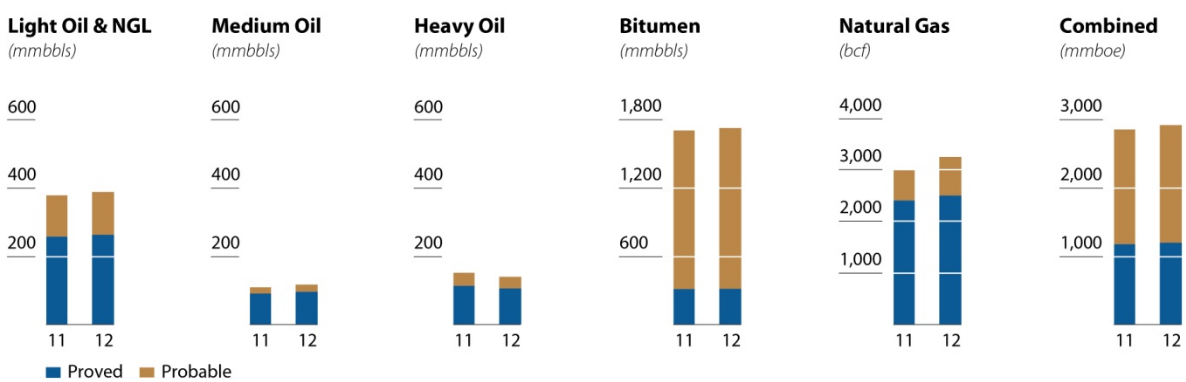
The Husky-operated SeaRose FPSO completed its planned maintenance dry-docking in Belfast, Northern Ireland with zero lost-time incidents and ahead of schedule with production resuming on August 13, 2012, approximately three weeks ahead of plan. Production from the White Rose field and satellite extensions returned to expected levels by the end of the third quarter of 2012.

The non-operated Terra Nova FPSO resumed production in December following a planned 26-week turnaround shutdown and continues to ramp up more slowly than anticipated.

In third quarter of 2013, a one week turnaround is scheduled for the SeaRose FPSO. The Terra Nova FPSO turnaround plans for 2013 are being evaluated.

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, 2012. 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 .

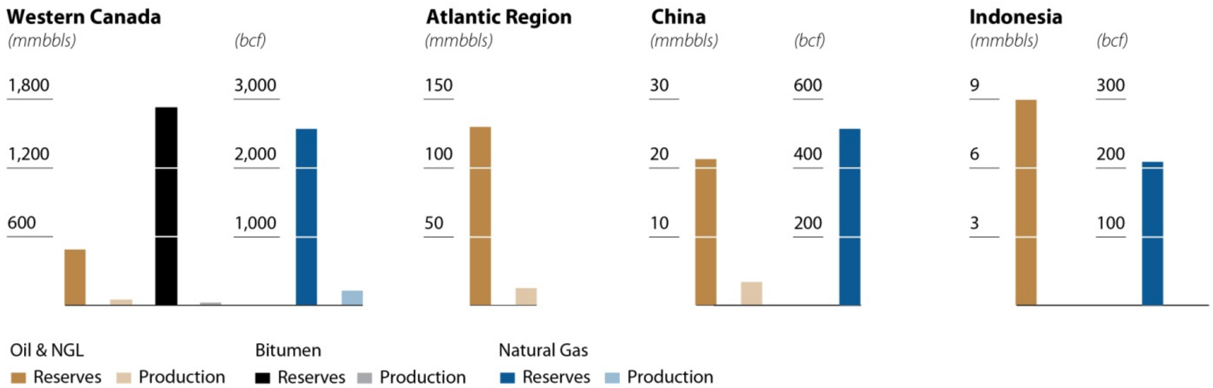


The Company's complete Oil and Gas Reserves Disclosure prepared in accordance with NI 51-101 is contained in Husky's Annual Information Form, which is available at www.sedar.com, or Husky's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com.

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

At December 31, 2012, Husky's proved oil and gas reserves were 1,192 mmboe, up from 1,172 mmboe at the end of 2011. Addition to proved reserves, including acquisitions and divestitures, represents 140% (118% after economic revisions) of 2012 production. Major additions to proved reserves in 2012 included:

- the initial booking of reserves in the Liwan 3-1 deepwater project that resulted in the addition of 51 mmboe of natural gas and natural gas liquids in proved undeveloped reserves;
- the improved recovery and expansion of heavy oil thermal projects that resulted in the booking of an additional 13 mmboe in proved reserves; and
- the extension through additional drilling locations at the liquids-rich Ansell project that resulted in the booking of an additional 27 mmboe of natural gas and natural gas liquids in proved reserves.



Note: Reserves reported represent proved plus probable reserves.

Reconciliation of Proved Reserves

	Canada						International		Total		
	Western Canada					Atlantic Region					
(forecast prices and costs before royalties)	Light Crude Oil & NG *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	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, 2011	169	90	113	309	2,253	76	12	167	769	2,420	1,172
Revision of previous estimate	–	8	2	1	14	4	5	–	20	14	22
Purchase of reserves in place	1	–	–	–	–	–	–	–	1	–	1
Sale of reserves in place	–	(1)	–	–	–	–	–	–	(1)	–	(1)
Discoveries, extensions and improved recovery	16	7	18	14	146	–	8	267	63	413	132
Economic revision	(1)	–	–	–	(137)	–	–	–	(1)	(137)	(24)
Production	(12)	(9)	(28)	(13)	(203)	(12)	(3)	–	(77)	(203)	(110)
Proved reserves December 31, 2012	**173**	**95**	**105**	**311**	**2,073**	**68**	**22**	**434**	**774**	**2,507**	**1,192**
Proved and probable reserves December 31, 2012	**229**	**117**	**140**	**1,725**	**2,547**	**130**	**30**	**718**	**2,371**	**3,265**	**2,915**
December 31, 2011	220	109	151	1,709	2,813	141	17	207	2,347	3,020	2,851

Reconciliation of Proved Developed Reserves

(forecast prices and costs before royalties)	Canada – Western Canada – Light Crude Oil & NGL *(mmbbls)*	Canada – Western Canada – Medium Crude Oil *(mmbbls)*	Canada – Western Canada – Heavy Crude Oil *(mmbbls)*	Canada – Western Canada – Bitumen *(mmbbls)*	Canada – Western Canada – Natural Gas *(bcf)*	Canada – Atlantic Region – Light Crude Oil *(mmbbls)*	International – Light Crude Oil & NGL *(mmbbls)*	International – Natural Gas *(bcf)*	Total – Crude Oil & NGL *(mmbbls)*	Total – Natural Gas *(bcf)*	Total – Equivalent Units *(mmboe)*
Proved developed reserves											
December 31, 2011	148	77	86	56	1,916	65	5	–	437	1,916	757
Revision of previous estimate	6	18	16	14	85	3	5	–	62	85	74
Purchase of reserves in place	1	–	–	–	–	–	–	–	1	–	1
Sale of reserves in place	–	(1)	–	–	–	–	–	–	(1)	–	(1)
Discoveries, extensions and improved recovery	7	3	10	2	13	–	1	–	23	13	25
Economic revision	(1)	–	–	–	(97)	–	–	–	(1)	(97)	(17)
Production	(12)	(9)	(28)	(13)	(203)	(12)	(3)	–	(77)	(203)	(110)
Proved developed reserves December 31, 2012	**149**	**88**	**84**	**59**	**1,714**	**56**	**8**	**–**	**444**	**1,714**	**729**

Infrastructure and Marketing

Infrastructure and Marketing Earnings Summary *($ millions, except where indicated)*	2012	2011
Infrastructure gross margin	**162**	169
Marketing and other gross margin	**387**	90
Gross margin	**549**	259
Operating and administrative expenses	**70**	60
Depletion, depreciation and amortization	**22**	24
Other expenses	**–**	1
Income taxes	**116**	44
Net earnings	**341**	130
Commodity trading volumes managed (mboe/day)	**180.1**	181.0

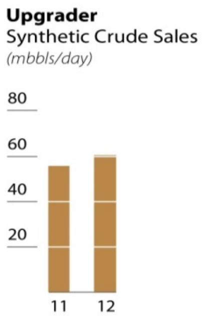
Infrastructure and Marketing net earnings increased by $211 million compared with the same period in 2011 as a result of marketing activities utilizing the Company's access to infrastructure to move crude oil from Canada to the United States to mitigate the impact of wider Western Canadian crude oil differentials on the Exploration and Production business by capturing widening Canadian crude discounts through integration.

