Husky Energy Inc.

Management's Discussion and Analysis

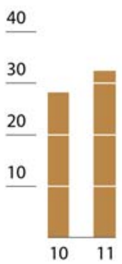
For the Year Ended December 31, 2011
March 8, 2012

MANAGEMENT'S DISCUSSION AND ANALYSIS

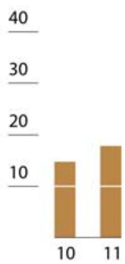
1.0 Financial Summary

1.1 Financial Position

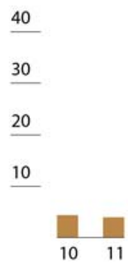
Total Assets
($ billions)



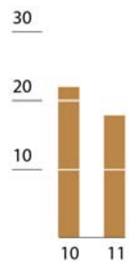
Total Equity
($ billions)



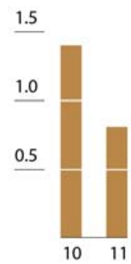
Total Long-term Debt
($ billions)



Debt to Capital Employed[1]
(%)

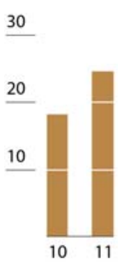


Debt to Cash Flow[1]
(times)

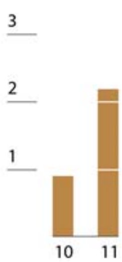


1.2 Financial Performance

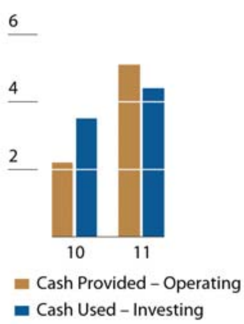
Gross Revenues
($ billions)



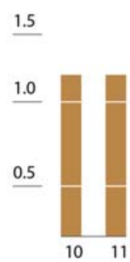
Net Earnings
($ billions)



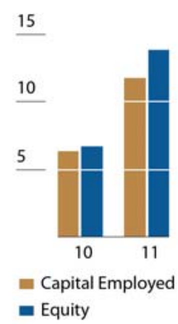
Cash Flow
($ billions)



Dividends
($ per share)



Return[1]
(%)

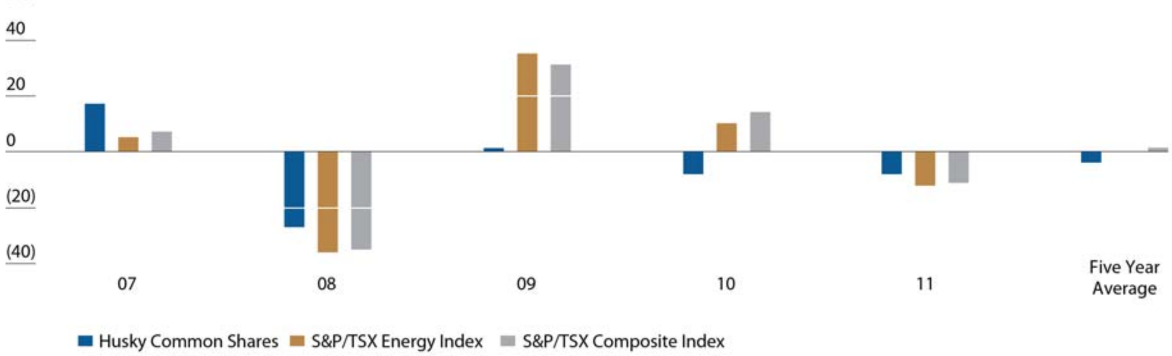


[1] *Debt to capital employed, debt to cash flow, return on equity and return on capital employed constitute non-GAAP measures. (Refer to Section 11.3)*

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)	**2011**	2010	2009[1]
Gross revenues[2]	**24,489**	18,085	15,935
Net earnings by sector			
Upstream	**1,502**	861	1,113
Midstream	**246**	160	200
Downstream	**813**	160	319
Corporate	**(286)**	(187)	(172)
Eliminations	**(51)**	(47)	(44)
Net earnings	**2,224**	947	1,416
Net earnings per share – basic	**2.40**	1.11	1.67
Net earnings per share – diluted	**2.34**	1.05	1.67
Ordinary dividends per common share	**1.20**	1.20	1.20
Cash flow from operations[3]	**5,198**	3,072	2,507
Total assets	**32,426**	28,050	26,295
Other long-term financial liabilities	**–**	102	96
Long-term debt including current portion	**3,911**	4,187	3,229
Cash and cash equivalents	**1,841**	252	392
Return on equity *(percent)*[3][4]	**13.8**	6.7	9.8
Return on average capital employed *(percent)*[3][5]	**11.8**	6.4	9.1

[1] *Results are reported in accordance with previous Canadian GAAP. The results for 2009 are not incorporated into Sections 1.1 and 1.2 as IFRS comparative information is not available.*
[2] *In 2011, the Company changed its treatment of certain intersegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for 2010. The recasting reduced each of gross revenues and purchases of crude oil and products by $217 million and did not impact net earnings.*
[3] *Cash flow from operations and financial ratios constitute non-GAAP measures. (Refer to Section 11.3)*
[4] *Return on equity equals net earnings divided by the two-year average shareholder's equity.*
[5] *Return on average 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.*

2.0 Husky Business Overview

Husky Energy Inc. ("Husky" or the "Company") is an international integrated energy company headquartered in Calgary, Alberta, and is publicly traded on the TSX under the symbols HSE and HSE.PR.A. The Company operates worldwide in the Upstream, Midstream and Downstream business segments. Husky uses a combination of technological innovation, prudent investment, sound project management and responsible resource development to deliver consistent shareholder returns.

- In the Upstream segment, the Company explores for, develops and produces crude oil, bitumen, natural gas and natural gas liquids.
- In the Midstream segment, the Company markets and operates storage facilities for crude oil and natural gas and processes and transports heavy crude oil through pipelines (infrastructure and marketing).
- In the Downstream segment, the Company upgrades heavy crude oil feedstock into synthetic oil (upgrading), distributes motor fuel and ancillary and convenience products, manufactures and markets asphalt products, produces ethanol and operates two regional refineries in Canada (Canadian refined products), refines crude oil through interests in two refineries in Ohio and markets refined products in the U.S. Midwest (U.S. refining and marketing).

In 2012, the Company commenced evaluating and reporting activities of the Midstream reporting segment as a service provider to the Upstream and Downstream operations. As a result, the Company will reclassify and report its Midstream activities into the Upstream and Downstream reportable business segments commencing the first quarter of 2012 (Refer to Note 25 to the Consolidated Financial Statements).

3.0 The 2011 Business Environment

3.1 Business Risk Factors

Husky's results of operations are significantly influenced by the global and domestic business environment. Some risk factors are entirely beyond the Company's control and others, to some extent, can be strategically managed. Husky has implemented risk management processes that are intended to manage these risks. Salient factors include:

Financial and Economic Risks

An adverse change in any of the following conditions could affect the Company's ability to realize the value and quantity of its oil and natural gas reserves, achieve expected cash flow and financial performance, optimize project economics and sanction capital projects, and could negatively impact the Company's results of operations, liquidity and financial condition:

- the demand for the Company's products and the prices the Company receives for crude oil, bitumen and natural gas production and refined petroleum products;
- the economic conditions of the markets in which Husky conducts business;
- the exchange rate between the Canadian and U.S. dollar;
- the cost and availability of capital, including access to capital markets at acceptable rates; and
- other financial risks as described in Section 8.6.

Operational Risks

An adverse change in any of the following conditions could affect the Company's ability to gain access to the resources required to increase oil and natural gas reserves and production, retain adequate markets for its products and services and complete development projects:

- the ability to replace reserves of oil and gas, whether sourced from exploration, improved recovery or acquisitions;
- the availability of prospective drilling rights;
- the costs to acquire exploration rights and undertake geological studies, appraisal drilling and project development;
- the availability and cost of labour, material and equipment to efficiently, effectively and safely undertake capital projects;
- the ability and costs to operate properties, plants and equipment in an efficient, reliable and safe manner;
- access to supporting infrastructure and crude oil feedstock;
- prevailing climatic conditions in the Company's operating locations;
- the competitive actions of other companies, including increased competition from other oil and gas companies;
- the ability to access different geographic markets for products;
- business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events affecting the Company or other parties whose operations or assets directly or indirectly affect the Company;
- the inability to reach the Company's estimated production levels from existing and future oil and gas development projects as a result of technological or commercial difficulties; and
- changes in workforce demographics.

Legislative Risks

An adverse change in any of the following conditions could affect the Company's ability to access markets, utilize its financial resources in an efficient manner and undertake exploration, development and construction projects and could impact the Company's interests in its foreign operations and future profitability:

- potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations;
- changes to taxes and royalty regimes;
- regulations intended to deal with climate change issues;
- changes to government fiscal, monetary and other financial policies; and
- the ability to obtain regulatory approvals to operate existing properties or develop significant growth projects.

3.2 Economic Sensitivities

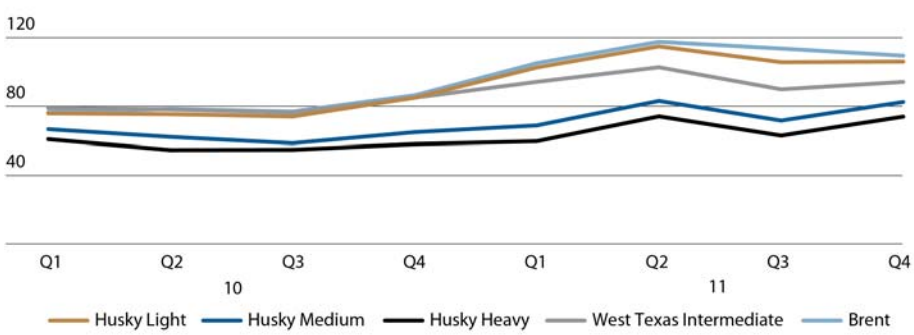
Average Benchmarks		2011	2010
WTI crude oil	*(U.S. $/bbl)*	**95.12**	79.46
Brent crude oil	*(U.S. $/bbl)*	**111.27**	79.42
Canadian light crude 0.3% sulphur	*($/bbl)*	**95.32**	77.75
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**67.61**	59.87
NYMEX natural gas	*(U.S. $/mmbtu)*	**4.04**	4.39
NIT natural gas	*($/GJ)*	**3.48**	3.91
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**17.44**	14.48
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**25.26**	9.64
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**24.65**	9.20
U.S./Canadian dollar exchange rate	*(U.S. $)*	**1.011**	0.971
Canadian Equivalents			
WTI crude oil	*($/bbl)*	**94.09**	81.83
Brent crude oil	*($/bbl)*	**110.06**	81.79
WTI/Lloyd crude blend differential	*($/bbl)*	**17.25**	14.91
NYMEX natural gas	*($/mmbtu)*	**4.00**	4.52

As an integrated producer, Husky's profitability is largely determined by realized prices for crude oil and natural gas 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 global factors and is beyond the Company's control. The price for natural gas is determined more by the North America 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 dramatic effect on short-term supply and demand.

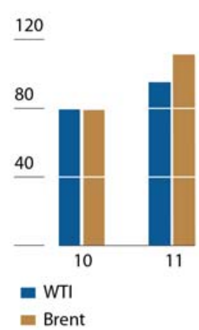
The Downstream segment is heavily impacted by the price of crude oil and natural gas. The largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil. In the upgrading business segment, heavy crude oil feedstock is processed into light synthetic crude oil. 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, Ohio Refinery and approximately 50% heavy crude oil feedstock at the Toledo, Ohio 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
(US $/bbl)



Average WTI and Brent
(US $/bbl)

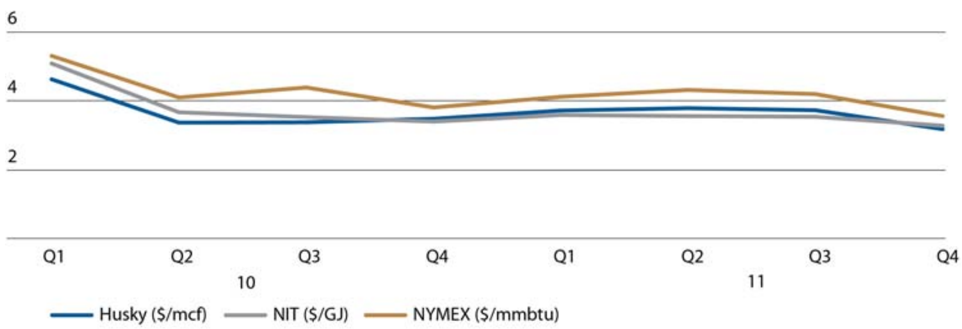


The price Husky receives for production from Western Canada is primarily driven by changes in the price of West Texas Intermediate ("WTI") while the majority of the Company's production in the Atlantic Region and the Asia Pacific Region is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2011 at U.S. $98.83/bbl compared to U.S. $91.38/bbl on December 31, 2010, and averaged U.S. $95.12/bbl in 2011 compared with U.S. $79.46/bbl in 2010. The price of Brent ended 2011 at U.S. $106.51/bbl, compared to U.S. $92.55/bbl on December 31, 2010, and averaged U.S. $111.27/bbl in 2011 compared with U.S. $79.42/bbl in 2010.

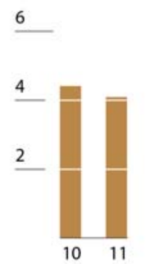
A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2011, 47% of Husky's crude oil production was heavy crude oil or bitumen compared with 48% in 2010. The light/heavy crude oil differential averaged U.S. $17.44/bbl or 18% of WTI in 2011 compared to U.S. $14.48/bbl or 18% of WTI in 2010.

Natural Gas

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices
(US $)



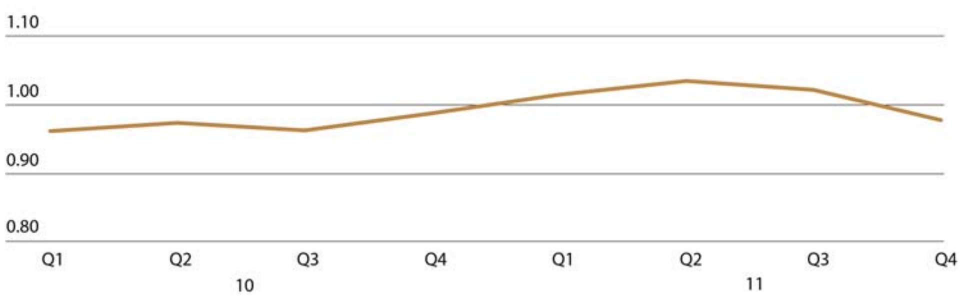
Average NYMEX
(US $/mmbtu)



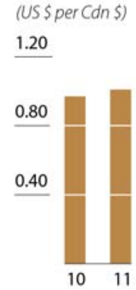
In 2011, 32% of Husky's total oil and gas production was natural gas compared with 29% in 2010. The near-month natural gas price quoted on the NYMEX ended 2011 at U.S. $2.99/mmbtu compared with U.S. $4.41/mmbtu at December 31, 2010. During 2011, the NYMEX near-month contract price of natural gas averaged U.S. $4.04/mmbtu compared with U.S. $4.39/mmbtu in 2010.

