Table of Contents

1. Summary of Quarterly Results

Quarterly and Annual Financial Summary (millions of dollars, except per share amounts)	Three months ended Dec. 31 2010	Sept. 30 2010	June 30 2010	March 31 2010	Dec. 31 2009	Sept. 30 2009	June 30 2009	March 31 2009	Year ended December 31 2010	2009
Sales and operating revenues, net of royalties	$ 4,731	$ 4,408	$ 4,568	$ 4,471	$ 3,605	$ 3,903	$ 3,916	$ 3,650	$18,178	$15,074
Net earnings	305	257	266	345	320	338	430	328	1,173	1,416
Per share - Basic and diluted	0.35	0.30	0.31	0.41	0.38	0.40	0.51	0.39	1.38	1.67
Cash flow from operations [1]	1,037	811	806	895	657	452	833	565	3,549	2,507
Per share - Basic and diluted	1.21	0.96	0.95	1.05	0.77	0.53	0.98	0.67	4.16	2.95

[1] Cash flow from operations is a non-GAAP measure. Refer to Section 11 for a reconciliation to GAAP.

Performance

- Cash flow from operations in the quarter increased to $1,037 million compared to $657 million in the same period in 2009 and $811 million in the third quarter of 2010.
- Net earnings in the quarter increased 19% from the previous quarter, but are slightly lower compared to the same period in 2009 due to:
  - Higher average realized crude oil prices offset by lower realized natural gas prices and the stronger Canadian dollar relative to the U.S. dollar; and
  - Increased realized refining margins and volume in U.S. Downstream; partially offset by
  - Lower Upstream production and increased depletion in South East Asia; and
  - The Enbridge Line 6A/6B shutdowns which reduced net earnings by an estimated $17 million.
- Production of 280,500 boe/day, down from 291,500 boe/day in the fourth quarter of 2009. Production in the quarter was impacted by the scheduled maintenance turnaround of the SeaRose FPSO. Total production at year-end was 292,500 boe/day.

Acquisitions and Divestitures

- Announced acquisition of natural gas and oil properties in Alberta and northeast British Columbia.
  - Acquisition adds approximately 21.9 mboe/day of production, 104 mmboe of proved reserves and 9 mmboe of probable reserves. The reserve estimates are as of December 1, 2010.

    - Effective date of acquisition is December 1, 2010; closed on February 4, 2011.
- Closed acquisition of natural gas properties in west central Alberta adding 32.6 mmboe of proved reserves, 10.8 mmboe of probable reserves and production of 10.8 mboe/day effective June 1, 2010. The reserve estimates are as of December 31, 2010.
- Agreement for sale of oil sands mining leases for consideration of $200 million which closed in January 2011.

Key Projects

- Phase I of the Sunrise Energy Project sanctioned for development.
- Completed the successful drilling of a second appraisal well at the Liuhua 29-1 discovery on Block 29/26 in the South China Sea.

Financial

- Strengthened the Company's financial position by a successful issue of common shares, raising a total of $1.0 billion in equity financing.

2. Business Environment

Average Benchmarks		Year ended December		Three months ended					
		2010	2009	Dec. 31 2010	Sept. 30 2010	June 30 2010	Mar. 31 2010	Dec. 31 2009	Sept. 30 2009
WTI crude oil [(1)]	(U.S. $/bbl)	79.46	61.80	84.89	76.20	78.03	78.71	76.19	68.30
Brent crude oil [(2)]	(U.S. $/bbl)	79.42	61.54	86.27	76.86	78.30	76.24	74.56	68.43
Canadian light crude 0.3% sulphur	($/bbl)	77.75	66.19	80.48	74.77	75.44	80.31	76.75	71.82
Lloyd heavy crude oil @ Lloydminster	($/bbl)	59.87	53.60	60.76	57.29	57.10	65.11	62.66	59.83
NYMEX natural gas [(3)]	(U.S. $/mmbtu)	4.39	3.99	3.80	4.38	4.09	5.30	4.17	3.39
NIT natural gas	($/GJ)	3.91	3.92	3.39	3.52	3.66	5.08	4.01	2.87
WTI/Lloyd crude blend differential	(U.S. $/bbl)	14.48	9.93	18.37	15.90	14.34	9.29	12.37	10.26
Chicago 3:2:1 crack spread	(U.S. $/bbl)	9.20	8.43	9.13	10.16	11.33	6.23	4.92	8.38
New York Harbor 3:2:1 crack spread	(U.S. $/bbl)	9.64	8.33	11.41	8.62	10.44	8.21	6.06	8.03
U.S./Canadian dollar exchange rate	(U.S. $)	0.971	0.880	0.987	0.962	0.973	0.961	0.947	0.912
Canadian Equivalents									
WTI crude oil [(4)]	($/bbl)	81.83	70.23	86.01	79.21	80.20	81.90	80.45	74.89
Brent crude oil [(4)]	($/bbl)	81.79	69.93	87.41	79.90	80.47	79.33	78.73	75.03
WTI/Lloyd crude blend differential [(4)]	($/bbl)	14.91	11.28	18.61	16.53	14.74	9.67	13.06	11.25
NYMEX natural gas [(4)]	($/mmbtu)	4.52	4.53	3.85	4.55	4.20	5.52	4.40	3.72

(1) Prices quoted are near-month contract prices for settlement during the next month.
(2) Dated Brent prices are dated less than 15 days prior to loading for delivery.
(3) Prices quoted are average settlement prices for deliveries during the period.
(4) Prices quoted are calculated using U.S. benchmark commodity prices and U.S./Canadian dollar exchange rates.

Oil and Gas Prices

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 is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2010 at U.S. $91.38/bbl, increasing from U.S. $79.36/bbl on December 31, 2009, averaging U.S. $79.46/bbl in 2010 compared with U.S. $61.80/bbl in 2009, and U.S. $84.89/bbl in the fourth quarter of 2010 compared with U.S. $76.19/bbl in the fourth quarter of 2009. The price of Brent ended 2010 at U.S. $92.55/bbl, increasing from U.S. $77.67/bbl on December 31, 2009, averaging U.S. $79.42/bbl in 2010 compared with U.S. $61.54/bbl in 2009 and averaged U.S. $86.27/bbl in the fourth quarter of 2010 compared with U.S. $74.56/bbl in the fourth quarter of 2009.

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 2010, 48% of Husky's crude oil production was heavy oil or bitumen compared with 47% in 2009. The light/heavy crude oil differential averaged U.S. $14.48/bbl or 18% of WTI in 2010 increasing from U.S. $9.93/bbl or 16% of WTI in 2009. In the fourth quarter of 2010, 49% of Husky's crude oil production was heavy oil or bitumen compared with 50% in the fourth quarter of 2009. The light/heavy crude oil differential averaged U.S. $18.37/bbl or 22% of WTI in the fourth quarter of 2010 increasing from U.S. $12.37/bbl or 16% of WTI in the fourth quarter of 2009.

The near-month natural gas price quoted on the NYMEX ended 2010 at U.S. $4.41/mmbtu compared with U.S. $5.57/mmbtu at December 31, 2009. During 2010, the NYMEX near-month contract price of natural gas averaged U.S. $4.39/mmbtu compared with U.S. $3.99/mmbtu in 2009. During the fourth quarter of 2010, the NYMEX near-month contract price of natural gas averaged U.S. $3.80/mmbtu compared with U.S. $4.17/mmbtu in the fourth quarter of 2009.

Foreign Exchange

The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities.

The Canadian dollar ended 2009 at U.S. $0.956 and closed at U.S. $1.005 at December 31, 2010. In 2010, the Canadian dollar averaged U.S. $0.971 strengthening by 10% compared with U.S. $0.880 during 2009. In the fourth quarter of 2010, the Canadian dollar averaged U.S. $0.987, strengthening by 4% compared with U.S. $0.947 during the fourth quarter of 2009.

Increased U.S. crude oil prices have been partially offset by the significant strengthening of the Canadian dollar against the U.S. dollar in 2010. The price of WTI in 2010 in U.S. dollars increased 29% compared with an increase of 17% in Canadian dollars when compared to 2009. In the fourth quarter of 2010, the price of WTI in U.S. dollars increased 11% compared with 7% in Canadian dollars when compared to the fourth quarter of 2009.

Refining Crack Spreads

The 3:2:1 crack spread is the key indicator for refining margins as refinery gasoline output is approximately twice the distillate output. This crack spread is equal to the price of two-thirds of a barrel of gasoline plus one-third of a barrel of fuel oil (distillate) less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel, and do not necessarily reflect the actual crude purchase costs or product configuration of a specific refinery.

During 2010, the Chicago 3:2:1 crack spread averaged U.S. $9.20/bbl compared with U.S. $8.43/bbl in 2009. During the fourth quarter of 2010, the Chicago 3:2:1 crack spread averaged U.S. $9.13/bbl compared with U.S. $4.92/bbl in the fourth quarter of 2009. During 2010, the New York Harbor 3:2:1 crack spread averaged U.S. $9.64/bbl compared with U.S. $8.33/bbl in 2009. During the fourth quarter of 2010, the New York Harbor 3:2:1 crack spread averaged U.S. $11.41/bbl compared with U.S. $6.06/bbl in the fourth quarter of 2009.

Husky's realized refining margins are affected by the product configuration of its refineries, 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 Canadian generally accepted accounting principles ("GAAP").

Cost Environment

From 2003 to 2008, the oil and gas industry experienced increasing costs that rose above the general trend of inflation. This resulted when the high level of industry activity, precipitated by escalating oil and gas prices, created demand for goods and services that exceeded supply. This increased the cost of operating the Company's oil and gas properties, processing plants and refineries. As a result of the global economic and financial crisis, the level of drilling and completions in the Western Canada Sedimentary Basin was significantly reduced in 2009, recovering in respect of oil well completions in 2010 while low natural gas prices continued to depress gas well completions. In addition, prospective capital projects including oil sands developments and major plant modifications were deferred pending cost improvements. Oil and gas prices declined rapidly in the latter half of 2008 and the first quarter of 2009, however, a corresponding decline in costs was delayed until the latter half of 2009. Crude oil prices have since recovered to the U.S. $80/bbl to

U.S. $90/bbl range and industry activity, both drilling and field services, is increasing. The cost of field services is beginning to rise with higher demand, particularly in new technology driven plays.

Enbridge Line 6A/6B Shutdowns

During the third quarter of 2010, a crude oil release occurred on both Line 6A near Romeoville, Illinois and Line 6B near Marshall, Michigan. The pipelines in those vicinities were shutdown until appropriate repairs were made. Line 6A was shutdown on September 9 and returned to service September 17. Line 6B was shutdown on July 26 and resumed service on September 27. Since resuming service, Line 6B has continued to operate at less than full capacity.

The Enbridge Line 6A/6B shutdowns caused a widening in the light/heavy crude oil differential which negatively impacted medium and heavy crude oil and bitumen realized prices in Upstream. The shutdowns also reduced throughput at the Toledo Refinery in the third quarter of 2010 due to limited heavy crude oil availability and increased feed stock costs as heavy oil was partially replaced with light oil where available. In the fourth quarter, the widened differential resulted in lower feedstock costs which benefited the Midstream and Downstream segments as unit margins increased for the Lloydminster Upgrader, Lloydminster Refinery and Toledo Refinery, which partially offset the negatively impacted medium and heavy crude oil and bitumen realized prices in Upstream. The shutdowns also increased Husky's inventory volumes at the end of the year as the Company increased storage volumes to mitigate the impact of selling medium and heavy crude oil and bitumen at distressed prices to third parties as a result of the widened differential. The result of the Enbridge Line 6A/6B shutdowns was an approximate $53 million dollar reduction to Husky's net earnings ($60 million reduction in Upstream, $10 million increase in Midstream, $3 million reduction in Downstream) in 2010.

