MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") JULY 26, 2011

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1. Summary of Quarterly Results

Quarterly Summary *(millions of dollars, except per share amounts)*	Three months ended June 30 2011[1]	March 31 2011[1]	Dec. 31 2010[2]	Sept. 30 2010[2]	June 30 2010[1]	March 31 2010[1]	Dec. 31 2009[2]	Sept. 30 2009[2]
Production *(mboe/day)*	**311.6**	310.4	280.5	288.7	283.9	295.9	291.5	276.2
Gross revenues	**$ 6,695**	$ 5,860	$ 4,942	$ 4,641	$ 4,630	$ 4,493	$ 3,856	$ 4,087
Net earnings	**669**	626	305	257	179	368	320	338
Per share - Basic	**0.73**	0.70	0.35	0.30	0.21	0.43	0.38	0.40
Per share - Diluted	**0.71**	0.70	0.35	0.30	0.19	0.41	0.38	0.40
Cash flow from operations [3]	**1,511**	1,164	1,037	811	739	854	657	452
Per share – Basic	**1.68**	1.31	1.21	0.96	0.87	1.00	0.77	0.53
Per share - Diluted	**1.67**	1.30	1.21	0.96	0.87	1.00	0.77	0.53

(1) *Results are reported in accordance with IFRS.*
(2) *Results are reported in accordance with previous Canadian GAAP.*
(3) *Cash flow from operations is a non-GAAP measure. Refer to Section 11 for a reconciliation to the GAAP measure.*

Performance

- Production in the quarter increased by 27.7 mboe/day to 311.6 mboe/day compared with the second quarter of 2010 as a result of new production from the North Amethyst field and acquisitions in Western Canada in the fourth quarter of 2010 and the first quarter of 2011, partially offset by the Plains Rainbow pipeline shut-in in Northern Alberta impacting average production over the second quarter by approximately 8.5 mboe/day.
- Net earnings in the quarter increased 274% compared with the second quarter of 2010 due to:
  - Higher crude oil and natural gas production;
  - Higher average realized crude oil and natural gas prices partially offset by the stronger Canadian dollar relative to the U.S. dollar;
  - Increased realized refining and marketing margins and volumes in both Canadian and U.S. Downstream.
- Cash flow from operations in the quarter increased by 104% to $1,511 million compared to $739 million in the second quarter of 2010.

Key Projects

- Sunrise Energy Project Phase I drilling of 12 horizontal well pairs completed and progressing with detailed engineering design for surface facilities.
- Drilled one water injection well and one production well at the North Amethyst satellite field.
- Awarded all of the deepwater contracts for the Liwan 3-1 field with progress on drilling and completion of development wells.
- Drilled 21 Cardium formation wells at Ansell area near Edson, Alberta.
- South Pikes Peak 8,000 bbls/day heavy oil thermal project 67% complete.
- Added 457,000 acres to land base in Western Canada and the Northwest Territories.

Financial

- Strengthened the Company's financial position by a successful issue of common shares in late June, raising a net total of $1.2 billion in equity financing.
- Dividends on common shares of $270 million were declared during the second quarter of 2011 of which $77 million and $193 million were accepted in cash and common shares, respectively.

2. Business Environment

Average Benchmarks		Three months ended				
		June 30 2011	March 31 2011	Dec. 31 2010	Sept. 30 2010	June 30 2010
WTI crude oil [1]	*(U.S. $/bbl)*	**102.56**	94.10	84.89	76.20	78.03
Brent crude oil [2]	*(U.S. $/bbl)*	**117.36**	104.97	86.27	76.86	78.30
Canadian light crude 0.3% sulphur	*($/bbl)*	**102.64**	88.45	80.48	74.77	75.44
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**71.82**	59.54	60.76	57.29	57.10
NYMEX natural gas [3]	*(U.S. $/mmbtu)*	**4.31**	4.11	3.80	4.38	4.09
NIT natural gas	*($/GJ)*	**3.55**	3.58	3.39	3.52	3.66
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**17.89**	23.11	18.37	15.90	14.34
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**28.90**	16.58	9.13	10.16	11.33
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**25.32**	19.34	11.41	8.62	10.44
U.S./Canadian dollar exchange rate	*(U.S. $)*	**1.034**	1.014	0.987	0.962	0.973
Canadian Equivalents						
WTI crude oil [4]	*($/bbl)*	**99.19**	92.80	86.01	79.21	80.20
Brent crude oil [4]	*($/bbl)*	**113.50**	103.52	87.41	79.90	80.47
WTI/Lloyd crude blend differential [4]	*($/bbl)*	**17.30**	22.79	18.61	16.53	14.74
NYMEX natural gas [4]	*($/mmbtu)*	**4.17**	4.05	3.85	4.55	4.20

(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 the price of West Texas Intermediate ("WTI"), adjusted to Western Canada, while the majority of the Company's production in the Atlantic Region is referenced to the price of Brent crude oil ("Brent"). The price of WTI averaged U.S. $102.56/bbl in the second quarter of 2011 compared with U.S. $78.03/bbl in the second quarter of 2010. The price of WTI averaged U.S. $98.33/bbl in the first six months of 2011 compared with U.S. $78.37/bbl in the first six months of 2010. The price of Brent averaged U.S. $117.36/bbl in the second quarter of 2011 compared with U.S. $78.30/bbl in the second quarter of 2010. The price of Brent averaged U.S. $111.16/bbl in the first six months of 2011 compared with U.S. $77.27 in the first six months of 2010.

Increased U.S. crude oil prices have been partially offset by the strengthening of the Canadian dollar. In the second quarter of 2011, the price of WTI in U.S. dollars increased 31% compared with 24% in Canadian dollars when compared to the second quarter of 2010. In the first six months of 2011, the price of WTI in U.S. dollars increased 25% compared with 18% in Canadian dollars in the first six months of 2010.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In the second quarter of 2011, 47% of Husky's crude oil production was heavy oil or bitumen compared with 48% in the second quarter of 2010. The light/heavy crude oil differential averaged U.S. $17.89/bbl or 17% of WTI in the second quarter of 2011 compared with U.S. $14.34/bbl or 18% of WTI in the second quarter of 2010. In the first six months of 2011, 46% of Husky's crude oil production was heavy oil or bitumen compared with 48% in the first six months of 2010. The light/heavy crude oil differential averaged U.S. $20.50/bbl or 21% of WTI in the first six months of 2011 compared with $11.82/bbl or 15% of WTI in the first six months of 2010.

During the second quarter of 2011, the NYMEX near-month contract price of natural gas averaged U.S. $4.31/mmbtu compared with U.S. $4.09/mmbtu in the second quarter of 2010. During the first six months of 2011, the NYMEX near-month contract price of natural gas averaged U.S. $4.21/mmbtu compared with U.S. $4.70/mmbtu during the first six months of 2010.

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.

In the second quarter of 2011, the Canadian dollar averaged U.S. $1.034 per Canadian dollar, strengthening by 6% compared with U.S. $0.973 during the second quarter of 2010. The Canadian dollar ended 2010 at U.S. $1.005 and closed at U.S. $1.037 on June 30, 2011. In the first six months of 2011, the Canadian dollar averaged U.S. $1.024 per Canadian dollar, strengthening by 6% compared with U.S. $0.967 during the first six months of 2010.

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 the second quarter of 2011, the Chicago 3:2:1 crack spread averaged U.S. $28.90/bbl compared with U.S. $11.33/bbl in the second quarter of 2010. In the first six months of 2011, the Chicago 3:2:1 crack spread averaged U.S. $22.63/bbl compared with U.S. $8.82/bbl in the first six months of 2010. During the second quarter of 2011, the New York Harbor 3:2:1 crack spread averaged U.S. $25.32/bbl compared with U.S. $10.44/bbl in the second quarter of 2010. In the first six months of 2011, the New York Harbour 3:2:1 crack spread averaged U.S. $22.27/bbl compared with U.S. $9.34/bbl in the first six months of 2010.

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 International Financial Reporting Standards ("IFRS").

Global Economic and Financial Environment

In its July 12, 2011 Short-term Energy Outlook[1] the Energy Information Administration ("EIA") indicated that it still expects markets for crude oil and liquid fuels to tighten over the next two years. The EIA maintains its expectation that world oil consumption will grow an average of 1.4 mmbbls/day in 2011 and 1.6 mmbbls/day in 2012 and that supply from both the Organization of the Petroleum Exporting Countries ("OPEC") and other producing countries will increase marginally and as a result the market will need to rely partly on inventories. OPEC spare productive capacity was estimated at 4.0 mmbbls/day at the end of 2010 and is expected to decline to 3.5 mmbbls/day by the end of 2011 and further decline to 3.1 mmbbls/day by the end of 2012. 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 decline to approximately 56 days of forward cover in 2011 and 55 days of forward cover in 2012. The movement toward lower inventory levels underscores potential supply risk as crude oil exports from Libya are disrupted and instability continues in other Middle East and North African countries while world demand for crude oil remains robust.

In the EIA's July 12, 2011 Short-term Energy Outlook, natural gas consumption in U.S. markets is expected to rise 2% to 67.4 bcf/day in 2011 and roughly the same in 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 5.8% in 2011 and 0.9% in 2012. Imports of both pipeline natural gas and liquefied natural gas into the U.S. are expected to decline by 3.9% in 2011 and a further 4.0% in 2012. In its Weekly Natural Gas Storage Report[2] released on July 7, 2011, the EIA reported that natural gas stocks were 1.9% below the five year average and 8.1% below the previous year. The EIA expects continued natural gas price volatility in the near term.

The EIA now expects a marginal decrease in U.S. gasoline consumption in 2011 compared with the previous year reflecting slow economic growth and higher fuel prices. The EIA has reduced its previous estimate of distillate fuels consumption during 2011 to a 1.9% increase over the prior year from 2.4%.