Infrastructure and Marketing capital expenditures totalled $54 million in 2012 compared to $43 million in 2011. The majority of Infrastructure and Marketing capital expenditures during the year related to the completion of the 300,000 barrel tank at the Hardisty terminal and pipeline maintenance and integrity projects.

6.4 Downstream

2012 Total Downstream Earnings $895 million

Upgrader



Upgrader Earnings Summary *($ millions, except where indicated)*	2012	2011
Gross revenues	**2,191**	2,217
Gross margin [(1)]	**555**	589
Operating and administration expenses[(1)]	**153**	149
Depreciation and amortization	**102**	164
Other expenses (income)	**(6)**	74
Income taxes	**80**	52
Net earnings	**226**	150
Upgrader throughput[(2)] *(mbbls/day)*	**77.4**	69.6
Synthetic crude oil sales *(mbbls/day)*	**60.4**	55.3
Upgrading differential *($/bbl)*	**22.34**	27.34
Unit margin[(1)] ($/bbl)	**25.17**	29.18
Unit operating cost[(3)] ($/bbl)	**5.42**	5.87

(1) The Company reclassified certain hydrogen feedstock costs from operating and administrative expenses to cost of sales in the third quarter of 2012. Prior periods have been reclassified to conform with current period presentation.
(2) Throughput includes diluent returned to the field.
(3) Based on throughput.

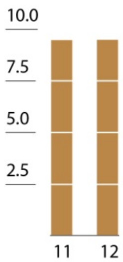
The Upgrading operations add value by processing heavy sour crude oil into high value synthetic crude oil and low sulphur distillates. The Upgrader profitability is primarily dependent on the differential between the cost of heavy crude oil feedstock and the sales price of synthetic crude oil.

Upgrading earnings in 2012 were impacted by lower upgrading differentials resulting from lower synthetic crude oil prices offsetting lower heavy oil feedstock costs. Lower margins were offset by a decrease in the fair value of the remaining upside interest payment obligations included in other income and a decrease in depreciation and amortization as intangible costs were derecognized in the second quarter of 2011.

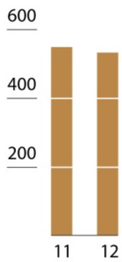
During 2012, the price of Husky's synthetic crude oil averaged $91.90/bbl compared with the average cost of blended heavy crude oil from the Lloydminster area of $69.56/bbl. During 2011, the price of Husky's synthetic crude oil averaged $101.68/bbl compared with an average cost of blended heavy crude oil from the Lloydminster area of $74.34/bbl. This resulted in an average synthetic/heavy crude differential of $22.34/bbl in 2012 compared to $27.34/bbl in 2011 and a gross unit margin of $25.17/bbl in 2012 compared to $29.18/bbl in 2011. The cost of upgrading averaged $5.42/bbl in 2012 compared to $5.87/bbl in 2011, which resulted in a net margin for upgrading heavy crude of $19.75/bbl, down 15% compared with $23.31/bbl in 2011. The decrease in Upgrading differentials, unit margins and net margins in 2012 compared to 2011 was primarily due to Western Canadian synthetic crude oil prices which traded at a discount to WTI in 2012 compared to a premium to WTI in 2011. This new trend is mainly due to export pipeline constraints in Western Canada and new supply in the U.S. which has resulted in a decrease in demand for Western Canadian crude oil.

Canadian Refined Products

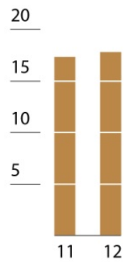
Light Oil Product Marketing
Volume
(millions of litres/day)



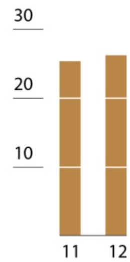
Outlets



Volume per Outlet
(thousands of litres/day)



Asphalt Products
Volume
(mbbls/day)



Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	2012	2011
Gross revenues	**3,848**	3,877
Gross margin [(1)]		
Fuel	**153**	153
Refining	**180**	171
Asphalt	**257**	239
Ancillary	**50**	49
	640	612
Operating and administration expenses	**242**	231
Depreciation and amortization	**83**	80
Other expense	**4**	6
Income taxes	**80**	75
Net earnings	**231**	220
Number of fuel outlets [(2)]	**531**	547
Refined products sales volume		
Light oil products *(million of litres/day)* [(3)]	**9.5**	9.5
Light oil products per outlet *(thousand of litres/day)* [(3)]	**17.8**	17.3
Asphalt products *(mbbls/day)*	**26.2**	25.3
Refinery throughput		
Prince George refinery *(mbbls/day)*	**11.1**	10.6
Lloydminster refinery *(mbbls/day)*	**28.3**	28.1
Ethanol production *(thousand of litres/day)*	**721.2**	711.3

(1) *Gross margin and operating and administrative expenses have been recast for reclassification of certain purchases and operating expenses. Prior periods have been recast to reflect this classification.*
(2) *Average number of fuel outlets for period indicated.*
(3) *Light oil products have been redefined to include ethanol sales. Prior periods have been recast to reflect this change in definition.*

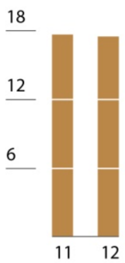
Refining gross margins increased in 2012 primarily due to higher refining market crack spreads and higher throughput and ethanol production compared to 2011. Included in ethanol gross margins in 2012 was $37 million related to government assistance grants compared with $46 million in 2011.

Asphalt gross margins increased compared to the same period in 2011 primarily due to higher realized market prices and increased sales volumes for residuals as a result of strong demand for drilling fluids.

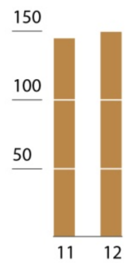
Higher operating and administration expenses were primarily due to increased maintenance activity in 2012 compared to 2011.

U.S. Refining and Marketing

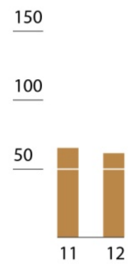
Refining Margin
U.S.
(U.S. $/bbl crude throughput)



Throughput
Lima Refinery
(mbbls/day)



Toledo Refinery
(mbbls/day)



U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*

	2012	2011
Gross revenues	**10,038**	9,752
Gross refining margin	**1,314**	1,299
Operating and administration expenses	**398**	403
Depreciation and amortization	**212**	195
Other expenses	**9**	4
Income taxes	**257**	254
Net earnings	**438**	443
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**150.0**	144.3
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**60.6**	63.9
Refining margin *(U.S. $/bbl crude throughput)*	**17.51**	17.60
Refinery inventory (feedstocks and refined products) *(mmbbls)*	**11.3**	11.8

U.S. Refining and Marketing net earnings in 2012 were comparable to 2011. Stronger throughput at Lima and higher market crack spreads in 2012 compared to 2011 were offset by the impacts of FIFO accounting on realized margins, lower throughput at the BP-Husky Toledo Refinery due to turnaround activity and higher depreciation and amortization.

The Chicago crack spread market benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while crude oil feedstock costs included in realized margins are based on FIFO accounting which reflects purchases made earlier in the previous year when crude oil prices were higher. The estimated FIFO impact was a reduction in net earnings of approximately $28 million in 2012 compared to an increase in net earnings of $122 million in 2011.

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

Downstream Capital Expenditures

Downstream capital expenditures totalled $457 million for 2012 compared to $373 million in 2011. In Canada, capital expenditures were $144 million related to upgrades at the Prince George Refinery, the Upgrader and at retail stations. In the United States, capital expenditures totalled $313 million. At the Lima Refinery, $150 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $163 million (Husky's 50% share) primarily for engineering work and procurement on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

The Lloydminster Refinery has a turnaround scheduled in the spring of 2013. The refinery is expected to be shut down for 30 days for inspections and equipment repair.

The Lima Refinery is scheduled to complete a turnaround in 2014 on 70% of the operating units. The refinery is expected to be shut down for 45 days. The remaining 30% of the operating units are scheduled to be addressed in a turnaround currently planned for 2015.

The Upgrader has a turnaround scheduled in the fall of 2013 and is expected to be shut down for 45 days.

