MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") JULY 22, 2009

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1. Summary of Quarterly Results

- Solid results in earnings and cash flow despite impact of significantly lower commodity prices compared with 2008.
- Financial position remains strong with debt to cash flow ratio of 1.0 and debt to capital employed ratio of 19.8%.
- Cash flow from operations includes $252 million of cash tax instalments related to 2008 earnings with total cash taxes paid in the quarter of $258 million.
- Overall production on target compared with guidance; however natural gas production reflects impact of lower capital expenditures and prices.
- Total upstream operating costs declined by 11% compared with 2008, and have stabilized on a boe basis.
- Major capital projects offshore Canada's East Coast and South East Asia on schedule.
- Drilling of the second Liwan appraisal well completed with encouraging results.

Quarterly Financial Summary [1]	Three months ended							
(millions of dollars, except per share amounts)	June 30 2009	March 31 2009	Dec. 31 2008	Sept. 30 2008	June 30 2008	March 31 2008	Dec. 31 2007	Sept. 30 2007
Sales and operating revenues, net of royalties	$ 3,916	$ 3,650	$ 4,701	$ 7,715	$ 7,199	$ 5,086	$ 4,760	$ 4,351
Net earnings	430	328	231	1,274	1,358	888	1,077	777
Per share - Basic and diluted	0.51	0.39	0.27	1.50	1.60	1.05	1.27	0.92
Cash flow from operations	833	565	332	1,997	2,079	1,538	1,423	1,425
Per share - Basic and diluted	0.98	0.67	0.39	2.35	2.45	1.81	1.68	1.68

[1] 2008 and 2007 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.

2. Business Environment

Average Benchmarks		Three months ended					
		June 30 2009	March 31 2009	Dec. 31 2008	Sept. 30 2008	June 30 2008	March 31 2008
WTI crude oil [(1)]	(U.S. $/bbl)	59.62	43.08	58.73	117.98	123.98	97.90
Brent crude oil [(2)]	(U.S. $/bbl)	58.79	44.40	54.91	114.78	121.38	96.90
Canadian light crude 0.3% sulphur	($/bbl)	66.21	50.09	63.92	122.53	126.73	98.20
Lloyd heavy crude oil @ Lloydminster	($/bbl)	56.36	35.72	39.76	96.17	89.70	64.23
NYMEX natural gas [(1)]	(U.S. $/mmbtu)	3.50	4.89	6.94	10.24	10.93	8.03
NIT natural gas	($/GJ)	3.47	5.34	6.43	8.76	8.86	6.76
WTI/Lloyd crude blend differential	(U.S. $/bbl)	7.72	9.20	19.41	18.34	21.95	21.81
Chicago 3:2:1 crack spread	(U.S. $/bbl)	10.91	9.49	6.37	17.01	13.60	7.70
New York Harbor 3:2:1 crack spread	(U.S. $/bbl)	9.05	10.15	6.59	11.60	13.02	9.34
U.S./Canadian dollar exchange rate	(U.S. $)	0.858	0.803	0.825	0.960	0.990	0.996

[(1)] Prices quoted are near-month contract prices for settlement during the next month.
[(2)] Dated Brent prices which are dated less than 15 days prior to loading for delivery.

Oil and Gas Prices

Husky's earnings are largely determined by realized prices for crude oil and natural gas including the U.S./Canadian dollar exchange rate. Fluctuations in Husky's earnings are primarily related to the volatility of oil and gas prices, which are determined by market forces over which the Company has no control.

Crude oil prices rose steadily from February to June, partially due to market expectations that the global economy will begin to recover in late 2009. The sustainability of the recent increase in crude oil prices is uncertain, particularly in light of the current high global level of inventories, surplus productive capacity and uncertainty on the timing of the economic recovery.

The price Husky receives for production from Western Canada is primarily driven by changes in the price of West Texas Intermediate ("WTI") while the majority of the Company's production offshore the East Coast of Canada is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2008 at U.S. $44.60/bbl, subsequently averaged approximately U.S. $43.08/bbl in the first quarter of 2009 compared with U.S. $97.90/bbl in the first quarter of 2008 and increased to an average of U.S. $59.62/bbl in the second quarter of 2009 compared with U.S. $123.98/bbl in the second quarter of 2008. During most of the second quarter of 2009, WTI returned to trading at a premium to Brent. The price of Brent ended 2008 at U.S. $36.55/bbl, subsequently averaged approximately U.S. $44.40/bbl in the first quarter of 2009 compared with U.S. $96.90/bbl in the first quarter of 2008 and increased to an average of U.S. $58.79/bbl in the second quarter of 2009 compared with U.S. $121.38/bbl in the second quarter of 2008.

A portion of Husky's crude oil production is classified as heavy crude oil, which trades at a discount to light crude oil. In the second quarter of 2009, 45% of Husky's crude oil production was heavy compared with 41% in the second quarter of 2008. The light/heavy crude oil differential averaged U.S. $7.72/bbl in the second quarter of 2009 compared with U.S. $21.95/bbl in the second quarter of 2008.

The near-month natural gas price quoted on the NYMEX ended 2008 at U.S. $5.62/mmbtu and subsequently declined steadily through the first half of 2009 to U.S. $3.84/mmbtu at June 30, 2009. During the second quarter of 2009, the NYMEX near-month contract price of natural gas averaged U.S. $3.50/mmbtu compared with U.S. $10.93/mmbtu in the second quarter of 2008. During the first quarter of 2009, the NYMEX near-month contract price of natural gas averaged U.S. $4.89/mmbtu compared with U.S. $8.03/mmbtu in the first quarter of 2008. Low natural gas prices continue to reflect higher than average storage levels, and, more significantly, the decline in industrial consumption as a result of the continued decline in economic activity. Natural gas storage levels were above historic levels throughout the first half of 2009. At the end of the second quarter of 2009, natural gas inventories were 29% higher than the five-year average and 21% higher than the previous year.

Foreign Exchange

The majority of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. Husky's results are affected by the exchange rate between the Canadian and U.S. dollar with a decrease in the value of the Canadian dollar relative to the U.S. dollar increasing the revenues received from the sale of oil and gas commodities, offsetting the effect of lower oil and natural gas prices.

The Canadian dollar ended 2008 at U.S. $0.817 and subsequently strengthened by 5% against the U.S. dollar in the first half, closing at U.S. $0.860 at June 30, 2009. In the first quarter of 2009, the Canadian dollar averaged U.S. $0.803 per Canadian dollar compared with U.S. $0.996 during the first quarter of 2008. During the second quarter of 2009, the Canadian dollar averaged U.S. $0.858 per Canadian dollar compared with U.S. $0.990 during the second quarter of 2008.

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 quarter of 2009 the Chicago 3:2:1 crack spread averaged U.S. $9.49/bbl compared with U.S. $7.70/bbl in the first quarter of 2008. During the second quarter of 2009, the Chicago 3:2:1 crack spread averaged U.S. $10.91/bbl compared with U.S. $13.60/bbl in the second quarter of 2008. In the first quarter of 2009, the New York Harbor 3:2:1 crack spread averaged U.S. $10.15/bbl compared with U.S. $9.34/bbl in the first quarter of 2008. During the second quarter of 2009, the New York Harbor 3:2:1 crack spread averaged U.S. $9.05/bbl compared with U.S. $13.02/bbl in the second quarter of 2008.

During the second quarter of 2009, the 3:2:1 crack spreads were lower than the same period in 2008 reflecting the continuing weak U.S. economic environment more than offsetting the increased demand for gasoline associated with the commencement of summer driving season.

Realized refining margins are affected by the product configuration of each refinery 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

The oil and gas industry experienced an increase in costs in excess of the general rate of inflation during the recent years of increasing energy prices. These increases affect the cost of operating the Company's oil and gas properties, processing plants and refineries. They also affect capital projects, which are susceptible to cost volatility. With the exception of energy consumed by the industry, the cost environment has not yet reflected, to the same extent as commodity prices, the impact of the current economic conditions. However, there are encouraging signs that current economic conditions may result in reduced capital and operating costs in the future.

Global Economic and Financial Environment

The global economic and financial crisis has reduced liquidity in financial markets, restricted access to financing and caused significant declines in economic activity resulting in demand destruction for commodities and lower pricing. This affected the economy in the latter half of 2008 and continued into the first quarter of 2009.

In the wake of the economic downturn world oil consumption declined and commercial inventories of crude oil have reached above average historical levels. The Energy Information Administration's ("EIA") July 2009 Short-Term Energy Outlook[1] indicates that world oil consumption declined by 3.0 mmbbls/day from the fourth quarter of 2008 through the second quarter of 2009 primarily in OECD countries. The EIA now expects oil consumption to decline by 1.6 mmbbls/day in 2009 compared with 2008, but expects world oil consumption will grow by 0.9 mmbbls/day in 2010, due to an expected positive growth in the global economy. The EIA expects 2009 non-OPEC supply of crude oil will rise by 0.4 mmbbls/day in 2009 and remain at that level during 2010. OPEC production is estimated to have declined to 28.6 mmbbls/day in the second quarter 2009 and is expected to remain at current levels in the second half of 2009. OPEC production is expected to trend upward in 2010 in line with anticipated increasing demand. OPEC surplus productive capacity, primarily in Saudi Arabia, should restrain rising prices.