Foreign Exchange

Average US/Canadian Dollar Exchange Rate
(US $ per Cdn $)



Average US/Canadian Dollar Exchange Rate
(US $ per Cdn $)



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 of the 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 2010 at U.S. $1.005 and closed at U.S. $0.983 at December 31, 2011. In 2011, the Canadian dollar averaged U.S. $1.011 strengthening by 4% compared with U.S. $0.971 during 2010.

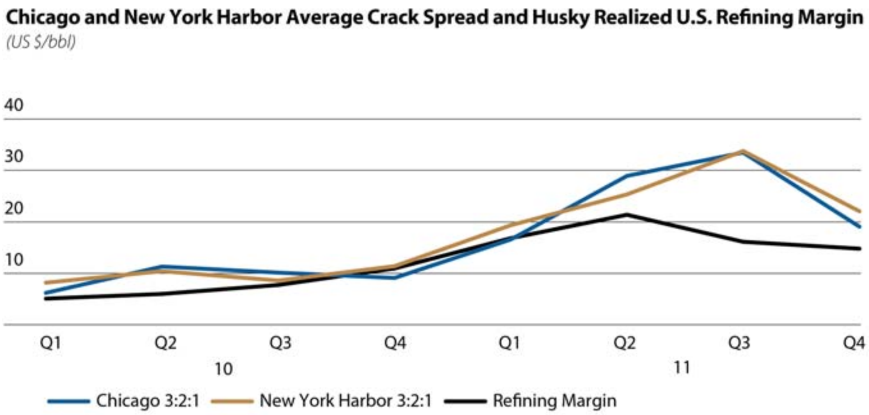
Increased U.S. crude oil prices were partially offset by the strengthening of the Canadian dollar against the U.S. dollar in 2011. The price of WTI in 2011 in U.S. dollars increased 20% compared with an increase of 15% in Canadian dollars when compared to 2010.

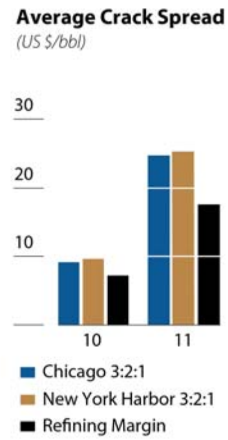
Refining Crack Spreads

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 2011, the New York Harbor 3:2:1 refining crack spread averaged U.S. $25.26/bbl compared with U.S. $9.64/bbl in 2010. During 2011, the Chicago 3:2:1 crack spread averaged U.S. $24.65/bbl compared with U.S. $9.20/bbl in 2010.

During 2011, the 3:2:1 crack spreads were higher than 2010 reflecting the change in WTI relative to Brent crude oil pricing.





Global Economic and Financial Environment

The EIA Short-Term Energy Outlook[1], published on February 7, 2012, provided the following insights to the near-term energy environment. World energy demand is expected to continue to increase in 2012 and 2013, mostly in countries outside of the Organization for Economic Cooperation and Development ("OECD"). World liquid fuels consumption grew by 0.8 mmbbls/day to reach 87.9 mmbbls/day in 2011 and is expected to reach 89.3 mmbbls/day in 2012 and 90.7 mmbbls/day in 2013. Modest growth in consumption in the United States and Japan is expected to be more than offset by lower consumption in Europe over the next two years. The Organization of Petroleum Exporting Countries ("OPEC") spare capacity is expected to rise from 2.2 mmbbls/day in December 2011 to 3.9 mmbbls/day by the end of 2013.

During 2011, natural gas production in Canada continued to decline while production in the United States increased by an estimated 4.8 bcf/day over the previous year. Ample natural gas supply and high storage levels have resulted in continued low prices. Although the natural gas rig count has declined, natural gas markets are expected to remain well supplied in the near-term as a backlog of shale natural gas wells near markets in the U.S. Gulf Coast, mid-continent and eastern states continue to be completed and tied-in. As a result, investment in Canadian natural gas exploration and development is expected to be focused on resource plays that utilize new technology and are in natural gas liquid prone areas[2]. Conventional natural gas exploration is expected to be focused on the traditionally less accessible areas along the eastern slope of the Rocky Mountains.

Notes:

[1] *"Short-Term Energy Outlook," February 7, 2012, Energy Information Administration U.S. Department of Energy.*

[2] *"Winter Energy Outlook 2011 – 2012 Adjusting to Economic Uncertainty", November 2011, National Energy Board.*

3.3 Sensitivities for 2011 Results

The following table is indicative of the relative annualized effect on pre-tax cash flow and net earnings from changes in certain key variables in 2011. The table below shows what the effect would have been on 2011 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2011. 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	2011 Average	Increase	Effect on Pre-tax Cash Flow[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	$ 95.12	*U.S. $1.00/bbl*	66	0.07	49	0.05
NYMEX benchmark natural gas price[5]	$ 4.04	*U.S. $0.20/mmbtu*	28	0.03	20	0.02
WTI/Lloyd crude blend differential[6]	$ 17.44	*U.S. $1.00/bbl*	(9)	(0.01)	(7)	(0.01)
Canadian light oil margins	$ 0.043	*Cdn $0.005/litre*	16	0.02	12	0.01
Asphalt margins	$ 22.13	*Cdn $1.00/bbl*	9	0.01	7	0.01
New York Harbor 3:2:1 crack spread[7]	$ 25.26	*U.S. $1.00/bbl*	73	0.08	46	0.05
Exchange rate (U.S. $ per Cdn $)[3][8]	$ 1.011	*U.S. $0.01*	(48)	(0.05)	(36)	(0.04)
Interest rate		*100 basis points*	(7)	(0.01)	(5)	(0.01)

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 957.5 million common shares outstanding as of December 31, 2011.*
(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 Capability to Deliver Results

Husky's results are dependent on a number of factors including commodity prices, foreign exchange rates, interest rates, the Company's continued success in exploring for oil and natural gas, efficient and safe execution of capital projects and operations, effective marketing of crude oil and natural gas, retention of expertise, and continued access to the financial markets. Husky is engaged in several key projects within each operating segment to maximize the potential for achieving targets.

4.1 Upstream

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 exploitation 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 stabilize decline rates of light and heavy crude oil. Emerging EOR techniques are being field tested, while techniques that have been in practice for several decades continue to be optimized;
- A growing position in Western Canada gas resource plays with approximately 850,000 acres associated with both liquids-rich and dry gas positions;
- A growing oil resource play position with existing activities in the Viking, Bakken, Lower Shaunavon, and Cardium formations;
- Expertise and experience exploring and developing the high-impact natural gas potential in the Alberta Deep Basin, Foothills, and northwest plains of Alberta and British Columbia;
- Substantial position in the Alberta oil sands. The initial stages of the development of these assets include the Sunrise Energy Project that is in the development phase and the Tucker oil sands project that is currently on production. The Sunrise Energy Project is proceeding as a joint 50/50 partnership with BP and is an integral part of a North American oil sands business which includes the BP-Husky Toledo Refinery. Husky holds approximately 550,000 acres in 13 undeveloped oil sands leases;
- 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;
- Husky has a 40% interest in approximately 690,400 acres (2,800 square kilometers) of the Madura Strait block, located offshore East Java, south of Madura Island, Indonesia. Offshore Indonesia is focused on the development of the Madura BD, MDA and MBH natural gas and natural gas liquids fields; and
- Husky has a large portfolio of significant discovery and exploration licences offshore Newfoundland and Labrador and offshore Greenland (collectively referred to as the "Atlantic Region"). Husky's offshore East Coast exploration and development program is

focused in the Jeanne d'Arc Basin on the Grand Banks, which contains the Hibernia, Terra Nova, White Rose and North Amethyst oil fields. Husky holds ownership interests in the Terra Nova, White Rose and North Amethyst oil fields as well as in a number of smaller undeveloped fields in the central part of the basin. Husky also holds significant exploration acreage in the area.

4.2 Midstream

Highlights of the Midstream segment include:

- Integrated heavy oil pipeline systems in the Lloydminster producing region;
- Natural gas storage in excess of 45 bcf, owned and leased;
- Petroleum marketer balancing the needs of both customers and suppliers; and
- Supplier of crude oil, natural gas, petroleum coke, sulphur and electrical power for the Company's plants and facilities.

4.3 Downstream

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 549 retail marketing locations as at December 31, 2011 including bulk plants and travel centres with strategic land positions in Western Canada and Ontario. Retail outlets include, in many cases, convenience stores, restaurants, service bays and car washes.

5.0 Strategic Plan

Husky's strategy is to maintain production in its foundation of Western Canada and Heavy Oil and reposition these areas to resource play and thermal development, while advancing its three major growth pillars in the Asia Pacific Region, the Atlantic Region and the Oil Sands. The Company is not integrated on a barrel-for-barrel basis and seeks to operate and maintain Midstream and Downstream assets which provide specialized support and value to its Upstream heavy oil and bitumen assets. The Company's strategy is to maximize the efficiency of its Midstream and Downstream operations and extract the greatest value from production.

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

5.1 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 on resource play and thermal development by growing oil resource plays, directing capital into liquids-rich gas plays and increasing horizontal drilling for heavy oil production. Approximately two-thirds of Upstream production is oil-weighted with the objective of maintaining this weighting. Husky is advancing its oil resource play position with activities in the Muskwa, Canol, Viking, Bakken, Lower Shaunavon and Cardium formations, with approximately 800,000 net acres of oil resource play inventory. Husky also has a growing position in Western Canada gas resource plays, with approximately 850,000 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 commencing in 2011. The first phase, which represents a $2.5 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 BD, MDA and MBH field developments in 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 mid-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. Combined with the producing Wenchang oil field, further 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"), the Asia Pacific Region represents a growth area for Husky.

The Atlantic Region stretches from Greenland to the Sydney Basin, south of Newfoundland and Labrador. The Atlantic Region continues to be a focus area, with the Company holding 18 Exploration Licences and interests in eight Production Licences and 23 Significant Discovery Areas. Work is well underway to identify new and innovative ways to further develop the significant resources in the basin.

5.2 Midstream

Midstream is focused on supporting Upstream production and making prudent reinvestments. The Company's spending will be focused on maintenance and optimization of existing infrastructure.

5.3 Downstream

Downstream is focused on supporting heavy oil and oil sands production and making prudent reinvestments. Husky plans to continue to pursue projects to optimize, integrate and reconfigure the Lima, Ohio Refinery for additional crude oil feedstock flexibility and reconfigure and increase capacity at the BP-Husky Toledo, Ohio Refinery to accommodate Sunrise production as its primary feedstock. The Company also plans to expand terminalling and product storage opportunities.

5.4 Financial

Husky is committed to ensuring adequate liquidity and financial flexibility to fund the Company's growth and support dividend payments. Over the business cycle, the Company's objective is to maintain a debt to cash flow ratio of 1.5 to 2.5 times and a debt to capital employed target of 25% to 35%.

The Company also aims to retain investment grade credit ratings by continuing to focus on financial discipline around costs and the efficiency of Husky's operations and, at the same time, emphasizing the Company's focus on its return on capital.

6.0 Key Growth Highlights

The 2011 capital program was established with focus on projects offering the highest potential for returns and mid to long-term growth. Husky's 2011 capital program was built on the momentum achieved in 2010 with respect to accelerating near-term production growth as well as continuing to advance its three major growth pillars in the Asia Pacific Region, the Atlantic Region and the Oil Sands.

6.1 Upstream

Western Canada (excluding Heavy Oil and Oil Sands)

Gas Resource Plays
The liquids-rich formations at Ansell in west central Alberta continues to be a key area of focus. During 2011, Husky drilled 34 Cardium formation wells and seven multi-zone wells, and commenced a Cardium horizontal well at Ansell. Completion operations continued and offload capacity expansion construction progressed during 2011.

The evaluation of the Duvernay liquids-rich gas play in Kaybob continued in 2011 with the drilling, coring and logging of two vertical wells. A program of horizontal wells to establish the productive capacity of this zone commenced in late 2011 with the first well rig released and the second being drilled at year end. Completion of these horizontal wells is expected to occur in 2012.

In 2011, three wells in the multi-zone program were drilled at Kakwa and placed on production.

Oil Resource Plays

In the Viking oil resource project, 16 wells were drilled in the Dodsland/Elrose area of southwest Saskatchewan. The horizontal program conducted in Redwater, Alberta resulted in 22 gross Viking horizontal wells drilled. Approximately 50 wells are planned for the Redwater and Saskatchewan Viking projects in 2012.

During 2011, Husky was successful in acquiring approximately 11,500 acres of high potential Bakken Formation acreage adjacent to its Oungre Oil Resource Project lands in south central Saskatchewan. Husky holds a total of approximately 18,700 net acres in this play. Husky drilled a total of 12 wells in 2011 and acquired additional three-dimensional ("3-D") seismic in 2011 in order to obtain full coverage over all landholdings at Oungre.

Husky drilled five gross wells in the lower Shaunavon zone in early 2011 with four wells currently producing and one well abandoned due to surface casing issues. Five additional wells are planned in the Shaunavon resource play for 2012.

Husky drilled three vertical pilot wells and two horizontal wells at the Rainbow Muskwa project during 2011. It is anticipated that these wells will provide information for resource and reservoir characterization across the Rainbow area. One of the horizontal wells was completed in late 2011 and is undergoing post fracture clean up. Husky holds a significant acreage position in this emerging oil resource play which compliments its wholly owned infrastructure at Rainbow Lake.

Husky currently holds approximately 29,000 net acres in the Northern Cardium oil resource trend at Wapiti and Kakwa. In 2011, four horizontal wells were drilled with two wells completed at Wapiti. During the year, a four-well pilot program was drilled at Kakwa. Completion operations are planned throughout 2012 with two wells already completed in early 2012.

In mid-2011, Husky was granted the rights to two exploration blocks in the Mackenzie Valley area of the Northwest Territories covering approximately 437,000 acres for a work commitment bid of $188 million per license. The rights have a primary term of five years with a term extension to nine years when a well is drilled. The project received regulatory approvals for the construction and drilling operations of two vertical pilot wells and a 220 square kilometer 3-D seismic program. Husky drilled one vertical pilot well to total depth in early 2012 with the second vertical well planned for late 2012.

Heavy Oil

In 2011, construction of the 8,000 bbls/day Pikes Peak South thermal project progressed according to plan with production expected to commence in mid-2012. Husky also continued construction of its 3,000 bbls/day Paradise Hill development. The project is on schedule and is anticipated to become operational by late 2012. In addition, the Rush Lake single well pair thermal pilot achieved first oil in October 2011.

