

Table of Contents

1. Summary of Quarterly Results
2. Business Environment
3. Capability to Deliver Results and the Strategic Plan
4. Key Growth Highlights
5. Results of Operations
6. Liquidity and Capital Resources
7. Risks and Risk Management
8. Critical Accounting Estimates
9. Accounting Policies
10. Outstanding Share Data
11. Reader Advisories
12. Forward-Looking Statements and Information

1. Summary of Quarterly Results

- Production of 288,700 boe/day, up from 276,200 boe/day in the third quarter of 2009 and 283,900 boe/day in the second quarter of 2010.
- Announced acquisition of natural gas properties in west central Alberta, subject to final closing and regulatory approvals, adding 10.8 mboe/day of production, 37 mmboe of proved reserves and 11.7 mmboe of probable reserves. The reserve estimates are as of June 1, 2010.
- 2010 capital spending program, including acquisitions, increased to \$4.0 billion from \$3.1 billion:
 - o includes an additional \$590 million directed to the development of organic Western Canada Upstream projects.
 - o capital expenditures in the third quarter of 2010 were \$986 million, up from \$517 million in the same period of 2009.
- Completion of second production well at North Amethyst.
- Sunrise Energy Project phase one remains on schedule for sanction in the fourth quarter of 2010.
- Successfully drilled first development well on the Liwan 3-1 field and continued appraisal of the Liuhua 29-1 field.
- Received approval from Government of Indonesia in October 2010 for an extension to the existing Madura Strait Production Sharing Contract ("PSC").
- Cash flow from operations in the quarter increased to \$811 million compared to \$452 million in the same period in 2009.
- Net earnings in the quarter in line with the previous quarter despite Enbridge Line 6A/6B shutdowns and lower compared with the third quarter of 2009 due to:
 - o higher Upstream production and higher average realized crude oil and natural gas prices, offset by;
 - o increased depletion expense in Southeast Asia; and
 - o lower realized natural gas storage profits and commodity trading margins in Midstream; and
 - o the Enbridge Line 6A/6B shutdowns which reduced net earnings by an estimated \$36 million; and
 - o the stronger Canadian dollar in the quarter relative to the U.S. dollar which reduced the benefit of higher benchmark commodity prices year over year.

Quarterly Financial Summary

	Three months ended							
	Sept. 30 2010	June 30 2010	March 31 2010	Dec. 31 2009	Sept. 30 2009	June 30 2009	March 31 2009	Dec. 31 2008
<i>(millions of dollars, except per share amounts)</i>								
Sales and operating revenues, net of royalties	\$ 4,408	\$ 4,568	\$ 4,471	\$ 3,605	\$ 3,903	\$ 3,916	\$ 3,650	\$ 4,701
Net earnings	257	266	345	320	338	430	328	231
Per share - Basic and diluted	0.30	0.31	0.41	0.38	0.40	0.51	0.39	0.27
Cash flow from operations ⁽¹⁾	811	806	895	657	452	833	565	330
Per share - Basic and diluted	0.96	0.95	1.05	0.77	0.53	0.98	0.67	0.39

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

2. Business Environment

Average Benchmarks

		Three months ended					
		Sept. 30 2010	June 30 2010	March 31 2010	Dec. 31 2009	Sept. 30 2009	June 30 2009
WTI crude oil ⁽¹⁾	(U.S. \$/bbl)	76.20	78.03	78.71	76.19	68.30	59.62
Brent crude oil ⁽²⁾	(U.S. \$/bbl)	76.86	78.30	76.24	74.56	68.43	58.79
Canadian light crude 0.3% sulphur	(\$/bbl)	74.77	75.44	80.31	76.75	71.82	66.21
Lloyd heavy crude oil @ Lloydminster	(\$/bbl)	57.29	57.10	65.11	62.66	59.83	56.36
NYMEX natural gas ⁽³⁾	(U.S. \$/mmbtu)	4.38	4.09	5.30	4.17	3.39	3.50
NIT natural gas	(\$/GJ)	3.52	3.66	5.08	4.01	2.87	3.47
WTI/Lloyd crude blend differential	(U.S. \$/bbl)	15.90	14.34	9.29	12.37	10.26	7.72
Chicago 3:2:1 crack spread	(U.S. \$/bbl)	10.16	11.33	6.23	4.92	8.38	10.91
New York Harbor 3:2:1 crack spread	(U.S. \$/bbl)	8.62	10.44	8.21	6.06	8.03	9.05
U.S./Canadian dollar exchange rate	(U.S. \$)	0.962	0.973	0.961	0.947	0.912	0.858
Canadian Equivalents							
WTI crude oil ⁽⁴⁾	(\$/bbl)	79.21	80.20	81.90	80.45	74.89	69.49
Brent crude oil ⁽⁴⁾	(\$/bbl)	79.90	80.47	79.33	78.73	75.03	68.52
WTI/Lloyd crude blend differential ⁽⁴⁾	(\$/bbl)	16.53	14.74	9.67	13.06	11.25	9.00
NYMEX natural gas ⁽⁴⁾	(\$/mmbtu)	4.55	4.20	5.52	4.40	3.72	4.08

⁽¹⁾ Prices quoted are near-month contract prices for settlement during the next month.

⁽²⁾ Dated Brent prices are dated less than 15 days prior to loading for delivery.

⁽³⁾ Prices quoted are average settlement prices for deliveries during the period.

⁽⁴⁾ Prices quoted are calculated using U.S. benchmark commodity prices and U.S./Canadian dollar exchange rates.

Oil and Gas Prices

The price Husky receives for production from Western Canada is primarily driven by changes in the price of West Texas Intermediate ("WTI") while the majority of the Company's production offshore the East Coast of Canada is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI averaged U.S. \$77.65/bbl in the first nine months of 2010 compared with U.S. \$57.00/bbl in the first nine months of 2009, and averaged U.S. \$76.20/bbl in the third quarter of 2010 compared with U.S. \$68.30/bbl in the third quarter of 2009. The price of Brent averaged U.S. \$77.13/bbl in the first nine months of 2010 compared with U.S. \$57.21/bbl in the first nine months of 2009, and averaged U.S. \$76.86/bbl in the third quarter of 2010 compared with U.S. \$68.43/bbl in the third quarter of 2009.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In the first nine months of 2010, 47% of Husky's crude oil production was heavy oil or bitumen compared with 46% in the first nine months of 2009. The light/heavy oil differential averaged U.S. \$13.18/bbl or 17% of WTI in the first nine months of 2010 compared with U.S. \$9.06/bbl or 16% of WTI in the first nine

months of 2009. In the third quarter of 2010, 46% of Husky's crude oil production was heavy oil or bitumen compared with 53% in the third quarter of 2009. The light/heavy crude oil differential averaged U.S. \$15.90/bbl or 21% of WTI in the third quarter of 2010 compared with U.S. \$10.26/bbl or 15% of WTI in the third quarter of 2009.

During the first nine months of 2010, the NYMEX near-month contract price of natural gas averaged U.S. \$4.59/mmbtu compared with U.S. \$3.93/mmbtu in the first nine months of 2009. During the third quarter of 2010, the NYMEX near-month contract price of natural gas averaged U.S. \$4.38/mmbtu compared with U.S. \$3.39/mmbtu in the third quarter of 2009. Natural gas prices continue to reflect higher than average storage levels combined with increasing supply.

Foreign Exchange

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

Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities.

The Canadian dollar ended 2009 at U.S. \$0.956 and closed at U.S. \$0.971 at September 30, 2010. In the first nine months of 2010, the Canadian dollar averaged U.S. \$0.966 strengthening by 12.6% compared with U.S. \$0.858 during the first nine months of 2009. In the third quarter of 2010, the Canadian dollar averaged U.S. \$0.962, strengthening by 6% compared with U.S. \$0.912 during the third quarter of 2009.

Increased U.S. crude oil and natural gas prices have been partially offset by the significant strengthening of the Canadian dollar against the U.S. dollar in the first nine months of 2010. The price of WTI in the first nine months of 2010 in U.S. dollars increased 36% compared with an increase of 13% in Canadian dollars when compared to the first nine months of 2009. In the third quarter of 2010, the price of WTI in U.S. dollars increased 12% compared with 6% in Canadian dollars when compared to the third quarter of 2009.

For an analysis on the relative annual effect of changes in the exchange rate on Husky's pre-tax cash flow and net earnings, refer to the Sensitivity Analysis at the end of Section 2, "Business Environment".

Refining Crack Spreads

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

In the first nine months of 2010, the Chicago 3:2:1 crack spread averaged U.S. \$9.28/bbl compared with U.S. \$9.60/bbl in the first nine months of 2009. During the third quarter of 2010, the Chicago 3:2:1 crack spread averaged U.S. \$10.16/bbl compared with U.S. \$8.38/bbl in the third quarter of 2009. In the first nine months of 2010, the New York Harbor 3:2:1 crack spread averaged U.S. \$9.10/bbl compared with U.S. \$9.08/bbl in the first nine months of 2009. During the third quarter of 2010, the New York Harbor 3:2:1 crack spread averaged U.S. \$8.62/bbl compared with U.S. \$8.03/bbl in the third quarter of 2009.

Husky's realized refining margins are affected by the product configuration of its refineries, transportation costs to benchmark hubs and by the time lag between the

purchase and delivery of crude oil, which is accounted for on a first in first out ("FIFO") basis in accordance with Canadian generally accepted accounting principles ("GAAP").

Cost Environment

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

Enbridge Line 6A/6B Shutdowns

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

The Enbridge Line 6A/6B shutdowns caused a widening in the light/heavy crude oil differential which negatively impacted heavy crude oil realized prices in Upstream and resulted in inventory write downs in Midstream. The shutdowns also reduced throughput at the Toledo Refinery due to limited heavy crude oil availability and increased feed stock costs as heavy oil was partially replaced with light oil where available. The result of the Enbridge Line 6A/6B shutdowns was an approximate \$36 million dollar reduction to Husky's net earnings (\$12 million in Upstream, \$4 million in Midstream, \$20 million in Downstream) in the third quarter of 2010.