6.5 Corporate

2012 Loss $193 million

Corporate Summary *($ millions) income (expense)*	2012	2011
Administration expenses	**(128)**	(195)
Stock-based compensation	**(54)**	1
Depreciation and amortization	**(40)**	(38)
Other income	**3**	–
Foreign exchange gains	**14**	10
Interest - net	**(52)**	(143)
Income taxes	**64**	65
Net loss	**(193)**	(300)

The Corporate segment reported a loss in 2012 of $193 million compared with a loss of $300 million in 2011. Administration expenses were lower in 2012 compared to 2011 in which the Company incurred costs related to financing projects and other initiatives. Stock-based compensation expense increased by $55 million in 2012 due to a higher share price at the end of 2012 compared to 2011. Interest - net decreased by $91 million in 2012 compared to 2011 due to increases in amounts of capitalized interest related to projects in the Asia Pacific Region and the Sunrise Energy Project.

Foreign Exchange Summary *($ millions, except exchange rate amounts)*	2012	2011
Gains (losses) on translation of U.S. dollar denominated long-term debt	**43**	(47)
Gains (losses) on cross currency swaps	**2**	7
Gains (losses) on contribution receivable	**(7)**	34
Other foreign exchange gains (losses)	**(24)**	16
Foreign exchange gains (losses)	**14**	10
U.S./Canadian dollar exchange rates:		
At beginning of year	**U.S. $0.983**	U.S. $1.005
At end of year	**U.S. $1.005**	U.S. $0.983

Consolidated Income Taxes

Consolidated income taxes decreased in 2012 to $814 million from $916 million in 2011 resulting in an effective tax rate of 29% for both 2012 and 2011.

($ millions)	2012	2011
Income taxes as reported	**814**	916
Cash taxes paid	**(575)**	(282)

Taxable income from Canadian operations is primarily generated through partnerships. This structure previously allowed a deferral of taxable income and related taxes to a future period. Starting in 2012, the Canadian government has removed this deferral, and any income taxes related to previously deferred taxable income will now be payable over a 5-year period commencing in 2013.

Corporate Capital Expenditures

Corporate capital expenditures of $84 million in 2012 were primarily related to computer hardware and software and system upgrades.

7.0 Risk and Risk Management

7.1 Enterprise Risk Management

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

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

7.2 Significant Risk Factors

Operational, Environmental and Safety Incidents

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

Commodity Price Volatility

Husky's results of operations and financial condition are dependent on the prices received for its crude oil and natural gas production. Lower prices for crude oil and natural gas could adversely affect the value and quantity of Husky's oil and gas reserves. Husky's reserves include significant quantities of heavier grades of crude oil that trade at a discount to light crude oil. Heavier grades of crude oil are typically more expensive to produce, process, transport and refine into high value refined products. Refining and transportation capacity for heavy crude oil is limited and planned increases of North American heavy crude oil production may create the need for additional heavy oil refining and transportation capacity. As a result, wider price differentials could have adverse effects on Husky's financial performance and condition, reduce the value and quantities of Husky'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.

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

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

The fluctuations in crude oil and natural gas prices are beyond Husky's control and accordingly, could have a material adverse effect on the Company's business, financial condition and cash flow. For information on 2012 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 natural gas liquids and maintain the value of the reserves portfolio, additional reserves must be added through discoveries, extensions, improved recovery, performance-related revisions and acquisitions. The production rate of oil and gas properties tends to decline as reserves are depleted while the associated unit operating costs increase. 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

Husky'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. 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.

Security and Terrorist Threats

A security threat or terrorist attack on a facility owned or operated by the Company could result in the interruption or cessation of key elements of its operations, which could have a material impact on the Company's financial position, business strategy and cash flow.

International Operations

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

Gas Offtake

The potential inability to deliver an effective gas storage solution as inventories grow over the life of the White Rose field may potentially result in prolonged shutdown of these operations, which may have a material impact on the Company's financial position, 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 Husky's current and future business strategies. However, a tight labour market, an insufficient number of qualified candidates, and an aging workforce are factors that precipitate a human resource risk for the Company. 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 major projects relating to oil and gas exploration, development and production. Risks associated with the execution of Husky's major projects, as well as the commissioning and integration of new assets into its existing infrastructure, may result in cost overruns, project or production delays, and missed financial targets, thereby eroding project economics. Typical project execution risks include: the availability and cost of capital, inability to find mutually agreeable parameters with key project partners for large growth projects, availability of manufacturing and processing capacity, faulty construction and design errors, labour disruptions, bankruptcies, productivity issues affecting Husky directly or indirectly, unexpected changes in the scope of a project, health and safety incidents, need for government approvals or permits, unexpected cost increases, availability of qualified and skilled labour, availability of critical equipment, severe weather, and availability and proximity of pipeline capacity.

Partner Misalignment

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

Reserves Data, Future Net Revenue and Resource Estimates

The reserves data in this Management's Discussion and Analysis represent estimates only. The accurate assessment of oil and gas reserves is critical to the continuous and effective management of the Company's Upstream assets. Reserves estimates support various investment decisions about the development and management of resource plays. In general, estimates of economically recoverable crude oil and gas reserves and the future net cash flow therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties, and the assumed effects of regulation by governmental agencies, including with respect to royalty payments, all of which may vary considerably from actual results. All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. 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, prepared by different engineers or by the same engineers at different times, may vary substantially. 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 Husky's operations, the Company may be subject to regulation and intervention by governments at the federal, provincial, state and municipal levels in the countries in which it conducts its operations or exploratory activities. As these governments continually balance competing demands from different interest groups and stakeholders, the Company recognizes that the magnitude of regulatory risks has the potential to change over time. Changes in government policy, legislation or regulation could impact the Company's existing and planned projects as well as impose costs of compliance, increase capital expenditures and operating expenses, and expose the Company to other risks including environmental and safety risks. Examples of the Company's regulatory risks include, but are not limited to, uncertain or negative interactions with governments, uncertain energy policies, environmental and safety controls related to the reduction of greenhouse gasses and other emissions, penalties, taxes, royalties, government fees, reserves access, limitations or increase in costs relating to the exportation of commodities, restrictions on the acquisition of exploration and production rights and land tenure, expropriation or cancellation of PSCs and/or contract rights, limitations on control over the development and abandonment of fields, and loss of licenses to operate.

Environmental Regulation

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

The 2010 Deepwater Horizon oil spill in the Gulf of Mexico has led to numerous public and governmental expressions of concern about the safety and potential environmental impact of offshore oil and gas operations. Stricter regulation of offshore oil and gas operations has already been implemented by the U.S. with respect to operations in the Outer Continental Shelf, including in the Gulf of Mexico. Further regulation, increased financial assurance requirements and increased caps on liability are likely to be applied to offshore oil and gas operations in these areas. In the event that similar changes in environmental regulation occur with respect to Husky's operations in the Atlantic or Asia Pacific Regions, such changes could increase the cost of complying with environmental regulation in connection with these operations and have a material adverse impact on Husky's operations.

Climate Change Regulation

Husky continues to monitor international efforts to address climate change, including developments on the Kyoto Protocol and the Copenhagen Accord. Canada has withdrawn from participation in the Kyoto Protocol. The effect of these initiatives on the Company's operations cannot be determined with any certainty at this time. The Alberta and BC governments have regulations in place with the Saskatchewan government anticipated to soon follow with similar regulation. These regulations include limiting the intensity limits for large emitters of greenhouse gases in Alberta emitting 100,000 tonnes or more of greenhouse gas in any year. Under the regulations, a 12-15% intensity reduction will be applied to the average of that facility's 2003-2005 baseline emissions intensity for established facilities. New facilities are required to reduce emissions starting with the fourth year of commercial operation by 2%, and then by 2% every year after, until the 12-15% reduction target has been achieved. These regulations impact all of Husky's Upstream operations in BC, the Prince George Refinery, the Ram River gas plant and the Tucker thermal oil facility. In addition, the Federal Government of Canada has announced pending regulations in respect of greenhouse gases and other pollutants. Although the impact of these regulations is uncertain, they may adversely affect the Company's operations and increase costs. These regulations may become more onerous over time as public and political pressures increase to implement initiatives that further reduce the emission of greenhouse gases.

While the U.S. EPA regulations are currently in effect, they have not yet had a material impact on Husky. However, the Company's operations may be materially impacted by future application of these rules or by future U.S. greenhouse gas legislation applying to the oil and gas industry or the consumption of petroleum products or by these or any further restrictive regulations issued by the EPA. Such legislation or regulation could require Husky's U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

Competition

The energy industry is highly competitive with respect to gaining access to the resources required to increase oil and gas reserves and production and gain access to markets. Husky 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. Husky'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. Husky's competitors comprise all types of energy companies, some of which have greater resources.