Note:

(1) Energy Information Administration, Short-Term Energy Outlook DOE/EIA – July 7, 2009 Release

Demand for natural gas in North American markets has also retracted in line with lower industrial and commercial consumption; as a result, working gas in storage continues to increase above five-year averages. The EIA currently forecasts a 2.3% decline in U.S. natural gas consumption in 2009 and to remain at 2009 levels in 2010. The EIA expects U.S. marketed natural gas production to decline year over year by 0.6% and 2.9%, respectively, in 2009 and 2010. Natural gas shortages are not anticipated as demand begins to ramp up due to improvements in technology that has reduced finding and development costs, improved completion times and enhanced well productivity. The EIA expects liquefied natural gas imports to increase in 2009 to 506 bcf from 352 bcf in 2008.

In its July outlook the EIA estimates that fuel consumption in the United States in 2009 will fall by 650 mbbls/day or 3.3%, including 280 mbbls/day or 7.0% in diesel and 140 mbbls/day or 8.7% in jet fuel. Consumption of motor gasoline is expected to remain flat as lower gasoline prices have partly offset the effects of the lower economic activity. The EIA's July forecast expects a 310 mbbls/day or 1.6% increase in fuel consumption in 2010. According to EIA data released on July 8, 2009, U.S. gasoline stocks were 213 mmbbls, 1.3 mmbbls higher than the previous year; U.S. distillate stocks were 159 mmbbls, 36.2 mmbbls higher than the previous year.

The current prospect that demand for energy will increase later in 2009 and 2010 depends on a number of assumptions about the timing and sustainability of a global economic recovery.

Companies with low operating costs and flexible capital expenditure plans, strong cash generation from operations, availability of cash and cash equivalents, low debt with long maturities and unused committed credit facilities will be better positioned to manage through this crisis.

In view of the current economic environment, Husky took action in 2008 and prudently reduced capital spending in 2009 and is reviewing and implementing cost containment and efficiency opportunities throughout the organization. Husky is managing its credit facilities and access to capital markets in order to enhance liquidity in the near term.

Sensitivity Analysis

The following table indicates the relative annual effect of changes in certain key variables on Husky's pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the second quarter of 2009. 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	2009 Second Quarter Average		Increase	Effect on Annual Pre-tax Cash Flow [6]		Effect on Annual Net Earnings [6]	
				($ millions)	($/share) [7]	($ millions)	($/share) [7]
Upstream and Midstream							
WTI benchmark crude oil price [1]	$	59.62	U.S. $1.00/bbl	77	0.09	55	0.06
NYMEX benchmark natural gas price [2]	$	3.50	U.S. $0.20/mmbtu	29	0.03	21	0.02
WTI/Lloyd crude blend differential [3]	$	7.72	U.S. $1.00/bbl	(13)	(0.01)	(10)	(0.01)
Downstream							
Canadian light oil margins	$	0.044	Cdn $0.005/litre	14	0.02	10	0.01
Asphalt margins	$	25.93	Cdn $1.00/bbl	6	0.01	5	0.01
New York Harbor 3:2:1 crack spread [4]	$	9.05	U.S. $1.00/bbl	90	0.11	57	0.07
Consolidated							
Exchange rate (U.S. $ per Cdn $) [1] [5]	$	0.858	U.S. $0.01	(67)	(0.08)	(43)	(0.05)
Interest rate			100 basis points	-	-	-	-

(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 derivatives.
(7) Based on 849.9 million common shares outstanding as of June 30, 2009.

3. Results of Operations

3.1 Upstream

Upstream Net Earnings Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2009	2008	2009	2008
Gross revenues	$ 1,391	$ 3,081	$ 2,638	$ 5,334
Royalties	224	657	426	1,081
Net revenues	1,167	2,424	2,212	4,253
Operating and administration expenses	364	409	741	793
Depletion, depreciation and amortization	348	352	719	742
Other	-	(81)	-	(52)
Income taxes	132	505	218	814
Net earnings	$ 323	$ 1,239	$ 534	$ 1,956

Second Quarter

Upstream earnings in the second quarter of 2009 decreased by $916 million compared with the second quarter of 2008 primarily as a result of significant declines in the prices realized for crude oil and natural gas combined with a 12% decrease in production compared to the same period in 2008. Production of crude oil and natural gas declined mainly due to lower light oil production off the East Coast of Canada and lower natural gas production in Western Canada.

During the second quarter of 2009, Husky's realized heavy crude oil and bitumen prices averaged $54.02/bbl compared to a light crude oil and NGL price of $65.32/bbl. In the second quarter of 2008 Husky's realized heavy crude oil and bitumen prices averaged $89.35/bbl compared to a light crude oil and NGL price of $121.71/bbl. The decreasing heavy oil differential partially offset the impacts of lower production and declining commodity prices.

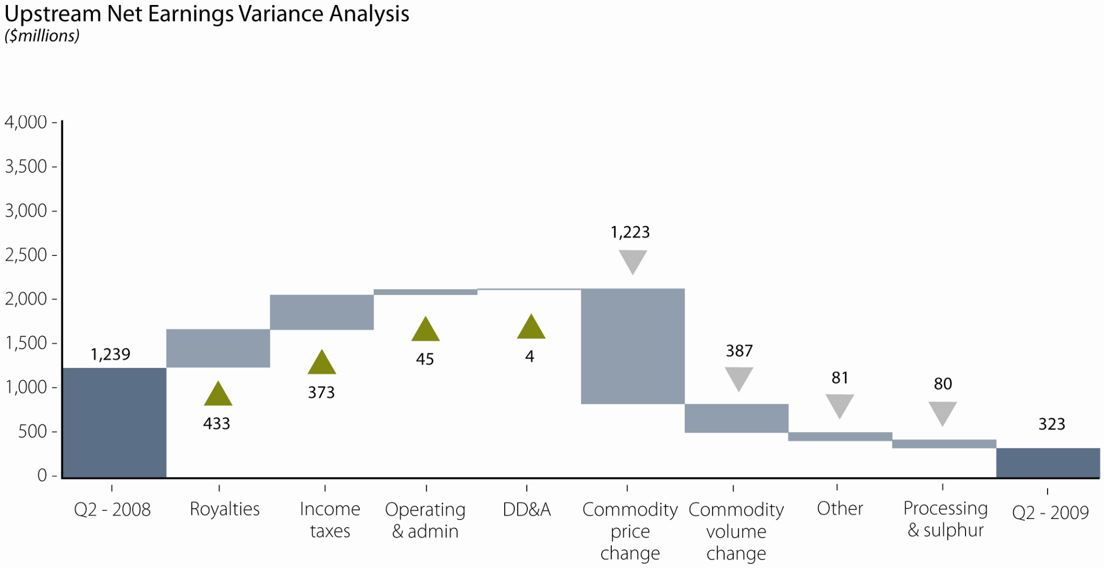
Six Months

Upstream earnings in the first six months of 2009 were $1,422 million lower than the same period in 2008 primarily as a result of the same factors impacting the second quarter.

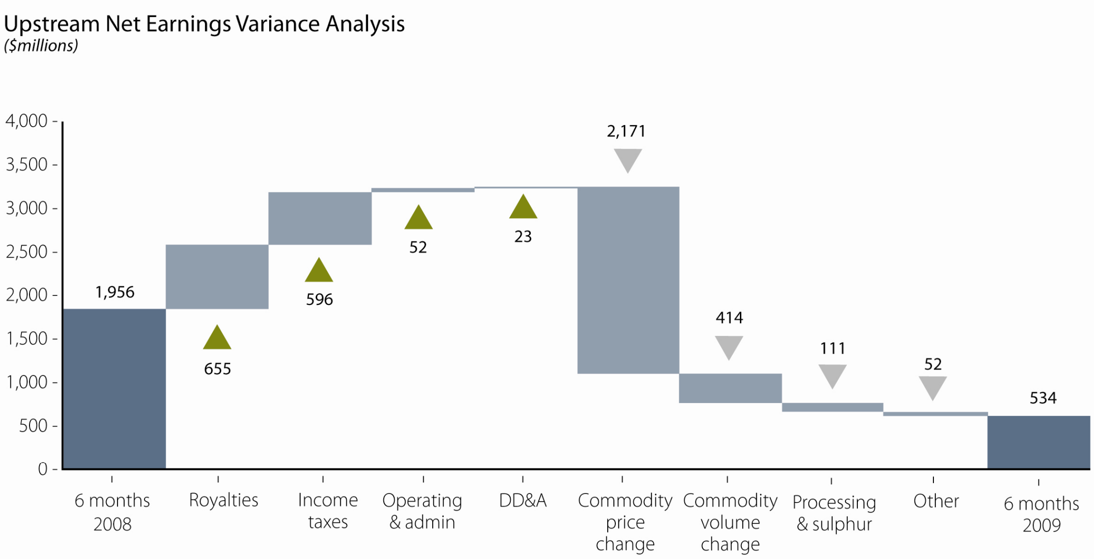
During the first six months of 2009, Husky's realized heavy crude oil and bitumen prices averaged $44.58/bbl compared to a light crude oil and NGL price of $57.24/bbl. In the first six months of 2008 Husky's realized heavy crude oil and bitumen prices averaged $76.69/bbl compared to a light crude oil and NGL price of $108.64/bbl.