Global Economic and Financial Environment

The economic outlook remains substantially unchanged from the previous quarter with Asian countries leading global economic growth. During the third quarter of 2010 WTI spot prices fluctuated between U.S. \$71/bbl and U.S. \$83/bbl and in the first half of October remained above U.S. \$80/bbl on expectations of higher crude oil consumption in China. In the October 13, 2010 Short-term Energy Outlook⁽¹⁾ the Energy Information Administration (“EIA”) revised its 2010 world oil consumption growth to 2.1% over consumption in 2009 in response to higher demand in China and countries in the Organization for Economic Cooperation and Development (“OECD”). The EIA forecasts that world oil consumption will increase in 2011 by 3.7% compared with 2009. The EIA currently estimates that the supply of crude oil will increase by 2.2% in 2010 compared with 2009. OPEC spare productive capacity is expected to average an estimated 5.1 mmbbls/day during 2010 and 5.2 mmbbls/day in 2011. OPEC liquid fuel supply, which is not subject to OPEC’s production policy, is expected to increase in 2010 and again in 2011. At its meeting on October 14, 2010 OPEC agreed to maintain its current production policy and is scheduled to meet again on December 11, 2010. OPEC also announced that it had adopted a new long-term strategy, the substance of which will be made available later in 2010. The EIA estimates that OECD countries held 2.78 billion barrels of commercial oil inventories at the end of the third quarter of 2010. This represents approximately 60 days of forward cover. The EIA expects OECD oil inventories to remain at the upper end of the historical range through 2011.

In the EIA’s October Short-term Energy Outlook, demand for natural gas in the United States markets is expected to increase in 2010 and 2011 compared with 2009. The industrial and electrical generation sectors are expected to account for 89% of the increase in natural gas consumption between 2009 and 2011. The EIA expects consumption of natural gas for electrical generation to decrease in 2011 as nuclear and renewable-based electrical generation increases, partially offset by continued economic recovery and higher consumption in the industrial sector. In its Weekly Natural Gas Storage Report⁽²⁾ released October 14, 2010, the EIA reported that natural gas stocks were 7.4% above the five year average and 3.2% below the previous year.

According to the EIA, gasoline consumption in the United States during the 2010 driving season, which runs from April 1 to September 30, increased by an estimated 2.3% over 2009. During this period, consumption of total liquid fuels was estimated to increase due to higher consumption of gasoline and distillate fuel oil.

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

Note:

⁽¹⁾ *Energy Information Administration, Short-Term Energy Outlook DOE/EIA – October 13, 2010 Release.*

⁽²⁾ *“Weekly Natural Gas Storage Report”, October 14, 2010, Energy Information Administration, U.S. Department of Energy.*

Sensitivity Analysis

The following table indicates the relative annual effect of changes in certain key variables on Husky's pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the third quarter of 2010. Each item in the sensitivity analysis shows the effect of an increase in that variable only; all other

variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis	2010		Effect on Annual		Effect on Annual	
	Third Quarter	Increase	Pre-tax Cash Flow ⁽⁶⁾		Net Earnings ⁽⁶⁾	
	Average		(\$ millions)	(\$/share) ⁽⁷⁾	(\$ millions)	(\$/share) ⁽⁷⁾
Upstream and Midstream						
WTI benchmark crude oil price ⁽¹⁾	\$ 76.20	U.S. \$1.00/bbl	63	0.07	46	0.05
NYMEX benchmark natural gas price ⁽²⁾	\$ 4.38	U.S. \$0.20/mmbtu	28	0.03	20	0.02
WTI/Lloyd crude blend differential ⁽³⁾	\$ 15.90	U.S. \$1.00/bbl	(17)	(0.02)	(13)	(0.02)
Downstream						
Canadian light oil margins	\$ 0.029	Cdn \$0.005/litre	16	0.02	11	0.01
Asphalt margins	\$ 23.55	Cdn \$1.00/bbl	11	0.01	8	0.01
New York Harbor 3:2:1 crack spread ⁽⁴⁾	\$ 8.62	U.S. \$1.00/bbl	77	0.09	48	0.06
Consolidated						
Exchange rate (U.S. \$ per Cdn \$) ⁽¹⁾⁽⁵⁾	\$ 0.962	U.S. \$0.01	(50)	(0.06)	(36)	(0.04)
Interest rate		100 basis points	(11)	(0.01)	(8)	(0.01)

⁽¹⁾ Does not include gains or losses on inventory.

⁽²⁾ Includes decrease in net earnings related to natural gas consumption.

⁽³⁾ Excludes impact on asphalt operations.

⁽⁴⁾ Relates to U.S. Refining & Marketing.

⁽⁵⁾ Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.

⁽⁶⁾ Excludes mark to market accounting impacts.

⁽⁷⁾ Based on 849.9 million common shares outstanding as of September 30, 2010.

3. Capability to Deliver Results and the Strategic Plan

Husky's capacity to deliver results and the strategic plan are described in the Company's 2009 annual MD&A and also in its 2009 Annual Information Form ("AIF"), both of which are available from www.sedar.com and www.sec.gov.

In summary, Husky's current strategy is to continue to exploit oil and gas assets in Western Canada while expanding into new areas with large scale sustainable

growth potential. The Company's plans include projects in Canada (the Alberta oil sands and the basins offshore Canada's East Coast), Asia (the South China Sea, the Madura Strait and the East Java Sea), and offshore Greenland. In the midstream and downstream sectors, Husky is enhancing performance and maximizing the value chain through integrating its businesses, optimizing plant operations and expanding plant and infrastructure.

4. Key Growth Highlights

The 2010 capital program was established with a view of maintaining the strength of Husky's balance sheet and taking advantage of opportunities as economic conditions improve and financial uncertainty abates. Capital expenditures will continue to focus on those projects offering the highest potential for returns and mid to long-

term growth. However, as a result of an ongoing comprehensive review of the Company's operations and business strategies, Husky has increased its 2010 capital program and redirected a portion of it to focus on delivering near-term production growth.

Upstream

East Coast Canada and Greenland

White Rose Satellite Development Projects

Husky continued to ramp up production at the North Amethyst satellite oil field through the third quarter of 2010. A second production well was completed in early September and drilling is ongoing on a supporting water injection well. A total of 11 wells are planned for North Amethyst. Drilling of additional wells will continue through to 2013.

In August 2010, Husky received regulatory approval for a 2-well pilot project to target the West White Rose reservoir. These wells will be drilled from existing infrastructure at the White Rose field, and will provide additional information on the reservoir to refine development plans for the full West White Rose field. First production is anticipated in 2011.

East Coast Canada Exploration

Husky completed a 3,000 kilometre 2-dimensional ("2-D") seismic acquisition survey in the Sydney Basin between Newfoundland and Nova Scotia. Husky also acquired over 2,500 kilometres of 2-D seismic surveys on exploration acreage offshore Labrador.

Data from the Glenwood H-69 exploration well, drilled in March 2010, continues to be evaluated.

Offshore Greenland

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

Heavy Oil and Oil Sands

Heavy Oil

Construction of the 8,000 bbl/day South Pike's Peak project was approximately 37% complete at the end of the third quarter of 2010. Production is expected to commence in the first half of 2012.

Horizontal well developments progressed through the third quarter of 2010, targeting new geological horizons in existing regions. Twenty-eight wells were drilled in the third quarter to bring the total number of wells drilled year to date to 54 and the Company expects to drill an additional 46 wells in the fourth quarter of 2010.

Sunrise Energy Project

Husky and BP PLC ("BP") continue to advance the development of the Sunrise Energy Project in multiple stages. Husky and BP are equal partners in the Sunrise Energy Project with Husky operating Sunrise. Tenders for major engineering and construction contracts are currently under evaluation. Husky reached an agreement with Enbridge, Inter Pipeline Fund and Keyera Facilities Income Fund on the movement of diluted bitumen to market and transportation of diluent to the Sunrise oil sands site. Development drilling is on track for commencement in the first quarter of 2011. Project sanction of phase one is expected in the fourth quarter of this year and first production is planned for 2014.

Tucker Oil Sands Project

Based on a greater understanding of the Tucker reservoir, Husky is addressing production challenges by drilling new wells and initiating new start up procedures; the results will be evaluated over the next six to twelve months. Husky is drilling 19 wells in 2010 and 2011 with production phased in as wells are completed.

In late September 2010, three new well pairs, which incorporated a number of design changes, commenced production, and an additional four well pairs were drilled during the third quarter. Prefabrication of the piping and field facilities continued on schedule, with three pairs tied in and eight more pairs planned for tie-in by year-end. Applications to the Energy Resources Conservation Board ("ERCB") are proceeding for additional drilling and field development in 2011 and 2012.

McMullen

Cold production from McMullen averaged 1,450 bbls/day in the third quarter of 2010. Twenty-two wells were drilled in the third quarter, with an additional six to be drilled in the fourth quarter.

Western Canada (excluding Heavy Oil and Oil Sands)

West Central Alberta

In September 2010, Husky announced that a purchase agreement had been signed to acquire natural gas properties in west central Alberta, subject to final closing and regulatory approvals. The acquired assets will add 10.8 mboe/day to production and contribute 37 mmboe of proved reserves and 11.7 mmboe of probable reserves to a core gas producing area. The acquisition also adds 160,000 acres of land to the Company's holdings, including 122,000

undeveloped acres. The reserve estimates are as of June 1, 2010.

Husky's Ram River Gas Plant is strategic to the future growth of the Foothills region. The Company's Ram River Gas Plant opened in 1972 and has a raw gas processing capacity of 622 mmcf/day and sulphur handling capacity of 2,877 tonnes/day. The Ram River Gas Plant currently processes a significant portion of the acquired production. Over the next five years, further production from the acquired properties will be integrated into the plant.

Gas Resource Plays

Husky continues to build its gas resource play inventory. In the third quarter of 2010, Husky acquired additional land in the Ansell and Kakwa area of the Alberta deep basin, and the Bivouac area of Northeast British Columbia.

As part of Husky's heightened focus on growing near term production, the Company continued exploration and development drilling of its natural gas liquids-rich assets in the Ansell area. In the third quarter, four Cardium formation development wells were drilled and six exploration wells were spud to test the deeper multi-zone potential. Drilling and completion operations are expected to continue for the rest of 2010 and into 2011.

