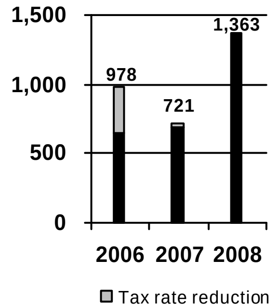
Quarterly Report to the Shareholders for the period ended June 30, 2008

HUSKY ENERGY REPORTS SECOND QUARTER AND FIRST SIX MONTHS RESULTS FOR 2008

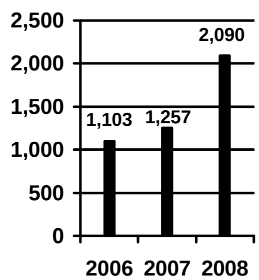
Second Quarter Net Earnings

($ millions)



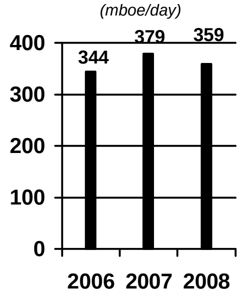
Second Quarter Cash Flow from Operations

($ millions)



Second Quarter Total Production

(mboe/day)



Calgary, Alberta – Husky Energy Inc. (TSX - HSE) reported net earnings of $1.36 billion or $1.61 per share (diluted) in the second quarter of 2008, an increase of 89 percent from $721 million or $0.85 per share (diluted) in the same quarter of 2007. Cash flow from operations in the second quarter of 2008 was $2.1 billion or $2.46 per share (diluted), a 66 percent increase compared with $1.3 billion or $1.48 per share (diluted) in the same quarter of 2007. Sales and operating revenues, net of royalties, were $7.20 billion in the second quarter of 2008, an increase of 128 percent compared with $3.16 billion in the same quarter of 2007.

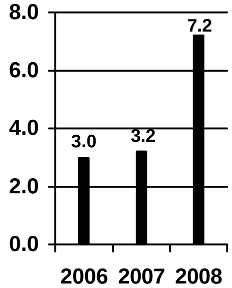
"Husky achieved record results in the second quarter of 2008 in terms of earnings, cash flow and revenue in a strong commodity price environment," said John C.S. Lau, President & Chief Executive Officer, Husky Energy Inc. "In the second quarter, our U.S. refining facilities also contributed to our strong results. In addition, excellent progress was made in the development of our major growth projects and we continued to strengthen our financial position."

In the second quarter of 2008, total production averaged 359,100 barrels of oil equivalent per day, compared with 379,100 barrels of oil equivalent per day in the second quarter of 2007, a reduction of 5 percent. Total crude oil and natural gas liquids production was 256,100 barrels per day, compared with 276,500 barrels per day in 2007. The decrease in crude oil production was mainly due to the suspension of operations at White Rose for 11 days due to severe ice pack and iceberg conditions and the advancement of a scheduled 14 day turnaround at Terra Nova. Natural gas production was 618 million cubic feet per day, compared with 616 million cubic feet per day in the same period of 2007.

For the first six months of 2008, Husky's net earnings were $2.3 billion or $2.65 per share (diluted), compared with $1.4 billion or $1.61 per share (diluted) in the first six months of 2007. Cash flow from operations was $3.6 billion or $4.28 per share (diluted) in the first six months of 2008, compared with $2.6 billion or $3.04 per share (diluted) in the same period of 2007. Sales and operating revenues, net of royalties, were $12.3 billion in the first six months of 2008, compared with $6.4 billion in the first six months of 2007.

Production for the first six months of 2008 was 354,700 barrels of oil equivalent per day, compared with 384,600 barrels of oil equivalent per day in the same period in 2007. Crude oil and natural gas liquids production was 253,900 barrels per day, compared with 279,900 barrels per day in the first six months of 2007 reflecting the advancement of scheduled turnarounds at Terra Nova and White Rose originally planned later in 2008 and the severe ice pack and iceberg conditions off the East Coast of Canada. Natural gas production was 604 million cubic feet per day, compared with 628 million cubic feet per day during the same period of 2007 as a result of a strategic decision in 2007 to reduce natural gas drilling due to weak gas prices.

Second Quarter Sales and Operating Revenues
($ billions)



Work on area infrastructure and site preparation, including roads and well pads, progressed on schedule for the Sunrise Oil Sands Project. Phase one of the Sunrise Project for 60,000 barrels per day of bitumen is expected to be operational in late 2012, subject to corporate sanction.

Planning for the development of the McMullen property located in the west central region of the Athabasca oil sands of northern Alberta progressed. Husky plans to develop production through a multi-well drilling program in 2008 using cold production technology.

The White Rose - North Amethyst satellite development off Canada's East Coast remains on schedule for a late 2009 or early 2010 start up. The West White Rose satellite development is planned for production in 2011.

Offshore China, Husky increased its holdings by signing a petroleum contract for a new exploration block, Block 63/05. Husky also completed the acquisition of 3-D seismic data on Blocks 29/26, 29/06 and 35/18 in the second quarter. The drilling rig Seadrill West Hercules is currently undergoing commissioning in South Korea. Husky plans to commence delineation drilling on the Liwan 3-1 discovery in the third quarter of 2008.

In Indonesia, Husky completed an agreement with CNOOC Ltd. to jointly develop the Madura BD gas and natural gas liquids field located offshore East Java, Indonesia. The agreement covers the development and further exploration of the Madura Strait Production Sharing Contract ("PSC"). The Madura BD field development plan was approved and the PSC extension has been submitted to the regulatory authorities for approval.

Second Quarter Financial Highlights 2008 versus 2007

- Earnings per share to $1.61 from $0.85
- Cash flow per share to $2.46 from $1.48
- Return on equity to 34.6% from 27.1%
- Return on average capital employed to 30.9% from 23.8%
- Debt to capital employed ratio to 14% from 12%
- Debt to cash flow ratio unchanged at 0.3
- Market capitalization increased to $41 billion from $37 billion

In the downstream business, Husky completed the conceptual stage of the reconfiguration for the Lima refinery to process heavier feedstocks. With the completion of the BP/Husky joint venture, Husky is working with BP on the reconfiguration of the Toledo refinery to process bitumen feedstock.

Following the completion of the turnarounds at White Rose and Terra Nova in the first half of 2008, crude oil production is expected to increase from current levels in the second half of the year. However, the severe ice conditions which suspended production at White Rose during the first half of the year and the ramp-up of production at the Tucker Oil Sands project will impact our annual production. Production for 2008 is now expected to be five to seven percent below our guidance range.

Husky continues to strengthen its financial position and balance sheet. Total long-term debt including current portion at June 30, 2008 was $2,129 million compared with $2,814 million at December 31, 2007. Debt to capital employed improved to 14 percent at June 30, 2008 from 19 percent at December 31, 2007. Debt to cash flow from operations decreased to 0.3 times at June 30, 2008 compared with 0.5 times at December 31, 2007.

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1. Summary of Quarterly Financial Results

The following table shows our net earnings by industry sector and includes corporate expenses and intersegment profit eliminations.

	Three months ended							
	June 30	March 31	Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30
(millions of dollars, except per share amounts and ratios)	**2008**	2008	2007	2007	2007	2007	2006	2006
Sales and operating revenues, net of royalties	**$ 7,199**	$ 5,086	$ 4,760	$ 4,351	$ 3,163	$ 3,244	$ 3,084	$ 3,436
Net earnings by sector								
Upstream	**$ 1,239**	$ 717	$ 864	$ 516	$ 636	$ 580	$ 453	$ 608
Midstream	**153**	144	218	129	77	111	105	87
Downstream	**194**	38	103	121	53	20	10	28
Corporate and eliminations	**(223)**	(12)	(111)	3	(45)	(61)	(26)	(41)
Net earnings	**$ 1,363**	$ 887	$ 1,074	$ 769	$ 721	$ 650	$ 542	$ 682
Per share - Basic and diluted	**$ 1.61**	$ 1.04	$ 1.26	$ 0.91	$ 0.85	$ 0.77	$ 0.64	$ 0.80
Cash flow from operations	**2,090**	1,541	1,425	1,420	1,257	1,324	1,207	1,224
Per share - Basic and diluted	**2.46**	1.82	1.68	1.67	1.48	1.56	1.42	1.44
Ordinary quarterly dividend per common share	**0.40**	0.33	0.33	0.25	0.25	0.25	0.25	0.25
Special dividend per common share	**-**	-	-	-	-	0.25	-	-
Total assets	**25,296**	24,391	21,697	20,718	17,969	17,781	17,933	17,324
Total long-term debt including current portion	**2,129**	3,019	2,814	2,835	1,423	1,527	1,611	1,722
Return on equity [(1)] *(percent)*	**34.9**	31.2	30.2	26.6	27.1	32.1	31.8	34.2
Return on average capital employed [(1)] *(percent)*	**30.9**	26.5	25.7	22.3	23.8	27.3	27.0	28.7

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

Analysis of Consolidated Earnings

Second Quarter

Sales and operating revenues in the second quarter of 2008 were more than double the same period in 2007 due to increased commodity prices, the addition of the Lima and Toledo refineries and the Minnedosa ethanol plant. During the second quarter of 2008, sales prices realized by Husky averaged U.S. $106/bbl (light, medium and heavy crude combined) compared with $57/bbl average for the second quarter of 2007. Realized natural gas prices averaged $9.14/mcf for the second quarter compared with $6.91/mcf during the same period in 2007. Commodity price increases in the upstream sector more than offset lower production.

Production in the second quarter averaged 359,100 boe per day compared with 379,100 boe per day in the same period in 2007. Production levels were lower in the second quarter due to the acceleration, from the third quarter, of the 2008 scheduled 14 day maintenance shut down at Terra Nova. Severe ice pack and iceberg conditions off the East Coast continued to be a factor in the second quarter, suspending production for 11 days and increasing operating costs at White Rose.

Operating revenues earned in the midstream sector increased significantly as a result of increased commodity prices. This was offset by corresponding increases in operating costs, largely made up of the cost of acquiring product for resale.

Downstream operating revenues and net earnings in 2008 include U.S. refining and marketing results from the Lima and Toledo refineries. The Lima refinery was acquired effective July 1, 2007 and 50% of the Toledo refinery was acquired on March 31, 2008 with an effective date of January 1, 2008. Earnings from Toledo during the period January 1, 2008 to March 31, 2008 have been included as an adjustment to the acquisition cost. In Canada, the addition of the Minnedosa ethanol plant contributed to increased operating revenues, operating costs and net earnings. The addition of these assets is the primary driver behind the increase in downstream revenue, operating costs and net earnings compared with the second quarter of 2007.

Six Months

Operating revenues increased 92% to $12.3 billion in the first six months of 2008 compared with the same period in 2007. Net earnings in the first six months of 2008 increased 64% to $2.3 billion compared with the same period in 2007. The primary drivers are the same as those discussed above impacting the second quarter.

Prices realized by Husky in the first half of 2008 were $93/bbl for light, medium and heavy oil combined and $55/bbl during the same period in 2007. Natural gas prices in 2008 averaged $8.11/mcf compared with $6.92/mcf during the same period in 2007.

Production during the six month period averaged 354,700 boe per day compared with 384,600 boe per day in the same period in 2007. In addition to the factors described above, production in the first quarter in Western Canada was impacted by extreme cold weather conditions, resulting in lower natural gas production and on the East Coast, the White Rose 2008 scheduled maintenance shut down was accelerated from August. The maintenance was moved forward in order to take advantage of an unplanned production shut down in the first quarter, which was due to operational issues.