Global Economic and Financial Environment

During the fourth quarter of 2010 WTI spot prices fluctuated between U.S. $91.50/bbl and U.S. $79.60/bbl and in the first month and a half of 2011 averaged above U.S. $89.00/bbl. In its February 8, 2011 Short-term Energy Outlook[(1)] the Energy Information Administration ("EIA") indicated that it expects markets for crude oil and liquid fuels to tighten over the next two years. The EIA expects world oil consumption to grow an average of 1.5 mmbbls/day through 2012 and for supply from non-Organization of the Petroleum Exporting Countries ("non-OPEC") to increase marginally. As a result the market will need to draw on inventories and increased supply from OPEC. OPEC spare productive capacity averaged an estimated 4.7 mmbbls/day during 2010 and is expected to average 4.7 mmbbls/day in 2011 and 4.2 mmbbls/day in 2012. OPEC liquid fuel supply, which is not subject to OPEC's production policy, is expected to add marginally to total OPEC supply through 2012. At its meeting on December 11, 2010 OPEC agreed to maintain its current production policy and is scheduled to meet again June 2, 2011. The EIA estimates that Organization for Economic Cooperation and Development ("OECD") countries held 2.7 billion barrels of commercial oil inventories at the end of 2010. This represents approximately 57 days of forward cover. The EIA expects OECD oil inventories to remain close to the middle of the past five year range throughout the forecast period, ending 2012 with 55 days of forward cover.

In the EIA's February 8, 2011 Short-term Energy Outlook, natural gas consumption in U.S. markets is expected to remain flat through 2012. Higher consumption in the industrial and electrical generation sectors is mostly offset by reductions in the residential and commercial sectors. Natural gas production in the U.S. is expected to level off in the near term, increasing by 2% from 2010 to 2012. Imports of both pipeline natural gas and liquefied natural gas into the U.S. are expected to decline over the forecast period. In its Weekly Natural Gas Storage Report[(2)] released February 3, 2011, the EIA reported that natural gas stocks were equal to the five year average and 2.8% below the previous year. The EIA expects continued natural gas price volatility in the near term.

There are a number of uncertainties that could result in higher or lower commodity prices. They include decisions made by OPEC regarding their production levels, the rate of global and U.S. economic recovery, the response by governments to various fiscal issues, the effect of China's efforts to address its growth and inflation and the general political stability of certain key strategic areas in the world.

Note:

(1) Energy Information Administration, Short-Term Energy Outlook DOE/EIA – February 8, 2011 Release.

(2) "Weekly Natural Gas Storage Report", February 3, 2011, Energy Information Administration, U.S. Department of Energy.

Sensitivity Analysis

The following table indicates the relative annual effect of changes in certain key variables on Husky's pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the fourth quarter of 2010. Each 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	2010 Fourth Quarter Average		Increase	Effect on Annual Pre-tax Cash Flow [6]		Effect on Annual Net Earnings [6]	
				($ millions)	($/share) [7]	($ millions)	($/share) [7]
Upstream and Midstream							
WTI benchmark crude oil price [1]	$	84.89	U.S. $1.00/bbl	62	0.07	45	0.05
NYMEX benchmark natural gas price [2]	$	3.80	U.S. $0.20/mmbtu	24	0.03	18	0.02
WTI/Lloyd crude blend differential [3]	$	18.37	U.S. $1.00/bbl	(12)	(0.01)	(10)	(0.01)
Downstream							
Canadian light oil margins	$	0.048	Cdn $0.005/litre	14	0.02	10	0.01
Asphalt margins	$	14.87	Cdn $1.00/bbl	7	0.01	5	0.01
New York Harbor 3:2:1 crack spread [4]	$	11.41	U.S. $1.00/bbl	75	0.08	47	0.05
Consolidated							
Exchange rate (U.S. $ per Cdn $) [1] [5]	$	0.987	U.S. $0.01	(55)	(0.06)	(39)	(0.04)
Interest rate			100 basis points	(15)	(0.02)	(11)	(0.01)

(1) Does not include gains or losses on inventory.
(2) Includes decrease in net earnings related to natural gas consumption.
(3) Excludes impact on asphalt operations.
(4) Relates to U.S. Refining & Marketing.
(5) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.
(6) Excludes mark to market accounting impacts.
(7) Based on 890.7 million common shares outstanding as of December 31, 2010.

3. Strategic Plan

Husky's current strategy is to continue to exploit oil and gas assets in Western Canada, while advancing its three major growth pillars in the oil sands, the Atlantic Region and South East Asia. Husky is an integrated company in a specialized sense. 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 assets. The Company's strategy is to maximize the efficiency of its Midstream and Downstream operations and extract the greatest value from production.

4. Key Growth Highlights

The 2010 capital program was established with a view of maintaining Husky's balance sheet and taking advantage of opportunities as economic conditions improve and financial uncertainty abates. Capital expenditures continued to focus on those projects offering the highest potential for returns and mid to long-term growth. During 2010, as a result of an ongoing comprehensive review of the Company's operations and business strategies, Husky increased its capital program and redirected a portion of it to focus on delivering near-term production growth.

Husky's 2011 capital program has been established with a view of enabling the Company to build 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 oil sands, the Atlantic Region and South East Asia.

Upstream

Atlantic Region

White Rose Satellite Development Projects

Drilling of development wells continues at North Amethyst with a second water injector completed and on production in January 2011. A total of 11 wells are planned for North Amethyst, including 2 to 3 wells in 2011.

Husky continues to progress plans for a staged development of the West White Rose field. In August 2010, the Company received regulatory approval for a 2-well pilot project to be drilled from existing infrastructure at the White Rose field. These wells will provide additional information on the reservoir to refine development plans for the full West White Rose field. A production licence was received in the fourth quarter of 2010, and first production is anticipated mid-2011.

Atlantic Region Exploration

Husky was successful in acquiring a new significant discovery licence ("SDL") as well as exploration rights to three additional parcels of land in the Canada-Newfoundland and Labrador Offshore Petroleum Board's November land sale. The exploration properties are adjacent to other Husky land holdings in the Jeanne d'Arc Basin and Flemish Pass.

The new SDL extends the previous Mizzen discovery which was awarded in the first quarter of 2010. Husky holds a 35% working interest in the Mizzen property. An appraisal well is planned at Mizzen in the third quarter of 2011.

Offshore Greenland

Husky is continuing its evaluation of 2-D and 3-D seismic acquired in 2008 and 2009. Final processing of the 3-D seismic for Block 7 was completed in the fourth quarter of 2010. Final processing of Block 5 data is expected to be completed in late February 2011. Preliminary evaluation of the seismic data has identified several leads. Potential drilling locations will be identified over the course of the first quarter of 2011.

Heavy Oil

Construction of the 8,000 bbls/day South Pike's Peak commercial project was approximately 49% complete at the end of 2010. Production is expected to commence in the first half of 2012.

Horizontal well developments progressed through the fourth quarter of 2010, targeting new geological horizons in existing regions. Forty-seven wells were drilled in the fourth quarter of 2010 which brings the total number of wells drilled in 2010 to 101.

Husky continued to operate two solvent enhanced oil recovery ("EOR") pilots through the fourth quarter of 2010 at Edam and Mervin. A CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant is under construction with expected completion in the third quarter of 2011. This liquefied CO_2 is to be used in the ongoing piloting program.

A microbial EOR pilot in Wainwright, Alberta continued in the fourth quarter of 2010 with nine wells continuing to show a substantial response eight months after initial treatments. A second pilot in Devonia Lake has commenced with two cycles of treatments completed. The preliminary results show a 20% increase in oil production.

Oil Sands

Sunrise Energy Project

Husky and BP PLC ("BP") continue to advance the development of the Sunrise Energy Project in multiple stages and sanctioned Phase I in the fourth quarter of 2010. Husky awarded major engineering and construction contracts to Snamprogetti Canada for the central processing facilities and to Worley Parsons for the field facilities. Development drilling commenced in the first quarter of 2011. Husky has initiated conceptual development engineering for subsequent phases and is expecting a comprehensive full field development plan to be established by the end of 2011. First production for Phase I is planned for 2014.

Tucker Oil Sands Project

Based on a greater understanding of the Tucker reservoir, Husky is addressing production challenges by remediating older wells with innovative new stimulation techniques, drilling new wells and initiating new start up procedures. The results will be evaluated over the next six to twelve months. Husky drilled 32 wells (16 well pairs) in 2010 and is expecting to drill eight wells (four well pairs) in 2011. Three well pairs commenced production in late September 2010 and are exceeding the performance of well pairs previously drilled. Production at Tucker for December 2010 was 6.1 mboe/day compared to 5.0 mboe/day in December 2009. Several applications to the Energy Resources Conservation Board ("ERCB") have been approved or are proceeding for additional drilling and field development through to 2015.

McMullen

Cold production from McMullen averaged 1,950 bbls/day in the fourth quarter of 2010 up from 1,450 bbls/day in the third quarter of 2010. Six slant development wells and 12 evaluation wells were drilled in the fourth quarter of 2010.

Husky has submitted an application and received ERCB approval for an air injection pilot. Construction will be proceeding in the first quarter of 2011 with ignition scheduled for late in the second quarter of 2011. Husky intends to use the heat generated from the combustion front from an air injection well to facilitate bitumen movement.

Sale of Oil Sands Leases

On January 14, 2011, the Company completed a sales agreement to sell 23 square miles of mining leases in Alberta for a consideration of $200 million.

Western Canada (excluding Heavy Oil and Oil Sands)

Asset Acquisitions

In November 2010, Husky announced that a purchase and sale agreement had been signed with ExxonMobil Canada Ltd. to acquire oil and natural gas properties in Alberta and northeast British Columbia. The acquired assets will add 16.3 mboe/day to natural gas production, 4.8 mboe/day to oil production and 0.8 mboe/day to natural gas liquids production. Based on reserve estimates at December 1, 2010, the acquisition will contribute 104 mmboe of proved reserves and nine mmboe of probable reserves to a core producing area. The acquisition closed on February 4, 2011.

The purchase of natural gas properties in west central Alberta, announced in September 2010, was closed on November 30, 2010. The acquisition added 10.8 mboe/day of natural gas production, 32.6 mmboe of proved reserves and 10.8 mmboe of probable reserves to a core producing area. The reserve estimates are as at December 31, 2010.

Husky recognizes operating results from the acquisitions after the closing date. The operating results between the effective date and the closing date are adjusted against the purchase price.

Gas Resource Plays

The Company continues to selectively add additional land to its gas resource portfolio with approximately 28 sections acquired during the fourth quarter of 2010.

As part of Husky's heightened focus on growing near-term production, the Company continued exploration and development drilling of its liquids-rich natural gas assets in the Ansell area. In the fourth quarter of 2010, 12 Cardium formation development wells and six exploration wells were drilled to test the deeper multi-zone potential. Drilling operations are expected to continue into 2011. Facility capacity expansion work proceeded through the fourth quarter with approximately 70% of the detailed engineering completed and a majority of the long lead equipment orders placed.

Husky is also accelerating development drilling in the Bivouac and Galloway areas with an additional two Bivouac dual leg wells and eight Galloway wells drilled in the fourth quarter with production expected in the second quarter of 2011.

At Kakwa, the first well in a three well exploration program was spud in late December 2010. This program will test the multi-zone Cretaceous potential that targets the same formations as Husky's exploration program at Ansell.

In British Columbia, a partner operated horizontal well was drilled to further evaluate the Montney Formation on Husky's Cypress lands, and completion of this well is expected to be done in the first quarter of 2011. Also, near the end of the fourth quarter of 2010, 3-D seismic programs were initiated in the Ansell, Komie (Horn River), and Sierra areas.

