MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") JULY 27, 2010

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1. Summary of Quarterly Results

- Cash flow from operations in the quarter of $806 million, comparable to the second quarter of 2009.
- Net earnings in the quarter lower compared with the second quarter of 2009 due to lower product margins in Downstream, increased depletion expense in Southeast Asia, and declines in Upstream production.
- Lower production in the second quarter of 2010 compared with the same period in 2009 is primarily due to:
  - lower natural gas and heavy crude oil production in Western Canada due to reduced capital investment in 2009 in response to economic conditions at the time; and
  - the decline in crude oil production from the White Rose field which will be partially offset by production from the North Amethyst satellite field; however, the impact to production rates for the quarter from North Amethyst was minimal as first oil was achieved on May 31, 2010.
- The stronger Canadian dollar in the quarter relative to the U.S. dollar reduced the benefit of higher benchmark commodity prices year over year.
- Capital expenditures of $638 million compared to $492 million in the second quarter of 2009.
- Successful appraisal well Liuhua 29-1-2 drilled on Block 29/26 in the South China Sea.
- Sunrise Energy Project phase one remains on schedule for full sanction in the fourth quarter of 2010.

Quarterly Financial Summary

	Three months ended							
(millions of dollars, except per share amounts)	**June 30 2010**	March 31 2010	Dec. 31 2009	Sept. 30 2009	June 30 2009	March 31 2009	Dec. 31 2008	Sept. 30 2008
Sales and operating revenues, net of royalties	**$ 4,568**	$ 4,471	$ 3,605	$ 3,903	$ 3,916	$ 3,650	$ 4,701	$ 7,715
Net earnings	**266**	345	320	338	430	328	231	1,274
Per share - Basic and diluted	**0.31**	0.41	0.38	0.40	0.51	0.39	0.27	1.50
Cash flow from operations [(1)]	**806**	895	657	452	833	565	330	1,999
Per share - Basic and diluted	**0.95**	1.05	0.77	0.53	0.98	0.67	0.39	2.35

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

2. Business Environment

Average Benchmarks		Three months ended					
		June 30 2010	March 31 2010	Dec. 31 2009	Sept. 30 2009	June 30 2009	March 31 2009
WTI crude oil [1]	*(U.S. $/bbl)*	**78.03**	78.71	76.19	68.30	59.62	43.08
Brent crude oil [2]	*(U.S. $/bbl)*	**78.30**	76.24	74.56	68.43	58.79	44.40
Canadian light crude 0.3% sulphur	*($/bbl)*	**75.44**	80.31	76.75	71.82	66.21	50.09
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**57.10**	65.11	62.66	59.83	56.36	35.72
NYMEX natural gas [3]	*(U.S. $/mmbtu)*	**4.09**	5.30	4.17	3.39	3.50	4.89
NIT natural gas	*($/GJ)*	**3.66**	5.08	4.01	2.87	3.47	5.34
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**14.34**	9.29	12.37	10.26	7.72	9.20
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**11.33**	6.23	4.92	8.38	10.91	9.49
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**10.44**	8.21	6.06	8.03	9.05	10.15
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.973**	0.961	0.947	0.912	0.858	0.803
Canadian Equivalents							
WTI crude oil [4]	*($/bbl)*	**80.20**	81.90	80.45	74.89	69.49	53.65
Brent crude oil [4]	*($/bbl)*	**80.47**	79.33	78.73	75.03	68.52	55.29
WTI/Lloyd crude blend differential [4]	*($/bbl)*	**14.74**	9.67	13.06	11.25	9.00	11.46
NYMEX natural gas [4]	*($/mmbtu)*	**4.20**	5.52	4.40	3.72	4.08	6.09

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

Oil and Gas Prices

The price Husky receives for production from Western Canada is primarily driven by changes in the price of West Texas Intermediate ("WTI") while the majority of the Company's production offshore the East Coast of Canada is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2009 at U.S. $79.36/bbl, decreasing to U.S. $75.63/bbl on June 30, 2010, averaging U.S. $78.37/bbl in the first six months of 2010 compared with U.S. $51.35/bbl in the first six months of 2009, and averaging U.S. $78.03/bbl in the second quarter of 2010 compared with U.S $59.62/bbl in the second quarter of 2009. The price of Brent averaged U.S. $77.27/bbl in the first six months of 2010 compared with U.S. $51.60/bbl in the first six months of 2009, and averaged U.S. $78.30/bbl in the second quarter of 2010 compared with U.S. $58.79/bbl in the second quarter of 2009.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In the first six months of 2010, 48% of Husky's crude oil production was heavy oil or bitumen compared with 43% in the first six months of 2009.

The light/heavy oil differential averaged U.S. $11.82/bbl or 15% of WTI in the first six months of 2010 compared with U.S. $8.46/bbl or 16% of WTI in the first six months of 2009. In the second quarter of 2010, 48% of Husky's crude oil production was heavy oil or bitumen compared with 45% in the second quarter of 2009. The light/heavy crude oil differential averaged U.S. $14.34/bbl or 18% of WTI in the second quarter of 2010 compared with U.S. $7.72/bbl or 13% of WTI in the second quarter of 2009.

The natural gas price for January 2010 delivery quoted on the NYMEX closed in 2009 at U.S. $5.81/mmbtu declining in June 2010 to close at U.S. $4.72/mmbtu for July delivery. During the first six months of 2010, the NYMEX near-month contract price of natural gas averaged U.S. $4.70/mmbtu compared with U.S. $4.19/mmbtu in the first six months of 2009. During the second quarter of 2010, the NYMEX near-month contract price of natural gas averaged U.S. $4.09/mmbtu compared with U.S. $3.50/mmbtu in the second quarter of 2009. Low natural gas prices continue to reflect higher than average storage levels and stable supply. At the end of the second quarter of 2010, U.S. natural gas inventories were 11.5% higher than the five-year average and the same as the end of the second quarter of 2009.

Foreign Exchange

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

The Canadian dollar ended 2009 at U.S. $0.956 and closed at U.S. $0.943 at June 30, 2010. In the first quarter of 2010, the Canadian dollar averaged U.S. $0.961, strengthening by 20% compared with U.S. $0.803 during the first quarter of 2009. In the second quarter of 2010, the Canadian dollar averaged U.S. $0.973, strengthening by 13% compared with U.S. $0.858 during the second quarter of 2009.

Increased U.S. crude oil and natural gas prices have been partially offset by the significant strengthening of the Canadian dollar against the U.S. dollar in the first six months of 2010. The price of WTI in the first six months of 2010 in U.S. dollars increased 53% compared with an increase of 32% in Canadian dollars when compared to the first six months of 2009. In the second quarter of 2010, the price of WTI in U.S. dollars increased 31% compared with 15% in Canadian dollars when compared to the second quarter of 2009.

Refining Crack Spreads

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

In the first six months of 2010, the Chicago 3:2:1 crack spread averaged U.S. $8.82/bbl compared with U.S. $10.21/bbl in the first six months of 2009. During the second quarter of 2010, the Chicago 3:2:1 crack spread averaged U.S. $11.33/bbl compared with U.S. $10.91/bbl in the second quarter of 2009. In the first six months of 2010, the New York Harbor 3:2:1 crack spread averaged U.S. $9.34/bbl compared with U.S. $9.59/bbl in the first six months of 2009. During the second quarter of 2010, the New York Harbor 3:2:1 crack spread averaged U.S. $10.44/bbl compared with U.S. $9.05/bbl in the second quarter of 2009.

Husky's realized refining margins are affected by the product configuration of its refineries, transportation costs to benchmark hubs and by the time lag between the purchase and delivery of crude oil, which is accounted for on a first in first out ("FIFO") basis in accordance with Canadian generally accepted accounting principles ("GAAP").

Cost Environment

From 2003 to 2008, the oil and gas industry experienced increasing costs that rose above the general trend of inflation. This resulted when the high level of industry activity, precipitated by escalating oil and gas prices, created demand for goods and services that exceeded supply. This increased the cost of operating the Company's oil and gas properties, processing plants and refineries. As a result of the global and financial crisis, the level of drilling and completions in the Western Canada Sedimentary Basin was strategically reduced. In addition, prospective capital projects including oil sands developments and major plant modifications were deferred pending cost improvements. Oil and gas prices declined rapidly in the latter half of 2008 and the first quarter of 2009, however, a corresponding decline in costs was delayed until the latter half of 2009. Crude oil prices have since recovered to the U.S. $70/bbl to U.S. $80/bbl range and industry activity, both drilling and field services, is increasing. The cost of field services is beginning to rise with higher demand, particularly in new technology driven plays.

Global Economic and Financial Environment

During the second quarter of 2010, WTI spot prices fluctuated between U.S. $87/bbl and U.S. $65/bbl largely on concerns that the world economic recovery was weakening, particularly with respect to Europe's debt crisis, the tightening of credit by China, and the liquidation of futures contracts. The Energy Information Administration's ("EIA") July 7, 2010 Short-term Energy Outlook[(1)] continues to forecast that world oil consumption will increase in 2010 compared with 2009 and again in 2011. The EIA estimates supply of crude oil will increase in 2010 compared with 2009. OPEC spare productive capacity is expected to average an estimated 5.2 mmbbls/day during 2010. OPEC agreed in March to maintain its current production policy and is not scheduled to meet again to review the production policy until October 2010. OPEC liquid fuel supply, which is not subject to OPEC's production policy, is expected to increase in 2010. The EIA estimates that OECD countries held 2.76 billion barrels of commercial oil inventories at the end of the second quarter of 2010. This represents approximately 58 days of forward cover. The EIA expects OECD oil inventories to remain at the upper end of the historical range through 2011.

In the EIA's July Short-term Energy Outlook, demand for natural gas in the United States markets is expected to increase in 2010 compared with 2009. The industrial and electrical generation sectors are expected to account for 88% of the increase in natural gas consumption in 2010. The EIA expects a decline in natural gas consumption in 2011 as electrical generation moves back to coal due to higher natural gas prices, partially offset by continued economic recovery and higher consumption in the industrial sector. In its Weekly Natural Gas Storage Report[2] released July 2, 2010, the EIA reported that natural gas stocks were 11.5% above the five year average and approximately 1% below the previous year.