Primary drivers in midstream and downstream operating revenue and net earnings for the first six months are the same as those impacting the second quarter.

2. Capability to Deliver Results and the Strategic Plan

Our current capacity to deliver results and the strategic plan are described in our annual MD&A and also in our Annual Information Form that are available from www.sedar.com and www.sec.gov.

In summary, our strategy is to continue to exploit our oil and gas asset base in Western Canada while expanding into new areas with large scale sustainable growth potential. Our plans include projects in Canada (the Alberta oil sands, the basins off the East Coast of Canada and the Central Mackenzie River Valley), Asia (the South China Sea, the Madura Strait and the East Java Sea) and offshore Greenland. In the midstream and downstream sectors we are enhancing performance and capturing new value throughout the value chain by further integrating our businesses, optimizing our plant operations and expanding plant and infrastructure.

3. Key Growth Highlights

To achieve corporate strategic objectives and enhance shareholder value and return on investment, we continue to develop opportunities that will drive future growth. Key highlights for the second quarter of 2008, are noted below:

Upstream

Western Canada

Husky obtained approval for its Alkaline Surfactant Polymer ("ASP") project at Gull Lake in southwest Saskatchewan (Husky's share 73.6%). Start up of the project is planned for the second quarter of 2009. This project is designed to increase production and improve the recovery of original oil in place by 15%.

In Lloydminster, Husky commenced commissioning on an additional heavy oil cold enhanced recovery pilot project. This project is designed to test injection of CO_2 into the reservoir as a further enhancement to the recovery process. The first cold enhanced recovery pilot project continues to demonstrate positive results.

Drilling at the Trident coal bed methane development (Husky's share 50%) is expected to increase in the second half of the year following an agreement with our partner on cost sharing. Between 100 and 120 new wells are planned for the remainder of 2008.

White Rose Development and Delineation

The North Amethyst tie-back development plan was approved by the federal and provincial governments in April 2008. Procurement of long lead equipment for the North Amethyst field is proceeding on schedule. Additional delineation and reservoir analysis at the West White Rose tie-back project will take place in the second half of 2008 and the development application is progressing as planned. The front-end engineering design for West White Rose is planned to run concurrently with the North Amethyst project execution. The South White Rose extension, the smaller of the satellite tie-back developments, was approved by the federal and provincial governments in September 2007 and is expected to augment production following completion of the North Amethyst and West White Rose tie-back projects.

The semi-submersible drilling rig, Henry Goodrich, is expected to arrive in Newfoundland and Labrador waters in August 2008. The Henry Goodrich will be available for Husky operated wells for 17 months of a total 27-month drilling program. The GSF Grand Banks semi-submersible drilling rig, which has been working at White Rose, has also been contracted for an additional period ending in January 2011. These rigs will drill several development wells in the White Rose and satellite fields, the Terra Nova field as well as exploration prospects in the Jeanne d'Arc Basin.

East Coast Exploration

Husky, together with its partners, commenced a 3-D seismic program covering 2,500 square kilometres over the White Rose and satellite fields, the Terra Nova field and on portions of five exploration licences in the Jeanne d'Arc Basin. This activity is expected to be concluded in the third quarter of 2008 and is expected to identify additional drilling opportunities.

We will participate in the drilling of an exploration well on Exploration Licence ("EL") 1049 in the Flemish Pass Basin off the east coast of Newfoundland and Labrador. Drilling is expected to commence in the fourth quarter of 2008. StatoilHydro is the operator and Husky has a 35% interest in the licence.

Tucker Oil Sands Project

Optimization strategies to resolve start up issues and enhance the ramp-up of production are continuing. Modifications of three wells on Pad A, designed to improve the effectiveness of steam heating of the reservoir, are close to commissioning. Pad C has been expanded with eight new well pairs and steam injection has commenced on six of the eight well pairs. Drilling on the new Pad D is planned for early 2009 and will utilize experience gained from work currently underway on Pads A and C.

Sunrise Oil Sands Project

The development of the Sunrise oil sands project will proceed in multiple phases. The first development phase will produce 60 mbbls/day of bitumen commencing late 2012 and the second and third phases are targeted to increase the Sunrise production capacity to approximately 200 mbbls/day of bitumen by 2015 to 2020, subject to corporate sanction. Work on area infrastructure and site preparation, including roads and pads, progressed on schedule during the second quarter. In addition, detailed design of the facilities commenced and preparation for long lead equipment procurement and construction contracts was initiated.

McMullen Development

Planning for the development of the McMullen property located in the west central region of the Athabasca oil sands of northern Alberta is progressing. Husky plans to develop production through a multi-well drilling program in 2008 using cold production technology similar to that used in the Lloydminster heavy oil operations. Husky also progressed plans to implement a pilot project that will test thermal recovery techniques.

Caribou

The preliminary engineering design of the 10 mbbls/day demonstration project commenced in the second quarter of 2008.

Saleski

Seismic analysis and reservoir studies are proceeding in preparation for the 2009 drilling program.

Offshore China Exploration

On June 25, 2008, Husky announced the acquisition of exploration Block 63/05 covering 1,777 square kilometres located in the natural gas prone Qiondongnan Basin approximately 100 kilometres south of Hainan Island. CNOOC Ltd. has the right to participate in the development of any discoveries up to a 51% working interest. Under the terms of the petroleum contract, we have committed to drill one well and acquire 300 square kilometres of seismic data within a three-year period.

The West Hercules deep water drilling rig is undergoing commissioning and is expected to arrive in the South China Sea in August 2008. The rig will initially drill the second of our planned exploration wells on Block 39/05 which surrounds the Wenchang oil field. Upon completion of this well, the first of four delineation wells is expected to spud in September 2008 at the Liwan natural gas discovery on Block 29/26.

In the second quarter of 2008, we completed a 3-D seismic data program on Blocks 29/26 and 29/06, which surround the Liwan natural gas discovery. Acquisition of 3-D seismic data was also completed on Blocks 35/18 and 50/14, which are located to the west of Hainan Island in the Yinggehai Basin. We are working toward securing a drilling rig for a multi-well program on these two blocks in 2009. The first phase exploration work commitment for these two Yinggehai blocks expires on September 30, 2009.

During the second quarter of 2008, the Wushi 23-2-1 exploration well was abandoned without testing. This well was on Block 23/15 in the Beibu Wan Basin north of Hainan Island in the South China Sea.

Indonesia Exploration and Development

In April 2008, we completed an agreement with CNOOC Ltd. to jointly develop the Madura BD gas and natural gas liquids field located offshore East Java, Indonesia. Under the agreement, CNOOC Ltd. acquired a 50% equity interest and operatorship of Husky Oil (Madura) Limited, which holds a 100% interest in the Madura Strait Production Sharing Contract ("PSC"). The agreement covers the development and further exploration of the Madura Strait PSC. The Madura BD field development plan has been approved by the regulatory authorities and the PSC extension has been submitted for approval. Regulatory authorities are currently reviewing the work plan for the East Bawean II exploration block. Final 3-D seismic data has been delivered and preparatory work for two exploration wells is underway for the 2009 drilling program.

Offshore Greenland

The seismic acquisition vessel, Wavefield Akademic Shatsky, arrived in Nuuk, Greenland in early July, 2008 to perform a 7,000 kilometre 2-D seismic data program on Blocks 5 and 7. Husky is the operator and holds an 87.5% interest in these two blocks. The acquisition of 3,000 kilometres of 2-D seismic is planned for Block 6 later in 2008. We hold a 43.75% interest in this block. A hi-resolution aero-gravity and magnetic survey covering Husky's blocks is approximately 40% complete.

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 feedstocks; realize complex refining processing margins; and increase flexibility in product outputs. The current configuration at the Lima refinery restricts it to a predominantly light sweet crude oil feedstock. This limits our ability to process a lower cost heavier crude feedstock to meet seasonal and longer term market demands. The results are being evaluated to determine the best approach to achieve the reconfiguration.

BP/Husky Toledo, Ohio Refinery

The acquisition of 50% of the BP/Husky Toledo refinery, which has the capacity to process 150 mbbls/day of crude oil including 60 mbbls/day of blended heavy sour crude oil, closed on March 31, 2008 with an effective date of January 1, 2008. BP and Husky are planning to convert this refinery to process bitumen feedstock in conjunction with their investment in the Sunrise oil sands project.

4. Business Environment

Average Benchmarks

		Three months ended					
		June 30 2008	March 31 2008	Dec. 31 2007	Sept. 30 2007	June 30 2007	March 31 2007
WTI crude oil [(1)]	*(U.S. $/bbl)*	**123.98**	97.90	90.68	75.38	65.03	58.16
Brent crude oil [(2)]	*(U.S. $/bbl)*	**121.38**	96.90	88.70	74.87	68.76	57.75
Canadian light crude 0.3% sulphur	*($/bbl)*	**126.73**	98.20	87.19	80.70	72.61	67.76
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**89.70**	64.23	42.03	43.61	39.02	38.25
NYMEX natural gas [(1)]	*(U.S. $/mmbtu)*	**10.93**	8.03	6.97	6.16	7.55	6.77
NIT natural gas	*($/GJ)*	**8.86**	6.76	5.69	5.31	6.99	7.07
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**21.95**	21.81	34.06	23.50	20.36	17.32
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**14.50**	10.09	8.23	11.91	24.18	12.32
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.990**	0.996	1.018	0.957	0.911	0.854

[(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.*

Commodity Prices

As an integrated producer, profitability is largely determined by realized prices for crude oil and natural gas and refinery processing margins, including the effect of changes in the U.S./Canadian dollar exchange rate. All of our crude oil production and the majority of our natural gas production receive the prevailing market price. The price for crude oil is determined mainly by global factors and is beyond our control. The price for natural gas is determined primarily by the North America fundamentals since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. Weather conditions also have a dramatic effect on short-term supply and demand.

During 2007, the price of WTI averaged U.S. $72/bbl and ended the year at U.S. $96/bbl. In the first quarter of 2008, the price of WTI averaged U.S. $ 98/bbl and ended the quarter at U.S. $102/bbl. During the second quarter of 2008, WTI averaged U.S. $124/bbl and ended the quarter at U.S. $140/bbl.

The steady rise in global crude oil prices over the last 18 months reflects a number of complex issues that are maintaining strong demand and uncertain supply. Chief among those issues are the emergence of new growing economies and their increasing demand for petroleum products, production uncertainties caused by geopolitical tension and uncertainties in respect of surplus productive capacity. The economic downturn in the United States during the first six months of 2008 has only marginally reduced consumption of petroleum in spite of record high fuel prices.

Natural gas prices quoted on the NYMEX rose sharply through the first six months of 2008 and were, on average, 37% higher than the same period in 2007. Higher prices in the first half of 2008 are largely attributed to comparatively colder weather, supply concerns related to facility outages in the Gulf of Mexico, comparatively lower LNG imports and working gas in storage that was lower than five-year averages. At the end of the second quarter of 2008, natural gas inventory in underground storage in the United States was 16% lower than at the same date in 2007 and the NYMEX near month price ended the second quarter of 2008 at U.S. $13.30/mmbtu.

Refinery Crack Spreads

The 3:2:1 crack spread is the key indicator for refining margins since, on average, 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 diesel (distillate) less one barrel of crude oil. Prices are based on NYMEX near month contract averages.

During the second quarter of 2008, the U.S. New York Harbor crack spread improved compared with the first quarter of 2008 as global markets for distillate tightened and U.S. refiners shifted their yield to favour distillate production.