Oil Resource Plays

Fourteen Viking wells are now on production in the Dodsland/Elrose area of southwest Saskatchewan. Two wells were drilled in December 2010 and will be completed in the first quarter of 2011. Seven Viking horizontal wells were drilled at Redwater, Alberta in the fourth quarter of 2010, to bring the total wells drilled in 2010 to 23. Three evaluation wells are currently under production testing to assess the Cardium zone at Lanaway.

Production and evaluation of the Lower Shaunavon and Bakken zones continues in southern Saskatchewan. In the Lower Shaunavon zone, three successful horizontal wells were brought on production in 2010 with three additional wells to be drilled in the first quarter of 2011. In the Bakken zone, four successful horizontal wells were drilled in 2010 with two producing in 2010 and two expected to be producing in the first quarter of 2011. An additional two Bakken wells are to be drilled in the first quarter of 2011.

Alkaline Surfactant Polymer Floods

Husky's Alkaline Surfactant Polymer ("ASP") EOR Program is underway with active projects at Warner and Crowsnest in Southern Alberta and Gull Lake, Saskatchewan. Future floods include Fosterton and Bone Creek, Saskatchewan. At Fosterton, the facility design work is nearing completion and long lead equipment orders have been placed. Facility construction is expected to commence in 2011 with an expected start up in the first half of 2012.

South East Asia

Offshore China Exploration, Delineation and Development

In the fourth quarter of 2010, the West Hercules rig completed drilling of the Liuhua 29-1-3 appraisal well. This well, which represents the second appraisal well to be drilled on the Liuhua 29-1 field, encountered quality reservoir sands with approximately 60 metres of gas pay and was cased for possible future re-entry and completion as a producing well. The West Hercules rig then successfully drilled the Liwan 3-1-11 appraisal well with the aim of testing the eastern part of the Liwan 3-1 field. The well encountered a quality gas charged reservoir and was cased for future re-entry and completion as a producing well. In December 2010, the West Hercules completed the Liwan 3-1-9 development well and in late January 2011 completed the Liwan 3-1-5 development well as part of the nine well development program for the field. The West Hercules is currently drilling the Liwan 3-1-8 development well.

In early December Husky Oil China Ltd. signed a Heads of Agreement with China National Offshore Oil Corporation ("CNOOC") which specifies key principles of the joint venture to fund, develop and operate the Liwan 3-1 deep water gas field, shallow water and onshore gas processing facilities. This document is a precursor to the Supplemental Development Agreement ("SDA") which will be the definitive agreement governing these issues. Husky expects the plan of development for the Liwan 3-1 field to be submitted in the first quarter of 2011 and is currently tendering all of the deep water equipment and installation activity. Under the current plan, the Liwan 3-1 and Liuhua 34-2 fields on Block 29/26 will be developed in parallel, with first gas production targeted in late 2013. The plan of development for the Liuhua 29-1 field is targeted for submission in 2012, after appraisal drilling and evaluation work has been completed. Gas production from the Liuhua 29-1 field will share common gas processing and transportation infrastructure with the aforementioned fields. Husky holds a 100% working interest in Block 29/26, which CNOOC has the right to participate up to 51%.

On Block 63/05 in the Qiongdongnan Basin, 50 kilometres south of Hainan Island, processing of new 2-D and 3-D seismic data has been completed and the data is currently being interpreted. A decision will be made in the first quarter of 2011 on the drilling of an exploration well which is planned for later in the year. Husky holds a 100% interest in Block 63/05, for which CNOOC has the right to participate up to 51%.

Indonesia Exploration and Development

In October 2010, the Government of Indonesia approved the extension of the existing Madura Strait Production Sharing Contract ("PSC") that was originally awarded in 1982. The approval provides Husky and its partner, CNOOC, a 20-year extension to the existing contract which would have expired in 2012. This extension provides the basis for the development of the Madura BD field as the gas sales agreements are in place and the plan of development has been approved by the Indonesian government. The front end engineering was completed in the second quarter of 2010 with the engineering tendering process to begin in early 2011.

Both Husky and CNOOC agreed to sell a 10% equity stake in Husky Oil (Madura) Ltd. to Samudra Energy Ltd. through its affiliate, SMS Development Ltd. Following the completion of the sale, Husky and CNOOC respectively hold a 40% equity interest in Husky Oil (Madura) Ltd. with the remaining 20% balance held by SMS Development Ltd. This sale closed in January 2011.

At the North Sumbawa II Exploration Block, interpretation of 1,020 kilometres of new 2-D seismic data is at an advanced stage. Husky will use this data to define an exploration prospect for future drilling, which is currently planned to commence in 2012. Husky holds a 100% interest in the North Sumbawa II Block, comprised of 5,000 square kilometres in the East Java Sea and may seek to farm-out part of its working interest prior to drilling.

Downstream

Lima, Ohio Refinery

The Lima, Ohio Refinery successfully completed a turnaround on the fluid catalytic cracker, coker, and associated units in the fourth quarter of 2010. Several large safety, environmental, reliability, and optimization projects were completed. The refinery continues to advance short term reliability and profitability projects and is evaluating a staged repositioning approach pending an improvement in the light/heavy crude differential outlook.

Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery is continuing as planned and construction formally commenced in August 2010. The refinery continues to advance a multi-year program to improve operational integrity and plant performance and reduce operating costs and environmental impacts.

Retail

At the end of 2010, Husky completed the rebranding of all 98 sites in Eastern Canada acquired in late 2009.

At the end of 2010, the Company's total number of fuel outlets was 555.

5. Results of Operations

5.1 Upstream

Upstream Net Earnings Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)	2010	2009	2010	2009
Gross revenues	$ 1,487	$ 1,451	$ 5,744	$ 5,313
Royalties	211	251	978	861
Net revenues	1,276	1,200	4,766	4,452
Operating and administration expenses	419	372	1,599	1,495
Depletion, depreciation and amortization	404	351	1,572	1,397
Other income	-	-	(2)	-
Income taxes	131	143	462	447
Net earnings	$ 322	$ 334	$ 1,135	$ 1,113

Fourth Quarter

Upstream net earnings in the fourth quarter of 2010 decreased by $12 million compared with the fourth quarter of 2009 primarily as a result of a decrease in total production, the impact of the Enbridge Line 6A/6B shutdowns on realized medium and heavy crude oil and bitumen prices and an increase in operating costs and depletion, partially offset by increased realized prices for light crude oil and the settlement of redetermined participation interests in Terra Nova resulting in a gain of $31.8 million, net of tax.

Production of crude oil and natural gas was 280,500 boe/day in the fourth quarter of 2010 compared to 291,500 boe/day in the fourth quarter of 2009 and 288,700 boe/day in the third quarter of 2010, primarily due to lower production at the White Rose field as a result of a 16-day scheduled turnaround, as well as lower production of natural gas and heavy crude oil in Western Canada, partially offset by additional production from the North Amethyst field.

The average realized price in the fourth quarter of 2010 was $68.87/bbl for crude oil, NGL and bitumen compared with $66.65/bbl during the same period in 2009 with higher realized prices for light oil partially offset by lower realized prices for heavy oil and bitumen. Realized natural gas prices averaged $3.52/mcf in the fourth quarter of 2010 compared with $3.94/mcf in the same period in 2009. Stronger U.S. dollar crude oil and natural gas pricing was partially offset by the strengthening of the Canadian dollar. The realized price for medium and heavy crude oil and bitumen was negatively impacted by the Enbridge Line 6A/6B shutdowns as the differential increased.

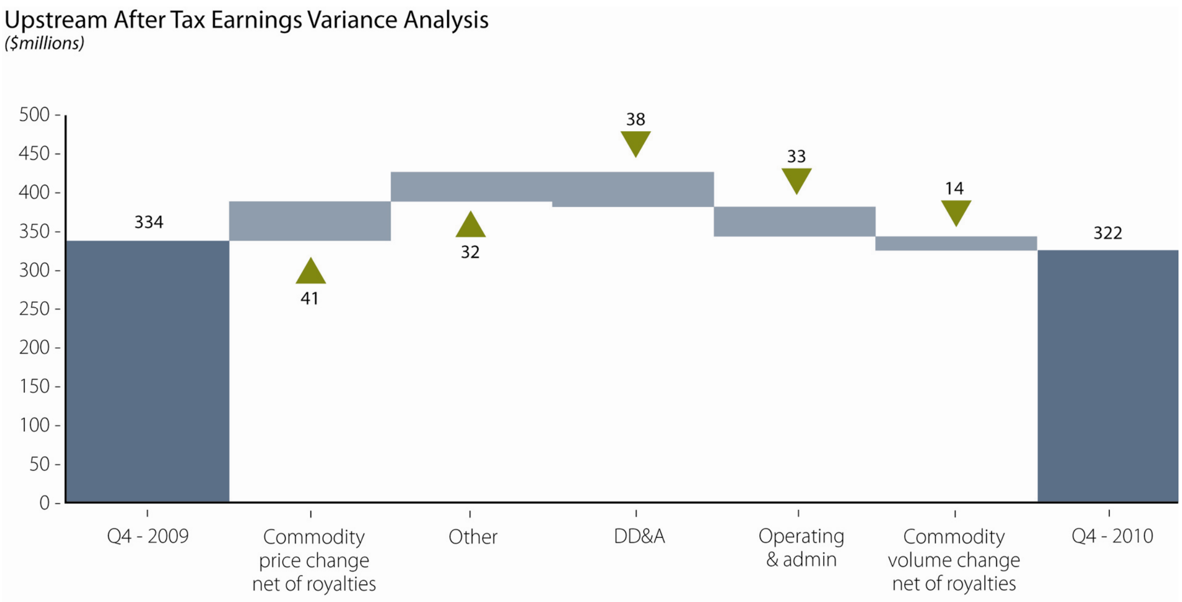
Twelve Months

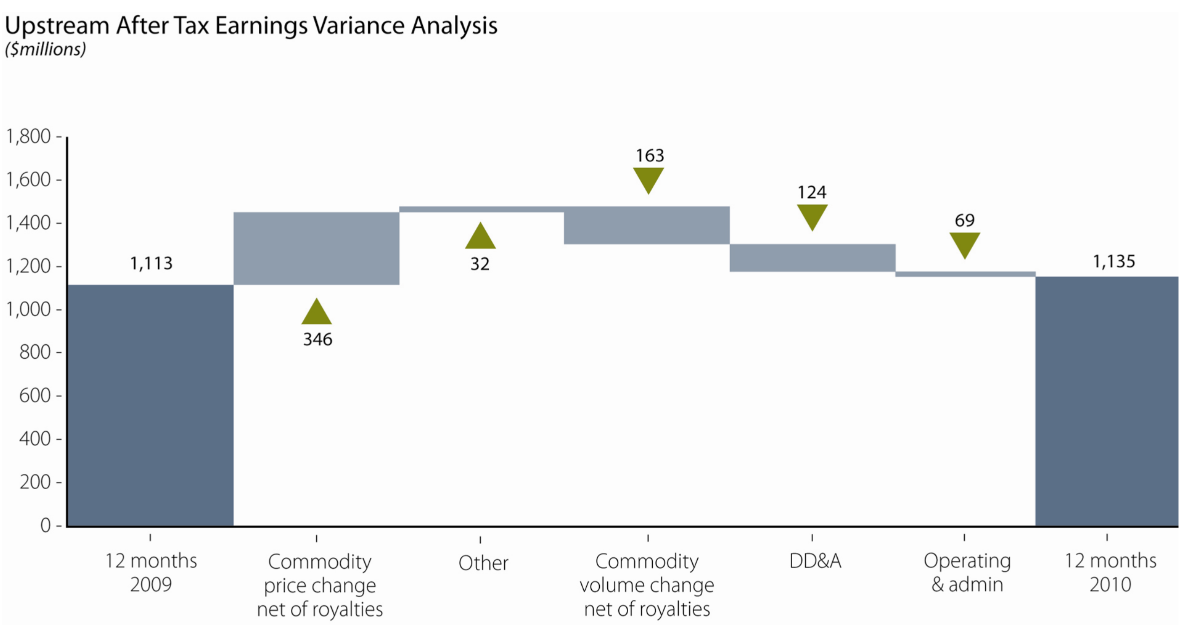
Upstream earnings in 2010 were $22 million higher compared with the same period in 2009. The increase was primarily due to the higher average price realized on crude oil and bitumen and the settlement of redetermined participation interests for Terra Nova, partially offset by lower oil and natural gas production in 2010 compared with 2009, the impact of the Enbridge Line 6A/6B shutdowns and increased depletion in South East Asia.