Husky is also accelerating development drilling in the Bivouac and Galloway areas with an additional three Bivouac wells and five Galloway wells to be drilled by the end of 2010 with production expected in the second quarter of 2011.

Oil Resource Plays

Three Viking wells were placed on production in the Dodsland/Elrose area of Southwest Saskatchewan to bring the total number of producing wells to 14. Eight Viking horizontal wells were drilled at Redwater, Alberta, and an additional seven wells are planned for the remainder of the year. Evaluation wells are currently in progress to assess the Cardium zone at Lanaway, the Lower Shaunavon zone in Southwest Saskatchewan and the Bakken zone in Southeast Saskatchewan. A second successful horizontal well was completed in the Shaunavon zone in the third quarter of 2010 and Husky plans to drill an additional three wells in this area in the fourth quarter. In the Bakken zone, two successful horizontal wells were brought on production in the third quarter of 2010 with plans for an additional two wells to be on-stream by the end of the year.

Northeastern British Columbia Conventional Exploration

Husky participated in a well in the Grizzly Valley located in the foothills of northeastern British Columbia (42% after earned working interest) which has been tested at a rate of 33 mmcf/day. Tie-in of the well is expected to be completed in early 2011.

Alkaline Surfactant Polymer Floods

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

South East Asia

Offshore China Exploration, Delineation and Development

In the third quarter of 2010, the *West Hercules* rig completed drilling and testing the Liuhua 34-3-1 exploration well, which encountered natural gas. The well was suspended pending further evaluation of the suitability to develop this new field as part of the overall Block 29/26 deepwater gas development project.

Following the Liuhua 34-3-1 exploration well, the Liwan 3-1-10 well was drilled, which is the first development well on the Liwan 3-1 field. This well was successfully cased and will be used as a future producing well.

The *West Hercules* then drilled the Liuhua 29-1-3 appraisal well, the second appraisal well on the Liuhua 29-1 field, which has been cased for possible re-entry and development as a producing well in the future. The well was drilled approximately three kilometers north of the initial Liuhua 29-1 discovery. Initial results from the well were positive and demonstrate an extension of the Liuhua 29-1 field to the north.

In the third quarter of 2010, the Government of China approved the Original Gas-In-Place ("OGIP") report for the Liwan 3-1 field, which was submitted in December of 2009. As at September 30, 2010, the Company estimates that total Petroleum initially in-place ("PIIP") for the Liwan 3-1 field as well as the Liuhua 34-2 and Liuhua 29-1 fields is in the range of 2.6 to 3.0 tcf of gas. Husky holds a 100%

working interest in Block 29/26; which CNOOC has the right to participate up to 51%.

Husky is currently tendering the deepwater equipment and installation contracts in concert with submission of the plan of development for the Liwan 3-1 project. Under the current plan, the Liwan 3-1 and Liuhua 34-2 fields on Block 29/26 will be developed in parallel, with first gas production targeted in late 2013. The plan of development for the Liuhua 29-1 field is targeted for submission in late 2011, after all appraisal drilling and evaluation work has been completed. Gas production from the Liuhua 29-1 field will share common gas processing and transportation infrastructure as the Liwan 3-1 and Liuhua 34-2 fields.

On Block 63/05 in the Qiongdongnan Basin, 50 kilometres south of Hainan Island, acquisition of new 2-D and 3-D seismic data was completed in August 2010 and the data is currently being evaluated. Following evaluation later in the year, a decision will be made on an exploration well to be drilled in 2011. Husky holds a 100% interest in Block 63/05, for which CNOOC has the right to participate up to 51%.

Indonesia Exploration and Development

In October, 2010, Husky and its partner, CNOOC, received approval from the Government of Indonesia for a 20-year extension to the existing Madura Strait PSC. The extension of the PSC, along with the approval of the plan of development and existing gas sale agreements in place, provides the basis for advancing the existing Madura BD field into development. The next step is to tender major contract work, which is expected to commence in late 2010.

Also in October, 2010, Husky and CNOOC announced that they have each agreed to sell a 10% equity stake in Husky Oil (Madura) Limited ("HOML") to SMS Development Ltd., an affiliate of Samudra Energy Ltd. Following the completion of the sale, Husky and CNOOC will each hold a 40% equity interest in HOML, with the remaining 20% held by SMS Development Ltd.

Processing of 2-D seismic on the North Sumbawa II Block has been completed and interpretation is at an advanced stage. Husky will use this data to define an exploration prospect for future drilling, which is currently planned to commence in 2011. Husky holds a 100% interest in the North Sumbawa II Block, comprising 5,000 square kilometres in the East Java Sea.

Midstream

Husky has received regulatory approval to add an additional 300,000 barrel storage tank at Hardisty. This tank will be connected to the Keystone Pipeline. Construction for the new tank is expected to be completed in 2012.

Downstream

Lima, Ohio Refinery

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

Toledo, Ohio Refinery

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

Retail

At the end of the third quarter, Husky completed the rebranding of 73 sites acquired in late 2009, with the remainder to be transferred in the fourth quarter of 2010.

5. Results of Operations

5.1 Upstream

Upstream Net Earnings Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
	2010	2009	2010	2009
<i>(millions of dollars)</i>				
Gross revenues	\$ 1,385	\$ 1,224	\$ 4,257	\$ 3,862
Royalties	233	184	767	610
Net revenues	1,152	1,040	3,490	3,252
Operating and administration expenses	400	382	1,180	1,123
Depletion, depreciation and amortization	399	327	1,168	1,046
Other income	(1)	-	(2)	-
Income taxes	102	86	331	304
Net earnings	\$ 252	\$ 245	\$ 813	\$ 779

Third Quarter

Upstream net earnings in the third quarter of 2010 increased by \$7 million compared with the third quarter of 2009 primarily as a result of an increase in total production and increased realized prices for light crude oil and natural gas, partially offset by the impact of the Enbridge Line 6A/6B shutdowns and increased depletion in South East Asia.

The Enbridge Line 6A/6B shutdowns caused a widening in the light/heavy crude oil differential which negatively impacted heavy crude oil realized prices as heavy production was sold into the market at a lower price as a result of inventory build up in Western Canada. This resulted in an estimated \$12 million negative impact to net earnings in the third quarter.

Production of crude oil and natural gas increased to 288,700 boe/day in the third quarter of 2010 compared to 276,200 boe/day in the third quarter of 2009, primarily due to additional production at the North Amethyst field, a satellite development of the White Rose field. North Amethyst currently has two producing wells averaging 13.2 mbbls/day for the third quarter.

The average realized price in the third quarter of 2010 was \$64.28/bbl for crude oil, NGL and bitumen compared with \$62.19/bbl during the same period in 2009. Realized natural gas prices averaged \$3.50/mcf in the third quarter of 2010 compared with \$2.84/mcf in the same period in 2009. Stronger U.S. dollar crude oil and natural gas pricing was partially offset by the significant strengthening of the Canadian dollar over the period.

Nine Months

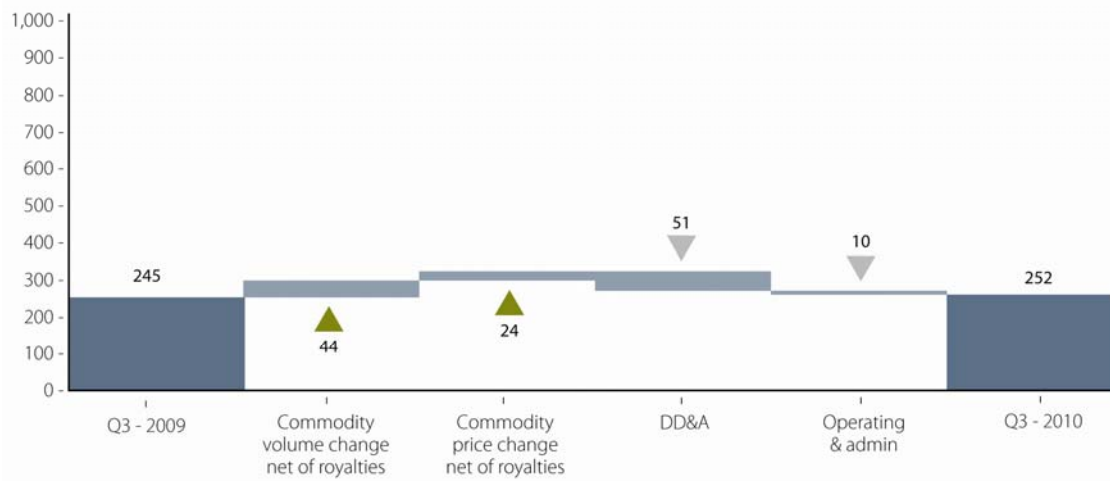
Upstream earnings in the first nine months of 2010 were \$34 million higher compared with the same period in 2009. The increase was primarily due to the higher average price realized on crude oil, NGL and bitumen in the first nine months of 2010 compared with the first nine months of 2009, partially offset by a decline in total production, the impact of the Enbridge Line 6A/6B shutdowns and increased depletion in South East Asia.

During the first nine months of 2010, the average realized price increased 22% to \$65.98/bbl for crude oil, NGL and bitumen compared with \$54.15/bbl during the same period in 2009. Realized natural gas prices averaged \$3.89/mcf during the first nine months of 2010 compared with \$3.80/mcf in the same period in 2009.