Sensitivity Analysis

The following table indicates the relative annual effect of changes in certain key variables on our pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the second quarter of 2008. Each separate 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	2008 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	$ 123.98	*U.S. $1.00/bbl*	73	0.09	52	0.06
NYMEX benchmark natural gas price [1]	$ 10.93	*U.S. $0.20/mmbtu*	25	0.03	18	0.02
WTI/Lloyd crude blend differential [2]	$ 21.95	*U.S. $1.00/bbl*	(17)	(0.02)	(13)	(0.01)
Downstream						
Light oil margins	$ 0.06	*Cdn $0.005/litre*	14	0.02	9	0.01
Asphalt margins	$ 10.80	*Cdn $1.00/bbl*	8	0.01	5	0.01
New York Harbor 3:2:1 crack spread [3]	$ 14.50	*U.S. $1.00/bbl*	71	0.08	45	0.05
Consolidated						
Exchange rate (U.S. $ per Cdn $) [4]	$ 0.990	*U.S. $0.01*	(108)	(0.13)	(72)	(0.08)
Interest rate		*100 basis points*	(10)	(0.01)	(7)	(0.01)
Period end translation of U.S. $ debt (U.S. $ per Cdn $)	$ 0.982 [5]	*U.S. $0.01*	-	-	13	0.02

(1) Includes decrease in net earnings related to natural gas consumption.
(2) Includes impact of upstream and upgrading operations only.
(3) Relates to U.S. Refining & Marketing.
(4) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items.
(5) U.S./Canadian dollar exchange rate at June 30, 2008.
(6) Excludes derivatives.
(7) Based on 849.1 million common shares outstanding as of June 30, 2008.

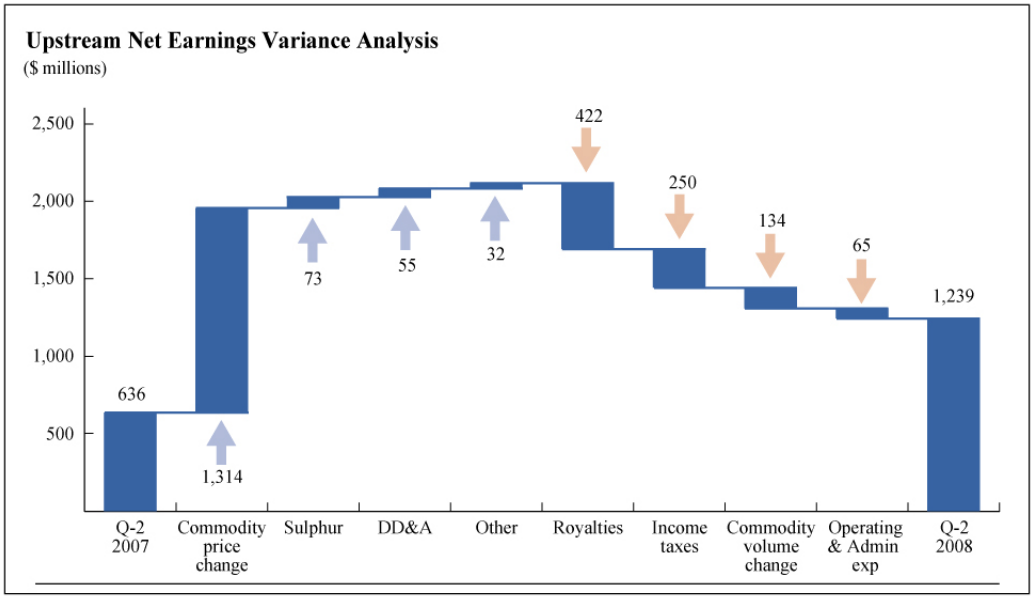
5. Results of Operations

5.1 Upstream

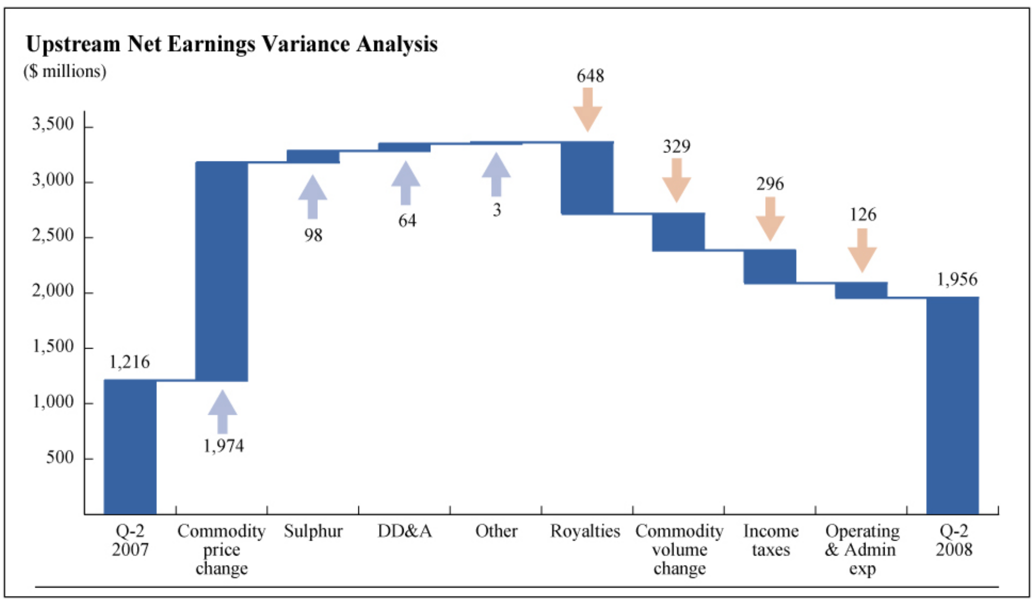
Upstream Net Earnings Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2008**	2007	**2008**	2007
Gross revenues	**$ 3,081**	$ 1,828	**$ 5,334**	$ 3,591
Royalties	**657**	235	**1,081**	433
Net revenues	**2,424**	1,593	**4,253**	3,158
Operating and administration expenses	**409**	344	**793**	667
Depletion, depreciation and amortization	**352**	407	**742**	806
Other	**(81)**	(49)	**(52)**	(49)
Income taxes	**505**	255	**814**	518
Net earnings	**$ 1,239**	$ 636	**$ 1,956**	$ 1,216

Upstream Net Earnings Variance Analysis

Second Quarter



Six Months



Net Revenue

Upstream Revenue Mix	Three months ended June 30		Six months ended June 30	
Percentage of upstream net revenues	**2008**	2007	**2008**	2007
Crude oil & NGL				
Light crude oil & NGL	**40**	53	**42**	52
Medium crude oil	**8**	6	**8**	6
Heavy crude oil & bitumen	**31**	20	**30**	20
Total crude oil & NGL	**79**	79	**80**	78
Natural gas	**21**	21	**20**	22
	100	100	**100**	100

Pricing

Average Sales Prices Realized		Three months ended June 30		Six months ended June 30	
		2008	2007	**2008**	2007
Crude Oil	*($/bbl)*				
Light crude oil & NGL		**$ 121.71**	$ 72.28	**$ 108.64**	$ 68.28
Medium crude oil		**101.87**	48.15	**88.13**	47.26
Heavy crude oil & bitumen		**89.35**	38.19	**76.69**	37.91
Total average		**106.29**	56.99	**93.26**	54.68
Natural Gas	*($/mcf)*				
Average		**9.14**	6.91	**8.11**	6.92

Second Quarter

During the second quarter of 2008, upstream net revenues increased by $831 million compared with the same period in 2007. Higher crude oil, natural gas and sulphur prices more than offset lower crude oil sales volumes and higher royalties.

During the second quarter of 2008, our realized heavy crude oil prices averaged 72% of our realized light crude oil prices versus 52% during the same period in 2007.

Six Months

For the six months ended June 30, 2008, upstream net revenues increased by $1,095 million compared with the same period in 2007. Higher crude oil, natural gas and sulphur prices more than offset lower crude oil and natural gas sales volumes and higher royalties.

During the first six months of 2008, our realized heavy crude oil prices averaged 69% of our realized light crude oil prices versus 55% during the same period in 2007.

Oil and Gas Production

Daily Gross Production		Three months ended June 30		Six months ended June 30	
		2008	2007	**2008**	2007
Crude oil & NGL	*(mbbls/day)*				
Western Canada					
Light crude oil & NGL		**24.0**	25.3	**24.7**	27.6
Medium crude oil		**27.0**	26.8	**27.0**	27.2
Heavy crude oil & bitumen		**105.5**	105.4	**104.9**	106.7
		156.5	157.5	**156.6**	161.5
East Coast Canada					
White Rose - light crude oil		**75.6**	90.3	**71.6**	89.9
Terra Nova - light crude oil		**12.5**	15.5	**13.7**	15.0
China					
Wenchang - light crude oil & NGL		**11.5**	13.2	**12.1**	13.5
Total crude oil & NGL		**256.1**	276.5	**254.0**	279.9
Natural gas	*(mmcf/day)*	**618.0**	615.7	**604.2**	627.8
Total	*(mboe/day)*	**359.1**	379.1	**354.7**	384.6

Crude Oil and NGL Production

Second Quarter

In the second quarter of 2008, crude oil and NGL production decreased by 7% compared with the same period in 2007. Production from the White Rose field was shut down for 11 days in April as a result of ice encroachment due to severe ice pack and iceberg conditions. Production from White Rose averaged 76 mbbls/day during the second quarter of 2008 compared with 90 mbbls/day during the same period in 2007.

In June 2008, Terra Nova was shut down for 14 days for a scheduled maintenance turnaround that was originally planned to take place in July.

Six Months

In the first half of 2008, crude oil and NGL production decreased by 9% compared with the same period of the previous year. In addition to the issues impacting the second quarter, White Rose production was reduced by a 13-day turnaround for scheduled maintenance of the *SeaRose FPSO* during the first quarter of 2008. This maintenance turnaround was originally scheduled for August.

During the first half of 2008, crude oil and NGL production from Western Canada was down 3% compared with the first half of 2007, primarily due to the disposition of non-core oil properties.

Natural Gas Production

Second Quarter

Production of natural gas was marginally higher in the second quarter of 2008 compared with the same period in 2007. During the second quarter of 2008, new natural gas wells tied-in offset normal reservoir declines and reduced production resulting from turnarounds.

In the second quarter of 2008, 60% of our natural gas production was from the foothills of Alberta and British Columbia, the deep basin of Alberta and the plains of northeast British Columbia and northwest Alberta; the remainder was from the plains throughout Alberta and southwest Saskatchewan.

Six Months

During the first half of 2008, natural gas production was 4% lower than the year before due to severe cold weather in Western Canada in the first quarter and reduced drilling activity in 2007 in response to low natural gas prices and pending higher Alberta gas royalties. This was offset by higher second quarter production as discussed above.

Production Guidance

2008 Gross Production Guidance		Guidance	Six months ended June 30	Year ended Dec. 31
		2008	**2008**	2007
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		139 - 148	**122**	139
Medium crude oil		28 - 29	**27**	27
Heavy crude oil & bitumen		114 - 124	**105**	107
		281 - 301	**254**	273
Natural gas	*(mmcf/day)*	625 - 655	**604**	623
Total barrels of oil equivalent	*(mboe/day)*	385 - 410	**355**	377

Following the completion of the turnarounds at White Rose and Terra Nova in the first half of 2008, crude oil production is expected to increase from current levels in the second half of the year. However, the severe ice conditions which suspended production at White Rose during the first half of the year and the ramp-up of production at the Tucker Oil Sands project will impact our annual production. Production for 2008 is now expected to be five to seven percent below our guidance range.