During 2010, the average realized price increased 17% to $66.70/bbl for crude oil, NGL and bitumen compared with $57.11/bbl during the same period in 2009. Realized natural gas prices averaged $3.86/mcf during 2010 compared with $3.83/mcf in 2009.

The Enbridge Line 6A/6B shutdowns caused a widening in the light/heavy crude oil differential which negatively impacted medium and heavy crude oil and bitumen realized prices as a result of industry wide inventory build up in Western Canada. This resulted in an estimated $60 million negative impact to Upstream net earnings for the year.

Upstream After Tax Variance Analysis





Pricing

Average Sales Prices Realized		Three months ended Dec. 31		Year ended Dec. 31	
		2010	2009	2010	2009
Crude oil	($/bbl)				
Light crude oil & NGL		$ 82.90	$ 73.98	$ 76.90	$ 62.70
Medium crude oil		65.75	65.78	64.92	56.37
Heavy crude oil (1)		58.82	61.55	58.91	52.54
Bitumen (1)		59.14	60.70	57.84	51.90
Total average		68.87	66.65	66.70	57.11
Natural gas average	($/mcf)	3.52	3.94	3.86	3.83

(1) A portion of the Company's heavy crude oil production meets the U.S. Securities and Exchange Commission's definition of bitumen.

Increased U.S. dollar crude oil prices were partially offset by the strengthening of the Canadian dollar against the U.S. dollar in 2010 compared to 2009. The realized price for medium and heavy crude oil and bitumen was negatively impacted by the Enbridge Line 6A/6B shutdowns as the differential increased.

Oil and Gas Production

Daily Gross Production		Three months ended Dec. 31		Year ended Dec. 31	
		2010	2009	2010	2009
Crude oil & NGL	(mbbls/day)				
Western Canada					
Light crude oil & NGL		23.0	22.4	23.0	22.8
Medium crude oil		25.3	24.8	25.4	25.4
Heavy crude oil (1)		74.6	78.6	74.5	78.6
Bitumen (1)		23.1	23.3	22.3	23.1
		146.0	149.1	145.2	149.9
Atlantic Region					
White Rose - light crude oil		21.7	34.8	31.2	45.2
North Amethyst - light crude oil		12.5	-	7.0	-
Terra Nova - light crude oil		7.1	9.0	8.5	10.0
China					
Wenchang - light crude oil & NGL		10.8	10.5	10.7	11.1
Total crude oil & NGL		198.1	203.4	202.6	216.2
Natural gas	(mmcf/day)	494.2	528.7	506.8	541.7
Total	(mboe/day)	280.5	291.5	287.1	306.5

(1) A portion of the Company's heavy crude oil production meets the U.S. Securities and Exchange Commission's definition of bitumen.

Crude Oil and NGL Production

Fourth Quarter

Crude oil, bitumen and NGL production in the fourth quarter of 2010 decreased by 5.3 mbbls/day or 3% compared with 2009. The decrease is primarily due to lower heavy crude oil production as a result of the impact of extremely wet weather which delayed the drilling program, and lower production from Terra Nova due to operational (H_2S contamination) problems throughout the fourth quarter, slightly offset by additional production from

Tucker due to success in its 2010 drilling and perforation program. Production of crude oil at White Rose decreased by 13.1 mbbls/day compared with 2009 as the 2009 annual planned turnaround took place in the third quarter of 2009 whereas the 2010 turnaround (16 days) took place in October. The decreased production at White Rose was offset by additional production at North Amethyst. Production at North Amethyst was also impacted by the planned turnaround in the fourth quarter of 2010.

Twelve Months

During 2010, crude oil, bitumen and NGL production decreased by 13.6 mbbls/day or 6% compared with 2009, primarily due to the decline in production from White Rose as a result of declines from peak production rates post the 2009 turnaround and natural reservoir declines, partially offset by production at North Amethyst. Terra Nova production was primarily impacted by the same factors impacting the fourth quarter. Heavy oil production was impacted by extremely wet weather conditions in the third quarter and the subsequently delayed drilling program in the fourth quarter.

Natural Gas Production

Fourth Quarter

Natural gas production decreased by 34.5 mmcf/day or 7% in the fourth quarter of 2010 compared with the fourth quarter of 2009 due to the impact of lower capital expenditure on development and natural reservoir decline, partially offset by additional production from the west central Alberta acquisition that was closed on November 30, 2010.

Twelve Months

In 2010, natural gas production decreased by 34.9 mmcf/day or 6% compared with 2009 primarily due to the same factors impacting the fourth quarter.

2010 Production Guidance			Actual Production	
		Revised Guidance	Year ended Dec. 31 2010	Year ended Dec. 31 2009
Crude oil & NGL	(mbbls/day)			
Light crude oil & NGL		81 – 84	81	89
Medium crude oil		25 – 27	25	25
Heavy crude oil & bitumen		94 – 97	97	102
		200 – 208	203	216
Natural gas	(mmcf/day)	510 – 520	507	542
Natural gas	(mboe/day)	85 – 87	84	91
Total barrels of oil equivalent	(mboe/day)	285 – 295	287	307

Husky's production for the year ended December 31, 2010 is within the revised guidance set by the Company in the 2010 Second Quarter MD&A.

Royalties

Fourth Quarter

In the fourth quarter of 2010, royalty rates averaged 15% as a percentage of gross revenue compared with 17% in 2009. Royalty rates in Western Canada averaged 13%, down from 15% in the same period in 2009 as a result of a favourable royalty provision adjustment recorded in the fourth quarter of 2010. Rates for the Atlantic Region averaged 18% in the fourth quarter of 2010 down from 24% in the fourth quarter of 2009. The lower rate this quarter is attributable to the North Amethyst field which is subject to a basic royalty of 1%, while Terra Nova and White Rose, being mature fields, are subject to higher rates. Rates at North Amethyst will increase and reach the same level as Terra Nova and White Rose after certain project payouts as prescribed in the royalty regulations are met. Royalty rates in Wenchang averaged 24% in the fourth quarter of 2010, comparable to 23% in the fourth quarter of 2009.

Twelve Months

Royalty rates averaged 17% of gross revenue in 2010 compared with 16% in 2009. Rates in Western Canada averaged 15%, up from 13% in 2009 primarily as a result of increased commodity prices. In the Atlantic Region the average rate was 24% compared with 25% in 2009. Royalty rates in Wenchang averaged 23% compared with 17% in 2009 due to the sliding scale royalty clause in the PSC that results in higher rates in a higher commodity price environment.

Operating Costs

(millions of dollars)	Three months ended Dec. 31 2010	Three months ended Dec. 31 2009	Year ended ended Dec. 31 2010	Year ended ended Dec. 31 2009
Western Canada	$ 310	$ 289	$ 1,199	$ 1,124
Atlantic Region	43	33	176	177
International	7	8	24	23
Total	$ 360	$ 330	$ 1,399	$ 1,324
Unit operating costs ($/boe)	$ 13.85	$ 12.24	$ 13.33	$ 11.82

Fourth Quarter

Total upstream operating costs increased to $360 million from $330 million as a result of increased treating, servicing and maintenance costs. Total upstream unit operating costs in the fourth quarter of 2010 averaged $13.85/boe compared with $12.24/boe in the fourth quarter of 2009 due to higher costs and lower production.

Operating costs in Western Canada averaged $14.63/boe in the fourth quarter compared with $13.21/boe in the same period in 2009 primarily as a result of increased energy, treating and maintenance costs, increased handling, transportation and disposal of increased water and emulsion production, as well as lower production in the fourth quarter of 2010 compared with the same period in 2009. The increase is also due to additional well work overs resulting from acquisitions, and additional perforation activity to stimulate production at Tucker. Maturing fields in Western Canada require increasing amounts of infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive gathering systems, crude and water trucking and more complex natural gas compression systems. Husky is focused on managing operating costs associated with the increased infrastructure through cost reduction and efficiency initiatives and keeping infrastructure fully utilized.

Operating costs in the Atlantic Region averaged $11.43/boe in the fourth quarter of 2010 compared with $8.10/boe in 2009 primarily as a result of increased vessel costs, labour, servicing and maintenance costs at White Rose and North Amethyst in the fourth quarter of 2010 compared with the same period in 2009.

Operating costs at the South China Sea offshore operations averaged $6.31/bbl in the fourth quarter of 2010 compared with $7.33/bbl in the same period in 2009, as a result of slightly higher production and lower maintenance and work over operation costs in the fourth quarter of 2010 compared with 2009.

Twelve Months

Total upstream operating costs in 2010 increased by 6% compared with 2009 primarily due to the same factors affecting the fourth quarter.

Unit Depletion, Depreciation and Amortization (“DD&A”)

Fourth Quarter

In the fourth quarter of 2010, total DD&A averaged $15.66/boe compared with $13.10/boe in the fourth quarter of 2009. The increased DD&A rate in the fourth quarter of 2010 was primarily due to a larger full cost base in the Atlantic Region and China compared with the same period in 2009 primarily as a result of relinquished exploration blocks and dry holes as well as additions related to the development program at North Amethyst.

Twelve Months

During 2010, total DD&A averaged $15.00/boe compared with $12.49/boe during 2009 due primarily to the same factors affecting the fourth quarter. Depletion expense in the Atlantic Region and China was higher in 2010 compared with 2009 due to the same factors impacting the fourth quarter, which was partially offset by lower DD&A in Western Canada as a result of lower production.

Upstream Capital Expenditures

During 2010, upstream capital expenditures were $3,171 million, relative to the revised 2010 capital expenditure program of $3,150 million. Upstream capital expenditures were $2,235 million (70%) in Western Canada, $492 million (16%) in the Atlantic Region and $444 million (14%) in South East Asia. Husky's major projects remain on schedule.

Capital Expenditures Summary [1]	Three months ended Dec. 30		Year ended Dec. 31	
(millions of dollars)	2010	2009	2010	2009
Exploration				
Western Canada	$ 95	$ 134	$ 441	$ 266
Atlantic Region	16	37	96	95
Northwest United States	-	10	-	25
International	91	127	381	495
	202	308	918	881
Development				
Western Canada	927	445	1,794	923
Atlantic Region	91	84	396	510
International	60	4	63	12
	1,078	533	2,253	1,445
	$ 1,280	$ 841	$ 3,171	$ 2,326

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

The following table discloses the number of gross and net exploration and development wells Husky completed in Western Canada and the oil sands during the periods indicated:

Western Canada and Oil Sands Wells Drilled		Three months ended Dec. 31				Year ended Dec. 31			
		2010		2009		2010		2009	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	15	12	9	5	60	51	18	9
	Gas	11	9	3	-	37	31	37	22
	Dry	-	-	1	1	8	8	7	6
		26	21	13	6	105	90	62	37
Development	Oil	283	257	136	116	815	722	315	278
	Gas	46	38	19	8	73	53	122	61
	Dry	2	2	2	2	10	9	7	7
		331	297	157	126	898	784	444	346
Total		357	318	170	132	1,003	874	506	383

Western Canada

During 2010, Husky invested $2,235 million on exploration and development throughout the Western Canada Sedimentary Basin compared with $1,189 million in 2009. Of this, $877 million was invested in oil exploration and development and $426 million was invested in natural gas exploration and development compared with $379 million for oil exploration and development and $375 million for natural gas exploration and development in 2009. The Company drilled 874 net wells in the basin during 2010 resulting in 773 net oil wells and 84 net natural gas wells compared with 383 net wells resulting in 287 net oil wells and 83 net natural gas wells in 2009. In addition, $134 million was spent on production optimization initiatives in 2010. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to $331 million and $401 million was primarily spent on acquisition of natural gas properties in west central Alberta. During 2010, capital expenditures on oil sands projects were $66 million compared with $29 million in 2009.