Husky advanced its horizontal drilling program in 2011 with the completion of an expanded 130 well program. Based on the positive performance of the past horizontal drilling programs, Husky is expanding the drilling program to approximately 140 to 150 wells in 2012. Husky also drilled 332 gross cold heavy oil production with sand ("CHOPS") wells during 2011. In addition, Husky is operating four solvent EOR pilots, two of which became operational in 2011. A CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant is under construction and is expected to be commissioned in early 2012. The liquefied CO_2 from this facility will be used in the ongoing solvent EOR piloting program.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages. To date, Husky has drilled more than half of the planned 49 SAGD horizontal well pairs for Phase I and is on track for the full drilling program to be completed by the second half of 2012, with first production anticipated in 2014.

Detailed engineering activities for the facilities and supporting infrastructure continued in 2011. The field facilities engineering contractor has mobilized on site to begin construction on the first well pad. The Central Processing Facility contractor has also mobilized on site and commenced foundation installation for facilities. The first major equipment delivery was completed in January 2012. Major construction of the camp building is also underway and is expected to be available for use in early 2012.

A contract for the Design Basis Memorandum and front end engineering design ("FEED") of the next development stage of the Sunrise Energy Project was awarded in October 2011 with FEED expected to be completed in 2013.

Tucker Oil Sands Project

Based on a greater understanding of the Tucker reservoir, Husky has addressed production challenges by remediating mature wells with new stimulation techniques, drilling new wells, and initiating new start up procedures.

Husky completed its 16 well pair A Pad development in 2011. Production was phased in during the year with all 16 wells on production by year end. One well pair was drilled in the Grand Rapids pilot with production expected in early 2012. Several applications to the Energy Resources Conservation Board have been approved or are proceeding for additional drilling and field development through to 2015. Daily production rates reached 10,000 boe/day in December 2011 and have been sustained at 10,000 boe/day for the first two months of 2012.

McMullen

Husky's development of the McMullen property, which is located in the west central region of the Athabasca oil sands of northern Alberta, involves a cold production development project and an air injection pilot project. Alberta Environment approval for the McMullen air injection pilot was achieved in early 2011 and was the final regulatory approval required for the project. In 2011, six observation wells and one horizontal production well were drilled as per plan. Facility construction commenced in May 2011 and was completed on schedule in August 2011. Steam injection was successfully initiated at the end of September, with first air injection initiated in December 2011. During 2011, 83 slant development wells were drilled with a total of 41 slant development wells equipped and put on production in the cold production project. The remaining wells are expected to be equipped, completed and placed on production at the end of first quarter of 2012.

Saleski

In 2011, Husky acquired approximately 100 kilometers of two-dimensional ("2-D") seismic data as part of a continuing assessment program. In addition, survey work has been completed for the applications for 30 vertical stratigraphic wells and 144 kilometers of 2-D seismic data for the upcoming 2012 winter program.

Asia Pacific Region

Offshore China Exploration, Delineation and Development

Husky sanctioned the development of the principal fields of the Liwan Gas Project, Liwan 3-1 and Liuhua 34-2, following the finalization of the gas sales agreement for production for Liwan 3-1 and submission of the Overall Development Plan to the Chinese government authorities for regulatory approval. Production will supply the Guangdong Province. The price mechanism will be in line with the anticipated Guangdong market price which, as published by the Chinese government in December 2011, was a maximum current Guangdong gate station price of 2.74 RMB/m^3, which equates approximately to U.S. $12.20/mcf. In December 2011, the Original Gas In-Place report for the Liuhua 29-1 gas field was approved by the Chinese government. FEED for the development of this field is scheduled to commence in March 2012. Regulatory approvals in relation to environmental matters and civil construction were received for the Liwan Gas Project in late 2011.

The project is proceeding on schedule towards planned first gas delivery in late 2013/early 2014. The Liwan 3-1 and Liuhua 34-2 fields are expected to ramp up through 2014 with expected gross production rates above 300 mmcf/day. Development of the Liuhua 34-2 field is planned to proceed in parallel with and be tied into the development of the Liwan 3-1 field. The Liuhua 29-1 field is intended to be developed in an overlapping sequence to the development of the Liwan 3-1 and Liuhua 34-2 fields. The total project is expected to reach gross production of approximately 500 mmcf/day in the 2015 timeframe.

In the first half of 2011, Husky successfully completed the development well drilling program for the field. In addition, Husky successfully drilled two appraisal wells on the Liuhua 29-1 field. The wells encountered commercial quantities of gas and will be completed as production wells. The Company also drilled three exploration wells in the second half of 2011. One well encountered hydrocarbons and well results are being evaluated. Two wells encountered hydrocarbons in non-commercial quantities and were abandoned without testing. Husky completed an exploration well on Block 63/05 in the shallow water of the Qiongdongnan Basin located 50 kilometers south of Hainan Island. The exploration well was drilled to a total depth of 3,620 meters however, commercial hydrocarbons were not encountered and the well was plugged and abandoned. Husky has a 49% ownership interest in the net production after expenses, taxes and royalties of the Liwan Gas Project.

Indonesia Exploration and Development

Both Husky and CNOOC completed the sale of 10% equity stakes in Husky-CNOOC Madura Ltd. to Samudra Energy Ltd. through its affiliate SMS Development Ltd in January 2011. As a result of the sale, Husky and CNOOC each hold a 40% interest in Husky-CNOOC Madura Ltd. with the remaining 20% held by SMS Development Ltd. During 2011, CNOOC as the operator for the Madura Strait Block commenced the tendering of equipment and services for the Madura BD field development. Two exploration wells were drilled in 2011 which confirmed additional gas resources in the MDA and MBH fields. A Plan of Development is expected to be filed in 2012 with first gas production from the Madura Straits Block expected in 2014.

Husky currently holds a 100% working interest in the North Sumbawa II Exploration Block, comprised of 5,000 square kilometers in the East Java Sea, where interpretation of 1,020 kilometers of new 2-D seismic data is under review.

Atlantic Region

White Rose Extension Projects

Development continued at the North Amethyst satellite extension in 2011. At the end of 2011, the North Amethyst field had three production and three water injection wells on stream with one production well brought on stream in June 2011. While further wells are expected to be drilled to sustain production, the field has now fully met its target production rate of 37,000 bbls/day. During 2011, Husky filed an application to amend the development plan for North Amethyst to include the Hibernia reservoir. In 2012, Husky plans to continue development drilling at North Amethyst and to drill an infill well at the main White Rose field to facilitate incremental oil recovery.

First production from a two-well pilot project at the West White Rose field was achieved in September 2011 with completion of a production well. A supporting water injection well was drilled to total depth during the fourth quarter and is expected to be completed in 2012. The pilot program will assist in refining the development plan for the full West White Rose resource.

The Company continues to evaluate the feasibility of a concrete wellhead and drilling platform for development of future resources in the White Rose region including the full development of West White Rose. Pre-FEED and FEED contracts to support this work are expected to be awarded at the end of the first quarter of 2012.

Atlantic Region Exploration

Husky participated in a non-operated Mizzen well which was completed in September 2011. Husky holds a 35% working interest in the field which is located in the Flemish Pass Basin.

Husky commenced drilling of an exploration well in late 2011 to test the non-operated Fiddlehead prospect located south of the Terra Nova field. Husky holds a 50% working interest in the well.

Husky plans to participate in two to three exploratory wells in the Atlantic Region in 2012.

Offshore Greenland

Husky has a significant position in three blocks off the west coast of Greenland. Geological and geophysical work continues in order to define potential well locations.

6.2 Midstream

Husky's project to construct a 300,000 barrel tank at the Hardisty terminal is on target to be in service in mid-2012. The tank will facilitate moving volumes to U.S. Petroleum Administration for Defense Districts ("PADD") II and PADD III markets.

6.3 Downstream

Lima, Ohio Refinery

The refinery continues to implement short term reliability and profitability improvement projects. Ordering of equipment and site construction has commenced on a 20 mbbls/day kerosene hydrotreater which is expected to increase jet fuel production volume. The kerosene hydrotreater is expected to be operational in the first quarter of 2013.

Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery is progressing as planned. Overall detailed engineering and procurement is complete and construction activities are progressing. All major construction contracts have been awarded including mechanical, electrical and instrumentation contracts. All heavy haul transports were completed and equipment continues to be installed at the site. The refinery continues to advance a multi-year program to improve operational integrity and plant performance while reducing operating costs and environmental impacts.

7.0 Results of Operations

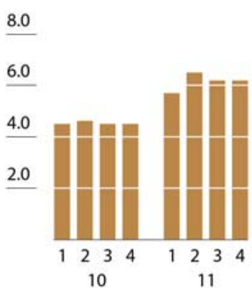
7.1 Segment Earnings

($ millions)	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[1]	
	2011	2010	**2011**	2010	**2011**	2010
Upstream	**2,032**	1,211	**1,502**	861	**4,131**	2,812
Midstream	**328**	219	**246**	160	**43**	40
Downstream						
Upgrading	**207**	89	**153**	63	**55**	182
Canadian Refined Products	**295**	159	**220**	117	**94**	244
U.S. Refining and Marketing	**693**	(32)	**440**	(20)	**224**	256
Corporate and Eliminations	**(415)**	(429)	**(337)**	(234)	**71**	37
Total	**3,140**	1,217	**2,224**	947	**4,618**	3,571

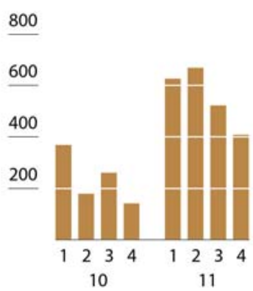
[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

7.2 Summary of Quarterly Results

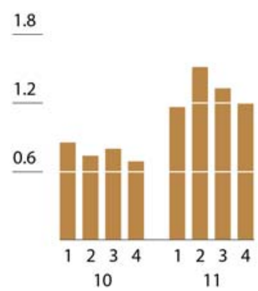
Gross Revenues
($ billions)



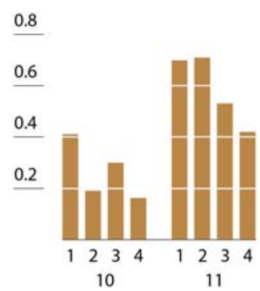
Net Earnings
($ millions)



Cash Flow from Operations[1]
($ billions)



Net Earning Per Share[2]
($ per share)

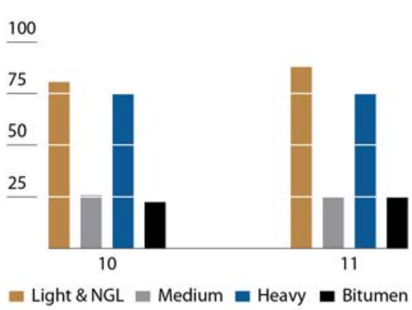


[1] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*
[2] *Reported figure represents net earnings per share – diluted*

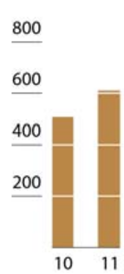
7.3 Upstream

2011 Earnings $1,502 million

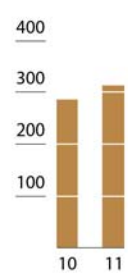
Production
Oil
(mbbls/day)



Production
Natural Gas
(mmcf/day)

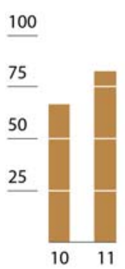


Production
Combined
(mboe/day)

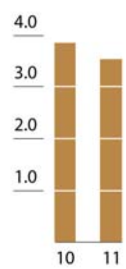


Upstream Earnings Summary *($ millions)*	2011	2010
Gross revenues	**7,250**	5,744
Royalties	**1,125**	978
Net revenues	**6,125**	4,766
Operating, transportation and administration expenses	**1,890**	1,595
Exploration and evaluation expense	**470**	438
Depletion, depreciation, amortization and impairment	**1,996**	1,521
Other expenses (income)	**(263)**	1
Income taxes	**530**	350
Net earnings	**1,502**	861

Average Price Realized
Crude Oil
($/bbl)



Average Price Realized
Natural Gas
($/mcf)

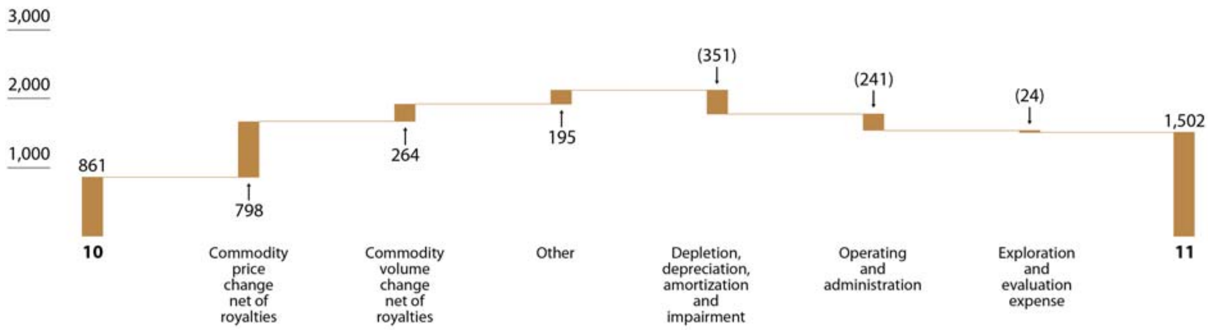


Average Sales Prices Realized	2011	2010
Crude oil *($/bbl)*		
Light crude oil & NGL	**103.25**	76.90
Medium crude oil	**75.65**	64.92
Heavy crude oil	**66.99**	58.91
Bitumen	**64.34**	57.84
Total average	**82.72**	66.70
Natural gas average *($/mcf)*	**3.55**	3.86
Total average *($/boe)*	**63.23**	54.25

Upstream net earnings were $641 million higher in 2011 compared with 2010 primarily due to increased crude oil and natural gas production, higher realized crude oil prices and realized gains on the sale of assets, partially offset by lower realized natural gas prices and higher depletion, depreciation, amortization and impairment, operating expenses and exploration and evaluation expenses.

During 2011, the average realized price increased 24% to $82.72/bbl for crude oil, NGL and bitumen compared with $66.70/bbl during 2010. Realized natural gas prices averaged $3.55/mcf during 2011 compared with $3.86/mcf in 2010. Production in the Atlantic Region and Asia Pacific Region benefited from higher realized prices as the price of Brent increased by approximately 40% compared with 2010, while WTI increased by approximately 20%. Higher U.S. dollar crude oil pricing was partially offset by the strengthening of the Canadian dollar against the U.S. dollar throughout the majority of the year.

After Tax Earnings Variance Analysis
($ millions)



Daily Gross Production	2011	2010
Crude oil *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**24.8**	23.0
Medium crude oil	**24.5**	25.4
Heavy crude oil	**74.5**	74.5
Bitumen	**24.7**	22.3
	148.5	145.2
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**48.7**	38.2
Terra Nova – light crude oil	**5.6**	8.5
	54.3	46.7
China		
Wenchang – light crude oil & NGL	**8.5**	10.7
	211.3	202.6
Natural gas *(mmcf/day)*	**607.0**	506.8
Total *(mboe/day)*	**312.5**	287.1

Upstream Revenue Mix *Percentage of Upstream Net Revenues*	2011	2010
Crude oil		
Light crude oil & NGL	**44%**	36%
Medium crude oil	**9%**	11%
Heavy crude oil	**26%**	29%
Bitumen	**8%**	8%
	87%	84%
Natural gas	**13%**	16%
Total	**100%**	100%

During 2011, crude oil, bitumen and NGL production increased by 8.7 mbbls/day or 4% compared with 2010, primarily due to higher production from North Amethyst and the impact of acquisitions in the fourth quarter of 2010 and the first quarter of 2011, partially offset by the impacts of the Plains Rainbow pipeline outages and operational issues at Terra Nova.