Royalties

In the second quarter of 2008, royalty rates in Western Canada averaged 16% as a percentage of gross revenue, unchanged from the second quarter of 2007.

In March 2008, the Tier II incremental royalty rate became effective for White Rose. East coast offshore royalty rates averaged 31% as a percentage of gross revenue in the second quarter compared with 8% in the second quarter of 2007.

Royalty rates for the first six months of 2008 averaged 16% in Western Canada and 28% offshore east coast compared with 16% and 6% in 2007.

Unit Operating Costs

Second Quarter

In the second quarter of 2008, operating costs in Western Canada averaged $12.95/boe compared with $11.10/boe in the same period in 2007. Increasing operating costs in Western Canada are generally related 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 extensive natural gas compression systems. These factors in turn require higher energy consumption, workovers and generally more material costs. In addition, higher levels of industry activity lead naturally to competition for resources and consequential higher service rates and unit costs. Our efforts are focused on managing rising operating costs with initiatives such as the establishment of a logistics support division to control costs of transporting production. We strive to keep our 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 $5.47/bbl in the second quarter of 2008 compared with $4.00/bbl in the second quarter of 2007. The higher unit operating cost in 2008 was due to lower production volume. Operating costs in total were $5 million higher in the second quarter of 2008 compared with 2007 due to additional resources required to manage ice encroachment and subsurface mechanical issues. Operating costs at the South China Sea offshore operations averaged $5.19/bbl in the second quarter of 2008 compared with $3.04/bbl in the same period in 2007 as a result of higher maintenance costs.

Six Months

Total upstream operating costs in the first half of 2008 increased by 17% over 2007. In addition to the factors affecting the second quarter, operating costs were adversely affected in the first quarter by extreme cold weather in Western Canada, which resulted in increased costs for gas well servicing and methanol injection to deal with gas well freeze ups and the scheduled turnaround of the *Sea Rose FPSO*.

Unit Depletion, Depreciation and Amortization

Second Quarter

Total unit DD&A averaged $10.78/boe in the second quarter of 2008 compared with $11.79/boe in the second quarter of 2007. In Canada, unit DD&A was $10.81/boe, a decrease of 8% over the second quarter of 2007. The lower DD&A rate in Canada was primarily due to the disposition of 50% of the Sunrise oil sands asset, which reduced the full cost base by approximately $1.8 billion or $1.90/boe in the second quarter of 2008. The Sunrise oil sands project currently does not have any proved reserves attributed to it.

Six Months

For the first six months of 2008 total unit DD&A averaged $11.50/boe compared with $11.58/boe during the same period in 2007 primarily due to the effect of the Sunrise disposition largely offset by a higher full cost base in the first quarter of 2008 compared with the first half of 2007.

Netback Analysis	Three months ended June 30		Six months ended June 30	
	2008	2007	**2008**	2007
	$	**$**	$	$
Total				
Crude oil equivalent *(per boe)* (1)				
Gross price	**91.53**	52.56	**80.60**	51.10
Royalties	**19.77**	6.81	**16.52**	6.21
Net sales price	**71.76**	45.75	**64.08**	44.89
Operating costs (2)	**10.91**	8.84	**10.83**	8.59
Operating netback	**60.85**	36.91	**53.25**	36.30
DD&A	**10.78**	11.79	**11.50**	11.58
Administration expenses and other (2)	**(3.30)**	(0.71)	**(1.17)**	(0.19)
Earnings before income taxes	**53.37**	25.83	**42.92**	24.91
Western Canada				
Crude oil *(per boe)* (1)				
Light crude oil				
Gross price	**99.68**	59.41	**88.70**	58.08
Royalties	**13.61**	6.32	**11.88**	6.26
Net sales price	**86.07**	53.09	**76.82**	51.82
Operating costs (2)	**14.17**	13.89	**15.29**	12.82
Operating netback	**71.90**	39.20	**61.53**	39.00
Medium crude oil				
Gross price	**99.28**	47.81	**85.87**	46.99
Royalties	**17.71**	8.38	**15.48**	8.17
Net sales price	**81.57**	39.43	**70.39**	38.82
Operating costs (2)	**16.23**	12.48	**15.36**	13.03
Operating netback	**65.34**	26.95	**55.03**	25.79
Heavy crude oil & bitumen				
Gross price	**88.74**	38.30	**76.19**	37.98
Royalties	**12.17**	4.97	**10.21**	4.84
Net sales price	**76.57**	33.33	**65.98**	33.14
Operating costs (2)	**15.91**	12.96	**15.43**	12.40
Operating netback	**60.66**	20.37	**50.55**	20.74
Natural gas *(per mcfge)* (3)				
Gross price	**9.52**	7.04	**8.51**	7.03
Royalties	**1.86**	1.37	**1.65**	1.41
Net sales price	**7.66**	5.67	**6.86**	5.62
Operating costs (2)	**1.43**	1.35	**1.49**	1.34
Operating netback	**6.23**	4.32	**5.37**	4.28
East Coast				
Light crude oil *(per boe)* (1)				
Gross price	**124.72**	73.79	**111.74**	70.17
Royalties (4)	**38.89**	6.04	**31.62**	4.10
Net sales price	**85.83**	67.75	**80.12**	66.07
Operating costs (2)	**5.47**	4.00	**5.37**	3.52
Operating netback	**80.36**	63.75	**74.75**	62.55
International				
Light crude oil *(per boe)* (1)				
Gross price	**131.62**	75.14	**115.39**	71.65
Royalties	**36.99**	14.43	**31.55**	12.36
Net sales price	**94.63**	60.71	**83.84**	59.29
Operating costs (2)	**5.19**	3.04	**4.90**	3.98
Operating netback	**89.44**	57.67	**78.94**	55.31

1) *Includes associated co-products converted to boe.*
2) *Operating costs exclude accretion, which is included in administration expenses and other.*
3) *Includes associated co-products converted to mcfge.*
4) *During March 2008, White Rose royalties achieved payout status for Tier 2 royalties.*

Other Items

During the second quarter of 2008, an $11 million gain was recorded on an embedded derivative related to a drilling rig contract requiring payment in U.S. currency compared with a $49 million gain in the second quarter of 2007. A loss of $17 million was recorded in the first six months of 2008 compared with a gain of $49 million for the same period in 2007. The payments are expected to occur over the three-year period from mid-2008. The amount will fluctuate with the U.S./Cdn forward exchange rate until actual contract settlement. Contracts to purchase U.S. currency have been entered into which offset approximately 60% of this derivative. (Refer to Note 16 to the Consolidated Financial Statements).

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

By the end of the first half of 2008, overall upstream capital expenditures were 47% of the 2008 capital expenditure guidance. Delays are related to semi-submersible drilling rig delivery dates, contracting for consulting engineering services and receiving regulatory approvals. Our major upstream projects remain on schedule and their ultimate completion dates are expected to be maintained.

Capital Expenditures Summary [1]	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2008**	2007	**2008**	2007
Exploration				
Western Canada	**$ 103**	$ 76	**$ 309**	$ 241
East Coast Canada and Frontier	**20**	-	**45**	5
International	**32**	20	**62**	25
	155	96	**416**	271
Development				
Western Canada	**394**	357	**863**	745
East Coast Canada	**73**	62	**141**	116
International	**3**	5	**3**	5
	470	424	**1,007**	866
	$ 625	$ 520	**$ 1,423**	$ 1,137

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

During the first six months of 2008, capital expenditures were $1,172 million (82%) in Western Canada, $186 million (13%) off the East Coast of Canada and $65 million (5%) offshore China and Indonesia.

The following table discloses the number of gross and net exploration and development wells we completed in Western Canada and the oil sands during the periods indicated. All of the net exploration wells and net development wells we drilled in the second quarter of 2008 resulted in wells capable of commercial production.

Western Canada and Oil Sands Wells Drilled		Three months ended June 30				Six months ended June 30			
		2008		2007		**2008**		2007	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**5**	**3**	13	13	**28**	**26**	33	33
	Gas	**7**	**4**	4	3	**64**	**53**	69	59
	Dry	**-**	**-**	1	1	**20**	**19**	10	10
		12	**7**	18	17	**112**	**98**	112	102
Development	Oil	**73**	**73**	58	54	**193**	**177**	196	184
	Gas	**19**	**17**	6	4	**135**	**104**	174	141
	Dry	**-**	**-**	2	2	**3**	**3**	12	12
		92	**90**	66	60	**331**	**284**	382	337
Total		**104**	**97**	84	77	**443**	**382**	494	439

Western Canada - Excluding Oil Sands

During the first six months of 2008, we invested $994 million on exploration and development in Western Canada excluding oil sands, which produces variously light, medium, heavy crude oil or natural gas throughout the Western Canada Sedimentary Basin. Of this, $527 million was invested on properties in Alberta, northeast British Columbia and southern Saskatchewan primarily to further develop and extend properties with proved reserves. We drilled 382 net wells in these regions during the first six months of 2008, resulting in 203 net oil wells and 144 net natural gas wells. In the Lloydminster area of Alberta and Saskatchewan, from which the majority of our heavy crude oil is produced, we invested $388 million in this same period, to extend proved properties, implement cost reduction initiatives and perform engineering studies in respect of improved recovery schemes.

Our 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 2008, we invested $79 million drilling in these natural gas prone areas. During the first six months of 2008, we drilled 15 net exploration wells in the foothills/deep basin regions; 13 were cased as natural gas wells. The remaining 83 net exploration wells were drilled primarily in the shallow regions of the Western Canada Sedimentary Basin.

Oil Sands

Oil sands capital expenditures totaled $178 million during the first six months of 2008. At Tucker, we spent $63 million on drilling new well pairs, facility modification and new pad preparation. At Sunrise, we spent $84 million on engineering design, site preparation and facilities and equipment requisitions. At Caribou and Saleski we spent $31 million on project development.

East Coast Development

During the first half of 2008, we spent $141 million primarily for *SeaRose FPSO* tie-back projects and White Rose capital enhancements. Construction commenced on North Amethyst long lead equipment, engineering design began for the West White Rose development and infill drilling commenced at the White Rose South Avalon field.

East Coast and Northwest Territories Exploration

During the first half of 2008, we spent $45 million on two exploration wells in the Central Mackenzie Valley and on preliminary planning for our East Coast seismic program.

International

During the first half of 2008, we spent $62 million on exploration drilling in the South China Sea and seismic on the East Bawean II exploration block in the Java Sea.

2008 Guidance

Our 2008 Upstream Capital expenditure guidance remains unchanged from that reported in our 2007 annual MD&A.