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 – July 12, 2011 Release.*

(2) *"Weekly Natural Gas Storage Report", July 7, 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 second quarter of 2011. 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	2011 Second Quarter Average		Increase	Effect on Annual Pre-tax Cash Flow [6]		Effect on Annual Net Earnings [6]	
				($ millions)	*($/share)* [7]	*($ millions)*	*($/share)* [7]
WTI benchmark crude oil price [1]	$	102.56	*U.S. $1.00/bbl*	64	0.07	47	0.05
NYMEX benchmark natural gas price [2]	$	4.31	*U.S. $0.20/mmbtu*	28	0.03	21	0.02
WTI/Lloyd crude blend differential [3]	$	17.89	*U.S. $1.00/bbl*	(8)	(0.01)	(6)	(0.01)
Canadian retail margins	$	0.042	*Cdn $0.005/litre*	15	0.02	11	0.01
Asphalt margins	$	23.40	*Cdn $1.00/bbl*	7	0.01	5	0.01
New York Harbor 3:2:1 crack spread [4]	$	25.32	*U.S. $1.00/bbl*	74	0.08	47	0.05
Exchange rate (U.S. $ per Cdn $) [1] [5]	$	1.034	*U.S. $0.01*	(45)	(0.05)	(33)	(0.04)
Interest rate			*100 basis points*	(10)	(0.01)	(7)	(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 941.6 million common shares outstanding as of June 30, 2011.*

3. Strategic Plan

Husky's 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 heavy oil and bitumen assets. The Company's strategy is to maximize the efficiency of its Midstream and Downstream operations and extract the greatest value from production.

4. Key Growth Highlights

The 2011 capital program was established with focus on projects offering the highest potential for returns and mid to long-term growth. Husky's 2011 capital program continues 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 Extension Projects

Development continues at North Amethyst with the drilling of one producing well and one water injection well during the second quarter of 2011. The G-25-6 production well was brought online June 23, 2011, adding approximately 6,200 bbls/day to North Amethyst production. The supporting water injector well will be completed in the third quarter of 2011.

In August 2010, the Company received regulatory approval for a two-well pilot project to be drilled from existing infrastructure at the West White Rose field. One production well was drilled and cased in 2010 with completion expected in the third quarter of 2011. A supporting water injection well was spud in June 2011. Husky will flow the pilot producer unassisted for a period of time before adding water injection which will provide information to assist in the development plan for the full West White Rose resource.

Husky continues to look at opportunities for incremental oil recovery at the White Rose field and is considering an infill well in the main South Avalon Pool.

The Company continues to evaluate the feasibility of a concrete wellhead platform for development of future resources in the White Rose region.

Atlantic Region Exploration

Husky will participate in a Statoil-operated Mizzen well planned for the third quarter of 2011. The well will aid in evaluating the 2009 discovery at the same field. Husky holds a 35% working interest in the field which is located in the Flemish Pass Basin.

An exploration well is planned for the fourth quarter of 2011 to test the Statoil-operated Fiddlehead prospect located south of the Terra Nova field. Husky holds a 50% working interest in the well.

Offshore Greenland

Husky has a significant position in three blocks off the west coast of Greenland. Final processing of the 3-dimensional ("3-D") seismic acquired over Blocks 5 and 7 was completed in the first quarter of 2011. For the remainder of the year, the focus will be on participation in environmental and ice studies, finalizing well locations and initiation of the well planning process.

In 2012, Husky plans to progress drilling plans, acquire well site drilling hazard surveys, and conduct environmental and socio-economic impact assessments in anticipation of exploratory drilling in 2013.

Heavy Oil

Construction of the 8,000 bbls/day South Pikes Peak thermal project is progressing within original cost estimates and on schedule with production expected to commence in mid-2012. The project was 67% complete at the end of the second quarter of 2011.

Husky continued its 3,000 bbls/day Paradise Hill development which will utilize existing Bolney infrastructure. The project was 28% complete at the end of the second quarter of 2011 and is planned to become operational by the third quarter of 2012.

Construction of a single thermal pilot well pair at Rush Lake was completed during the second quarter of 2011 with first production expected in the third quarter of 2011. Four additional commercial thermal projects are in the early delineation and concept selection phase.

To sustain cold production, Husky advanced its horizontal drilling program in the second quarter of 2011, drilling 12 wells of a 104 well program for 2011. Based on the positive performance of the previous horizontal drilling programs, Husky is expanding its horizontal portfolio and has identified an additional 500 potential drilling locations.

Husky continued to exploit its mature cold heavy oil production with sand ("CHOPS") reservoirs by drilling 60 wells during the second quarter of 2011.

Husky is operating two solvent Enhanced Oil Recovery ("EOR") pilots. A CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant is under construction with expected completion in the fourth quarter of 2011. This liquefied CO_2 is to be used in the ongoing solvent EOR piloting program.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages. In the second quarter of 2011, Husky completed drilling of the first 12 Steam-Assisted Gravity Drainage ("SAGD") horizontal well pairs as part of the initial 49 well pairs planned for Phase I of the Sunrise project. SAGD drilling costs are trending on budget and on schedule with the full drilling program forecast to be completed by the third quarter of 2012 and first production from Phase I planned for 2014.

Detailed engineering activities for facilities and supporting infrastructure continued during the second quarter of 2011. Engineering contractors achieved the 30% design review milestone while purchases of major equipment and preparation for surface facility construction mobilization remain on schedule for the third quarter of 2011.

Husky has also initiated conceptual development engineering for subsequent phases of the Sunrise Energy Project.

Tucker Oil Sands Project

Based on a greater understanding of the Tucker reservoir, Husky has addressed production challenges by remediating mature wells with new stimulation techniques, drilling new wells, and initiating new start up procedures. The results have been encouraging with year-to-date production averaging 6,400 bbls/day versus 3,500 bbls/day in the first six months of 2010. Second quarter exit rates exceeded 7,000 bbls/day.

Husky completed its 16 well pair A Pad development in the second quarter of 2011 with five well pairs on production. Steaming has commenced on the remaining 11 well pairs with production to phase in during the third quarter of 2011.

McMullen

Cold production from McMullen averaged 3,000 bbls/day in the second quarter of 2011. Eight slant development wells were drilled in the second quarter with a total of 16 slant development wells equipped and put onto production.

Husky received Alberta Environmental ("AENV") approval for the McMullen air injection pilot in the first quarter of 2011 which was the final regulatory approval required for the project. Six pilot observation wells were drilled in the first quarter while one horizontal producing well was spud in late June 2011. Facility construction commenced in May 2011 and will continue into the third quarter of 2011 with steam injection, which is the first phase of the ignition process, and air injection scheduled for the third quarter of 2011. Production is expected in early 2012.

Saleski

In the second quarter of 2011, Husky progressed its evaluation of the information from the vertical stratigraphic test wells and 2-dimensional ("2-D") - seismic data obtained earlier in 2011. Husky is preparing for the drilling of approximately 30 vertical stratigraphic wells and completing an additional 144 kilometers of 2-D seismic data in the upcoming 2012 winter program. Husky is evaluating options to develop a pilot at Saleski.

Western Canada (excluding Heavy Oil and Oil Sands)

Oil Resource Plays

Husky continues to advance exploration and development projects on its extensive Western Canadian oil resource land base of approximately 500,000 acres.

In the second quarter, Husky was successful in acquiring approximately 11,500 acres (18 sections) of high potential Bakken Formation acreage adjacent to its Oungre Oil Resource Project lands in south central Saskatchewan. Husky holds a total of approximately 18,700 net acres (29.25 sections) in this play. Current production from four producing wells is approximately 600 bbls/day after 10 months of production. In the first quarter of 2011, two Bakken horizontal wells were drilled at Oungre. One well was completed prior to spring break up and the second will be completed when wet weather conditions improve. Given the results from the six initial Bakken wells, Husky has committed additional capital resources to accelerate the drilling program with ten additional wells in the second half of 2011. Husky intends to acquire additional 3-D seismic by the end of the year in order to obtain full coverage over all landholdings at Oungre.

In the emerging Shaunavon oil resource play, Husky drilled four Lower Shaunavon horizontal wells in the first quarter of 2011. One well was abandoned due to surface casing problems. The remaining three wells will be completed when wet weather conditions improve. The results from these wells will assist in determining the extent of the prospective nature of this play.

Following a six well program in the first quarter of 2011 in the Viking Oil Resource Project at Redwater, two additional wells were drilled in the second quarter of 2011. A total of 11 wells have been placed on production in 2011, including six carry over wells from 2010. Of the 11 wells, eight were placed on production in the second quarter of which two have been producing for over 60 days at an average rate of 95 bbls/day. Up to nine additional wells are planned in 2011 at Redwater.

In the Southwestern Saskatchewan Viking Oil Resource Project, five wells were drilled in the first quarter of 2011. Two of these wells and one carry over well from 2010 were placed on production in the second quarter of 2011. Drilling of up to 13 wells is being considered for the second half of 2011.

Husky currently holds approximately 28,000 acres (44 sections) in the Northern Cardium oil resource trend at Wapiti and Kakwa. Husky has committed to two Northern Cardium pilot projects including four Cardium horizontal wells at Wapiti and four additional Cardium horizontal wells at Kakwa. These pilot projects will determine the effectiveness of the play and allow Husky to optimize drilling and completion practices.

Gas Resource Plays

Husky continues to build its gas resource play portfolio in Alberta and British Columbia, with approximately 16,000 acres of new crown land acquired in the second quarter of 2011, complementing the approximately 800,000 acres in the Company's existing land base. In 2011, Husky is focusing its activities on the liquids-rich gas resource plays at Ansell, Kaybob and Kakwa.

