MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") NOVEMBER 2, 2011

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1. Summary of Quarterly Results

Quarterly Summary *(millions of dollars, except per share amounts)*	Three months ended **Sept. 30 2011** [(1)]	June 30 2011 [(1)]	March 31 2011 [(1)]	Dec. 31 2010 [(2)]	Sept. 30 2010 [(1)]	June 30 2010 [(1)]	March 31 2010 [(1)]	Dec. 31 2009 [(2)]
Production *(mboe/day)*	**309.1**	311.6	310.4	280.5	288.7	283.9	295.9	291.5
Gross revenues	**$ 6,495**	$ 6,695	$ 5,860	$ 4,942	$ 4,472	$ 4,630	$ 4,493	$ 3,856
Net earnings	**521**	669	626	305	261	179	368	320
Per share - Basic	**0.55**	0.73	0.70	0.35	0.31	0.21	0.43	0.38
Per share - Diluted	**0.53**	0.71	0.70	0.35	0.30	0.19	0.41	0.38
Cash flow from operations [(3)]	**1,326**	1,511	1,164	1,037	794	739	854	657
Per share - Basic	**1.40**	1.68	1.31	1.21	0.93	0.87	1.00	0.77
Per share - Diluted	**1.39**	1.67	1.30	1.21	0.93	0.87	1.00	0.77

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

Performance

- Production in the quarter increased by 20.4 mboe/day to 309.1 mboe/day compared with the third quarter of 2010 as a result of higher production from the North Amethyst field and acquisitions in Western Canada in the fourth quarter of 2010 and the first quarter of 2011, partially offset by third party pipeline disruptions impacting average production over the third quarter by approximately 6 mboe/day.
- Net earnings in the quarter increased 100% compared with the third quarter of 2010 due to:
  - Higher crude oil and natural gas production;
  - Higher average realized crude oil and natural gas prices partially offset by the stronger Canadian dollar relative to the U.S. dollar; and
  - Increased realized refining, upgrading and marketing margins and volumes in both Canadian and U.S. Downstream.
- Cash flow from operations in the quarter increased by 67% to $1,326 million compared to $794 million in the third quarter of 2010.

Key Projects

- Sunrise Energy Project Phase I approximately 50% of the planned 49 horizontal well pairs completed and detailed engineering and construction activities for facilities and supporting infrastructure progressing.
- First production achieved from the West White Rose two-well pilot program.
- Sanctioned development of the Liwan 3-1 and Liuhua 34-2 fields with drilling activities progressing.
- South Pikes Peak 8,000 bbls/day heavy oil thermal project 73% complete.
- Western Canada resource play development drilling progressing.

Financial

- Dividends on common shares of $285 million were declared during the third quarter of 2011 of which $87 million and $198 million were accepted in cash and common shares, respectively.

2. Business Environment

Average Benchmarks		Three months ended				
		Sept. 30 2011	June 30 2011	March 31 2011	Dec. 31 2010	Sept. 30 2010
WTI crude oil [1]	*(U.S. $/bbl)*	**89.76**	102.56	94.10	84.89	76.20
Brent crude oil [2]	*(U.S. $/bbl)*	**113.46**	117.36	104.97	86.27	76.86
Canadian light crude 0.3% sulphur	*($/bbl)*	**92.06**	102.64	88.45	80.48	74.77
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**62.08**	71.82	59.54	60.76	57.29
NYMEX natural gas [3]	*(U.S. $/mmbtu)*	**4.19**	4.31	4.11	3.80	4.38
NIT natural gas	*($/GJ)*	**3.53**	3.55	3.58	3.39	3.52
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**18.12**	17.89	23.11	18.37	15.90
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**33.43**	28.90	16.58	9.13	10.16
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**33.72**	25.32	19.34	11.41	8.62
U.S./Canadian dollar exchange rate	*(U.S. $)*	**1.021**	1.034	1.014	0.987	0.962
Canadian Equivalents						
WTI crude oil [4]	*($/bbl)*	**87.91**	99.19	92.80	86.01	79.21
Brent crude oil [4]	*($/bbl)*	**111.13**	113.50	103.52	87.41	79.90
WTI/Lloyd crude blend differential [4]	*($/bbl)*	**17.75**	17.30	22.79	18.61	16.53
NYMEX natural gas [4]	*($/mmbtu)*	**4.10**	4.17	4.05	3.85	4.55

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

Oil and Gas Prices

The price Husky receives for production from Western Canada is primarily driven by the price of West Texas Intermediate ("WTI"), adjusted to Western Canada, while the majority of the Company's production in the Atlantic Region is referenced to the price of Brent crude oil ("Brent"). The price of WTI averaged U.S. $89.76/bbl in the third quarter of 2011 compared with U.S. $76.20/bbl in the third quarter of 2010. The price of WTI averaged U.S. $95.48/bbl in the first nine months of 2011 compared with U.S. $77.65/bbl in the first nine months of 2010. The price of Brent, which impacts Atlantic and Asia Pacific Region production, averaged U.S. $113.46/bbl in the third quarter of 2011 compared with U.S. $76.86/bbl in the third quarter of 2010. The price of Brent averaged U.S. $111.93/bbl in the first nine months of 2011 compared with U.S. $77.13/bbl in the first nine months of 2010.

Increased U.S. crude oil prices have been partially offset by the strengthening of the Canadian dollar. In the third quarter of 2011, the price of WTI increased by 18% in U.S. dollars compared with 11% in Canadian dollars when compared to the third quarter of 2010. In the first nine months of 2011, the price of WTI increased by 23% in U.S. dollars versus 16% in Canadian dollars compared to the first nine months of 2010.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In the third quarter of 2011, 48% of Husky's crude oil production was heavy oil or bitumen compared with 46% in the third quarter of 2010. The light/heavy crude oil differential averaged U.S. $18.12/bbl or 20% of WTI in the third quarter of 2011 compared with U.S. $15.90/bbl or 21% of WTI in the third quarter of 2010. In the first nine months of both 2011 and 2010, 47% of Husky's crude oil production was heavy oil or bitumen. The light/heavy crude oil differential averaged U.S. $19.71/bbl or 21% of WTI in the first nine months of 2011 compared with $13.18/bbl or 17% of WTI in the first nine months of 2010.

During the third quarter of 2011, the NYMEX near-month contract price of natural gas averaged U.S. $4.19/mmbtu compared with U.S. $4.38/mmbtu in the third quarter of 2010. During the first nine months of 2011, the NYMEX near-month contract price of natural gas averaged U.S. $4.20/mmbtu compared with U.S. $4.59/mmbtu during the first nine months of 2010.

Foreign Exchange

The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, changes in foreign exchange rates impact the translation of U.S. Downstream and International Upstream operations.

In the third quarter of 2011, the Canadian dollar averaged U.S. $1.021 per Canadian dollar, strengthening by 6% compared with U.S. $0.962 during the third quarter of 2010. The Canadian dollar ended 2010 at U.S. $1.005 and closed at U.S. $0.963 on September 30, 2011. In the first nine months of 2011, the Canadian dollar averaged U.S. $1.023 per Canadian dollar, strengthening by 6% compared with U.S. $0.966 during the first nine months of 2010.

Refining Crack Spreads

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

During the third quarter of 2011, the Chicago 3:2:1 crack spread averaged U.S. $33.43/bbl compared with U.S. $10.16/bbl in the third quarter of 2010. In the first nine months of 2011, the Chicago 3:2:1 crack spread averaged U.S. $26.27/bbl compared with U.S. $9.28/bbl in the first nine months of 2010. During the third quarter of 2011, the New York Harbour 3:2:1 crack spread averaged U.S. $33.72/bbl compared with U.S. $8.62/bbl in the third quarter of 2010. In the first nine months of 2011, the New York Harbour 3:2:1 crack spread averaged U.S. $26.12/bbl compared with U.S. $9.10/bbl in the first nine months of 2010.

Husky's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, slates, transportation costs to benchmark hubs and by the time lag between the purchase and delivery of crude oil, which is accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

Global Economic and Financial Environment

In its October 12, 2011 Short-term Energy Outlook[(1)], the Energy Information Administration ("EIA") maintained its forecast that world oil consumption by emerging economies will more than offset lower consumption of the Organization for Economic Cooperation and Development ("OECD") countries and will increase to an average of 88.4 mmbbls/day in 2011 and 89.8 mmbbls/day in 2012. The EIA further expects that world oil supply from both the Organization of the Petroleum Exporting Countries ("OPEC") and other producing countries will be marginally lower than consumption thus requiring some withdrawal from inventories. OPEC spare productive capacity was estimated at 4.0 mmbbls/day at the end of 2010 and is expected to decline to 3.0 mmbbls/day by the end of 2011 and then increase to 3.5 mmbbls/day by the end of 2012 as Libyan production is fully restored. The EIA estimates that OECD countries held 2.7 billion barrels of commercial oil inventories at the end of 2010. This represents approximately 58 days of forward cover. The EIA expects OECD oil inventories to decline to approximately 57 days of forward cover in 2011 and 56 days of forward cover in 2012. The movement toward lower inventory levels underscores potential supply risk as crude oil production remains subject to the instability of oil producing countries in the Middle East and Africa while world demand for crude oil by the emerging economies in Asia and other non-OECD countries remains robust.

According to the EIA, natural gas consumption in U.S. markets is expected to rise 1.9% to 67.2 bcf/day in 2011 and 67.7 bcf/day in 2012. Higher consumption in the electrical generation and industrial sectors will be partially offset by lower consumption in the residential sector. Natural gas production in the U.S., which has been buoyed by increased onshore drilling activity despite low prices, is expected to increase by 6.7% in 2011 and 2.1% in 2012. Imports of both pipeline natural gas and liquefied natural gas into the U.S. are expected to decline by 4.8% in 2011 and a further 3.1% in 2012. In its Weekly Natural Gas Storage Report[(2)] released on October 13, 2011, the EIA reported that natural gas stocks were 2.0% above the five year average and 1.6% below the previous year. The EIA expects continued natural gas price volatility in the near term.