2008 Capital Expenditure Guidance [1]

(millions of dollars)	
Western Canada - oil & gas	$ 1,670
- oil sands	300
East Coast Canada	650
International	430
	$ 3,050

[1] *Excludes capitalized administrative costs and capitalized interest.*

5.2 Midstream

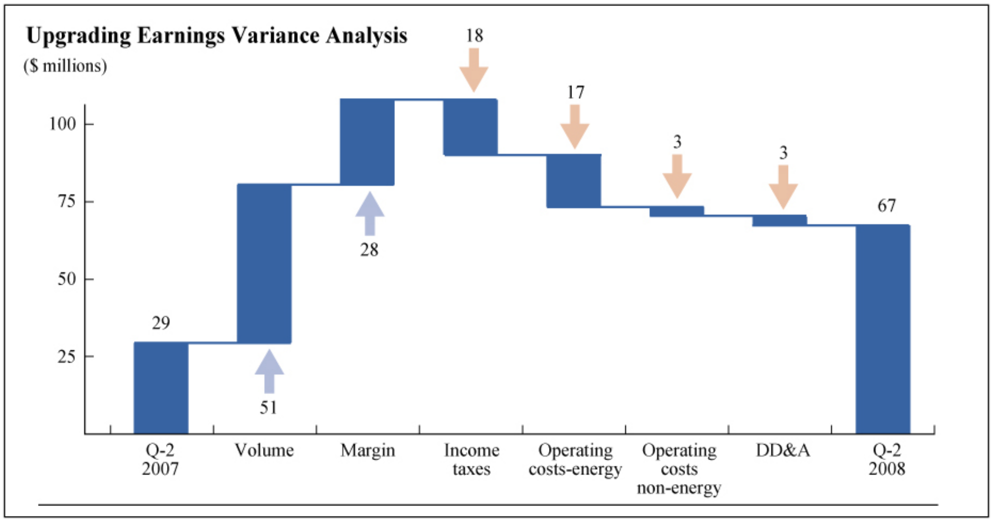
Upgrading Net Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2008**	2007	**2008**	2007
Gross margin		**$ 168**	$ 89	**$ 339**	$ 227
Operating and administration expenses		**67**	47	**130**	105
Other recoveries		**(1)**	(1)	**(2)**	(2)
Depreciation and amortization		**7**	4	**13**	10
Income taxes		**28**	10	**59**	34
Net earnings		**$ 67**	$ 29	**$ 139**	$ 80
Selected operating data:					
Upgrader throughput [1]	*(mbbls/day)*	**58.5**	36.1	**60.7**	52.5
Synthetic crude oil sales	*(mbbls/day)*	**51.6**	32.9	**53.6**	45.3
Upgrading differential	*($/bbl)*	**$ 30.12**	$ 30.41	**$ 29.28**	$ 26.42
Unit margin	*($/bbl)*	**$ 35.61**	$ 29.74	**$ 34.69**	$ 27.64
Unit operating cost [2]	*($/bbl)*	**$ 12.53**	$ 14.37	**$ 11.73**	$ 11.05

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

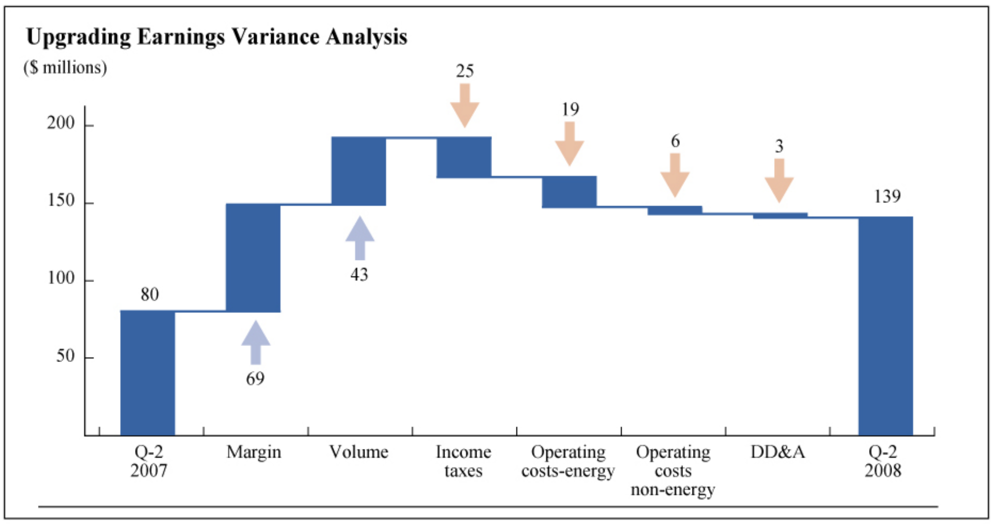
The upgrading business segment adds value by processing heavy sour crude oil into high value synthetic crude oil and low sulphur distillates. The upgrader profitability is primarily dependent on the differential between the cost of the heavy crude feedstock and the sales price of the synthetic crude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

Upgrading Net Earnings Variance Analysis

Second Quarter



Six Months



Second Quarter

During the second quarter of 2008, the upgrading differential averaged $30.12/bbl, marginally lower than a year earlier. The *differential* is equal to Husky Synthetic Blend, which sells at a premium to West Texas Intermediate, less Lloyd Heavy Blend. During the second quarter of 2008, the overall unit margin was 20% higher than a year earlier partly due to the addition of low sulphur off-road diesel to the upgrader's product stream.

Upgrader throughput was 62% higher in the second quarter of 2008 compared with the same period in 2007. Throughput was low during the second quarter of 2007 due to a 49-day scheduled turnaround and installation of new coke drums. Throughput was below capacity during the second quarter of 2008 due to a temporary shutdown to replace the hydrogen plant catalyst. Unit operating costs decreased by 13% in the second quarter of 2008 compared with a year earlier as a result of higher throughput which increased at a higher rate than increases in total operating costs. Operating cost increases were mainly attributable to higher energy costs.

Six Months

During the first half of 2008, upgrading earnings were 74% higher than the year earlier, primarily due to the same factors that affected 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)	**2008**	2007	**2008**	2007
Gross margin - pipeline	**$ 44**	$ 28	**$ 69**	$ 54
- other infrastructure and marketing	**90**	48	**179**	120
	134	76	**248**	174
Operating and administration expenses	**4**	-	**7**	4
Depreciation and amortization	**7**	7	**15**	14
Income taxes	**37**	21	**68**	48
Net earnings	**$ 86**	$ 48	**$ 158**	$ 108
Selected operating data:				
Aggregate pipeline throughput *(mbbls/day)*	**539**	506	**521**	500

Second Quarter

Infrastructure and marketing net earnings in the second quarter of 2008 were $86 million compared with $48 million in the second quarter of 2007. Higher earning were primarily due to higher pipeline throughput and tariffs and higher brokering margins on crude oil and sulphur.

Six Months

During the first half of 2008, infrastructure and marketing earnings were 46% higher than the year earlier primarily because of the same factors that affected the second quarter of 2008.

Midstream Capital Expenditures

Midstream capital expenditures totalled $65 million in the first six months of 2008: $51 million was spent at the Lloydminster upgrader, primarily for contingent consideration and facility reliability projects. The remaining $14 million was spent on the pipeline extension between Lloydminster and Hardisty, Alberta.

5.3 Downstream

Canadian Refined Products Net Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2008**	2007	**2008**	2007
Gross margin - fuel sales		**$ 50**	$ 63	**$ 88**	$ 105
- ancillary sales		**14**	10	**24**	19
- asphalt sales		**28**	36	**47**	49
		92	109	**159**	173
Operating and administration expenses		**22**	20	**26**	38
Depreciation and amortization		**20**	15	**40**	31
Income taxes		**15**	21	**28**	31
Net earnings		**$ 35**	$ 53	**$ 65**	$ 73
Selected operating data:					
Number of fuel outlets				**498**	504
Light oil sales	*(million litres/day)*	**7.9**	8.6	**7.9**	8.8
Light oil retail sales per outlet	*(thousand litres/day)*	**12.6**	13.3	**12.9**	12.8
Prince George refinery throughput	*(mbbls/day)*	**10.5**	8.4	**11.0**	9.7
Asphalt sales	*(mbbls/day)*	**23.0**	19.5	**20.4**	18.4
Lloydminster refinery throughput	*(mbbls/day)*	**26.4**	18.5	**24.2**	21.6
Ethanol production	*(thousand litres/day)*	**600.1**	305.9	**624.6**	313.7

Canadian Refined Products

Second Quarter

During the second quarter of 2008, we benefited from higher throughput at the Prince George refinery, which produces a high gasoline yield. However, earnings from sales of gasoline and diesel were lower than a year earlier due to lower sales volume and slightly lower margins. Sales volumes were down as a result of supply shortages from our third party refined product suppliers due to refinery outages. Ancillary income from convenience store and restaurant sales continues to grow.

Second quarter 2008 ethanol production increased 96% due to the start-up of the Minnedosa ethanol plant, which commenced operations at the end of 2007. This was offset by a 68% reduction in margins in 2008 due to the run up of corn prices, reduced demand and increases in natural gas prices.

During the second quarter of 2008, asphalt product margins were approximately 42% lower than a year earlier, partially offset by increased sales volumes. Asphalt margins were impacted by the increase in heavy crude oil feedstock costs. Additional value was captured in the quarter from higher volumes of residuals and distillates produced at the Lloydminster refinery and processed at the Lloydminster upgrader into low sulphur off-road diesel and synthetic crude oil.

Six Months

During the first half of 2008, earnings from gasoline and diesel were lower than the same period of 2007 as a result of the same factors affecting the second quarter. Earnings from ethanol sales were higher than the previous year as higher sales volume more than offset lower unit margins. Margins on asphalt products were lower than the same period in the previous year due to rising crude oil feedstock costs.

U.S. Refining and Marketing Net Earnings Summary	Three months ended June 30	Six months ended June 30
(millions of dollars, except where indicated)	**2008**	**2008**
Gross refining margin	**$ 398**	**$ 485**
Processing costs	**106**	**159**
Operating and administration expenses	**1**	**2**
Interest - net	**-**	**1**
Depreciation and amortization	**43**	**62**
Income taxes	**89**	**94**
Net earnings	**$ 159**	**$ 167**
Selected operating data:		
Lima refinery throughput *(mbbls/day)*	**144.1**	**141.2**
Toledo refinery throughput *(mbbls/day)*	**66.0**	**66.0** [(1)]

[(1)] *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

The U.S. Refining and Marketing segment commenced operations on July 1, 2007 with the acquisition of the Lima, Ohio refinery. The Lima refinery has a crude oil throughput capacity of 160 mbbls/stream day.

On March 31, 2008, we completed a transaction that resulted in the formation of two joint entities forming an integrated oil sands business. The downstream entity is a 50% interest in the BP Toledo refinery, which has a crude distillation capacity of 150 mbbls/day. The transaction was effective January 1, 2008 and the results of its operations for the first quarter of 2008 were reflected as an adjustment to the value assigned to the refinery assets transferred to the downstream entity on March 31, 2008. The second quarter of 2008 is the first period that the BP/Husky Toledo refinery's results of operations have been reflected in our earnings.

In the downstream sector, the drop in demand for motor fuels that began in mid-2007 continued through the first half of 2008, in line with U.S. economic conditions and record high fuel prices. Lower consumption combined with higher product stocks resulted in narrow refinery crack spreads. Crack spreads improved in the second quarter primarily on distillates, which were in high demand globally.

Downstream Capital Expenditures

Downstream capital expenditures totalled $88 million during the first six months of 2008. Capital spending was primarily related to various environmental protection and reliability upgrades at our refineries and plants and for marketing location upgrades and construction.

5.4 Corporate

Corporate Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars) income (expense)	**2008**	2007	**2008**	2007
Intersegment eliminations - net	**$ (128)**	$ (33)	**$ (137)**	$ (58)
Administration expenses	**(139)**	(55)	**(90)**	(93)
Depreciation and amortization	**(7)**	(7)	**(14)**	(12)
Interest - net	**(41)**	(22)	**(86)**	(43)
Foreign exchange	**(6)**	36	**(16)**	37
Income taxes	**98**	36	**108**	63
Net earnings (loss)	**$ (223)**	$ (45)	**$ (235)**	$ (106)

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

In the second quarter of 2008, administration expenses included stock-based compensation expense of $114 million compared with $43 million in the same period in 2007. The increase in net interest expense during the second quarter of 2008 compared with a year earlier was primarily due to a higher level of debt. Additional debt was issued during 2007 for the acquisition of the Lima refinery.