Gasoline consumption in the United States during the 2010 driving season, which runs from April 1 to September 30, is estimated by the EIA to increase. During this period, consumption of total liquid fuels is estimated to increase due to higher consumption of distillate fuel oil.

The current prospect that demand for energy will increase in 2010 and 2011 depends on a number of assumptions about the timing and sustainability of a global economic recovery.

Husky took action at the onset of the economic downturn in the latter half of 2008 and prudently reduced capital spending in 2009. The Company continues to review and implement cost containment and efficiency opportunities throughout the organization. Husky's cash position, credit facilities and access to debt capital markets provide adequate liquidity to meet the Company's needs at present, and the Company continues to examine ways of enhancing its access to capital on an ongoing basis.

Note:

(1) *Energy Information Administration, Short-Term Energy Outlook DOE/EIA – July 7, 2010 Release.*

(2) *"Weekly Natural Gas Storage Report", July 2, 2010, 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 2010. Each item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis	2010 Second Quarter Average		Increase	Effect on Annual Pre-tax Cash Flow [6]		Effect on Annual Net Earnings [6]	
				($ millions)	*($/share)* [7]	*($ millions)*	*($/share)* [7]
Upstream and Midstream							
WTI benchmark crude oil price [1]	$	78.03	*U.S. $1.00/bbl*	60	0.07	44	0.05
NYMEX benchmark natural gas price [2]	$	4.09	*U.S. $0.20/mmbtu*	26	0.03	19	0.02
WTI/Lloyd crude blend differential [3]	$	14.34	*U.S. $1.00/bbl*	(7)	(0.01)	(7)	(0.01)
Downstream							
Canadian light oil margins	$	0.012	*Cdn $0.005/litre*	14	0.02	10	0.01
Asphalt margins	$	13.81	*Cdn $1.00/bbl*	7	0.01	5	0.01
New York Harbor 3:2:1 crack spread [4]	$	10.44	*U.S. $1.00/bbl*	83	0.10	52	0.06
Consolidated							
Exchange rate (U.S. $ per Cdn $) [1] [5]	$	0.973	*U.S. $0.01*	(48)	(0.06)	(36)	(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 849.9 million common shares outstanding as of June 30, 2010.*

3. Capability to Deliver Results and the Strategic Plan

Husky's capacity to deliver results and the strategic plan are described in the Company's annual MD&A and also in its Annual Information Form that are available from www.sedar.com and www.sec.gov.

In summary, Husky's current strategy is to continue to exploit oil and gas assets in Western Canada while expanding into new areas with large scale sustainable growth potential. The Company's plans include projects in Canada (the Alberta oil sands and the basins offshore Canada's East Coast), Asia (the South China Sea, the Madura Strait and the East Java Sea), and offshore Greenland. In the midstream and downstream sectors, Husky is enhancing performance and maximizing the value chain through integrating its businesses, optimizing plant operations and expanding plant and infrastructure.

4. Key Growth Highlights

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

Upstream

East Coast Canada and Greenland

White Rose Satellite Development Projects

The North Amethyst satellite oil field achieved first production on May 31, 2010 with one production well in operation and a water injection well that commenced operation in early June. Production is tied back to the existing *SeaRose FPSO* infrastructure. During April 2010, Husky completed drilling the H-14 delineation well in the south portion of the North Amethyst field. The data provided by this well will be used to optimize future well placement. Drilling of an additional nine wells will continue through 2010 and 2011.

Regulatory review continues on Husky's application for a two-well pilot project to target the West White Rose reservoir. The well pair will provide additional information on the satellite field, and will help Husky refine its development plan for the full West White Rose field.

East Coast Canada Exploration

In June 2010, Husky commenced a 2-dimensional ("2-D") seismic acquisition survey in the Sydney Basin between Newfoundland and Nova Scotia. On completion of these activities, Husky will conduct 2-D seismic surveys on exploration acreage offshore Labrador. Exploration rights for these areas were awarded to Husky during land sales in 2008 and public consultations related to the environmental assessment process were carried out in late 2009 and early 2010.

During March 2010, Husky completed drilling the Glenwood H-69 exploratory stratigraphic test well on EL 1090R (100% working interest). The Glenwood well was suspended and the data continues to be evaluated.

In April 2010, Husky along with Suncor and Statoil Canada announced plans to enter into a second rig sharing agreement for the mobile semi-submersible drilling rig *Henry Goodrich*. The agreement will keep the rig in Eastern Canada until November 2013. Husky intends to use its portion of rig time to pursue a combination of exploration, appraisal and development drilling opportunities.

Offshore Greenland

Husky is continuing its evaluation of 2-D and 3-D seismic acquired in 2008 and 2009. Final processing is expected to be completed in the third quarter of 2010.

Heavy Oil and Oil Sands

Heavy Oil

Construction of the 8,000 bbl/day South Pike's Peak commercial project was approximately 30% complete at the end of the second quarter of 2010. Production is expected to commence in the first half of 2012.

Horizontal well developments progressed through the second quarter of 2010, targeting geological horizons in regions which had previously been bypassed. Seven wells were drilled in the second quarter, a total of 59 wells are expected to be drilled in 2010, with additional projects planned in 2011 and 2012.

Husky continued to operate two solvent enhanced oil recovery ("EOR") pilots through the second quarter at Edam and Mervin, and construction of a CO_2 liquefaction plant at the Lloydminster Ethanol Plant is underway, which will capture CO_2 emissions for use in the ongoing piloting program.

A microbial EOR pilot continued in the second quarter of 2010 with nine wells responding and showing increased oil production. Plans are progressing for another pilot in Devonia Lake in the third quarter of 2010 which will pilot microbial EOR technology in heavier oil waterfloods.

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages (Husky 50% interest). Bitumen production from phase one is planned at 60 mbbls/day. Tenders for major engineering and construction contracts for the Sunrise Energy Project were issued in the first quarter of 2010. Project sanction is planned for the fourth quarter of this year and first production is planned in 2014. Husky progressed negotiations for the transportation of diluent to the Sunrise oil sands site and the movement of diluted bitumen to the Toledo, Ohio Refinery.

Tucker Oil Sands Project

Based on a greater understanding of the Tucker reservoir, Husky is addressing production challenges by drilling new wells and will evaluate the results over the next twelve months.

During the second quarter of 2010, three new well pairs, which incorporated a number of design changes, were tied-in and commenced steam injection and an additional four well pairs were drilled. During the second quarter, the plant was shut down for a two week period for maintenance and tie-in work. Applications are proceeding for additional drilling and field development in 2010 and 2011.

McMullen

Husky's development of the McMullen property, which is located in the west central region of the Athabasca oil sands of northern Alberta, involves a cold production drilling project, an air injection pilot and plans for a thermal pilot project.

Cold production from McMullen averaged 1,600 bbls/day in the second quarter of 2010. Sixty-four cold production wells are planned to be drilled in 2010.

Plans are progressing for an air injection pilot. Husky has submitted an application and is currently waiting for Energy Resources Conservation Board ("ERCB") approval.

Plans are also progressing for a thermal pilot to test steam assisted gravity drainage ("SAGD") and horizontal cyclic steam stimulation ("CSS") performance over a portion of the lease. ERCB approval is expected later this year, with construction planned in 2011.

Western Canada (excluding Heavy Oil and Oil Sands)

Gas Resource Plays

Husky continues to build its gas resource play inventory and now has 952,000 acres in its portfolio of nine resource plays. In the second quarter, Husky acquired additional land in Bivouac, located in northeast British Columbia as well as land in the Ansell area of the Alberta deep basin. Two wells were spud in May 2010 at Ansell to test the multi-zone potential in the area.

Husky is accelerating exploration and development drilling in the NGL rich Ansell area with 22 development wells and eight exploration wells to be complete by the end of the year. Incremental production is expected to be on-stream in 2011.

Husky is also accelerating development drilling in the Bivouac and Galloway areas with an additional four Bivouac wells and four Galloway wells to be completed by the end of 2010 with production expected in 2011.

Northeastern British Columbia Conventional Exploration

Husky is participating in a well in the Grizzly Valley of the Alberta foothills (42% after earned working interest) which has now reached total depth. A completion of the Permian section is expected to commence in late July 2010. Husky successfully acquired four additional drilling licenses in the Grizzly Valley area during the quarter.

Oil Resource Plays

Oil resource play evaluation and testing activity continued in Western Canada. In the second quarter of 2010, six Viking wells were placed on production in the Dodsland/Elrose area of Southwest Saskatchewan to bring the total number of producing wells to 11. An additional 15 wells are planned for Redwater, Alberta for the remainder of the year. Evaluation wells are currently in progress to assess the Cardium at Lanaway, the Lower Shaunavon in Southwest Saskatchewan and the Bakken in Southeast Saskatchewan. A successful Lower Shaunavon horizontal well was brought on-stream in the second quarter with plans to drill an additional three Lower Shaunavon wells by year end. A successful Bakken horizontal well was drilled and completed in the second quarter with production expected early in the third quarter of 2010. Plans are in place for an additional two Bakken wells to be completed by the end of the year.

Alkaline Surfactant Polymer Floods

Husky's Alkaline Surfactant Polymer ("ASP") Enhanced Oil Recovery Program is underway with active projects at Warner, Crowsnest in Southern Alberta and Gull Lake, Saskatchewan. Future floods under development include Fosterton and Bone Creek, Saskatchewan. The Fosterton ASP reservoir and detailed facility design will be completed in late 2010. Facility construction is expected to commence in 2011 with an expected start up in the first half of 2012. Husky is the operator and holds a 62.4% working interest in this project. Bone Creek (95% working interest) is in the initial ASP design phase with a potential start up in early 2013.

United States

Husky continues to evaluate its Columbia River Basin holdings in Washington and Oregon. The results of the Grey 31-23 well, which was drilled in 2009, will be incorporated into this study. Husky holds up to a 50% working interest in this area.