Upstream Net Earnings Variance Analysis

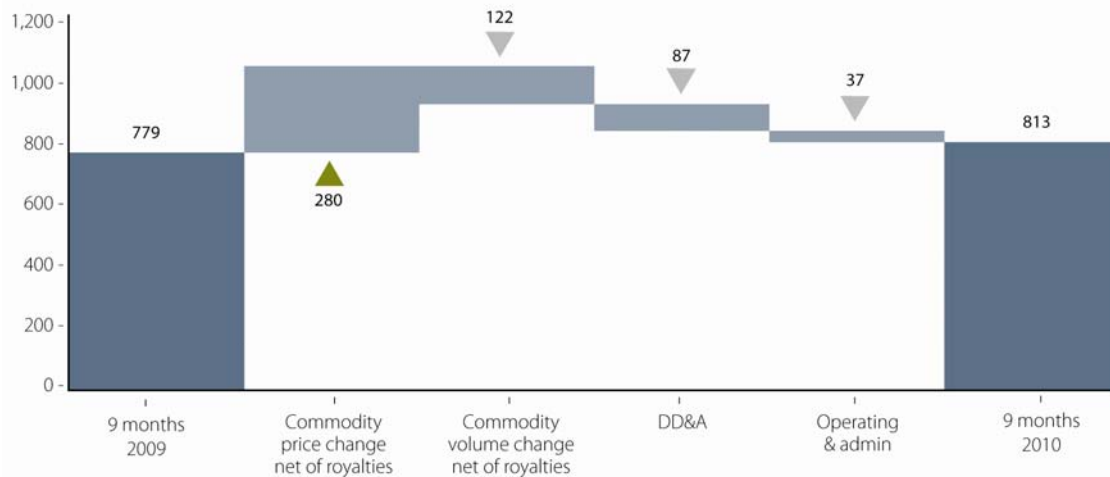
Third Quarter

Upstream After Tax Earnings Variance Analysis (Millions)



Nine Months

Upstream After Tax Earnings Variance Analysis (Millions)



Pricing

Average Sales Prices Realized		Three months ended Sept. 30		Nine months ended Sept. 30	
		2010	2009	2010	2009
Crude oil	(\$/bbl)				
Light crude oil & NGL		\$ 73.88	\$ 67.56	\$ 75.05	\$ 59.58
Medium crude oil		60.88	61.28	64.65	53.30
Heavy crude oil		56.96	59.21	58.94	49.50
Bitumen		55.41	58.44	57.38	48.89
Total average		64.28	62.19	65.98	54.15
Natural gas average	(\$/mcf)	3.50	2.84	3.89	3.80

Increased U.S. dollar crude oil and natural gas prices were partially offset by the significant strengthening of the Canadian dollar against the U.S. dollar in the first nine months of 2010 compared to the same period in 2009. The realized price for medium and heavy crude oil and bitumen was impacted by the Enbridge Line 6A/6B shutdowns.

Oil and Gas Production

Daily Gross Production		Three months ended Sept. 30		Nine months ended Sept. 30	
		2010	2009	2010	2009
Crude oil & NGL	(mbbls/day)				
Western Canada					
Light crude oil & NGL		23.5	23.0	23.2	23.0
Medium crude oil		25.7	24.8	25.4	25.5
Heavy crude oil		72.4	75.7	74.4	78.6
Bitumen		21.9	24.0	22.0	23.0
		143.5	147.5	145.0	150.1
East Coast Canada					
White Rose - light crude oil		31.2	21.3	34.4	48.7
North Amethyst - light crude oil		13.2	-	5.1	-
Terra Nova - light crude oil		6.4	7.7	9.0	10.3
China					
Wenchang - light crude oil & NGL		10.1	10.5	10.7	11.5
Total crude oil & NGL		204.4	187.0	204.2	220.6
Natural gas	(mmcf/day)	505.5	535.0	511.0	546.1
Total	(mboe/day)	288.7	276.2	289.4	311.6

Crude Oil and NGL Production

Third Quarter

Crude oil, bitumen and NGL production in the third quarter of 2010 increased by 17.4 mbbls/day or 9% compared with the same period in 2009. Production of crude oil at the North Amethyst field averaged 13.2 mbbls/day for the third

quarter, partially offsetting lower production from Terra Nova of 1.3 mbbls/day which was due to the planned 20 day turnaround in July 2010. Production of crude oil at White Rose increased by 9.9 mbbls/day compared with the same period in 2009 as the 2009 annual planned

turnaround took place in the third quarter of 2009 whereas the 2010 turnaround is scheduled for October.

During the third quarter of 2010, crude oil, bitumen and NGL production from Western Canada decreased by 4 mbbls/day or 3% compared with the third quarter of 2009 primarily due to reduced capital investment in the first three quarters of 2009 and natural reservoir declines. Heavy oil production was also impacted by extremely wet weather conditions.

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

Nine Months

In the first nine months of 2010, crude oil, bitumen and NGL production decreased by 16.4 mmbls/day or 7% compared with the same period in 2009, primarily due to the decline in production from White Rose as a result of declines from

peak production rates post the 2009 turnaround, partially offset by production at North Amethyst. Production in Western Canada, Terra Nova, and South East Asia was primarily impacted by the same factors impacting the third quarter.

Natural Gas Production

Third Quarter

Natural gas production decreased by 29.5 mmcf/day or 6% in the third quarter of 2010 compared with the third quarter of 2009 due to reduced capital investment and natural reservoir decline.

Nine Months

In the first nine months of 2010, natural gas production decreased by 35.1 mmcf/day or 6% compared with the same period in 2009 primarily due to the same factors impacting the third quarter.

2010 Production Guidance

	Revised Guidance	Actual Production	
		Nine months ended Sept. 30 2010	Year ended Dec. 31 2009
Crude oil & NGL (mbbls/day)			
Light crude oil & NGL	81 – 84	83	89
Medium crude oil	25 – 27	25	25
Heavy crude oil & bitumen	94 – 97	96	102
Natural gas (mmcf/day)	200 – 208	204	216
Natural gas (mboe/day)	510 – 520	511	542
	85 – 87	85	91
Total barrels of oil equivalent (mboe/day)	285 – 295	289	307

Husky's production for the nine months ended September 30, 2010 remains within revised guidance set by the Company in the second quarter.

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

- Performance on recently commissioned facilities, new wells brought onto production and unanticipated reservoir response from existing fields.
- Unplanned or extended maintenance and turnarounds at any of the Company's production, upgrading, refining, pipeline or offshore assets.

- Business interruptions due to unexpected events such as severe weather, fires, blowouts, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events.

- Significant declines in crude oil and natural gas commodity prices which may result in the decision to temporarily shut-in production.

- Foreign operations and related assets which are subject to a number of political, economic and socio-economic risks.

Royalties

Third Quarter

In the third quarter of 2010, royalty rates averaged 17% as a percentage of gross revenue compared with 15% in 2009. Royalty rates in Western Canada averaged 15%, up from 13% in the third quarter of 2009 primarily as a result of increased natural gas prices. Rates for the East Coast averaged 21% in the third quarter of 2010 down from 25% in the third quarter of 2009. The lower rate this quarter is attributable to the North Amethyst field which is subject to a basic royalty of 1%, while Terra Nova and White Rose, being mature fields, are subject to higher rates. Rates at North Amethyst will increase and reach the same level as Terra Nova and White Rose after certain project payouts as

prescribed in the royalty regulations are met. Royalty rates in Wenchang averaged 22% in the third quarter of 2010, comparable to 21% in the third quarter of 2009.

Nine Months

Royalty rates averaged 18% of gross revenue in the first nine months of 2010 compared with 16% in the same period in 2009. Rates in Western Canada averaged 15%, up from 12% in 2009 primarily as a result of increased commodity prices. Off the East Coast of Canada the average rate was 26%, consistent with the same period in 2009.

Operating Costs

<i>(millions of dollars)</i>	Three months ended Sept. 30		Nine months ended Sept. 30	
	2010	2009	2010	2009
Western Canada	\$ 296	\$ 269	\$ 889	\$ 835
East Coast Canada	49	61	133	144
International	7	5	17	15
Total	\$ 352	\$ 335	\$ 1,039	\$ 994
Unit operating costs (\$/boe)	\$ 13.24	\$ 13.14	\$ 13.16	\$ 11.69

Third Quarter

Total upstream operating costs increased to \$352 million from \$335 million as a result of increased treating and maintenance costs. Total upstream unit operating costs in the third quarter of 2010 averaged \$13.24/boe compared with \$13.14/boe in the third quarter of 2009.

Operating costs in Western Canada averaged \$14.07/boe in the third quarter compared with \$12.33/boe in the same period in 2009 primarily as a result of increased energy, treating and maintenance costs as well as lower production in the third quarter of 2010 compared with the same period in 2009. Maturing fields in Western Canada require increasing amounts of infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive gathering systems, crude and water trucking and more complex natural gas compression systems. Husky is focused on managing operating costs associated with the increased infrastructure through cost reduction and efficiency initiatives and keeping infrastructure fully utilized.

Operating costs at the East Coast offshore operations averaged \$10.60/boe in the third quarter of 2010 compared with \$22.75/boe in 2009 primarily as a result of higher

production from White Rose and North Amethyst, together with lower fuel, maintenance and labour costs in the third quarter of 2010 compared with the same period in 2009.

Operating costs at the South China Sea offshore operations averaged \$7.68/bbl in the third quarter of 2010 compared with \$4.81/bbl in the same period in 2009, as a result of lower production and higher maintenance and subsea costs in the third quarter of 2010 compared with 2009.

Nine Months

Total upstream operating costs in the first nine months of 2010 increased by 5% compared with the same period in 2009 primarily due to the same factors affecting the third quarter.

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

Third Quarter

In the third quarter of 2010, total DD&A averaged \$15.01/boe compared with \$12.84/boe in the third quarter of 2009. The increased DD&A rate in the third quarter of 2010 was due to both a larger full cost base and a lower reserve base, compared with the same period in 2009, primarily due to the larger full cost base in the South China Sea. Costs associated with relinquished exploration blocks and dry holes offshore China in the second quarter of 2010, resulted in a \$30 million increase in depletion expense in the third quarter.

Nine Months

For the first nine months of 2010, total DD&A averaged \$14.78/boe compared with \$12.29/boe during the same period in 2009 due primarily to the same factors affecting the third quarter. Depletion expense in China rose to \$142 million in the first nine months of 2010 from \$42 million in the first nine months of 2009 due to the same factors impacting the third quarter, which was partially offset by lower DD&A in Canada as a result of lower production.

Upstream Capital Expenditures

For the first nine months of 2010, upstream capital expenditures were \$1,891 million, 58% of the revised 2010 capital expenditure program. Husky's major projects remain on schedule. Upstream capital expenditures were \$1,213 million (64%) in Western Canada, \$382 million (20%) offshore the East Coast of Canada, \$293 million (16%) in South East Asia and \$3 million (less than 1%) offshore Greenland.