The EIA expects a decrease in U.S. gasoline consumption of 2.0% in 2011 compared with the previous year reflecting declining economic growth and higher fuel prices. The EIA further reduced its previous estimate of distillate fuels consumption during 2011 to a 1.0% increase over the prior year from its estimated increase of 1.9% reported at the end of the second quarter.

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

Note:

(1) *Energy Information Administration, Short-Term Energy Outlook DOE/EIA – October 12, 2011 Release.*

(2) *"Weekly Natural Gas Storage Report", October 13, 2011, Energy Information Administration, U.S. Department of Energy.*

Sensitivity Analysis

The following table indicates the relative annual effect of changes in certain key variables on Husky's pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the third quarter of 2011. Each item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis	2011 Third Quarter Average		Increase	Effect on Annual Pre-tax Cash Flow [6]		Effect on Annual Net Earnings [6]	
				($ millions)	*($/share)* [7]	*($ millions)*	*($/share)* [7]
WTI benchmark crude oil price [1]	$	89.76	*U.S. $1.00/bbl*	66	0.07	49	0.05
NYMEX benchmark natural gas price [2]	$	4.19	*U.S.$0.20/mmbtu*	33	0.03	23	0.02
WTI/Lloyd crude blend differential [3]	$	18.12	*U.S. $1.00/bbl*	(6)	(0.01)	(5)	(0.01)
Canadian retail margins	$	0.040	*Cdn $0.005/litre*	17	0.02	13	0.01
Asphalt margins	$	20.60	*Cdn $1.00/bbl*	13	0.01	9	0.01
New York Harbour 3:2:1 crack spread [4]	$	33.72	*U.S. $1.00/bbl*	71	0.07	44	0.05
Exchange rate (U.S. $ per Cdn $) [1] [5]	$	1.021	*U.S. $0.01*	(45)	(0.05)	(33)	(0.04)
Interest rate			*100 basis points*	(9)	(0.01)	(6)	(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 948.9 million common shares outstanding as of September 30, 2011.*

3. Strategic Plan

Husky's strategy is to continue to exploit oil and gas assets in Western Canada to maintain production, while advancing its three major growth pillars in the Asia Pacific Region, the Atlantic Region and the Oil Sands. Husky is an integrated company in a specialized sense. The Company is not integrated on a barrel-for-barrel basis and seeks to operate and maintain Midstream and Downstream assets which provide specialized support and value to its Upstream heavy oil and bitumen assets. The Company's strategy is to maximize the efficiency of its Midstream and Downstream operations and extract the greatest value from production.

4. Key Growth Highlights

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

4.1 Upstream

Asia Pacific Region

Offshore China Exploration, Delineation and Development

In September 2011, Husky sanctioned the development of the principal fields of the Liwan Gas Project, Liwan 3-1 and Liuhua 34-2, based on the Overall Development Plan ("ODP") for Liwan 3-1 which was submitted to the Chinese government authorities for regulatory approval. The gas sales agreement for production from Liwan 3-1 is now in place. The ODP for the Liuhua 34-2 field is in preparation.

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

The Liuhua 29-1 field is intended to be developed in an overlapping sequence to the development of the Liwan 3-1 and Liuhua 34-2 fields. The total project is expected to reach gross production of approximately 500 mmcf/day in the 2015 timeframe. Husky has a 49% ownership interest in production from this block.

During the third quarter of 2011, Husky drilled the Liuhua 32-1-1 exploration well and the Liwan 5-1-1 exploration well, both on Block 29/26. The Liuhua 32-1-1 well encountered a 26 metre interval of hydrocarbons. Well results are being evaluated to determine next steps. The Liwan 5-1-1 exploration well found hydrocarbons that were deemed non-commercial and the well was abandoned in October 2011.

Husky has also commenced drilling the YC 5-1-1 exploration well on Block 63/05 in the shallow water of the Qiongdongnan Basin located 50 kilometres south of Hainan Island. Husky holds a 100% working interest in Block 63/05, in which China National Offshore Oil Corporation ("CNOOC") has the right to participate up to 51% in any discoveries.

Indonesia Exploration and Development

Tendering of equipment and services for the Madura BD field development in the Madura Straits Block is underway. Also in the Madura Straits Block, the MDA-4 exploration well was successful and confirmed additional gas resources in the MDA field. The well was tested at rates up to 18.7 mmcf/day and a Plan of Development is expected to be filed for this field in 2012. Also in the Madura Straits Block, drilling of the MBH-1 exploration well commenced and is expected to be completed in the fourth quarter of 2011. First gas production from the Madura Straits Block is expected in 2014. Husky holds a 40% working interest in the block which is operated by CNOOC.

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

Atlantic Region

White Rose Extension Projects

First production from the West White Rose two-well pilot program was achieved in September 2011 with completion of the E-18-10 production well. A supporting water injection well is expected to be drilled in the fourth quarter of 2011. This pilot program will assist in refining the development plan for the full West White Rose resource.

Development continues at the North Amethyst satellite extension with the completion of a third water injection well during the third quarter of 2011. As of the end of the third quarter, three production wells and three water injection wells have been completed. While further wells are expected to be drilled to sustain production, the field has now fully met its target production rate of 37,000 bbls/day.

Husky intends to commence drilling of an infill well in the main White Rose field during the fourth quarter of 2011 to facilitate incremental oil recovery from the main White Rose field. The infill well will be completed in 2012.

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

Atlantic Region Exploration

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

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

Offshore Greenland

Husky has a significant position in three blocks off the west coast of Greenland. Geological and geophysical work continues in order to define well locations. During 2012, Husky intends to progress drilling plans, acquire well site drilling hazard surveys and conduct environmental and socio-economic impact assessments in anticipation of exploratory drilling in 2013.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages. To date, Husky has drilled approximately half of the planned 49 Steam-Assisted Gravity Drainage ("SAGD") horizontal well pairs for Phase I of the Sunrise Energy Project. SAGD drilling costs are trending on budget and on schedule. Husky is on track for the full drilling program to be completed by the second half of 2012 with anticipated first production planned for 2014.

Detailed engineering activities for the facilities and supporting infrastructure continued in the third quarter of 2011. The field facilities engineering contractor has mobilized on site to begin construction on the first well pad. The Central Processing Facility ("CPF") contractor has also mobilized on site and commenced foundation installation for facilities. Major construction of the camp building is also underway.

A contract for the Design Basis Memorandum ("DBM") and Front End Engineering Design ("FEED") of the next development stage of the Sunrise Energy Project was awarded in October 2011 with FEED expected to be completed in 2013.

Tucker Project

The production remediation plan for the Tucker Project continues to be on track. Year-to-date production has averaged 6,600 bbls/day compared to 3,700 bbls/day in the first nine months of 2010. Third quarter exit rates exceeded 9,000 bbls/day.

McMullen

During the third quarter of 2011, 28 slant development wells were drilled at McMullen with a total of seven slant development wells equipped and put on production.

At the McMullen air injection pilot project, facility construction commenced in May 2011 and was completed on schedule in August 2011. Commissioning of the facilities was completed in September and steam injection, which is the first phase of the process, was initiated at the end of September 2011.

Saleski

Husky continued its evaluation of the information from the vertical stratigraphic test wells and 2-D seismic data obtained earlier in 2011, in preparation for the drilling of vertical stratigraphic wells in the upcoming 2012 winter drilling program.

Heavy Oil

Construction of the 8,000 bbls/day South Pikes Peak thermal project is progressing within original cost estimates and on schedule. Production is expected to commence in mid-2012. The project was 73% complete at the end of the third quarter of 2011.

Husky continued construction of its 3,000 bbls/day Paradise Hill development which will utilize existing Bolney infrastructure. The project is on schedule achieving 45% completion at the end of the third quarter of 2011. It is anticipated to become operational by the third quarter of 2012.

Rush Lake, a single well pair thermal pilot, achieved first oil in October 2011. The design and planning process commenced on four additional commercial thermal projects which are in the early stages of reservoir evaluation and concept selection.

Husky advanced its horizontal drilling program in the third quarter of 2011, drilling 40 wells of an expanded 130 well program for 2011. Based on the positive performance of the previous horizontal drilling programs, Husky is expanding its horizontal drilling portfolio and has identified approximately 500 additional potential locations.

Husky drilled 121 cold heavy oil production with sand ("CHOPS") wells during the third quarter of 2011.

Husky is operating four solvent Enhanced Oil Recovery ("EOR") pilots, two of which became operational in the third quarter of 2011. A CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant is under construction with expected commissioning in the first quarter of 2012. The liquefied CO_2 from this facility will be used in the ongoing solvent EOR piloting program.

Western Canada (excluding Heavy Oil and Oil Sands)

Gas Resource Plays

The liquids-rich formations at Ansell in west central Alberta continue to be a key area of focus. The preliminary development plan in place includes the potential drilling of up to 2,600 Cardium and deeper Mannville wells which are mainly comprised of horizontal wells. Year to date, Husky has drilled 28 Cardium formation wells and four multi-zone wells at Ansell. Planned activity for the remainder of the year includes six additional Cardium wells (one horizontal) and five multi-zone wells. Completion operations are expected to recommence during the fourth quarter of 2011. Offload capacity expansion construction is progressing and start-up is also expected early in the fourth quarter of 2011. This expansion is expected to increase total production capacity at Ansell to over 50 mmcf/day of gas and 2,000 bbls/day of liquids.