Production from natural gas increased by 100.2 mmcf/day or 20% in 2011 compared with 2010 due to the impact of acquisitions of properties in Western Canada during the fourth quarter of 2010 and the first quarter of 2011, partially offset by natural reservoir declines in mature properties as capital investment has been focused on higher return projects.

2012 Production Guidance and 2011 Actual

Gross Production	Guidance 2012	Year ended December 31 2011	Guidance 2011
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	70 – 75	**88**	75 – 80
Medium crude oil	25 – 30	**24**	25 – 30
Heavy crude oil & bitumen	100 – 110	**99**	95 – 105
	195 – 215	**211**	195 – 215
Natural gas *(mmcf/day)*	560 – 610	**607**	560 – 610
Total *(mboe/day)*	290 – 315	**312**	290 – 315

The Company's total production for the year ended December 31, 2011 was at the high end of the production guidance set by the Company in 2010 due to strong performance from the Atlantic Region. Husky expects that production levels will be marginally lower in 2012 as compared to 2011 due to a decrease in production from the Atlantic Region as a result of a maintenance offstation of the SeaRose floating, production, and storage offloading vessel ("FPSO") and a maintenance offstation for the Terra Nova FPSO. Although the Company does not expect production growth in fiscal 2012, it expects to meet its long-term compound annual growth target of three to five percent over the term of the five-year plan ending 2015.

Factors that could potentially impact Husky's production performance for 2012 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 facilities, offstations at the SeaRose and Terra Nova FPSO, 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 16% of gross revenue in 2011 compared with 17% in 2010. Royalty rates in Western Canada averaged 14% compared with 15% in 2010. In the Atlantic Region, the average rate was 17% in 2011 compared with 24% in 2010. The lower royalty rate is attributable to the North Amethyst field which is subject to a basic royalty rate of 1%, while Terra Nova and White Rose, being mature fields, are subject to higher rates. Royalty rates at North Amethyst will increase and reach levels similar to Terra Nova and White Rose after certain project payouts as prescribed in the royalty regulations are met. Royalty rates in the Asia Pacific Region averaged 30% compared with 23% in 2010 due to the sliding scale Chinese government's "Special Oil Gain Levy" that applies higher rates in a higher commodity price environment.

Operating Costs

($ millions)	2011	2010
Western Canada	**1,462**	1,199
Atlantic Region	**174**	176
Asia Pacific	**25**	24
Total	**1,661**	1,399
Unit operating costs *($/boe)*	**14.56**	13.35

Total Upstream operating costs increased to $1,661 million in 2011 from $1,399 million in 2010. Total Upstream unit operating costs in 2011 averaged $14.56/boe compared with $13.35/boe in 2010 due to increased fuel and electrical costs combined with treating, servicing, maintenance and labour costs that were impacted by acquisitions in the fourth quarter of 2010 and the first quarter of 2011.

Operating costs in Western Canada increased to $16.04/boe in 2011 compared with $14.44/boe in 2010 primarily as a result of increased costs associated with fuel, electrical, servicing, treating and maintenance, transportation, disposal of water and emulsion production, partially offset by higher production in 2011 compared with 2010. The increase was also due to maturing fields in Western Canada which require more extensive infrastructure servicing and maintenance, the impact of additional wells and facilities acquired through acquisitions, facilities associated with enhanced recovery schemes, extensive gathering systems, and complex natural gas compression systems.

Operating costs in the Atlantic Region averaged $8.75/boe in 2011 compared with $10.33/boe in 2010 primarily as a result of higher production from North Amethyst in 2011.

Operating costs in the Asia Pacific Region averaged $8.17/boe in 2011 compared with $6.06/boe in 2010 primarily as a result of increased workover activity at Wenchang combined with declining production.

Exploration and Evaluation Expenses

($ millions)	**2011**	2010
Seismic, geological and geophysical	**170**	186
Expensed drilling	**245**	252
Expensed land	**55**	–
Total	**470**	438

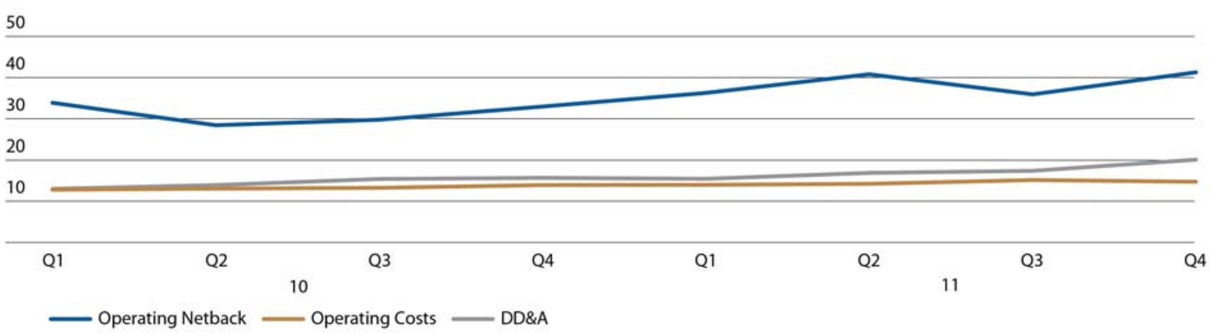
Total exploration and evaluation expenses increased in 2011 to $470 million from $438 million in 2010 due to land costs of $43 million relating to the Columbia River Basin located in the states of Washington and Oregon that were expensed in 2011.

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

During 2011, total unit DD&A was $17.51/boe compared with $14.52/boe during 2010. The higher DD&A rate in 2011 was primarily due to higher production from the North Amethyst offshore project and a pre-tax impairment charge of $70 million on conventional natural gas properties located in east central Alberta.

At December 31, 2011, capital costs in respect of unproved properties and major development projects were $5.3 billion compared with $4.1 billion at the end of 2010. These costs are excluded from the Company's DD&A calculation until the unproved properties are evaluated and proved reserves are attributed to the project that commences production or the project is deemed to be impaired.

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



[1] Operating netbacks are Husky's average price less royalties and operating costs on a per unit basis.

Upstream Capital Expenditures

In 2011, Upstream capital expenditures were $4,131 million compared to the 2011 capital expenditure program of $4,395 million. Upstream capital expenditures were $714 million (17%) in the Asia Pacific Region, $260 million (6%) in the Atlantic Region and $3,157 million (77%) in Western Canada which included $874 million for acquisitions. Husky's major projects remain on budget and on schedule.

Upstream Capital Expenditures[1] *($ millions)*	**2011**	2010
Exploration		
Western Canada	**233**	344
Atlantic Region	**2**	68
Asia Pacific	**168**	229
	403	641
Development		
Western Canada	**2,050**	1,334
Atlantic Region	**258**	375
Asia Pacific	**546**	62
	2,854	1,771
Acquisitions		
Western Canada	**874**	400
	4,131	2,812

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

Asia Pacific Region

The following table discloses Husky's offshore China and Indonesia drilling activity completed during 2011:

Asia Pacific Region Offshore Drilling Activity

China			
Liuhua 29-1-4 Block 29/26	WI 100%[1]	Stratigraphic test	Delineation
Liuhua 29-1-5 Block 29/26	WI 100%[1]	Stratigraphic test	Delineation
Liuhua 32-1-1 Block 29/26	WI 100%[1]	Stratigraphic test	Exploratory
Liwan 5-1-1 Block 29/26	WI 100%[1]	Stratigraphic test	Exploratory
Liwan 4-3-1 Block 29/26	WI 100%[1]	Stratigraphic test	Exploratory
Yacheng 5-1-1 Block 63/05	WI 100%[1]	Stratigraphic test	Exploratory
Liwan 3-1-5 Block 29/26	WI 49%	Production	Development
Liwan 3-1-6 Block 29/26	WI 49%	Production	Development
Liwan 3-1-7 Block 29/26	WI 49%	Production	Development
Liwan 3-1-8 Block 29/26	WI 49%	Production	Development
Wenchang 13-2-A4h1 side track	WI 40%	Production	Development
Indonesia			
MDA-4 Madura Strait	WI 40%	Stratigraphic test	Exploratory
MBH-1 Madura Strait	WI 40%	Stratigraphic test	Exploratory

(1) *CNOOC has the right to participate in development of discoveries up to 51%.*

During 2011, $700 million of capital expenditures was spent in China primarily on the construction of the Liwan Gas Project and the drilling of four exploration, two delineation and five development wells on Block 29/26 in the South China Sea. In Indonesia, $14 million was spent on two exploratory wells in the Madura Strait.

Atlantic Region

The following table discloses Husky's offshore Atlantic Region drilling activity during 2011:

Offshore Atlantic Region Drilling Activity

North Amethyst G-25-5	WI 68.875%	Water injection	Development
North Amethyst G-25-6	WI 68.875%	Production	Development
White Rose E-18-10 (West pilot)	WI 68.875%	Production	Development
Mizzen F-09	WI 35%	Exploratory	Exploratory
Fiddlehead D-83	WI 50%	Exploratory	Exploratory

During 2011, $260 million was invested in Atlantic Region development projects, primarily for the drilling of water injection and production wells in North Amethyst. Two exploration wells were drilled in the Atlantic Region in 2011 including one well in the Flemish Pass Basin and one well located south of the Terra Nova field.

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:

Wells Drilled *(wells)*	2011 Gross	2011 Net	2010 Gross	2010 Net
Exploration				
Oil	**50**	**40**	60	51
Gas	**24**	**24**	37	31
Dry	**3**	**3**	8	8
	77	**67**	105	90
Development				
Oil	**880**	**765**	815	722
Gas	**57**	**42**	73	53
Dry	**4**	**4**	10	9
	941	**811**	898	784
Total	**1,018**	**878**	1,003	874

The Company drilled 878 net wells in the Western Canada Sedimentary Basin in 2011 resulting in 805 net oil wells and 66 net natural gas wells compared with 874 net wells resulting in 773 net oil wells and 84 net natural gas wells in 2010. Capital expenditures for wells drilled in Western Canada increased substantially in 2011 compared with 2010 due to the increased focus on resource development drilling in areas such as the Ansell liquids rich gas resource play. In addition, a larger number of horizontal wells were drilled and more multi-stage fracture completions were performed in 2011.

During 2011, Husky invested $3,157 million on exploration, development and acquisitions throughout the Western Canada Sedimentary Basin compared with $2,078 million in 2010. Property acquisitions of $874 million were completed during 2011, primarily in the Rainbow Lake area of northwestern Alberta, the Foothills and Deep Basin areas of Alberta and in northeastern British Columbia.

In 2011, $591 million was invested in oil related exploration and development and $359 million was invested in natural gas related exploration and development compared with $410 million for oil related exploration and development and $163 million for natural gas related exploration and development in 2010.

Capital expenditures include $176 million spent on production optimization and cost reduction initiatives in 2011. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $307 million.

During 2011, capital expenditures on heavy oil projects including thermal projects, CHOPS drilling and horizontal drilling were $587 million compared with $469 million in 2010.

During 2011, capital expenditures on Oil Sands projects were $263 million compared with $171 million in 2010 as Sunrise Phase I progressed.

2012 Upstream Capital Program

($ millions)	
Western Canada	
Oil and gas	**1,800**
Oil sands	**640**
Atlantic Region	**500**
Asia Pacific Region	**1,100**
Total Upstream capital expenditures(1)	**4,040**

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

The 2012 Capital Program will enable Husky to build on the continuous momentum in accelerating near-term production and support the continued execution of the Company's mid and long-term growth initiatives.

Investment in the Sunrise Energy Project is expected to more than double to $610 million as construction activity ramps up and the project advances towards planned first production in 2014. Over $1 billion is budgeted for the Asia Pacific Region as fabrication of deep water and shallow water facilities for the Liwan Gas Project accelerates. Investment in the Atlantic Region of $500 million will be directed at continued development of the White Rose fields and extensions, a scheduled turnaround of the SeaRose FPSO and continued evaluation of the feasibility of a concrete wellhead and drilling platform for the development of future resources in the White Rose region including the full development of West White Rose.

In addition to advancing mid and long-term growth pillars, the 2012 Capital Program provides support to the Company's efforts to reinvigorate and transform its foundation in Western Canada. A substantial oil and liquids-rich natural gas resource play portfolio has been acquired and drilling is scheduled to take place across the portfolio in 2012. The Company is making progress in its strategy to transition a greater percentage of its heavy oil production to long-life thermal. The 8,000 bbls/day Pikes Peak South thermal project is expected to become operational in mid-2012 and the 3,000 bbls/day Paradise Hill thermal project is on target to become operational in late 2012.

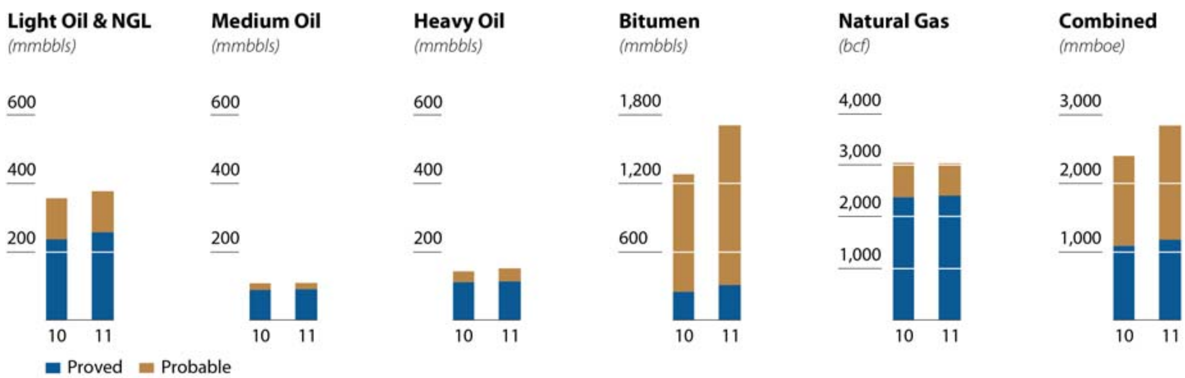
Upstream Planned Turnarounds

Husky intends to proceed with an offstation for the SeaRose FPSO propulsion system in the second and third quarters of 2012 which is expected to result in production shut-in for approximately 125 days. Production from the White Rose, North Amethyst, and West White Rose fields will be shut-in during the offstation maintenance. The impact to Husky's production, averaged over the entire year, is forecasted to be approximately 12,000 bbls/day.