Capital Expenditures Summary ⁽¹⁾

(millions of dollars)	Three months ended Sept. 30		Nine months ended Sept. 30	
	2010	2009	2010	2009
Exploration				
Western Canada	\$ 159	\$ 33	\$ 346	\$ 132
East Coast Canada	8	1	77	53
Northwest United States	-	3	-	15
International	91	144	246	373
	258	181	669	573
Development				
Western Canada	343	119	867	478
East Coast Canada	116	110	305	426
International	2	2	50	8
	461	231	1,222	912
	\$ 719	\$ 412	\$ 1,891	\$ 1,485

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

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

Western Canada and Oil Sands Wells Drilled		Three months ended Sept. 30				Nine months ended Sept. 30			
		2010		2009		2010		2009	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	18	17	3	1	45	39	9	4
	Gas	8	6	3	1	26	22	34	22
	Dry	1	1	1	-	8	8	6	5
		27	24	7	2	79	69	49	31
Development	Oil	267	235	78	72	532	465	179	162
	Gas	12	6	11	2	27	15	103	53
	Dry	2	2	1	1	8	7	5	5
		281	243	90	75	567	487	287	220
Total		308	267	97	77	646	556	336	251

Western Canada

During the first nine months of 2010, Husky invested \$1,213 million on exploration and development throughout the Western Canada Sedimentary Basin compared with \$610 million in the first nine months of 2009. Of this, \$519 million was invested in oil exploration and development and \$267 million was invested in natural gas exploration and development compared with \$240 million for oil exploration and development and \$263 million for natural gas exploration and development in the first nine months of 2009. The Company drilled 556 net wells in the basin during the first nine months of 2010 resulting in 504 net oil

wells and 37 net natural gas wells compared with 251 net wells resulting in 166 net oil wells and 75 net natural gas wells in the first nine months of 2009. In addition, \$85 million was spent on production optimization initiatives in the first nine months of 2010. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to \$243 million and \$40 million was spent on property acquisitions. During the first nine months of 2010, capital expenditures on oil sands projects were \$59 million.

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

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

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

Offshore East Coast Development

During the first nine months of 2010, \$305 million was invested for East Coast development projects primarily for North Amethyst and West White Rose satellite tie-back development projects, including drilling operations at North Amethyst and completion of facilities construction and installation. At West White Rose, capital expenditures focused on advancing engineering design and planning.

Offshore East Coast Exploration

During the first nine months of 2010, Husky spent \$77 million primarily on the Glenwood H-69 exploration well Northwest of the West White Rose field and geological and geographic data and studies.

Offshore China and Indonesia

During the first nine months of 2010, \$293 million was spent primarily on offshore projects in China, including the drilling of four exploration, three delineation and one development well on Block 29/26 in the South China Sea and one exploration well on Block 04/35 in the East China Sea.

2010 Upstream Capital Program ⁽¹⁾	Original Program	Revised Program
<i>(millions of dollars)</i>		
Western Canada - oil and gas	\$ 1,200	\$ 2,200
- oil sands	85	70
East Coast Canada	485	480
International	660	500
Total upstream capital expenditures	\$ 2,430	\$ 3,250

⁽¹⁾ Excludes capitalized administrative costs and capitalized interest.

The 2010 capital budget was established with a view to enable Husky to maintain production levels and support its medium and long-term growth strategies. Capital expenditures continue to focus on those projects offering the highest potential for returns. As a result of the ongoing review of Husky's business priorities and the outlook for the remainder of the year, Husky has adjusted its planned 2010 upstream capital spending, including acquisitions, to \$3.3 billion. The additional capital will be allocated to progress the Company's strategic initiatives and advance the development of its extensive upstream portfolio, including acquisitions.

Capital expenditures for Western Canada upstream development and exploration are focused on heavy oil properties, oil resource plays, enhanced oil recovery projects and unconventional gas holdings. Capital

spending on oil sands is primarily focused on development at Sunrise.

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

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

Upstream Planned Turnarounds

A regular maintenance turnaround for the *SeaRose FPSO* commenced on October 5, and was completed on October 22, 2010.

5.2 Midstream

Upgrading Net Earnings Summary	Three months ended Sept. 30		Nine months ended Sept. 30		
	2010	2009	2010	2009	
<i>(millions of dollars, except where indicated)</i>					
Gross revenues	\$ 291	\$ 415	\$ 1,204	\$ 1,127	
Gross margin	\$ 50	\$ 51	\$ 234	\$ 217	
Operating and administration expenses	44	40	138	139	
Depreciation and amortization	33	9	58	25	
Other income	(1)	(1)	(3)	(3)	
Income taxes	(7)	1	12	16	
Net earnings (loss)	\$ (19)	\$ 2	\$ 29	\$ 40	
Selected operating data:					
Upgrader throughput ⁽¹⁾	<i>(mbbls/day)</i>	13.5	67.8	60.5	72.9
Synthetic crude oil sales	<i>(mbbls/day)</i>	21.0	58.6	49.0	60.9
Upgrading differential	<i>(\$/bbl)</i>	\$ 13.80	\$ 10.16	\$ 14.01	\$ 11.66
Unit margin	<i>(\$/bbl)</i>	\$ 25.72	\$ 9.37	\$ 17.47	\$ 13.04
Unit operating cost ⁽²⁾	<i>(\$/bbl)</i>	\$ 18.02	\$ 6.53	\$ 8.37	\$ 6.99

⁽¹⁾ Throughput includes diluent returned to the field.

⁽²⁾ Based on throughput.

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

Third Quarter

During the third quarter of 2010, the upgrading differential averaged \$13.80/bbl, an increase of \$3.64/bbl or 36% compared with the third quarter of 2009. The differential is equal to Husky Synthetic Blend, which sells at a premium to WTI, less Lloyd Heavy Blend. The overall unit margin increased to \$25.72/bbl in the third quarter of 2010 from \$9.37/bbl in the same period in 2009 primarily as a result of

significantly wider heavy to light crude oil price differentials. The decrease in throughput was primarily due to a 53 day major scheduled turnaround at the Lloydminster Upgrader that commenced in late August and was completed on October 22. The Enbridge 6A/6B Line shutdowns resulted in inventory writedowns that negatively impacted earnings by an estimated \$4 million due to the widening of the heavy to light crude oil price differential. The increase in depreciation and amortization is due to changes in the estimated remaining life of certain components of the Upgrader.

Nine Months

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

Infrastructure and Marketing Net Earnings Summary

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2010	2009	2010	2009
<i>(millions of dollars, except where indicated)</i>				
Gross revenues	\$ 1,872	\$ 1,497	\$ 5,918	\$ 5,292
Gross margin - pipeline	\$ 24	\$ 23	\$ 93	\$ 80
- other infrastructure and marketing	18	32	122	144
	42	55	215	224
Operating and administration expenses	5	5	15	14
Depreciation and amortization	10	9	30	27
Other (income) expense	(8)	(19)	14	(28)
Income taxes	10	18	42	60
Net earnings	\$ 25	\$ 42	\$ 114	\$ 151
Selected operating data:				
Commodity volumes managed	<i>(mboe/day)</i>	886	830	929
Aggregate pipeline throughput	<i>(mbbls/day)</i>	489	498	516

Third Quarter

Infrastructure and Marketing net earnings in the third quarter of 2010 were \$25 million compared with \$42 million in the third quarter of 2009. Pipeline margins were comparable to the same period in 2009. Decreased margins on other infrastructure and marketing were the result of lower realized natural gas storage profits and lower commodity trading margins. Other income in the third quarter of 2010 included unrealized gains of \$8 million on natural gas storage contracts resulting from changes in the fair value of natural gas forward purchase and sale contracts compared with \$19 million in the third quarter of 2009.

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

Nine Months

The first nine months of 2010 were primarily impacted by the same factors that affected the third quarter of 2010.

Other expense in the first nine months of 2010 included unrealized losses of \$14 million on natural gas storage contracts resulting from changes in the fair value of natural gas forward purchase and sale contracts compared with a \$28 million gain in the same period in 2009.

Midstream Capital Expenditures

For the first nine months of 2010, midstream capital expenditures totalled \$151 million. At the Lloydminster Upgrader, Husky spent \$56 million primarily for facility reliability projects and \$70 million was spent on the scheduled major turnaround. The remaining \$25 million was spent on the acquisition of equipment used for sulphur operations and various pipeline upgrades.

Midstream Planned Turnaround

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

5.3 Downstream

Canadian Refined Products Net Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
		2010	2009	2010	2009
<i>(millions of dollars, except where indicated)</i>					
Gross revenues		\$ 834	\$ 786	\$ 2,140	\$ 1,861
Gross margin - fuel		\$ 21	\$ 32	\$ 48	\$ 95
- ethanol		13	17	47	43
- ancillary		12	20	35	40
- asphalt		87	69	126	153
Operating and administration expenses		133	138	256	331
Depreciation and amortization		40	32	86	78
Income taxes		22	23	73	69
Income taxes		19	24	26	53
Net earnings		\$ 52	\$ 59	\$ 71	\$ 131
Selected operating data:					
Number of fuel outlets (average)				494	485
Light oil sales	<i>(million litres/day)</i>	8.5	7.8	8.0	7.6
Light oil retail sales per outlet	<i>(thousand litres/day)</i>	14.2	13.6	13.8	12.7
Prince George Refinery throughput	<i>(mbbls/day)</i>	11.9	10.2	9.5	10.3
Asphalt sales	<i>(mbbls/day)</i>	30.9	32.4	20.3	23.9
Lloydminster Refinery throughput	<i>(mbbls/day)</i>	28.9	27.5	27.3	24.7
Ethanol production	<i>(thousand litres/day)</i>	519.1	705.9	595.0	656.9

Third Quarter

Gross margins on fuel sales were lower in the third quarter of 2010 compared to 2009 as a result of lower retail and wholesale market prices for products combined with higher crude feedstock costs.

The lower ethanol gross margin in the third quarter of 2010 was due primarily to lower production and sales volumes combined with lower realized product margins. Ethanol production in the third quarter of 2010 was 27% lower than in the same period of 2009 due to a turnaround at the Lloydminster Ethanol Plant which occurred during the Upgrader turnaround. Included in ethanol gross margin in the third quarter of 2010 was \$9 million related to government assistance grants compared with \$13 million in the third quarter of 2009.