The evaluation of the Duvernay liquids-rich gas play continued in the third quarter of 2011 with the drilling, coring and logging of a second vertical well. Based on these results, a horizontal well is expected to spud in the fourth quarter of 2011 to establish the productive capacity of this zone.

The third well in a three-well multi-zone program at Kakwa was drilled in the third quarter of 2011. The first well was recently put on production and completion is underway on the second and third wells. Further activity in the area will be dependent on these results.

Oil Resource Plays

Following wet weather conditions during the second quarter, drilling and completion operations resumed on Husky's Bakken project at Oungre in southeast Saskatchewan. Husky drilled four wells in the third quarter and plans to drill a further five wells before the end of 2011. Current production from four wells completed in 2010 and one well drilled in 2011 is 570 bbls/day. Three wells have been completed in the third quarter of 2011 and are awaiting surface facilities. The remaining two wells are scheduled for fracturing in the fourth quarter of 2011. A 3-dimensional ("3-D") seismic survey is progressing which will provide increased 3-D coverage over Husky's land holdings at Oungre.

In the third quarter of 2011, Husky commenced operations on its northern Cardium oil resource project. To date, three horizontal wells have been drilled at Wapiti as part of a four well pilot program. The first well of a four well pilot program at Kakwa was drilled during the third quarter. Husky holds 29,000 acres (44 sections) of prospective acreage along this productive trend.

In the southwestern Saskatchewan Viking oil resource project, a five-well horizontal program was conducted in the first half of 2011. The fall drilling program was initiated in late September 2011. The first well was drilled and cased with an additional 11 wells planned for the fourth quarter.

An eight well horizontal program was conducted at the Redwater Alberta Viking oil resource project during the first half of 2011. In the third quarter, an additional six wells were drilled with four additional wells scheduled for the fourth quarter.

Husky has participated in five gross wells in 2011 in the emerging Shaunavon oil resource play. One well was abandoned due to surface casing issues. The four remaining wells were completed in the third quarter and are undergoing post-fracture clean up with evaluations underway.

Northwest Territories

On July 4, 2011, Husky was granted the rights to two exploration blocks in the Mackenzie Valley area of the Northwest Territories covering 437,000 acres for a work commitment bid of $188 million per license. Husky will assess the hydrocarbon potential of the lands over a term of five years with a potential term extension to nine years.

Alkaline Surfactant Polymer Floods

At Fosterton, the first 18 of 30 planned wells were drilled during the third quarter of 2011. Pipeline construction is underway and site preparation was completed on schedule. Site construction is expected to commence in the fourth quarter of 2011 with polymer injection planned for mid-2012.

4.2 Midstream

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

4.3 Downstream

Lima, Ohio Refinery

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

Toledo, Ohio Refinery

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

5. Results of Operations

5.1 Upstream

Upstream Net Earnings Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2011**	2010	**2011**	2010
Gross revenues	**$ 1,715**	$ 1,385	**$ 5,266**	$ 4,257
Royalties	**247**	233	**794**	767
Net revenues	**1,468**	1,152	**4,472**	3,490
Operating, transportation and administration expenses	**486**	398	**1,421**	1,176
Exploration and evaluation expenses	**95**	25	**276**	205
Depletion, depreciation and amortization	**494**	408	**1,406**	1,115
Other (income) expense	**(2)**	(1)	**(265)**	3
Income taxes	**85**	93	**425**	287
Net earnings	**$ 310**	$ 229	**$ 1,209**	$ 704

Third Quarter

Upstream net earnings in the third quarter of 2011 increased by $81 million compared with the third quarter of 2010 primarily as a result of increased crude oil and natural gas production and higher realized crude oil and natural gas prices, partially offset by higher exploration and evaluation expenses, operating expenses and depletion, depreciation and amortization.

Production increased by 20.4 mboe/day due to higher production from North Amethyst and acquisitions in the fourth quarter of 2010 and the first quarter of 2011, partially offset by the impacts of the Plains Rainbow pipeline outages which decreased average crude oil production over the third quarter by approximately 6 mbbls/day. The pipeline was brought back online in early September.

The average realized price in the third quarter of 2011 increased to $77.95/bbl for crude oil, NGL and bitumen compared with $64.28/bbl during the same period in 2010. Realized natural gas prices averaged $3.64/mcf in the third quarter of 2011 compared with $3.50/mcf in the same period in 2010. Production in the Atlantic Region and Wenchang benefited from higher realized prices as the price of Brent increased by approximately 48% compared with the third quarter of 2010, while WTI increased by approximately 18%.

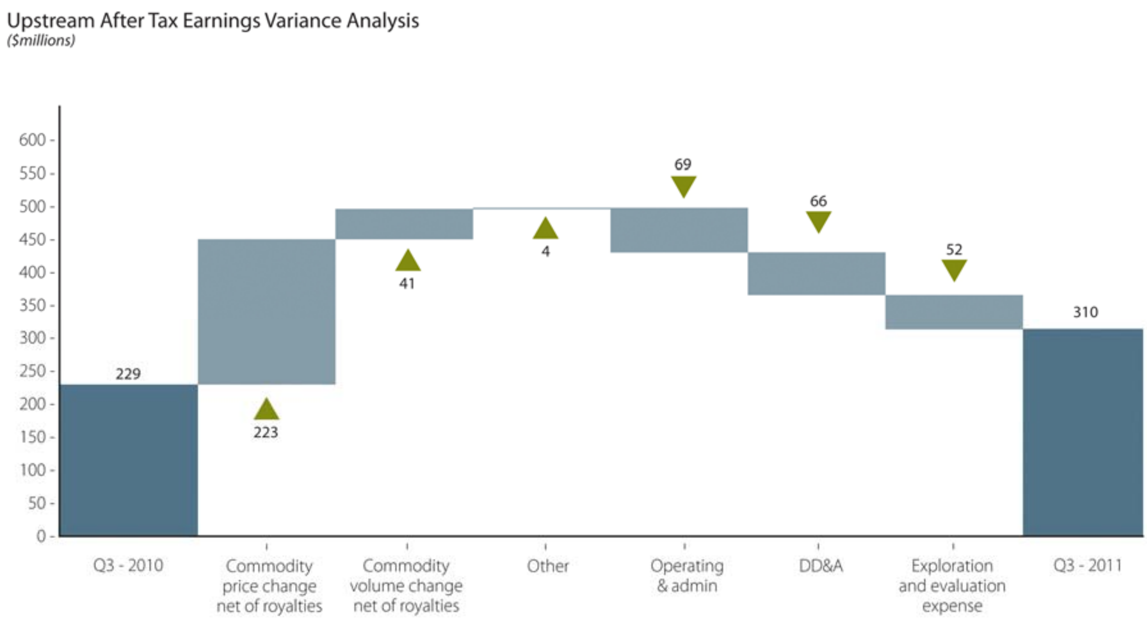
Nine Months

Upstream net earnings in the first nine months of 2011 were $505 million higher compared with the same period in 2010. In addition to the same factors impacting the third quarter, Husky realized a pre-tax gain of $177 million on the sale of oil sands mining leases and a pre-tax gain of $68 million on a property swap deal in the first half of 2011.

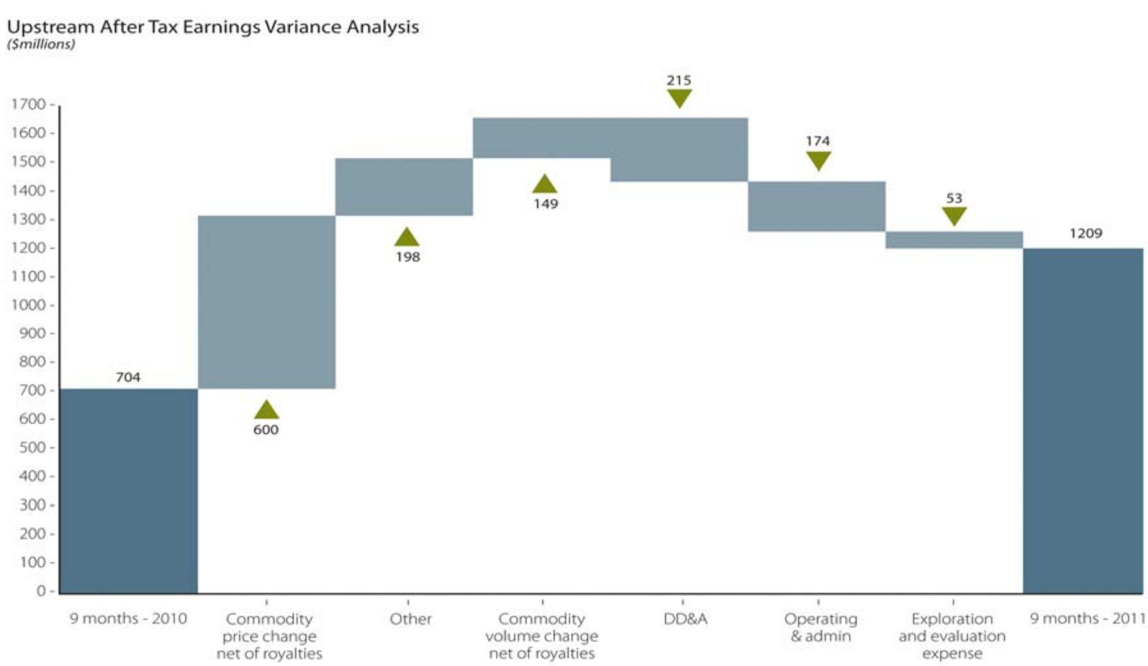
During the first nine months of 2011, average realized prices increased 22% to $80.51/bbl for crude oil, NGL and bitumen combined compared with $65.98/bbl during the same period in 2010 while average realized natural gas prices decreased to $3.66/mcf during the first nine months of 2011 compared to $3.89/mcf in the same period in 2010.