A key focus of activity has been the liquids-rich Cardium formation at Ansell in west central Alberta with a preliminary development plan in place that includes the potential drilling of up to 2,600 Cardium and deeper Mannville wells, most of which would be horizontal wells, over the course of the project development. To date in 2011, Husky has drilled 21 Cardium Formation wells at Ansell. While second quarter activity has been reduced due to spring break-up, three rigs will be active during the second half of 2011 in which 12 additional Cardium wells and nine deeper multi-zone wells are expected to be drilled. Completion operations will recommence in the third quarter of 2011 and the 33 recently drilled wells are expected to be completed by the end of the fourth quarter of 2011. Offload capacity expansion is currently under construction and expected to be completed at the end of the third quarter which will result in an increase to total production capacity at Ansell to 56 mmcf/day and over 2,000 bbls/day of liquids.

In the second quarter, a vertical well was drilled, cored and logged in Kaybob to evaluate the Duvernay liquids-rich gas play. Based on the result of this well, an offsetting horizontal well is planned for the third quarter of 2011 to establish the productive capability of this zone. A second vertical test well is also planned for the third quarter to evaluate the play on other existing landholdings.

A third deep multi-zone exploration well will be drilled at Kakwa to complete the three well program initiated in the first quarter and Husky plans to complete all three wells in the third quarter of 2011.

Alkaline Surfactant Polymer Floods

The Company commenced its next Alkaline Surfactant Polymer ("ASP") flood at Fosterton, Saskatchewan, with planned drilling of approximately 30 wells through the remainder of the year. Facility site preparation is planned to commence in the third quarter of 2011 with facility construction targeted to be completed by mid-2012. Planning for the future ASP flood at Bone Creek has commenced.

Northwest Territories

Husky acquired exploration rights for two parcels of land, totalling approximately 430,000 acres in the June 2011 Northwest Territories land sale. The land parcels are located southwest of Norman Wells in the Central Mackenzie Valley. Each block contains a five-year primary term and a term extension to nine years when a well is drilled. Husky's work commitment bid reflects the activities that are expected to fully assess the potential of the blocks.

South East Asia

Offshore China Exploration, Delineation and Development

Development of the Liwan Gas Project achieved a significant milestone, with the approval of the Overall Development Plan ("ODP") for the Liwan 3-1 field by Husky and its joint partner, China National Offshore Oil Corporation ("CNOOC"). Submission of the ODP to Chinese government authorities will now take place.

Husky and CNOOC continue to advance the development towards planned production in late 2013 or early 2014. In support of the ODP submission, a natural gas sale agreement has been executed with CNOOC Gas and Power Group, Guangdong Trade Branch, for the sale of natural gas from the Liwan 3-1 field. The natural gas will supply the Guangdong Province natural gas grid from an onshore gas plant on Gaolan Island, Zhuhai. The natural gas price mechanism is in line with the anticipated Guangdong market price.

Tendering of all major deep water equipment, pipelines, and installation services has been completed for the Liwan 3-1 field development and the contracts have been awarded. CNOOC is similarly progressing with the development of the shallow water portion of the project with significant progress made in the tendering process.

In the second quarter of 2011, Husky successfully drilled the Liuhua 29-1-4 and Liuhua 29-1-5 appraisal wells. The wells encountered commercial quantities of gas and will be completed as production wells. The Liwan 4-3-1 exploration well encountered hydrocarbons in non-commercial quantities and was abandoned without testing.

Development of the Liuhua 34-2 field is planned to proceed in parallel with and be tied in to the development of the Liwan 3-1 field. The ODP for the Liuhua 34-2 field is in preparation and planned for submission to the Chinese authorities in the fourth quarter of 2011. Production from the Liwan 3-1 field and the Liuhua 34-2 field is anticipated to start in late 2013, ramping up through 2014.

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 drilling of an exploration well is planned for the third quarter of 2011. Husky holds a 100% interest in Block 63/05, in which CNOOC has the right to participate up to 51%.

Indonesia Exploration and Development

The Indonesian government regulator has approved a gas sales price for the Madura Block and final gas sales amendments to existing agreements are expected to be completed later this year. Tendering of equipment and services for the BD field development is underway. A delineation well, MDA-4 is planned on the MDA field in the third quarter of 2011 and a further exploration well, MBH-1 is planned for the first quarter of 2012. First gas production from the Madura Block is expected in 2014.

Husky currently holds a 100% working interest in the North Sumbawa II Exploration Block, comprised of 5,000 square kilometres in the East Java Sea, where interpretation of 1,020 kilometres of new 2-D seismic data has been completed and several leads have been identified.

Midstream

Husky's project to construct a 300,000 barrel tank at the Hardisty terminal is on target to be in service in the first quarter of 2012. The tank will facilitate moving volumes from the Enbridge system to the Keystone pipeline system and will enhance Husky's long term commitment to ship volumes on the Keystone pipeline.

Downstream

Lima, Ohio Refinery

The refinery continues to implement short term reliability and profitability improvement projects. Detailed engineering design has commenced on a 20 mbbls/day kerosene hydrotreater which will increase jet fuel production volume and improve quality.

Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery is continuing as planned. Overall detailed engineering and procurement is substantially completed and all major construction contracts have been awarded. The Mechanical, Electrical and Instrumentation contract is anticipated to be awarded in the third quarter of 2011. The refinery continues to advance a multi-year program to improve operational integrity and plant performance while reducing operating costs and environmental impacts.

5. Results of Operations

5.1 Upstream

Upstream Net Earnings Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2011**	2010	**2011**	2010
Gross revenues	**$ 1,880**	$ 1,334	**$ 3,551**	$ 2,872
Royalties	**289**	248	**547**	534
Net revenues	**1,591**	1,086	**3,004**	2,338
Operating, transportation and administration expenses	**485**	396	**935**	778
Exploration and evaluation expense	**88**	131	**181**	180
Depletion, depreciation and amortization	**480**	361	**912**	707
Other (income) expense	**(73)**	3	**(263)**	4
Income taxes	**168**	57	**340**	194
Net earnings	**$ 443**	$ 138	**$ 899**	$ 475

Second Quarter

Upstream net earnings in the second quarter of 2011 increased by $305 million compared with the second quarter of 2010 primarily as a result of increased crude oil and natural gas production, higher realized crude oil and natural gas prices, lower exploration and evaluation expenses and a pre-tax gain of $68 million on a property swap, partially offset by higher operating expenses and higher depletion.

Production increased by 27.7 mboe/day due to production from the North Amethyst field which commenced in May 2010 and production from acquisitions in the fourth quarter of 2010 and the first quarter of 2011, partially offset by lower production at White Rose, Terra Nova and Wenchang. Production was also impacted by difficult operating conditions in the Slave Lake region where forest fires caused production interruptions and the outage of the Rainbow pipeline. The northern portion of the Rainbow pipeline shut-in decreased average production over the second quarter by approximately 8.5 mboe/day. The shut-in caused the pipeline to be out of operation through May and June 2011 which impacted production by approximately 13.6 mboe/day over the period of disruption. Although the northern portion of the pipeline remains shut down, Husky has been able to reduce the impact of the outage to approximately 11.0 mboe/day through a number of mitigating activities.

The average realized price in the second quarter of 2011 increased to $86.90/bbl for crude oil, NGL and bitumen compared with $64.75/bbl during the same period in 2010. Realized natural gas prices averaged $3.66/mcf in the second quarter of 2011 compared with $3.45/mcf in the same period in 2010. Production in the Atlantic Region and Wenchang benefited from higher realized prices as the price of Brent increased by 50% compared with the second quarter of 2010, while WTI increased by 31%.

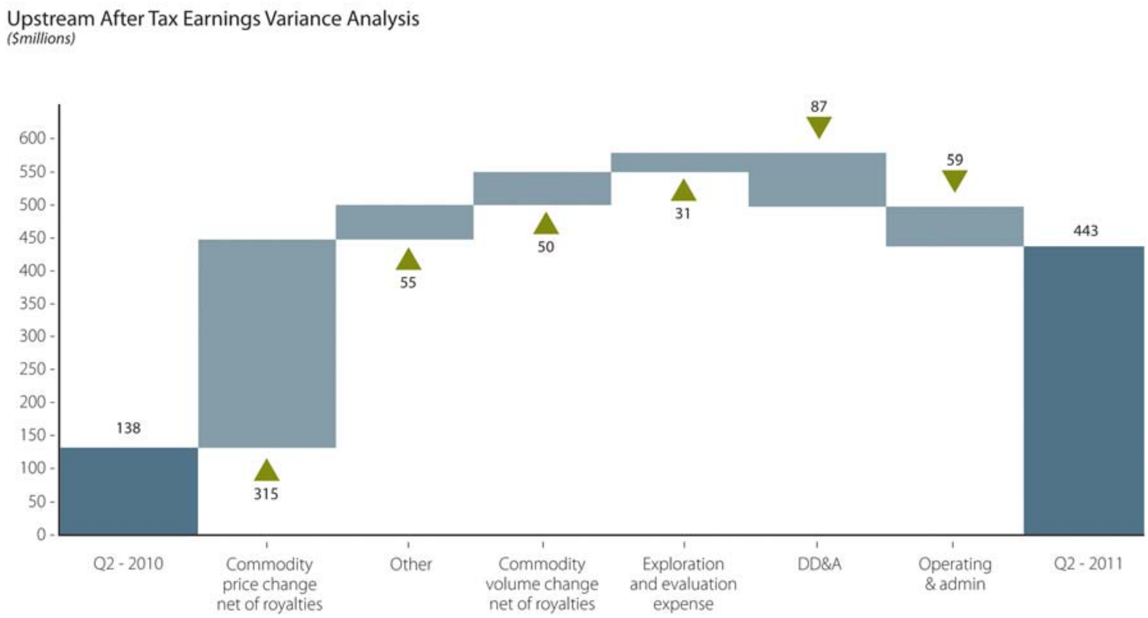
Six Months

Upstream earnings in the first six months of 2011 were $424 million higher compared with the same period in 2010. In addition to the same factors impacting the second quarter, Husky realized a pre-tax gain of $177 million on the sale of oil sands mining leases in the first quarter of 2011.