A 21-week dockside maintenance for the non-operated Terra Nova FPSO is scheduled to be completed during the second half of 2012. The impact to annual production is estimated to be approximately 4,000 bbls/day. The program anticipates a return to the field and reinstatement of production by the end of 2012.

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, 2011. Prior to 2010, Husky applied for and was granted an exemption from certain of the provisions of NI 51-101, which permitted the Company to present oil and gas reserves disclosures in accordance with the rules of the United States Securities and Exchange Commission and the United States Financial Accounting Standards Board (the "U.S. Rules"). This is no longer available for the Company's reserves reporting in Canada, although the Company 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. Rules 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 .

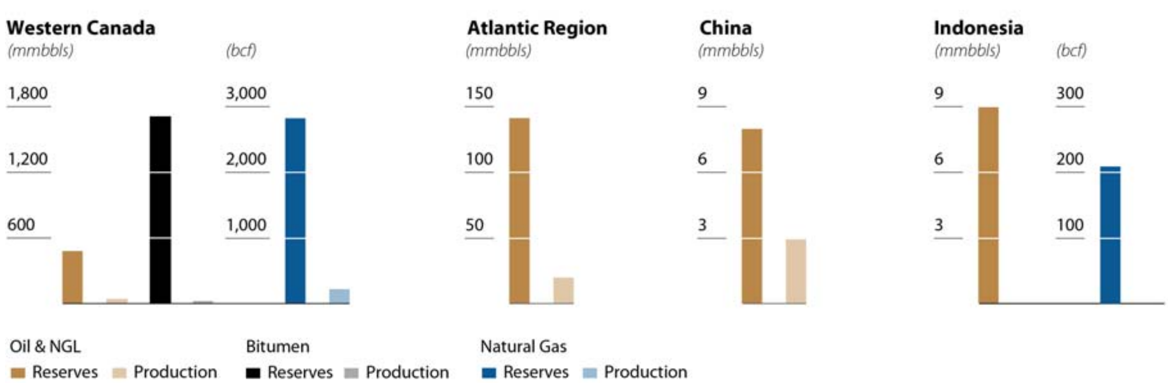


The Company's complete Oil and Gas Reserves Disclosure prepared in accordance with NI 51-101 is contained in Husky's Annual Information Form available at www.sedar.com or Husky's Form 40-F available at www.sec.gov or on the Company's website at www.huskyenergy.com.

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, 2011, Husky's proved oil and gas reserves were 1,172 mmboe, up from 1,081 mmboe at the end of 2010. The net addition to proved reserves, including acquisitions and divestitures, represents 180% of 2011 production. Major additions to proved reserves in 2011 included:

- the extension through additional drilling and seismic interpretation of the Sunrise Energy Project that resulted in booking an additional 60 mmbbls of bitumen to proved undeveloped reserves;
- the acquisitions of properties in the first quarter of 2011 that resulted in the booking of an additional 108 mmboe in proved reserves; and
- the extension through additional drilling locations at Ansell in the Alberta Deep Basin area that resulted in the booking of an additional 12 mmboe of natural gas and natural gas liquids in proved reserves.



Note: Reserves reported represent proved plus probable reserves.

Reconciliation of Proved 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 – Equiva-lent Units (mmboe)
Proved reserves											
December 31, 2010	133	88	110	247	2,186	88	16	209	682	2,395	1,081
Revision of previous estimate	(4)	1	7	2	–	3	1	–	10	–	10
Purchase of reserves in place	41	–	5	–	398	–	–	–	46	398	112
Sale of reserves in place	–	–	(3)	–	(1)	–	(2)	(42)	(5)	(43)	(12)
Discoveries, extensions and improved recovery	10	10	21	69	77	5	–	–	115	77	128
Economic revision	(2)	–	–	–	(185)	–	–	–	(2)	(185)	(33)
Production	(9)	(9)	(27)	(9)	(222)	(20)	(3)	–	(77)	(222)	(114)
Proved reserves December 31, 2011	**169**	**90**	**113**	**309**	**2,253**	**76**	**12**	**167**	**769**	**2,420**	**1,172**
Proved and probable reserves December 31, 2011	**220**	**109**	**151**	**1,709**	**2,813**	**141**	**17**	**207**	**2,347**	**3,020**	**2,851**
December 31, 2010	176	108	143	1,287	2,766	159	22	258	1,895	3,024	2,399

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, 2010	111	79	82	51	1,721	64	7	–	394	1,721	681
Revision of previous estimate	(2)	3	19	14	21	19	1	–	54	21	58
Purchase of reserves in place	41	–	3	–	393	–	–		44	393	109
Sale of reserves in place	–	–	(3)	–	(1)	–	–	–	(3)	(1)	(3)
Discoveries, extensions and improved recovery	7	4	12	–	48	2	–		25	48	33
Economic revision	–	–	–	–	(44)	–	–	–	–	(44)	(7)
Production	(9)	(9)	(27)	(9)	(222)	(20)	(3)	–	(77)	(222)	(114)
Proved developed reserves December 31, 2011	**148**	**77**	**86**	**56**	**1,916**	**65**	**5**	**–**	**437**	**1,916**	**757**

7.4 Midstream

2011 Earnings $246 million

Infrastructure and Marketing Earnings Summary *($ millions, except where indicated)*	**2011**	2010
Gross revenues	**9,446**	7,002
Gross margin		
Pipeline	**150**	124
Other infrastructure and marketing	**255**	193
	405	317
Operating and administration expenses	**25**	21
Depreciation and amortization	**46**	43
Other expenses	**6**	34
Income taxes	**82**	59
Net earnings	**246**	160
Commodity volumes managed *(mboe/day)*	**1,028**	952
Aggregate pipeline throughput *(mbbls/day)*	**559**	512

Infrastructure and marketing net earnings in 2011 increased by $86 million compared with 2010 due primarily to higher pipeline throughput and marketed volumes and trading gains captured on light and synthetic crude oil moving from Canada to the U.S. as a result of the widening WTI to Brent differential, partially offset by lower natural gas storage earnings. Other expenses, which include the fair value impact of the Company's commodity price risk management activities, decreased by $28 million in 2011 as compared to 2010 due to the timing of realized gains on natural gas storage contracts.

Midstream Capital Expenditures

Midstream capital expenditures totalled $43 million in 2011 compared to $40 million in 2010. The majority of midstream capital expenditures during the year related to the construction of the 300,000 barrel tank at the Hardisty terminal.

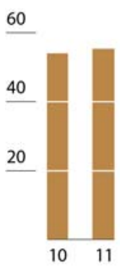
7.5 Downstream

Effective 2011, Husky commenced evaluating and reporting its Upgrading activities as part of Downstream operations. As a result, Upgrading was moved from the Midstream segment to the Downstream segment. All prior periods have been reclassified to conform to these segment definitions.

2011 Earnings $813 million

Total downstream earnings in 2011 were $813 million, up from $160 million in 2010. The increase was primarily due to higher realized refining margins in the U.S. as a result of higher market crack spreads, higher fuel and asphalt margins for Canadian refined products and higher throughput at the Lloydminster Upgrader.

Upgrader
Synthetic Crude Sales
(mbbls/day)



Upgrader
Unit Margin & Operating Costs
($/bbl)

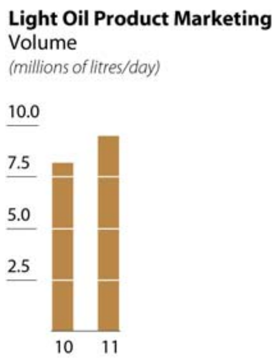
Upgrader

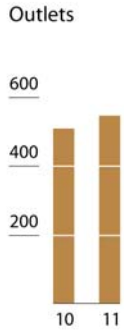
Upgrader Earnings Summary *($ millions, except where indicated)*		2011	2010
Gross revenues		**2,217**	1,570
Gross margin		**636**	311
Operating and administration expenses		**191**	185
Depreciation and amortization		**164**	74
Other expenses (income)		**74**	(37)
Income taxes		**54**	26
Net earnings		**153**	63
Upgrader throughput[(1)]	*(mbbls/day)*	**69.6**	65.4
Synthetic crude oil sales	*(mbbls/day)*	**55.3**	54.1
Upgrading differential	*($/bbl)*	**27.34**	14.52
Unit margin	*($/bbl)*	**31.51**	15.73
Unit operating cost[(2)]	*($/bbl)*	**7.40**	7.76

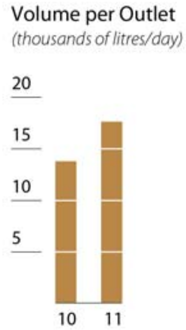
(1) *Throughput includes diluent returned to the field.*
(2) *Based on throughput.*

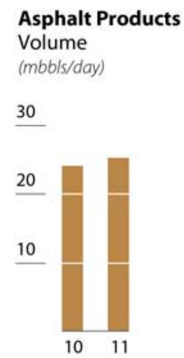
Upgrading earnings in 2011 increased by $90 million compared with 2010 primarily due to higher realized differentials and higher production as a result of improved reliability which more than offset the impact of a fire in early February that resulted in a reduction in average throughput at the Upgrader to 53.2 mbbls/day in the first quarter. In addition, increased earnings were offset by higher depreciation and amortization and the derecognition of certain intangible costs.

During 2011, the price of Husky's synthetic crude oil averaged $101.68/bbl compared with the average cost of blended heavy crude oil from the Lloydminster area of $74.34/bbl. During 2010, the price of Husky's synthetic crude oil averaged $80.97/bbl compared with the average cost of blended heavy crude oil from the Lloydminster area of $66.45/bbl. This resulted in an average synthetic/heavy crude differential of $27.34/bbl in 2011 compared to $14.52/bbl in 2010 and a gross unit margin of $31.51/bbl in 2011 compared to $15.73/bbl in 2010. The cost of upgrading averaged $7.40/bbl compared with $7.76/bbl in 2010, which results in a net margin for upgrading heavy crude of $24.11/bbl, up 203% compared with $7.97/bbl in 2010. The increase in other expenses is due to the increase in the fair value of the remaining upside interest payment obligation to Natural Resources Canada and the Alberta Department of Energy through 2014 as a result of higher upgrading differentials throughout the year.









Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*		2011	2010
Gross revenues		**3,860**	2,975
Gross margin			
Fuel		**149**	87
Refining		**90**	64
Asphalt		**204**	160
Ancillary		**49**	46
		492	357
Operating and administration expenses		**117**	110
Depreciation and amortization		**80**	88
Income taxes		**75**	42
Net earnings		**220**	117
Number of fuel outlets[1]		**547**	508
Refined products sales volume			
Light oil products	*(million of litres/day)*	**9.5**	8.2
Light oil products per outlet	*(thousand of litres/day)*	**17.3**	13.8
Asphalt products	*(mbbls/day)*	**25.3**	24.1
Refinery throughput			
Prince George refinery	*(mbbls/day)*	**10.6**	10.0
Lloydminster refinery	*(mbbls/day)*	**28.1**	27.8
Ethanol production	*(thousand of litres/day)*	**711.3**	619.7

[1] *Average number of fuel outlets for period indicated.*

During 2011, fuel gross margins were higher than in 2010 primarily due to higher retail and wholesale market prices combined with increased volumes due to the purchase of 97 retail stations in 2010.

Refining gross margins increased in 2011 primarily due to higher market crack spreads, higher total ethanol production from a successful recycle thermal oxidiser installation at the Lloydminster Ethanol Plant and higher realized prices for gasoline, diesel and ethanol partially offset by lower production at the Prince George Refinery and Minnedosa Ethanol Plant due to turnaround activity. Included in ethanol gross margins in 2011 was $46 million related to government assistance grants compared with $50 million in 2010.

Asphalt gross margins increased compared to the same period in 2010 primarily due to higher realized market prices and increased sales volumes for residuals as a result of strong demand for drilling fluids.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*		2011	2010
Gross revenues		**9,593**	7,107
Gross refining margin		**1,290**	547
Operating and administration expenses		**400**	386
Interest – net		**2**	2
Depreciation and amortization		**195**	191
Income taxes (recoveries)		**253**	(12)
Net earnings (loss)		**440**	(20)
Selected operating data:			
Lima Refinery throughput	*(mbbls/day)*	**144.3**	136.6
Toledo Refinery throughput	*(mbbls/day)*	**63.9**	64.4
Refining margin	*(U.S. $/bbl crude throughput)*	**17.60**	7.29
Refinery inventory (feedstocks and refined products)	*(mmbbls)*	**11.8**	11.9

U.S. refining and marketing net earnings increased in 2011 compared with 2010 as a result of higher realized refining margins including FIFO inventory gains. In addition to increased market crack spreads, feedstock at the Toledo Refinery was approximately half heavy crude oil which added to increased margins as differentials between heavy and light crude oil were higher in 2011 compared with 2010. The increase in net earnings was partially offset at the Lima Refinery where over half of the feedstock in 2011 was based on the price of Brent which traded at a significant premium to WTI and at the Toledo Refinery where there was crude oil supply constraints due to the Enbridge pipeline curtailment and planned maintenance.

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 year when crude oil prices were lower.

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.

The overall strengthening of the Canadian dollar against the U.S. dollar compared with 2010 had a negative impact on the translation of U.S. dollar financial results into Canadian dollars.

Downstream Capital Expenditures

Downstream capital expenditures totalled $373 million for 2011 compared to $682 million in 2010. In Canada, capital expenditures were $149 million related to upgrades at the Prince George Refinery, the Upgrader and retail stations. In the United States, capital expenditures totalled $224 million. At the Lima Refinery, $124 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled $100 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

An outage is scheduled for approximately three weeks in the first half of 2012 at the Upgrader to expedite hydrogen plant repairs and catalyst change out. The next major turnaround is scheduled to commence in the fall of 2013.

The Lloydminster Refinery will have a major turnaround in the spring of 2013. The refinery will be shut down during the turnaround for inspections and equipment repair. The turnaround is scheduled to last approximately 21 days.

The next minor turnaround at the Toledo Refinery is expected to occur in mid-2012 with the partial outage expected to last approximately 21 days.

The Lima Refinery is scheduled to have a 15-day Diesel Hydrotreater outage in late 2012 to replace the catalyst. In addition, a 29-day aromatics turnaround is expected in late 2012. Neither of the planned outages are expected to have a material impact on crude throughputs. The Lima Refinery is scheduled to complete a major turnaround in 2014 on 70 percent of its operating units. The refinery is expected to be shut down for 45 days during the turnaround. The remaining 30 percent of operating units will be addressed in a major turnaround currently planned for 2015.

7.6 Corporate

2011 Loss $337 million

Corporate Earnings Summary *($ millions) income (expense)*	2011	2010
Intersegment eliminations – net	**(51)**	(47)
Administration expenses	**(199)**	(88)
Other income	**3**	3
Stock-based compensation	**1**	13
Depreciation and amortization	**(38)**	(75)
Interest – net	**(141)**	(186)
Foreign exchange gains (losses)	**10**	(49)
Income taxes	**78**	195
Net loss	**(337)**	(234)

The Corporate segment reported a loss in 2011 of $337 million compared with a loss of $234 million in 2010. Administration expenses increased by $111 million as compared to 2010 primarily due to increased administration costs on financing projects and other initiatives. Interest – net decreased by $45 million as compared to 2010 due to increased amounts capitalized related to projects in the Asia Pacific Region. Intersegment eliminations are profit earned on inventory that has not been sold to third parties at the end of the period.