Upstream Net Earnings Variance Analysis

Second Quarter



Six Months



Pricing

Average Sales Prices Realized		Three months ended June 30		Six months ended June 30	
		2009	2008	2009	2008
Crude oil	($/bbl)				
Light crude oil & NGL		$ 65.32	$ 121.71	$ 57.24	$ 108.64
Medium crude oil		58.32	101.87	49.42	88.13
Heavy crude oil & bitumen		54.02	89.35	44.58	76.69
Total average		59.49	106.29	50.92	93.26
Natural gas	($/mcf)				
Average		3.26	9.14	4.28	8.11

Oil and Gas Production

Daily Gross Production		Three months ended June 30		Six months ended June 30	
		2009	2008	2009	2008
Crude oil & NGL	(mbbls/day)				
Western Canada					
Light crude oil & NGL		21.7	24.0	22.9	24.7
Medium crude oil		25.6	27.0	26.0	27.0
Heavy crude oil & bitumen		100.3	105.5	102.5	104.9
		147.6	156.5	151.4	156.6
East Coast Canada					
White Rose - light crude oil		55.2	75.6	62.6	71.6
Terra Nova - light crude oil		10.7	12.5	11.6	13.7
China					
Wenchang - light crude oil & NGL		11.7	11.5	12.0	12.1
Total crude oil & NGL		225.2	256.1	237.6	254.0
Natural gas	(mmcf/day)	552.3	618.0	551.7	604.2
Total	(mboe/day)	317.2	359.1	329.6	354.7

Crude Oil and NGL Production

Second Quarter

Crude oil and NGL production in the second quarter of 2009 decreased by 12% compared with the same period in 2008. Off the East Coast of Canada, production from White Rose decreased by 20.4 mbbls/day or 27%. Subsea operational issues which commenced in October 2008 resulted in the loss of approximately 7.0 mbbls/day with the remainder of the decline due to heavy iceberg conditions, which resulted in facility throughput restrictions on the SeaRose due to a lower tank top requirement and offloading restrictions, general facilities maintenance and general reservoir decline. At Terra Nova, facility operational issues resulted in lower production in 2009 compared with 2008. Terra Nova was shut down for scheduled maintenance on June 22, 2009 and in the second quarter of 2008 was shut down for 14 days.

During the second quarter of 2009, crude oil, bitumen and NGL production from Western Canada decreased by 8.9 mboe/day or 6% compared with the second quarter of 2008 primarily due to the shut in of higher cost facilities, reservoir decline and a strategic decision to decrease bitumen production to focus on steam chamber development at Tucker.

Six Months

In the first six months of 2009, crude oil and NGL production decreased by 6% primarily due to the same factors impacting the second quarter.

Natural Gas Production

Second Quarter

Production of natural gas decreased by 65.7 mmcf/day or 11% in the second quarter of 2009 compared with the second quarter of 2008 due to the impact of reduced capital expenditures on drilling and tie-ins, flowline restrictions and general reservoir decline.

Six Months

In the first six months of 2009, natural gas production decreased by 9% primarily due to the same factors impacting the second quarter.

2009 Gross Production Guidance			Actual Production	
		Guidance 2009	Six months ended June 30 2009	Year ended Dec. 31 2008
Crude oil & NGL	(mbbls/day)			
Light crude oil & NGL		92 - 109	109	123
Medium crude oil		25 - 28	26	27
Heavy crude oil & bitumen		95 - 105	103	107
		212 - 242	238	257
Natural gas	(mmcf/day)	585 - 620	552	594
Total barrels of oil equivalent	(mboe/day)	310 - 345	330	356

Royalties

Second Quarter

In the second quarter of 2009, royalty rates averaged 16% compared with 21% in 2008. Royalty rates in Western Canada averaged 11% as a percentage of gross revenue, down from 16% in the second quarter of 2008 due to commodity price decreases of approximately 50% which resulted in reduced price sensitive royalty rates across all products and provinces. Off the East Coast of Canada, rates averaged 28% compared with 31% in the second quarter of 2008 primarily as a result of positive adjustments to 2008 royalties recaptured in 2009 as a result of annual reconciliations filed in accordance with East Coast royalty regulations. Royalty rates in Wenchang averaged 16% compared with 28% in the second quarter of 2008. The royalty rate for Wenchang has declined due to the sliding scale royalty clause in the PSC that results in lower rates in lower commodity price environments.

Six Months

Royalty rates averaged 16% of gross revenue in the first six months compared with 20% in the same period in 2008. Rates in Western Canada averaged 12% compared with 16% in 2008 and off the East Coast of Canada the average rate was 26% compared with 28% in the same period in 2008. The decrease in rates for the first six months was due to the same factors impacting the second quarter.

Operating Costs

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2009	2008	2009	2008
Western Canada	$ 267	$ 309	$ 566	$ 607
East Coast Canada	47	43	83	83
International	5	6	10	11
Total	$ 319	$ 358	$ 659	$ 701

Second Quarter

Total upstream operating costs have decreased 11% from $358 million to $319 million primarily as a result of reduced energy costs in all areas, partially offset by higher maintenance costs. Total upstream unit operating costs in the second quarter of 2009 have stabilized, averaging $11.05/boe compared with $10.91/boe in the second quarter of 2008, as lower costs were offset by lower production.

Operating costs in Western Canada averaged $12.29/boe in the second quarter of 2009 compared with $12.95/boe in the same period in 2008 primarily as a result of lower energy costs partially offset by lower production. Reduced energy costs and consumption were partially offset by increased maintenance costs. Costs are generally increasing in Western Canada due to the nature of exploitation necessary to manage production from maturing fields and new more extensive but less prolific reservoirs. Western Canada operations require increasing amounts of infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive pipeline systems, crude and water trucking and more complex natural gas compression systems. These factors in turn require higher energy consumption, workovers and generally more material costs. Husky is focused on managing rising operating costs through cost reduction and efficiency initiatives and keeping infrastructure, including gas plants, crude processing plants, transportation systems, compression systems, lease access and other infrastructure fully utilized.

Operating costs at the East Coast offshore operations averaged $7.73/bbl in the second quarter of 2009 compared with $5.47/bbl in the same period in 2008 primarily as a result of lower production and higher maintenance costs partially offset by reduced energy and labour costs.

Operating costs at the South China Sea offshore operations averaged $4.45/bbl in the second quarter of 2009 compared with $5.19/bbl in the same period in 2008, as a result of lower energy and reduced maintenance costs.

Six Months

Total upstream operating costs in the first half of 2009 decreased by 6% compared with the same period in 2008 primarily due to the same factors affecting the second quarter.

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

Second Quarter

In the second quarter of 2009, total unit DD&A averaged $12.06/boe compared with $10.78/boe in the second quarter of 2008. The higher DD&A rate in 2009 was primarily due to lower oil and gas reserves and a higher full cost base.

Six Months

For the first six months of 2009, total unit DD&A averaged $12.06/boe compared with $11.50/boe during the same period in 2008 primarily due to lower oil and gas reserves and a higher full cost base, partially offset by the effect of the disposition of 50% of the Sunrise oil sands asset on March 31, 2008.

Other Items

During the fourth quarter of 2008, a drilling contract previously treated as an embedded derivative no longer met the criteria and the related accounting treatment was discontinued. A gain of $11 million was recorded in the second quarter of 2008. A loss of $17 million was recorded for the first six months of 2008. Other items also include a gain of $69 million on the sale of 50% of Husky Oil (Madura) Limited to CNOOC Ltd. in the second quarter of 2008.

Upstream Capital Expenditures

For the first six months of 2009, upstream capital expenditures were $1,073 million, 51% of the 2009 capital expenditure guidance. Husky's major upstream projects offshore the East Coast of Canada and offshore China remain on schedule. Upstream capital expenditures were $458 million (43%) in Western Canada, $368 million (34%) offshore the East Coast of Canada, $232 million (22%) in South East Asia, $12 million (1%) in the Northwest United States and $3 million offshore Greenland.

Capital Expenditures Summary [1]	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2009	2008	2009	2008
Exploration				
Western Canada	$ 31	$ 103	$ 99	$ 309
East Coast Canada and Frontier	-	20	52	45
Northwest United States	7	-	12	-
International	123	32	229	62
	161	155	392	416
Development				
Western Canada	78	394	359	863
East Coast Canada	160	73	316	141
International	6	3	6	3
	244	470	681	1,007
	$ 405	$ 625	$ 1,073	$ 1,423

[1] Excludes capitalized costs related to asset retirement obligations incurred during the period and the BP joint venture transaction.

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

Western Canada and Oil Sands Wells Drilled		Three months ended June 30				Six months ended June 30			
		2009		2008		2009		2008	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	4	1	5	3	6	3	28	26
	Gas	9	3	7	4	31	21	64	53
	Dry	-	-	-	-	5	5	20	19
		13	4	12	7	42	29	112	98
Development	Oil	26	19	73	73	101	90	193	177
	Gas	15	2	19	17	92	51	135	104
	Dry	-	-	-	-	4	4	3	3
		41	21	92	90	197	145	331	284
Total		54	25	104	97	239	174	443	382

Western Canada

During the first six months of 2009, Husky invested $458 million on exploration and development throughout the Western Canadian Sedimentary Basin. Of this, $172 million was invested on oil development and $107 million was invested on natural gas development. The Company drilled 174 net wells in the basin resulting in 93 net oil wells and 72 net natural gas wells. In addition, $28 million was spent on production optimization and operating cost reduction initiatives. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to $32 million.

During the first six months of 2009, $2 million was spent on property acquisitions. Capital expenditures on oil sands projects were minimal.