Asphalt gross margins were higher in the third quarter of 2010 compared with 2009 due to higher realized market prices combined with lower heavy crude oil feedstock prices partially offset by lower sales.

Nine Months

During the first nine months of 2010, refined products earnings were lower than the same period in 2009 primarily due to lower realized fuel, ancillary, and asphalt margins, partially offset by higher ethanol margins.

The ethanol gross margin increased during the first nine months of 2010, primarily due to higher production and sales volumes at the Minnedosa Ethanol Plant which was partially offset by lower production at the Lloydminster Ethanol Plant. Included in ethanol gross margin in the first nine months of 2010 was \$41 million related to government assistance grants compared with \$40 million in the same period of 2009. Asphalt margins decreased compared to the same period in 2009 primarily due to lower sales volumes and higher feedstock costs during the year.

During the first nine months of 2010, fuel margins were lower than the same period in 2009 primarily due to the same factors that affected the third quarter of 2010.

U.S. Refining and Marketing Net Earnings Summary

	Three months ended Sept. 30		Nine months ended Sept. 30		
	2010	2009	2010	2009	
<i>(millions of dollars, except where indicated)</i>					
Gross revenues	\$ 1,683	\$ 1,555	\$ 5,283	\$ 4,180	
Gross refining margin	\$ 146	\$ 163	\$ 366	\$ 772	
Processing costs	94	97	283	322	
Operating and administration expenses	2	3	7	7	
Interest - net	1	1	2	2	
Depreciation and amortization	47	48	140	147	
Other (income) expense	-	(2)	-	31	
Income taxes (recoveries)	1	6	(24)	96	
Net earnings (loss)	\$ 1	\$ 10	\$ (42)	\$ 167	
Selected operating data:					
Lima Refinery throughput	<i>(mbbls/day)</i>	140.8	131.6	144.3	135.1
Toledo Refinery throughput	<i>(mbbls/day)</i>	54.6	66.2	64.3	64.1
Realized refining margin	<i>(U.S. \$/bbl crude throughput)</i>	\$ 7.77	\$ 8.96	\$ 6.22	\$ 14.37
Refinery feedstocks and refined products inventory	<i>(mmbbls)</i>	12.8	9.9	12.8	9.9

Third Quarter

U.S. Refining and Marketing earnings decreased in the third quarter of 2010 compared with the third quarter of 2009 as a result of lower realized refining margins and lower total throughput. Increased throughput at the Lima Refinery was more than offset by the impact of the Enbridge Line 6A/6B shutdowns on the Toledo Refinery. Realized refining margins reflect differences in product configuration, location differences and FIFO accounting for the purchase of crude oil.

The Enbridge Line 6A/6B shutdowns reduced throughput at the Toledo Refinery due to limited heavy crude oil availability and increased feedstock costs as heavy oil was partially replaced with light oil where available. The result was an estimated decrease to the Toledo Refinery earnings of \$20 million.

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

The Chicago crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI which was decreasing at the end of the third quarter of 2010 while on a FIFO basis crude oil feedstock costs reflect purchases made earlier in the quarter when crude oil prices were higher.

In addition, the 6% strengthening of the Canadian dollar against the U.S. dollar compared with the third quarter of 2009 has had a negative impact on the translation of U.S. dollar financial results into Canadian dollars.

Other income in the third quarter of 2009 included of \$3 million of gains on feedstock purchase contracts.

Nine Months

Refining margins in the first nine months of 2010 were impacted by the same factors affecting the third quarter. Other expense in the first nine months of 2009 included \$30 million of losses on feedstock purchase contracts.

Downstream Capital Expenditures

For the first nine months of 2010, downstream capital expenditures totalled \$300 million.

In Canada, capital expenditures totalled \$165 million primarily for rebranding of retail outlets acquired in 2009 as well as upgrades and environmental protection at the retail outlets, refineries and ethanol plants.

In the United States, capital expenditures totalled \$135 million. At the Lima, Ohio Refinery, \$86 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled \$49 million (Husky's 50% share) primarily for engineering work on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection.

Downstream Planned Turnaround

The Lima, Ohio Refinery is in the process of a turnaround on the fluid catalytic cracker and coker units. The turnaround will improve operational reliability and complete major safety, environmental and capital improvement projects. The turnaround commenced on October 15 and is expected to be completed on November 20, 2010. During this period throughput has been reduced to approximately 100,000 boe/day.

5.4 Corporate

Corporate Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
	2010	2009	2010	2009
<i>(millions of dollars) income (expense)</i>				
Intersegment eliminations - net	\$ -	\$ 22	\$ 14	\$ (41)
Administration expense	(17)	(14)	(46)	(45)
Other income (expense)	6	5	4	(13)
Stock-based compensation	-	2	1	(1)
Depreciation and amortization	(19)	(14)	(57)	(36)
Interest - net	(53)	(52)	(156)	(139)
Foreign exchange	(11)	-	9	(1)
Income taxes	40	31	114	104
Net loss	\$ (54)	\$ (20)	\$ (117)	\$ (172)

Third Quarter

The corporate segment reported a loss of \$54 million in the third quarter of 2010 compared with \$20 million in the third quarter of 2009. Foreign exchange losses increased by \$11 million compared to nil in the third quarter of 2009 mainly due to foreign exchange movement on cash and working capital transactions in the quarter. The increase in depreciation and amortization was a result of adjustments to the book value of legacy sites that have been deemed inactive.

Nine Months

In the first nine months of 2010, the corporate segment reported a loss of \$117 million compared with \$172 million in the same period of 2009. In addition to the factors that impacted the third quarter, the corporate segment was impacted by additional expenses in the first nine months of 2009 that were recorded in other expenses including insurance costs of \$5 million and realized losses on forward purchases of U.S. dollars of \$9 million. Net interest expense increased in the first nine months of 2010 primarily due to higher debt levels compared with the same period in 2009. The foreign exchange gain in the first nine months of 2010 was due to the strengthening of the Canadian dollar and its impact on Husky's net U.S. dollar liabilities position.

Foreign Exchange Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
	2010	2009	2010	2009
<i>(millions of dollars)</i>				
Gain on translation of U.S. dollar denominated long-term debt	\$ (64)	\$ (215)	\$ (35)	\$ (266)
Loss on cross currency swaps	11	32	6	54
Loss on contribution receivable	39	110	21	184
Other (gains) losses	25	73	(1)	29
Foreign exchange (gain) loss	\$ 11	\$ -	\$ (9)	\$ 1
U.S./Canadian dollar exchange rates:				
At beginning of period	U.S. \$0.943	U.S. \$0.860	U.S. \$0.956	U.S. \$0.817
At end of period	U.S. \$0.971	U.S. \$0.933	U.S. \$0.971	U.S. \$0.933

Corporate Capital Expenditures

For the first nine months of 2010, corporate capital expenditures of \$16 million were primarily for computer hardware and software, office furniture, renovations and equipment and system upgrades.

Consolidated Income Taxes

Third Quarter

During the third quarter of 2010, consolidated income tax expense was \$85 million compared with \$104 million in the same period in 2009. Current taxes in the third quarter of

2010 decreased compared with the third quarter of 2009 due to a decrease in partnership deferred revenue taxable in 2010.

Nine Months

Cash taxes paid in the first nine months of 2010 were \$748 million compared to \$1,143 million in the first nine months of 2009, of which \$509 million relates to final instalments paid in respect of 2008 earnings, included in current liabilities at December 31, 2009, and \$239 million relating to instalments paid in respect of 2009 earnings. Further cash tax instalments in respect of 2009 earnings are estimated to be approximately \$19 million.

6. Liquidity and Capital Resources

In the third quarter of 2010, Husky funded its capital programs and dividend payments by cash generated from operating activities, cash on hand and long-term debt. Husky maintained its financial position with debt of \$4,086 million partially offset by cash on hand of \$31 million for \$4,055 million of net debt. Husky has no long-term debt

maturing until 2012. At September 30, 2010, the Company had \$2.9 billion in unused committed credit facilities, \$155 million in unused short-term uncommitted credit facilities and unused capacity under the debt shelf prospectuses filed in Canada and the U.S. in 2009 of \$300 million and U.S. \$1.5 billion, respectively. (Refer to Section 6.4).

Cash Flow Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
	2010	2009	2010	2009
<i>(millions of dollars, except ratios)</i>				
Cash flow - operating activities	\$ 959	\$ 744	\$ 2,047	\$ 1,542
- financing activities	\$ (77)	\$ (220)	\$ 135	\$ 889
- investing activities	\$ (955)	\$ (515)	\$ (2,543)	\$ (2,098)
Financial Ratios				
Debt to capital employed <i>(percent)</i>			22.0	18.7
Debt to cash flow <i>(times)</i> ⁽¹⁾			1.3	1.5
Corporate reinvestment ratio <i>(percent)</i> ⁽¹⁾⁽²⁾			107	143
Interest coverage ratios on long-term debt only ⁽¹⁾⁽³⁾				
Earnings			8.0	10.5
Cash flow			13.8	25.4
Interest coverage ratios on total debt ⁽¹⁾⁽⁴⁾				
Earnings			8.0	10.0
Cash flow			13.7	24.3

⁽¹⁾ Calculated for the 12 months ended for the dates shown.

⁽²⁾ Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

⁽³⁾ Interest coverage on long-term debt on an earnings basis is equal to earnings before interest expense on long-term debt and income taxes divided by interest expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow from operating activities before interest expense on long-term debt and current income taxes divided by interest expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.

⁽⁴⁾ Interest coverage on total debt on an earnings basis is equal to earnings before interest expense on total debt and income taxes divided by interest expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow from operating activities before interest expense on total debt and current incomes taxes divided by interest expense on total debt and capitalized interest. Total debt includes short and long-term debt.

6.1 Operating Activities

Third Quarter

In the third quarter of 2010, cash generated from operating activities amounted to \$959 million compared with \$744 million in the third quarter of 2009. Higher cash flows from operating activities was primarily due to higher Upstream production and higher realized light crude oil and natural gas prices, partially offset by lower U.S. Refining margins and both lower realized natural gas storage profits and lower commodity trading margins in Midstream.