Foreign Exchange Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2008**	2007	**2008**	2007
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**$ (10)**	$ (101)	**$ 34**	$ (115)
Cross currency swaps	**3**	32	**(11)**	36
Contribution receivable	**11**	-	**11**	-
Other (gains) losses	**2**	33	**(18)**	42
	$ 6	$ (36)	**$ 16**	$ (37)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.973**	U.S. $0.867	**U.S. $1.012**	U.S. $0.858
At end of period	**U.S. $0.982**	U.S. $0.940	**U.S. $0.982**	U.S. $0.940

Corporate Capital Expenditures

Corporate capital expenditures totaled $26 million in the first six months of 2008 primarily for office and information system upgrades.

Consolidated Income Taxes

During the second quarter of 2008, consolidated income taxes consisted of $234 million of current taxes and $342 million of future taxes compared with current taxes of $66 million and future taxes of $205 million in the same period of 2007. The increase in current taxes in the second quarter of 2008 compared with the second quarter of 2007 was due to the deferral of White Rose income in 2007. The increase in future taxes in the second quarter of 2008 compared with the same period in 2007 was due to an increase in earnings.

6. Liquidity and Capital Resources

During the second quarter of 2008, cash flow from operating activities financed all of our capital requirements, dividend payment and repayment of debt. At June 30, 2008 we had $1.5 billion in unused committed credit facilities.

Cash Flow Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars, except ratios)	**2008**	2007	**2008**	2007
Cash flow - operating activities	**$ 2,054**	$ 1,136	**$ 3,281**	$ 1,808
- financing activities	**$ (1,217)**	$ (454)	**$ (1,318)**	$ (676)
- investing activities	**$ (667)**	$ (549)	**$ (1,635)**	$ (1,441)
Financial Ratios				
Debt to capital employed *(percent)*			**13.8**	12.1
Corporate reinvestment ratio *(percent)* [(1) (2)]			**78**	54

(1) Calculated for the 12 months ended for the dates shown.
(2) Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

6.1 Operating Activities

In the second quarter of 2008, cash generated from operating activities amounted to $2.1 billion compared with $1.1 billion in the second quarter of 2007. Higher cash flow from operating activities was primarily due to higher upstream commodity prices, the introduction of the operations of the Lima and Toledo refineries, higher upgrading throughput and unit margin, higher crude oil and sulphur brokering income, higher pipeline throughput and tariffs partially offset by higher cost of sales and operating and administrative expenses, cash taxes and interest.

6.2 Financing Activities

In the second quarter of 2008, cash used in financing activities was $1,217 million compared with $454 million in the second quarter of 2007. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities. The remaining bridge financing of $741 million in respect of the acquisition of the Lima refinery was repaid in June 2008.

6.3 Investing Activities

In the second quarter of 2008, cash used in investing activities amounted to $667 million compared with $549 million in the second quarter of 2007. Cash invested in both periods was used primarily for capital expenditures.

6.4 Sources of Capital

We are currently able to fund our capital programs principally by cash provided from operating activities. We also maintain access to sufficient capital via debt markets commensurate with the strength of our balance sheet and continually examine our options with respect to sources of long and short-term capital resources.

Working capital is the amount by which current assets exceed current liabilities. At June 30, 2008, our working capital was $1,488 million compared with a working capital deficiency of $51 million at December 31, 2007. In addition to increases in cash balances, working capital increased due to higher feedstock and refined product inventories, higher accounts receivable at our U.S. refining operations and higher accounts receivable for our Canadian crude oil production. The higher working capital from cash, accounts receivable and inventories was partially offset by higher accounts payable, primarily for U.S. refinery feedstock purchases.

(millions of dollars)	June 30 2008	Dec. 31 2007	Change	
Current assets				
Cash and cash equivalents	**$ 536**	$ 208	$ 328	Strong earnings, sale of 50% of Madura PSC
Accounts receivable	**2,171**	1,622	549	Higher crude oil prices
Inventories	**1,889**	1,190	699	Inclusion of Toledo inventory; increased Lima inventory
Prepaid expenses	**66**	28	38	Certain 2008 expenses paid early in the year
	4,662	3,048	1,614	
Current liabilities				
Accounts payable	**1,847**	1,460	(387)	Higher crude oil and gas prices; higher royalties; inclusion of Toledo refinery
Accrued interest payable	**32**	20	(12)	
Income taxes payable	**214**	36	(178)	Higher taxable income
Other accrued liabilities	**852**	842	(10)	
Long-term debt due within one year	**229**	741	512	Repayment of bridge financing offset by capital securities reclassed to current
	3,174	3,099	(75)	
Working capital	**$ 1,488**	$ (51)	$ 1,539	

Capital Structure

(millions of dollars)	June 30, 2008 Outstanding	Available
Total short-term and long-term debt	$ 2,129	$ 1,588
Common shares, retained earnings and accumulated other comprehensive income	$ 13,308	

At June 30, 2008, we had unused committed long and short-term borrowing credit facilities totalling $1.5 billion. A total of $82 million of our borrowing credit facilities were used in support of outstanding letters of credit and an additional $44 million of letters of credit were outstanding at June 30, 2008 supported by dedicated letters of credit lines.

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

We currently have a shelf prospectus dated September 21, 2006 that enables us to offer up to U.S. $1.0 billion of debt securities in the United States until October 21, 2008. During the period that the prospectus is effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of the date of this MD&A, U.S. $750 million of debt securities had been issued under this shelf prospectus and the remaining amount of U.S. $250 million is eligible for issue.

On June 12, 2008, we initiated a cash tender offer to purchase any and all of the 8.90% capital securities. As of June 12, 2008, there were U.S. $225 million of capital securities outstanding. The tender offer expired on July 11, 2008 at which date U.S. $ 214 million or 95% of the capital securities had been tendered. The settlement date occurred July 11, 2008. The remaining capital securities will be redeemed on August 14, 2008.

6.5 Credit Ratings

On March 31, 2008, DBRS upgraded our Senior Unsecured Notes and Debentures to A (low) and our Capital Securities to BBB (high) both with stable trends.

Our other credit ratings are available in our recently filed Annual Information Form at www.sedar.com.

6.6 Contractual Obligations and Commercial Commitments

Refer to Husky's 2007 annual and first quarter 2008 MD&A under the caption "Liquidity and Capital Resources," which summarizes contractual obligations and commercial commitments.

6.7 Off Balance Sheet Arrangements

We do not utilize off balance sheet arrangements with unconsolidated entities to enhance perceived liquidity.

We engage, in the ordinary course of business, in the securitization of accounts receivable. At June 30, 2008 and December 31, 2007, we had no accounts receivable sold under the securitization program. The securitization program permits the sale of a maximum of $350 million of accounts receivable on a revolving basis. The accounts receivable are sold to an unrelated third party and in accordance with the agreement we must provide a loss reserve to replace defaulted receivables. The securitization agreement expires on January 31, 2009.

The securitization program provides us with cost effective short-term funding for general corporate use. We account for these securitizations as asset sales. In the event the program is terminated our liquidity would not be materially reduced.

6.8 Transactions with Related Parties

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 34.58% shareholder in Husky. TransAlta Power, L.P. is a 49.99% owner of TransAlta Cogeneration, L.P., our partner in the Meridian cogeneration plant in Lloydminster, Saskatchewan. We sell natural gas to the Meridian cogeneration plant and other cogeneration plants owned by TransAlta Power, L.P. We received the market price or negotiated medium-term contracts based on market-related terms for these commodities. During the first six months of 2008, we sold $64 million of natural gas to TransAlta Power, L.P.

7. Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks see our 2007 Annual Information Form filed on the Canadian Securities Administrator's web site, www.sedar.com, the Securities Exchange Commission's web site, www.sec.gov or our web site www.huskyenergy.com.

Our financial risks are largely related to commodity prices, exchange rates, interest rates, credit risk, changes in fiscal policy related to royalties and taxes and others. From time to time, we use financial and derivative instruments to manage our exposure to these risks.

Interest Rate Risk Management

In the first six months of 2008, 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. During the first six months of 2008, these swaps resulted in an offset to interest expense amounting to $1 million.

The amortization of previous interest rate swap terminations resulted in an additional $1 million offset to interest expense in the first six months of 2008.

Cross currency swaps resulted in an addition to interest expense of $2 million in the first six months of 2008.

Foreign Currency Risk Management

At June 30, 2008, we had the following cross currency debt swaps in place:

- U.S. $150 million at 6.25% swapped at $1.41 to $212 million at 7.41% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.19 to $90 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, 2008, we had the following freestanding derivatives in place where Husky had entered into forward purchases of U.S. dollars to partially offset exposure on an embedded derivative (refer to Note 16 to the Consolidated Financial Statements):

- U.S. $119 million bought at $0.9854 for $117 million from January 2008 to June 2011.
- U.S. $119 million bought at $0.9772 for $116 million from January 2008 to June 2011.
- U.S. $119 million bought at $0.9670 for $115 million from January 2008 to June 2011.

At June 30, 2008 the cost of a U.S. dollar in Canadian currency was $1.0186.

Our results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of our 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 our 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, 2008, 90% or $1.9 billion of our long-term debt was denominated in U.S. dollars. The percentage of our long-term debt exposed to the Cdn/U.S. exchange rate decreases to 73% when cross currency swaps are considered.

Effective July 1, 2007, our U.S. $1.5 billion of debt financing related to the Lima acquisition was designated as a hedge of the net investment in the U.S. refining operations, which are considered self-sustaining. During the second quarter of 2008, we repaid our bridge financing of U.S. $750 million. As a result, the net investment hedge is limited to the remaining U.S. $750 million. As at June 30, 2008, unrealized foreign exchange losses arising from the translation of the debt were $40 million, net of tax of $7 million which was recorded in "Other Comprehensive Income."

8. Critical Accounting Estimates

Certain of our accounting policies require that we make 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 our Management's Discussion and Analysis for the year ended December 31, 2007 available at www.sedar.com.

9. Changes in Accounting Policies

Inventories

Effective January 1, 2008, we adopted the Canadian Institute of Chartered Accountants ("CICA") section 3031, "Inventories," which replaced CICA section 3030 of the same name. The new guidance provides additional measurement and disclosure requirements and requires the reversal of previous impairment write-downs when there is a change in the situation that caused the impairment. The transitional provisions of section 3031 provided entities with the option of applying this guidance retrospectively and restating prior periods in accordance with section 1506, "Accounting Changes" or adjusting opening retained earnings and not restating prior periods. The adoption of this standard did not have an impact on our financial statements.

Financial Instruments - Disclosure and Presentation

Effective January 1, 2008, we adopted CICA section 3862, "Financial Instruments - Disclosures" and CICA section 3863, "Financial Instruments - Presentation," which replaced CICA section 3861, "Financial Instruments - Disclosure and Presentation." Section 3862 outlines the disclosure requirements for financial instruments and non-financial derivatives. This guidance prescribes an increased importance on risk disclosures associated with recognized and unrecognized financial instruments and how such risks are managed. Specifically, section 3862 requires disclosure of the significance of financial instruments on our financial position. In addition, the guidance outlines revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments.

The presentation requirements under section 3863 are relatively unchanged from section 3861. Refer to Note 16 to the Consolidated Financial Statements for the additional disclosures under section 3862.