South East Asia

Offshore China Exploration and Delineation

In late May 2010, the *West Hercules* rig successfully completed the drilling and testing of the Liuhua 29-1-2 appraisal well. This appraisal well, first on the Liuhua 29-1 field, discovered in January 2010 tested natural gas at an equipment restricted rate of 55 million cubic feet per day. A second appraisal well on the Liuhua 29-1 field is scheduled to be drilled later in the year.

Following the drilling of the Liuhua 29-1-2 appraisal well, a new exploration well was drilled at Liwan 5-2-1, which did not encounter hydrocarbons and was plugged and abandoned. This was followed by the successful drilling of the Liuhua 34-3-1 exploration well which encountered natural gas. The well is located about 24 kilometres northeast of the Liwan 3-1 gas field, the Company's first major discovery in Block 29/26. The well was cased and suspended without testing due to the impending typhoon season and evaluations are on-going to assess the suitability to develop this new field as part of the overall Block 29/26 deepwater gas development project.

The next well the Company plans to drill, the Liwan 3-1-10 well, will be the first development well drilled on the Liwan 3-1 field. This well will also appraise the resource potential associated with a deeper reservoir interval in the Liwan 3-1 field.

Husky expects plans of development for the Liwan 3-1 and Liuhua 34-2 fields to be submitted to regulatory authorities later in 2010. The plan of development for Liuhua 29-1 field will be submitted in 2011 and will incorporate results of additional appraisal drilling planned for late 2010. Under the current plan, the Liwan 3-1 and Liuhua 34-2 fields on Block 29/26 will be developed in parallel, with first gas production targeted in 2013. Gas production from the Liuhua 29-1 field will subsequently share common gas processing and transportation infrastructure.

Effective June 30, 2010 Husky relinquished Block 04/35, which is located in the East China Sea approximately 300 kilometres east of Shanghai. The decision to relinquish the block, at the end of the first exploration term of the Petroleum Contract, was made following the results from the drilling of the HZ 8-1-1 exploration well which was drilled in April 2010 and did not encounter hydrocarbons.

On Block 63/05 in the Qiongdongnan Basin, 50 kilometres south of Hainan Island, acquisition of new 2-D and 3-D seismic data commenced during April 2010 but operations were suspended and resumed in July 2010. Seismic acquisition is expected to be completed by August 2010.

Indonesia Exploration and Development

In the Madura Strait, the Madura BD field development plan has been approved by the Government of Indonesia and contracts for the sale of the gas are in place. Husky, together with the operator CNOOC, continues to await approval of an extension to the Production Sharing Contract ("PSC"), which expires in October 2012. Engineering work has been tendered but work will not proceed until the PSC extension has been approved. Husky holds a 50% interest in the Madura Strait Block.

During the fourth quarter of 2009, Husky acquired 1,020 kilometres of new 2-D seismic on the North Sumbawa II Block and processing has been completed and interpretation commenced in late May 2010. Husky will use this data to define exploration prospects and plans to drill the first exploration well in 2011. Husky holds a 100% interest in the North Sumbawa II Block, comprising of 5,000 square kilometres in the East Java Sea.

Downstream

Lima, Ohio Refinery

The reconfiguration of the Lima, Ohio Refinery that is intended to increase processing capacity of heavier, less costly, crude oil feedstock, continues to be on hold pending an improvement in the light/heavy crude oil differential outlook.

Toledo, Ohio Refinery

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

Retail

In 2009, Husky entered into an agreement to purchase 98 retail outlets in the southern Ontario region. The first site was rebranded and transferred to Husky in March 2010. At the end of the second quarter, Husky completed the rebranding of 37 sites, with the remainder to be transferred throughout the last half of 2010.

5. Results of Operation

5.1 Upstream

Upstream Net Earnings Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Gross revenues	**$ 1,335**	$ 1,391	**$ 2,872**	$ 2,638
Royalties	**249**	224	**534**	426
Net revenues	**1,086**	1,167	**2,338**	2,212
Operating and administration expenses	**397**	364	**780**	741
Depletion, depreciation and amortization	**394**	348	**769**	719
Other income	**(1)**	-	**(1)**	-
Income taxes	**86**	132	**229**	218
Net earnings	**$ 210**	$ 323	**$ 561**	$ 534

Second Quarter

Upstream net earnings in the second quarter of 2010 decreased by $113 million compared with the second quarter of 2009 primarily as a result of a decline in total production and increased depletion in South East Asia partially offset by increased realized prices for crude oil.

Production of crude oil and natural gas has decreased compared to the second quarter of 2009, primarily as a result of lower natural gas and heavy oil production in Western Canada as a result of reduced capital expenditures in 2009 in response to economic conditions at the time and declining crude oil production from the White Rose field. Partially offsetting these declines is first crude oil production at the North Amethyst field, a satellite development of the White Rose field, which commenced on May 31, 2010 at an initial rate of 5.8 mbbls/day and averaged 2.1 mbbls/day for the second quarter.

Average realized prices in the second quarter of 2010 were $64.75/bbl for crude oil, NGL and bitumen compared with $59.49/bbl during the same period in 2009. Realized natural gas prices averaged $3.45/mcf in the second quarter of 2010 compared with $3.26/mcf in the same period in 2009. Stronger U.S. dollar crude oil and natural gas pricing was offset by the significant strengthening of the Canadian dollar over the period.

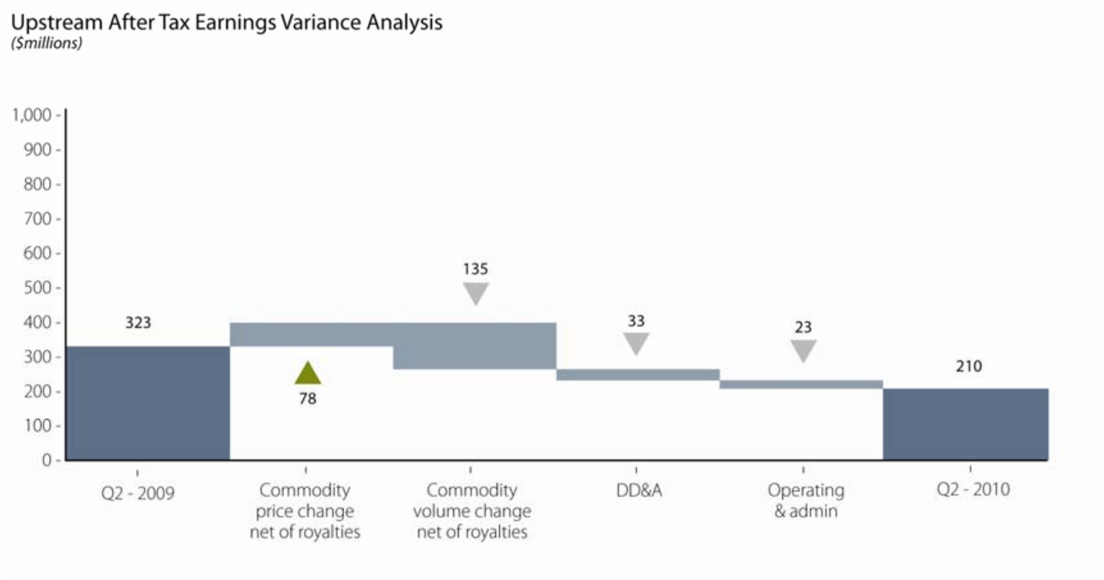
Six Months

Upstream earnings in the first six months of 2010 were $27 million higher compared with the same period in 2009. In addition to the same factors impacting the second quarter, Husky's average price realized on crude oil, NGL and bitumen in the first quarter of 2010 was 61% higher compared with the first quarter of 2009.

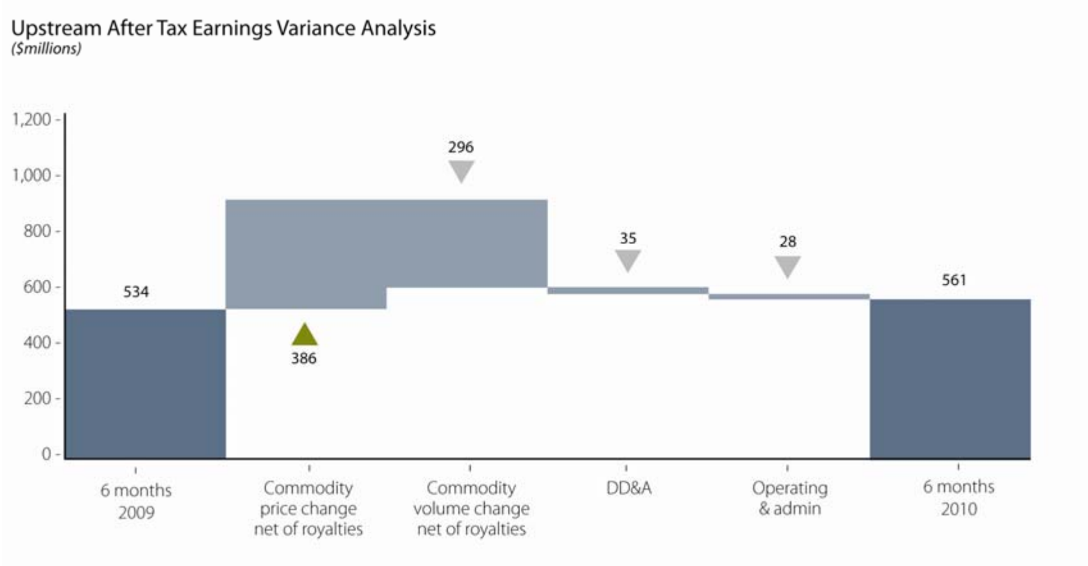
During the first six months of 2010, average realized prices increased 32% to $67.26/bbl for crude oil, NGL and bitumen combined compared with $50.92/bbl during the same period in 2009. Average realized natural gas prices were $4.21/mcf during the first six months of 2010 compared with $4.28/mcf in the same period in 2009.