Foreign Exchange Summary *($ millions)*	2011	2010
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(47)**	108
Gains (losses) on cross currency swaps	**7**	(18)
Gains (losses) on contribution receivable	**34**	(67)
Other gains (losses)	**16**	(72)
Foreign exchange gains (losses)	**10**	(49)
U.S./Canadian dollar exchange rates:		
At beginning of year	**U.S. $1.005**	U.S. $0.956
At end of year	**U.S. $0.983**	U.S. $1.005

Consolidated Income Taxes

Consolidated income taxes increased in 2011 to $916 million from $270 million in 2010 resulting in an effective tax rate of 29% for 2011 and 22% for 2010.

($ millions)	2011	2010
Income taxes as reported	**916**	270
Cash taxes paid	**282**	784

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 due over the 5-year period ending in 2016.

In 2012, cash tax instalments of $730 million are estimated to be payable in respect of a combination of 2012 reported earnings and a portion of 2011 earnings which were previously deferred.

Corporate Capital Expenditures

Corporate capital expenditures of $71 million in 2011 were primarily for construction of a new building in Lloydminster, computer hardware and software, office furniture, renovations and equipment and system upgrades.

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

In 2011, Husky funded its capital programs, including acquisitions and dividend payments, by cash generated from operating activities, equity issuances and cash on hand. At December 31, 2011, Husky had total debt of $3,911 million partially offset by cash on hand of $1,841 million for $2,070 million of net debt compared to $3,935 million of net debt at December 31, 2010 consisting of $4,187 million of total debt and $252 million of cash on hand. At December 31, 2011, the Company had $3.5 billion in unused committed credit facilities, $110 million in unused short-term uncommitted credit facilities, unused capacity under the debt shelf prospectus filed in Canada of $300 million, which expired in January 2012, unused capacity under the November 2010 universal short form base shelf prospectus filed in Canada of $1.4 billion, and unused capacity under the June 2011 U.S. base shelf prospectus of U.S. $2.0 billion. The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions (Refer to Section 8.2).

	2011	2010
Cash flow		
Operating activities *($ millions)*	**5,092**	2,222
Financing activities *($ millions)*	**910**	1,085
Investing activities *($ millions)*	**(4,420)**	(3,453)
Financial Ratios[(1)]		
Debt to capital employed *(percent)*[(2)]	**18.0**	22.3
Debt to cash flow *(times)*[(3)(4)]	**0.8**	1.4
Corporate reinvestment ratio *(percent)*[(3)(5)]	**98**	134
Interest coverage ratios on long-term debt only[(3)(6)]		
Earnings	**14.5**	6.2
Cash flow	**24.7**	11.4
Interest coverage on ratios of total debt[(3)(7)]		
Earnings	**14.1**	6.0
Cash flow	**23.9**	11.2

(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 $5,092 million in 2011 compared with $2,222 million in 2010. Higher cash flow from operating activities was primarily due to higher production, higher crude oil prices in Upstream and higher realized margins in Canadian and U.S. Downstream.

Cash Flow from Financing Activities

Cash generated from financing activities was $910 million in 2011 compared with $1,085 million in 2010. The decrease in cash provided by financing activities was due to a decrease in long-term debt issuances, net of repayments, partially offset by an increase in proceeds from common and preferred share issuances and the adoption of a stock dividend plan in the second quarter of 2011.

Cash Flow used for Investing Activities

Cash used in investing activities for 2011 was $4,420 million compared with $3,453 million in 2010. 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, 2011, Husky's working capital was $2,054 million compared with $1,181 million at December 31, 2010.

Movement in Working Capital

($ millions)	December 31, 2011	December 31, 2010	Increase/ (Decrease)
Cash and cash equivalents	**1,841**	252	1,589
Accounts receivable	**1,235**	1,183	52
Income taxes receivable	**273**	346	(73)
Inventories	**2,059**	1,935	124
Prepaid expenses	**36**	34	2
Accounts payable and accrued liabilities	**(2,867)**	(2,506)	(361)
Asset retirement obligations	**(116)**	(63)	(53)
Long-term debt due within one year	**(407)**	–	(407)
Net working capital	**2,054**	1,181	873

The increase in cash was primarily due to increased production, higher crude oil prices in Upstream and higher realized margins in Canadian and U.S. Downstream. The increase in accounts receivable was primarily as a result of increased crude oil sales. The increase in accounts payable and accrued liabilities was mainly due to higher capital expenditures. The increase in long-term debt due within one year is due to certain debt maturing in 2012.

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 upstream capital programs principally by cash generated from operating activities, cash on hand, issuances of equity, the issuance of long-term debt and 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, 2011, no production was hedged.

At December 31, 2011 Husky had the following available credit facilities:

($ millions)	Available[(1)]	Unused
Operating facilities[(2)]	465	215
Syndicated bank facilities	3,300	3,300
Bilateral credit facility[(3)]	100	100
Total	3,865	3,615

(1) *Available short and long-term debt includes committed and uncommitted credit facilities.*
(2) *The operating facilities included $265 million of demand credit facilities and $200 million of committed credit facilities. The $200 million of committed credit facilities were increased to $250 million and converted to demand credit facilities in 2012.*
(3) *The $100 million bilateral credit facility was cancelled effective February 3, 2012.*

Cash and cash equivalents at December 31, 2011 totalled $1,841 million compared with $252 million at the beginning of the year.

At December 31, 2011, Husky had unused committed short and long-term borrowing credit facilities of $3.5 billion and uncommitted short-term borrowing facilities of $110 million. A total of $250 million of the Company's short-term borrowing credit facilities were used in support of outstanding letters of credit.

On December 21, 2009, Husky filed a debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enabled Husky to offer up to $1.0 billion of medium-term notes in Canada until January 21, 2012. As of December 31, 2011, $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020 had been issued under this shelf prospectus (Refer to Note 14 to the Consolidated Financial Statements).

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. As of December 31, 2011, there was no balance outstanding under these facilities.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility available of $10 million for general purposes. Husky's proportionate share is $5 million. As of December 31, 2011, there was no balance outstanding under this facility.

On November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 26, 2012 (the "Canadian Shelf Prospectus"). During the 25-month period that the Canadian Shelf Prospectus is effective, Securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement.

On December 7, 2010, Husky issued 11.9 million common shares at a price of $24.50 per share for total gross proceeds of $293 million under the Canadian Shelf Prospectus. Husky also issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of approximately $707 million to principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. The common shares issued under the private placements were not issued under the Canadian Shelf Prospectus. The Company received total net proceeds of $988 million from this issuance.

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 would be 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. Quarterly dividends of $0.30 ($1.20 annually) per common share were declared during 2011 totalling $1.1 billion in 2011 of which $328 million was accepted in cash and $781 million was accepted in common shares. The declaration of dividends is at the discretion of the Board of Directors, which will consider earnings, capital requirements, the Company's financial condition and other relevant factors.

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 the 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, Husky filed a universal short form base shelf prospectus with the Alberta Securities Commission and the U.S. Securities and Exchange Commission that enables Husky 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 until July 13, 2013 (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 Canadian Shelf Prospectus and accompanying prospectus supplement in Canada.

Capital Structure

	December 31, 2011	
($ millions)	Outstanding	Available[(1)]
Total short-term and long-term debt	3,911	3,615
Common shares, retained earnings and accumulated other comprehensive income	17,773	

[(1)] *Available short and 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)	2012	2013–2014	2015–2016	Thereafter	Total
Long-term debt and interest on fixed rate debt	631	1,163	819	3,030	5,643
Operating leases	108	165	123	119	515
Firm transportation agreements	187	400	367	3,291	4,245
Unconditional purchase obligations[(1)]	2,926	1,352	309	89	4,676
Lease rentals and exploration work agreements	77	240	524	519	1,360
Asset retirement obligations[(2)]	116	231	248	7,905	8,500
	4,045	3,551	2,390	14,953	24,939

(1) *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling rig services and natural gas purchases.*

(2) *Asset retirement obligation amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets.*

Based on Husky's 2012 commodity price forecast, the Company believes that its non-cancellable contractual obligations, other commercial commitments and the 2012 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

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 Consolidated Financial Statements).

Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery LLC (Refer to Note 8 to the 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, 2011, Husky's share of this obligation was U.S. $1.4 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 asset retirement obligations ("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

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 and Major Customers

On May 11, 2009, the Company issued 5 and 10-year senior notes of U.S. $251 million and U.S. $107 million, respectively, to certain management, shareholders, affiliates and directors as part of the U.S. $750 million 5-year and U.S. $750 million 10-year senior notes issued through a base shelf prospectus, which was filed with the Alberta Securities Commission and U.S. Securities and Exchange Commission in February 2009. The coupon rates offered were 5.90% and 7.25% for the 5 and 10-year tranches, respectively. Subsequent to this offering, U.S. $122 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. At December 31, 2011, the U.S. $1.5 billion senior notes are included in long-term debt on the Company's balance sheet.

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

In April 2011, Husky and TransAlta Cogeneration, L.P., which was the Company's 50% joint venture partner for the Meridian cogeneration facility at Lloydminster, sold the Meridian cogeneration facility to a related party. The consideration for Husky's share of the cogeneration facility was $61 million, resulting in no net gain or loss on the transaction.

The Company continues to sell natural gas to and purchase steam from the Meridian cogeneration facility and other cogeneration facilities owned by a related party. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the year ended December 31, 2011, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by the related party was $108 million. For the year ended December 31, 2011, the total value of obligated steam purchases from the Meridian and other cogeneration facilities owned by the related party was $13 million.

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

All debt and equity issuance transactions with related parties have been measured at the exchange amount, which was equivalent to the fair market value at the date of the transaction and have been carried out on the same terms as would apply with unrelated parties.

8.6 Financial Risk and Risk Management

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates, interest rates, credit risk and changes in fiscal, monetary and other financial policies related to royalties, taxes and others (Refer to Section 3.0). On occasion, the Company will use derivative instruments to manage its exposure to these risks.

Political Risk

Husky is exposed to risks associated with operating in developed and developing countries, including risks associated with political and regulatory instability. The Company monitors the changes to regulations and government policies in the areas within which it operates.

Environmental Risk

Husky's business operations are subject to numerous laws and regulations regarding environmental, health and safety matters, including those relating to emissions to air, discharges to water and the storage and disposal of regulated materials. The nature of Husky's business is exposed to risks of liabilities under such laws and regulations due to the production, storage, use, transportation and disposal of materials that can cause contamination or personal injury if released into the environment.

Husky's offshore operations are subject to the risk of blowouts and other catastrophic events, resulting from actions of the Company or its contractors or agents, or those of third parties, that could result in suspension of operations, damage to equipment and harm to personnel, and damage to the natural environment. The consequences of such catastrophic events occurring in deep water operations, in particular, can be more costly and time-consuming to remedy. The remedy may be made more difficult or uncertain by the extreme pressures and cold temperatures encountered in deep water operations, shortages of equipment and specialist personnel required to work in these conditions, or the absence of appropriate and proven means to effectively remedy such consequences. The costs associated with such events could be material and Husky may not maintain sufficient insurance to cover such costs. Husky currently has a working interest in non-operated offshore deepwater drilling operations in Canada and a development program in China includes deep water drilling.

The 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 United States 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.

The United States Environmental Protection Agency ("EPA") is implementing regulations pertaining to greenhouse gas emissions, which could increase costs of doing business. In particular, the so-called 'Tailoring Rule' now requires sources emitting greater than 100,000 tons per year of greenhouse gases to obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. The Tailoring Rule also can require the installation and operation of expensive pollution control technology as a part of any project that results in a significant greenhouse gas emissions increase. The EPA has promulgated regulations requiring greenhouse gas emissions reporting from certain U.S. operations. The EPA also is required to issue greenhouse gas emission guidelines for existing refineries and new source performance standards for new refineries or modifications to existing refineries by November 10, 2012. These and other EPA regulations regarding greenhouse gas emissions are subject to legislative and judicial challenges, including current Congressional proposals to block or delay the EPA's authority to regulate greenhouse gas emissions. It is not possible to predict the ultimate outcome of these challenges. While these EPA regulations are currently in effect, they have not yet had a material impact on Husky. Husky's operations may, however, be materially impacted by future application of these rules or by future United States 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.

Financial Risk

Husky's financial risks are largely related to commodity prices, refinery crack spreads, foreign exchange rates, interest rates, credit risk, changes in fiscal policy related to royalties and taxes and others. From time to time, Husky uses financial and derivative instruments to manage its exposure to these risks.

Commodity Price Risk Management

Husky uses derivative commodity instruments from time to time 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.

At December 31, 2011, the Company had third-party physical natural gas purchase and sale derivative contracts and natural gas storage contracts. These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized loss of $8 million has been recorded in other expenses in the Consolidated Statements of Income for the year ended December 31, 2011. Natural gas inventory held in storage relating to the natural gas storage contracts is recorded at fair value. At December 31, 2011, the fair value of the inventory was $121 million, resulting in an unrealized loss of $3 million recorded in other expenses in the Consolidated Statements of Income for the year ended December 31, 2011.

At December 31, 2011, the Company had third-party crude oil purchase and sale derivative contracts, which have been designated as a fair value hedge. These contracts have been recorded at their fair value in accrued liabilities and the resulting unrealized loss of $8 million has been recorded in purchases of crude oil and products in the Consolidated Statements of Income for the year ended December 31, 2011. The crude oil inventory held in storage is recorded at fair value. At December 31, 2011, the fair value of the inventory was $16 million, resulting in an unrealized gain of $2 million recorded in purchases of crude oil and products in the Consolidated Statements of Income for the year ended December 31, 2011.

The Company also enters into derivative contracts for future crude oil purchases, whereby there is a requirement to pay the market difference of the inventory price paid at delivery and the current market price at the settlement date in the future. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. As at December 31, 2011, a loss related to these contracts of $7 million was recorded in purchases of crude oil and products in the Consolidated Statements of Income for the year ended December 31, 2011.

The Company enters into certain crude oil purchase and sale derivative contracts to minimize its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities. At December 31, 2011, the Company had 1.1 mmbbls of purchase and sale contracts resulting in an unrealized gain of $4 million recorded in other expenses in the Consolidated Statements of Income for the year ended December 31, 2011. A portion of the crude oil inventory is sold to third parties. This inventory is measured at fair value. At December 31, 2011, the fair value of the inventory was $147 million, resulting in an unrealized gain of less than $1 million in other expenses in the Consolidated Statements of Income for the year ended December 31, 2011.

During 2011, the Company entered into third party commodity swaps based on the price of butane and crude oil. These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain of less than $1 million for the year ended December 31, 2011 has been recorded in other expenses in the Consolidated Statements of Income.