The following table discloses Husky's offshore and international drilling activity during 2010:

Offshore and International Drilling Activity			
Canada - Atlantic Region			
Glenwood H-69	WI 100%	Stratigraphic test	Exploratory
North Amethyst G-25-1	WI 68.875%	Water injection	Development
North Amethyst G-25-2	WI 68.875%	Production	Development
North Amethyst G-25-3	WI 68.875%	Production	Development
North Amethyst G-25-4	WI 68.875%	Water Injection	Development
North Amethyst H-14	WI 68.875%	Stratigraphic test	Delineation
West White Rose E-18-10	WI 68.875%	Production	Development
South East Asia - China			
Liuhua 29-1-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liuhua 34-2-2 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 3-3-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liuhua 29-1-2 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 5-2-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liuhua 34-3-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 3-1-10 Block 29/26	WI 100% (1)	Stratigraphic test	Development
Liuhua 29-1-3 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 3-1-11 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 3-1-9 Block 29/26	WI 49%	Production	Development
Liwan 3-1-5 Block 29/26	WI 49%	Production	Development
Liwan 3-1-8 Block 29/26	WI 49%	Production	Development
HZ 8-1-1 Block 04/35	WI 100% (1)	Stratigraphic test	Exploratory

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

Atlantic Region Development

During 2010, $396 million was invested on Atlantic Region development projects primarily at North Amethyst and West White Rose satellite tie-back development projects, including drilling operations at North Amethyst and completion of facilities construction and installation. At West White Rose, capital expenditures focused on drilling, advancing engineering design and planning.

Atlantic Region Exploration

During 2010, Husky spent $93 million primarily on the Glenwood H-69 exploration well northwest of the West White Rose field and geological and geographic data and studies.

Offshore China and Indonesia

During 2010, $444 million was spent primarily on offshore projects in China, including the drilling of four exploration, four delineation and three development wells on Block 29/26 in the South China Sea and one exploration well on Block 04/35 in the East China Sea.

2011 Upstream Capital Program [1] (millions of dollars)	
Western Canada - oil and gas	$ 2,450
- oil sands	415
Atlantic Region	350
International	1,180
Total upstream capital expenditures	$ 4,395

[1] Excludes capitalized administrative costs and capitalized interest.

The 2011 capital program will enable Husky to build on the momentum achieved in accelerating near-term production, and represents an increase of over 20% from the 2010 program, including the acquisition of producing properties in Alberta and northeast British Columbia from ExxonMobil Canada Ltd. The capital program enables the Company to advance its three major growth pillars in the oil sands, the Atlantic Region and South East Asia.

Upstream capital spending for Western Canada is targeted at opportunities offering the highest potential returns and focuses on the Company's heavy oil, oil and liquid-rich gas resource plays. Highlights include Phase I of the Sunrise Energy Project, heavy oil investment, including an increased focus on the use of horizontal wells to access producing zones, and advancement of the 8,000 bbls/day South Pikes Peak thermal heavy oil project. Spending has also been allocated to advance the Company's liquid rich gas resource play developments and new oil resource play exploration and development.

In the Atlantic Region, capital spending is focused on the continued development drilling at North Amethyst and West White Rose.

In South East Asia, capital spending is focused on the continuing development of the deepwater Liwan Gas Project and exploration and development programs offshore China and Indonesia.

Upstream Planned Turnarounds

The annual maintenance turnaround for the SeaRose FPSO is scheduled for 16 days in July 2011. The next Terra Nova FPSO turnaround is scheduled to commence in July 2011.

Off-station turnaround planning for the SeaRose FPSO for 2012 to address the maintenance of the propulsion system, is currently being progressed. Husky continues to investigate the various options available for this work.

5.2 Midstream

Upgrading Net Earnings Summary		Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)		2010	2009	2010	2009
Gross revenues		$ 366	$ 445	$ 1,570	$ 1,572
Gross margin		$ 77	$ 79	$ 311	$ 296
Operating and administration expenses		47	49	185	188
Depreciation and amortization		42	9	100	34
Other income		(2)	-	(5)	(3)
Income taxes (recoveries)		(3)	7	9	23
Net earnings (loss)		$ (7)	$ 14	$ 22	$ 54
Selected operating data:					
Upgrader throughput [(1)]	(mbbls/day)	55.7	77.4	65.4	74.1
Synthetic crude oil sales	(mbbls/day)	45.1	64.5	54.1	61.8
Upgrading differential	($/bbl)	$ 16.39	$ 13.06	$ 14.52	$ 11.89
Unit margin	($/bbl)	$ 18.55	$ 13.29	$ 15.73	$ 13.11
Unit operating cost [(2)]	($/bbl)	$ 9.19	$ 6.72	$ 7.76	$ 6.92

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

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

Fourth Quarter

During the fourth quarter of 2010, the upgrading differential averaged $16.39/bbl, an increase of $3.33/bbl or 26% compared with the fourth quarter of 2009. The differential is equal to Husky Synthetic Blend, which sells at a premium to WTI, less Lloyd Heavy Blend. The overall unit margin increased to $18.55/bbl in the fourth quarter of 2010 from $13.29/bbl in the same period in 2009 primarily as a result of wider heavy to light crude oil price differentials due to the Enbridge Line 6A/6B shutdowns. The decrease in throughput was primarily due to a 53-day major scheduled turnaround at the Lloydminster Upgrader that commenced in late August and was completed on October 22, 2010. The increase in depreciation and amortization is due to changes in the estimated remaining life of certain components of the Upgrader.

Twelve Months

Upgrading earnings for 2010 were affected by the same factors impacting the fourth quarter. The Enbridge Line 6A/6B shutdowns caused a widening in the upgrading differentials which resulted in an estimated $10 million increase to net earnings in 2010.

Infrastructure and Marketing Net Earnings Summary		Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)		2010	2009	2010	2009
Gross revenues		$ 1,936	$ 1,692	$ 7,854	$ 6,984
Gross margin	- pipeline	$ 31	$ 26	$ 124	$ 106
	- other infrastructure and marketing	71	51	193	195
		102	77	317	301
Operating and administration expenses		6	5	21	19
Depreciation and amortization		13	9	43	36
Other (income) expense		20	(5)	34	(33)
Income taxes		17	19	59	79
Net earnings		$ 46	$ 49	$ 160	$ 200
Selected operating data:					
Commodity volumes managed	(mboe/day)	1,021	808	952	912
Aggregate pipeline throughput	(mbbls/day)	501	498	512	514

Fourth Quarter

Infrastructure and Marketing net earnings in the fourth quarter of 2010 were $46 million compared with $49 million in the fourth quarter of 2009. Pipeline margins increased due to higher pipeline blending differentials and broker margins. Increased margins on other infrastructure and marketing were the result of higher realized oil prices and higher commodity trading margins. Other expenses in the fourth quarter of 2010 decreased by $25 million compared to the same period in 2009. Other expenses include the fair value impact of the Company's commodity price risk management activities. Refer to Section 7.5.

Twelve Months

Infrastructure and marketing earnings decreased $40 million in 2010 compared to 2009 primarily due to the same factors that impacted the fourth quarter.

Midstream Capital Expenditures

Midstream capital expenditures totalled $216 million in 2010 compared to $94 million in 2009. At the Lloydminster Upgrader, Husky spent $84 million primarily for facility reliability projects and $92 million was spent on the scheduled major turnaround. The remaining $40 million was spent on the acquisition of equipment used for sulphur operations and various pipeline upgrades.

Midstream Planned Turnaround

Husky is scheduled to complete a minor turnaround at the Lloydminster Upgrader in the third quarter of 2011, primarily for inspection and equipment maintenance. During this time the Upgrader is expected to be at 70% capacity. The next major turnaround is scheduled to commence in the fall of 2013.

5.3 Downstream

Canadian Refined Products Net Earnings Summary		Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)		2010	2009	2010	2009
Gross revenues		$ 835	$ 634	$ 2,975	$ 2,495
Gross margin	- fuel	$ 39	$ 16	$ 87	$ 111
	- ethanol	17	19	64	62
	- ancillary	11	11	46	43
	- asphalt	34	14	160	169
		101	60	357	385
Operating and administration expenses		24	22	110	94
Depreciation and amortization		18	24	91	93
Income taxes		15	4	41	57
Net earnings		$ 44	$ 10	$ 115	$ 141
Selected operating data:					
Number of fuel outlets (average)				508	482
Light oil sales	(million litres/day)	8.7	7.7	8.2	7.6
Light oil retail sales per outlet	(thousand litres/day)	13.9	13.8	13.8	13.2
Prince George Refinery throughput	(mbbls/day)	11.5	10.4	10.0	10.3
Asphalt sales	(mbbls/day)	27.5	18.9	24.1	22.6
Lloydminster Refinery throughput	(mbbls/day)	29.0	22.2	27.8	24.1
Ethanol production	(thousand litres/day)	691.4	736.4	619.3	676.9

Fourth Quarter

Gross margins on fuel sales were higher in the fourth quarter of 2010 compared to 2009 as a result of higher retail and wholesale market prices.

The lower ethanol gross margin in the fourth quarter of 2010 was due primarily to lower production compared to the same period in 2009 as a result of a scheduled 39-day turnaround at the Lloydminster Ethanol Plant as well as lower government assistance grants, partially offset by higher realized market prices. Included in ethanol gross margin in the fourth quarter of 2010 was $9 million related to government assistance grants compared with $13 million in the fourth quarter of 2009.

Asphalt gross margins were higher in the fourth quarter of 2010 compared with 2009 due to higher realized market prices and sales volumes. Asphalt margins were also positively impacted by lower feedstock costs due to the widening of the heavy to light crude oil price differential resulting from the Enbridge Line 6A/6B shutdowns.

Twelve Months

During 2010, refined products earnings were lower than the same period in 2009 primarily due to lower realized fuel and asphalt gross margins.

During 2010, fuel gross margins were lower than the same period in 2009 primarily due to lower realized market margins, partially offset by higher sales volumes.

Asphalt gross margins decreased compared to the same period in 2009 primarily due to higher input costs resulting in lower realized margins, partially offset by higher sales volumes. Ethanol gross margins increased during 2010 primarily due to higher production and sales volumes at the Minnedosa Ethanol Plant as well as lower input costs which were partially offset by lower production at the Lloydminster Ethanol Plant. Included in ethanol gross margin in 2010 was $50 million related to government assistance grants compared with $53 million in 2009.

The Enbridge Line 6A/6B shutdowns caused a widening in the heavy to light oil crude price differential which resulted in lower feedstock costs to the Lloydminster Refinery. This positively impacted Asphalt net earnings by an estimated $15 million in the second half of 2010.