Upstream Net Earnings Variance Analysis

Second Quarter



Six Months



Pricing

Average Sales Prices Realized		Three months ended June 30		Six months ended June 30	
		2010	2009	**2010**	2009
Crude oil	*($/bbl)*				
Light crude oil & NGL		**$ 75.61**	$ 65.32	**$ 76.70**	$ 57.24
Medium crude oil		**63.90**	58.32	**66.60**	49.42
Heavy crude oil		**56.18**	54.22	**59.66**	44.83
Bitumen		**52.58**	53.32	**56.74**	43.70
Total average		**64.75**	59.49	**67.26**	50.92
Natural gas	*($/mcf)*				
Average		**3.45**	3.26	**4.21**	4.28

Increased U.S. dollar crude oil and natural gas prices were offset by the significant strengthening of the Canadian dollar against the U.S. dollar in the first six months of 2010 compared to the same period in 2009.

Oil and Gas Production

Daily Gross Production		Three months ended June 30		Six months ended June 30	
		2010	2009	**2010**	2009
Crude oil & NGL	*(mbbls/day)*				
Western Canada					
Light crude oil & NGL		**22.5**	21.7	**23.0**	22.9
Medium crude oil		**25.1**	25.6	**25.2**	26.0
Heavy crude oil		**74.6**	78.1	**75.4**	80.1
Bitumen		**21.5**	22.2	**22.1**	22.4
		143.7	147.6	**145.7**	151.4
East Coast Canada					
White Rose - light crude oil		**32.9**	55.2	**36.0**	62.6
North Amethyst - light crude oil		**2.1**	-	**1.1**	-
Terra Nova - light crude oil		**10.0**	10.7	**10.3**	11.6
China					
Wenchang - light crude oil & NGL		**11.2**	11.7	**11.0**	12.0
Total crude oil & NGL		**199.9**	225.2	**204.1**	237.6
Natural gas	*(mmcf/day)*	**503.9**	552.3	**513.8**	551.7
Total	*(mboe/day)*	**283.9**	317.2	**289.7**	329.6

Crude Oil and NGL Production

Second Quarter

Crude oil, bitumen and NGL production in the second quarter of 2010 decreased by 25.3 mbbls/day or 11% compared with the same period in 2009. Production of crude oil at the North Amethyst field commenced on May 31, 2010 and averaged 6.1 mbbls/day for June and 2.1 mbbls/day for the second quarter, partially offsetting the decline in production from White Rose of 22.3 mbbls/day which was due primarily to declines from peak production rates post the 2009 turnaround. Rates have stabilized at current levels.

During the second quarter of 2010, crude oil, bitumen and NGL production from Western Canada decreased by 3.9 mbbls/day or 3% compared with the second quarter of 2009 primarily due to reduced capital investment in the first three quarters of 2009 and natural reservoir declines.

Production in South East Asia at the Wenchang field was slightly lower in the second quarter of 2010 compared with 2009 due to natural reservoir declines.

Six Months

In the first six months of 2010, crude oil, bitumen and NGL production decreased by 14% compared with the same period in 2009, primarily due to the same factors impacting the second quarter.

Natural Gas Production

Second Quarter

Natural gas production decreased by 48.4 mmcf/day or 9% in the second quarter of 2010 compared with the second quarter of 2009 due to lower capital expenditures in 2009 on drilling and tie-ins to support 2010 production and natural reservoir decline.

Six Months

In the first six months of 2010, natural gas production decreased by 7% primarily due to the same factors impacting the second quarter.

2010 Production Guidance

		Guidance 2010	Revised Guidance	Actual Production: Six months ended June 2010	Actual Production: Year ended Dec. 31 2009
Crude oil & NGL	*(mbbls/day)*				
Light crude oil & NGL		90 – 98	81 – 84	**81**	89
Medium crude oil		27 – 30	25 – 27	**25**	25
Heavy crude oil & bitumen		104 – 114	94 – 97	**98**	102
		221 – 242	200 – 208	**204**	216
Natural gas	*(mmcf/day)*	510 – 530	510 – 520	**514**	542
Natural gas	*(mboe/day)*	85 – 88	85 – 87	**86**	91
Total barrels of oil equivalent	*(mboe/day)*	306 – 330	285 – 295	**290**	307

As a result of a comprehensive review of Husky's operational activities in the first half of the year and an assessment of the production forecast and planned business activities for the remainder of the year, production guidance has been adjusted to 285,000 – 295,000 barrels of oil equivalent per day. The primary reasons for this adjustment are:

- The delay in commencement and ramp up of oil production at North Amethyst.
- Higher than forecasted decline within the main White Rose field which has stabilized after strong performance over the past four years.
- Weather related issues in Western Canada affecting the servicing of wells and drilling activity for heavy oil combined with higher than expected production declines for heavy oil.

Factors that could potentially impact Husky's production performance for 2010 include, but are not limited to:

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

Royalties

Second Quarter

In the second quarter of 2010, royalty rates averaged 19% as a percentage of gross revenue compared with 16% in 2009. Royalty rates in Western Canada averaged 15%, up from 11% in the second quarter of 2009 and for the East Coast of Canada rates averaged 28% in the second quarters of 2010 and 2009. The increase in royalty rates in Western Canada is reflective of the increase in commodity prices in the second quarter of 2010 compared to the same period of 2009. Royalty rates in Wenchang averaged 22% compared with 16% in the second quarter of 2009 due to the sliding scale royalty clause in the PSC that results in higher rates in higher commodity price environments.

Six Months

Royalty rates averaged 19% of gross revenue in the first six months compared with 16% in the same period in 2009. Rates in Western Canada averaged 15% compared with 12% in 2009 and off the East Coast of Canada the average rate was 28% compared with 26% in the same period in 2009. The increase in rates for the first six months was due to the same factors impacting the second quarter.

Operating Costs

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Western Canada	**$ 293**	$ 267	**$ 593**	$ 566
East Coast Canada	**46**	47	**84**	83
International	**6**	5	**10**	10
Total	**$ 345**	$ 319	**$ 687**	$ 659
Unit operating costs ($/boe)	**$ 13.41**	$ 11.05	**$ 13.10**	$ 11.07

Second Quarter

Total upstream operating costs increased 8% to $345 million from $319 million as a result of increased energy, servicing and maintenance costs. Total upstream unit operating costs in the second quarter of 2010 averaged $13.41/boe compared with $11.05/boe in the second quarter of 2009, as a result of higher costs and lower production in the second quarter of 2010 compared with the same period in 2009.

Operating costs in Western Canada averaged $14.24/boe in the second quarter compared with $12.29/boe in the same period in 2009 primarily as a result of increased energy, servicing and maintenance costs as well as lower production in the second quarter of 2010 compared with the same period in 2009. Maturing fields in Western Canada require increasing amounts of infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive gathering systems, crude and water trucking and more complex natural gas compression systems. Husky is focused on managing operating costs associated with the increased infrastructure through cost reduction and efficiency initiatives and keeping infrastructure fully utilized.

Operating costs at the East Coast offshore operations averaged $10.94/boe in the second quarter of 2010 compared with $7.73/boe in 2009 primarily as a result of lower production in the second quarter of 2010 compared with the same period in 2009.

Operating costs at the South China Sea offshore operations averaged $6.21/bbl in the second quarter of 2010 compared with $4.45/bbl in the same period in 2009, as a result of lower production in the second quarter of 2010 compared with 2009.

Six Months

Total upstream operating costs in the first half of 2010 increased by 4% compared with the same period in 2009 primarily due to the same factors affecting the second quarter.

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

Second Quarter

In the second quarter of 2010, total DD&A averaged $15.26/boe compared with $12.06/boe in the second quarter of 2009. The increased DD&A rate in the second quarter of 2010 was due to both a larger full cost base and a lower reserve base, compared with the same period in 2009. The resulting higher depletion expense in the quarter was primarily due to the larger full cost base in the South China Sea, with the addition of costs associated with relinquished exploration blocks and dry holes, resulting in a $40 million increase in depletion expense in the quarter.

Six Months

For the first six months of 2010, total DD&A averaged $14.67/boe compared with $12.06/boe during the same period in 2009 due to the same factors affecting the second quarter. Depletion expense in China rose to $98 million in the first six months of 2010 from $28 million in the first six months of 2009 due to the same factors impacting the second quarter, which was partially offset by lower DD&A in Canada as a result of lower production.

Upstream Capital Expenditures

For the first six months of 2010, upstream capital expenditures were $1,172 million, 48% of the 2010 capital expenditure guidance. Husky's major projects remain on schedule. Upstream capital expenditures were $711 million (61%) in Western Canada, $258 million (22%) offshore the East Coast of Canada, $201 million (17%) in South East Asia and $2 million (less than 1%) offshore Greenland.

Capital Expenditures Summary [1]

(millions of dollars)	Three months ended June 30		Six months ended June 30	
	2010	2009	**2010**	2009
Exploration				
Western Canada	**$ 70**	$ 31	**$ 187**	$ 99
East Coast Canada	**10**	-	**69**	52
Northwest United States	**-**	7	**-**	12
International	**95**	123	**202**	229
	175	161	**458**	392
Development				
Western Canada	**217**	78	**524**	359
East Coast Canada	**98**	160	**189**	316
International	**-**	6	**1**	6
	315	244	**714**	681
	$ 490	$ 405	**$ 1,172**	$ 1,073

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

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

Western Canada and Oil Sands Wells Drilled		Three months ended June 30				Six months ended June 30			
		2010		2009		2010		2009	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	6	3	4	1	27	22	6	3
	Gas	1	1	9	3	18	16	31	21
	Dry	-	-	-	-	7	7	5	5
		7	4	13	4	52	45	42	29
Development	Oil	62	52	26	19	267	231	101	90
	Gas	-	-	15	2	15	9	92	51
	Dry	-	-	-	-	6	5	4	4
		62	52	41	21	288	245	197	145
Total		69	56	54	25	340	290	239	174

Western Canada

During the first six months of 2010, Husky invested $711 million on exploration and development throughout the Western Canada Sedimentary Basin compared with $458 million in the first six months of 2009. Of this, $305 million was invested in oil exploration and development and $168 million was invested in natural gas exploration and development compared with $172 million for oil exploration and development and $224 million for natural gas exploration and development in the first six months of 2009. The Company drilled 290 net wells in the basin during the first half of 2010 resulting in 253 net oil wells and 25 net natural gas wells compared with 174 net wells resulting in 93 net oil wells and 72 net natural gas wells in the first half of 2009. In addition, $59 million was spent on production optimization initiatives in the first half of 2010. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to $126 million and $13 million was spent on property acquisitions. During the first six months of 2010, capital expenditures on oil sands projects were $40 million.