Upstream After Tax Variance Analysis

Third Quarter



Nine Months



Pricing

Average Sales Prices Realized		Three months ended Sept. 30		Nine months ended Sept. 30	
		2011	2010	**2011**	2010
Crude oil	*($/bbl)*				
Light crude oil & NGL		**$ 100.44**	$ 73.88	**$ 102.28**	$ 75.05
Medium crude oil		**70.11**	60.88	**72.76**	64.65
Heavy crude oil		**61.61**	56.96	**64.02**	58.94
Bitumen		**58.70**	55.41	**60.88**	57.38
Total average		**77.95**	64.28	**80.51**	65.98
Natural gas average	*($/mcf)*	**3.64**	3.50	**3.66**	3.89
Total average	*($/boe)*	**60.01**	51.95	**61.74**	53.79

The price realized for light crude oil reflects increases in WTI and the significant premium realized for offshore production referenced to Brent prices. In Western Canada, heavy oil differentials widened due to continued non-operated pipeline capacity restraints. Western Canada light and synthetic oils were trading at a higher premium to WTI compared to 2010. The increased U.S. dollar crude oil prices were partially offset by the strengthening of the Canadian dollar against the U.S. dollar in 2011 compared to 2010.

Oil and Gas Production

Daily Gross Production		Three months ended Sept. 30		Nine months ended Sept. 30	
		2011	2010	**2011**	2010
Crude oil & NGL	*(mbbls/day)*				
Western Canada					
Light crude oil & NGL		**22.9**	23.5	**23.5**	23.2
Medium crude oil		**24.6**	25.7	**24.6**	25.4
Heavy crude oil		**75.1**	72.4	**74.0**	74.4
Bitumen		**23.6**	21.9	**23.8**	22.0
		146.2	143.5	**145.9**	145.0
Atlantic Region					
White Rose and Satellite Fields - light crude oil		**46.8**	44.4	**48.3**	39.5
Terra Nova - light crude oil		**6.6**	6.4	**5.8**	9.0
China					
Wenchang - light crude oil & NGL		**7.0**	10.1	**8.6**	10.7
Total crude oil & NGL		**206.6**	204.4	**208.6**	204.2
Natural gas	*(mmcf/day)*	**614.7**	505.5	**610.1**	511.0
Total	*(mboe/day)*	**309.1**	288.7	**310.3**	289.4

Crude Oil and NGL Production

Third Quarter

Crude oil and NGL production in the third quarter of 2011 increased by 2.2 mbbls/day or 1% compared with the same period in 2010. The increase was primarily due to higher production from the North Amethyst field, partially offset by the impacts of the Plains Rainbow pipeline outages and decreased production at White Rose and Wenchang due to natural reservoir decline.

Nine Months

In the first nine months of 2011, crude oil and NGL production increased by 2% compared with the same period in 2010, primarily due to the same factors impacting the third quarter and operational issues at Terra Nova.

Natural Gas Production

Natural gas production increased by 109.2 mmcf/day or 22% in the third quarter of 2011 compared with the third quarter of 2010 due to the acquisitions of properties in Western Canada during the fourth quarter of 2010 and first quarter of 2011, partially offset by natural reservoir declines in mature properties as capital investment has been focused on higher return projects.

2011 Production Guidance			Actual Production	
		Guidance	**Nine months ended Sept. 30 2011**	Year ended Dec. 31 2010
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		75 – 80	**85**	81
Medium crude oil		25 – 30	**25**	25
Heavy crude oil & bitumen		95 – 105	**98**	97
		195 – 215	**208**	203
Natural gas	*(mmcf/day)*	560 – 610	**610**	507
Natural gas	*(mboe/day)*	93 – 102	**102**	84
Total barrels of oil equivalent	*(mboe/day)*	290 – 315	**310**	287

Royalties

Third Quarter

In the third quarter of 2011, royalty rates averaged 14% as a percentage of gross revenue compared with 17% in 2010. Royalty rates in Western Canada averaged 13% compared to 15% in the same period in 2010. Rates for the Atlantic Region averaged 15% in the third quarter of 2011 down from 21% in the third quarter of 2010 due to the North Amethyst field which is subject to a basic royalty of 1%, while Terra Nova and White Rose, being mature fields, are subject to higher rates. Rates at North Amethyst will increase and reach the same level as White Rose after certain project payouts as prescribed in the royalty regulations are met. Royalty rates in Wenchang averaged 29% in the third quarter of 2011 compared with 22% in the third quarter of 2010 due to price increases combined with a sliding scale price sensitive rate.

Nine Months

Royalty rates averaged 15% of gross revenue in the first nine months of 2011 compared with 18% in the same period in 2010. Rates in Western Canada averaged 13% compared with 15% in 2010 and for the Atlantic Region the average rate was 16% compared with 25% in the same period in 2010. Royalty rates in Wenchang averaged 29% in the first nine months of 2011 compared with 22% in the same period in 2010. The change in rates for the first nine months of 2011 was due to the same factors impacting the third quarter.

Operating Costs

(millions of dollars)	Three months ended Sept. 30 2011	Three months ended Sept. 30 2010	Nine months ended Sept. 30 2011	Nine months ended Sept. 30 2010
Western Canada	$ 376	$ 296	$ 1,079	$ 889
Atlantic Region	48	49	131	133
International	7	7	18	17
Total	$ 431	$ 352	$ 1,228	$ 1,039
Unit operating costs ($/boe)	$ 15.17	$ 13.27	$ 14.50	$ 13.17

Third Quarter

Total Upstream operating costs in the third quarter of 2011 increased to $431 million from $352 million in the third quarter of 2010 as a result of increased natural gas and electrical costs combined with treating, servicing and maintenance costs that were impacted by acquisitions in the fourth quarter of 2010 and the first quarter of 2011. Total Upstream unit operating costs in the third quarter of 2011 averaged $15.17/boe compared with $13.27/boe in the third quarter of 2010.

Operating costs in Western Canada averaged $16.45/boe in the third quarter of 2011 compared with $14.14/boe in the same period in 2010. The impact of higher operating costs in 2011 was partially offset by the effect of an increase in production volumes. Acquisitions in the fourth quarter of 2010 and the first quarter of 2011 increased natural gas, propane and electrical consumption along with increased costs associated with custom processing, servicing and labour when compared to the third quarter of 2010. Higher handling costs of produced fluids resulted from increased water and emulsion production in the third quarter of 2011. Maturing fields in Western Canada require more extensive infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive gathering systems, crude and water trucking and more complex natural gas compression systems. Husky is focused on managing operating costs associated with the increased infrastructure through cost reduction and efficiency initiatives and by fully utilizing infrastructures in place.

Operating costs in the Atlantic Region averaged $9.82/boe in the third quarter of 2011 compared with $10.48/boe in 2010. The decrease was as a result of increased production from North Amethyst in the third quarter of 2011 compared with the third quarter of 2010.

Operating costs at the South China Sea offshore operations averaged $10.41/bbl in the third quarter of 2011 compared with $7.69/bbl in the same period in 2010. This increase was the result of lower production, partially offset by lower maintenance costs in the third quarter of 2011 compared with the same period in 2010.

Nine Months

Total Upstream operating costs in the first nine months of 2011 increased compared with the same period in 2010 primarily due to the same factors affecting the third quarter costs.

Exploration and Evaluation Expense

Exploration and Evaluation Expense Summary

(millions of dollars)	Three months ended Sept. 30 2011	Three months ended Sept. 30 2010	Nine months ended Sept. 30 2011	Nine months ended Sept. 30 2010
Seismic	$ 2	$ 7	$ 39	$ 60
Expensed drilling	61	1	121	98
Expensed land	10	-	53	-
Other	22	17	63	47
Total	$ 95	$ 25	$ 276	$ 205

Third Quarter

Exploration and evaluation expenses for the third quarter of 2011 were $95 million compared with $25 million in the third quarter of 2010 primarily due to higher expensed drilling, partially offset by lower seismic costs. Expensed drilling costs in the third quarter of 2011 relate to wells drilled in Canada which did not encounter economic quantities of oil and gas.

Nine Months

Exploration and evaluation expenses for the first nine months of 2011 were $276 million compared to $205 million during the same period of 2010. Land costs of $43 million relating to previous years' acquisition costs for properties in the Columbia River Basin located in the states of Washington and Oregon were expensed in the second quarter of 2011.

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

Third Quarter

In the third quarter of 2011, total DD&A averaged $17.41/boe compared with $15.43/boe in the third quarter of 2010. The increased DD&A rate in the third quarter of 2011 was primarily due to higher production from the North Amethyst offshore project.

Nine Months

For the first nine months of 2011, total DD&A averaged $16.60/boe compared with $14.14/boe during the same period in 2010 due to the same factors affecting the third quarter.

Upstream Capital Expenditures

Capital Expenditures Summary [1]	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2011**	2010	**2011**	2010
Exploration				
Western Canada	**$ 19**	$ 134	**$ 146**	$ 281
Atlantic Region	**2**	-	**2**	61
International	**79**	7	**131**	164
	100	141	**279**	506
Development				
Western Canada	**541**	275	**1,316**	772
Atlantic Region	**62**	115	**197**	304
International	**150**	2	**320**	3
	753	392	**1,833**	1,079
Acquisitions				
Western Canada	**-**	62	**860**	75
	$ 853	$ 595	**$ 2,972**	$ 1,660

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

In the first nine months of 2011, Upstream capital expenditures were $2,972 million. Capital expenditures were $451 million (15%) in the Asia Pacific Region, $199 million (7%) in the Atlantic Region and $2,322 million (78%) in Western Canada including acquisitions of $860 million. Husky's major projects remain on budget and schedule.