Interest Rate Risk Management

The Company had entered into a fair value hedge using interest rate swap arrangements whereby the fixed interest rate coupon on the long-term debt was swapped to floating rates. These interest rate swap arrangements have been sold and derecognized during the year. Accordingly, the accrued gains on these interest rate swaps will be amortized over the remaining life of the underlying long-term debt to which the hedging relationship was originally designated.

During 2011, these swaps resulted in a reduction of finance expenses of $13 million. The amortization of terminated interest rate swaps resulted in additional finance expenses of $8 million for the year ended December 31, 2011. The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $9 million for the year ended December 31, 2011.

Foreign Currency Risk Management

Husky's results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of Husky's expenditures are in Canadian dollars. The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. 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, as expressed in Canadian dollars, as well as in the related interest expense. At December 31, 2011, 82% or $3.1 billion of Husky's outstanding debt was denominated in U.S. dollars (74% or $3.1 billion at December 31, 2010). The percentage of the Company's debt exposed to the Canadian/U.S. exchange rate decreases to 73% when cross currency swaps are considered (2010 – 67%).

At December 31, 2011, Husky had the following cross currency swaps in place:

- U.S. $50 million at 6.25% swapped at $1.17 to $59 million at 5.67% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.19 to $89 million at 5.65% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.17 to $88 million at 5.61% until June 15, 2012.
- U.S. $150 million at 6.25% swapped at $1.41 to $211 million at 7.41% until June 15, 2012.

At December 31, 2011, the cost of a U.S. dollar in Canadian currency was $1.017.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars in order to hedge against the foreign exchange exposures from oil and natural gas revenues. Aside from offsetting unrealized gains or losses from oil and natural gas sales, these contracts have a resulting unrealized gain of $1 million based on changes in fair value recorded in other expenses for the year ended December 31, 2011. For the year ended December 31, 2011, the impact of these contracts was a realized loss of $5 million recorded in net foreign exchange gains or losses.

At December 31, 2011, the Company had designated U.S. $1.3 billion of its U.S. debt as a hedge of the Company's net investment in the U.S. refining operations, which are considered foreign functional currency. In 2011, the unrealized foreign exchange loss arising from the translation of the debt was $18 million, net of tax of $3 million, which was recorded in other comprehensive income ("OCI").

Including cross-currency swaps and the debt that has been designated as a hedge of a net investment, 27% of long-term debt is exposed to changes in the Canadian/U.S. exchange rate (2010 – 42%).

Husky holds 50% of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and this receivable is denominated in U.S. dollars. Related gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in net foreign exchange gains or losses in current period net earnings. At December 31, 2011, Husky's share of this receivable was U.S. $1.1 billion (2010 – U.S. $1.3 billion) including accrued interest. Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a foreign functional currency entity. At December 31, 2011 Husky's share of this obligation was U.S. $1.4 billion (2010 – U.S. $1.4 billion) including accrued interest.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meets its liabilities when they become due. The Company prepares annual capital expenditure budgets, which are monitored and are updated as required. In addition, the Company requires authorizations for expenditures on projects to assist with the management of capital.

The following are the contractual maturities of the Company's financial liabilities as at December 31, 2011:

	2012	2013	2014	2015	2016	Thereafter
Accounts payable and accrued liabilities	2,867	–	–	–	–	–
Other long-term liabilities	20	43	43	30	1	25
Long-term debt	407	–	779	306	208	2,211

The Company's contribution payable to the joint arrangement with BP of U.S. $1.4 billion is payable between December 31, 2011 and December 31, 2015, with the final balance due by December 31, 2015 (Refer to Section 8.3 for additional contractual obligations).

Credit and Contract Risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial instrument, in owing an amount to the Company, fail to meet or discharge their obligation to the Company. Husky actively manages its exposure to credit and contract execution risk from both a customer and a supplier perspective.

The Company's debt instruments are rated by various credit rating agencies. These ratings affect the Company's ability to gain access to debt financing at attractive terms. If any of the Company's credit rating agencies downgrade the Company's debt instruments, it may restrict the Company's ability to issue debt and may also increase the cost of borrowing, including under existing credit facilities.

Fair Value of Financial Instruments

The derivative portion of cash flow hedges, fair value hedges, and freestanding derivatives that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon the fair value hierarchy that reflects the significance of the inputs used in determining fair value. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. 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 valuations are based on inputs that are unobservable and significant to the overall fair value measurement.

8.7 Outstanding Share Data

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

Issued and outstanding: February 29, 2012

• common shares	965,757,608
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	32,792,775
• stock options exercisable	18,341,697

8.8 Liquidity Summary

The following information relating to Husky's credit ratings is provided as it relates to Husky's financing costs, liquidity and operations. Specifically, 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 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. In addition, changes in credit ratings may affect Husky's ability to enter, and the associated costs of entering, (i) into ordinary course derivative or hedging transactions, which may require Husky to post additional collateral under certain of its contracts, and (ii) into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

	Rating	Last Review	Last Rating Change
Moody's:			
Outlook	Stable	August 17, 2011	August 17, 2011
Senior Unsecured Debt	Baa2	August 17, 2011	April 25, 2001
Standard and Poor's:			
Outlook	Stable	December 9, 2011	July 27, 2006
Senior Unsecured Debt	BBB+	December 9, 2011	July 27, 2006
Series 1 Preferred Shares	P-2 (low)	March 11, 2011	March 11, 2011
Dominion Bond Rating Service:			
Trend	Stable	March 10, 2011	March 31, 2008
Senior Unsecured Debt	A (low)	March 10, 2011	March 31, 2008
Series 1 Preferred Shares	Pfd-2 (low)	March 10, 2011	March 10, 2011

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 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.

9.0 Application of Critical Accounting Estimates

Husky's Consolidated Financial Statements have been prepared in accordance with IFRS. Significant accounting policies are disclosed in Note 3 to the Consolidated Financial Statements. Certain of the Company's accounting policies require subjective judgment about uncertain circumstances. The following discussion highlights the nature and potential effect of these estimates. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

Depletion Expense

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 reserves using the unit of production method.

Withheld Costs

Costs related to exploration and evaluation activities and major development projects 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.

Impairment of Long-Lived Assets

Impairment is indicated if the carrying value of the long-lived asset or oil and gas cash generating unit exceeds its recoverable amount. 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 judgments 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.

Fair Value of Derivative Instruments

Periodically Husky utilizes financial derivatives and hedge accounting to manage market risk.

The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through forward market prices and compared with quotes from financial institutions. The estimation of fair value of forward purchases of U.S. dollars is determined using forward market prices.

Asset Retirement Obligations ("ARO")

Husky has significant obligations to remove tangible assets and restore land after operations cease and Husky retires or relinquishes the asset. The Company's ARO primarily relates to the Upstream business. The retirement of Upstream assets consists primarily of plugging and abandoning wells, removing and disposing of surface and subsea equipment and facilities and restoring land to a state required by regulation or contract. Estimating the 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 the ARO are numerous assumptions and judgments 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.

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 assumptions that affect expected future benefit payments. These assumptions 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.

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.

Income Tax Accounting

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Business Combinations

Under the acquisition method, the acquiring company includes the fair value of the various assets and liabilities of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. In some circumstances the fair value of an asset is determined by estimating the amount and timing of future cash flows associated with that asset. The actual amounts and timing of cash flow may differ materially and may possibly lead to an impairment charged to net earnings. Contingent consideration associated with a business combination is based on the satisfaction of future conditions which requires Husky to make certain judgments of the probability of such conditions being fulfilled to estimate the contingent consideration to be paid in future years. The actual consideration paid may differ materially from amounts estimated in the provision recorded.

10.0 Recent Accounting Standards

International Financial Reporting Standards ("IFRS")

Husky has completed its adoption of IFRS for the year beginning on January 1, 2011. As a result, the Company's financial results for the year ended December 31, 2011 and comparative periods are reported under IFRS while selected historical data continues to be reported under previous Canadian GAAP (Refer to Note 26 of the Consolidated Financial Statements for the Company's assessment of impacts of the transition to IFRS).

Presentation of Financial Statements

In June 2011, the IASB issued IAS 1, "Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements." The amendments stipulate the presentation of net earnings and OCI and also require the Company to group items within OCI based on whether the items may be subsequently reclassified to net earnings. Amendments to IAS 1 were effective for the Company beginning on January 1, 2012 with required retrospective application and early adoption permitted.

The Company retrospectively adopted the amendments on January 1, 2012. The adoption of the amendments to this standard did not have a material impact on the Company's financial statements.

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 linkage 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 in its financial statements for the annual period beginning January 1, 2013. The adoption of the standard is not expected to have a significant 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 are 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 retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 11 in its financial statements for the annual period beginning January 1, 2013 and is currently reviewing the classification of its joint arrangements. The extent of the impact of adoption of IFRS 11 has not yet been determined.

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 in its financial statements for the annual period beginning January 1, 2013. It is expected that IFRS 12 will increase the current level of disclosure related to the Company's interests in other entities upon adoption.

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 will be 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 in its financial statements for the annual period beginning on January 1, 2013. The Company does not expect the amendments to IAS 28 to have a material impact on the 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. The standard also provides a framework for recurring valuations that are subject to measurement uncertainty and 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 prospectively in its financial statements for the annual period beginning January 1, 2013. The extent of the impact of adoption of IFRS 13 has not yet been determined.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19, "Employee Benefits", to eliminate the corridor method that permits the deferral of actuarial gains and losses, to revise the presentation requirements for changes in defined benefit plan assets and liabilities and to enhance the required disclosures for defined benefit plans. Amendments to IAS 19 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 in its financial statements for the annual period beginning 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 in its financial statements for the annual period beginning January 1, 2013 and the IAS 32 amendments for the annual period beginning 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 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 significant 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 2012 Capital Program; the Company's financial strategy; the Company's 2012 production guidance; and the timing of adoption and anticipated impact of recent accounting standards;
- with respect to the Company's Asia Pacific Region: the timetable for project execution, development plans, timing of FEED, anticipated rates of production and anticipated timing of first gas for the Company's Liwan Gas Project; planned timing of regulatory submissions and anticipated timing of first gas at the Company's Madura Straits block, offshore Indonesia; and exploration plans for the Company's North Sumbawa II block, offshore Indonesia;
- with respect to the Company's Atlantic Region: timing of well completions and expected effect of the pilot program at the Company's West White Rose field; drilling plans at the Company's North Amethyst and White Rose fields; exploration plans for offshore Canada's East Coast and Greenland; continued evaluation of a concrete wellhead and drilling platform in the White Rose region; and the timing, duration and expected impact of the planned offstation of the SeaRose and Terra Nova FPSOs;
- with respect to the Company's Oil Sands properties: project schedule, anticipated costs and anticipated timing and rates of first production at Phase I of the Company's Sunrise Energy Project; expected timing of availability for use of the construction camp building at the Sunrise Energy Project; expected timing of completion of FEED for the next development stage of the Sunrise Energy Project; drilling and development plans and timetable for the Company's Tucker project; expected timing of well completion and production at the Company's McMullen property; and 2012 evaluation plans at the Company's Saleski property;
- with respect to the Company's Heavy Oil properties: anticipated timing of when the Company's Pikes Peak South and Paradise Hill thermal projects are expected to become operational; the expected timing of commissioning of the CO_2 capture and liquefaction plant project at the Lloydminster Ethanol Plant, and planned use of CO_2 from the plant; and 2012 drilling plans for the Company's horizontal drilling program;
- with respect to the Company's Western Canadian oil and gas resource plays: 2012 drilling plans at the Company's Kaybob property, Redwater project, Saskatchewan Viking project, Shaunavon oil resource play, Wapiti project and Kakwa project; and timing of the pilot drilling program at the Company's Mackenzie Valley properties;
- with respect to the Company's Midstream operating segment: the expected timing and outcome of construction of a 300,000 barrel tank at the Hardisty terminal; and
- with respect to the Company's Downstream operating segment: bitumen processing and capacity expansion plans for the Toledo Refinery; continued reconfiguration of the Lima Refinery for heavy crude oil feedstock; anticipated timing and expected outcomes of the construction of the kerosene hydrotreater at the Lima Refinery; advancement of the Company's Continuous Catalyst Regeneration Reformer Project; the timing of planned turnarounds at the Upgrader, Lloydminster Refinery, Toledo Refinery and Lima Refinery; and the timing and expected impact of planned outages at the Lima Refinery.

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

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

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

The Company's Annual Information Form for the year ended December 31, 2011 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 Reserve 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, 2011.

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 and also on secondary non-GAAP measurements. The non-GAAP measurements included in this report are cash flow from operations, operating netback, return on equity, return on average capital employed, debt to capital employed, debt to cash flow, corporate reinvestment ratio, interest coverage on long-term debt and interest coverage on total debt. None of these measurements are used to enhance the Company's reported financial performance or position. With the exception of cash flow from operations, there are no comparable measures in accordance with IFRS. These are useful complementary measurements in assessing Husky's financial performance, efficiency and liquidity. The non-GAAP measurements do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other users. They are common in the reports of other companies but may differ by definition and application. Except as described below, the definitions of these measurements are found in Section 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 from operations to cash flow – operating activities for the years ended December 31:

($ millions)		2011	2010
Non-GAAP	Cash flow from operations	**5,198**	3,072
	Settlement of asset retirement obligations	**(105)**	(60)
	Income taxes paid	**(282)**	(784)
	Interest received	**12**	1
	Change in non-cash working capital	**269**	(7)
GAAP	Cash flow – operating activities	**5,092**	2,222

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 2011 netback was determined by taking 2011 upstream netback (gross revenues less operating costs less royalties) divided by 2011 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 March 1, 2012. 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 2011, 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, 2011 and 2010 and Husky's financial position as at December 31, 2011 and at December 31, 2010.