Husky's major gas resource and conventional high impact exploration program is conducted in various regions along the foothills and northern plains of Alberta and British Columbia and in the deep basin region of Alberta. In the first six months of 2010, $90 million of the natural gas exploration and development capital expenditures was invested on exploration activities in these natural gas prone areas, approximately 73% of which was invested on gas resource plays. During this period, 6.9 net exploration wells were drilled resulting in 5.2 net gas wells and 1.7 net wells awaiting completion. At June 30, 2010 drilling of 4.0 net exploration wells was underway in these regions. An additional $27 million of the natural gas exploration and development capital expenditures was spent on follow-up activities in these regions during the first six months of 2010 including tie-ins, facility installation and development drilling.

The following table discloses Husky's offshore and international drilling activity during the first six months of 2010:

Offshore and International Drilling Activity			
Canada - East Coast			
Glenwood H-69	WI 100%	Stratigraphic test	Exploratory
North Amethyst G-25-1	WI 68.875%	Water injection	Development
North Amethyst G-25-2	WI 68.875%	Production	Development
North Amethyst H-14	WI 68.875%	Stratigraphic test	Delineation
South East Asia - China			
Liuhua 29-1-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liuhua 34-2-2 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 3-3-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liuhua 29-1-2 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 5-2-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liuhua 34-3-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
HZ 8-1-1 Block 04/35	WI 100% (1)	Stratigraphic test	Exploratory

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

Offshore East Coast Development

During the first six months of 2010, $189 million was invested for East Coast development projects primarily for North Amethyst and West White Rose satellite tie-back development projects, including drilling operations at North Amethyst and completion of facilities construction and installation. At West White Rose, capital expenditures focused on advancing engineering design and planning.

Offshore East Coast Exploration

During the first six months of 2010, Husky spent $69 million primarily on the Glenwood H-69 exploration well northwest of the White Rose fields, as well as on geological and geophysical data and studies.

Offshore China and Indonesia

During the first six months of 2010, $201 million was spent on offshore projects in China, including the drilling of four exploration and two delineation wells on Block 29/26 in the South China Sea, and one exploration well on Block 04/35 in the East China Sea.

2010 Upstream Capital Program (1)

(millions of dollars)

Western Canada - oil and gas	$ 1,200
- oil sands	85
East Coast Canada	485
International	660
Total upstream capital expenditures	$ 2,430

(1) *Excludes capitalized administrative costs and capitalized interest.*

The 2010 capital budget was established with a view to enable Husky to maintain production levels and support its medium and long-term growth strategies. Capital expenditures continue to focus on those projects offering the highest potential for returns. However, as a result of an ongoing comprehensive review of the Company's operations and business strategies, Husky is redirecting a portion of its capital program to the lowest cost, highest return projects focused on delivering near-term production growth.

Capital expenditures for Western Canada upstream development and exploration are focused on heavy oil properties, enhanced oil recovery projects and unconventional gas holdings. Capital spending on oil sands is primarily focused on development at Sunrise.

Offshore the East Coast of Canada, spending is concentrated on the drilling of development wells at North Amethyst and drilling the first well of the two-well pilot project to target the West White Rose reservoir.

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

Upstream Planned Turnarounds

Husky commenced a 24-day planned maintenance turnaround for Terra Nova on July 11, 2010. A regular maintenance turnaround for the *SeaRose FPSO* is scheduled for October 2010.

5.2 Midstream

Upgrading Net Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2010**	2009	**2010**	2009
Gross revenues		**$ 405**	$ 399	**$ 913**	$ 712
Gross margin		**$ 94**	$ 54	**$ 184**	$ 166
Operating and administration expenses		**44**	45	**94**	99
Depreciation and amortization		**16**	8	**25**	16
Other income		**(1)**	(1)	**(2)**	(2)
Income taxes		**10**	-	**19**	15
Net earnings		**$ 25**	$ 2	**$ 48**	$ 38
Selected operating data:					
Upgrader throughput [1]	*(mbbls/day)*	**73.5**	74.9	**77.8**	75.6
Synthetic crude oil sales	*(mbbls/day)*	**58.0**	63.1	**63.3**	62.0
Upgrading differential	*($/bbl)*	**$ 15.44**	$ 8.31	**$ 14.06**	$ 12.05
Unit margin	*($/bbl)*	**$ 17.78**	$ 9.34	**$ 16.08**	$ 14.81
Unit operating cost [2]	*($/bbl)*	**$ 6.60**	$ 6.53	**$ 6.69**	$ 7.21

[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

During the second quarter of 2010, the upgrading differential averaged $15.44/bbl, an increase of $7.13/bbl or 86% compared with the second quarter of 2009. The differential is equal to Husky Synthetic Blend, which sells at a premium to WTI, less Lloyd Heavy Blend. The overall unit margin increased to $17.78/bbl in the second quarter of 2010 from $9.34/bbl in the same period in 2009 primarily as a result of significantly wider heavy to light crude oil price differentials.

Six Months

Upgrading earnings for the first six months of 2010 were affected by the same factors impacting the second quarter.

Infrastructure and Marketing Net Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2010**	2009	**2010**	2009
Gross revenues		**$ 1,959**	$ 1,760	**$ 4,046**	$ 3,795
Gross margin	- pipeline	**$ 37**	$ 25	**$ 69**	$ 57
	- other infrastructure and marketing	**23**	38	**104**	112
		60	63	**173**	169
Operating and administration expenses		**5**	5	**10**	9
Depreciation and amortization		**10**	9	**20**	18
Other (income) expense		**(9)**	(24)	**22**	(9)
Income taxes		**14**	20	**32**	42
Net earnings		**$ 40**	$ 53	**$ 89**	$ 109
Selected operating data:					
Commodity volumes managed	*(mboe/day)*	**964**	934	**950**	1,017
Aggregate pipeline throughput	*(mbbls/day)*	**537**	534	**531**	531

Second Quarter

Infrastructure and Marketing net earnings in the second quarter of 2010 were $40 million compared with $53 million in the second quarter of 2009. Pipeline margins increased due to higher pipeline blending differentials and brokering margins. Decreased margins on other infrastructure and marketing were the result of lower realized natural gas storage profits and lower commodity trading margins. Other income in the second quarter of 2010 included unrealized gains of $9 million on natural gas storage contracts resulting from changes in the fair value of natural gas forward purchase and sale contracts compared with $24 million in the second quarter of 2009.

Commodity volumes managed increased due to increased natural gas storage capacity.

Six Months

During the first half of 2010, pipeline margins were higher and other infrastructure and marketing margins were lower than the same period in 2009 primarily due to the same factors that affected the second quarter of 2010.

Other expense in the first half of 2010 included unrealized losses of $22 million on natural gas storage contracts resulting from changes in the fair value of natural gas forward purchase and sale contracts compared with a $9 million gain in the same period in 2009.

Midstream Capital Expenditures

For the first six months of 2010, midstream capital expenditures totalled $40 million. At the Lloydminster Upgrader, Husky spent $25 million, primarily for facility reliability projects and contingent consideration. The remaining $15 million was spent on the acquisition of equipment used for sulphur operations and various pipeline upgrades.

Midstream Planned Turnaround

The Lloydminster Upgrader has scheduled a major maintenance turnaround in September and October of 2010.

5.3 Downstream

Canadian Refined Products Net Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2010**	2009	**2010**	2009
Gross revenues		**$ 700**	$ 587	**$ 1,306**	$ 1,075
Gross margin	- fuel	**$ 9**	$ 29	**$ 27**	$ 63
	- ethanol	**13**	20	**34**	26
	- asphalt	**29**	48	**39**	84
	- ancillary	**11**	11	**23**	20
		62	108	**123**	193
Operating and administration expenses		**21**	27	**46**	46
Depreciation and amortization		**25**	23	**51**	46
Income taxes		**4**	16	**7**	29
Net earnings		**$ 12**	$ 42	**$ 19**	$ 72
Selected operating data:					
Number of fuel outlets (average)				**479**	488
Light oil sales	*(million litres/day)*	**7.8**	7.4	**7.7**	7.5
Light oil retail sales per outlet	*(thousand litres/day)*	**13.5**	12.1	**13.5**	12.3
Prince George Refinery throughput	*(mbbls/day)*	**6.9**	10.0	**8.3**	10.3
Asphalt sales	*(mbbls/day)*	**19.2**	17.5	**18.9**	19.6
Lloydminster Refinery throughput	*(mbbls/day)*	**26.1**	17.8	**26.5**	23.3
Ethanol production	*(thousand litres/day)*	**547.6**	659.3	**633.9**	631.9

Second Quarter

Gross margin on fuel sales was lower in the second quarter of 2010 compared to 2009 due to lower production at the Prince George Refinery which was shut down for 22 days for scheduled maintenance combined with lower unit margins as a result of lower market prices for products and higher crude feedstock costs.

The lower ethanol gross margin in the second quarter of 2010 was due to lower production and sales volumes combined with lower realized product margins. Ethanol production in the second quarter of 2010 was 17% lower than in the same period in 2009 due to a planned turnaround at the Lloydminster Ethanol Plant. Included in ethanol gross margin in the second quarter of 2010 was $15 million related to government assistance grants compared with $16 million in the second quarter of 2009.

Asphalt gross margins were lower in the second quarter of 2010 compared with 2009 due to higher crude feedstock costs. Asphalt sales volumes were higher in the second quarter of 2010 compared with 2009 as 2009 included a 32-day scheduled turnaround at the Lloydminster Refinery.