Internal Credit Risk

Credit ratings affect Husky's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of Husky to engage in ordinary course derivative or hedging transactions, maintain ordinary course contracts with customers and suppliers on acceptable terms and enter into certain collateralized business activities on a cost effective basis depends on Husky's credit ratings. A reduction in the current rating on Husky's debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in Husky's ratings outlook could adversely affect Husky's cost of financing and its access to sources of liquidity and capital. Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to Husky's securities by the rating agencies are not recommendations to purchase, hold or sell the securities inasmuch 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 adversely affects 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, which 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 financial losses.

7.3 Financial Risks

Husky's financial risks are largely related to commodity price risk, foreign currency risk, interest rate risk, credit risk, and liquidity risk. From time to time, Husky uses derivative financial instruments to manage its exposure to these risks. These derivative financial instruments are not intended for trading or speculative purposes. For further details on the Company's derivative financial instruments, including assumptions made in the calculation of fair value and additional discussion of exposure to risks and mitigation activities see Note 22 Financial Instrument and Risk Management within the Company's 2012 audited Consolidated Financial Statements and Section 3.0 of this Management's Discussion and Analysis. For a discussion on commodity price risk, refer to the Commodity Price Volatility section above.

Foreign Currency Risk

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

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. revenue dollars to hedge against these potential fluctuations. Husky also designates a portion of its U.S debt as a hedge of the Company's net investment in the U.S. refining operations which are considered as a foreign functional currency. At December 31, 2012, the amount that the Company designated was U.S. $2.8 billion (December 31, 2011 - U.S. $1.3 billion). For the year ended December 31, 2012, the unrealized loss arising from the translation of the debt was $15 million (2011 - loss of $18 million), net of tax of $2 million (2011 - $3 million), which was recorded in OCI. At December 31, 2012, the fair value of the hedge was $97 million recorded in long-term debt in the consolidated balance sheets (December 31, 2011 - $80 million).

Interest Rate Risk

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

Credit Risk

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

Liquidity Risk

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

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

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

Fair Value of Financial Instruments

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

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

The following table summarizes by measurement classification, derivatives, contingent consideration and hedging instruments that are carried at fair value through profit or loss ("FVTPL") in the consolidated balance sheets:

Financial Instruments at Fair Value

($ millions)	**December 31, 2012**	December 31, 2011
Derivatives – FVTPL (held-for-trading)		
Accounts receivable	**13**	65
Accounts payable and accrued liabilities	**(5)**	(45)
Other assets, including derivatives	**1**	2
Other – FVTPL (held-for-trading)[1]		
Accounts payable and accrued liabilities	**(27)**	(17)
Other long-term liabilities	**(78)**	(112)
Hedging instruments		
Other assets, including derivatives	**1**	–
Accounts payable and accrued liabilities	**–**	(93)
Long-term debt[2]	**25**	(13)
	(70)	(213)
Net gains (losses) for the year related to financial instruments held at fair value	**122**	(73)
Included in net earnings	**104**	(55)
Included in OCI	**18**	(18)

(1) Non-derivative items related to contingent consideration recognized as part of a business acquisition.

(2) Represents the foreign exchange adjustment related to translation of U. S. denominated long-term debt designated as a hedge of the Company's net investment in its U.S. refining operations.

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

In 2012, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At December 31, 2012, Husky had total debt of $3,918 million partially offset by cash on hand of $2,025 million for $1,893 million of net debt compared to $2,070 million of net debt as at December 31, 2011. At December 31, 2012, the Company had $3.1 billion in unused committed credit facilities, $280 million in unused short-term uncommitted credit facilities, $3.0 billion in unused capacity under its Canadian universal short form base shelf prospectus filed December 31, 2012 and U.S. $1.5 billion in unused capacity under its U.S universal short form base shelf prospectus filed June 13, 2011. The ability of the Company to utilize the capacity under its shelf prospectuses is subject to market conditions. Refer to Section 8.2.

	2012	2011
Cash flow		
Operating activities *($ millions)*	**5,189**	5,092
Financing activities *($ millions)*	**(162)**	910
Investing activities *($ millions)*	**(4,830)**	(4,420)
Financial Ratios[(1)]		
Debt to capital employed *(percent)*[(2)]	**17**	18
Debt to cash flow *(times)*[(3)(4)]	**0.8**	0.8
Corporate reinvestment ratio *(percent)*[(3)(5)]	**106**	98
Interest coverage on long-term debt only[(3)(6)]		
Earnings	**12.5**	14.5
Cash flow	**24.9**	24.7
Interest coverage on total debt[(3)(7)]		
Earnings	**12.3**	14.1
Cash flow	**24.6**	23.9

(1) *Financial ratios constitute non-GAAP measures. (Refer to Section 11.3)*
(2) *Debt to capital employed is equal to long-term debt and long-term debt due within one year divided by capital employed. (Refer to Section 11.3)*
(3) *Calculated for the 12 months ended for the dates shown.*
(4) *Debt to cash flow (times) is equal to long-term debt and long-term debt due within one year divided by cash flow from operations. (Refer to Section 11.3)*
(5) *Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations. (Refer to Section 11.3)*
(6) *Interest coverage on long-term debt on a net earnings basis is equal to net earnings before finance expense on long-term debt and income taxes divided by finance expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow – operating activities before finance expense on long-term debt and current income taxes divided by finance expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.*
(7) *Interest coverage on total debt on a net earnings basis is equal to net earnings before finance expense on total debt and income taxes divided by finance expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow – operating activities before finance expense on total debt and current income taxes divided by finance expense on total debt and capitalized interest. Total debt includes short and long-term debt.*

Cash Flow from Operating Activities

Cash generated from operating activities was $5,189 million in 2012 compared with $5,092 million in 2011. Slightly higher cash flows from operations were mainly due to changes in non-cash working capital, partially offset by higher taxes paid and lower net earnings when compared to 2011.

Cash Flow from Financing Activities

Cash used for financing activities was $162 million in 2012 compared with cash flow from financing activities of $910 million in 2011. Cash flow from financing activities was lower in 2012 compared to 2011 due to a preferred share issuance of $300 million and a common share issuance of $1.2 billion in 2011.

Cash Flow used for Investing Activities

Cash used in investing activities for 2012 was $4,830 million compared with $4,420 million in 2011. Cash invested in both periods was primarily for acquisitions and capital expenditures.

8.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2012, Husky's working capital was $2,404 million compared with $2,054 million at December 31, 2011.

Movement in Working Capital

($ millions)	December 31, 2012	December 31, 2011	Increase/ (Decrease)
Cash and cash equivalents	**2,025**	1,841	184
Accounts receivable	**1,349**	1,235	114
Income taxes receivable	**323**	273	50
Inventories	**1,736**	2,059	(323)
Prepaid expenses	**64**	36	28
Accounts payable and accrued liabilities	**(2,986)**	(2,867)	(119)
Asset retirement obligations	**(107)**	(116)	9
Long-term debt due within one year	**–**	(407)	407
Net working capital	**2,404**	2,054	350

The increase in cash was primarily due to strong cash flow from operations in the year which was in excess of cash flow used for financing and investing activities. Cash flow used for financing and investing activities in 2012 primarily consisted of dividends paid on common and preferred shares, interest paid on long-term debt and Upstream capital expenditures. Increases in accounts receivable and accounts payable were due to the timing of settlements compared to 2011. Inventory levels held at December 31, 2012 decreased from levels held at December 31, 2011 due to comparable production combined with higher throughput in Downstream in the fourth quarter of 2012 compared to the same period in 2011 and the timing of lifts and sales of upstream offshore production. The decrease in long-term debt due within one year was due to the repayment of debt which matured in 2012 compared to no long-term debt maturities in 2013.

Sources and Uses of Cash

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and develop reserves, to acquire strategic oil and gas assets, and to repay maturing debt and pay dividends. Husky is currently able to fund its capital programs principally by cash generated from operating activities, cash on hand, issuances of equity, issuances of long-term debt and borrowings under committed and uncommitted credit facilities. During times of low oil and gas prices, a portion of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, Husky frequently evaluates the options with respect to sources of short and long-term capital resources. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines. At December 31, 2012, no production was hedged.