Husky's high impact exploration program is conducted along the foothills of Alberta and British Columbia and in the deep basin region of Alberta. In the first six months of 2009, $66 million was invested in drilling in these natural gas prone areas and $51 million was spent on follow-up development including tie-ins, facility installation and development drilling. During this period, 10 net exploration wells were drilled in the foothills and deep basin regions; 9 net wells were cased as natural gas wells and 1 was cased as a net oil well. The remaining 20 net exploration wells were drilled primarily in the shallow regions of the Western Canada Sedimentary Basin.

The following table discloses Husky's offshore drilling activity during the first six months of 2009:

Offshore Drilling Activity			
Canada - East Coast			
Mizzen O-16 Flemish Pass	WI 35%	Stratigraphic test	Exploratory
White Rose J-22-3	WI 72.5%	Gas injection well	Development
South East Asia - China			
QH 29-2-1 Block 39/05	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 3-1-2 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 3-1-3 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation

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

East Coast Development

During the first six months of 2009, $316 million was incurred for East Coast development projects primarily for the North Amethyst and West White Rose tie-back development projects, including the commencement of two development wells at North Amethyst and continuation of facilities construction. Capital expenditures on the West White Rose satellite development were related to advancing engineering design.

East Coast Exploration

During the first six months of 2009, Husky spent $52 million primarily on the Mizzen exploration well in the Flemish Pass off the coast of Newfoundland.

Northwest United States

During the first six months of 2009, Husky spent $12 million on the Gray 31-23 exploration well, which is currently drilling in the Columbia River Basin in south Washington State. Husky has a 50% working interest in this exploration well.

Greenland

During the first six months of 2009, Husky spent $3 million completing an airborne gravity and magnetic survey.

Offshore China and Indonesia

During the first six months of 2009, $230 million was spent on offshore China projects including the Liwan natural gas discovery delineation program and drilling an exploration well on Block 39/05. In Indonesia, capital expenditures during the first six months of 2009 were $2 million.

2009 Upstream Capital Program (1) (2) (millions of dollars)	
Western Canada - oil and gas	$ 725
- oil sands	65
East Coast Canada	800
International	500
Total upstream capital expenditures	$ 2,090

(1) Excludes capitalized administrative costs and capitalized interest.
(2) Upstream capital expenditures for the six months ended June 30, 2009 were $1,073 million.

The 2009 capital budget has been established with a view to maintaining the strength of Husky's balance sheet during a period of significant economic and financial uncertainty. Capital expenditures are focused on those projects offering the highest potential for returns and mid to long-term growth. A number of projects have been deferred pending improved market conditions.

Capital expenditures for Western Canada upstream development and exploration will continue to optimize oil and gas producing assets and develop new resource plays.

Capital spending on oil sands will be primarily to optimize development planning at Sunrise.

Offshore the East Coast of Canada, spending will be for North Amethyst tie-back development and to advance the West White Rose tie-back project.

In China and Indonesia, capital spending will be for the delineation and evaluation of the Liwan natural gas discovery, Madura BD, Indonesia natural gas and liquids development and exploration programs offshore China and Indonesia.

3.2 Midstream

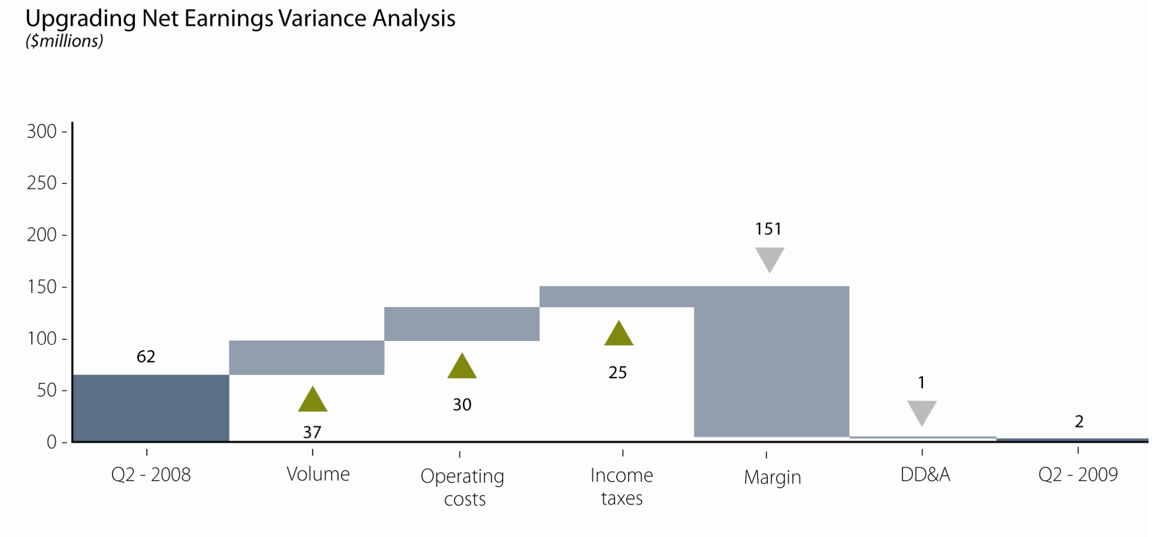
Upgrading Net Earnings Summary [(1)]		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		2009	2008	2009	2008
Gross margin		$ 54	$ 168	$ 166	$ 339
Operating and administration expenses		45	75	99	137
Other recoveries		(1)	(1)	(2)	(2)
Depreciation and amortization		8	7	16	13
Income taxes		-	25	15	57
Net earnings		$ 2	$ 62	$ 38	$ 134
Selected operating data:					
Upgrader throughput [(2)]	(mbbls/day)	74.9	61.0	75.6	62.9
Synthetic crude oil sales	(mbbls/day)	63.1	51.6	62.0	53.6
Upgrading differential	($/bbl)	$ 8.31	$ 30.12	$ 12.05	$ 29.28
Unit margin	($/bbl)	$ 9.34	$ 35.61	$ 14.81	$ 34.69
Unit operating cost [(3)]	($/bbl)	$ 6.53	$ 12.53	$ 7.21	$ 11.73

(1) 2008 amounts as restated for adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.
(2) Throughput includes diluent returned to the field.
(3) Based on throughput.

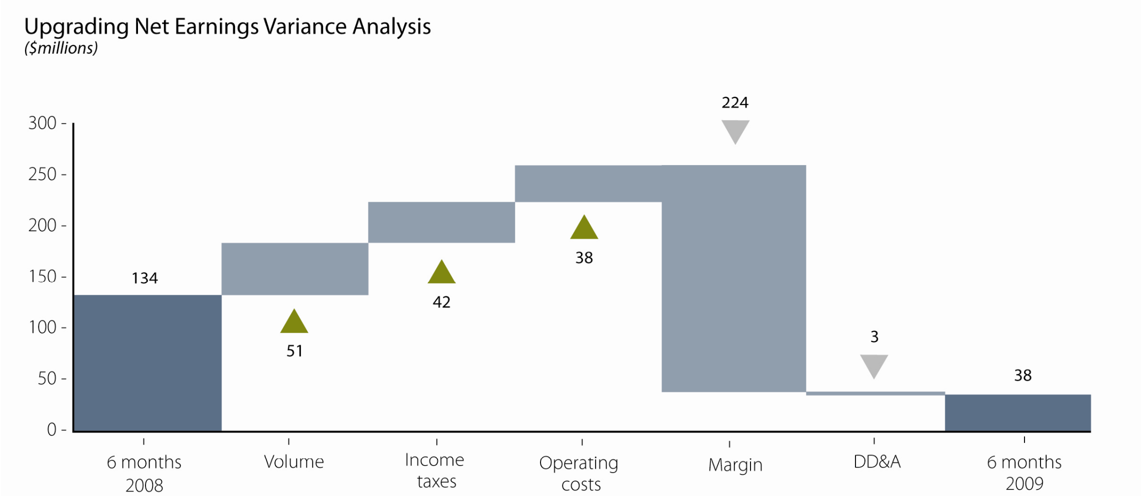
The upgrading business segment adds value by processing heavy sour crude oil into high value synthetic crude oil and low sulphur distillates. The upgrader profitability is primarily dependent on the differential between the cost of heavy crude feedstock and the sales price of synthetic crude oil.

Upgrading Net Earnings Variance Analysis

Second Quarter



Six Months



Second Quarter

During the second quarter of 2009, the upgrading differential averaged $8.31/bbl, a decrease of $21.81/bbl or 72% compared with the second quarter of 2008. The differential is equal to Husky Synthetic Blend, which sells at a premium to West Texas Intermediate, less Lloyd Heavy Blend. The overall unit margin was $9.34/bbl in 2009 compared with $35.61/bbl during the same period in 2008 primarily as a result of the significantly narrower heavy to light crude oil price difference. This decrease was partially offset by lower unit operating costs in the second quarter of 2009 compared with the second quarter of 2008 which resulted from lower energy costs. Upgrader throughput was 23% higher in the second quarter of 2009 compared with the same period in 2008 when throughput was below capacity due to a shutdown to replace the hydrogen plant catalyst.

Six Months

Upgrading earnings for the first six months of 2009 were affected by the same factors impacting the second quarter.