Western Canada

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

Western Canada (including Heavy Oil and Oil Sands) Wells Drilled		Three months ended Sept. 30				Nine months ended Sept. 30			
		2011		2010		**2011**		2010	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**13**	**8**	18	17	**30**	**21**	45	39
	Gas	**3**	**3**	8	6	**13**	**13**	26	22
	Dry	**-**	**-**	1	1	**3**	**3**	8	8
		16	**11**	27	24	**46**	**37**	79	69
Development	Oil	**343**	**286**	267	235	**652**	**569**	532	465
	Gas	**14**	**8**	12	6	**50**	**38**	27	15
	Dry	**2**	**2**	2	2	**4**	**3**	8	7
		359	**296**	281	243	**706**	**610**	567	487
Total		**375**	**307**	308	267	**752**	**647**	646	556

During the first nine months of 2011, Husky invested $2,322 million on exploration, development and acquisitions throughout the Western Canada Sedimentary Basin compared with $1,128 million in the first nine months of 2010. Property acquisitions of $860 million were completed during the first nine months of 2011, primarily in the Rainbow Lake area of northwestern Alberta, the Foothills and Deep Basin areas of Alberta and in northeastern British Columbia.

In addition, $377 million was invested in oil related exploration and development and $230 million was invested in natural gas related exploration and development compared with $519 million for oil related exploration and development and $267 million for natural gas related exploration and development in the first nine months of 2010.

During the first nine months of 2011, capital expenditures on heavy oil projects were $396 million for thermal projects, CHOPS drilling, and horizontal drilling as compared to $421 million in the same period in 2010.

During the first nine months of 2011, capital expenditures on Oil Sands projects were $182 million compared with $59 million in the same period in 2010 as Sunrise Phase I progresses.

In addition, $122 million was spent on production optimization and cost reduction initiatives in the first nine months of 2011. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $155 million.

The Company drilled 647 net wells in the Western Canada Sedimentary Basin in the first nine months of 2011 resulting in 590 net oil wells and 51 net natural gas wells compared with 556 net wells resulting in 504 net oil wells and 37 net natural gas wells in the first nine months of 2010. Capital expenditures for wells drilled in Western Canada have increased substantially due to the larger numbers of horizontal wells drilled and more multi-stage fracture completions performed compared with 2010.

Atlantic Region

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

Offshore Atlantic Region Drilling Activity			
North Amethyst G-25-5	WI 68.875%	Water injection	Development
North Amethyst G-25-6	WI 68.875%	Production	Development
White Rose E-18-10 (West pilot)	WI 68.875%	Production	Development
Mizzen F-09	WI 35%	Exploratory	Exploratory

During the first nine months of 2011, $197 million was invested in Atlantic Region development projects, primarily drilling of water injection and production wells in North Amethyst. One exploration well was drilled in the Atlantic Region in the first nine months of 2011 in the Flemish Pass Basin.

International

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

International Offshore Drilling Activity			
Asia Pacific Region - China			
Liuhua 29-1-4 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liuhua 29-1-5 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liuhua 32-1-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 5-1-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 4-3-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
YC 5-1-1 Block 63/05	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 3-1-5 Block 29/26	WI 49%	Production	Development
Liwan 3-1-6 Block 29/26	WI 49%	Production	Development
Liwan 3-1-7 Block 29/26	WI 49%	Production	Development
Liwan 3-1-8 Block 29/26	WI 49%	Production	Development
Wenchang 13-2-A4h1 side track	WI 40%	Production	Development
Asia Pacific Region - Indonesia			
MDA-4 Madura Strait	WI 40%	Stratigraphic test	Exploratory
MBH-1 Madura Strait	WI 40%	Stratigraphic test	Exploratory

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

During the first nine months of 2011, $451 million was spent primarily on offshore projects in China and Indonesia.

Upstream Planned Turnarounds

A scheduled 16-day turnaround of the *SeaRose FPSO* was reduced to two days and was completed in early July 2011. Husky will proceed with an offstation for the *SeaRose FPSO* propulsion system in the second quarter of 2012 which is expected to last approximately 125 days. Production from the White Rose, North Amethyst, and West White Rose fields will be shut-in during the offstation maintenance. The impact to Husky's production, averaged over the entire year, is forecasted to be approximately 12,000 bbls/day.

A 28-day turnaround of the *Terra Nova FPSO* operated by Suncor was rescheduled from September 2011 to October 2011. The turnaround commenced in mid-October with expected completion during the fourth quarter. The originally scheduled 15 week dockside maintenance for the *Terra Nova FPSO* in July has been deferred to 2012.

5.2 Midstream

Infrastructure and Marketing Net Earnings Summary			Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)			**2011**	2010	**2011**	2010
Gross revenues			**$ 2,228**	$ 1,704	**$ 7,010**	$ 5,302
Gross margin	- pipeline		**$ 37**	$ 24	**$ 110**	$ 93
	- other infrastructure and marketing		**38**	18	**180**	122
			75	42	**290**	215
Operating and administration expenses			**7**	5	**19**	15
Depreciation and amortization			**9**	10	**29**	30
Other expense (income)			**(16)**	(8)	**4**	14
Income taxes			**19**	10	**60**	42
Net earnings			**$ 56**	$ 25	**$ 178**	$ 114
Selected operating data:						
Commodity volumes managed		*(mboe/day)*	**944**	886	**1,021**	929
Aggregate pipeline throughput		*(mbbls/day)*	**534**	489	**561**	516

Third Quarter

Infrastructure and Marketing net earnings in the third quarter of 2011 were $56 million compared with $25 million in the third quarter of 2010. The increase in net earnings was primarily due to higher pipeline throughputs and marketed volumes and trading gains captured on light and synthetic crude oil moving from Canada to the U.S. as a result of the widening WTI to Brent differential, partially offset by lower natural gas storage earnings.

Nine Months

During the first nine months of 2011, Infrastructure and Marketing net earnings were $64 million higher than the same period of 2010 primarily due to the same factors that affected the third quarter of 2011.

Other expenses, which include the fair value impact of the Company's commodity price risk management activities (refer to Section 7.5), decreased by $10 million in the first nine months of 2011 compared with the same period in 2010.

Midstream Capital Expenditures

In the first nine months of 2011, Midstream capital expenditures totalled $29 million compared to $25 million in the same period in 2010.

5.3 Downstream

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

Upgrading Net Earnings Summary

(millions of dollars, except where indicated)		Three months ended Sept. 30 2011	Three months ended Sept. 30 2010	Nine months ended Sept. 30 2011	Nine months ended Sept. 30 2010
Gross revenues		$ 585	$ 291	$ 1,602	$ 1,204
Gross margin		$ 195	$ 50	$ 484	$ 234
Operating and administration expenses		47	44	151	138
Depreciation and amortization		27	26	139	39
Other expense (income)		20	(1)	48	(5)
Income taxes		26	(5)	38	18
Net earnings (loss)		$ 75	$ (14)	$ 108	$ 44
Selected operating data:					
Upgrader throughput [1]	*(mbbls/day)*	75.6	13.5	67.4	60.5
Synthetic crude oil sales	*(mbbls/day)*	60.7	21.0	54.3	49.0
Upgrading differential	*($/bbl)*	$ 29.87	$ 13.80	$ 28.97	$ 14.01
Unit margin	*($/bbl)*	$ 34.92	$ 25.72	$ 32.65	$ 17.47
Unit operating cost [2]	*($/bbl)*	$ 9.46	$ 18.02	$ 10.32	$ 8.37

[1] *Throughput includes diluent returned to the field.*
[2] *Based on throughput.*

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

Third Quarter

Upgrading net earnings in the third quarter of 2011 were $75 million compared with a loss of $14 million in the same period in 2010. The increase was primarily due to higher realized differentials and higher production due to a 53-day turnaround in the third and fourth quarters of 2010. During the third quarter of 2011, the upgrading differential averaged $29.87/bbl, an increase of $16.07/bbl or 116% compared with the third quarter of 2010. The differential is equal to Husky Synthetic Blend, which sells at a premium to WTI, less Lloyd Heavy Blend. The average price for Husky Synthetic Blend in the third quarter of 2011 was $98.09/bbl compared to $77.91/bbl in the same period in 2010. The overall unit margin increased to $34.92/bbl in the third quarter of 2011 from $25.72/bbl in the same period in 2010 primarily as a result of wider heavy to light crude oil price differentials. The increase in other expenses is due to the increase in the fair value of the remaining upside interest payment obligation to Natural Resources Canada and the Alberta Department of Energy as a result of higher upgrading differentials.

Nine Months

Upgrading earnings for the first nine months of 2011 were affected by the same factors impacting the third quarter, in addition to a minor fire at the Lloydminster Upgrader in early February which resulted in a reduction in average throughput at the Upgrader to 53.2 mbbls/day in the first quarter of 2011. The increase in depreciation and amortization was due to turnaround costs from the fall of 2010 which were depreciated starting in the fourth quarter of 2010, and the derecognition of certain intangible costs. Increased operating and administration expenses were primarily due to costs associated with the minor fire at the Lloydminster Upgrader.