Six Months

During the first half of 2010, refined products earnings were lower than the same period in 2009 primarily due to the same factors that affected the second quarter of 2010.

U.S. Refining and Marketing Net Earnings Summary

(millions of dollars, except where indicated)		Three months ended June 30 2010	Three months ended June 30 2009	Six months ended June 30 2010	Six months ended June 30 2009
Gross revenues		$ 1,881	$ 1,497	$ 3,600	$ 2,625
Gross refining margin		$ 123	$ 391	$ 220	$ 609
Processing costs		97	108	189	225
Operating and administration expenses		3	2	5	4
Interest - net		-	-	1	1
Depreciation and amortization		47	49	93	99
Other (income) expense		(2)	21	-	33
Income taxes (recoveries)		(8)	77	(25)	90
Net earnings (loss)		$ (14)	$ 134	$ (43)	$ 157
Selected operating data:					
Lima Refinery throughput	*(mbbls/day)*	150.3	137.4	146.0	136.9
Toledo Refinery throughput	*(mbbls/day)*	70.4	65.2	69.2	63.0
Realized refining margin	*(U.S. $/bbl crude throughput)*	$ 6.03	$ 18.37	$ 5.51	$ 14.47
Refinery feedstocks and refined products inventory	*(mmbbls)*	12.54	11.11	12.54	11.11

Second Quarter

U.S. Refining and Marketing earnings decreased in the second quarter of 2010 compared with the second quarter of 2009 as a result of lower realized refining margins offsetting increased production and sales volumes. Realized refining margins reflect differences in product configuration, location differences and FIFO accounting for the purchase of crude oil compared to benchmark pricing.

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

The Chicago crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI which was declining at the end of the second quarter of 2010 while on a FIFO basis crude oil feedstock costs reflect purchases made earlier in the quarter when crude oil prices were higher. The second quarter of 2009 includes significant benefits of consuming lower cost crude feedstock, which is accounted for on a FIFO basis, during a period of rising WTI prices.

In addition, the 13% strengthening of the Canadian dollar against the U.S. dollar compared with the second quarter of 2009 has had a negative impact on the translation of U.S. dollar financial results into Canadian dollars.

Other expense in the second quarter of 2010 consisted of $2 million of gains on forward feedstock purchase contracts compared with $21 million of losses recorded in 2009.

Six Months

Refining margins in the first six months of 2010 were impacted by the same factors affecting the second quarter. Other expense in the first six months of 2009 consisted of $33 million of losses on forward feedstock purchase contracts.

Downstream Capital Expenditures

For the first six months of 2010, downstream capital expenditures totalled $154 million.

In Canada, capital expenditures totalled $81 million primarily for rebranding of retail outlets acquired in 2009 as well as upgrades and environmental protection at the retail outlets, refineries and ethanol plants.

In the United States, capital expenditures totalled $73 million. At the Lima, Ohio Refinery, $45 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $28 million (Husky's 50% share) primarily for engineering work on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection.

Downstream Planned Turnaround

The Lima, Ohio Refinery has a planned turnaround on the fluid catalytic cracker and coker units including several major environmental and reliability components scheduled for fall 2010.

5.4 Corporate

Corporate Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars) income (expense)	**2010**	2009	**2010**	2009
Intersegment eliminations - net	**$ 39**	$ (24)	**$ 14**	$ (63)
Administration expense	**(18)**	(23)	**(29)**	(31)
Other expense	**(1)**	(2)	**(2)**	(18)
Stock-based compensation	**1**	(7)	**1**	(3)
Depreciation and amortization	**(19)**	(13)	**(38)**	(22)
Interest - net	**(55)**	(50)	**(103)**	(87)
Foreign exchange	**19**	(34)	**20**	(1)
Income taxes	**27**	29	**74**	73
Net loss	**$ (7)**	$ (124)	**$ (63)**	$ (152)

Second Quarter

The Corporate segment reported a loss of $7 million in the second quarter of 2010 compared with $124 million in the second quarter of 2009. Foreign exchange gains increased by $53 million to $19 million in the second quarter of 2010 compared with the same period of 2009. The gain in the second quarter of 2010 was a result of the weakening of the U.S./Canadian dollar from the beginning of the quarter and its impact on Husky's net U.S. dollar asset position.

The increase in depreciation and amortization was a result of adjustments to the book value of legacy sites that have been deemed inactive. Net interest expense increased in the second quarter of 2010 primarily due to higher debt levels compared with the same period in 2009.

Six Months

In the first half of 2010, the corporate segment reported a loss of $63 million compared with $152 million in the same period of 2009. In addition to the same factors that impacted the second quarter, the corporate segment was impacted by additional expenses in the first six months of 2009 that were recorded in other expense including insurance costs of $5 million and realized losses on forward purchases of U.S. dollars of $9 million.

Foreign Exchange Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2010**	2009	**2010**	2009
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ 94**	$ (83)	**$ 29**	$ (51)
(Gain) loss on cross currency swaps	**(16)**	34	**(5)**	22
(Gain) loss on contribution receivable	**(57)**	116	**(18)**	74
Other gains	**(40)**	(33)	**(26)**	(44)
Foreign exchange (gain) loss	**$ (19)**	$ 34	**$ (20)**	$ 1
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.985**	U.S. $0.794	**U.S. $0.956**	U.S. $0.817
At end of period	**U.S. $0.943**	U.S. $0.860	**U.S. $0.943**	U.S. $0.860

Corporate Capital Expenditures

For the first six months of 2010, corporate capital expenditures of $6 million were primarily for computer hardware and software, office furniture, renovations and equipment and system upgrades.

Consolidated Income Taxes

Second Quarter

During the second quarter of 2010, consolidated income tax expense was $79 million compared with $216 million in the same period in 2009. Current taxes in the second quarter of 2010 decreased compared with the second quarter of 2009 due to a decrease in partnership deferred revenue taxable in 2010.

Six Months

Cash taxes paid in the first six months of 2010 were $689 million compared to $955 million in the first six months of 2009, of which $509 million relates to final instalments paid in respect of 2008 earnings, included in current liabilities at December 31, 2009, and $180 million relating to instalments paid in respect of 2009 earnings. Further cash tax instalments in respect of 2009 earnings are estimated to be approximately $110 million.

6. Liquidity and Capital Resources

In the second quarter of 2010, Husky funded its capital programs and dividend payments by cash generated from operating activities and cash on hand. Husky maintained its strong financial position with debt of $4,016 million partially offset by cash on hand of $104 million for $3,912 million of net debt. Husky has no long-term debt maturing until 2012. At June 30, 2010, the Company had $1.5 billion in unused committed credit facilities, $152 million in unused short-term uncommitted credit facilities and unused capacity under the debt shelf prospectuses filed in Canada and the U.S. in 2009 of $300 million and U.S. $1.5 billion, respectively. (Refer to Section 6.4).

Cash Flow Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars, except ratios)	**2010**	2009	**2010**	2009
Cash flow - operating activities	**$ 491**	$ 563	**$ 1,088**	$ 798
- financing activities	**$ (262)**	$ 1,237	**$ 212**	$ 1,109
- investing activities	**$ (627)**	$ (658)	**$ (1,588)**	$ (1,583)
Financial Ratios				
Debt to capital employed *(percent)*			**21.6**	19.8
Debt to cash flow *(times)* [(1)]			**1.4**	1.0
Corporate reinvestment ratio *(percent)* [(1) (2)]			**104**	99
Interest coverage ratios on long-term debt only [(1) (3)]				
Earnings			**8.4**	21.9
Cash flow			**14.0**	38.7
Interest coverage ratios on total debt [(1) (4)]				
Earnings			**8.3**	21.0
Cash flow			**13.7**	37.2

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

6.1 Operating Activities

Second Quarter

In the second quarter of 2010, cash generated from operating activities amounted to $491 million compared with $563 million in the second quarter of 2009. Lower cash flow from operating activities was primarily due to lower production and lower downstream product margins, partially offset by higher realized crude oil and natural gas prices.

Six Months

Cash generated from operating activities amounted to $1.1 billion in the first six months of 2010 compared with $798 million in the first six months of 2009. Higher cash flow from operating activities was primarily due to higher commodity prices and lower cash taxes paid offsetting decreases in production.

6.2 Financing Activities

Second Quarter

In the second quarter of 2010, cash used in financing activities was $262 million compared with cash provided by financing activities of $1.2 billion in the second quarter of 2009. In the second quarter of 2010, cash used was primarily for the payment of dividends on common shares. In the second quarter of 2009, cash was primarily provided by the issuance of long-term notes of U.S. $1.5 billion partially offset by the payment of dividends on common shares. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

Six Months

Cash provided by financing activities was $212 million in the first six months of 2010 compared with $1.1 billion in the first six months of 2009. In addition to the same factors impacting the second quarter, $700 million of medium-term notes were issued in March 2010.

6.3 Investing Activities

Second Quarter

In the second quarter of 2010, cash used in investing activities amounted to $627 million compared with $658 million in the second quarter of 2009. 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 2010 and 2009 was $1.6 billion. Cash invested in both periods was primarily for capital expenditures.

6.4 Sources of Capital

Husky is currently able to fund its capital programs, non-cancellable contractual obligations and other commercial commitments principally by cash generated from operating activities, the issuance of long-term debt and committed 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, 2010, working capital was $1.2 billion compared with $726 million at December 31, 2009.

At June 30, 2010, Husky had unused committed long and short-term borrowing credit facilities totalling $1.5 billion. A total of $129 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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

Husky filed a debt shelf prospectus with the Alberta Securities Commission on February 26, 2009 and the U.S. Securities and Exchange Commission on February 27, 2009. The shelf prospectus enables Husky to offer up to U.S. $3 billion of debt securities in the United States until March 26, 2011. During the 25-month period that the shelf prospectus is effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of June 30, 2010, $1.5 billion of long-term notes had been issued under this shelf prospectus. On December 21, 2009, Husky filed an additional debt shelf prospectus with the Alberta Securities Commission that enables Husky to offer up to $1 billion of medium-term notes in Canada until January 21, 2012. During the 25-month period that the shelf prospectus is effective, medium-term notes may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of June 30, 2010, $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020 had been issued under this shelf prospectus. (Refer to Note 6 to the Consolidated Financial Statements).