Infrastructure and Marketing Net Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		2009	2008	2009	2008
Gross margin	- pipeline	$ 25	$ 44	$ 57	$ 69
	- other infrastructure and marketing	38	90	112	179
		63	134	169	248
Operating and administration expenses		5	4	9	7
Depreciation and amortization		9	7	18	15
Other recoveries		(24)	-	(9)	-
Income taxes		20	37	42	68
Net earnings		$ 53	$ 86	$ 109	$ 158
Selected operating data:					
Commodity volumes managed	(mboe/day)	934	1,045	1,017	1,036
Aggregate pipeline throughput	(mbbls/day)	534	539	531	521

Second Quarter

Infrastructure and marketing net earnings in the second quarter of 2009 were $53 million compared with $86 million in the second quarter of 2008. Lower earnings were primarily due to lower margins on crude oil and natural gas trading contracts and lower pipeline blending differentials and brokering margins. Other recoveries in the second quarter of 2009 consisted of $24 million of unrealized gains on natural gas storage contracts as a result of falling natural gas prices.

Six Months

During the first half of 2009, infrastructure and marketing earnings were lower than the same period in 2008 primarily because of the same factors that affected the second quarter of 2009.

Midstream Capital Expenditures

For the first six months of 2009, midstream capital expenditures totalled $50 million. At the Lloydminster upgrader, Husky spent $31 million, primarily for contingent consideration and facility reliability projects. The remaining $19 million was spent on the pipeline extension between Lloydminster and Hardisty, Alberta, tankage upgrades at Hardisty and capital enhancements of the cogeneration plants.

3.3 Downstream

Canadian Refined Products Net Earnings Summary [1] (millions of dollars, except where indicated)		Three months ended June 30 2009	Three months ended June 30 2008	Six months ended June 30 2009	Six months ended June 30 2008
Gross margin	- fuel	$ 29	$ 44	$ 63	$ 73
	- ethanol	20	6	26	15
	- ancillary	11	14	20	24
	- asphalt	48	28	84	47
		108	92	193	159
Operating and administration expenses		27	21	46	24
Depreciation and amortization		23	20	46	40
Income taxes		16	16	29	29
Net earnings		$ 42	$ 35	$ 72	$ 66
Selected operating data:					
Number of fuel outlets				488	498
Light oil sales	(million litres/day)	7.4	7.9	7.5	7.9
Light oil retail sales per outlet	(thousand litres/day)	12.1	12.6	12.3	12.9
Prince George refinery throughput	(mbbls/day)	10.0	10.5	10.3	11.0
Asphalt sales	(mbbls/day)	17.5	23.0	19.6	20.4
Lloydminster refinery throughput	(mbbls/day)	17.8	26.4	23.3	24.2
Ethanol production	(thousand litres/day)	659.3	600.1	631.9	624.6

[1] 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.

Canadian Refined Products

Second Quarter

Gross margin on fuel sales was lower in the second quarter of 2009 compared with 2008 due to lower rack prices for gasoline while volumes remained at levels comparable to the same period in 2008. Asphalt gross margins increased in the second quarter of 2009 compared with 2008 due to lower crude feedstock costs as a result of low crude oil prices compared with the same period in 2008. This was partially offset by reduced volumes as the Lloydminster Refinery was shut down for 32 days for scheduled maintenance in the second quarter of 2009.

The higher ethanol gross margin in the second quarter of 2009 was due to the receipt of funds earned under government incentive programs partially offset by lower prices resulting primarily from reduced gasoline rack pricing and low prices for U.S. imported ethanol. Ethanol volumes increased in 2009 compared with 2008 as 2008 included a 12-day shut down for planned and unplanned maintenance.

Six Months

During the first half of 2009, refined products earnings were higher than the same period in 2008 primarily due to the same factors that affected the second quarter of 2009.

Operating and administration expenses in the first six months of 2008 included a $15 million credit resulting from an insurance settlement.

U.S. Refining and Marketing Net Earnings Summary [1]		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		2009	2008	2009	2008
Gross refining margin		$ 391	$ 398	$ 609	$ 485
Processing costs		108	107	225	160
Operating and administration expenses		2	1	4	2
Interest - net		-	-	1	1
Depreciation and amortization		49	43	99	62
Other		21	-	33	-
Income taxes		77	88	90	93
Net earnings		$ 134	$ 159	$ 157	$ 167
Selected operating data:					
Lima Refinery throughput	(mbbls/day)	137.4	144.1	136.9	141.2
Toledo Refinery throughput	(mbbls/day)	65.2	66.0	63.0	66.0 [2]
Refining margin	($/bbl crude throughput)	$ 21.36	$ 21.05	$ 17.27	$ 15.42
Refinery feedstocks and refined products inventory	(mmbbls)	11.11	11.56	11.11	11.56

(1) 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.
(2) The Toledo Refinery operating results are included from March 31, 2008, the date the acquisition was completed. Throughput represents three months of operations.

U.S. Refining and Marketing

On March 31, 2008, Husky completed a transaction that resulted in the formation of two joint venture entities forming an integrated oil sands business and a refining joint venture. Husky holds a 50% interest in the BP-Husky Toledo Refinery. Net earnings for the first six months of 2009 include both the Lima and Toledo refineries whereas the comparative period in 2008 only includes the results from the Toledo Refinery for three months.

Second Quarter

Pricing for product output at the Lima and Toledo refineries is impacted by the New York Harbor 3:2:1 and the Chicago 3:2:1 refining crack spread. Average refining crack spreads at Chicago decreased to U.S. $10.91/bbl in the second quarter of 2009 from U.S. $13.60/bbl in the second quarter of 2008, a 20% decrease and a 15% increase compared with the first quarter of 2009. In the second quarter of 2009, average New York Harbor 3:2:1 refining crack spreads decreased to U.S. $9.05/bbl from U.S. $13.02/bbl in the same quarter in 2008, a 30% decrease and an 11% decrease compared with the first quarter of 2009.

The market refining crack spread is based on crude feedstock accounted for on a last in first out basis ("LIFO"). However, Husky's financial statements are based on FIFO inventory accounting which is in accordance with Canadian GAAP. The rising crude oil prices in the second quarter of 2009 contribute to the higher than market refining margins in the second quarter of 2009. In a stable commodity price environment FIFO and LIFO accounting should not result in significant differences between market benchmarks and individual refinery results.

Throughput at the Lima Refinery in the second quarter of 2009 was impacted by various facility issues as the refinery is in its fifth year of a five year turnaround cycle. The next turnaround is planned for the fourth quarter of 2009.

Other expenses in the second quarter of 2009 consisted of $21 million of losses on feedstock purchase contracts.

Six Months

Earnings for the first six months of 2009 include both the Lima and the BP-Husky Toledo Refineries and in the same period in 2008 include earnings from the Lima Refinery for six months and the BP-Husky Toledo Refinery for the second quarter only.

Average refining crack spreads at Chicago decreased to U.S. $10.21/bbl in the first six months of 2009 from U.S. $10.72/bbl in the same period in 2008, a 4.8% decrease. In the first six months of 2009, average New York Harbor 3:2:1 refining crack spreads decreased to U.S. $9.59/bbl from U.S. $11.22/bbl in the same period in 2008, a 14.5% decrease.

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

Downstream Capital Expenditures

Downstream capital expenditures totalled $94 million for the first six months of 2009.

In Canada, capital expenditures totalled $25 million primarily for upgrades and environmental protection at the retail outlets, refineries and ethanol plants.

In the United States, capital expenditures totalled $69 million, of which $38 million was spent at the Lima Refinery for front end engineering related to various debottleneck projects, optimizations and environmental initiatives that will be undertaken during the fall 2009 turnaround. At the BP-Husky Toledo Refinery, capital expenditures totalled $31 million (Husky's 50% share) primarily for the continuous catalyst regeneration reformer project, facility upgrades and environmental protection.

3.4 Corporate

Corporate Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars) income (expense)	2009	2008	2009	2008
Intersegment eliminations - net	$ (24)	$ (128)	$ (63)	$ (137)
Administration expense	(23)	(17)	(31)	(24)
Other income (expense)	(2)	(8)	(18)	5
Stock-based compensation	(7)	(114)	(3)	(71)
Depreciation and amortization	(13)	(7)	(22)	(14)
Interest - net	(50)	(41)	(87)	(86)
Foreign exchange	(34)	(6)	(1)	(16)
Income taxes	29	98	73	108
Net earnings (loss)	$ (124)	$ (223)	$ (152)	$ (235)

Intersegment eliminations are profit included in inventory that has not been sold to third parties at the end of the period. The decrease in stock-based compensation is due to the decrease in Husky's share price in 2009. The increase in net interest expense in the second quarter and the first six months of 2009 is due to higher debt levels compared to the same periods in 2008. In the first six months of 2009, other expenses includes additional insurance costs of $5 million and realized losses on forward purchases of U.S. dollars of $9 million compared to an unrealized gain on forward purchases of U.S. dollars of $8 million in the first six months of 2008.

Foreign Exchange Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2009	2008	2009	2008
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	$ (83)	$ (10)	$ (51)	$ 34
Loss (gain) on Cross currency swaps	34	3	22	(11)
Loss (gain) on Contribution receivable	116	11	74	11
Other (gains) losses	(33)	2	(44)	(18)
Foreign exchange loss	$ 34	$ 6	$ 1	$ 16
U.S./Canadian dollar exchange rates:				
At beginning of period	U.S. $0.794	U.S. $0.973	U.S. $0.817	U.S. $1.012
At end of period	U.S. $0.860	U.S. $0.982	U.S. $0.860	U.S. $0.982

Corporate Capital Expenditures

For the first six months of 2009, corporate capital expenditures of $13 million were primarily for computer hardware, software, office furniture, renovations and equipment and system upgrades.