Canadian Refined Products Net Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2011**	2010	**2011**	2010
Gross revenues		**$ 1,162**	$ 834	**$ 2,922**	$ 2,140
Gross margin	- fuel	**$ 36**	$ 21	**$ 108**	$ 48
	- refining	**14**	13	**67**	47
	- asphalt	**107**	87	**162**	126
	- ancillary	**14**	12	**38**	35
		171	133	**375**	256
Operating and administration expenses		**26**	40	**84**	86
Depreciation and amortization		**23**	22	**60**	71
Income taxes		**32**	18	**59**	26
Net earnings		**$ 90**	$ 53	**$ 172**	$ 73
Selected operating data:					
Number of fuel outlets (average)		**544**	523	**547**	494
Light oil sales	*(million litres/day)*	**9.9**	8.5	**9.5**	8.0
Light oil retail sales per outlet	*(thousand litres/day)*	**18.3**	14.2	**17.4**	13.8
Prince George Refinery throughput	*(mbbls/day)*	**7.9**	11.9	**9.2**	9.5
Asphalt sales	*(mbbls/day)*	**36.4**	30.9	**25.8**	20.3
Lloydminster Refinery throughput	*(mbbls/day)*	**28.5**	28.9	**27.8**	27.3
Ethanol production	*(thousand litres/day)*	**652.5**	519.1	**697.6**	595.0

Third Quarter

Gross margins on fuel sales were higher in the third quarter of 2011 compared with 2010 as a result of higher retail and wholesale market prices combined with increased volumes due to the purchase of 97 retail stations in 2010.

Higher refining gross margins in the third quarter of 2011 were primarily due to higher market crack spreads, higher total ethanol production from a successful recycle thermal oxidiser installation at the Lloydminster Ethanol Plant and higher realized prices for gasoline, diesel and ethanol, partially offset by lower production at the Prince George Refinery and Minnedosa Ethanol Plant due to turnaround activity.

Included in refining gross margins in the third quarter of 2011 and 2010 are government assistance grants of $10 million and $9 million, respectively.

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

Nine Months

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

U.S. Refining and Marketing Net Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2011**	2010	**2011**	2010
Gross revenues		**$ 2,413**	$ 1,683	**$ 7,222**	$ 5,283
Gross refining margin		**$ 286**	$ 146	**$ 1,010**	$ 366
Operating and administration expenses		**110**	96	**296**	290
Interest - net		**-**	1	**1**	2
Depreciation and amortization		**48**	47	**143**	140
Income taxes (recoveries)		**47**	1	**208**	(24)
Net earnings (loss)		**$ 81**	$ 1	**$ 362**	$ (42)
Selected operating data:					
Lima Refinery throughput	*(mbbls/day)*	**136.8**	140.8	**144.7**	144.3
Toledo Refinery throughput	*(mbbls/day)*	**60.8**	54.6	**63.5**	64.3
Realized refining margin	*(U.S. $/bbl crude throughput)*	**$ 16.13**	$ 7.77	**$ 18.55**	$ 6.22
Refinery feedstocks and refined products inventory	*(mmbbls)*	**12.5**	12.8	**12.5**	12.8

Third Quarter

U.S. Refining and Marketing net earnings increased significantly in the third quarter of 2011 compared with the third quarter of 2010 as a result of higher realized refining margins. In addition to increased market crack spreads, feedstock at the Toledo Refinery was approximately half heavy crude oil which added to increased margins as differentials between heavy and light crude oil remained high in the third quarter of 2011. This was partially offset by consumption of Lima feedstock of which over half is based on the price of Brent, crude supply constraints due to the Enbridge pipeline construction, and planned maintenance at the Toledo Refinery.

The Chicago crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter when crude oil prices were higher.

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

On June 27, 2011, a controlled shutdown of the crude unit furnace was initiated at the Lima Refinery which lasted for nine days. On September 10, 2011, a 20-day planned isocracker outage was initiated at the Lima Refinery to replace the reactor catalyst. The Lima Refinery continued to be operational at 85% capacity and the impact of the outages is reflected in third quarter results.

Nine Months

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

Downstream Capital Expenditures

In the first nine months of 2011, Downstream capital expenditures totalled $248 million compared with $436 million in the same period of 2010.

In Canada, capital expenditures were $96 million related to upgrades at the Prince George Refinery, the Upgrader and retail stations.

In the United States, capital expenditures totalled $152 million. At the Lima Refinery, $84 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled $68 million (Husky's 50% share) primarily for engineering work and procurement on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

Husky commenced a minor turnaround primarily for inspection and equipment maintenance at the Lloydminster Upgrader in September which was completed in October 2011. The Upgrader was operating at approximately 80% capacity during this turnaround. A minor outage is scheduled for March 2012 to expedite hydrogen plant repairs and catalyst change out. The next major turnaround is scheduled to commence in the fall of 2013.

The Lloydminster Refinery has a major turnaround scheduled in the spring of 2013. The refinery is expected to be shutdown for 21 days during the turnaround for inspections and equipment repair. Two minor turnarounds commenced at the Prince George Refinery during the third quarter and will be completed by year end.

The Toledo Refinery will have two minor turnarounds in the fourth quarter of 2011 which are scheduled to last approximately 14 days and 25 days during which time throughput will be reduced to 93% of normal levels. The next minor turnaround is scheduled to occur in mid-2012 and the partial outage is expected to last approximately 21 days.

The Lima Refinery will have a 15-day Diesel Hydrotreater outage in the third quarter of 2012 to replace the catalyst. In addition, there will be a 29-day aromatics turnaround in the fourth quarter of 2012. Neither of the planned outages is expected to have a material impact on crude throughputs.

5.4 Corporate

Corporate Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars) income (expense)	**2011**	2010	**2011**	2010
Intersegment eliminations - net	**$ 47**	$ -	**$ 32**	$ 14
Administration expense	**(56)**	(18)	**(151)**	(46)
Other income (expense)	**(6)**	6	**(5)**	4
Stock-based compensation	**5**	1	**8**	19
Exploration and evaluation expenses	**-**	-	**-**	(3)
Depreciation and amortization	**(10)**	(19)	**(26)**	(56)
Interest - net	**(29)**	(43)	**(119)**	(128)
Foreign exchange	**6**	11	**25**	27
Income taxes	**(48)**	29	**23**	84
Net loss	**$ (91)**	$ (33)	**$ (213)**	$ (85)

Third Quarter

The Corporate segment reported a loss of $91 million in the third quarter of 2011 compared with a loss of $33 million in the third quarter of 2010. Stock-based compensation expense was a recovery of $5 million in the third quarter of 2011 due to a decrease in the share price during the quarter. Foreign exchange was a gain of $6 million during the third quarter of 2011 compared with a gain of $11 million in the same period of 2010. Administration expense increased by $38 million in the third quarter of 2011 compared with the third quarter of 2010 due to increased administration costs on financing projects and other initiatives. Intersegment eliminations are net earnings included in inventory that has not been sold to third parties at the end of the period.

Nine Months

In the first nine months of 2011, the Corporate segment reported a loss of $213 million compared with a loss of $85 million in the same period of 2010 due to the same factors affecting the third quarter.

Foreign Exchange Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)	**2011**	2010	**2011**	2010
(Gains) losses on translation of U.S. dollar denominated long-term debt	**$ 155**	$ (64)	**$ 92**	$ (35)
(Gains) losses on cross currency swaps	**(27)**	11	**(16)**	6
(Gains) losses on contribution receivable	**(94)**	39	**(59)**	21
Other (gains) losses	**(40)**	3	**(42)**	(19)
Foreign exchange gains	**$ (6)**	$ (11)	**$ (25)**	$ (27)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $1.037**	U.S. $0.943	**U.S. $1.005**	U.S. $0.956
At end of period	**U.S. $0.963**	U.S. $0.971	**U.S. $0.963**	U.S. $0.971

Included in other foreign exchange (gains) losses are realized foreign exchange and unrealized foreign exchange (gains) losses on working capital and intercompany financing. The foreign exchange (gains) losses on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period.

Corporate Capital Expenditures

In the first nine months of 2011, Corporate capital expenditures of $37 million were primarily for computer hardware and software and construction of a new building in Lloydminster.

Consolidated Income Taxes

During the third quarter of 2011, consolidated income tax expense was $257 million compared with $88 million in the same period in 2010. Cash taxes paid in the first nine months of 2011 were $242 million compared with $748 million in the first nine months of 2010, of which $50 million related to instalments paid in respect of 2010 net earnings, $48 million related to 2011 earnings and $144 million related to prior period payments. Further 2011 cash tax instalments are estimated to be approximately $23 million, $8 million in respect of 2010 earnings and $15 million in respect of 2011 earnings.

6. Liquidity and Capital Resources

In the third quarter of 2011, Husky funded its capital programs, including acquisitions and dividend payments, by cash generated from operating activities and cash on hand. At September 30, 2011, Husky had total debt of $3,990 million partially offset by cash on hand of $1,772 million for $2,218 million of net debt compared to $3,935 million of net debt at December 31, 2010. At September 30, 2011, the Company had $3.2 billion in unused committed credit facilities, $98 million in unused short-term uncommitted credit facilities, unused capacity under the debt shelf prospectus filed in Canada of $300 million, unused capacity under the November 2010 universal short form base shelf prospectus filed in Canada of $1.4 billion, and unused capacity under the June 2011 U.S. base shelf prospectus of U.S. $2.0 billion. The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions. (Refer to Section 6.4).