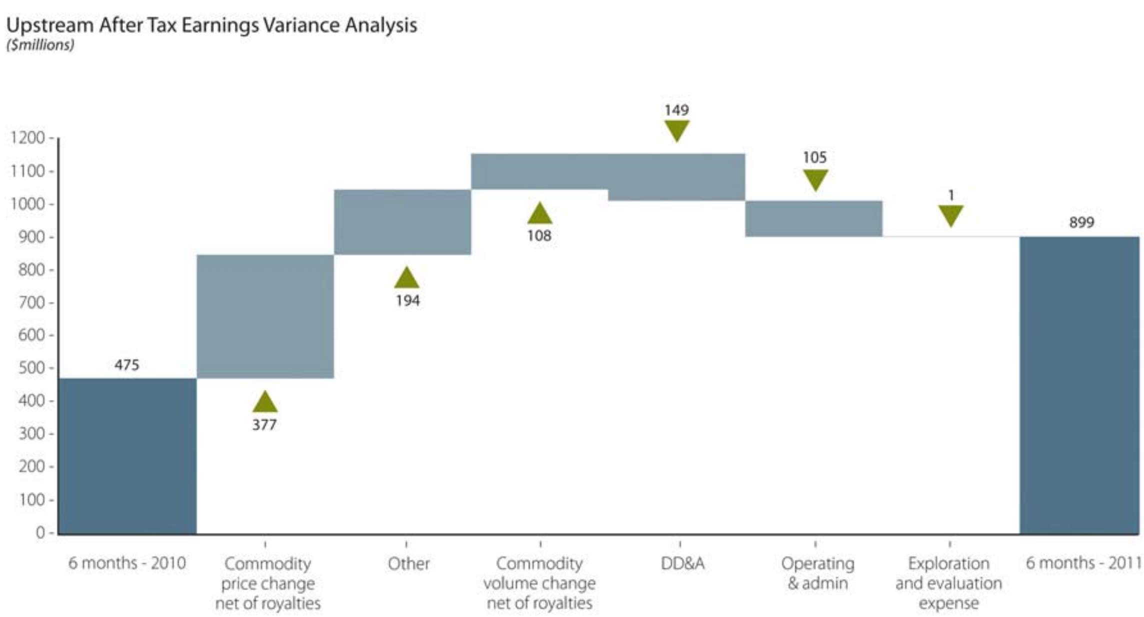
During the first six months of 2011, average realized prices increased 22% to $81.78/bbl for crude oil, NGL and bitumen combined compared with $67.26/bbl during the same period in 2010. Average realized natural gas prices were $3.66/mcf during the first six months of 2011 compared with $4.21/mcf in the same period in 2010.

Upstream After Tax Variance Analysis

Second Quarter



Six Months



Pricing

Average Sales Prices Realized		Three months ended June 30		Six months ended June 30	
		2011	2010	**2011**	2010
Crude oil	*($/bbl)*				
Light crude oil & NGL		**$ 107.29**	$ 75.61	**$ 103.16**	$ 76.70
Medium crude oil		**80.27**	63.90	**74.10**	66.60
Heavy crude oil		**71.59**	56.18	**65.27**	59.66
Bitumen		**68.62**	52.58	**61.97**	56.74
Total average		**86.90**	64.75	**81.78**	67.26
Natural gas average	*($/mcf)*	**3.66**	3.45	**3.66**	4.21
Total average	*($/boe)*	**65.36**	51.40	**62.61**	54.72

The price realized for light crude oil reflects increases in WTI and the significant premium realized for offshore production referenced to Brent prices. In Western Canada, non-operated pipeline disruptions resulted in a widening of the differentials for medium and heavy crude oil and bitumen. In addition, the increased U.S. dollar crude oil prices were partially offset by the strengthening of the Canadian dollar against the U.S. dollar in 2011 compared to 2010.

Oil and Gas Production

Daily Gross Production		Three months ended June 30		Six months ended June 30	
		2011	2010	**2011**	2010
Crude oil & NGL	*(mbbls/day)*				
Western Canada					
Light crude oil & NGL		**21.7**	22.5	**23.8**	23.0
Medium crude oil		**24.6**	25.1	**24.6**	25.2
Heavy crude oil		**73.6**	74.6	**73.5**	75.4
Bitumen		**23.6**	21.5	**23.9**	22.1
		143.5	143.7	**145.8**	145.7
Atlantic Region					
White Rose - light crude oil		**25.8**	32.9	**27.1**	36.0
North Amethyst - light crude oil		**23.0**	2.1	**22.2**	1.1
Terra Nova - light crude oil		**4.9**	10.0	**5.3**	10.3
China					
Wenchang - light crude oil & NGL		**9.1**	11.2	**9.3**	11.0
Total crude oil & NGL		**206.3**	199.9	**209.7**	204.1
Natural gas	*(mmcf/day)*	**631.8**	503.9	**607.7**	513.8
Total	*(mboe/day)*	**311.6**	283.9	**311.0**	289.7

Crude Oil and NGL Production

Second Quarter

Crude oil and NGL production in the second quarter of 2011 increased by 6.4 mbbls/day or 3% compared with the same period in 2010. The increase is primarily due to additional production at North Amethyst, which commenced in May 2010, partially offset by the impact of the Plains Rainbow pipeline outage, decreased production at White Rose and Wenchang due to natural reservoir decline and at Terra Nova due to operational impacts of H_2S contamination.

Six Months

In the first six months of 2011, crude oil and NGL production increased by 3% compared with the same period in 2010, primarily due to the same factors impacting the second quarter.

Natural Gas Production

Natural gas production increased by 127.9 mmcf/day or 25% in the second quarter of 2011 compared with the second quarter of 2010 due to the acquisitions of properties in Western Canada during the fourth quarter of 2010 and first quarter of 2011, partially offset by the impact of the Plains Rainbow pipeline outage and natural reservoir declines in mature properties.

2011 Production Guidance			Actual Production	
		Guidance	Six months ended June 30 2011	Year ended Dec. 31 2010
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		75 – 80	88	81
Medium crude oil		25 – 30	25	25
Heavy crude oil & bitumen		95 – 105	97	97
		195 – 215	210	203
Natural gas	*(mmcf/day)*	560 – 610	608	507
Natural gas	*(mboe/day)*	93 – 102	101	84
Total barrels of oil equivalent	*(mboe/day)*	290 – 315	311	287

Royalties

Second Quarter

In the second quarter of 2011, royalty rates averaged 16% as a percentage of gross revenue compared with 19% in 2010. Royalty rates in Western Canada averaged 14%, comparable to 15% in the same period in 2010. Rates for the Atlantic Region averaged 17% in the second quarter of 2011 down from 28% in the second quarter of 2010 due 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 33% in the second quarter of 2011, compared with 22% in the second quarter of 2010 due to price increases and a sliding scale price sensitive rate.

Six Months

Royalty rates averaged 16% of gross revenue in the first six months compared with 19% in the same period in 2010. Rates in Western Canada averaged 14% compared with 15% in 2010 and for the Atlantic Region the average rate was 17% compared with 28% in the same period in 2010. Royalty rates in Wenchang averaged 29% in the first six months compared with 23% in the same period in 2010. The change in rates for the first six months was due to the same factors impacting the second quarter.

Operating Costs

(millions of dollars)	Three months ended June 30 2011	2010	Six months ended June 30 2011	2010
Western Canada	**$ 354**	$ 293	**$ 703**	$ 593
Atlantic Region	**44**	46	**82**	84
International	**6**	6	**12**	10
Total	**$ 404**	$ 345	**$ 797**	$ 687
Unit operating costs ($/boe)	**$ 14.25**	$ 13.08	**$ 14.16**	$ 13.10

Second Quarter

Total Upstream operating costs in the second quarter of 2011 increased to $404 million from $345 million in the second quarter of 2010 as a result of increased natural gas costs combined with treating, servicing and maintenance costs that were impacted by acquisitions in the fourth quarter of 2010 and the first quarter of 2011. Total Upstream unit operating costs in the second quarter of 2011 averaged $14.25/boe compared with $13.08/boe in the second quarter of 2010.

Operating costs in Western Canada averaged $15.63/boe in the second quarter compared with $14.36/boe in the same period in 2010. Higher operating costs in 2011 were partially offset by an increase in production volumes. Acquisitions in the fourth quarter of 2010 and the first quarter of 2011 increased natural gas and propane consumption along with increased costs associated with custom processing, servicing, maintenance and labour when compared to the second quarter of 2010. Higher handling costs of produced fluids resulted from increased water and emulsion production in the second quarter of 2011 and major joint venture partner facility equalizations also added to the increase in costs. Maturing fields in Western Canada require more extensive 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 by fully utilizing infrastructures in place.

Operating costs in the Atlantic Region averaged $9.00/boe in the second quarter of 2011 compared with $11.20/boe in 2010 due to increased production from North Amethyst in the second quarter of 2011 compared with the second quarter of 2010.

Operating costs at the South China Sea offshore operations averaged $7.38/bbl in the second quarter of 2011 compared with $6.23/bbl in the same period in 2010, as a result of lower production and higher servicing, maintenance and insurance costs, partially offset by lower workover costs in the second quarter of 2011 compared with the same period in 2010.

Six Months

Total Upstream operating costs in the first half of 2011 increased by 16% compared with the same period in 2010 primarily due to the same factors affecting the second quarter.

Exploration and Evaluation Expense

Exploration and Evaluation Expense Summary

(millions of dollars)	Three months ended June 30 2011	2010	Six months ended June 30 2011	2010
Seismic	**$ 22**	$ 20	**$ 37**	$ 53
Expensed drilling	**23**	93	**60**	97
Expensed land	**43**	-	**43**	-
Other	**-**	18	**41**	33
Total	**$ 88**	$ 131	**$ 181**	$ 183

Second Quarter

Exploration and evaluation expenses for the second quarter of 2011 were $88 million compared with $131 million in the second quarter of 2010 primarily due to lower expensed drilling costs, partially offset by land costs expensed in the quarter.