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.
- 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 Average Capital Employed	*Net earnings plus after tax interest expense divided by the two-year average capital employed*
Return on Equity	*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 oil and gas 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 oil and gas 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, 2011, 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, 2011, management assessed the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective and that there are no material weaknesses in Husky's internal control over financial reporting that have been identified by management.
4) KPMG LLP, who has audited the Consolidated Financial Statements of Husky for the year ended December 31, 2011, 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, 2011, 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

		2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	2010 Q3	2010 Q2	2010 Q1
Upstream									
Daily production, before royalties									
Light crude oil & NGL *(mbbls/day)*		**91.7**	**83.3**	**84.5**	**91.0**	75.1	84.4	78.7	84.3
Medium crude oil *(mbbls/day)*		**24.3**	**24.6**	**24.6**	**24.6**	25.3	25.7	25.1	25.3
Heavy crude oil *(mbbls/day)*		**75.8**	**75.1**	**73.6**	**73.4**	74.6	72.4	74.6	76.4
Bitumen *(mbbls/day)*		**27.4**	**23.6**	**23.6**	**24.2**	23.1	21.9	21.5	22.6
		219.2	**206.6**	**206.3**	**213.2**	198.1	204.4	199.9	208.6
Natural gas *(mmcf/day)*		**597.9**	**614.7**	**631.8**	**583.3**	494.2	505.5	503.9	523.7
Total production *(mboe/day)*		**318.9**	**309.1**	**311.6**	**310.4**	280.5	288.7	283.9	295.9
Average sales prices									
Light crude oil & NGL *($/bbl)*		**105.97**	**100.44**	**107.29**	**99.29**	82.90	73.88	75.61	76.72
Medium crude oil *($/bbl)*		**84.32**	**70.11**	**80.27**	**67.83**	65.75	60.88	63.90	69.30
Heavy crude oil *($/bbl)*		**75.60**	**61.61**	**71.59**	**58.86**	58.82	56.96	56.18	63.31
Bitumen *($/bbl)*		**73.24**	**58.70**	**68.62**	**55.41**	59.14	55.41	52.58	61.82
Natural gas *($/mcf)*		**3.24**	**3.64**	**3.66**	**3.66**	3.52	3.50	3.45	4.81
Operating costs *($/boe)*		**14.75**	**15.17**	**14.25**	**14.00**	13.94	13.27	13.08	12.81
Operating netbacks[1]									
Lloydminster – Thermal Oil *($/boe)*[2]		**47.67**	**37.04**	**43.34**	**29.10**	37.77	32.05	31.06	36.51
Lloydminster – Non-Thermal Oil *($/boe)*[2]		**45.42**	**33.78**	**41.63**	**31.48**	32.12	31.31	30.30	37.51
Oil Sands – Bitumen *($/boe)*[2]		**36.23**	**25.28**	**36.39**	**20.07**	(0.03)	11.14	(4.76)	9.18
Western Canada – Crude Oil *($/boe)*[2]		**46.21**	**33.77**	**44.39**	**35.00**	40.57	36.70	33.23	35.42
Western Canada – Natural gas *($/mcf)*[3]		**1.82**	**2.29**	**2.36**	**2.36**	2.08	1.53	1.95	3.26
Atlantic – Light Oil *($/boe)*[2]		**82.17**	**81.94**	**85.91**	**80.25**	60.55	51.14	44.68	48.65
Asia Pacific – Light Oil & NGL *($/boe)*[2]		**69.98**	**67.01**	**67.25**	**73.37**	61.48	54.66	59.46	56.93
Total *($/boe)*[2]		**41.25**	**35.88**	**40.77**	**36.23**	32.91	29.70	28.36	33.82
Net wells drilled[4]									
Exploration	Oil	**19**	**8**	**4**	**9**	12	17	3	19
	Gas	**11**	**3**	**1**	**9**	9	6	1	15
	Dry	**–**	**–**	**–**	**3**	–	1	–	7
		30	**11**	**5**	**21**	21	24	4	41
Development	Oil	**196**	**286**	**93**	**190**	257	235	52	179
	Gas	**4**	**8**	**3**	**27**	38	6	–	9
	Dry	**–**	**2**	**1**	**–**	2	2	–	5
		200	**296**	**97**	**217**	297	243	52	193
		230	**307**	**102**	**238**	318	267	56	234
Success ratio *(percent)*		**100**	**99**	**99**	**99**	99	99	100	95
Midstream									
Pipeline throughput *(mbbls/day)*		**548**	**534**	**568**	**580**	501	489	537	524
Upgrader									
Synthetic crude oil sales *(mbbls/day)*		**58.2**	**60.7**	**61.0**	**41.0**	45.1	21.0	58.0	68.6
Upgrading differential *($/bbl)*		**22.32**	**29.87**	**33.09**	**24.00**	16.39	13.80	15.44	12.54
Canadian Refined Products									
Refined products sales volumes									
Light oil products *(million litres/day)*		**9.4**	**9.9**	**8.3**	**8.4**	8.7	8.5	7.8	7.6
Asphalt products *(mbbls/day)*		**20.1**	**36.4**	**20.2**	**19.9**	27.5	30.9	19.2	18.7
Refinery throughput									
Lloydminster refinery *(mbbls/day)*		**29.0**	**28.5**	**26.2**	**28.9**	29.0	28.9	26.1	27.0
Prince George refinery *(mbbls/day)*		**11.1**	**7.9**	**9.1**	**11.0**	11.5	11.9	6.9	9.7
Refinery utilization *(percent)*		**97**	**88**	**85**	**96**	99	100	80	90

(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 Financial Information

	Upstream				Midstream				Downstream			
					Infrastructure and Marketing				Upgrading			
2011 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues[(2)]	**1,984**	**1,715**	**1,880**	**1,671**	**2,436**	**2,228**	**2,414**	**2,368**	**615**	**585**	**649**	**368**
Royalties	**(331)**	**(247)**	**(289)**	**(258)**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Revenues, net of royalties	**1,653**	**1,468**	**1,591**	**1,413**	**2,436**	**2,228**	**2,414**	**2,368**	**615**	**585**	**649**	**368**
Expenses												
Purchases of crude oil and products[(2)]	**–**	**–**	**–**	**–**	**2,295**	**2,131**	**2,317**	**2,203**	**463**	**390**	**459**	**269**
Production and operating expenses	**426**	**437**	**416**	**393**	**26**	**22**	**13**	**34**	**37**	**47**	**46**	**58**
Selling, general and administrative expenses	**24**	**33**	**51**	**42**	**6**	**7**	**6**	**6**	**3**	**–**	**–**	**–**
Depletion, depreciation, amortization and impairment	**590**	**494**	**480**	**432**	**17**	**9**	**10**	**10**	**25**	**27**	**87**	**25**
Exploration and evaluation expenses	**194**	**95**	**88**	**93**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Other – net	**3**	**(1)**	**(72)**	**(189)**	**2**	**(16)**	**10**	**10**	**24**	**18**	**15**	**10**
Earnings from operating activities	**416**	**410**	**628**	**642**	**90**	**75**	**58**	**105**	**63**	**103**	**42**	**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	**398**	**395**	**611**	**628**	**90**	**75**	**58**	**105**	**61**	**101**	**41**	**4**
Provisions for (recovery of) income taxes												
Current	**–**	**(29)**	**11**	**20**	**26**	**45**	**30**	**20**	**–**	**(2)**	**1**	**1**
Deferred	**105**	**114**	**157**	**152**	**(4)**	**(26)**	**(15)**	**6**	**16**	**28**	**10**	**–**
	105	**85**	**168**	**172**	**22**	**19**	**15**	**26**	**16**	**26**	**11**	**1**
Net earnings (loss)	**293**	**310**	**443**	**456**	**68**	**56**	**43**	**79**	**45**	**75**	**30**	**3**
Capital expenditures[(3)]	**1,159**	**853**	**607**	**1,512**	**14**	**13**	**10**	**6**	**20**	**19**	**6**	**10**
Total assets	**20,117**	**19,343**	**18,869**	**18,631**	**1,543**	**1,532**	**1,410**	**1,717**	**1,315**	**1,266**	**1,301**	**1,335**

(1) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.*

(2) *In 2011, the Company changed its treatment of certain intersegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast by approximately $250 million per quarter and did not impact net earnings.*

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

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
938	1,162	927	833	2,371	2,413	2,585	2,224	(2,190)	(1,884)	(2,001)	(1,802)	6,154	6,219	6,454	5,662
–	–	–	–	–	–	–	–	–	–	–	–	(331)	(247)	(289)	(258)
938	1,162	927	833	2,371	2,413	2,585	2,224	(2,190)	(1,884)	(2,001)	(1,802)	5,823	5,972	6,165	5,404
795	957	783	713	2,091	2,127	2,189	1,896	(2,111)	(1,924)	(2,008)	(1,771)	3,533	3,681	3,740	3,310
44	48	48	42	102	107	90	92	(1)	–	1	(10)	634	661	614	609
13	11	12	13	2	2	1	2	60	43	68	23	108	96	138	86
20	23	19	18	52	48	45	50	12	10	9	7	716	611	650	542
–	–	–	–	–	–	–	–	–	–	–	–	194	95	88	93
–	–	–	–	–	–	–	–	(8)	6	–	(1)	21	7	(47)	(170)
66	123	65	47	124	129	260	184	(142)	(19)	(71)	(50)	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)
64	122	63	46	123	128	259	183	(179)	(43)	(99)	(94)	557	778	933	872
14	4	3	4	20	54	–	–	93	(13)	27	25	153	59	72	70
2	28	12	8	25	(7)	94	67	(148)	61	(66)	(57)	(4)	198	192	176
16	32	15	12	45	47	94	67	(55)	48	(39)	(32)	149	257	264	246
48	90	48	34	78	81	165	116	(124)	(91)	(60)	(62)	408	521	669	626
33	28	18	15	72	68	62	22	34	22	12	3	1,332	1,003	715	1,568
1,623	1,630	1,616	1,569	5,476	5,459	5,043	5,034	2,352	2,456	1,852	507	32,426	31,686	30,091	28,793

2010 *($ millions)*	Upstream				Midstream – Infrastructure and Marketing				Downstream – Upgrading			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues[2]	1,487	1,385	1,334	1,538	1,700	1,704	1,772	1,826	366	291	405	508
Royalties	(211)	(233)	(248)	(286)	–	–	–	–	–	–	–	–
Revenues, net of royalties	1,276	1,152	1,086	1,252	1,700	1,704	1,772	1,826	366	291	405	508
Expenses												
Purchases of crude oil and products[2]	–	–	–	–	1,555	1,627	1,672	1,667	288	241	311	418
Production and operating expenses	364	352	344	343	42	35	40	46	46	43	43	49
Selling, general and administrative expenses	46	35	42	29	7	5	5	5	–	–	–	–
Depletion, depreciation, amortization and impairment	406	408	361	346	13	10	10	10	35	26	10	3
Exploration and evaluation expenses	233	25	131	49	–	–	–	–	–	–	–	–
Other – net	(2)	(1)	3	1	20	(8)	(9)	31	(32)	(2)	–	(7)
Earnings from operating activities	229	333	205	484	63	35	54	67	29	(17)	41	45
Net foreign exchange gains (losses)	–	–	–	–	–	–	–	–	–	–	–	–
Finance income	–	–	–	–	–	–	–	–	–	–	–	–
Finance expenses	(9)	(11)	(10)	(10)	–	–	–	–	(2)	(2)	(2)	(3)
	(9)	(11)	(10)	(10)	–	–	–	–	(2)	(2)	(2)	(3)
Earnings (loss) before income taxes	220	322	195	474	63	35	54	67	27	(19)	39	42
Provisions for (recovery of) income taxes												
Current	(68)	13	16	16	15	16	16	15	(20)	(4)	15	10
Deferred	131	80	41	121	2	(6)	(2)	3	28	(1)	(4)	2
	63	93	57	137	17	10	14	18	8	(5)	11	12
Net earnings (loss)	157	229	138	337	46	25	40	49	19	(14)	28	30
Capital expenditures[3]	1,152	595	439	626	15	10	12	3	49	108	16	9
Total assets	17,354	16,307	16,072	16,016	1,325	1,680	1,694	1,551	1,987	1,233	1,290	1,325

(1) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.*

(2) *In 2011, the Company changed its treatment of certain intersegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for 2010. The recast reduced gross revenues and purchases of crude oil and products by $217 million which did not impact net earnings.*

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

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
835	834	700	606	1,824	1.683	1,881	1,719	(1,722)	(1,425)	(1,462)	(1,704)	4,490	4.472	4,630	4.493
–	–	–	–	–	–	–	–	–	–	–	–	(211)	(233)	(248)	(286)
835	834	700	606	1,824	1,683	1,881	1,719	(1,722)	(1,425)	(1,462)	(1,704)	4,279	4,239	4,382	4,207
701	683	598	516	1,640	1,537	1,758	1,623	(1,643)	(1,432)	(1,500)	(1,680)	2,541	2,656	2,839	2,544
45	45	51	40	94	94	97	92	(8)	9	1	2	583	578	576	572
12	12	12	13	2	2	2	1	38	16	8	(1)	105	70	69	47
17	22	24	25	51	47	47	46	19	19	18	19	541	532	470	449
–	–	–	–	–	–	–	–	(3)	–	–	3	230	25	131	52
–	–	(2)	–	–	–	(2)	2	1	(8)	–	–	(13)	(19)	(10)	27
60	72	17	12	37	3	(21)	(45)	(126)	(29)	11	(47)	292	397	307	516
–	–	–	–	–	–	–	–	(76)	11	(14)	30	(76)	11	(14)	30
–	–	–	–	–	–	–	–	17	19	20	23	17	19	20	23
–	(1)	–	(1)	(3)	(1)	(1)	(1)	(75)	(63)	(67)	(63)	(89)	(78)	(80)	(78)
–	(1)	–	(1)	(3)	(1)	(1)	(1)	(134)	(33)	(61)	(10)	(148)	(48)	(74)	(25)
60	71	17	11	34	2	(22)	(46)	(260)	(62)	(50)	(57)	144	349	233	491
12	14	15	15	–	–	–	–	24	24	22	22	(37)	63	84	78
4	4	(10)	(12)	12	1	(8)	(17)	(135)	(53)	(47)	(52)	42	25	(30)	45
16	18	5	3	12	1	(8)	(17)	(111)	(29)	(25)	(30)	5	88	54	123
44	53	12	8	22	1	(14)	(29)	(149)	(33)	(25)	(27)	139	261	179	368
79	83	66	16	118	67	50	21	20	11	4	2	1,433	874	587	677
1,517	1,403	1,403	1,370	5,092	5,102	5,144	4,940	775	556	633	938	28,050	26,281	26,236	26,140

Segmented Capital Expenditures[1]

($ millions)	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	2010 Q3	2010 Q2	2010 Q1
Upstream								
Exploration								
Western Canada	**87**	**19**	**5**	**122**	63	134	64	83
Atlantic Region	**–**	**2**	**–**	**–**	7	–	5	56
Asia Pacific	**37**	**79**	**52**	**–**	65	7	63	94
	124	**100**	**57**	**122**	135	141	132	233
Development								
Western Canada	**734**	**541**	**336**	**439**	562	275	205	292
Atlantic Region	**61**	**62**	**73**	**62**	71	115	98	91
Asia Pacific	**226**	**150**	**123**	**47**	59	2	–	1
	1,021	**753**	**532**	**548**	692	392	303	384
Acquisitions								
Western Canada	**14**	**–**	**18**	**842**	325	62	4	9
Total Upstream	**1,159**	**853**	**607**	**1,512**	1,152	595	439	626
Midstream								
Infrastructure and Marketing	**14**	**13**	**10**	**6**	15	10	12	3
	14	**13**	**10**	**6**	15	10	12	3
Downstream								
Upgrader	**20**	**19**	**6**	**10**	49	108	16	9
Canadian Refined Products	**33**	**28**	**18**	**15**	79	83	66	16
U.S. Refining and Marketing	**72**	**68**	**62**	**22**	118	67	50	21
	125	**115**	**86**	**47**	246	258	132	46
Corporate	**34**	**22**	**12**	**3**	20	11	4	2
	1,332	**1,003**	**715**	**1,568**	1,433	874	587	677

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