Consolidated Income Taxes

During the second quarter of 2009, consolidated income taxes were $216 million compared with $573 million in the same period of 2008 due to lower earnings. Current taxes in the second quarter of 2009 increased compared with the second quarter of 2008 due to record 2008 earnings that are taxable in 2009.

Cash taxes paid in the first six months of 2009 were $955 million, of which $615 million relates to final instalments paid in respect of 2007 earnings, included in current liabilities at December 31, 2008, and $308 million relating to instalments paid in respect of 2008 earnings. Further cash tax instalments for the remainder of 2009 in respect of 2008 earnings are estimated to be $510 million with a further final payment of approximately $500 million in the first quarter of 2010.

4. Liquidity and Capital Resources

In the second quarter of 2009, Husky funded its capital programs and dividend payments by cash generated from operating activities, cash on hand, available credit facilities and long-term debt. Husky maintained its strong financial position with debt of $3,589 million partially offset by cash on hand of $1,237 million for $2,352 million of net debt.

Husky has no long-term debt maturing until 2012. At June 30, 2009, the Company had $1.6 billion in unused committed credit facilities, $97 million in unused short-term uncommitted credit facilities and U.S. $1.5 billion of unused capacity under the renewed debt shelf prospectus (refer to Section 4.4).

Cash Flow Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars, except ratios)	2009	2008	2009	2008
Cash flow - operating activities (1)	$ 563	$ 2,043	$ 798	$ 3,267
- financing activities	$ 1,237	$ (1,217)	$ 1,109	$ (1,318)
- investing activities (1)	$ (658)	$ (656)	$ (1,583)	$ (1,621)
Financial Ratios				
Debt to capital employed (percent)			19.8	13.8
Debt to cash flow (times) (2)			1.0	0.3
Corporate reinvestment ratio (percent) (2) (3)			99	78

(1) 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.
(2) Calculated for the 12 months ended for the dates shown.
(3) Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

4.1 Operating Activities

Second Quarter

In the second quarter of 2009, cash generated from operating activities amounted to $563 million compared with $2,043 million in the second quarter of 2008. Lower cash flow from operating activities was primarily due to lower commodity prices, payment of current income taxes related to 2008 earnings and lower upgrading unit margins.

Six Months

Cash generated from operating activities amounted to $798 million in the first six months of 2009 compared with $3,267 million in the first six months of 2008. Lower cash flow from operating activities was mainly due to lower commodity prices, lower upgrading unit margins and payment of current income taxes in the first quarter of 2009 related to 2008 and 2007 earnings.

4.2 Financing Activities

Second Quarter

In the second quarter of 2009, cash provided by financing activities was $1.2 billion compared with cash used in financing activities of $1.2 billion in the second quarter of 2008. Long-term bonds totaling U.S. $1.5 billion were issued in May 2009. In the second quarter of 2008, bridge financing related to the Lima acquisition was repaid. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

Six Months

Cash provided by financing activities was $1.1 billion in the first six months of 2009 compared with cash used in financing activities of $1.3 billion in the first six months of 2008 primarily due to the same factors impacting the second quarter.

4.3 Investing Activities

Second Quarter

In the second quarter of 2009, cash used in investing activities amounted to $658 million compared with $656 million in the second quarter of 2008. Cash invested in both periods was used primarily for capital expenditures.

Six Months

Cash used in investing activities for the first six months of 2009 and 2008 was $1.6 billion in each year. Cash invested in both periods was used primarily for capital expenditures.

4.4 Sources of Capital

Husky is currently able to fund its capital programs 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 the strength of its balance sheet. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

Working capital is the amount by which current assets exceed current liabilities. At June 30, 2009, working capital was $1,744 million compared with $404 million at December 31, 2008.

Capital Structure (millions of dollars)	June 30, 2009 Outstanding	 Available
Total short-term and long-term debt	$ 3,589	$ 1,676
Common shares, retained earnings and accumulated other comprehensive income	$ 14,500	

At June 30, 2009, Husky had unused committed long and short-term borrowing credit facilities totalling $1.6 billion. A total of $119 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 remains effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of June 30, 2009, U.S. $1.5 billion of long-term debt securities had been issued under this shelf prospectus. (Refer to Note 7 to the Consolidated Financial Statements).

4.5 Credit Ratings

Husky's credit ratings are available in its recently filed Annual Information Form at www.sedar.com.

4.6 Contractual Obligations and Commercial Commitments

Refer to Husky's 2008 annual Management's Discussion and Analysis under the caption "Liquidity and Capital Resources," which summarizes contractual obligations and commercial commitments as at December 31, 2008. At June 30, 2009, Husky had additional contractual obligations and commercial commitments totalling approximately $2,963 million comprised of U.S. bond issues, purchase obligations related to East Coast development and office leases. The U.S. bonds require payments amounting to $57 million in the second half of 2009; $229 million in the period 2010 - 2011; $229 million in the period 2012 - 2013 and $2,147 million thereafter. The purchase commitments amount to $65 million in the second half of 2009; $150 million in the period 2010 - 2011 and $24 million in 2012. Office lease payments amount to $2 million in the second half of 2009; $9 million in the period 2010 - 2011; $19 million in the period 2012 - 2013 and $32 million thereafter.

4.7 Off Balance Sheet Arrangements

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

Husky has chosen not to renew the securitization agreement which expired on March 31, 2009.

4.8 Transactions with Related Parties

On May 11, 2009, the Company issued 5 and 10 year senior notes of U.S. $251 million and U.S. $107 million respectively to certain management, shareholders and directors as part of the U.S. $1.5 billion 5 and 10 year senior notes issued through the existing base shelf prospectus, which was filed in February 2009. (Refer to Note 7 to the Consolidated Financial Statements). The coupon rates offered were 5.90% and 7.25% for the 5 and 10 year tranches respectively. These transactions were measured at the exchange amount, which was equivalent to the fair market value at the date of the transaction and have been carried out on the same terms as would apply with unrelated parties. At June 30, 2009, the senior notes were included in long-term debt on the Company's balance sheet.

TransAlta Power, L.P. is an indirect subsidiary of Cheung Kong Infrastructure Holdings Ltd., which is majority owned by Hutchison Whampoa Limited, which owns 100% of U.F. Investments (Barbados) Ltd., a 34.57% shareholder in Husky. TransAlta Power, L.P. is a 49.99% owner of TransAlta Cogeneration, L.P., Husky's partner in the Meridian cogeneration plant in Lloydminster, Saskatchewan. Husky sells natural gas to the Meridian cogeneration plant and other cogeneration plants owned by TransAlta Power, L.P. Husky received the market price or negotiated medium-term contracts based on market-related terms for these commodities. For the first six months of 2009, Husky sold $21 million of natural gas to TransAlta Power, L.P.

5. Capability to Deliver Results and the Strategic Plan

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

In summary, Husky's current strategy is to continue to exploit oil and gas assets in Western Canada while expanding into new areas with large scale sustainable growth potential. The Company's plans include projects in Canada (the Alberta oil sands and the basins offshore Canada's East Coast), Asia (the South China Sea, the Madura Strait and the East Java Sea), the U.S. Columbia River Basin 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.

6. Key Growth Highlights

The 2009 capital program of $2.6 billion focuses mainly on optimizing upstream production, midstream and downstream development and progressing major projects offshore Canada's East Coast and South East Asia. The 2009 capital budget has been established with a view to maintaining the strength of Husky's balance sheet during a period of significant economic and financial uncertainty. Capital expenditures will be focused on those projects offering the highest potential for returns and mid to long-term growth.

Upstream

White Rose Development Projects

At the North Amethyst oil field, installation of subsea equipment commenced on schedule in early June, with the laying of subsea flowlines and the installation of manifold support frames in the North Amethyst glory hole. Subsea installation activities are expected to continue throughout the third quarter. Production is expected to come on stream in late 2009/early 2010. Work on the SeaRose FPSO (Floating Production, Storage and Offloading vessel) has commenced to prepare for the facility turnaround in the third quarter.

East Coast Canada Exploration

The results of a 2,150 square kilometre 3-D seismic program, completed during the third quarter of 2008, continue to be evaluated for prospective drilling locations.

Work is continuing on the application for a significant discovery licence based on the results of the December 2008 Mizzen exploration well (35% Husky working interest) located in the Flemish Pass Basin on Exploration Licence ("EL") 1049.

Offshore China Liwan Delineation

The West Hercules deep water drilling rig completed drilling and testing the second appraisal well, Liwan 3-1-3, on Block 29/26 in the South China Sea. The well tested natural gas at an equipment restricted rate of 55 mmcf/day with indications that future well deliveries could exceed 150 mmcf/day. Following the drilling and testing of the Liwan 3-1-3 appraisal well, two exploration wells were drilled, which encountered non-commercial quantities of natural gas. The rig is currently drilling a third appraisal well on Liwan 3-1. Front end engineering design commenced in the second quarter and first production is targeted in the 2012 - 2013 timeframe.

Offshore China Exploration

Planning is underway for an exploration well on Block 04/35 in the East China Sea. The well is expected to be spud in late 2009 or early 2010. A contract extension to June 30, 2010 was awarded by CNOOC. An exploration drilling program is also being planned for the Yinggehai Basin on Blocks 35/18 and 50/14 near the Dong Fang and Ledong natural gas fields immediately west of Hainan Island. On Block 63/05 in the Qiondongnan Basin, 50 kilometres south of Hainan Island, existing 2-D seismic has been interpreted and planning has commenced to acquire 300 square kilometres of 3-D seismic by early 2010.