Capital Disclosures

Effective January 1, 2008, we adopted CICA section 1535, "Capital Disclosures." This new guidance requires disclosure about our objectives, policies and processes for managing capital. These disclosures include a description of what we manage as capital, the nature of externally imposed capital requirements, how the requirements are incorporated into our management of capital, whether the requirements have been complied with, or consequence of non-compliance and an explanation of how we are meeting our objectives for managing capital. In addition, quantitative disclosures regarding capital are required. Refer to Note 17 to the Consolidated Financial Statements.

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. As part of the AcSB's strategic plan, Canadian publicly accountable entities will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian generally accepted accounting principles ("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. Currently, we are assessing the effects of adoption and developing a plan accordingly. We will continue to monitor any changes in the adoption of IFRS and will update plans as necessary.

10. Outstanding Share Data

(in thousands)	July 15 2008	December 31 2007
Issued and outstanding		
Number of common shares	849,143	848,960
Number of stock options	27,481	30,131
Number of stock options exercisable	7,456	4,494

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 2007 Annual Information Form filed in 2008 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 pronouns "we," "our" and "us" and 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, 2008 are compared with results for the three months ended June 30, 2007 and results for the six months ended June 30, 2008 are compared with results for the six months ended June 30, 2007. Discussions with respect to Husky's financial position as at June 30, 2008 are compared with its financial position at December 31, 2007.

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 our financial performance. Cash flow from operations or earnings is presented in our financial reports to assist management and investors in analyzing operating performance by business in the stated period. Our 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:

(millions of dollars)		Three months ended June 30 2008	Three months ended June 30 2007	Six months ended June 30 2008	Six months ended June 30 2007
Non-GAAP	Cash flow from operations	**$ 2,090**	$ 1,257	**$ 3,631**	$ 2,581
	Settlement of asset retirement obligations	**(7)**	(7)	**(24)**	(21)
	Change in non-cash working capital	**(29)**	(114)	**(326)**	(752)
GAAP	Cash flow - operating activities	**$ 2,054**	$ 1,136	**$ 3,281**	$ 1,808

Disclosure of Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. This measurement helps management and investors to evaluate the specific operating performance by product at the oil and gas lease level. It is equal to product revenue less transportation costs, royalties and lease operating costs divided by either a barrel of oil equivalent or an mcf of gas equivalent.

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 2 of our Annual Information Form for the year ended December 31, 2007 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*
SEDAR	*System for Electronic Document Analysis and Retrieval*
FPSO	*Floating production, storage and offloading vessel*
FEED	*Front-end engineering design*

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*
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*
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*
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 divided by average capital employed*
Return on Shareholders' Equity	*Net earnings 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 release 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. We hereby provide cautionary statements identifying important factors that could cause our 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 our 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. Therefore, any such forward-looking statements are qualified in their entirety by reference to the factors discussed throughout this release.*

In particular, forward-looking statements in this release and Interim Report include, but are not limited to: our 2008 revised production guidance and capital spending guidance, our development plans for the North Amethyst, West White Rose oil fields and South White Rose oil field extension, our plans to undertake a 3-D seismic acquisition program in the Jeanne d’Arc Basin and our plans to participate in an exploration well in the Flemish Pass Basin, our production optimization plans for the Tucker in-situ oil sands project, our Sunrise multiphase development plans, our development plans for the McMullen property, our Caribou and Saleski oil sands projects plans, our Northwest Territories exploration program, our exploration and delineation drilling plans for the South China Sea, the receipt of an extension of the PSC for the Madura BD natural gas and NGL field and regulatory approval for the East Bawean II exploration block two-well work program, our 2-D seismic acquisition programs and completion of an aero-gravity and magnetic survey for offshore Greenland, our plans to install various enhanced recovery schemes in Western Canada intended to increase reserves and our review options in respect of reconfiguring and expanding the Lima refinery and our plans to modify the Toledo refinery.

Although we believe that the expectations reflected by the forward-looking statements presented in this release and Interim Report are reasonable, our 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 us about ourselves and the businesses in which we operate. Information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources. In some instances, material assumptions are disclosed elsewhere in this release and Interim Report in respect of forward-looking statements. We caution the reader that the following list of assumptions is not exhaustive. The material factors and assumptions used to develop the forward-looking statements include but are not limited to:

- *no significant adverse changes to energy markets, competitive conditions, the supply and demand for crude oil, natural gas, NGL and refined petroleum products, or the political, economic and social stability of the jurisdictions in which we operate;*
- *no significant delays of the development, construction or commissioning of our projects that may result from the inability of suppliers to meet their commitments, lack of regulatory approvals or other governmental actions, harsh weather or other calamitous event;*
- *no significant disruption of our operations such as may result from harsh weather, natural disaster, accident, civil unrest or other calamitous event;*
- *no significant unexpected technological or commercial difficulties that adversely affect our exploration, development, production, processing or transportation;*
- *continuing availability of economical capital resources; demand for our products and our cost of operations;*
- *no significant adverse legislative and regulatory changes, in particular changes to the legislation and regulation governing fiscal regimes and environmental issues; environmental risks and liability under provincial/state, federal or other jurisdictions;*
- *stability of general domestic and global economic, market and business conditions; and*
- *no significant increase in the cost of our major growth projects.*

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. The risks, uncertainties and other factors, many of which are beyond our control, that could influence actual results include, but are not limited to:

- *the prices we receive for our crude and natural gas production;*
- *demand for our products and our cost of operations;*
- *our ability to replace our proved oil and gas reserves in a cost-effective manner;*
- *the effect of weather and other environmental conditions;*
- *inability to obtain regulatory approvals to operate existing properties or develop significant growth projects;*
- *competitive actions of other companies, including increased competition from other oil and gas companies;*
- *business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us and that may or may not be financially recoverable;*
- *fluctuations in interest rates and foreign currency exchange rates;*
- *actions by governmental authorities, including changes in environmental and other regulations that may impose operating costs or restrictions in areas where we operate; and*

- *the inability to reach our estimated production levels from existing and future oil and gas development projects as a result of technological, commercial difficulties or other risk factor.*

These risks, uncertainties and other factors are discussed in our Annual Information Form and our Form 40-F, available at www.sedar.com and www.sec.gov, respectively.

Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable law, we undertake 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 our 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.

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of dollars, except share data)	**June 30 2008**	December 31 2007
	(unaudited)	
Assets		
Current assets		
Cash and cash equivalents	**$ 536**	$ 208
Accounts receivable	**2,171**	1,622
Inventories	**1,889**	1,190
Prepaid expenses	**66**	28
	4,662	3,048
Property, plant and equipment *(note 6)*	**31,062**	29,407
Less accumulated depletion, depreciation and amortization	**12,460**	11,602
	18,602	17,805
Goodwill *(note 8)*	**675**	660
Contribution receivable *(note 6)*	**1,183**	-
Other assets	**174**	184
	$ 25,296	$ 21,697
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 2,945**	$ 2,358
Long-term debt due within one year *(note 10)*	**229**	741
	3,174	3,099
Long-term debt *(note 10)*	**1,900**	2,073
Contribution payable *(note 6)*	**1,339**	-
Other long-term liabilities *(note 11)*	**959**	918
Future income taxes	**4,616**	3,957
Shareholders' equity		
Common shares *(note 13)*	**3,559**	3,551
Retained earnings	**9,806**	8,176
Accumulated other comprehensive income	**(57)**	(77)
	13,308	11,650
	$ 25,296	$ 21,697
Common shares outstanding *(millions) (note 13)*	**849.1**	849.0

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Earnings and Comprehensive Income

(millions of dollars, except share data) (unaudited)	Three months ended June 30 **2008**	Three months ended June 30 2007	Six months ended June 30 **2008**	Six months ended June 30 2007
Sales and operating revenues, net of royalties	**$ 7,199**	$ 3,163	**$ 12,285**	$ 6,407
Costs and expenses				
Cost of sales and operating expenses	**4,666**	1,701	**7,973**	3,480
Selling and administration expenses	**71**	52	**122**	90
Stock-based compensation *(note 13)*	**114**	43	**71**	64
Depletion, depreciation and amortization	**436**	440	**886**	873
Interest - net *(note 10)*	**41**	22	**87**	43
Foreign exchange *(note 10)*	**6**	(36)	**16**	(37)
Other - net	**(74)**	(51)	**(75)**	(45)
	5,260	2,171	**9,080**	4,468
Earnings before income taxes	**1,939**	992	**3,205**	1,939
Income taxes				
Current	**234**	66	**459**	138
Future	**342**	205	**496**	430
	576	271	**955**	568
Net earnings	**1,363**	721	**2,250**	1,371
Other comprehensive income *(note 16)*				
Derivatives designated as cash flow hedges, net of tax	**(3)**	2	**(5)**	4
Cumulative foreign currency translation adjustment	**(27)**	-	**65**	-
Hedge of net investment, net of tax	**11**	-	**(40)**	-
	(19)	2	**20**	4
Comprehensive income	**$ 1,344**	$ 723	**$ 2,270**	$ 1,375
Earnings per share				
Basic and diluted	**$ 1.61**	$ 0.85	**$ 2.65**	$ 1.61
Weighted average number of common shares outstanding *(millions)*				
Basic and diluted	**849.1**	848.7	**849.1**	848.6

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Changes in Shareholders' Equity

(millions of dollars) (unaudited)	Three months ended June 30 **2008**	Three months ended June 30 2007	Six months ended June 30 **2008**	Six months ended June 30 2007
Common shares				
Beginning of period	**$ 3,555**	$ 3,536	**$ 3,551**	$ 3,533
Options exercised	**4**	11	**8**	14
End of period	**3,559**	3,547	**3,559**	3,547
Retained earnings				
Beginning of period	**8,783**	6,317	**8,176**	6,087
Net earnings	**1,363**	721	**2,250**	1,371
Dividends on common shares				
Ordinary	**(340)**	(212)	**(620)**	(424)
Special	**-**	-	**-**	(212)
Adoption of financial instruments	**-**	-	**-**	4
End of period	**9,806**	6,826	**9,806**	6,826
Accumulated other comprehensive income				
Beginning of period	**(38)**	(16)	**(77)**	-
Adoption of financial instruments	**-**	-	**-**	(18)
Other comprehensive income *(note 16)*				
Derivatives designated as cash flow hedges, net of tax	**(3)**	2	**(5)**	4
Cumulative foreign currency translation adjustment	**(27)**	-	**65**	-
Hedge of net investment, net of tax	**11**	-	**(40)**	-
	(19)	2	**20**	4
End of period	**(57)**	(14)	**(57)**	(14)
Shareholders' equity	**$ 13,308**	$ 10,359	**$ 13,308**	$ 10,359

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows

	Three months ended June 30		Six months ended June 30	
(millions of dollars) (unaudited)	**2008**	2007	**2008**	2007
Operating activities				
Net earnings	**$ 1,363**	$ 721	**$ 2,250**	$ 1,371
Items not affecting cash				
Accretion *(note 11)*	**14**	10	**27**	22
Depletion, depreciation and amortization	**436**	440	**886**	873
Future income taxes	**342**	205	**496**	430
Foreign exchange	**3**	(69)	**34**	(79)
Other	**(68)**	(50)	**(62)**	(36)
Settlement of asset retirement obligations *(note 11)*	**(7)**	(7)	**(24)**	(21)
Change in non-cash working capital *(note 7)*	**(29)**	(114)	**(326)**	(752)
Cash flow - operating activities	**2,054**	1,136	**3,281**	1,808
Financing activities				
Bank operating loans financing - net	**(77)**	(83)	**-**	-
Long-term debt issue	**372**	1,432	**747**	1,867
Long-term debt repayment	**(1,237)**	(1,432)	**(1,512)**	(1,967)
Proceeds from exercise of stock options	**1**	3	**2**	4
Dividends on common shares	**(340)**	(212)	**(620)**	(636)
Other	**-**	-	**(8)**	-
Change in non-cash working capital *(note 7)*	**64**	(162)	**73**	56
Cash flow - financing activities	**(1,217)**	(454)	**(1,318)**	(676)
Available for investing	**837**	682	**1,963**	1,132
Investing activities				
Capital expenditures	**(726)**	(647)	**(1,578)**	(1,381)
Joint venture arrangement *(note 6)*	**127**	-	**127**	-
Asset sales	**4**	327	**34**	327
Other	**(14)**	(36)	**5**	(38)
Change in non-cash working capital *(note 7)*	**(58)**	(193)	**(223)**	(349)
Cash flow - investing activities	**(667)**	(549)	**(1,635)**	(1,441)
Increase (decrease) in cash and cash equivalents	**170**	133	**328**	(309)
Cash and cash equivalents, beginning of period	**366**	-	**208**	442
Cash and cash equivalents, end of period	**$ 536**	$ 133	**$ 536**	$ 133

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to the Consolidated Financial Statements

Six months ended June 30, 2008 *(unaudited)*
Except where indicated, all dollar amounts are in millions.