Expensed drilling costs in the second quarter of 2011 included pilot test wells which are not subject to evaluation for economic viability and the Liwan 4-3-1 exploration well which was drilled and abandoned.

Expensed land costs in the second quarter of 2011 include previous years' acquisition costs for properties in the Columbia River Basin located in the states of Washington and Oregon.

Six Months

Exploration and evaluation expenses for the first half of 2011 were $181 million comparable to $183 million during the same period of 2010.

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

Second Quarter

In the second quarter of 2011, total DD&A averaged $16.91/boe compared with $13.94/boe in the second quarter of 2010. The increased DD&A rate in the second quarter of 2011 was primarily due to the increased capital cost base associated with the North Amethyst offshore project which commenced production in May 2010 and has therefore been depleted for all of the second quarter of 2011 as compared to one month in the second quarter of 2010.

Six Months

For the first six months of 2011, total DD&A averaged $16.20/boe compared with $13.47/boe during the same period in 2010 due to the same factors affecting the second quarter.

Upstream Capital Expenditures

Capital Expenditures Summary [1]

(millions of dollars)	Three months ended June 30 **2011**	Three months ended June 30 2010	Six months ended June 30 **2011**	Six months ended June 30 2010
Exploration				
Western Canada	**$ 5**	$ 64	**$ 127**	$ 147
Atlantic Region	**-**	5	**-**	61
International	**52**	63	**52**	157
	57	132	**179**	365
Development				
Western Canada	**336**	205	**775**	497
Atlantic Region	**73**	98	**135**	189
International	**123**	-	**170**	1
	532	303	**1,080**	687
Acquisitions				
Western Canada	**18**	4	**860**	13
	$ 607	$ 439	**$ 2,119**	$ 1,065

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

In the first six months of 2011, Upstream capital expenditures were $2,119 million. Capital expenditures including acquisitions of $860 million were $1,762 million (83%) in Western Canada, $135 million (6%) in the Atlantic Region and $222 million (11%) in South East Asia. Husky's major projects remain on budget and schedule.

Western Canada

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

Western Canada (including Heavy Oil and Oil Sands) Wells Drilled		Three months ended June 30				Six months ended June 30			
		2011		2010		**2011**		2010	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**7**	**4**	6	3	**17**	**13**	27	22
	Gas	**1**	**1**	1	1	**10**	**10**	18	16
	Dry	**-**	**-**	-	-	**3**	**3**	7	7
		8	**5**	7	4	**30**	**26**	52	45
Development	Oil	**107**	**93**	62	52	**309**	**283**	267	231
	Gas	**5**	**3**	-	-	**36**	**30**	15	9
	Dry	**2**	**1**	-	-	**2**	**1**	6	5
		114	**97**	62	52	**347**	**314**	288	245
Total		**122**	**102**	69	56	**377**	**340**	340	290

During the first six months of 2011, Husky invested $1,762 million on exploration, development and acquisitions throughout the Western Canada Sedimentary Basin compared with $657 million in the first six months of 2010. Property acquisitions of $860 million were completed during the first six months of 2011, primarily in the Rainbow Lake area of northwestern Alberta, the Foothills and Deep Basin areas of Alberta and in northeastern British Columbia. In addition, $218 million was invested in oil related exploration and development and $150 million was invested in natural gas related exploration and development compared with $305 million for oil related exploration and development and $168 million for natural gas related exploration and development in the first six months of 2010.

During the first six months of 2011, capital expenditures on heavy oil projects were $232 million spent on thermal projects, CHOPS drilling, and horizontal drilling.

During the first six months of 2011, capital expenditures on oil sands projects were $117 million compared with $40 million in the same period in 2010 as Sunrise Phase I progresses.

In addition, $77 million was spent on production optimization and cost reduction initiatives in the first six months of 2011. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to $108 million.

The Company drilled 340 net wells in the Western Canada Sedimentary Basin in the first half of 2011 resulting in 296 net oil wells and 40 net natural gas wells compared with 290 net wells resulting in 253 net oil wells and 25 net natural gas wells in the first half of 2010. Capital expenditures for wells drilled in Western Canada have increased substantially due to the larger numbers of horizontal wells drilled and more multi-stage fracture completions performed compared with 2010.

Atlantic Region

The following table discloses Husky's offshore Atlantic Region drilling activity during the first six months of 2011:

Offshore Atlantic Region Drilling Activity			
North Amethyst G-25-5	WI 68.875%	Water injection	Development
North Amethyst G-25-6	WI 68.875%	Production	Development

During the first six months of 2011, $135 million was invested in Atlantic Region development projects, primarily drilling of water injection and production wells in North Amethyst. No exploration wells were drilled in the Atlantic Region in the first half of 2011.

International

The following table discloses Husky's offshore China and Indonesia drilling activity during the first six months of 2011:

International Offshore Drilling Activity			
Liuhua 29-1-4 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liuhua 29-1-5 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 4-3-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 3-1-5 Block 29/26	WI 49%	Production	Development
Liwan 3-1-6 Block 29/26	WI 49%	Production	Development
Liwan 3-1-7 Block 29/26	WI 49%	Production	Development
Liwan 3-1-8 Block 29/26	WI 49%	Production	Development

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

During the first six months of 2011, $222 million was spent primarily on offshore projects in China, including the drilling of four Liwan 3-1 wells, two Liuhua 29-1 field delineation wells and one Liwan 4-3 field exploration well on Block 29/26 in the South China Sea.

Upstream Planned Turnarounds

A scheduled 16-day turnaround of the *SeaRose FPSO* for July 2011 was reduced to two days and has been completed as scheduled in early July. In addition, Husky continues to investigate various options to address the maintenance of the *SeaRose FPSO* propulsion system including an off-station turnaround in 2012.

The *Terra Nova FPSO* operated by Suncor has a 28-day turnaround scheduled for September 2011. The originally scheduled 15-week dockside maintenance for the *Terra Nova FPSO* in July 2011 has been deferred to 2012.

5.2 Midstream

Infrastructure and Marketing Net Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2011**	2010	**2011**	2010
Gross revenues		**$ 2,414**	$ 1,772	**$ 4,782**	$ 3,598
Gross margin	- pipeline	**$ 38**	$ 37	**$ 73**	$ 69
	- other infrastructure and marketing	**46**	23	**142**	104
		84	60	**215**	173
Operating and administration expenses		**6**	5	**12**	10
Depreciation and amortization		**10**	10	**20**	20
Other expense (income)		**10**	(9)	**20**	22
Income taxes		**15**	14	**41**	32
Net earnings		**$ 43**	$ 40	**$ 122**	$ 89
Selected operating data:					
Commodity volumes managed	*(mboe/day)*	**1,094**	964	**1,060**	950
Aggregate pipeline throughput	*(mbbls/day)*	**568**	537	**574**	531

Second Quarter

Infrastructure and Marketing net earnings in the second quarter of 2011 were $43 million compared with $40 million in the second quarter of 2010. The increase in net earnings was due to trading gains captured on light and synthetic crude oil moving from Canada to the U.S. as a result of the widening WTI to Brent differential partially offset by lower natural gas storage earnings. Other expenses, which include the fair value impact of the Company's commodity price risk management activities (refer to Section 7.5), increased in the second quarter of 2011 compared with the same period in 2010, due to unrealized gains on outstanding contracts in the prior quarter that were settled during the second quarter.

Six Months

During the first half of 2011, Infrastructure and Marketing net earnings were $33 million higher than the same period of 2010 due to the same factors affecting the second quarter of 2011.

Midstream Capital Expenditures

In the first six months of 2011, Midstream capital expenditures totalled $16 million compared to $15 million in the same period in 2010.

5.3 Downstream

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

Upgrading Net Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2011**	2010	**2011**	2010
Gross revenues		**$ 649**	$ 405	**$ 1,017**	$ 913
Gross margin		**$ 190**	$ 94	**$ 289**	$ 184
Operating and administration expenses		**46**	44	**104**	94
Depreciation and amortization		**87**	10	**112**	13
Other expense (income)		**16**	1	**28**	(4)
Income taxes		**11**	11	**12**	23
Net earnings		**$ 30**	$ 28	**$ 33**	$ 58
Selected operating data:					
Upgrader throughput [(1)]	*(mbbls/day)*	**76.1**	73.5	**64.7**	77.8
Synthetic crude oil sales	*(mbbls/day)*	**61.0**	58.0	**51.0**	63.3
Upgrading differential	*($/bbl)*	**$ 33.09**	$ 15.44	**$ 28.62**	$ 14.06
Unit margin	*($/bbl)*	**$ 27.66**	$ 17.78	**$ 24.93**	$ 16.08
Unit operating cost [(2)]	*($/bbl)*	**$ 8.44**	$ 6.60	**$ 10.81**	$ 6.69

(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.

Second Quarter

Upgrading net earnings in the second quarter of 2011 were $30 million compared with $28 million in the same period in 2010. The increase is primarily due to higher realized differentials and higher production, partially offset by higher depreciation and amortization.

During the second quarter of 2011, the upgrading differential averaged $33.09/bbl, an increase of $17.65/bbl or 114% compared with the second quarter of 2010. The differential is equal to Husky Synthetic Blend, which sells at a premium to WTI, less Lloyd Heavy Blend. The average price for Husky Synthetic Blend in the second quarter of 2011 was $110.79/bbl, compared to $78.50/bbl in the same period in 2010. The overall unit margin increased to $27.66/bbl in the second quarter of 2011 from $17.78/bbl in the same period in 2010 primarily as a result of wider heavy to light crude oil price differentials and higher synthetic blend sales prices.