U.S. Refining and Marketing Net Earnings Summary

(millions of dollars, except where indicated)		Three months ended Dec. 31 2010	Three months ended Dec. 31 2009	Year ended Dec. 31 2010	Year ended Dec. 31 2009
Gross revenues		$ 1,824	$ 1,169	$ 7,107	$ 5,349
Gross refining margin		$ 181	$ 80	$ 547	$ 852
Processing costs		95	101	378	423
Operating and administration expenses		1	-	8	7
Interest - net		-	1	2	3
Depreciation and amortization		51	47	191	194
Other (income) expense		-	(1)	-	30
Income taxes (recoveries)		12	(25)	(12)	71
Net earnings (loss)		$ 22	$ (43)	$ (20)	$ 124
Selected operating data:					
Lima Refinery throughput	(mbbls/day)	113.9	54.8	136.6	114.6
Toledo Refinery throughput	(mbbls/day)	64.6	67.5	64.4	64.9
Realized refining margin	(U.S. $/bbl crude throughput)	$ 10.97	$ 7.16	$ 7.29	$ 13.12
Refinery feedstocks and refined products inventory	(mmbbls)	11.9	12.3	11.9	12.3

Fourth Quarter

U.S. Refining and Marketing earnings increased in the fourth quarter of 2010 compared with the fourth quarter of 2009 as a result of higher realized refining margins and higher total throughput. Realized refining margins increased in the fourth quarter of 2010 compared to the same period in 2009 due to higher crack spreads and throughput increased due to a major turnaround at Lima that was completed in the fourth quarter of 2009. Realized refining margins reflect differences in product configuration, location differences and FIFO accounting for the purchase of crude oil.

The product slate produced at the Lima and Toledo refineries contains approximately 10% to 15% of other products which 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 Chicago crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI which was increasing at the end of the fourth quarter of 2010 while on a FIFO basis crude oil feedstock costs reflect purchases made earlier in the quarter when crude oil prices were lower.

In addition, the 4% strengthening of the Canadian dollar against the U.S. dollar compared with the fourth quarter of 2009 has had a negative impact on the translation of U.S. dollar financial results into Canadian dollars.

Other income in the fourth quarter of 2009 includes $1 million of unrealized gains on forward contracts for feedstock purchases.

Twelve Months

Refining gross margins were impacted by lower realized refining margins and the impact of the Enbridge Line 6A/6B shutdowns on the Toledo Refinery partially offset by higher total throughput. In the third quarter of 2010, the Enbridge Line 6A/6B shutdowns resulted in reduced throughput at the Toledo Refinery due to limited crude oil availability and increased feedstock costs as heavy oil was partially replaced with light oil where available. In the fourth quarter of 2010, the Toledo Refinery benefited from lower feedstock costs resulting from the widening of the heavy to light crude oil differential. The impact to the Toledo Refinery for 2010 was an estimated reduction to net earnings of $18 million. Other expenses in 2009 included $30 million of realized losses on forward contracts for feedstock purchases.

Downstream Capital Expenditures

Downstream capital expenditures totalled $502 million for 2010 compared to $341 million in 2009.

In Canada, capital expenditures were $245 million related to acquisition and rebranding of retail outlets acquired in 2009 as well as upgrades and environmental protection at the retail outlets, refineries and ethanol plants.

In the United States, capital expenditures totalled $257 million. At the Lima, Ohio Refinery, $132 million was spent on various debottleneck projects, optimizations and environmental initiatives, and $46 million was spent on the scheduled turnaround. At the Toledo Refinery, capital expenditures totalled $79 million (Husky's 50% share) primarily for engineering work on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

The Lloydminster Refinery will have a major turnaround in the spring of 2013. The Refinery will be completely shutdown during the turnaround for inspections and equipment repair.

The Prince George refinery will have two minor turnarounds for maintenance work in 2011, the first is scheduled in the second quarter and the second turnaround is scheduled in the third quarter. The next major turnaround will occur in 2012 during the third and fourth quarter. The refinery will be shut down for inspections and equipment repair during this time.

The Toledo refinery will have a minor turnaround in the second quarter of 2011 on the ISO cracker unit and general maintenance. The turnaround is scheduled to last approximately 30 days. The next major turnaround is scheduled to occur in 2012.

The Lima refinery will have a major turnaround in 2014 on the Naptha Hydrotreater, Hydrocracker, Reformer and Diesel Hydrotreater units. The turnaround is scheduled to last approximately 40 days and will be completely shutdown. Another minor turnaround will occur in 2015 for the Coker and Gasoline Distillation units. The turnaround is scheduled to last approximately 35 days and the refinery will be operating at 80% capacity.

5.4 Corporate

Corporate Summary (millions of dollars) income (expense)	Three months ended Dec. 31 2010	 2009	Year ended Dec. 31 2010	 2009
Intersegment eliminations - net	$ (61)	$ (3)	$ (47)	$ (44)
Administration expense	(43)	(24)	(89)	(69)
Other income (expense)	(1)	12	3	(1)
Stock-based compensation	(1)	-	-	(1)
Depreciation and amortization	(19)	(15)	(76)	(51)
Interest - net	(50)	(52)	(206)	(191)
Foreign exchange	(7)	6	2	5
Income taxes	60	32	174	136
Net loss	$ (122)	$ (44)	$ (239)	$ (216)

Fourth Quarter

The corporate segment reported a loss of $122 million in the fourth quarter of 2010 compared with a loss of $44 million in the fourth quarter of 2009. Administration expenses increased due to higher software expenses, professional services, corporate services, and corporate communications. Foreign exchange losses were $7 million compared to a gain of $6 million in the fourth quarter of 2009 mainly due to the strengthening of the Canadian dollar and its impact on cash and working capital transactions in the quarter. The increase in depreciation and amortization was a result of adjustments to the book value of legacy sites that have been deemed inactive.

Intersegment eliminations are profit included in inventory that has not been sold to third parties at the end of the period. The increase in the fourth quarter of 2010 compared to the fourth quarter of 2009 was due in large part to additional inventory in Western Canada held for storage and in pipelines to mitigate the impact of selling crude oil to third parties at distressed spot prices due to the impact of the Enbridge Line 6A/6B shutdowns on medium and heavy crude oil and bitumen prices.

Twelve Months

In 2010, the corporate segment reported a loss of $239 million compared with $216 million in 2009. In addition to the factors that impacted the fourth quarter, net interest expense increased in 2010 primarily due to higher debt levels compared to 2009.

Foreign Exchange Summary (millions of dollars)	Three months ended Dec. 31 2010	 2009	Year ended Dec. 31 2010	 2009
Gain on translation of U.S. dollar denominated long-term debt	$ (61)	$ (53)	$ (90)	$ (265)
Loss on contribution receivable	46	32	67	216
Other losses	22	15	21	44
Foreign exchange (gain) loss	$ 7	$ (6)	$ (2)	$ (5)
U.S./Canadian dollar exchange rates:				
At beginning of period	U.S. $0.971	U.S. $0.933	U.S. $0.956	U.S. $0.817
At end of period	U.S. $1.005	U.S. $0.956	U.S. $1.005	U.S. $0.956

Corporate Capital Expenditures

For 2010, corporate capital expenditures of $67 million were primarily for computer hardware and software, office furniture, renovations, equipment and system upgrades, construction of a new building in Lloydminster and capitalized interest.

Consolidated Income Taxes

Fourth Quarter

During the fourth quarter of 2010, consolidated income tax expense was $112 million compared with $116 million in the same period in 2009.

Twelve Months

In 2010, consolidated income tax expense was $385 million compared with $541 million in 2009. Current taxes in 2010 decreased compared with 2009 due to a decrease in partnership deferred revenue taxable in 2010.

Cash taxes paid in 2010 were $783 million compared to $1,323 million in 2009, of which $510 million relates to final instalments paid in respect of 2008 earnings, included in current liabilities at December 31, 2009, and $273 million relating to instalments paid in respect of 2009 earnings. No further cash tax instalments will be required in respect of 2009 earnings.

6. Liquidity and Capital Resources

In the fourth quarter and year ended 2010, Husky funded its capital programs, including acquisitions, and dividend payments by cash generated from operating activities, cash on hand, common share issuance, and long-term debt. At December 31, 2010, Husky had total debt of $4,187 million partially offset by cash on hand of $252 million for $3,935 million of net debt. Husky has no long-term debt maturing until 2012. At December 31, 2010, the Company had $2.7 billion in unused committed credit facilities, $166 million in unused short-term uncommitted credit facilities, unused capacity under the debt shelf prospectuses filed in Canada and the U.S. of $300 million and U.S. $1.5 billion respectively, and unused capacity under the universal short form base shelf prospectus filed in Canada of $2 billion. (Refer to Section 6.4).

Cash Flow Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except ratios)	2010	2009	2010	2009
Cash flow - operating activities	$ 656	$ 376	$ 2,703	$ 1,918
- financing activities	$ 950	$ (295)	$ 1,085	$ 594
- investing activities	$ (1,385)	$ (935)	$ (3,928)	$ (3,033)
Financial Ratios				
Debt to capital employed (percent)			21.3	18.3
Debt to cash flow (times) (1)			1.2	1.3
Corporate reinvestment ratio (percent) (1) (2)			111	111
Interest coverage ratios on long-term debt only (1) (3)				
Earnings			7.8	11.1
Cash flow			13.7	17.4
Interest coverage ratios on total debt (1) (4)				
Earnings			7.6	10.7
Cash flow			13.3	16.7

(1) Calculated for the 12 months ended for the dates shown
(2) Reinvestment ratio is based on net capital expenditures including corporate acquisitions.
(3) Interest coverage on long-term debt on an earnings basis is equal to earnings before interest expense on long-term debt and income taxes divided by interest expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow from operating activities before interest expense on long-term debt and current income taxes divided by interest expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.
(4) Interest coverage on total debt on an earnings basis is equal to earnings before interest expense on total debt and income taxes divided by interest expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow from operating activities before interest expense on total debt and current incomes taxes divided by interest expense on total debt and capitalized interest. Total debt includes short and long-term debt.

6.1 Operating Activities

Fourth Quarter

In the fourth quarter of 2010, cash generated from operating activities amounted to $656 million compared with $376 million in the fourth quarter of 2009. Higher cash flows from operating activities was primarily due to higher crude oil prices in Upstream, the widening of the upgrading differentials for Midstream, higher asphalt prices for Canadian Refined Products, and higher crack spreads in U.S. Downstream.

Twelve Months

Cash generated from operating activities amounted to $2.7 billion in 2010 compared with $1.9 billion in 2009. Higher cash flow from operating activities was primarily due to higher realized crude oil and natural gas prices, offset by lower production.

6.2 Financing Activities

Financing activities primarily include the issuance of common shares, the payment of dividends and the issuance and repayment of debt. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

Fourth Quarter

In the fourth quarter of 2010, cash provided by financing activities was $950 million compared with cash used in financing activities of $295 million in the fourth quarter of 2009. Higher cash flow provided by financing activities was due primarily to the issuance of common shares in the quarter.

Twelve Months

Cash provided by financing activities was $1,085 million in 2010 compared with $594 million in 2009. The increase was due to the same factors impacting the fourth quarter, partially offset by a lower amount of notes issued in 2010 compared to 2009. $700 million of medium-term notes were issued in March 2010 compared to $1.5 billion of long-term notes issued in May 2009.

6.3 Investing Activities

Fourth Quarter

In the fourth quarter of 2010, cash used in investing activities amounted to $1,385 million compared with $935 million in the fourth quarter of 2009. Cash invested in both periods was primarily for capital expenditures.

Twelve Months

Cash used in investing activities for 2010 was $3.9 billion compared with $3.0 billion in 2009. Cash invested in both periods was primarily for capital expenditures.

6.4 Sources of Capital

Husky is currently able to fund its capital programs, non-cancellable contractual obligations and other commercial commitments principally by cash generated from operating activities, the issuance of common shares, the issuance of long-term debt and committed and uncommitted credit facilities. The Company also maintains access to sufficient capital via debt markets commensurate with its balance sheet. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2010, working capital was $1,256 million compared with $726 million at December 31, 2009.

In August 2010, Husky added a second committed revolving syndicated credit facility of $1.5 billion. As at December 31, 2010, the Company had borrowings of $380 million under its $1.25 billion revolving syndicated credit facility and no borrowings under its $1.5 billion facility. Interest rates under these revolving syndicated credit facilities vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain rating agencies to the Company's senior unsecured debt.