At December 31, 2012 Husky had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[(1)]	**515**	**280**
Syndicated bank facilities	**3,100**	**3,100**
	3,615	**3,380**

(1) *Consists of demand credit facilities.*

Cash and cash equivalents at December 31, 2012 totalled $2,025 million compared with $1,841 million at the beginning of the year.

At December 31, 2012, Husky had unused short and long-term borrowing credit facilities totalling $3,380 million. A total of $235 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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

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

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. A shareholder must deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend confirming they will accept the dividend in common shares. Failure to do so will result in such shareholder receiving the dividend paid in cash. During the year ended December 31, 2012, the Company declared dividends payable of $1.20 per common share, resulting in dividends of $1.2 billion. An aggregate of $557 million was paid in cash during 2012. At December 31, 2012, $295 million, including $293 million in cash and $2 million in common shares, was payable to shareholders on account of dividends declared on November 1, 2012.

On March 18, 2011, Husky issued 12 million Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") at a price of $25.00 per share for aggregate gross proceeds of $300 million under a Canadian universal short form base shelf prospectus (the "Prior Canadian Shelf Prospectus"). Holders of the Series 1 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend payable on the last day of March, June, September and December in each year yielding 4.45% annually for the initial period ending March 31, 2016 as and when declared by Husky's Board of Directors. Thereafter, the dividend rate will be reset every five years at a rate equal to the 5-year Government of Canada bond yield plus 1.73%. Holders of Series 1 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares"), subject to certain conditions, on March 31, 2016 and on March 31 every five years thereafter. Holders of the Series 2 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the three-month Government of Canada Treasury Bill yield plus 1.73%.

On June 13, 2011, the Company filed a universal short form base shelf prospectus (the "U.S. Shelf Prospectus") with the Alberta Securities Commission and the U.S. Securities and Exchange Commission that enables the Company to offer up to U.S. $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units in the United States up to and including July 12, 2013. At December 31, 2012, approximately $1.5 billion remains available for issuance under the U.S. Shelf Prospectus.

On June 29, 2011, Husky issued 37 million common shares at a price of $27.05 per share for total gross proceeds of approximately $1.0 billion through a public offering, and a total of 7.4 million common shares at a price of $27.05 per share for total gross proceeds of $200 million through a private placement to L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. The Company received total gross proceeds of $1.2 billion from this issuance. The public offering was completed under the U.S. Shelf Prospectus and accompanying prospectus supplement in the United States and under the Prior Canadian Shelf Prospectus and accompanying prospectus supplement in Canada.

On March 22, 2012, the Company issued U.S. $500 million of 3.95% senior unsecured notes due April 15, 2022 pursuant to the U.S. Shelf Prospectus and an accompanying prospectus supplement. The notes are redeemable at the option of the Company at a make-whole premium and interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

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

On December 14, 2012, the Company amended and restated both of its revolving syndicated credit facilities to allow the Company to borrow up to $1.5 billion and $1.6 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis.

On December 31, 2012, the Company filed a universal short form base shelf prospectus (the "Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada, other than Quebec, that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada up to and including January 30, 2015. As of December 31, 2012, the Company had not issued Securities under the Canadian Shelf Prospectus. This Canadian Shelf Prospectus replaced the Prior Canadian Shelf Prospectus filed in Canada during November 2010 which had remaining unused capacity of $1.4 billion and expired in December 2012. The ability of the Company to raise capital utilizing the U.S. Shelf Prospectus and Canadian Shelf Prospectus is dependent on market conditions at the time of sale.

Capital Structure ($ millions)	December 31, 2012 Outstanding	Available[(1)]
Total long-term debt	**3,918**	**3,380**
Common shares, retained earnings and other reserves	**19,161**	

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

8.3 Cash Requirements

Contractual Obligations and Other Commercial Commitments

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

Contractual Obligations *Payments due by period ($ millions)*	2013	2014-2015	2016-2017	Thereafter	Total
Long-term debt and interest on fixed rate debt	227	1,428	826	3,125	5,606
Operating leases	130	370	436	556	1,492
Firm transportation agreements	217	561	476	2,652	3,906
Unconditional purchase obligations[(1)]	3,089	4,347	102	78	7,616
Lease rentals and exploration work agreements	85	174	212	571	1,042
Asset retirement obligations[(2)]	107	198	211	9,812	10,328
	3,855	7,078	2,263	16,794	29,990

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

The following additions during the year are included in total non-cancellable contracts and other commercial commitments:

- The Company executed an operating lease agreement with Seadrill for the semi-submersible rig, West Mira. The non-cancellable minimum future payments are approximately $129 million per year commencing 2015 for five years with an option to extend the contract to 2022.
- The Company executed contracts to purchase refined petroleum products in Canada over the next three years totalling approximately $4.5 billion.
- The Company updated its estimates for Asset Retirement Obligations ("ARO") as outlined in Note 16 of the 2012 audited Consolidated Financial Statements. On an undiscounted basis, the ARO increased from $8.5 billion as at December 31, 2011 to $10.3 billion as at December 31, 2012 due to increased cost estimates and asset growth in the Upstream and Downstream segments.

Based on Husky's 2013 commodity price forecast, the Company believes that its non-cancellable contractual obligations, including commercial commitments and the 2013 Capital Program, will be funded by cash flow from operating activities and, to the extent required, by available committed credit facilities and the issuance of long-term debt. In the event of significantly lower cash flow, Husky would be able to defer certain projected capital expenditures without penalty.

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 96 active employees, 110 participants with deferred benefits and 535 participants or joint survivors receiving benefits in Canada. This plan was closed to new entrants in 1991 after the majority of employees transferred to the defined contribution pension plan. Husky provides a defined benefit pension plan for approximately 237 active union represented employees in the United States. A defined benefit pension plan for 207 active non-represented employees in the United States was curtailed effective April 1, 2011. Approximately 10 participants in both U.S. plans have deferred benefits and no participants were receiving benefits at year end. These pension plans were established effective July 1, 2007 in conjunction with the acquisition of the Lima Refinery. Husky also assumed a post-retirement welfare plan covering all qualified employees at the Lima Refinery and contributes to a 401(k) plan (Refer to Note 19 to the 2012 audited Consolidated Financial Statements).

Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery LLC (Refer to Note 8 to the 2012 audited 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, 2012, Husky's share of this obligation was U.S. $1.3 billion including accrued interest.

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

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

8.4 Off-Balance Sheet Arrangements

Husky does not believe that it has any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance.

Standby Letters of Credit

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

8.5 Transactions with Related Parties

The Company continues to sell natural gas to and purchase steam from the Meridian cogeneration facility owned by a related party of Husky. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the year ended December 31, 2012, the total value of natural gas sales to the Meridian cogeneration facility owned by the related party was $74 million. For the year ended December 31, 2012, the total value of obligated steam purchases from the Meridian cogeneration facility owned by the related party was $13 million. In addition, the Company provides cogeneration and facility support services to Meridian, measured on a cost recovery basis. For the year ended December 31, 2012, the total cost recovery for these services was $19 million.

8.6 Outstanding Share Data

Authorized

unlimited number of common shares
unlimited number of preferred shares

Issued and outstanding: February 27, 2013	
common shares	982,541,821
cumulative redeemable preferred shares, series 1	12,000,000
stock options	28,389,305
stock options exercisable	10,224,925

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 2012 audited Consolidated Financial Statements. Certain of the Company's accounting policies require subjective judgment and estimation about uncertain circumstances.

9.1 Accounting Estimates

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

Depletion, Depreciation and Amortization

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

Asset Retirement Obligations

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

Fair Value of Financial Instruments

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

Employee Future Benefits

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

Income Taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Significant estimations are made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where 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 both determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine 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") and the designation of the Company's functional currency.

Successful Efforts Assessments

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

Impairment of Non-Financial Assets and Financial Assets

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

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

Functional and Presentation Currency

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

10.0 Recent Accounting Standards

Consolidated Financial Statements

In May 2011, the IASB published IFRS 10, "Consolidated Financial Statements," which provides a single model to be applied in the assessment of control for all entities in which the Company has an investment including special purpose entities currently in the scope of Standing Interpretations Committee ("SIC") 12. Under the new control model, the Company has control over an investment if the Company has the ability to direct the activities of the investment, is exposed to the variability of returns from the investment and there is a link between the ability to direct activities and the variability of returns. IFRS 10 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 10 on January 1, 2013. The adoption of the standard is not expected to have a material impact on the Company's financial statements.