The increase in other expenses is due to the increase in the fair value of the remaining upside interest payment obligation to Natural Resources Canada and the Alberta Department of Energy. The increase in depreciation and amortization is due to the derecognition of certain intangible costs and turnaround costs from the fall of 2010 which were depreciated starting in the fourth quarter of 2010.

Six Months

Upgrading earnings for the first six months of 2011 were affected by the same factors impacting the second quarter in addition to a minor fire at the Lloydminster Upgrader in early February which resulted in a reduction in average throughput at the Upgrader to 53.2 mbbls/day in the first quarter of 2011, increased repair, depreciation, operating and administration expenses partially offset by higher differentials. The fire was caused by a frozen pipeline which burst, releasing fuel onto nearby equipment damaging a hydrocracker fractionation unit, which supplies product to the coker. No injuries occurred. While damage was not extensive, repairs took place in a congested space under extremely cold weather conditions. Repairs were made incorporating measures to prevent a similar incident in the future. Normal operations resumed in April 2011.

Canadian Refined Products Net Earnings Summary			Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)			**2011**	2010	**2011**	2010
Gross revenues			**$ 927**	$ 700	**$ 1,760**	$ 1,306
Gross margin	- fuel		**$ 37**	$ 9	**$ 72**	$ 27
	- refining		**24**	12	**53**	34
	- asphalt		**43**	29	**55**	39
	- ancillary		**13**	12	**24**	23
			117	62	**204**	123
Operating and administration expenses			**35**	21	**58**	46
Depreciation and amortization			**19**	24	**37**	49
Income taxes			**15**	5	**27**	8
Net earnings			**$ 48**	$ 12	**$ 82**	$ 20
Selected operating data:						
Number of fuel outlets (average)					**549**	479
Light oil sales		*(million litres/day)*	**8.3**	7.8	**8.4**	7.7
Light oil retail sales per outlet		*(thousand litres/day)*	**12.1**	13.5	**12.7**	13.5
Prince George Refinery throughput		*(mbbls/day)*	**9.1**	6.9	**10.0**	8.3
Asphalt sales		*(mbbls/day)*	**20.2**	19.2	**20.1**	18.9
Lloydminster Refinery throughput		*(mbbls/day)*	**26.2**	26.1	**27.5**	26.5
Ethanol production		*(thousand litres/day)*	**730.0**	547.6	**724.1**	633.9

Second Quarter

Gross margins on fuel sales were higher in the second quarter of 2011 compared with 2010 as a result of higher retail and wholesale market prices combined with increased volumes due to the purchase of 98 retail stations in 2010 and changes to the retail business model.

Higher refining gross margins in the second quarter of 2011 were primarily due to higher production at the Prince George Refinery and higher total ethanol production from a successful recycle thermal oxidiser installation at the Lloydminster ethanol plant, as well as higher realized prices for gasoline, diesel and ethanol. Included in refining gross margins in the second quarter of 2011 and 2010 are government assistance grants of $13 million and $15 million, respectively.

Asphalt gross margins were higher in the second quarter of 2011 compared with the second quarter of 2010 due to higher realized market prices and higher sales volumes for residuals as a result of strong demand for drilling fluids.

Six Months

During the first half of 2011, refined products earnings were higher than the same period in 2010 primarily due to the same factors that affected the second quarter of 2011.

U.S. Refining and Marketing Net Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2011**	2010	**2011**	2010
Gross revenues		**$ 2,585**	$ 1,881	**$ 4,809**	$ 3,600
Gross refining margin		**$ 396**	$ 123	**$ 724**	$ 220
Operating and administration expenses		**91**	100	**186**	194
Interest - net		**1**	-	**1**	1
Depreciation and amortization		**45**	47	**95**	93
Other income		**-**	(2)	**-**	-
Income taxes (recoveries)		**94**	(8)	**161**	(25)
Net earnings (loss)		**$ 165**	$ (14)	**$ 281**	$ (43)
Selected operating data:					
Lima Refinery throughput	*(mbbls/day)*	**148.6**	150.3	**148.8**	146.0
Toledo Refinery throughput	*(mbbls/day)*	**62.6**	70.4	**64.0**	69.2
Realized refining margin	*(U.S. $/bbl crude throughput)*	**$ 21.37**	$ 6.03	**$ 19.29**	$ 5.51
Refinery feedstocks and refined products inventory	*(mmbbls)*	**11.65**	12.54	**11.65**	12.54

Second Quarter

U.S. Refining and Marketing net earnings increased significantly in the second quarter of 2011 compared with the second quarter of 2010 as a result of higher realized refining margins. In addition to increased market crack spreads, feedstock at the Toledo Refinery was approximately 60% heavy crude oil which added to increased margins as differentials between heavy and light crude oil remained high in the second quarter of 2011, partially offset by crude supply constraints due to Enbridge Pipeline construction, minor operational disruptions due to poor weather conditions and planned maintenance at the Toledo refinery.

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 hit its peak early in the second quarter, while on a FIFO basis crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter when crude oil prices were higher.

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 impact of product slates partially offset the factors above.

In addition, the strengthening of the Canadian dollar versus the U.S. dollar in the second quarter of 2011 compared with the same period in 2010 has had a negative impact on the translation of U.S. dollar financial results into Canadian dollars.

On June 27, 2011, a controlled shutdown of the crude unit furnace was initiated at the Lima Refinery and lasted for nine days. The impact of this shutdown will be reflected in third quarter results.

Six Months

Refining margins in the first six months of 2011 were impacted by the same factors affecting the second quarter.

Downstream Capital Expenditures

In the first six months of 2011, Downstream capital expenditures totalled $133 million compared with $178 million in the same period of 2010.

In Canada, capital expenditures were $49 million related to upgrades at the Prince George Refinery and the Upgrader.

In the United States, capital expenditures totalled $84 million. At the Lima Refinery, $40 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled $44 million (Husky's 50% share) primarily for engineering work and procurement on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

Husky is scheduled to complete a minor turnaround at the Lloydminster Upgrader in September and October 2011, primarily for inspection and equipment maintenance. During this time, the Upgrader is expected to be at 70% to 80% capacity. The next major turnaround is scheduled to commence in the fall of 2013.

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

The Prince George Refinery is scheduled to have two minor turnarounds in the last half of 2011. The next major turnaround will occur in 2012 during the third and fourth quarters.

The Toledo Refinery will have a minor turnaround in the third quarter of 2011 on the isocracker unit and general maintenance. The turnaround is scheduled to last approximately 38 days. There is also a minor turnaround planned for the fourth quarter of 2011. The next major turnaround is scheduled to occur in mid-2012 and the total outage is expected to last approximately 45 days.

The Lima Refinery will have a 15-day isocracker outage in the fall of 2011 to replace the reactor catalyst. The refinery will be operating at an estimated 90% capacity during that time. In addition, there will be a 15-day aromatics turnaround in the fall of 2012 which will not have a material impact on crude throughputs.

5.4 Corporate

Corporate Summary *(millions of dollars) income (expense)*	Three months ended June 30 2011	 2010	Six months ended June 30 2011	 2010
Intersegment eliminations - net	$ 8	$ 40	$ (15)	$ 14
Administration expense	(78)	(18)	(95)	(28)
Other income (expense)	-	(1)	1	(2)
Stock-based compensation	8	7	3	18
Exploration and evaluation expenses	-	-	-	(3)
Depreciation and amortization	(9)	(18)	(16)	(37)
Interest - net	(45)	(46)	(90)	(85)
Foreign exchange	17	(14)	19	16
Income taxes	39	25	71	55
Net loss	$ (60)	$ (25)	$ (122)	$ (52)

Second Quarter

The Corporate segment reported a loss of $60 million in the second quarter of 2011 compared with a loss of $25 million in the second quarter of 2010 due to increased administrative costs on financing projects and other initiatives. Stock-based compensation expense was a recovery of $8 million in the second quarter of 2011 due to a decrease in the share price during the quarter. Foreign exchange was a gain of $17 million during the second quarter of 2011 compared with a loss of $14 million in the same period of 2010 as a result of the strengthening Canadian dollar impacting U.S. denominated debt.

Intersegment eliminations are net earnings included in inventory that has not been sold to third parties at the end of the period.

Six Months

In the first half of 2011, the Corporate segment reported a loss of $122 million compared with $52 million in the same period of 2010 due to the same factors affecting the second quarter.

Foreign Exchange Summary *(millions of dollars)*	Three months ended June 30 2011	 2010	Six months ended June 30 2011	 2010
(Gains) losses on translation of U.S. dollar denominated long-term debt	$ (15)	$ 94	$ (63)	$ 29
(Gains) losses on cross currency swaps	3	(16)	11	(5)
(Gains) losses on contribution receivable	7	(57)	35	(18)
Other (gains) losses	(12)	(7)	(2)	(22)
Foreign exchange (gains) losses	$ (17)	$ 14	$ (19)	$ (16)
U.S./Canadian dollar exchange rates:				
At beginning of period	U.S. $1.029	U.S. $0.985	U.S. $1.005	U.S. $0.956
At end of period	U.S. $1.037	U.S. $0.943	U.S. $1.037	U.S. $0.943

Included in other foreign exchange (gains) losses is realized foreign exchange and unrealized foreign exchange (gains) losses on working capital and intercompany financing.

The foreign exchange (gains) losses on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period.

Corporate Capital Expenditures

In the first six months of 2011, Corporate capital expenditures of $15 million were primarily for computer hardware and software and construction of a new building in Lloydminster.

Consolidated Income Taxes

During the second quarter of 2011, consolidated income tax expense was $264 million compared with $54 million in the same period in 2010. Cash taxes paid in the first six months of 2011 were $53 million compared with $689 million in the first six months of 2010, of which $42 million relates to installments paid in respect of 2010 net earnings and $11 million relates to 2011 earnings. Further 2011 cash tax installments are estimated to be approximately $11 million, all of which are in respect of 2011 earnings.