Capital Structure *(millions of dollars)*	June 30, 2010 Outstanding	 Available
Total short-term and long-term debt	$ 4,016	$ 1,666
Common shares, retained earnings and accumulated other comprehensive income	$ 14,540	

6.5 Credit Ratings

Husky's credit ratings are available in its Annual Information Form at <u>*www.sedar.com.*</u> Subsequent to filing Husky's Annual Information Form, Moody's Investor Service affirmed its Baa2 rating on Husky's senior unsecured debt, but lowered its rating outlook from "stable" to "negative".

6.6 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 2009 annual MD&A under Section 8.3, "Cash Requirements," which summarizes contractual requirements and commercial commitments as at December 31, 2009 and Husky's First Quarter 2010 Management's Discussion and Analysis under Section 4.6 Contractual Obligations and Commercial Commitments. At June 30, 2010, Husky did not have any additional material contractual obligations and commercial commitments.

The Terra Nova oil field is divided into three distinct areas known as the Graben, the East Flank and the Far East. Husky currently holds a combined 12.51% working interest in the field, subject to redetermination. The process of working interest redetermination is before an arbitrator who is expected to make a decision by the end of 2010. Arbitration will result in Husky's combined working interest ranging between 10.58% and 15.15%, with a pre-tax earnings impact ranging between a loss of $150 million and a gain of $250 million. At this time, the outcome of the arbitration process is not reasonably determinable therefore no amount has been reflected in the Consolidated Financial Statements as at June 30, 2010.

6.7 Off Balance Sheet Arrangements

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

6.8 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. $22 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. These transactions were measured at the exchange amount, which was equivalent to the fair market value at the date of the transaction and have been carried out on the same terms as would apply with unrelated parties. At June 30, 2010, the U.S. $1.5 billion senior notes are included in long-term debt on the Company's balance sheet.

TransAlta Power, L.P. ("TAPLP") is under the indirect control of one of Husky's principal shareholders. TAPLP is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLP") which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLP. These natural gas sales are related party transactions and have been measured at the exchange amount. For the six months ended June 30, 2010, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $51 million.

7. Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's 2009 Annual Information Form 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.

Political Risk

Husky is exposed to risk factors associated with operating in developing countries, as well as political and regulatory instability. The Company maintains close contact with governments in the areas within which it operates.

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 recent Deepwater Horizon oil spill has led to numerous public and governmental expressions of concern about the safety and potential environmental impact of offshore oil operations. Stricter regulation of operations, 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 off the East Coast of Canada 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.

In June 2009, the United States House of Representatives passed the Waxman-Markey American Clean Energy and Security Act, which requires a 17% reduction of greenhouse gas emissions from 2005 levels by 2020 and an 80% reduction by 2050. The bill also sets a system of permitting under which regulated industries would need to acquire sufficient allowances for their emissions. Senator Harry Reid, the majority leader, recently announced that he expects a bill containing restrictions on greenhouse gas emissions to be introduced in the Senate soon, however, the restrictions on greenhouse gas emissions would only apply to energy utilities and power plants, significantly reducing the scope of proposed greenhouse gas regulation. The United States Environmental Protection Agency ("EPA") has also issued draft regulation that would require reporting of greenhouse gas emissions after January 1, 2011 from stationary sources in the oil and gas industry emitting more than 25,000 tons per year of greenhouse gases measured in carbon dioxide equivalent. This requirement would apply to Husky's U.S. facilities, however, the regulations have not yet been finalized. Regulations restricting greenhouse gas emissions may follow, though the precise nature and application of these regulations are currently unclear. Husky's operations may be impacted by future greenhouse gas legislation applying to the oil and gas industry or the consumption of petroleum products or by any such restrictive regulations issued by the EPA. Such legislation or regulation could require U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

Financial Risk

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

Liquidity Risk

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

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

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, 2010, the Company had third party physical natural gas purchase and sale contracts and natural gas storage contracts. These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized gain of $6 million has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income. Natural gas inventory held in storage relating to the natural gas storage contracts is recorded at fair value. At June 30, 2010, the fair value of the inventory was $173 million, resulting in a $24 million unrealized loss recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

At June 30, 2010, the Company had third party crude oil purchase and sale contracts, which have been designated as a fair value hedge. These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized loss of $5 million has been recorded in cost of sales in the Consolidated Statements of Earnings and Comprehensive Income. The crude oil inventory held in storage is recorded at fair value. At June 30, 2010, the fair value of the inventory was $136 million, resulting in an unrealized gain of less than $2 million recorded in cost of sales in the Consolidated Statements of Earnings and Comprehensive Income.

The Company has entered 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. For the six months ended June 30, 2010, an unrealized loss of $5 million has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Interest Rate Risk Management

At June 30, 2010, Husky had the following interest rate swaps in place:

- U.S. $200 million of long-term debt whereby a fixed interest rate of 7.55% was swapped for rates ranging from LIBOR + 399 bps to LIBOR + 420 bps until November 15, 2016.

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

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

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

During the first six months of 2010, these swaps resulted in an offset to interest expense amounting to $11 million. The amortization of previous interest rate swap terminations resulted in an addition to interest expense of $2 million in 2010.

Cross currency swaps resulted in an addition to interest expense of $3 million in the first six months of 2010.

Foreign Currency Risk Management

At June 30, 2010, Husky had the following cross currency debt swaps in place:

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

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

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

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

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. During the first six months of 2010, the impact of these contracts was a realized gain of $18 million (2009 – gain of $5 million) recorded in foreign exchange expense.

At June 30, 2010, the cost of a U.S. dollar in Canadian currency was $1.0606.

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, 2010, 82% or $3.3 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, 2010, the Company has designated U.S. $987 million of its U.S. debt as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. In the first six months of 2010, the unrealized foreign exchange loss arising from the translation of the debt was $13 million, net of tax recoveries of $1 million, which was recorded in Other Comprehensive Income.

Including cross currency swaps and the debt that has been designated as a hedge of a net investment, 47% 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, 2010, Husky's share of this receivable was U.S. $1.3 billion including accrued interest. Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in Other Comprehensive Income as this item relates to a self-sustaining foreign operation. At June 30, 2010, Husky's share of this obligation was U.S. $1.4 billion including accrued interest.

Fair Value of Financial Instruments

The derivative portion of cashflow hedges, fair value hedges, and free standing derivatives that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon fair value hierarchy in accordance with the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3862. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. All of Husky's assets and liabilities that are recorded at fair value on a recurring basis are included in Level 2.

8. Critical Accounting Estimates

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

9. Accounting Policies

Recent Accounting Pronouncements

In January 2009, the CICA issued Section 1582, "Business Combinations," which will replace CICA Section 1581 of the same name. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, which currently are capitalized as part of the purchase price.

Contingent liabilities are to be recognized at fair value at the acquisition date and re-measured at fair value through earnings each period until settled. Currently only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation. Section 1582 is effective for Husky on January 1, 2011 with prospective application and early adoption permitted.

In January 2009, the CICA issued Section 1601, "Consolidated Financial Statements," which will replace CICA Section 1600 of the same name. This guidance requires uniform accounting policies to be consistent throughout all consolidated entities and the difference between reporting dates of a parent and a subsidiary to be no longer than three months. These are not explicitly required under the current standard. Section 1601 is effective for Husky on January 1, 2011 with early adoption permitted. This standard will have no impact to the Company.

In January 2009, the CICA issued Section 1602, "Non-controlling Interests," which will replace CICA Section 1600, "Consolidated Financial Statements." Minority interest is now referred to as non-controlling interest ("NCI"), and is presented within equity. Under this new guidance, when there is a loss or gain of control, the Company's remaining or initial interest is revalued at fair value. Currently an increase in an investment is accounted for using the purchase method and a decrease in an investment is accounted for as a sale resulting in a gain or loss in earnings. In addition, at the time of acquisition, NCI may be reported at fair value or at the proportionate share of the fair value of the acquired net assets and allocation of the net income to the NCI will be on this basis. Currently, NCI is recorded at the carrying amount and can only be in a deficit position if the NCI has an obligation to fund the losses. This standard will have no impact to the Company. Section 1602 requires retrospective application as at its effective date of January 1, 2011 with early adoption permitted.

International Financial Reporting Standards

In January 2006, the Canadian Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. In February 2008, as part of its strategic plan, the AcSB confirmed that Canadian publicly accountable entities will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian GAAP for years beginning on or after January 1, 2011.

The Company commenced its IFRS transition project in 2008, which includes four key phases: project engagement, policy diagnostic, solution development and implementation. A description of the transition project's key phases is included in the Company's 2009 Annual Report.

As initial accounting policies are drafted by the Company, initiatives have commenced to incorporate conversion impacts into existing internal controls over financial reporting and disclosure controls and procedures. The Company has completed its risk assessment of key processes that will be impacted by IFRS. Internal control process documents are expected to be updated and implemented in the second half of 2010. The Company will monitor and assess any new or amended IFRS standards and incorporate any relevant changes into the Company's transition project and IFRS policies as necessary.

To date, the Company has progressed work on its information systems in preparation for IFRS. The Company has completed its most significant information technology systems conversion for property, plant, and equipment and foreign exchange. System initiatives for other areas of convergence including asset retirement obligations and impairments of assets are scheduled to be completed in the third quarter of 2010.

The Company held training sessions for key finance and operational staff in 2009. Training sessions for all levels of the business have commenced with expected delivery throughout 2010.

The Company is finalizing its assessments on IFRS transition issues with expected impacts. Evaluations of IFRS financial statement presentation and disclosure requirements have been completed. These assessments require further monitoring and evaluation throughout the implementation phase of the Company's project. The Company has determined that the areas of most significant impact will include property, plant, and equipment and asset retirement obligations. While the Company's IFRS policies are not yet finalized, a summary of the significant IFRS accounting policy differences identified to date is included below.