At December 31, 2010, Husky had unused committed long and short-term borrowing credit facilities totalling $2.7 billion. A total of $116 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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

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

Husky filed a debt shelf prospectus with the Alberta Securities Commission on February 26, 2009 and the U.S. Securities and Exchange Commission on February 27, 2009. The shelf prospectus enables Husky to offer up to U.S. $3 billion of debt securities in the United States until March 26, 2011. During the 25-month period that the shelf prospectus is effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of December 31, 2010, U.S. $1.5 billion of long-term notes had been issued under this shelf prospectus. On December 21, 2009, Husky filed an additional debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $1 billion of medium-term notes in Canada until January 21, 2012. During the 25-month period that the shelf prospectus is effective, medium-term notes may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of December 31, 2010, $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 6 to the Consolidated Financial Statements).

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 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 2012. During the 25-month period that the 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 via an overnight-marketed public offering and a total of 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 L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

Capital Structure (millions of dollars)	December 31, 2010 Outstanding	Available[(1)]
Total short-term and long-term debt	$ 4,187	$ 2,819
Common shares, retained earnings and accumulated other comprehensive income	$ 15,493	

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

6.5 Contractual Obligations and 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)	2011	2012-2013	2014-2015	Thereafter	Total
Long-term debt and interest on fixed rate debt	$ 232	$ 1,205	$ 1,389	$ 3,325	$ 6,151
Operating leases	105	169	121	117	512
Firm transportation agreements	166	274	331	3,197	3,968
Unconditional purchase obligations (1)	1,970	1,280	50	122	3,422
Lease rentals and exploration work agreements	98	115	238	491	942
Asset retirement obligations (2)	63	117	117	7,293	7,590
	$ 2,634	$ 3,160	$ 2,246	$ 14,545	$ 22,585

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

6.6 Off Balance Sheet Arrangements

Husky does not utilize off balance sheet arrangements with unconsolidated entities.

6.7 Transactions with Related Parties

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 the existing base shelf prospectus, which was filed with the 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. $65 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. These transactions were measured at 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. At December 31, 2010, the U.S. $1.5 billion senior notes are included in long-term debt on the Company's balance sheet.

TransAlta Power, L.P. ("TAPLP") is under the indirect control of one of Husky's principal shareholders. TAPLP is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLP") which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLP. These natural gas sales are related party transactions and have been measured at the exchange amount. For the year ended December 31, 2010, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $44 million.

7. Risks and Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's 2009 AIF filed on the Canadian Securities Administrator's website, www.sedar.com, the Securities and Exchange Commission's website www.sec.gov, or Husky's website www.huskyenergy.com.

The Company has processes in place to identify the principal risks of the business and put in place appropriate mitigation to manage such risks where possible.

7.1 Political Risk

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

7.2 Environmental Risk

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 address such costs. With the exception of Husky's Mizzen prospect, of which Husky is a non-operator, the Company currently does not participate in offshore deep water drilling operations in Canada; however, Husky's 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 operations. Stricter regulation of offshore oil and gas operations has already been implemented 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 the Gulf of Mexico. In the event that similar changes in environmental regulation occur with respect to Husky's operations in the Atlantic Region or in the South China Sea, 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") has promulgated the so-called 'Tailoring Rule', which, beginning January 2, 2011, phases in over time restrictions on greenhouse gas emissions from stationary sources, including power plants and petroleum refineries, beginning with the largest emitters, where such sources are required to obtain a new or modified permit based on non-greenhouse gas emissions. The EPA has also promulgated regulations requiring data collection, beginning January 1, 2010, and reporting, beginning March 31, 2011, of greenhouse gas emissions from stationary sources in the oil and gas industry emitting more than 25,000 tons per year of greenhouse gases in carbon dioxide equivalent. This reporting requirement applies to Husky's U.S. operations. However, these regulations are subject to challenge in Congress and the courts. Congress is expected to consider in the coming session proposals to block or delay the EPA's regulation of greenhouse gas emissions. Among several legal challenges, the State of Texas, the National Association of Manufacturers and other organizations are seeking a stay of the Tailoring Rule and the EPA's other regulations relating to greenhouse gas emissions from stationary sources. 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 and the pending and anticipated challenges could result in the staying of the regulations. Husky's operations may be impacted 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.

7.3 Financial Risk

Husky's financial risks are largely related to commodity prices, refinery crack spreads, 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.

7.4 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 meet 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.

Since the Company operates in the upstream oil and gas industry, it requires sufficient cash to fund capital programs necessary to maintain or increase production and develop reserves, to acquire strategic oil and gas assets, to repay maturing debt and to pay dividends. The Company's upstream capital programs are funded principally by cash provided from operating activities, common share issuance, long-term debt and available committed and uncommitted credit facilities. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of long and short-term capital resources. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines.

7.5 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, 2010, the Company had third party physical natural gas purchase and sale 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 gain of $18 million has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income. Natural gas inventory held in storage relating to the natural gas storage contracts is recorded at fair value. At December 31, 2010, the fair value of the inventory was $131 million, resulting in an unrealized loss of $51 million recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

At December 31, 2010, the Company had third party crude oil purchase and sale contracts, which have been designated as a fair value hedge. These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain of $2 million has been recorded in cost of sales in the Consolidated Statements of Earnings and Comprehensive Income. The crude oil inventory held in storage is recorded at fair value. At December 31, 2010, the fair value of the inventory was $30 million, resulting in an unrealized loss of $2 million recorded in cost of sales in the Consolidated Statements of Earnings and Comprehensive Income.

The Company enters into certain crude oil purchase and sale 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, 2010, the Company had 3 million bbls of purchase and sale contracts resulting in an unrealized loss of $8 million recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income. A portion of the crude oil inventory is sold to third parties. This inventory is considered held for trading and as such, has been recorded at its fair value. At December 31, 2010, the fair value of the inventory was $72 million, resulting in a $6 million unrealized gain recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

The Company also enters into 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, 2010, the fair value of these contracts was $1 million resulting in a loss of $1 million recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

7.6 Interest Rate Risk Management

At December 31, 2010, Husky had the following interest rate swaps in place:

- U.S. $200 million of long-term debt whereby a fixed interest rate of 7.55% was swapped for rates ranging from LIBOR + 399 bps to LIBOR + 430 bps until November 15, 2016.

- U.S. $300 million of long-term debt whereby a fixed interest rate of 6.20% was swapped for rates ranging from LIBOR + 255 bps to LIBOR + 275 bps until September 15, 2017.

- U.S. $150 million of long-term debt whereby a fixed interest rate of 5.90% was swapped for rates ranging from LIBOR + 349 bps to LIBOR + 350 bps until June 15, 2014.

- Cdn $300 million of long-term debt whereby a fixed interest rate of 3.75% was swapped for rates ranging from CDOR + 0.80% to CDOR + 0.85% until March 12, 2015.

During 2010, these swaps resulted in an offset to interest expense amounting to $23 million (2009 – addition of less than $1 million). The amortization of previous interest rate swap terminations resulted in an addition to interest expense of $2 million (2009 – offset of $3 million) in 2010.

Cross currency swaps resulted in an addition to interest expense of $6 million (2009 - $4 million) in 2010.

7.7 Foreign Currency Risk Management

At December 31, 2010, Husky had the following cross currency debt swaps in place:

- U.S. $150 million at 6.25% swapped at $1.41 to $211 million at 7.41% 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. $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 $1.17 to $88 million at 5.61% until June 15, 2012.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. For the year ending December 31, 2010, the impact of these contracts was a realized gain of $26 million (2009 – gain of $16 million) recorded in foreign exchange expense.

At December 31, 2010, the cost of a U.S. dollar in Canadian currency was $0.9946.

Husky's financial results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities.

In addition, 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, 2010, 74% or $3.1 billion of Husky's outstanding debt was denominated in U.S. dollars. The percentage of the Company's debt exposed to the Cdn/U.S. exchange rate decreases to 67% when the cross currency swaps are considered.

As at December 31, 2010, the Company has designated U.S. $987 million of its U.S. debt as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. In 2010, the unrealized foreign exchange gain arising from the translation of the debt was $44 million, net of tax expense of $7 million (2009 – gain of $104 million, net of tax expense of $18 million), which was recorded in Other Comprehensive Income.

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

Husky holds 50% of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and a major portion of 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 foreign exchange in current period earnings. At December 31, 2010, Husky's share of this receivable was U.S. $1.3 billion (2009 – U.S. $1.2 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 Other Comprehensive Income as this item relates to a self-sustaining foreign operation. At December 31, 2010, Husky's share of this obligation was U.S. $1.4 billion (2009 – U.S. $1.4 billion) including accrued interest.

7.8 Fair Value of Financial Instruments

The derivative portion of cash flow hedges, fair value hedges, and free standing derivatives that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon fair value hierarchy in accordance with the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3862. 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. All of Husky's assets and liabilities that are recorded at fair value on a recurring basis are included in Level 2.

8. Critical Accounting Estimates

Certain of Husky's accounting policies require that it makes appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. For a discussion about those accounting policies, please refer to Husky's MD&A for the year ended December 31, 2009 available at www.sedar.com and www.sec.gov.

9. Transition to International Financial Reporting Standards

The Company is progressing in its International Financial Reporting Standards ("IFRS") transition project in preparation for timely completion of the first IFRS interim financial report in the first quarter of 2011. The impact assessment of IFRS accounting policies chosen by the Company has been completed for the January 1, 2010 opening balance sheet based on the accounting standards and interpretations in effect at the time the assessment was completed and therefore subject to change based on potential modifications to accounting policies to comply with IFRS at December 31, 2011. The Company continues to monitor and assess any new or amended IFRS standards and incorporate any relevant changes into the Company's transition project and IFRS policies as necessary.

Initiatives are substantially complete to incorporate conversion impacts into existing internal controls over financial reporting and disclosure controls and procedures. The Company has completed its risk assessment of key processes that will be impacted by IFRS. Incremental process-level internal controls have been identified as a result of IFRS and are being incorporated into the Company's process documentation. No material changes to the internal control framework or entity-level controls have been noted as a result of transition to IFRS.

Property, Plant and Equipment

Under IFRS, the Company has applied accounting policies for its oil and natural gas exploration, evaluation and development expenditures that differ significantly when compared with the full cost method employed under Canadian GAAP, which allows for the capitalization of all costs associated with the acquisition, exploration, and development of oil and gas reserves on a country-by-country basis. Under IFRS, pre-exploration and evaluation costs, which include all exploratory costs incurred prior to the acquisition of the legal right to explore, are expensed as incurred. After the legal right to explore is acquired, land acquisition costs and expenditures directly associated with exploratory wells will be capitalized as exploration and evaluation assets. Geological and geophysical and other exploration costs will be immediately recognized in net earnings under exploration expense. Land acquisition costs will remain capitalized until the Company has chosen to discontinue all exploration activities in the associated area. Exploratory wells will remain capitalized until the drilling operation is complete and the results have been evaluated. If the well does not encounter reserves of commercial quantity, either on its own or in combination with other exploration wells associated with the same area of exploration, the costs of drilling the well or wells will be written-off to exploration expense. Wells that result in commercial quantities of reserves will remain capitalized and be reclassified into property, plant, and equipment.

In July 2009, the International Accounting Standards Board (''IASB'') approved an IFRS transitional exemption for entities that previously followed full cost accounting in accordance with Accounting Guideline 16 of the CICA Handbook. This permits the Company to allocate each of its upstream oil and gas asset balances as determined under full cost accounting to the IFRS categories of exploration and evaluation assets and development and producing assets. This exemption relieves the Company from significant adjustments resulting from retrospective application of IFRS. The Company will elect to apply this exemption for its Canadian upstream full cost asset base and measure these properties at the amount determined under Canadian GAAP as at January 1, 2010. The amount was allocated on a pro rata basis to the underlying assets using proved developed reserve volumes at the date of transition.