6. Liquidity and Capital Resources

In the second quarter of 2011, Husky funded its capital programs, including acquisitions and dividend payments, by cash generated from operating activities, cash on hand and equity issuances. At June 30, 2011, Husky had total debt of $3,722 million partially offset by cash on hand of $1,391 million for $2,331 million of net debt compared to $3,935 million of net debt at December 31, 2010. Husky has no long-term debt maturing until 2012. At June 30, 2011, the Company had $3.2 billion in unused committed credit facilities, $175 million in unused short-term uncommitted credit facilities, unused capacity under the debt shelf prospectus filed in Canada of $300 million, unused capacity under the November 2010 universal short form base shelf prospectus filed in Canada of $1.4 billion, and unused capacity under the June 13, 2011 U.S. base shelf prospectus of $2.0 billion. (Refer to Section 6.4).

Cash Flow Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except ratios)		**2011**	2010	**2011**	2010
Cash flow	- operating activities	**$ 1,451**	$ 441	**$ 2,734**	$ 1,002
	- financing activities	**$ 571**	$ (262)	**$ 648**	$ 212
	- investing activities	**$ (697)**	$ (580)	**$ (2,251)**	$ (1,501)
Financial Ratios [5]					
Debt to capital employed *(percent)*				**18.0**	21.6
Debt to cash flow *(times)* [1]				**0.9**	1.4
Corporate reinvestment ratio *(percent)* [1] [2]				**123**	104
Interest coverage ratios on long-term debt only [1] [3]					
Net earnings				**12.4**	8.4
Cash flow				**20.9**	14.0
Interest coverage ratios on total debt [1] [4]					
Net earnings				**11.9**	8.3
Cash flow				**20.1**	13.7

(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 a net earnings basis is equal to net earnings before finance expense on long-term debt and income taxes divided by finance expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow from operating activities before finance expense on long-term debt and current income taxes divided by finance expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.*
(4) *Interest coverage on total debt on a net earnings basis is equal to net earnings before finance expense on total debt and income taxes divided by finance expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow from operating activities before finance expense on total debt and current incomes taxes divided by finance expense on total debt and capitalized interest. Total debt includes short and long-term debt.*
(5) *2010 comparative results are reported in accordance with previous Canadian GAAP.*

6.1 Operating Activities

Second Quarter

In the second quarter of 2011, cash generated from operating activities amounted to $1,451 million compared with $441 million in the second quarter of 2010. Higher cash flow from operating activities is primarily due to higher crude oil and natural gas production, higher crude oil prices in Upstream and higher realized margins in Canadian and U.S. Downstream.

Six Months

Cash generated from operating activities amounted to $2,734 million in the first six months of 2011 compared with $1,002 million in the first six months of 2010. Higher cash flow from operating activities was primarily due to the same factors impacting the second quarter.

6.2 Financing Activities

Second Quarter

In the second quarter of 2011, cash provided by financing activities was due primarily to the issue in June 2011 of $1.2 billion in common shares during the quarter and debt issued of $960 million, offset by cash dividends of $81 million, debt repayments of $1,320 million and cash used in other financing activities of $188 million.

Six Months

Cash provided by financing activities was $648 million in the first six months of 2011 compared with $212 million in the first six months of 2010. In addition to the same factors impacting the second quarter, the Company issued $300 million of preferred shares in the first quarter of 2011.

6.3 Investing Activities

Second Quarter

In the second quarter of 2011, cash used in investing activities amounted to $697 million compared with $580 million in the second quarter of 2010. Cash invested in both periods was primarily for expenditures on property, plant and equipment.

Six Months

Cash used in investing activities for the first six months of 2011 was $2.3 billion compared with $1.5 billion in the first six months of 2010. Cash invested in both periods was primarily for acquisitions and 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 equity, 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 June 30, 2011, working capital was $2,146 million compared with $1,181 million at December 31, 2010.

At June 30, 2011, Husky had unused committed long and short-term borrowing credit facilities totalling $3.2 billion. A total of $106 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.

On December 21, 2009, Husky filed a debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $1.0 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 can be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and as set forth in an accompanying prospectus supplement. As of June 30, 2011, $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020 had been issued under this shelf prospectus. (Refer to Note 9 to the Condensed Interim 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 $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 26, 2012 ("the Canadian Shelf Prospectus"). During the 25-month period that the 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 approximately $293 million pursuant to the universal short form base shelf prospectus. Husky also issued 28.9 million common shares to L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. at a price of $24.50 per share for total proceeds of approximately $707 million. The Company received total net proceeds of $988 million from this issuance.

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

On June 13, 2011, Husky filed a universal short form base shelf prospectus with the Alberta Securities Commission and the U.S. Securities and Exchange Commission that enables Husky to offer up to U.S. $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units in the United States until July 13, 2013 ("the U.S. Shelf Prospectus").

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

Capital Structure *(millions of dollars)*	June 30, 2011 Outstanding	Available[1]
Total short-term and long-term debt	$ 3,722	$ 3,409
Common shares, preferred shares, retained earnings and other reserves	$ 16,900	

[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. Refer to Husky's 2010 annual Management's Discussion and Analysis under the caption "Liquidity and Capital Resources," which summarizes contractual obligations and commercial commitments as at December 31, 2010. At June 30, 2011, Husky did not have any additional material contractual obligations and commercial commitments. There were no material changes to commitments noted during the second quarter of 2011.

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. $122 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. At June 30, 2011, the U.S. $1.5 billion senior notes are included in long-term debt on the Company's balance sheet.

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

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

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

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

The Company continues to sell natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by the related party. These natural gas sales are related party transactions and have been measured at fair value. For the three and six months ended June 30, 2011, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by the related party was $30 million and $56 million, respectively.

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 2010 Annual Information Form ("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 nongreenhouse gas emissions. Beginning July 1, 2011, the Tailoring Rule will require that any emitters of greater than 100,000 tons per year of greenhouse gases obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. The EPA has also promulgated regulations requiring data collection, beginning January 1, 2010, and reporting, beginning September 30, 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 considering in the current session several legislation 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 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 and during the first quarter of 2011, the Company's articles were amended to allow shareholders to accept dividends in cash or common shares. 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 June 30, 2011, 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 $2 million and unrealized loss of $30 million have been recorded in other expenses in the Consolidated Statements of Income and Comprehensive Income for the three and six months ended June 30, 2011, respectively. Natural gas inventory held in storage relating to the natural gas storage contracts is recorded at fair value. At June 30, 2011, the fair value of the inventory was $64 million, resulting in an unrealized loss of $2 million and unrealized gain of $8 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income for the three and six months ended June 30, 2011, respectively.

At June 30, 2011, 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 accrued liabilities and the resulting unrealized gain of $2 million and $3 million have been recorded in purchases of crude oil and products in the Condensed Interim Consolidated Statements of Income for the three and six months ended June 30, 2011, respectively.

The crude oil inventory held in storage is recorded at fair value. At June 30, 2011, the fair value of the inventory was $55 million, resulting in an unrealized loss of $1 million and $2 million recorded in purchases of crude oil and products in the Condensed Interim Consolidated Statements of Income for the three and six months ended June 30, 2011, respectively.

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 June 30, 2011, a loss related to these contracts of nil and $7 million were recorded in other cost of sales in the Condensed Interim Consolidated Statements of Income for the three and six months ended June 30, 2011, respectively.

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 June 30, 2011, the Company had 1.3 mmbbls of purchase and sale contracts resulting in an unrealized gain of $2 million and $9 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income for the three and six months ended June 30, 2011, respectively. A portion of the crude oil inventory is sold to third parties. This inventory is measured at fair value. At June 30, 2011, the fair value of the inventory was $101 million, resulting in an unrealized loss of $10 million and $6 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income for the three and six months ended June 30, 2011, respectively.

7.6 Interest Rate Risk Management

At June 30, 2011, Husky had the following interest rate swaps in place:

- 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.

- 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.

- 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.

These swaps resulted in an offset to finance expense amounting to $6 million and $11 million for the three and six months ended June 30, 2011, respectively. The amortization of previous interest rate swap terminations resulted in an addition to finance expense of $1 million and $2 million for the three and six months ended June 30, 2011, respectively.

Cross currency swaps resulted in an addition to finance expense of $2 million and $4 million, net of tax, for the three and six months ended June 30, 2011, respectively.

7.7 Foreign Currency Risk Management

At June 30, 2011, Husky had the following cross currency debt swaps in place:

- U.S. $50 million at 6.25% swapped at $1.17 to $59 million at 5.67% until June 15, 2012.

- U.S. $75 million at 6.25% swapped at $1.19 to $89 million at 5.65% until June 15, 2012.

- U.S. $75 million at 6.25% swapped at $1.17 to $88 million at 5.61% until June 15, 2012.

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

At June 30, 2011, the cost of a U.S. dollar in Canadian currency was $0.9643.

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 June 30, 2011, 82% or $3 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 73% when the cross currency swaps are considered.

As at June 30, 2011, the Company has designated U.S. $987 million of its U.S. debt as a hedge of the Company's net investment in U.S. refining operations, which are considered to have a functional currency of U.S. dollars. During 2011, the unrealized foreign exchange gain arising from the translation of the debt was $7 million and $26 million, net of tax expense of $1 million and $4 million, which was recorded in Other Comprehensive Income for the three and six months ended June 30, 2011, respectively.

Including cross currency swaps and the debt that has been designated as a hedge of a net investment, 36% 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 June 30, 2011, Husky's share of this receivable was 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 U.S. dollar functional currency foreign operation. At June 30, 2011, Husky's share of this obligation was 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 the fair value hierarchy in accordance with the International Accounting Standards Board's ("IASB") IFRS 7. 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.