Property, Plant and Equipment

In July 2009, the International Accounting Standards Board ("IASB") approved additional IFRS transitional exemptions that will allow entities that previously followed full cost accounting in accordance with Accounting Guideline 16 of the CICA Handbook to allocate their upstream oil and gas asset balances as determined under full cost accounting to the IFRS categories of exploration and evaluation assets and development and producing assets. This exemption will relieve entities from significant adjustments resulting from retrospective adoption of IFRS. The Company intends to utilize this exemption.

Under IFRS, the Company is considering adopting accounting policies for its oil and natural gas exploration, evaluation and development expenditures that differ significantly when compared with the full cost method employed under Canadian GAAP, which allows for the capitalization of all costs associated with the acquisition, exploration, and development of oil and gas reserves on a country-by-country basis. Under IFRS 6, pre-exploration and evaluation costs, which include all exploratory costs incurred prior to the acquisition of the legal right to explore, will be expensed as incurred. The Company is finalizing its policy with respect to exploration costs incurred after the legal right to explore is acquired. These costs include geological and geophysical activity such as seismic programs and technical analysis and exploratory drilling. Land acquisition costs and expenditures directly associated with exploratory wells will be capitalized as exploration and evaluation assets. Land acquisition costs will remain capitalized until the Company has chosen to discontinue all exploration activities in the associated area. Exploratory wells will remain capitalized until the drilling operation is complete and the results have been evaluated. If the well does not encounter reserves of commercial quantity, either on its own or in combination with other exploration wells associated with the same area of exploration, the costs of drilling the well or wells will be charged to expense. Wells that result in commercial quantities of reserves will remain capitalized. Policies for accounting for seismic costs and other geological and geophysical technical costs are being evaluated.

Oil and gas properties will be depleted under IFRS on a unit-of-production basis based on the unit of measure to which an asset is assigned. In the case of assets whose useful life is shorter or longer than the lifetime of the associated fields' production profile, the straight-line method of depreciation is applied. The Company has not finalized the unit of measure definition for the unit-of-production depletion calculation; however, the unit of measure is required to be based on asset components. Under full cost accounting, depletion is calculated using the unit-of-production method on a country-by-country basis.

The Company is reviewing the useful lives of significant asset components for all other plant and equipment. A significant component is defined as a part of an asset that is significant in relation to the total cost of the asset. The Company expects that component depreciation will result in increased depletion, depreciation and amortization expense under IFRS.

Asset impairment is measured as the excess of the carrying value of the asset over its recoverable amount based on discounted cash flows. Impairment is tested on a cash generating unit basis which is defined as the lowest level of assets with separately identifiable cash inflows. Impairments can be reversed for assets other than goodwill if there is a change in the circumstances that resulted in the original impairment. If the recoverable amount exceeds the asset's carrying value, the asset is written up to the value determined based on discounted cash flows; however, the asset cannot be adjusted to a value higher than its original cost. Under Canadian GAAP, upstream impairment is tested on a country-by-country basis and cannot be reversed. Asset impairment within the midstream and downstream segments is assessed at the asset or group of similar assets level.

Asset Retirement Obligations

Asset retirement obligations *("*ARO") use a discount rate that is adjusted for the entity's credit standing under Canadian GAAP and ARO is not re-measured for changes in discount rates in each reporting period. Under IFRS, the discount rate is not adjusted for the entity's credit standing. IFRS requires current period discount rates to be used for all existing liabilities with changes in the balance recorded to property, plant, and equipment. As a result, the ARO balance is expected to be higher under IFRS compared with Canadian GAAP.

Other IFRS 1 Exemptions

The Company is also evaluating the use of other first-time adoption exemptions and elections available upon initial transition that provide relief from retrospective application of IFRS. One such exemption that is undergoing consideration permits foreign currency translation adjustments included in Accumulated Other Comprehensive Income to be deemed zero through an adjustment to retained earnings at the transition date.

The Company anticipates it will not restate business combinations entered into prior to January 1, 2010 in accordance with the permissible IFRS 1 exemption.

10. Oustanding Share Data

(in thousands)	July 22 2010	December 31 2009
Issued and outstanding		
Number of common shares	849,861	849,861
Number of stock options	31,199	28,399
Number of stock options exercisable	17,385	14,917

11. Reader Advisories

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

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

Use of Pronouns and Other Terms Denoting Husky

In this 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, 2010 are compared with results for the three months ended June 30, 2009 and the results for the six months ended June 30, 2010 are compared with results for the six months ended June 30, 2009. Discussions with respect to Husky's financial position as at June 30, 2010 are compared with its financial position at December 31, 2009.

Additional Reader Guidance

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

Non-GAAP Measures

Disclosure of Cash Flow from Operations

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

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)		**2010**	2009	**2010**	2009
Non-GAAP	Cash flow from operations	**$ 806**	$ 833	**$ 1,701**	$ 1,398
	Settlement of asset retirement obligations	**(7)**	(5)	**(22)**	(15)
	Change in non-cash working capital	**(308)**	(265)	**(591)**	(585)
GAAP	Cash flow - operating activities	**$ 491**	$ 563	**$ 1,088**	$ 798

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.

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)		**2010**	2009	**2010**	2009
GAAP	Net earnings	**$ 266**	$ 430	**$ 611**	$ 758
	Net foreign exchange	**(12)**	30	**(13)**	4
	Net financial instruments	**(8)**	-	**14**	27
	Net stock-based compensation	**-**	5	**-**	2
	Net inventory write-downs	**19**	6	**21**	25
Non-GAAP	Adjusted net earnings	**$ 265**	$ 471	**$ 633**	$ 816

Cautionary Note Required by National Instrument 51-101

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

Abbreviations

bbls	*barrels*
bps	*basis points*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mmbbls	*million barrels*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
bcf	*billion cubic feet*
tcf	*trillion cubic feet*
boe	*barrels of oil equivalent*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mmboe	*million barrels of oil equivalent*
mcfge	*thousand cubic feet of gas equivalent*
GJ	*gigajoule*
mmbtu	*million British thermal units*
mmlt	*million long tons*
NGL	*natural gas liquids*
WTI	*West Texas Intermediate*
NYMEX	*New York Mercantile Exchange*
NIT	*NOVA Inventory Transfer*
LIBOR	*London Interbank Offered Rate*
CDOR	*Certificate of Deposit Offered Rate*
EDGAR	*Electronic Data Gathering, Analysis and Retrieval (U.S.A.)*
SEDAR	*System for Electronic Document Analysis and Retrieval (Canada)*
FPSO	*Floating production, storage and offloading vessel*
FEED	*Front end engineering design*
OPEC	*Organization of Petroleum Exporting Countries*
GDP	*Gross domestic product*
MD&A	*Management's Discussion and Analysis*

Terms

Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
Capital Employed	*Short and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital*
Coal Bed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Corporate Reinvestment Ratio	*Net capital expenditures (capital expenditures net of proceeds from asset sales) plus corporate acquisitions (net assets acquired) divided by cash flow from operations calculated on a 12-month trailing basis*
Dated Brent	*Prices are dated less than 15 days prior to loading for delivery*
Debt to Capital Employed	*Total debt divided by total debt and shareholders' equity*
Debt to Cash Flow	*Total debt divided by cash flow from operations calculated on a 12-month trailing basis*
Delineation Well	*A well in close proximity to an oil or gas discovery well that helps determine the areal extent of the reservoir*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
Equity	*Shares, retained earnings and accumulated other comprehensive income*
Feedstock	*Raw materials which are processed into petroleum products*
Front End Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Glory Hole	*An excavation in the seabed where the wellheads and other equipment are situated to protect them from scouring icebergs*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which an interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Hectare	*One hectare is equal to 2.47 acres*
Near-month Prices	*Prices quoted for contracts for settlement during the next month*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Return on Capital Employed	*Net earnings plus after tax interest expense calculated on a 12-month trailing basis divided by average capital employed*
Return on Shareholders' Equity	*Net earnings calculated on a 12-month trailing basis divided by average shareholders' equity*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Three Dimensional (3-D) Seismic	*Seismic imaging which uses a grid of numerous cables rather than a few lines stretched in one line*
Total Debt	*Long-term debt including current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

12. Forward-Looking Statements and Information

Certain statements in this interim report are forward-looking statements and information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The Company hereby provides cautionary statements identifying important factors that could cause actual results to differ materially from those projected in these forward-looking statements. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intend," "plan," "projection," "could," "vision," "goals," "objective," "target," "schedules" and "outlook") are not historical facts and are forward-looking and may involve estimates and assumptions and are subject to risks, uncertainties and other factors some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

In particular, forward-looking statements in this interim report include, but are not limited to: the Company's general strategic plans; 2010 capital expenditure guidance; drilling and production plans for the West White Rose field; drilling, production and enhanced recovery plans for the South Pike's Peak field; exploration plans for Canada's East Coast; development and production plans for the North Amethyst oil field; offshore Greenland exploration plans; offshore China exploration plans; delineation drilling, development and production plans and applications for regulatory approval for the Liwan and Liuhua natural gas discoveries; exploration and drilling plans for the North Sumbawa II Block; development plans and receipt of an extension of the PSC for the Madura BD field; Sunrise multiphase development plans, production plans and production capacity; production optimization and drilling plans for the Tucker Oil Sands Project; development plans for the McMullen property; testing and implementation of various enhanced recovery techniques in Western Canada; conventional and shale gas exploration plans for Northeastern British Columbia; Husky's coal bed methane program; reconfiguration plans for the Lima Refinery; Continuous Catalyst Regeneration Reformer Project plans at the Toledo Refinery; plans to reposition and upgrade the Toledo Refinery; planned maintenance at the Lloydminster Upgrader; timing of rebranding of retail outlets in Southern Ontario; and timing of redetermination of Husky's working interest in the Terra Nova field.

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

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 which are incorporated herein by reference.

Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable law, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.