Cash Flow Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except ratios)		**2011**	2010	**2011**	2010
Cash flow	- operating activities	**$ 1,323**	$ 726	**$ 4,057**	$ 1,728
	- financing activities	**$ (197)**	$ (77)	**$ 451**	$ 135
	- investing activities	**$ (738)**	$ (730)	**$ (2,989)**	$ (2,231)
Financial Ratios [(5)]					
Debt to capital employed *(percent)*				**18.6**	22.0
Debt to cash flow *(times)* [(1)]				**0.8**	1.3
Corporate reinvestment ratio *(percent)* [(1)(2)]				**115**	107
Interest coverage ratios on long-term debt only [(1)(3)]					
Net earnings				**12.5**	8.0
Cash flow				**21.4**	13.8
Interest coverage ratios on total debt [(1)(4)]					
Net earnings				**12.1**	8.0
Cash flow				**20.6**	13.7

(1) *Calculated for the 12 months ended for the dates shown*
(2) *Reinvestment ratio is based on net capital expenditures including corporate acquisitions.*
(3) *Interest coverage on long-term debt on a net earnings basis is equal to net earnings before finance expense on long-term debt and income taxes divided by finance expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow - operating activities before finance expense on long-term debt and current income taxes divided by finance expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.*
(4) *Interest coverage on total debt on a net earnings basis is equal to net earnings before finance expense on total debt and income taxes divided by finance expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow - operating activities before finance expense on total debt and current incomes taxes divided by finance expense on total debt and capitalized interest. Total debt includes short and long-term debt.*
(5) *2010 comparative results are reported in accordance with previous Canadian GAAP.*

6.1 Operating Activities

Third Quarter

In the third quarter of 2011, cash generated from operating activities was $1,323 million compared with $726 million in the third quarter of 2010. Higher cash flow from operating activities was primarily due to higher production, higher commodity prices in Upstream and higher realized margins in Canadian and U.S. Downstream.

Nine Months

Cash generated from operating activities was $4,057 million in the first nine months of 2011 compared with $1,728 million in the first nine months of 2010. Higher cash flow from operating activities was primarily due to the same factors impacting the third quarter.

6.2 Financing Activities

Third Quarter

In the third quarter of 2011, cash used in financing activities was primarily payments of cash dividends of $79 million, interest paid of $86 million and cash used in other financing activities of $32 million.

Nine Months

Cash provided by financing activities was $451 million in the first nine months of 2011 compared with $135 million in the first nine months of 2010. In addition to the same factors impacting the third quarter, the Company issued $300 million of preferred shares in the first quarter of 2011 and $1.2 billion of common shares in the second quarter of 2011.

6.3 Investing Activities

Third Quarter

In the third quarter of 2011, cash used in investing activities amounted to $738 million compared with $730 million in the third quarter of 2010. Cash invested in both periods was primarily for expenditures on property, plant and equipment.

Nine Months

Cash used in investing activities for the first nine months of 2011 was $3.0 billion compared with $2.2 billion in the first nine months of 2010. Cash invested in both periods was primarily for acquisitions and capital expenditures.

6.4 Sources of Capital

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

Working capital is the amount by which current assets exceed current liabilities. At September 30, 2011, working capital was $2,369 million compared with $1,181 million at December 31, 2010.

At September 30, 2011, Husky had unused committed long and short-term borrowing credit facilities totalling $3.2 billion. A total of $209 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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

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

On December 21, 2009, Husky filed a debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $1.0 billion of medium-term notes in Canada until January 21, 2012. During the 25-month period that the shelf prospectus is effective, medium-term notes can be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and as set forth in an accompanying pricing supplement. As of September 30, 2011, $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020 had been issued under this shelf prospectus. (Refer to Note 9 to the Condensed Interim Consolidated Financial Statements).

On November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 26, 2012 (the "Canadian Shelf Prospectus"). During the 25-month period that the shelf prospectus is effective, Securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement. On December 7, 2010, Husky issued 11.9 million common shares at a price of $24.50 per share for total gross proceeds of approximately $293 million under the Canadian Shelf Prospectus. Husky also issued 28.9 million common shares to L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. at a price of $24.50 per share for total gross proceeds of approximately $707 million. The common shares issued under the private placements were not issued under the Canadian Shelf Prospectus. The Company received total net proceeds of $988 million from this issuance.

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

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

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

Capital Structure *(millions of dollars)*	September 30, 2011 Outstanding	 Available(1)
Total short-term and long-term debt	$ 3,990	$ 3,306
Common shares, preferred shares, retained earnings and other reserves	$ 17,517	

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

6.5 Contractual Obligations and Commercial Commitments

In the normal course of business, Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable. Refer to Husky's 2010 annual Management's Discussion and Analysis under the caption "Liquidity and Capital Resources," which summarizes contractual obligations and commercial commitments as at December 31, 2010. At September 30, 2011, Husky did not have any additional material contractual obligations and commercial commitments. There were no material changes to commitments noted during the third quarter of 2011.

6.6 Off Balance Sheet Arrangements

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

6.7 Transactions with Related Parties

On May 11, 2009, the Company issued 5 and 10-year senior notes of U.S. $251 million and U.S. $107 million, respectively, to certain management, shareholders, affiliates and directors as part of the U.S. $750 million 5-year and U.S. $750 million 10-year senior notes issued through the existing base shelf prospectus, which was filed with the U.S. Securities and Exchange Commission in February 2009. The coupon rates offered were 5.90% and 7.25% for the 5 and 10-year tranches respectively. Subsequent to this offering, U.S. $122 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. At September 30, 2011, the U.S. $1.5 billion senior notes are included in long-term debt on the Company's balance sheet.

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

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

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

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

The Company continues to sell natural gas and purchase steam from the Meridian cogeneration facility and other cogeneration facilities owned by a related party. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the three and nine months ended September 30, 2011, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by the related party was $25 million and $81 million, respectively. For the three and nine months ended September 30, 2011, the total value of obligated steam purchases from the Meridian and other cogeneration facilities owned by the related party was $2 million and $10 million, respectively.

7. Risks and Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's 2010 Annual Information Form ("AIF") filed on the Canadian Securities Administrator's website, *www.sedar.com*, the Securities and Exchange Commission's website *www.sec.gov*, or Husky's website *www.huskyenergy.com*.

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

7.1 Political Risk

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

7.2 Environmental Risk

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

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

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

The United States Environmental Protection Agency ("EPA") is implementing regulations pertaining to greenhouse gas emissions, which could increase costs of doing business. In particular, the so-called 'Tailoring Rule' now requires sources emitting greater than 100,000 tons per year of greenhouse gases to obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. The Tailoring Rule also can require the installation and operation of expensive pollution control technology as a part of any project that results in a significant greenhouse gas emissions increase. The EPA has promulgated regulations requiring data collection, beginning January 1, 2010, and reporting, beginning September 30, 2011, of greenhouse gas emissions from stationary sources in the oil and gas industry emitting more than 25,000 tons per year of greenhouse gases in carbon dioxide equivalent. This reporting requirement applies to Husky's U.S. operations. The EPA is also required to issue greenhouse gas emission guidelines for existing refineries and new source performance standards for new refineries or modifications to existing refineries by November 10, 2012. These and other EPA regulations regarding greenhouse gas emissions are subject to legislative and judicial challenges, including current Congressional proposals to block or delay the EPA's authority to regulate greenhouse gas emissions. It is not possible to predict the ultimate outcome of these challenges. While these EPA regulations are currently in effect, they have not yet had a material impact on Husky. Husky's operations may, however, be materially impacted by future application of these rules or by future United States greenhouse gas legislation applying to the oil and gas industry or the consumption of petroleum products or by these or any further restrictive regulations issued by the EPA. Such legislation or regulation could require Husky's U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

7.3 Financial Risk

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

7.4 Liquidity Risk

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

Since the Company operates in the Upstream oil and gas industry, it requires sufficient cash to fund capital programs necessary to maintain or increase production and develop reserves, to acquire strategic oil and gas assets, to repay maturing debt and to pay dividends. The Company's Upstream capital programs are funded principally by cash provided from operating activities, share issuance, long-term debt and available committed and uncommitted credit facilities. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of long and short-term capital resources and during the first quarter of 2011, the Company's articles were amended to allow shareholders to accept dividends in cash or common shares. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines.

7.5 Commodity Price Risk Management

Husky uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

At September 30, 2011, the Company had third party physical natural gas purchase and sale derivative contracts and natural gas storage contracts. These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized loss of $1 million and $30 million have been recorded in other expenses in the Consolidated Statements of Income and Comprehensive Income for the three and nine months ended September 30, 2011, respectively. Natural gas inventory held in storage relating to the natural gas storage contracts is recorded at fair value. At September 30, 2011, the fair value of the inventory was $137 million, resulting in an unrealized gain of $7 million and $14 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income for the three and nine months ended September 30, 2011, respectively.

At September 30, 2011, the Company had third party crude oil purchase and sale derivative contracts, which have been designated as a fair value hedge. These contracts have been recorded at their fair value in accrued liabilities and the resulting unrealized loss of $3 million and unrealized gain of less than $1 million have been recorded in purchases of crude oil and products in the Condensed Interim Consolidated Statements of Income for the three and nine months ended September 30, 2011, respectively. The crude oil inventory held in storage is recorded at fair value. At September 30, 2011, the fair value of the inventory was $15 million, resulting in an unrealized gain of $2 million and less than $1 million recorded in purchases of crude oil and products in the Condensed Interim Consolidated Statements of Income for the three and nine months ended September 30, 2011, respectively.

The Company also enters into derivative contracts for future crude oil purchases, whereby there is a requirement to pay the market difference of the inventory price paid at delivery and the current market price at the settlement date in the future. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. As at September 30, 2011, a loss related to these contracts of nil and $7 million was recorded in purchases of crude oil and products in the Condensed Interim Consolidated Statements of Income for the three and nine months ended September 30, 2011, respectively. The Company enters into certain crude oil purchase and sale derivative contracts to minimize its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities. At September 30, 2011, the Company had 2.3 mmbbls of purchase and sale contracts resulting in an unrealized gain of $2 million and $11 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income for the three and nine months ended September 30, 2011, respectively. A portion of the crude oil inventory is sold to third parties. This inventory is measured at fair value. At September 30, 2011, the fair value of the inventory was $228 million, resulting in an unrealized gain of $8 million and $2 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income for the three and nine months ended September 30, 2011, respectively.