The Company will elect not to apply the full cost exemption to its International upstream properties as detailed information for retrospective application of IFRS was available. As a result, previously capitalized costs related to unsuccessful exploration drilling, geological and geophysical expenditures, exploratory seismic and lease rental expenses have been recorded as a reduction to opening retained earnings upon adoption of IFRS 6. The Company noted this accounting policy choice will result in a decrease to property, plant and equipment and retained earnings of approximately $500 million as at January 1, 2010.

The application of the chosen IFRS accounting policies for oil and gas properties requires management to determine the proper classification of activities designated as developmental or exploratory, which then determines the appropriate accounting treatment of the costs incurred. For capitalized costs associated with exploratory activities, the Company has separately disclosed these costs on the balance sheet. Costs totaling approximately $2 billion at January 1, 2010 will be reclassified from property, plant, and equipment to exploration and evaluation assets.

Under Canadian GAAP, impairment is assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment is indicated, discounted cash flows are prepared to quantify the amount of the impairment. Under IFRS, impairment is assessed based on discounted cash flows compared with the asset's carrying amount to both determine the recoverable amount and measure the amount of the impairment. In addition, where an asset does not generate separately identifiable cash flows under IFRS, the Company is required to perform its test on cash generating units ("CGUs"), which are the smallest grouping of assets that generate independent, identifiable cash inflows. However, under Canadian GAAP asset groupings for impairment testing purposes are based on the generation of both independent cash inflows and cash outflows. The Company expects to record impairments on its ethanol plants and certain Western Canadian upstream properties totalling approximately $150 million under IFRS as at January 1, 2010.

The Company reviewed the major components and useful lives of items of property, plant, and equipment. A major component is defined as a part of an asset that is significant in relation to the total cost of the asset. As a result of component depreciation, the Company expects a reduction to the carrying values of net property, plant, and equipment and opening retained earnings by approximately $150 million due to component depreciation.

Asset Retirement Obligations

Consistent with IFRS, decommissioning provisions ("asset retirement obligations" or "ARO") have been previously measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to its net present value upon initial recognition. However, adjustments to the discount rate were not reflected in the provisions under Canadian GAAP. IFRS requires current period discount rates to be used for re-measurement of all existing liabilities with changes in the balance recorded to property, plant and equipment. Under IFRS, ARO will continue to be discounted using a credit-adjusted risk-free rate based on current interpretations of the accounting standards, which are presently being validated. The use of the full cost exemption for Canadian upstream properties will require the Company to record an immaterial change in the revaluation of its ARO liability to opening retained earnings. Retrospective application of IFRS for decommissioning provisions related to International oil and gas assets, midstream and downstream assets will not have a significant impact on property, plant, and equipment, other long-term liabilities, and retained earnings on transition to IFRS.

Under Canadian GAAP the accretion of the asset retirement obligations was included in cost of sales and operating expenses; however, under IFRS this is now classified as finance costs.

Other IFRS 1 Exemptions

IFRS 1, "First-Time Adoption of International Financial Reporting Standards," allows first-time adopters specific exemptions from the retrospective application of certain IFRS. In addition to the exemptions previously mentioned for property, plant and equipment and asset retirement obligations, the Company has also elected to apply other first-time adoption exemptions. Cumulative currency translation differences for all foreign operations have been deemed to be zero as at January 1, 2010. Accordingly, all cumulative foreign exchange gains and losses in the Company's cumulative translation account will be recognized in opening retained earnings at January 1, 2010. In addition, the Company has not restated business combinations entered into prior to January 1, 2010.

Anticipated IFRS Results of Operations

The adoption of IFRS accounting policies for oil and gas properties will result in increased expenses due to the recognition of certain exploration expenses in the period incurred. The Company's IFRS policies include expensing pre-exploration and evaluation costs which include all exploratory costs incurred prior to the acquisition of the legal right to explore. Certain exploration costs incurred after the legal right to explore is acquired will also be immediately recognized as an expense. Geological and geophysical activities such as exploratory seismic programs and technical analysis and exploratory drilling are among these costs subject to immediate recognition as exploration expenses.

Oil and gas properties will be depleted under IFRS using a unit-of-production method based on the unit of measure to which an asset is assigned. In the case of assets whose useful life is shorter or longer than the lifetime of the associated fields' production profile, the straight-line method of depreciation is applied. The Company defines unit of accounts at the field level for the unit-of-production depletion calculation. Under full cost accounting, depletion is calculated using the unit-of-production method on a country-by-country basis. Depletion, depreciation and amortization expense is expected to be higher under IFRS for the Company's Canadian upstream properties. Given that the Company does not intend to use the full cost exemption for International oil and gas assets, depletion for International unit of accounts will be lower under IFRS when compared to Canadian GAAP.

The Company is required to review the useful lives of significant asset components for all other plant and equipment on an annual basis. The Company expects that component depreciation will result in increased depletion, depreciation and amortization expense under IFRS.

Reported net earnings in 2010 are expected to be between $150 to $250 million lower when presented in accordance with IFRS primarily as a result of expensing certain exploration costs offset by adjustments to depletion and depreciation expenses.

10. Outstanding Share Data

(in thousands)	February 4 2011	December 31 2010
Issued and outstanding		
Number of common shares	890,709	890,709
Number of stock options	29,100	29,541
Number of stock options exercisable	17,163	17,325

11. Reader Advisories

This Interim Report should be read in conjunction with the Consolidated Financial Statements and related Notes.

Readers are encouraged to refer to Husky's MD&A and Consolidated Financial Statements and 2009 AIF filed in 2010 with Canadian regulatory agencies and Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and at www.huskyenergy.com.

Use of Pronouns and Other Terms Denoting Husky

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this Interim Report with respect to results for the three months ended December 31, 2010 are compared with results for the three months ended December 31, 2009 and the results for the year ended December 31, 2010 are compared with results for the year ended December 31, 2009. Discussions with respect to Husky's financial position as at December 31, 2010 are compared with its financial position at December 31, 2009.

Additional Reader Guidance

- The Consolidated Financial Statements and comparative financial information included in this Interim Report have been prepared in accordance with Canadian GAAP.
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices quoted include or exclude the effect of hedging as indicated.

Non-GAAP Measures

Disclosure of Cash Flow from Operations

This Interim Report contains 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 GAAP, as an indicator of Husky's financial performance. Cash flow from operations is presented in Husky's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items. Husky's determination of cash flow from operations, which is a non-GAAP measure, does not have any standardized meaning prescribed by GAAP and therefore is unlikely to be comparable to similar measures presented by other issuers.

The following table shows the reconciliation of cash flow from operations to cash flow - operating activities for the periods noted:

(millions of dollars)		Three months ended Dec. 31 2010	2009	Year ended ended Dec.31 2010	2009
Non-GAAP	Cash flow from operations	$ 1,037	$ 657	$ 3,549	$ 2,507
	Settlement of asset retirement obligations	(26)	(17)	(60)	(41)
	Change in non-cash working capital	(355)	(264)	(786)	(548)
GAAP	Cash flow - operating activities	$ 656	$ 376	$ 2,703	$ 1,918

Disclosure of Adjusted Net Earnings

This interim report may contain the term "adjusted net earnings," which is a non-GAAP measure of net earnings adjusted for certain items that are not an indicator of the Company's on-going financial performance. Husky's determination of adjusted net earnings, which is a non-GAAP measure, does not have any standardized meaning prescribed by GAAP and therefore is unlikely to be comparable to similar measures presented by other issuers.

The following table shows the reconciliation of net earnings to adjusted net earnings for the periods shown:

(millions of dollars)		Three months ended Dec. 31 2010	2009	Year ended Dec. 31 2010	2009
GAAP	Net earnings	$ 305	$ 320	$ 1,173	$ 1,416
	Net foreign exchange	6	(7)	1	(15)
	Net financial instruments	15	(3)	24	5
	Net stock-based compensation	-	-	-	1
	Net inventory write-downs	2	24	23	68
Non-GAAP	Adjusted net earnings	$ 328	$ 334	$ 1,221	$ 1,475

Cautionary Note Required by National Instrument 51-101

The Company uses the terms barrels of oil equivalent ("boe") and thousand cubic feet of gas equivalent ("mcfge"), which are 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 terms boe and mcfge 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.

Abbreviations

bbls	barrels
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
GJ	gigajoule
mmbtu	million British thermal units
mmlt	million long tons
NGL	natural gas liquids
WTI	West Texas Intermediate
NYMEX	New York Mercantile Exchange
NIT	NOVA Inventory Transfer
LIBOR	London Interbank Offered Rate
CDOR	Certificate of Deposit Offered Rate
EDGAR	Electronic Data Gathering, Analysis and Retrieval (U.S.A.)
SEDAR	System for Electronic Document Analysis and Retrieval (Canada)
FPSO	Floating production, storage and offloading vessel
FEED	Front end engineering design
OPEC	Organization of Petroleum Exporting Countries
GDP	Gross domestic product
MD&A	Management's Discussion and Analysis

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
Capital Employed	Short and long-term debt and shareholders' equity
Capital Expenditures	Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets
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 and change 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	Net capital expenditures (capital expenditures net of proceeds from asset sales) plus corporate acquisitions (net assets acquired) divided by cash flow from operations calculated on a 12-month trailing basis
Dated Brent	Prices are dated less than 15 days prior to loading for delivery
Debt to Capital Employed	Total debt divided by total debt and shareholders' equity
Debt to Cash Flow	Total debt divided by cash flow from operations calculated on a 12-month trailing basis
Delineation Well	A well in close proximity to an oil or gas discovery well that helps determine the areal extent of the reservoir
Diluent	A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline
Equity	Shares, retained earnings and accumulated other comprehensive income
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
Glory Hole	An excavation in the seabed where the wellheads and other equipment are situated to protect them from scouring icebergs
Gross/Net Acres/Wells	Gross refers to the total number of acres/wells in which an 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
Hectare	One hectare is equal to 2.47 acres
Near-month Prices	Prices quoted for contracts for settlement during the next month
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
Return on Capital Employed	Net earnings plus after tax interest expense calculated on a 12-month trailing basis divided by average capital employed
Return on Shareholders' Equity	Net earnings calculated on a 12-month trailing basis divided by average shareholders' equity
Stratigraphic Well	A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production
Synthetic Oil	A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content
Three Dimensional (3-D) Seismic	Seismic imaging which uses a grid of numerous cables rather than a few lines stretched in one line
Total Debt	Long-term debt including current portion and bank operating loans
Turnaround	Scheduled performance of plant or facility maintenance

12. Forward-Looking Statements and Information

Certain statements in this interim report are forward-looking statements and information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The 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 result," "are expected to," "will continue," "is anticipated," "estimated," "intend," "plan," "projection," "could," "vision," "goals," "objective," "target," "schedules" and "outlook") are not historical facts and 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 interim report include, but are not limited to: the Company's general strategic plans; growth strategies; 2011 capital expenditure plans and guidance; implementation and timing of development and drilling plans at North Amethyst, White Rose, Sunrise, Tucker, and South East Asia; anticipated timing of production at White Rose, Pike's Peak, Sunrise, Tucker, and in South East Asia; exploration and drilling plans in the Atlantic region, Western Canada, South East Asia and Indonesia; implementation and expected results of enhanced oil recovery initiatives; implementation and timing of the air injection pilot project at McMullen; scheduled maintenance and turnarounds of FPSO units; timing and effect of planned turnarounds and improvements at the Company's Lima, Prince George, Toledo and Lloydminster facilities; testing and implementation of various enhanced recovery techniques and carbon emissions and capture techniques in Western Canada; anticipated effect of recent asset acquisitions on the Company's production, reserves, business and operations; and expected implementation and impacts of the switch to IFRS.

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

This document and the Company's AIF 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 which are incorporated herein by reference.

Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable law, 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.