During the second quarter of 2009, the remaining 57 square kilometres in Block 39/05 in the Pearl River Mouth Basin, immediately southwest of the Wenchang oil fields, was relinquished following the drilling of the QH-29-2-1 exploration well, which was abandoned without testing.

Indonesia Exploration and Development

The Madura BD field development plan has been approved by the Government of Indonesia and Husky continues to await approval of an extension to the Production Sharing Contract ("PSC"). Engineering work has been tendered and will commence upon receipt of the PSC extension.

In the East Bawean II PSC, in which Husky holds a 100% interest, the Transocean Adriatic XI jack-up rig will drill two exploration wells, the first of which was spud on July 8, 2009.

During the second quarter of 2009, existing 2-D seismic was interpreted for Husky's 100% interest in the North Sumbawa II Block, comprising 5,000 square kilometres in the East Java Sea. Planning is now underway to acquire 800 kilometres of new 2-D seismic by early 2010.

Sunrise Oil Sands Integrated Project

Husky and BP continue to advance the development of the Sunrise project in multiple stages. Bitumen production from phase one (planned at 60 mbbls/day) is expected to commence approximately four years after project sanction and total production is currently planned to increase to 200 mbbls/day, subject to project sanction and market conditions. Work on optimization to simplify its scope and take advantage of the recent economic downturn in the demand for goods and services is ongoing. The development of the Sunrise Oil Sands Project is strategically linked to the repositioning project at the Toledo Refinery.

Tucker Oil Sands Project

The Company continues to optimize operational strategies to achieve full implementation of the SAGD process in this reservoir. A steam chamber development plan has been prepared, but due to low bitumen prices in the first half of 2009, the Company has delayed its full implementation until oil prices improve.

United States

Drilling of the Grey 31-23 well in the Columbia River Basin located in Washington State continued into the second quarter and the rig was released on May 17, 2009. Following the receipt of requisite permits in July, a service rig recommenced drilling to the target depth.

Western Canada

Husky's Alkaline Surfactant Polymer ("ASP") enhanced oil recovery program, which currently includes ASP developments at Gull Lake and Fosterton, Saskatchewan and operating ASP applications at Warner and Crowsnest, Alberta, continues to advance. Strong oil recovery was achieved subsequent to the chemical injection at Warner. The Crowsnest flood is showing signs of improved oil response. At Gull Lake, by the end of the first half of 2009, the drilling program, pipeline construction and the ASP facility and oil battery modifications were complete. Soft water injection and reservoir conditioning have started prior to chemical injection, which is expected in the third quarter of 2009. All preliminary reservoir technical work is complete at the Fosterton ASP project and Husky is proceeding with detailed facility cost design. The Fosterton ASP flood development is expected to extend into 2011. Husky holds a 62.4% working interest in this project.

Husky's development of the McMullen property, which is located in the west central region of the Athabasca oil sands of northern Alberta, involves a cold production project and plans for a thermal pilot project. Based on the results of a 2008 delineation and seismic program, the Company submitted an application to the Energy Resources Conservation Board in December 2008 to construct the thermal pilot. Husky is currently reassessing full thermal development until economic conditions improve.

Husky has participated in several successful gas well tests in the Bullmoose - Sukunka region of North East British Columbia during the 2008-2009 drilling season. Test results from the Bullmoose d-64-B (100% WI) and Burnt River C-A61-A (55% WI) wells each support initial production rates in the order of 30 million cubic feet per day.

During the second quarter of 2009, Husky tied in 18 gross (9 net) coal bed methane wells in the Trochu, Alberta area. A total of 31 gross (15.5 net) coal bed methane wells have been tied in during the first half of 2009. There were no coal bed methane wells drilled during the second quarter.

In the Lloydminster heavy oil producing area, Husky continues to test various non-thermal enhanced recovery techniques. Operations continue at the Company's first cold enhanced pilot project where six successful injection/production cycles have been completed. This pilot will continue to provide insight into reservoir response and process economics. Production commenced at a second pilot project utilizing CO_2 in the second quarter of 2009 following a six-month injection period.

Offshore Greenland

Evaluation of 7,000 kilometres of 2-D seismic acquired in the third quarter of 2008 on Blocks 5 and 7 is continuing. An airborne gravity and magnetics acquisition was completed in the second quarter of 2009 and is currently being evaluated. Husky is the operator and holds an 87.5% interest in these two blocks. Husky also holds a 43.75% working interest in Block 6 where 3,000 kilometres of 2-D seismic was acquired in the third quarter of 2008. Husky plans to acquire 2,000 square kilometres of 3-D seismic over Blocks 5 and 7 in the second half of 2009.

Downstream

Lima, Ohio Refinery

An engineering evaluation has been completed to determine the reconfiguration of the Lima Refinery to increase its capacity to process heavier, less costly, crude oil feedstock, realize complex refining processes to enhance margins and increase flexibility in product outputs. This project has been deferred due to current market conditions.

Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project progressed in the first half of 2009. The scope of this project is to replace two naphtha reformers and one hydrogen plant with one 42,000 bbls/day continuous catalyst regeneration reformer system plant. The project's objectives are to effectively and safely improve profitability while reducing operating risk, meet future product requirements and reduce the environmental footprint.

A project team has also been launched to reposition the refinery to process bitumen from the first two phases of the Sunrise oil sands integrated project. Due to the integrated nature of this project, progress will be coincident with the upstream development requirements. The refinery continues to advance a multi-year program to improve operational integrity and plant performance and reduce operating costs and environmental impacts.

7. Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks see the Company's 2008 Annual Information Form recently filed on the Canadian Securities Administrator's web site, www.sedar.com, the Securities and Exchange Commission's web site, www.sec.gov or Husky's web site www.huskyenergy.com.

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.

The global financial and economic crisis, which developed in 2008 has increased the risk associated with timely access to debt capital and banking markets and the current market instability may have an impact on Husky's ability to borrow in the capital debt markets at acceptable rates.

In June 2009, the United States House of Representatives passed the Waxman-Markey clean energy bill, which requires a 17% reduction of greenhouse gas emissions from 2005 levels by 2020 and an 80% reduction by 2050. The bill also sets a system of permitting under which regulated industries would need to acquire sufficient permits for their emissions. The proposed bill requires further legislative approvals before becoming law and its scope and requirements could be changed through this process before receiving final approval. Husky's operations may be impacted by this legislation, which commencing in 2013 would require U.S. refining operations to significantly reduce emissions and/or purchase permits, which may increase capital and operating expenditures.

Interest Rate Risk Management

In the first six months of 2009, interest rate risk management activities resulted in a decrease to interest expense of less than $1 million.

Husky has interest rate swaps on $200 million of long-term debt effective February 8, 2002 whereby 6.95% was swapped for CDOR + 175 bps until July 14, 2009. In 2008, the interest rate swaps were discontinued as a fair value hedge as the $200 million medium-term notes were redeemed. During the first six months of 2009, a loss of less than $1 million was recognized in other expenses on the Consolidated Statement of Earnings.

The amortization of previous interest rate swap terminations resulted in an additional $1 million offset to interest expense in the first six months of 2009.

Cross currency swaps resulted in an addition to interest expense of $1 million in the first six months of 2009.

Foreign Currency Risk Management

At June 30, 2009, 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.

At June 30, 2009 the cost of a U.S. dollar in Canadian currency was $1.1625.

During the first six months of 2009, the Company settled its two remaining forward purchases of U.S. dollars realizing a loss of $9 million recorded in other expenses in the Consolidated Statements of Earnings.

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

In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as in the related interest expense. At June 30, 2009, 100% or $3.6 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 88% when the cross currency swaps are considered.

Effective July 1, 2007, the Company's U.S. $1.5 billion of debt financing related to the Lima acquisition was designated as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. During 2008, the Company repaid U.S. $750 million of bridge financing and repurchased U.S. $63 million of bonds that were classified as a net investment hedge. As a result, the Company's net investment hedge is limited to the remaining U.S. $687 million. For the six months ended June 30, 2009, the unrealized foreign exchange gain arising from the translation of the debt was $37 million, net of tax expense of $6 million, which was recorded in "Other Comprehensive Income."

Husky holds 50% of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and a major portion of this receivable is denominated in U.S. dollars. Related gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in foreign exchange in current period earnings. At June 30, 2009, Husky's share of this receivable was U.S. $1.2 billion including accrued interest. Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in Other Comprehensive Income as this item relates to a self-sustaining foreign operation. At June 30, 2009, Husky's share of this obligation was U.S. $1.4 billion including accrued interest.

8. Critical Accounting Estimates

Certain of Husky's accounting policies require that it makes appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. For a discussion about those accounting policies, please refer to Husky's Management's Discussion and Analysis for the year ended December 31, 2008 available at www.sedar.com.

9. Accounting Policies

New Accounting Standards Adopted

As disclosed in Management's Discussion and Analysis for the year ended December 31, 2008, on January 1, 2009, Husky retroactively adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064, "Goodwill and Intangible Assets," which replaced CICA section 3062 of the same name. As a result of issuing this guidance, CICA section 3450, "Research and Development Costs," and Emerging Issues Committee ("EIC") Abstract No. 27, "Revenues and Expenditures during the Pre-operating Period," have been withdrawn. This new guidance requires recognizing all goodwill and intangible assets in accordance with CICA section 1000, "Financial Statement Concepts."

Section 3064 has eliminated the practice of recognizing items as assets that do not meet the section 1000 definition and recognition criteria. Under this new guidance, fewer items meet the criteria for capitalization. The adoption of this standard has resulted in a reduction of retained earnings at January 1, 2009 of $25 million, a reduction to assets of $36 million and a reduction to the future income tax liability of $11 million.