Nine Months

Cash generated from operating activities amounted to \$2.0 billion in the first nine months of 2010 compared with \$1.5 billion in the first nine months of 2009. Higher cash flow from operating activities was primarily due to higher commodity prices offsetting decreases in production.

6.2 Financing Activities

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

Third Quarter

In the third quarter of 2010, cash used in financing activities was \$77 million compared with \$220 million in the third quarter of 2009. Lower cash used in financing activities for the third quarter of 2010 was primarily due to borrowings of \$140 million under the Company's syndicated credit facility.

Nine Months

Cash provided by financing activities was \$135 million in the first nine months of 2010 compared with \$889 million in the first nine months of 2009. In addition to the same factors impacting the third quarter, \$700 million of medium-term notes were issued in March 2010 compared to \$1.5 billion of long-term notes issued in May 2009.

6.3 Investing Activities

Third Quarter

In the third quarter of 2010, cash used in investing activities amounted to \$955 million compared with \$515 million in the third quarter of 2009. 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 2010 was \$2.5 billion compared with \$2.1 billion in the first nine months of 2009. Cash invested in both periods was primarily for capital expenditures.

6.4 Sources of Capital

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

short-term capital resources to ensure it retains financial flexibility.

Working capital is the amount by which current assets exceed current liabilities. At September 30, 2010, working capital was \$894 million compared with \$726 million at December 31, 2009.

During the third quarter of 2010, Husky added a second committed revolving syndicated credit facility of \$1.5 billion. As at September 30, 2010, the Company had borrowings of \$140 million under the \$1.25 billion revolving syndicated credit facility and no borrowings under its \$1.5 billion facility. Interest rates under these revolving syndicated credit facilities vary based on Canadian prime, Bankers' Acceptance, U.S. Libor or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain rating agencies to the Company's senior unsecured debt.

At September 30, 2010, Husky had unused committed long and short-term borrowing credit facilities totalling \$2.9 billion. A total of \$107 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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

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

Capital Structure

(millions of dollars)

	Sept. 30, 2010	
	Outstanding	Available
Total short-term and long-term debt	\$ 4,086	\$ 3,048
Common shares, retained earnings and accumulated other comprehensive income	\$ 14,501	

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

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

6.6 Off Balance Sheet Arrangements

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

7. Risks and Risk Management

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

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

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

TransAlta Power, L.P. ("TAPLP") is under the indirect control of one of Husky's principal shareholders. TAPLP is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLPL") which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLPL. These natural gas sales are related party transactions and have been measured at the exchange amount. For the nine months ended September 30, 2010, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLPL was \$72 million.

Political Risk

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

Environmental Risk

Husky's offshore operations are subject to the risk of blowouts and other catastrophic events, resulting from actions of the Company or its contractors or agents, or those of third parties, that could result in suspension of

operations, damage to equipment and harm to personnel, and damage to the natural environment. The consequences of such catastrophic events occurring in deep water operations, in particular, can be more costly and time-consuming to remedy, the remedy may be made more difficult or uncertain by the extreme pressures and cold temperatures encountered in deep water operations, shortages of equipment and specialist personnel required to work in these conditions, or the absence of appropriate and proven means to effectively remedy such consequences. The costs associated with such events could be material and Husky may not maintain sufficient insurance to address such costs. With the exception of Husky's Mizzen prospect, of which Husky is a non-operator, the Company currently does not participate in offshore deep water drilling operations in Canada; however, Husky's development program in China includes deep water drilling.

The recent Deepwater Horizon oil spill in the Gulf of Mexico has led to numerous public and governmental expressions of concern about the safety and potential environmental impact of offshore oil operations. Stricter regulation of operations, increased financial assurance requirements and increased caps on liability are likely to be applied to offshore oil and gas operations in the Gulf of Mexico. In the event that similar changes in environmental regulation occur with respect to Husky's operations off the East Coast of Canada or in the South China Sea, such changes could increase the cost of complying with environmental regulation in connection with these operations and have a material adverse impact on Husky's operations.

The United States Environmental Protection Agency ("EPA") has promulgated the so-called 'Tailoring Rule', which, beginning January 2, 2011, phases in over time restrictions on greenhouse gas emissions from stationary sources, including power plants and petroleum refineries, beginning with the largest emitters, where such sources are required to obtain a new or modified permit based on non-greenhouse gas emissions. The EPA has also promulgated regulations requiring reporting, beginning January 2, 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 will apply to Husky's U.S. operations. However, these EPA regulations are subject to challenge in Congress and the courts. Congress is expected to consider in the current session proposals to block or delay the EPA's regulation of greenhouse gas emissions. Among several legal challenges, the State of Texas, the National Association of Manufacturers and other organizations are seeking a stay of the Tailoring Rule and the EPA's other regulations relating to greenhouse gas emissions from stationary sources. It is not possible to predict the ultimate outcome of these challenges. It appears unlikely that the United States Congress will pass legislation restricting

greenhouse gas emissions in its current session. However, it is likely that such legislation will be addressed by the U.S. Congress in future sessions. Husky's operations may be impacted by future United States greenhouse gas legislation applying to the oil and gas industry or the consumption of petroleum products or by any further restrictive regulations issued by the EPA. Such legislation or regulation could require Husky's U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

Financial Risk

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

Liquidity Risk

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

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

Commodity Price Risk

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, 2010, the Company had third party physical natural gas purchase and sale contracts and natural gas storage contracts. These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized gain of \$36 million has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income. Natural gas inventory held in storage relating to the natural gas storage contracts is recorded at fair value. At September 30, 2010, the fair value of the inventory was \$162 million, resulting in a \$49 million unrealized loss recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

At September 30, 2010, the Company had third party crude oil purchase and sale contracts, which have been designated as a fair value hedge. These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized loss of \$1 million has been recorded in cost of sales in the Consolidated Statements of Earnings and Comprehensive Income. The crude oil inventory held in storage is recorded at fair value. At September 30, 2010, the fair value of the inventory was \$29 million, resulting in an unrealized gain of \$1 million recorded in cost of sales in the Consolidated Statements of Earnings and Comprehensive Income.

The Company has entered into contracts for future crude oil purchases, whereby there is a requirement to pay the market difference of the inventory price paid at delivery and the current market price at the settlement date in the future. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. For the nine months ended September 30, 2010, an unrealized loss of less than \$1 million has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Interest Rate Risk

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

- U.S. \$200 million of long-term debt whereby a fixed interest rate of 7.55% was swapped for rates ranging from LIBOR + 399 bps to LIBOR + 430 bps until November 15, 2016.
- U.S. \$300 million of long-term debt whereby a fixed interest rate of 6.20% was swapped for rates ranging

from LIBOR + 255 bps to LIBOR + 275 bps until September 15, 2017.

- U.S. \$150 million of long-term debt whereby a fixed interest rate of 5.90% was swapped for rates ranging from LIBOR + 349 bps to LIBOR + 350 bps until June 15, 2014.
- CAD \$300 million of long-term debt whereby a fixed interest rate of 3.75% was swapped for rates ranging from CDOR + 0.80% to CDOR + 0.85% until March 12, 2015.

During the first nine months of 2010, these swaps resulted in an offset to interest expense amounting to \$5 million. The amortization of previous interest rate swap terminations resulted in an addition to interest expense of \$1 million in 2010.

Cross currency swaps resulted in an addition to interest expense of \$2 million in the first nine months of 2010.

Foreign Currency Risk

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

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

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. During the first nine months of 2010, the impact of these contracts was a realized gain of \$22 million recorded in foreign exchange expense.

At September 30, 2010, the cost of a U.S. dollar in Canadian currency was \$1.0298.

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, 2010, 79% 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 70% when the cross currency swaps are considered.

As at September 30, 2010, the Company has designated U.S. \$987 million of its U.S. debt as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. In the first nine months of 2010, the unrealized foreign exchange gain arising from the translation of the debt was \$13 million, net of tax expense of \$4 million, which was recorded in Other Comprehensive Income.

Including cross currency swaps and the debt that has been designated as a hedge of a net investment, 45% 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

8. Critical Accounting Estimates

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

9. Accounting Policies

Recent Accounting Pronouncements

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

Contingent liabilities are to be recognized at fair value at the acquisition date and re-measured at fair value through

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, 2010, Husky's share of this receivable was U.S. \$1.3 billion including accrued interest. Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in Other Comprehensive Income as this item relates to a self-sustaining foreign operation. At September 30, 2010, Husky's share of this obligation was U.S. \$1.5 billion including accrued interest.

Fair Value of Financial Instruments

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

discussion about those accounting policies, please refer to Husky's MD&A for the year ended December 31, 2009 available at www.sedar.com and www.sec.gov.

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

In January 2009, the CICA issued Section 1601, "Consolidated Financial Statements," which will replace CICA Section 1600 of the same name. This guidance requires uniform accounting policies to be consistent throughout all consolidated entities and the difference between reporting dates of a parent and a subsidiary to be

no longer than three months. These are not explicitly required under the current standard. Section 1601 is effective for Husky on January 1, 2011 with early adoption permitted. This standard will have no impact to the Company.

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

International Financial Reporting Standards

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

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

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

The Company has completed its most significant information technology systems conversion for dual reporting capabilities in preparation for IFRS. System initiatives for minor areas of convergence are progressing and will be completed by the end of 2010.

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

The Company is finalizing its assessments on IFRS transition issues with expected impacts. Evaluations of IFRS financial statement presentation and disclosure requirements have been completed. These assessments require further monitoring and evaluation throughout the implementation phase of the Company's project. The Company has determined that the areas of most significant impact will include property, plant and equipment and asset retirement obligations.

Property, Plant and Equipment

In July 2009, the International Accounting Standards Board ("IASB") approved additional IFRS transitional exemptions that will allow entities that previously followed full cost accounting in accordance with Accounting Guideline 16 of the CICA Handbook to allocate each of their upstream oil and gas asset balances as determined under full cost accounting to the IFRS categories of exploration and evaluation assets and development and producing assets. This exemption will relieve entities from significant adjustments resulting from retrospective adoption of IFRS. The Company intends to utilize this exemption for its Canadian upstream full cost asset base. The Company intends to not apply the full cost exemption for its International upstream properties as detailed information is available. As a result, the Company plans to retrospectively apply its proposed IFRS accounting policies and record incremental exploration expenses and depletion as an adjustment to opening retained earnings.