Depletion Expense

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

Withheld Costs

Costs related to exploration and evaluation activities and major development projects are excluded from costs subject to depletion until technical feasibility and commercial viability is assessed or production commences. At that time, costs are either transferred to property, plant and equipment or their value is impaired. Impairment is charged directly to earnings under IFRS.

Impairment of Long-Lived Assets

Impairment is indicated if the carrying value of the long-lived asset or oil and gas cash generating unit exceeds its recoverable amount under IFRS. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings. The determination of the recoverable amount for impairment purposes under IFRS involves the use of numerous assumptions and judgments including future net cash flows from oil and gas reserves, future third-party pricing, inflation factors, discount rates and other uncertainties. Future revisions to these assumptions impact the recoverable amount.

Fair Value of Derivative Instruments

Periodically Husky utilizes financial derivatives to manage market risk. IFRS provides for the recognition, measurement and disclosure requirements for financial instruments and hedge accounting. (Refer to Note 13 in the Condensed Interim Consolidated Financial Statements).

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

Asset Retirement Obligations ("ARO")

Husky has significant obligations to remove tangible assets and restore land after operations cease and Husky retires or relinquishes the asset. The Company's ARO primarily relates to the Upstream business. The retirement of Upstream assets consists primarily of plugging and abandoning wells, removing and disposing of surface and subsea equipment and facilities and restoration of land to a state required by regulation or contract. Estimating the ARO requires that Husky estimates costs that are many years in the future. Restoration technologies and costs are constantly changing, as are regulatory, political, environment, safety and public relations considerations.

Inherent in the calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, future third-party pricing, inflation factors, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in changes to the ARO.

Employee Future Benefits

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

Legal, Environmental Remediation and Other Contingent Matters

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

Income Tax Accounting

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

Business Combinations

Under the purchase method, the acquiring company includes the fair value of the various assets and liabilities of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. In some circumstances the fair value of an asset is determined by estimating the amount and timing of future cash flows associated with that asset. The actual amounts and timing of cash flow may differ materially and may possibly lead to an impairment charged to earnings.

9. New and Pending Accounting Standards

International Financial Reporting Standards ("IFRS")

Husky has completed its adoption of IFRS for the year beginning on January 1, 2011. As a result, the Company's financial results for the three and six month periods ended June 30, 2011 and comparative periods are reported under IFRS while selected historical data continues to be reported under previous Canadian GAAP. (Refer to Note 15 of the Condensed Interim Consolidated Financial Statements for the Company's assessment of impacts of the transition to IFRS).

Financial Instruments

In November 2009, the IASB published IFRS 9, "Financial Instruments," which covers the classification and measurement of financial assets as part of its project to replace IAS 39, "Financial Instruments: Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to own credit risk out of profit or loss and recognize the change in other comprehensive income ("OCI"). IFRS 9 is effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. There will be no significant impact to the Company upon implementation of the issued standard.

Consolidated Financial Statements

In May 2011, the IASB published IFRS 10, "Consolidated Financial Statements," which is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. IFRS 10 provides a single control model to be applied in the assessment of control for all entities in which the Company has an investment including special purpose entities currently in the scope of SIC 12. Under the new control model, the Company has control over an investment if the Company has the ability to direct the activities of the investment, is exposed to variability of returns from the investment and there is a linkage between the ability to direct and the variability of returns. The Company intends to retrospectively adopt IFRS 10 in its financial statements for the annual period beginning on January 1, 2013. The Company does not expect IFRS 10 to have a material impact on its financial statements.

Joint Arrangements

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

Disclosure of Interests in Other Entities

In May 2011, the IASB published IFRS 12, "Disclosure of Interests in Other Entities," which is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. IFRS 12 contains new disclosure requirements for interests the Company has in subsidiaries, joint arrangements, associates and unconsolidated structured entities. Required disclosures aim to provide readers of the financial statements with information to evaluate the nature of and risks associated with the Company's interests in other entities and the effects of those interests on the Company's financial statements. The Company intends to adopt IFRS 12 in its financial statements for the annual period beginning on January 1, 2013. It is expected that IFRS 12 will increase the current level of disclosure related to the Company's interests in other entities upon adoption.

Investments in Associates and Joint Ventures

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

Fair Value Measurement

In May 2011, the IASB published IFRS 13, "Fair Value Measurement," which is effective prospectively for annual periods beginning on or after January 1, 2013. IFRS 13 replaces fair value measurement guidance contained in individual IFRSs, providing a single source of fair value measurement guidance. The standard provides a framework for measuring fair value and establishes new disclosure requirements to enable readers to assess the methods and inputs used to develop fair value measurements and for recurring valuations that are subject to measurement uncertainty and the effect of those measurements on the financial statements. The Company intends to adopt IFRS 13 prospectively in its financial statements for the annual period beginning on January 1, 2013. The extent of the impact of adoption of IFRS 13 has not yet been determined.

Presentation of Financial Statements

In June 2011, the IASB issued IAS 1, "Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements." The amendments stipulate the presentation of net earnings and OCI and also require the Company to group items within OCI based on whether the items may be subsequently reclassified to earnings. Amendments to IAS 1 are effective for the Company on January 1, 2012 with retrospective application and early adoption permitted. The adoption of the amendments to this standard is not expected to have a material impact on the Company's financial statements.

Employee Benefits

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

10. Outstanding Share Data

(in thousands)	July 19 2011	December 31 2010
Issued and outstanding		
Number of common shares	**948,851**	890,709
Number of stock options	**35,726**	29,541
Number of stock options exercisable	**18,906**	17,325
Number of preferred shares	**12,000**	-

11. Reader Advisories

This MD&A should be read in conjunction with the Condensed Interim Consolidated Financial Statements and related Notes.

Readers are encouraged to refer to Husky's 2010 MD&A and Note 24 of the 2010 Consolidated Financial Statements and 2010 AIF filed with Canadian regulatory agencies and the 2010 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 MD&A, 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 MD&A with respect to results for the three months ended June 30, 2011 are compared with results for the three months ended June 30, 2010 and the results for the six months ended June 30, 2011 are compared with results for the six months ended June 30, 2010. Discussions with respect to Husky's financial position as at June 30, 2011 are compared with its financial position at December 31, 2010.

Additional Reader Guidance

- The Condensed Interim Consolidated Financial Statements and comparative financial information included in these Condensed Interim Consolidated Financial Statements have been prepared in accordance with IAS 34.
- 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 MD&A 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 IFRS, 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, deferred 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 IFRS 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:

		Three months ended June 30		Six months ended June 30	
(millions of dollars)		**2011**	2010	**2011**	2010
Non-GAAP	Cash flow from operations	**$ 1,511**	$ 739	**$ 2,675**	$ 1,593
	Settlement of asset retirement obligations	**(30)**	(7)	**(53)**	(22)
	Income taxes paid	**(32)**	(90)	**(53)**	(689)
	Interest received	**-**	1	**-**	1
	Change in non-cash working capital	**2**	(202)	**165**	119
GAAP	Cash flow – operating activities	**$ 1,451**	$ 441	**$ 2,734**	$ 1,002

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 IFRS 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:

		Three months ended June 30		Six months ended June 30	
(millions of dollars)		**2011**	2010	**2011**	2010
GAAP	Net earnings	**$ 669**	$ 179	**$ 1,295**	$ 547
	Foreign exchange	**(14)**	16	**(15)**	(10)
	Financial instruments	**7**	(8)	**15**	14
	Stock-based compensation	**(6)**	(5)	**(2)**	(13)
	Inventory write-downs	**-**	19	**-**	21
Non-GAAP	Adjusted net earnings	**$ 656**	$ 201	**$ 1,293**	$ 559

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*
IFRS	*International Financial Reporting Standards*

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 but does not include proceeds, other assets or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Net earnings from operations plus non-cash charges before settlement of asset retirement obligations, income taxes paid 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 other reserves*
Feedstock	*Raw materials which are processed into petroleum products*
Front End Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which 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 MD&A 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 MD&A include, but are not limited to: the Company's general strategic plans and growth strategies; objectives of the 2011 capital expenditure program; exploration, development and drilling plans, anticipated rates of production, evaluation and implementation of EOR techniques, and evaluation of a concrete wellhead platform in the Atlantic Region; evaluation and exploration plans for offshore Greenland; development plans and anticipated timing of production for South Pikes Peak; anticipated timing for completion of the Paradise Hill development; plans for evaluation, development, implementation and intended uses of EOR techniques for the Company's heavy oil assets, and anticipated timing of the completion of and production from these EOR projects; implementation of Phase I plans, anticipated timing of production and development plans for subsequent phases of the Sunrise Energy Project; anticipated timing of additional production form the Tucker Oil Sands Project; implementation and timing of the air injection pilot project and anticipated timing of production at McMullen; plans for evaluation, drilling and two pilot projects for the Company's Western Canadian oil resource plays; development and drilling plans for the Company's Western Canadian gas resource plays and anticipated timing of and rates of increased production capacity at Ansell; development, implementation and timing of ASP floods at Fosterton and Bone Creek; exploration plans for the Northwest Territories; exploration plans for Block 63/05 offshore China; anticipated timing of production for Liwan 3-1 and Liuhua 34-2; expected project sanction for the Liwan development project; development plans and anticipated timing of submission to the Chinese authorities of the ODP for Liuhua 34-2; plans to seek out prospective partners for the North Sumbawa II Exploration Block and development plans, drilling plans and anticipated timing of production for the Madura Block offshore Indonesia; evaluation, implementation and effect of planned improvements to the Company's Lima and Toledo refineries; development plans and anticipated timing of completion of the Hardisty storage tank; Continuous Catalyst Regeneration Reformer Project plans; 2011 production guidance; scheduled maintenance and turnarounds of FPSO units and timing of planned turnarounds at the Company's Lima, Prince George, Toledo and Lloydminster facilities.

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

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

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