Joint Arrangements

In May 2011, the IASB published IFRS 11, "Joint Arrangements," whereby joint arrangements are classified as either joint operations or joint ventures. Parties to a joint operation retain the rights and obligations to individual assets and liabilities of the operation, while parties to a joint venture have rights to the net assets of the venture. Joint operations shall be accounted for in a manner consistent with jointly controlled assets and operations whereby the Company's contractual share of the arrangement's assets, liabilities, revenues and expenses is included in the consolidated financial statements. Any arrangement structured through a separate vehicle that does effectively result in separation between the Company and the arrangement shall be classified as a joint venture and accounted for using the equity method of accounting. Under the existing IFRS standard, the Company has the option to account for any interests it has in joint arrangements using proportionate consolidation or equity accounting. IFRS 11 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 11 on January 1, 2013. The adoption of the standard is not expected to have a material impact on the Company's financial statements.

Disclosure of Interests in Other Entities

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

Investments in Associates and Joint Ventures

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

Fair Value Measurement

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

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 "Employee Benefits" to eliminate the corridor method that permits the deferral of actuarial gains and losses, to revise the presentation requirements for changes in defined benefit plan assets and liabilities and to enhance the required disclosures for defined benefit plans. The amendments to IAS 19 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt these amendments on January 1, 2013. The adoption of the amended standard is not expected to have a material impact on the Company's financial statements.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IFRS 7, "Financial Instruments: Disclosures" and IAS 32, "Financial Instruments: Presentation" to clarify the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Amendments to IFRS 7 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. Amendments to IAS 32 are effective for the Company on January 1, 2014 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the IFRS 7 amendments on January 1, 2013 and the IAS 32 amendments on January 1, 2014. The adoption of these amended standards is not expected to have a material impact on the Company's financial statements.

Financial Instruments

In November 2009, the IASB published IFRS 9, "Financial Instruments," which covers the classification and measurement of financial assets as part of its project to replace IAS 39, "Financial Instruments: Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to their own credit risk out of net earnings and recognize the change in OCI. IFRS 9 is effective for the Company on January 1, 2015 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the amendments on January 1, 2015. The adoption of the standard is not expected to have a material impact on the Company's financial statements.

11.0 Reader Advisories

11.1 Forward-looking Statements

Certain statements in this document are forward looking statements within the meaning of 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, and forward-looking information within the meaning of applicable Canadian securities legislation (collectively "forward-looking statements"). The Company hereby provides cautionary statements identifying important factors that could cause actual results to differ materially from those projected in these forward-looking statements. Any 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," "are expected to," "will continue," "is anticipated," "is targeting," "estimated," "intend," "plan," "projection," "could," "aim," "vision," "goals," "objective," "target," "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and are subject to risks, uncertainties and other factors some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

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 general financial plans and goals; target weighting of production among product types; target debt to cash flow ratio and target debt to capital employed ratio; expected sources of cash from the Company's growth projects; the Company's 2013 production guidance; target compound annual production growth for the periods 2010-2015 and 2012-2017, and the Company's ability to achieve such targets; the Company's 2013 capital program; and the funding sources for the Company's non-cancellable contractual obligations and other commercial commitments;
- with respect to the Company's Asia Pacific Region: anticipated timing of first production from the Company's Liwan Gas Project; planned timing of resumption of pipe laying activity at the Company's Liwan Gas Project; planned timing of floatover of the topsides for the central platform at the Company's Liwan Gas Project; planned timing of development of the single well Liuhua 34-2 field; and anticipated timing of first gas from the Company's Madura Strait Block;
- with respect to the Company's Atlantic Region: development and drilling plans for the South White Rose extension project; development and drilling plans for the North Amethyst field; expected timing of a decision on a preferred development option for the West White Rose project; expected timing of completion of the West Mira rig; planned participation in operated and non-operated exploratory wells in the region during 2013 and 2014; and 2013 turnaround plans at the SeaRose and Terra Nova FPSOs;
- with respect to the Company's Oil Sands properties: anticipated timing and volume of production from the Company's Sunrise Energy Project; expected timing of completion of the Design Basis Memorandum for the next phase of the Company's Sunrise Energy Project; expected timing of production from the Company's Tucker Oil Sands Project; and anticipated timing of filing a regulatory application for the bitumen carbonates pilot at the Company's Saleski Oil Sands project;
- with respect to the Company's Heavy Oil properties: scheduled timing of first production from the Company's Sandall thermal development project; anticipated timing of first commercial production at the Company's Rush Lake Project; anticipated timing of production from the second well pair pilot at the Company's Rush Lake project; and the Company's horizontal and CHOPS drilling programs for 2013;
- with respect to the Company's Western Canadian oil and gas resource plays: 2013 drilling plans in the Company's oil and gas resource play portfolio; tie-in plans at the Company's Kaybob property; and expected timing of production response from the Company's Fosterton Alkaline Surfactant Polymer facility;
- with respect to the Company's Infrastructure and Marketing business unit: intended focus of spending with the unit; and
- with respect to the Company's Downstream operating segment: project and expansion plans within the segment for 2013 and beyond; expected timing of operation of a kerosene hydrotreater at the Lima Refinery; expected timing of start up of the Continuous Catalyst Regeneration Reformer Project at the BP-Husky Toledo Refinery; and scheduled timing and anticipated duration of turnarounds at the Lloydminster Refinery, the Lima Refinery and the Lloydminster Upgrader.

In addition, statements relating to "reserves" and "resources" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves or resources described can be profitably produced in the future.

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.

Sections 7.2 and 7.3 of this Management's Discussion and Analysis and the Company's Annual Information Form for the year ended December 31, 2012 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe the risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

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

11.2 Oil and Gas Reserves Reporting

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

Unless otherwise noted in this document, all reserves estimates given have an effective date of December 31, 2012.

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

11.3 Non-GAAP Measures

Disclosure of non-GAAP Measurements

Husky uses measurements primarily based on IFRS as issued by the International Accounting Standards Board and also certain secondary non-GAAP measurements. The non-GAAP measurements included in this Management's Discussion and Analysis are 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 capital employed and return on capital in use. None of these measurements are used to enhance the Company's reported financial performance or position. With the exception of cash flow from operations, there are no comparable measures to these non-GAAP measures in accordance with IFRS. These non-GAAP measurements are considered to be useful as complementary measurements in assessing Husky's financial performance, efficiency and liquidity. The non-GAAP measurements do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable by definition to similar measures presented by other companies. Except as described below, the definitions of these measurements are found in Section 11.4, "Additional Reader Advisories."

Disclosure of 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 and amortization, future income taxes, foreign exchange 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)	2012	2011
GAAP Cash flow – operating activities	5,189	5,092
Settlement of asset retirement obligations	123	105
Income taxes paid	575	282
Interest received	(34)	(12)
Change in non-cash working capital	(843)	(269)
Non-GAAP Cash flow from operations	5,010	5,198
Cash flow from operations – basic	5.13	5.63
Cash flow from operations – diluted	5.13	5.58

Disclosure of Operating Netback

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

11.4 Additional Reader Advisories

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

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

Review by the Audit Committee

This MD&A was reviewed by the Audit Committee and approved by Husky's Board of Directors on February 27, 2013. Any events subsequent to that date could conceivably materially alter the veracity and usefulness of the information contained in this document.

Additional Husky Documents Filed with Securities Commissions

This MD&A should be read in conjunction with the Consolidated Financial Statements and related notes. The readers are also encouraged to refer to Husky's interim reports filed in 2012, which contain MD&A and Consolidated Financial Statements, and Husky's Annual Information Form filed separately with Canadian regulatory agencies and Form 40-F filed with the SEC, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and www.huskyenergy.com.

Use of Pronouns and Other Terms

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

Standard Comparisons in this Document

Unless otherwise indicated, comparisons of results are for the years ended December 31, 2012 and 2011 and Husky's financial position as at December 31, 2012 and at December 31, 2011.

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 the securities of Husky.