Under IFRS, the Company intends to adopt accounting policies for its oil and natural gas exploration, evaluation and development expenditures that differ significantly when compared with the full cost method employed under Canadian GAAP, which allows for the capitalization of all costs associated with the acquisition, exploration, and development of oil and gas reserves on a country-by-country basis. Under IFRS 6, pre-exploration and evaluation costs, which include all exploratory costs incurred prior to the acquisition of the legal right to explore, will be expensed as incurred. The Company will expense certain exploration costs incurred after the legal right to explore is acquired. These costs include geological and geophysical

activity such as seismic programs and technical analysis. Land acquisition costs and expenditures directly associated with exploratory wells will be capitalized as exploration and evaluation assets. Land acquisition costs will remain capitalized until the Company has chosen to discontinue all exploration activities in the associated area. Exploratory wells will remain capitalized until the drilling operation is complete and the results have been evaluated. If the well does not encounter reserves of commercial quantity, either on its own or in combination with other exploration wells associated with the same area of exploration, the costs of drilling the well or wells will be charged to expense. Wells that result in commercial quantities of reserves will remain capitalized in property, plant and equipment. The adoption of these accounting policies will result in increased expenses in net earnings due to earlier recognition of exploration expenses under IFRS.

Oil and gas properties will be depleted under IFRS on a unit-of-production basis based on the unit of measure to which an asset is assigned. In the case of assets whose useful life is shorter or longer than the lifetime of the associated fields' production profile, the straight-line method of depreciation is applied. The Company intends to define unit of accounts at the field level for the unit-of-production depletion calculation. Under full cost accounting, depletion is calculated using the unit-of-production method on a country-by-country basis. Depletion, depreciation and amortization expense is expected to be higher in the near term under IFRS for the Canadian upstream properties. As the Company's existing fields are depleted, depletion under IFRS is expected to be lower than under full cost accounting as the impact of expensing exploration costs earlier will result in a lower capital base in the future.

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

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

impairment is tested on a country-by-country basis and cannot be reversed. Asset impairment within the midstream and downstream segments is assessed at the asset or group of similar assets level.

Asset Retirement Obligations

Asset retirement obligations ("ARO") are not re-measured for changes in discount rates in each reporting period under Canadian GAAP. IFRS requires current period discount rates to be used for re-measurement of all existing liabilities with changes in the balance recorded to property, plant and equipment. As a result, the ARO balance is expected to vary under IFRS compared with Canadian GAAP based on changes in the discount rate.

The use of the full cost exemption for Canadian upstream properties will require the Company to revalue the ARO liability to its IFRS balance on transition with an adjustment to opening retained earnings.

Other IFRS 1 Exemptions

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

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

Impact of Conversion

The Company estimates that the impact of the conversion to IFRS will be a reduction in retained earnings on January 1, 2010 in the range of \$600 million to \$1.3 billion. Reported net earnings in 2010 are expected to be between \$150 to \$250 million lower when presented in accordance with IFRS primarily as a result of expensing certain exploration costs and adjustments to depletion and depreciation expenses.

10. Outstanding Share Data

<i>(in thousands)</i>	October 27 2010	December 31 2009
Issued and outstanding		
Number of common shares	849,892	849,861
Number of stock options	29,951	28,399
Number of stock options exercisable	17,310	14,917

11. Reader Advisories

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

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

Use of Pronouns and Other Terms Denoting Husky

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

Additional Reader Guidance

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

Non-GAAP Measures

Disclosure of Cash Flow from Operations

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

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

<i>(millions of dollars)</i>		Three months ended Sept. 30		Nine months ended Sept. 30	
		2010	2009	2010	2009
Non-GAAP	Cash flow from operations	\$ 811	\$ 452	\$ 2,512	\$ 1,850
	Settlement of asset retirement obligations	(12)	(9)	(34)	(24)
	Change in non-cash working capital	160	301	(431)	(284)
GAAP	Cash flow - operating activities	\$ 959	\$ 744	\$ 2,047	\$ 1,542

Disclosure of Adjusted Net Earnings

This interim report may contain the term "adjusted net earnings," which is a non-GAAP measure of net earnings adjusted for certain items that are not an indicator of the Company's on-going financial performance. Husky's

determination of adjusted net earnings, which is a non-GAAP measure, does not have any standardized meaning prescribed by GAAP and therefore is unlikely to be comparable to similar measures presented by other users.

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

<i>(millions of dollars)</i>		Three months ended Sept. 30		Nine months ended Sept. 30	
		2010	2009	2010	2009
GAAP	Net earnings	\$ 257	\$ 338	\$ 868	\$ 1,096
	Net foreign exchange	8	(12)	(5)	(8)
	Net financial instruments	(5)	(19)	9	8
	Net stock-based compensation	-	(1)	-	1
	Net inventory write-downs	-	19	21	44
Non-GAAP	Adjusted net earnings	\$ 260	\$ 325	\$ 893	\$ 1,141

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.

Disclosure of Oil and Gas Reserves and Other Oil and Gas Information

The P1IP disclosed in this document has been evaluated in accordance with the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101. P1IP is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those

estimated quantities in accumulations yet to be discovered. These resources were estimated following the drilling and testing of the Liuhua 34-3-1 exploration well, the Liwan 3-1-10 well, and the Liuhua 29-1-3 appraisal well. There is no certainty that it will be commercially viable to produce any portion of the resources.

Abbreviations

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

Terms

<i>Bitumen</i>	<i>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</i>
<i>Capital Employed</i>	<i>Short and long-term debt and shareholders' equity</i>
<i>Capital Expenditures</i>	<i>Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets</i>
<i>Capital Program</i>	<i>Capital expenditures not including capitalized administrative expenses or capitalized interest</i>
<i>Cash Flow from Operations</i>	<i>Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital</i>
<i>Coal Bed Methane</i>	<i>Methane (CH₄), the principal component of natural gas, is adsorbed in the pores of coal seams</i>
<i>Corporate Reinvestment Ratio</i>	<i>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</i>
<i>Dated Brent</i>	<i>Prices are dated less than 15 days prior to loading for delivery</i>
<i>Debt to Capital Employed</i>	<i>Total debt divided by total debt and shareholders' equity</i>
<i>Debt to Cash Flow</i>	<i>Total debt divided by cash flow from operations calculated on a 12-month trailing basis</i>
<i>Delineation Well</i>	<i>A well in close proximity to an oil or gas discovery well that helps determine the areal extent of the reservoir</i>
<i>Diluent</i>	<i>A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline</i>
<i>Equity</i>	<i>Shares, retained earnings and accumulated other comprehensive income</i>
<i>Feedstock</i>	<i>Raw materials which are processed into petroleum products</i>
<i>Front End Engineering Design</i>	<i>Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics</i>
<i>Glory Hole</i>	<i>An excavation in the seabed where the wellheads and other equipment are situated to protect them from scouring icebergs</i>
<i>Gross/Net Acres/Wells</i>	<i>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</i>
<i>Gross Reserves/Production Hectare</i>	<i>A company's working interest share of reserves/production before deduction of royalties</i>
<i>Hectare</i>	<i>One hectare is equal to 2.47 acres</i>
<i>Near-month Prices</i>	<i>Prices quoted for contracts for settlement during the next month</i>
<i>NOVA Inventory Transfer</i>	<i>Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline</i>
<i>Return on Capital Employed</i>	<i>Net earnings plus after tax interest expense calculated on a 12-month trailing basis divided by average capital employed</i>
<i>Return on Shareholders' Equity</i>	<i>Net earnings calculated on a 12-month trailing basis divided by average shareholders' equity</i>
<i>Stratigraphic Well</i>	<i>A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production</i>
<i>Synthetic Oil</i>	<i>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</i>
<i>Three Dimensional (3-D) Seismic</i>	<i>Seismic imaging which uses a grid of numerous cables rather than a few lines stretched in one line</i>
<i>Total Debt</i>	<i>Long-term debt including current portion and bank operating loans</i>
<i>Turnaround</i>	<i>Scheduled performance of plant or facility maintenance</i>

12. Forward-Looking Statements and Information

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

In particular, forward-looking statements in this interim report include, but are not limited to: the Company's general strategic plans; growth and 2010 capital expenditure plans and guidance; drilling and production plans for the West White Rose field; drilling, production and enhanced recovery plans and anticipated timing for the South Pike's Peak field; exploration plans for Canada's East Coast; development and production plans for the North Amethyst oil field; offshore Greenland exploration plans and anticipated results; offshore China exploration plans; delineation drilling, development and production plans and applications for regulatory approval for the Liwan and Liuhua natural gas discoveries; processing and transportation plans for the Liwan and Liuhua natural gas discoveries; exploration and drilling plans for the North Sumbawa II Block; development plans for the Madura BD field; Sunrise multiphase development plans, production plans and production capacity; anticipated timing of regulatory approvals and production at Sunrise and production optimization and drilling plans for the Tucker Oil Sands Project; development plans for the McMullen property; testing and implementation of various enhanced recovery techniques and carbon emissions and capture techniques in Western Canada; anticipated timing of integration of recent asset acquisitions; anticipated effect of recent asset acquisitions on the

Company's production, reserves, business and operations; conventional and shale gas exploration plans for Northeastern British Columbia; drilling plans in southern Saskatchewan; Husky's coal bed methane program; planned exploration for and development of gas resource plays; reconfiguration plans for the Lima Refinery; expected results of scheduled maintenance at the Lima Refinery; Continuous Catalyst Regeneration Reformer Project plans at the Toledo Refinery; plans to reposition and upgrade the Toledo Refinery; planned maintenance at the Lloydminster Upgrader and the SeaRose FPSO; timing of rebranding of retail outlets in Southern Ontario; timing of redetermination of Husky's working interest in the Terra Nova field; estimated tax instalments in respect of 2009 earnings; and expected implementation and impacts of the switch to IFRS.

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

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

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