Recent Accounting Pronouncements

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

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

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

In January 2009, the CICA issued section 1602, "Non-controlling Interests," which will replace CICA section 1600, "Consolidated Financial Statements." Minority interest is now referred to as non-controlling interest, ("NCI"), and is presented within equity. Under this new guidance, when there is a change in control the previously held interest is revalued at fair value. Currently a gain of control is accounted for using the purchase method and a loss of control is accounted for as a sale resulting in a gain or loss in earnings. In addition, NCI can be in a deficit position because it is recorded at fair value. 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. Section 1602 is effective for Husky on January 1, 2011 with early adoption permitted.

In May 2009, the CICA amended Section 3862, "Financial Instruments – Disclosures," to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. 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. These amendments are effective for Husky on December 31, 2009.

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. An omnibus exposure draft was issued by the AcSB in the second quarter of 2008, which incorporates IFRS into the CICA Handbook and prescribes the transitional provisions for adopting IFRS.

In March 2009, the AcSB issued a second omnibus exposure draft on the adoption of IFRS. This exposure draft confirms the IFRS transition date as January 1, 2011 for all Canadian publicly accountable enterprises, incorporates any changes to IFRS since the previous exposure draft was issued and discusses additional key transitional issues.

The Company commenced its IFRS transition project in 2008, which includes four key phases:

- Project awareness and engagement – This phase includes identifying and engaging the appropriate members for the core IFRS transition team, steering committee and other representatives as required. In addition, this phase includes communicating the key project requirements and objectives to the areas of the organization that will be impacted by IFRS conversion, including the Company's senior executive management team, Board of Directors and Audit Committee.

- Diagnostic – This phase includes an assessment of the differences between current Canadian GAAP and IFRS, focusing on the areas that will have the most significant impact to Husky. A preliminary conversion roadmap has been prepared as part of this phase.

- Design, planning and solution development – This phase focuses on determining the specific impacts to the Company based on the application of the IFRS requirements. This includes the design and development of detailed solutions and work plans by each key area to address implementation requirements. In addition, impact analysis will be performed on all areas of the business, including tax and information technology systems. Accounting policies will be finalized, first-time adoption exemptions will be considered, draft financial statements and disclosures will be prepared and a detailed implementation plan and timeline will be developed. This phase also includes the development of a training plan.

- Implementation – This phase includes implementing the required changes necessary for IFRS compliance. The focus of this phase is the finalization of IFRS conversion impacts, approval and implementation of accounting and tax policies, implementation and testing of new processes, systems and controls, execution of customized training programs and preparation of opening IFRS balances.

Corporate governance over the project has been established and a steering committee and project team have been formed. This committee is comprised of members of senior executive management and is responsible for final approval of project recommendations and deliverables to the Audit Committee and Board.

Due to the scope of the IFRS project, the Company ensured that the appropriate stakeholders have been engaged by establishing a project advisory committee, which includes representatives from each area of the organization that will be significantly impacted. Husky has also engaged an external advisor to assist with the IFRS conversion process.

The Company has completed the diagnostic assessment phase by performing comparisons of the differences between Canadian GAAP and IFRS. The Company has determined that the most significant impact of IFRS conversion is to property, plant and equipment. IFRS does not prescribe specific oil and gas accounting guidance other than for costs associated with the exploration and evaluation phase.

The Company currently follows full cost accounting as prescribed in Accounting Guideline ("AcG") 16, "Oil and Gas Accounting – Full Cost." Conversion to IFRS may have a significant impact on how the Company accounts for costs pertaining to oil and gas activities, in particular those related to the pre-exploration and development phases. In addition, the level at which impairment tests are performed and the impairment testing methodology will differ under IFRS.

The IFRS conversion will also result in other impacts, some of which may be significant in nature. Initial assessments of other impacts completed to date include foreign exchange, revenue recognition, provisions and asset retirement obligations. During the second quarter of 2009, the Company focused on further analysis and development of implementation strategies and processes for the key IFRS transition issues identified during the first quarter. In addition, the Company commenced preliminary accounting assessments on less critical IFRS transition issues. The analysis and evaluation of these transition issues will continue throughout the implementation phase of the Company's project. At this time, the impact on the Company's financial position and results of operations is not reasonably determinable or estimable for any of the IFRS conversion impacts identified.

The Company is currently completing the design, planning and solution development phase. Project team members have been working in conjunction with representatives from the various operational areas to evaluate the specific impacts of IFRS conversion to Husky and to develop recommendations and accounting policies. Communication, training and education are a critical aspect of the Company's IFRS conversion project; therefore training and education sessions will continue throughout each phase of the project.

In September 2008, the International Accounting Standards Board ("IASB") issued an exposure draft, which proposes additional exemptions for entities adopting IFRS for the first time. One of these proposed exemptions relates to companies using the full cost method of accounting. If the exposure draft is finalized, this exemption will allow entities to allocate their oil and gas asset balance as determined under full cost accounting to the IFRS categories of exploration and evaluation assets and development and producing properties. This exemption would relieve entities from significant adjustments resulting from retrospective adoption of IFRS. The Company intends to utilize this exemption if it is approved and finalized as part of IFRS. Husky is also evaluating other first-time adoption exemptions available upon initial transition that give relief from retrospective application of IFRS.

In addition, the Company is monitoring the IASB's active projects and all changes to IFRS prior to January 1, 2011 will be incorporated as required.

10. Outstanding Share Data

(in thousands)	July 15 2009	December 31 2008
Issued and outstanding		
Number of common shares	849,853	849,355
Number of stock options	28,829	30,827
Number of stock options exercisable	13,039	7,239

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 2008 Annual Information Form filed in 2009 with Canadian regulatory agencies and Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and at www.huskyenergy.com.

Use of Pronouns and Other Terms Denoting Husky

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended June 30, 2009 are compared with results for the three months ended June 30, 2008 and results for the six months ended June 30, 2009 are compared with results for the six months ended June 30, 2008. Discussions with respect to Husky's financial position as at June 30, 2009 are compared with its financial position at December 31, 2008.

Additional Reader Guidance

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

Non-GAAP Measures

Disclosure of Cash Flow from Operations

Management's Discussion and Analysis 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 generally accepted accounting principles, as an indicator of Husky's financial performance. Cash flow from operations or earnings is presented in Husky's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Husky's determination of cash flow from operations may not be comparable to that reported by other companies. 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.

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

		Three months ended June 30		Six months ended June 30	
(millions of dollars)		2009	2008 (1)	2009	2008 (1)
Non-GAAP	Cash flow from operations	$ 833	$ 2,079	$ 1,398	$ 3,617
	Settlement of asset retirement obligations	(5)	(7)	(15)	(24)
	Change in non-cash working capital	(265)	(29)	(585)	(326)
GAAP	Cash flow - operating activities	$ 563	$ 2,043	$ 798	$ 3,267

(1) 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.

Disclosure of Adjusted Net Earnings

This interim report may contain the term "adjusted net earnings," which is a non-GAAP measure of net earnings adjusted for certain items that are not an indicator of the Company's on-going financial performance. The following table shows the reconciliation of net earnings to adjusted net earnings for the periods shown:

		Three months ended June 30		Six months ended June 30	
(millions of dollars)		2009	2008 (1)	2009	2008 (1)
GAAP	Net earnings	$ 430	$ 1,358	$ 758	$ 2,246
	Net foreign exchange	30	4	4	16
	Net financial instruments	-	(3)	27	7
	Net stock-based compensation	5	79	2	49
	Net inventory write-downs	6	3	25	7
	Sale of 50% of Husky Oil (Madura) Limited to CNOOC Ltd.	-	(69)	-	(69)
Non-GAAP	Adjusted net earnings	$ 471	$ 1,372	$ 816	$ 2,256

(1) 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.

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.

Husky's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to Husky by Canadian securities regulatory authorities, which permits Husky to provide disclosure required by and consistent with the requirements of the United States Securities and Exchange Commission and the Financial Accounting Standards Board in the United States in place of much of the disclosure expected by National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Please refer to "Disclosure of Exemption Under National Instrument 51-101" on page 3 of Husky's Annual Information Form for the year ended December 31, 2008 filed with securities regulatory authorities for further information.

Abbreviations

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

Terms

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

12. Forward-Looking Statements and Information

Certain statements in this document and 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 document include, but are not limited to statements about the Company's general strategic plans; 2009 production and capital expenditure guidance; pursuit of cost containment and efficiency opportunities; plans to enhance liquidity in the near term; evaluation of prospective East Coast drilling locations; development and production plans for the North Amethyst oil field; the Company's intention to apply for a significant discovery license based on the results of the Company's Mizzen O-16 exploration well; production optimization plans for the Tucker in-situ oil sands project; Sunrise multiphase development plans, production plans and production capacity; development plans for the McMullen property; the exploration well in the Columbia River Basin; the offshore China exploration program; delineation drilling plans for the Liwan natural gas discovery; the receipt of an extension of the PSC for the Madura BD natural gas and NGL field; the two-well work program for the East Bawean II; exploration plans for the North Sumbawa II exploration blocks; testing and implementation of various enhanced recovery techniques in Western Canada; offshore Greenland exploration plans; plans to reposition and upgrade the Toledo Refinery; Continuous Catalyst Regeneration Reformer Project plans; and plans to reconfigure the Lima Refinery.

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

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