Additional Reader Guidance

Unless otherwise indicated:

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

Terms

Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
Brent Crude Oil	*Prices which are dated less than 15 days prior to loading for delivery*
Capital Employed	*Short and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest.*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations, income taxes paid, interest received and changes in non-cash working capital*
Coal Bed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Corporate Reinvestment Ratio	*Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations*
Debt to Capital Employed	*Long-term debt and long-term debt due within one year divided by capital employed*
Debt to Cash Flow	*Long-term debt and long-term debt due within one year divided by cash flow from operations*
Design Rate Capacity	*Maximum continuous rated output of a plant based on its design*
Embedded Derivative	*Implicit or explicit term(s) in a contract that affects some or all of the cash flows or the value of other exchanges required by the contract*
Feedstock	*Raw materials which are processed into petroleum products*
Front End Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Interest Coverage Ratio	*A calculation of a company's ability to meet its interest payment obligation. It is equal to net earnings or cash flow – operating activities before finance expense divided by finance expense and capitalized interest*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
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 shareholder's equity.*
Seismic	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
Shareholders' Equity	*Shares, retained earnings and other reserves*
Total Debt	*Long-term debt including current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

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

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

"Proved Undeveloped" 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 exceed the sum of the estimated proved plus probable plus possible reserves.

Abbreviations

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

11.5 Disclosure Controls and Procedures

Disclosure Controls and Procedures

Husky's management, with the participation 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, 2012, and have concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by Husky in reports that it files or submits under the Securities Exchange Act of 1934 and Canadian securities laws is (i) recorded, processed, summarized and reported within the time periods specified in SEC rules and forms and Canadian securities laws and (ii) accumulated and communicated to Husky's management, including its principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

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 is responsible for establishing and maintaining adequate internal control over financial reporting for Husky. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.
2) Husky's management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework to evaluate the effectiveness of Husky's internal control over financial reporting.
3) As at December 31, 2012, management assessed 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, 2012, 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) which 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, 2012, 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

	2012				2011			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream								
Daily production, before royalties								
Light crude oil & NGL *(mbbls/day)*	86.1	55.4	56.8	91.2	91.7	83.3	84.5	91.0
Medium crude oil *(mbbls/day)*	23.2	23.9	24.1	24.9	24.3	24.6	24.6	24.6
Heavy crude oil *(mbbls/day)*	76.0	77.1	78.1	76.2	75.8	75.1	73.6	73.4
Bitumen *(mbbls/day)*	46.7	37.8	29.6	29.6	27.4	23.6	23.6	24.2
Total crude oil production (mboe/day)	232.0	194.2	188.6	221.9	219.2	206.6	206.3	213.2
Natural gas *(mmcf/day)*	523.7	544.9	559.5	588.3	597.9	614.7	631.8	583.3
Total production *(mboe/day)*	319.3	285.0	281.9	319.9	318.9	309.1	311.6	310.4
Average sales prices								
Light crude oil & NGL *($/bbl)*	94.91	90.5	94.71	111.53	106.61	101.16	108.26	100.21
Medium crude oil *($/bbl)*	67.55	69.59	69.92	78.63	85.83	70.81	81.24	68.41
Heavy crude oil *($/bbl)*	57.9	60.58	60.42	68.93	76.37	62.35	72.51	61.02
Bitumen *($/bbl)*	55.74	60.1	58.09	65.83	74.19	59.60	69.76	58.11
Natural gas *($/mcf)*	3.25	2.48	2.05	2.64	3.53	4.12	4.02	3.87
Operating costs *($/boe)*	15.05	16.69	15.83	14.56	14.17	14.62	13.83	13.40
Operating netbacks[(1)]								
Lloydminster – Thermal Oil *($/boe)*[(2)]	45.47	48.42	43.42	50.25	49.90	39.20	45.61	33.34
Lloydminster – Non-Thermal Oil *($/boe)*[(2)]	30.09	33.35	37.07	47.94	47.47	35.75	43.70	35.33
Oil Sands – Bitumen *($/boe)*[(2)]	19.49	33.91	30.05	35.88	38.45	27.43	38.66	24.32
Western Canada – Crude Oil *($/boe)*[(2)]	38.31	37.12	38.52	43.67	48.12	35.40	45.67	36.81
Western Canada – Natural gas *($/mcf)*[(3)]	1.49	1.16	1.11	1.52	2.03	2.51	2.62	2.56
Atlantic – Light Oil *($/boe)*[(2)]	85.05	66.97	70.99	94.34	82.26	82.03	86.00	80.15
Asia Pacific – Light Oil & NGL *($/boe)*[(2)]	69.28	72.97	73.54	88.16	70.04	67.07	67.30	73.42
Total *($/boe)*[(2)]	35.99	30.08	30.43	43.00	42.65	37.22	42.16	38.04
Net wells drilled[(4)]								
Exploration Oil	8	1	3	18	19	8	4	9
Gas	–	2	–	10	11	3	1	9
Dry	–	–	–	–	–	–	–	3
	8	3	3	28	30	11	5	21
Development Oil	217	245	56	197	196	286	93	190
Gas	6	1	2	8	4	8	3	27
Dry	3	–	–	1	1	2	1	–
	226	246	58	206	201	296	97	217
	234	249	61	234	231	307	102	238
Success ratio *(percent)*	99	100	100	100	100	99	99	99
Upgrader								
Synthetic crude oil sales *(mbbls/day)*	63.4	64.1	53.1	61.1	58.2	60.7	61.0	41.0
Upgrading differential *($/bbl)*	24.27	22.04	22.64	20.38	22.32	29.87	33.09	24.00
Canadian Refined Products								
Refined products sales volumes								
Light oil products *(million litres/day)*	9.6	9.9	8.4	9.1	9.4	9.9	8.3	8.4
Asphalt products *(mbbls/day)*	24.1	34	26.2	20.4	20.1	36.4	20.2	19.9
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	28.3	28.7	29.1	27.2	29.0	28.5	26.2	28.9
Prince George refinery *(mbbls/day)*	11.4	11.3	10.4	11.1	11.1	7.9	9.1	11.0
Refinery utilization *(percent)*	97	97	96	93	97	88	85	96
U.S. Refining and Marketing								
Refinery throughput								
Lima refinery (mbbls/day)	155.9	153.9	150.7	139.4	142.9	136.8	148.6	148.9
BP-Husky Toledo refinery (mbbls/day)	58.1	52.7	64.9	67.3	64.4	60.8	62.6	67.9

(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)	2012 Q4	2012 Q3	2012 Q2	2012 Q1	2011 Q4	2011 Q3	2011 Q2	2011 Q1
Upstream								
Exploration								
Western Canada	79	43	29	87	87	19	5	122
Asia Pacific	(28)	17	–	–	37	79	–	–
Atlantic Region	5	35	6	–	–	2	–	–
	56	95	35	87	124	100	5	122
Development								
Western Canada	662	497	293	577	653	472	254	404
Oil Sands	220	152	132	154	81	69	82	35
Asia Pacific	91	175	203	134	226	150	175	47
Atlantic Region	213	150	101	58	61	62	73	62
	1,186	974	729	923	1,021	753	584	548
Acquisitions								
Western Canada	–	16	–	5	14	0	18	842
Total Exploration and Production	1,242	1,085	764	1,015	1,159	853	607	1,512
Infrastructure and Marketing	19	14	11	10	14	13	10	6
Total Upstream	1,261	1,099	775	1,025	1,173	866	617	1,518
Downstream								
Upgrader	17	13	9	8	20	19	6	10
Canadian Refined Products	33	32	19	13	33	28	18	15
U.S. Refining and Marketing	113	92	65	43	72	68	62	22
	163	137	93	64	125	115	86	47
Corporate	49	16	14	5	34	22	12	3
	1,473	1,252	882	1,094	1,332	1,003	715	1,568

[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			
2012 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	1,764	1,430	1,382	1,971	796	377	633	614	562	576	472	581
Royalties	(189)	(145)	(140)	(219)	–	–	–		–	–	–	–
Marketing and other	–	–	–	–	76	120	120	71	–	–	–	–
Revenues, net of royalties	1,575	1,285	1,242	1,752	872	497	753	685	562	576	472	581
Expenses												
Purchases of crude oil and products[2]	20	15	13	25	741	335	591	591	417	423	339	447
Production and operating expenses	508	446	431	455	7	16	14	12	40	33	47	40
Selling, general and administrative expenses	21	55	66	36	6	5	6	4	1	–	1	1
Depletion, depreciation, amortization and impairment	614	515	463	529	6	5	6	5	27	25	25	25
Exploration and evaluation expenses	163	59	53	75	–	–	–	–	–	–	–	–
Other – net	(72)	28	(60)	(1)	–	–	1	(1)	(17)	–	–	–
Earnings from operating activities	321	167	276	633	112	136	135	74	94	95	60	68
Net foreign exchange gains (losses)	–	–	–	–	–	–	–	–	–	–	–	–
Finance income	–	5	–	–	–	–	–	–	–	–	–	–
Finance expenses	(19)	(21)	(19)	(19)	–	–	–	–	(2)	(3)	(3)	(3)
	(19)	(16)	(19)	(19)	–	–	–	–	(2)	(3)	(3)	(3)
Earnings (loss) before income taxes	302	151	257	614	112	136	135	74	92	92	57	65
Provisions for (recovery of) income taxes												
Current	16	(44)	(47)	209	50	54	62	5	(1)	24	(11)	19
Deferred	62	85	114	(50)	(22)	(19)	(27)	13	25	–	26	(2)
	78	41	67	159	28	35	35	18	24	24	15	17
Net earnings (loss)	224	110	190	455	84	101	100	56	68	68	42	48
Capital expenditures[3]	1,242	1,085	764	1,015	19	14	11	10	17	13	9	8
Total assets	22,753	21,175	20,819	20,548	1,506	1,400	1,143	1,434	1,242	1,271	1,295	1,252