During the third quarter of 2011, the Company entered into third party commodity swaps based on the price of butane and crude oil. These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain of $1 million for both the three and nine months ended September 30, 2011 has been recorded in other expenses in the Consolidated Statements of Income and Comprehensive Income.

7.6 Interest Rate Risk Management

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

- U.S. $150 million of long-term debt whereby a fixed interest rate of 5.90% was swapped for rates ranging from LIBOR + 349 bps to LIBOR + 350 bps until June 15, 2014.
- U.S. $200 million of long-term debt whereby a fixed interest rate of 7.55% was swapped for rates ranging from LIBOR + 399 bps to LIBOR + 430 bps until November 15, 2016.
- U.S. $300 million of long-term debt whereby a fixed interest rate of 6.20% was swapped for rates ranging from LIBOR + 255 bps to LIBOR + 275 bps until September 15, 2017.
- Cdn $300 million of long-term debt whereby a fixed interest rate of 3.75% was swapped for rates ranging from CDOR + 0.80% to CDOR + 0.85% until March 12, 2015.

These swaps resulted in an offset to finance expense amounting to $6 million and $17 million for the three and nine months ended September 30, 2011, respectively. The amortization of previous interest rate swap terminations resulted in incremental finance expense of $1 million and $3 million for the three and nine months ended September 30, 2011, respectively.

Cross currency swaps resulted in incremental finance expense of $2 million and $6 million, net of tax, for the three and nine months ended September 30, 2011, respectively.

7.7 Foreign Currency Risk Management

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

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

At September 30, 2011, the cost of a U.S. dollar in Canadian currency was $1.0389.

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 September 30, 2011, 82% or $3.2 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 September 30, 2011, the Company has designated U.S. $987 million of its U.S. debt as a hedge of the Company's net investment in U.S. refining operations, which are considered to have a functional currency of U.S. dollars. During 2011, the unrealized foreign exchange loss arising from the translation of the debt was $63 million and $37 million, net of provisions for income taxes of $10 million and $6 million, which was recorded in Other Comprehensive Income for the three and nine months ended September 30, 2011, respectively.

Including cross currency swaps and the debt that has been designated as a hedge of a net investment, 37% 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 September 30, 2011, 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 U.S. dollar functional currency foreign operation. At September 30, 2011, Husky's share of this obligation was U.S. $1.5 billion including accrued interest.

7.8 Fair Value of Financial Instruments

The derivative portion of cash flow hedges, fair value hedges, and freestanding derivatives that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon the fair value hierarchy in accordance with the International Accounting Standards Board's ("IASB") IFRS 7. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. All of Husky's assets and liabilities that are recorded at fair value on a recurring basis are included in Level 2.

8. Critical Accounting Estimates

Certain of Husky's accounting policies require that it makes appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses.

Depletion Expense

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

Withheld Costs

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

Impairment of Long-Lived Assets

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

Fair Value of Derivative Instruments

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

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

Asset Retirement Obligations ("ARO")

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

Restoration technologies and costs are constantly changing, as are regulatory, political, environment, safety and public relations considerations.

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

Employee Future Benefits

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

Legal, Environmental Remediation and Other Contingent Matters

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

Income Tax Accounting

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

Business Combinations

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

9. Recent Accounting Standards

International Financial Reporting Standards ("IFRS")

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

Presentation of Financial Statements

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

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

Financial Instruments

In November 2009, the IASB published IFRS 9, "Financial Instruments," which covers the classification and measurement of financial assets as part of its project to replace IAS 39, "Financial Instruments: Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through earnings. If this option is elected, entities would be required to reverse the portion of the fair value change due to own credit risk out of earnings and recognize the change in OCI. IFRS 9 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the amendments on January 1, 2013. The adoption of the standard is not expected to have a significant impact to the Company's financial statements.

Consolidated Financial Statements

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

Joint Arrangements

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

Disclosure of Interests in Other Entities

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

Investments in Associates and Joint Ventures

In May 2011, the IASB issued amendments to IAS 28, "Investments in Associates and Joint Ventures," which provides additional guidance applicable to accounting for interests in joint ventures or associates when a portion of an interest is classified as held for sale or when the Company ceases to have joint control or significant influence over an associate or joint venture. When joint control or significant influence over an associate or joint venture ceases, the Company will no longer be required to remeasure the investment at that date. When a portion of an interest in a joint venture or associate is classified as held for sale, the portion not classified as held for sale shall be accounted for using the equity method of accounting until the sale is completed at which time the interest is reassessed for prospective accounting treatment. Amendments to IAS 28 are effective for the Company on

January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt these amendments in its financial statements for the annual period beginning on January 1, 2013. The Company does not expect the amendments to IAS 28 to have a material impact on the financial statements.

Fair Value Measurement

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

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19, "Employee Benefits" to eliminate the corridor method that permits the deferral of actuarial gains and losses, to revise the presentation requirements for changes in defined benefit plan assets and liabilities and to enhance the required disclosures for defined benefit plans. Amendments to IAS 19 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted.

The Company intends to retrospectively adopt these amendments in its financial statements for the annual period beginning on January 1, 2013. The adoption of the amended standard is not expected to have a material impact on the Company's financial statements.

10. Outstanding Share Data

(in thousands)	October 26 2011	December 31 2010
Issued and outstanding		
Number of common shares	**957,537**	890,709
Number of stock options	**34,049**	29,541
Number of stock options exercisable	**18,702**	17,325
Number of preferred shares	**12,000**	-

11. Reader Advisories

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

Readers are encouraged to refer to Husky's 2010 MD&A and Note 24 of the 2010 Consolidated Financial Statements and 2010 AIF filed with Canadian regulatory agencies and the 2010 Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and at www.huskyenergy.com.

Use of Pronouns and Other Terms Denoting Husky

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended September 30, 2011 are compared with results for the three months ended September 30, 2010 and the results for the nine months ended September 30, 2011 are compared with results for the nine months ended September 30, 2010. Discussions with respect to Husky's financial position as at September 30, 2011 are compared with its financial position at December 31, 2010.

Additional Reader Guidance

- The Condensed Interim Consolidated Financial Statements and comparative financial information included in these Condensed Interim Consolidated Financial Statements have been prepared in accordance with IAS 34.
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices quoted include or exclude the effect of hedging as indicated.

Non-GAAP Measures

Disclosure of Cash Flow from Operations

This MD&A contains the term "cash flow from operations," which should not be considered an alternative to, or more meaningful than "cash flow - operating activities" as determined in accordance with IFRS, as an indicator of Husky's financial performance. Cash flow from operations is presented in Husky's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, deferred taxes, foreign exchange and other non-cash items. Husky's determination of cash flow from operations, which is a non-GAAP measure, does not have any standardized meaning prescribed by IFRS and therefore is unlikely to be comparable to similar measures presented by other issuers.

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

		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)		**2011**	2010	**2011**	2010
Non-GAAP	Cash flow from operations	**$ 1,326**	$ 794	**$ 4,001**	$ 2,387
	Settlement of asset retirement obligations	**(15)**	(12)	**(68)**	(34)
	Income taxes paid	**(189)**	(59)	**(242)**	(748)
	Interest received	**4**	-	**4**	1
	Change in non-cash working capital	**197**	3	**362**	122
GAAP	Cash flow – operating activities	**$ 1,323**	$ 726	**$ 4,057**	$ 1,728

Disclosure of Adjusted Net Earnings

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

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

		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)		2011	2010	2011	2010
GAAP	Net earnings	$ 521	$ 261	$ 1,816	$ 808
	Foreign exchange	(4)	(11)	(19)	(21)
	Financial instruments	(12)	(5)	3	9
	Stock-based compensation	(3)	-	(5)	(13)
	Inventory write-downs	1	-	1	21
Non-GAAP	Adjusted net earnings	$ 503	$ 245	$ 1,796	$ 804

Cautionary Note Required by National Instrument 51-101

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

Abbreviations

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

Terms

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

12. Forward-Looking Statements and Information

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

In particular, forward-looking statements in this MD&A include, but are not limited to: the Company's general strategic plans and growth strategies; objectives of the 2011 capital expenditure program; exploration and drilling plans for Block 29/26 and Block 63/05 offshore China; development plans, anticipated rates and timing of production for Liwan 3-1, Liuhua 34-2 and Liuhua 29-1; drilling plans and anticipated timing of production for the Madura Straits Block offshore Indonesia; anticipated timing of submission of the Plan of Development for the MDA field in the Madura Straits Block offshore Indonesia; exploration, development and drilling plans in the Atlantic Region; evaluation, exploration and drilling plans for offshore Greenland; implementation of Phase I plans, anticipated timing of production and development plans for subsequent phases of the Sunrise Energy Project; evaluation and drilling plans for Saleski; development plans and anticipated timing of production for South Pikes Peak; anticipated timing for completion of the Paradise Hill development; plans for evaluation, development, implementation and intended uses of EOR techniques for the Company's heavy oil assets, and anticipated timing of the completion of some of these EOR projects; evaluation, development and drilling plans for the Company's Western Canadian gas resource plays and anticipated timing of and rates of increased production capacity at Ansell; evaluation, drilling and development plans for the Company's Western Canadian oil resource plays; evaluation plans for the Company's exploration block in the Northwest Territotories; development, implementation and timing of ASP floods at Fosterton; anticipated timing of completion of, and intended uses of, the Hardisty storage tank; evaluation, implementation and effect of planned improvements to the Company's Lima and Toledo refineries; anticipated outcomes and timing of implementing a new kerosene hydrotreater at the Lima Refinery; Continuous Catalyst Regeneration Reformer Project plans; 2011 production guidance; scheduled maintenance and turnarounds of FPSO units and the impact to average daily production; and the timing of planned turnarounds at the Company's Lima, Prince George, Toledo and Lloydminster facilities.

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

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

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