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

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

(3) *Certain hydrogen feedstock costs from production and operating expenses have been reclassified to purchases of crude oil and products in 2012. Prior periods have been reclassified to conform with current period presentation.*

Downstream (continued)								Corporate and Eliminations[1]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
933	1,067	968	880	2,412	2,477	2,657	2,492	(598)	(596)	(484)	(625)	5,869	5,331	5,628	5,913
–	–	–	–	–	–	–	–	–	–	–	–	(189)	(145)	(140)	(219)
–	–	–	–	–	–	–	–	–	–	–	–	76	120	120	71
933	1,067	968	880	2,412	2,477	2,657	2,492	(598)	(596)	(484)	(625)	5,756	5,306	5,608	5,765
794	849	802	763	2,102	2,021	2,368	2,233	(598)	(596)	(484)	(625)	3,476	3,047	3,629	3,434
49	45	50	40	102	91	100	92	(1)	1	1	3	705	632	643	642
15	14	15	14	3	4	3	3	63	34	40	41	109	112	131	99
21	21	21	20	57	52	52	51	13	11	9	7	738	629	576	637
–	–	–	–	–	–	–	–	–	–	–	–	163	59	53	75
–	(2)	–	–	4	–	–	–	(19)	4	7	5	(104)	30	(52)	3
54	140	80	43	144	309	134	113	(56)	(50)	(57)	(56)	669	797	628	875
–	–	–	–	–	–	–	–	(1)	16	–	(1)	(1)	16	–	(1)
–	–	–	–	–	–	–	–	21	17	23	27	21	22	23	27
(1)	(2)	(2)	(1)	(1)	(1)	(2)	(1)	(22)	(28)	(43)	(47)	(45)	(55)	(69)	(71)
(1)	(2)	(2)	(1)	(1)	(1)	(2)	(1)	(2)	5	(20)	(21)	(25)	(17)	(46)	(45)
53	138	78	42	143	308	132	112	(58)	(45)	(77)	(77)	644	780	582	830
16	32	23	18	(49)	48	–	–	29	35	16	32	61	149	43	283
(2)	3	(3)	(7)	104	65	48	41	(58)	(29)	(50)	(39)	109	105	108	(44)
14	35	20	11	55	113	48	41	(29)	6	(34)	(7)	170	254	151	239
39	103	58	31	88	195	84	71	(29)	(51)	(43)	(70)	474	526	431	591
33	32	19	13	113	92	65	43	49	16	14	5	1,473	1,252	882	1,094
1,646	1,658	1,656	1,625	5,326	5,160	5,260	5,334	2,667	2,802	2,669	3,093	35,140	33,466	32,842	33,286

2011 *($ millions)*	Upstream: Exploration and Production Q4	Q3	Q2	Q1	Upstream: Infrastructure and Marketing Q4	Q3	Q2	Q1	Downstream: Upgrading Q4	Q3	Q2	Q1
Gross revenues[(2)]	2,051	1,797	1,920	1,751	619	537	336	495	615	586	648	368
Royalties	(331)	(247)	(289)	(258)	–	–	–	–	–	–	–	–
Marketing and other	–	–	–	–	32	21	2	35	–	–	–	–
Revenues, net of royalties	1,720	1,550	1,631	1,493	651	558	338	530	615	586	648	368
Expenses												
Purchases of crude oil and products[(2)]	60	11	(12)	40	579	506	285	448	462	400	474	269
Production and operating expenses	477	429	408	400	3	2	21	17	29	36	46	58
Selling, general and administrative expenses	25	34	51	43	4	4	5	4	7	(1)	(3)	–
Depletion, depreciation, amortization and impairment	601	498	483	436	5	7	6	6	25	26	88	25
Exploration and evaluation expenses	194	95	88	93	–	–	–	–	–	–	–	–
Other – net	2	(1)	(73)	(189)	1	–	–	–	24	18	15	10
Earnings from operating activities	361	484	686	670	59	39	21	55	68	107	28	6
Net foreign exchange gains (losses)	–	–	–	–	–	–	–	–	–	–	–	–
Finance income	1	1	1	1	–	–	–	–	–	–	–	–
Finance expenses	(19)	(16)	(18)	(15)	–	–	–	–	(2)	(2)	(1)	(2)
	(18)	(15)	(17)	(14)	–	–	–	–	(2)	(2)	(1)	(2)
Earnings (loss) before income taxes	343	469	669	656	59	39	21	55	66	105	27	4
Provisions for (recovery of) income taxes												
Current	(25)	9	32	25	18	22	13	11	2	(2)	(3)	1
Deferred	115	96	150	154	(3)	(13)	(7)	3	15	29	10	–
	90	105	182	179	15	9	6	14	17	27	7	1
Net earnings (loss)	253	364	487	477	44	30	15	41	49	78	20	3
Capital expenditures[(3)]	1,159	853	607	1,512	14	13	10	6	20	19	6	10
Total assets	20,141	19,669	18,916	18,708	1,509	1,206	1,353	1,628	1,316	1,266	1,302	1,335

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

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

[(3)] *Certain hydrogen feedstock costs from production and operating expenses have been reclassified to purchases of crude oil and products in 2012. Prior periods have been reclassified to conform with current period presentation.*

Downstream (continued)								Corporate and Eliminations[1]				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
928	1,177	945	827	2,381	2,527	2,600	2,244	(738)	(566)	(408)	(648)	5,856	6,058	6,041	5,037
–	–	–	–	–	–	–	–	–	–	–	–	(331)	(247)	(289)	(258)
–	–	–	–	–	–	–	–	–	–	–	–	32	21	2	35
928	1,177	945	827	2,381	2,527	2,600	2,244	(738)	(566)	(408)	(648)	5,557	5,832	5,754	4,814
786	974	798	707	2,097	2,239	2,202	1,915	(738)	(566)	(408)	(648)	3,246	3,564	3,339	2,731
44	47	49	42	101	108	90	92	–	–	–	–	654	622	614	609
13	11	12	13	4	2	3	3	55	46	70	23	108	96	138	86
20	23	19	18	52	48	45	50	13	9	9	7	716	611	650	542
–	–	–	–	–	–	–	–	–	–	–	–	194	95	88	93
–	–	–	–	–	–	–	–	(5)	6	1	(2)	22	23	(57)	(181)
65	122	67	47	127	130	260	184	(63)	(61)	(80)	(28)	617	821	982	934
–	–	–	–	–	–	–	–	(15)	6	17	2	(15)	6	17	2
–	–	–	–	–	–	–	–	25	20	17	20	26	21	18	21
(2)	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(47)	(50)	(62)	(66)	(71)	(70)	(84)	(85)
(2)	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(37)	(24)	(28)	(44)	(60)	(43)	(49)	(62)
63	121	65	46	126	129	259	183	(100)	(85)	(108)	(72)	557	778	933	872
14	3	4	4	21	55	–	–	123	(28)	26	29	153	59	72	70
2	28	12	8	25	(8)	94	67	(158)	66	(67)	(56)	(4)	198	192	176
16	31	16	12	46	47	94	67	(35)	38	(41)	(27)	149	257	264	246
47	90	49	34	80	82	165	116	(65)	(123)	(67)	(45)	408	521	669	626
33	28	18	15	72	68	62	22	34	22	12	3	1,332	1,003	715	1,568
1,632	1,630	1,625	1,581	5,476	5,459	5,043	5,034	2,352	2,456	1,852	507	32,426	31,686	30,091	28,793