Note 1 Segmented Financial Information

	Upstream		Midstream				Downstream				Corporate and Eliminations [1]		Total	
			Upgrading		Infrastructure and Marketing		Canadian Refined Products		U.S. Refining and Marketing					
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Three months ended June 30														
Sales and operating revenues, net of royalties	**$ 2,424**	$ 1,593	**$ 648**	$ 229	**$ 3,909**	$ 2,521	**$ 982**	$ 709	**$ 2,553**	$ -	**$(3,317)**	$ (1,889)	**$ 7,199**	$ 3,163
Costs and expenses														
Operating, cost of sales, selling and general	**328**	295	**546**	186	**3,779**	2,445	**912**	620	**2,262**	-	**(3,050)**	(1,801)	**4,777**	1,745
Depletion, depreciation and amortization	**352**	407	**7**	4	**7**	7	**20**	15	**43**	-	**7**	7	**436**	440
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**41**	22	**41**	22
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**6**	(36)	**6**	(36)
	680	702	**553**	190	**3,786**	2,452	**932**	635	**2,305**	-	**(2,996)**	(1,808)	**5,260**	2,171
Earnings (loss) before income taxes	**1,744**	891	**95**	39	**123**	69	**50**	74	**248**	-	**(321)**	(81)	**1,939**	992
Current income taxes	**99**	3	**14**	-	**28**	29	**7**	7	**59**	-	**27**	27	**234**	66
Future income taxes	**406**	252	**14**	10	**9**	(8)	**8**	14	**30**	-	**(125)**	(63)	**342**	205
Net earnings (loss)	**$ 1,239**	$ 636	**$ 67**	$ 29	**$ 86**	$ 48	**$ 35**	$ 53	**$ 159**	$ -	**$ (223)**	$ (45)	**$ 1,363**	$ 721
Capital expenditures - Three months ended June 30 [2]	**$ 625**	$ 520	**$ 28**	$ 74	**$ 5**	$ 5	**$ 28**	$ 43	**$ 34**	$ -	**$ 14**	$ 11	**$ 734**	$ 653
Six months ended June 30														
Sales and operating revenues, net of royalties	**$ 4,253**	$ 3,158	**$1,131**	$ 588	**$ 7,011**	$ 5,076	**$ 1,704**	$ 1,327	**$ 3,882**	$ -	**$(5,696)**	$ (3,742)	**$12,285**	$ 6,407
Costs and expenses														
Operating, cost of sales, selling and general	**741**	618	**920**	464	**6,770**	4,906	**1,571**	1,192	**3,558**	-	**(5,469)**	(3,591)	**8,091**	3,589
Depletion, depreciation and amortization	**742**	806	**13**	10	**15**	14	**40**	31	**62**	-	**14**	12	**886**	873
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**1**	-	**86**	43	**87**	43
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**16**	(37)	**16**	(37)
	1,483	1,424	**933**	474	**6,785**	4,920	**1,611**	1,223	**3,621**	-	**(5,353)**	(3,573)	**9,080**	4,468
Earnings (loss) before income taxes	**2,770**	1,734	**198**	114	**226**	156	**93**	104	**261**	-	**(343)**	(169)	**3,205**	1,939
Current income taxes	**265**	25	**36**	1	**58**	45	**13**	15	**37**	-	**50**	52	**459**	138
Future income taxes	**549**	493	**23**	33	**10**	3	**15**	16	**57**	-	**(158)**	(115)	**496**	430
Net earnings (loss)	**$ 1,956**	$ 1,216	**$ 139**	$ 80	**$ 158**	$ 108	**$ 65**	$ 73	**$ 167**	$ -	**$ (235)**	$ (106)	**$ 2,250**	$ 1,371
Capital expenditures - Six months ended June 30 [2]	**$ 1,423**	$ 1,137	**$ 50**	$ 122	**$ 15**	$ 41	**$ 47**	$ 83	**$ 41**	$ -	**$ 26**	$ 16	**$ 1,602**	$ 1,399
Goodwill additions - Six months ended June 30	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -
Total assets - As at June 30	**$ 14,708**	$13,974	**$1,497**	$1,193	**$ 1,300**	$ 1,147	**$ 1,630**	$ 1,304	**$ 5,404**	$ -	**$ 757**	$ 351	**$25,296**	$17,969

[1] *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.*
[2] *Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.*

Geographical Financial Information

	Canada		United States		Other International		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Three months ended June 30								
Sales and operating revenues, net of royalties	**$ 4,143**	$ 2,828	**$ 2,957**	$ 262	**$ 99**	$ 73	**$ 7,199**	$ 3,163
Capital expenditures [(1)]	**665**	628	**34**	-	**35**	25	**734**	653
Six months ended June 30								
Sales and operating revenues, net of royalties	**$ 7,527**	$ 5,664	**$ 4,575**	$ 598	**$ 183**	$ 145	**$12,285**	$ 6,407
Capital expenditures [(1)]	**1,496**	1,369	**41**	-	**65**	30	**1,602**	1,399
As at June 30								
Property, plant and equipment, net	**$14,875**	$15,378	**$ 3,369**	$ 3	**$ 358**	$ 350	**$18,602**	$15,731
Goodwill [(2)]	**160**	160	**515**	-	**-**	-	**675**	160

[(1)] *Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.*
[(2)] *Changes in goodwill for the U.S. arise from translation of goodwill in our self-sustaining U.S. operations.*

Note 2 Significant Accounting Policies

The interim consolidated financial statements of Husky Energy Inc. ("Husky" or "the Company") have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2007, except as noted below. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto in the Company's annual report for the year ended December 31, 2007. Certain prior years' amounts have been reclassified to conform with current presentation.

Note 3 Changes in Accounting Policies

Inventories

Effective January 1, 2008, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") section 3031, "Inventories," which replaced CICA section 3030 of the same name. The new guidance provides additional measurement and disclosure requirements and requires the Company to reverse previous impairment write-downs when there is a change in the situation that caused the impairment. The transitional provisions of section 3031 provided entities with the option of applying this guidance retrospectively and restating prior periods in accordance with section 1506, "Accounting Changes" or adjusting opening retained earnings and not restating prior periods. The adoption of this standard did not have an impact on the Company's financial statements.

Note 4 New Disclosures

a) Financial Instruments - Disclosure and Presentation

Effective January 1, 2008, the Company adopted CICA section 3862, "Financial Instruments - Disclosures" and CICA section 3863, "Financial Instruments - Presentation," which replaced CICA section 3861, "Financial Instruments - Disclosure and Presentation." Section 3862 outlines the disclosure requirements for financial instruments and non-financial derivatives. This guidance prescribes an increased importance on risk disclosures associated with recognized and unrecognized financial instruments and how such risks are managed. Specifically, section 3862 requires disclosure of the significance of financial instruments on the Company's financial position. In addition, the guidance outlines revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments.

The presentation requirements under section 3863 are relatively unchanged from section 3861. Refer to Note 16, "Financial Instruments and Risk Management" for the additional disclosures under section 3862.

b) Capital Disclosures

Effective January 1, 2008, the Company adopted CICA section 1535, "Capital Disclosures." This new guidance requires disclosure about the Company's objectives, policies and processes for managing capital. These disclosures include a description of what the Company manages as capital, the nature of externally imposed capital requirements, how the requirements are incorporated into the Company's management of capital, whether the requirements have been complied with, or consequence of non-compliance and an explanation of how the Company is meeting its objectives for managing capital. In addition, quantitative disclosures regarding capital are required. Refer to Note 17, "Capital Disclosures."

Note 5 Pending Accounting Pronouncements

Goodwill and Intangible Assets

In February 2008, the CICA issued CICA section 3064, "Goodwill and Intangible Assets," which will replace 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 Abstract No. 27, "Revenues and Expenditures during the Pre-Operating Period" will be withdrawn. This new guidance reinforces a

principles-based approach to the recognition of costs as assets in accordance with the definition of an asset and the criteria for asset recognition under CICA section 1000, "Financial Statement Concepts." Moreover, section 3064 clarifies the application of the concept of matching revenues and expenses in section 1000 to eliminate the current practice of recognizing as assets items that do not meet the definition and recognition criteria. Under this new guidance, fewer items meet the criteria for capitalization. Section 3064 is effective for Husky on January 1, 2009. Intangible assets recognized prior to January 1, 2009 that do not meet the recognition or measurement criteria as outlined in section 3064 are accounted for in accordance with CICA section 1506, "Accounting Changes." An intangible item that was originally recognized as an expense is not recognized as part of the cost of an intangible asset upon transition to section 3064. The Company is currently determining the impact of this standard.

Note 6 Joint Ventures

a) BP

On March 31, 2008, the Company completed a transaction with BP, which resulted in the formation of a 50/50 joint venture upstream entity and a 50/50 joint venture downstream entity.

The upstream entity is a partnership to which Husky has contributed the Sunrise oil sands assets with a fair value of U.S. $2.5 billion as at January 1, 2008 plus capital expenditures for the three-month period ended March 31, 2008 of $41 million. BP's contribution was U.S. $250 million cash and a contribution receivable for the balance of U.S. $2.25 billion and $41 million. The contribution receivable accretes at a rate of 6% and is payable between March 31, 2008 and December 31, 2015 with the final balance due and payable by December 31, 2015. The upstream entity is included as part of the Upstream segment.

The downstream entity is a limited liability company ("LLC") to which BP has contributed the Toledo refinery with a fair value of U.S. $2.5 billion, plus capital expenditures for the three-month period ended March 31, 2008 of U.S. $12 million and inventories of U.S. $372 million, less inventory related payables of U.S. $109 million and adjusted earnings of U.S. $14 million. Husky's contribution was U.S. $250 million cash and a contribution payable for the balance of U.S. $2.5 billion. The contribution payable accretes at a rate of 6% and is payable between March 31, 2008 and December 31, 2015 with the final balance due and payable by December 31, 2015. The timing of payments during this period will be determined by the capital expenditures made at the refinery during this same period. The downstream entity is included as part of the U.S. Refining and Marketing segment. This entity is a self-sustaining foreign operation.

During the second quarter of 2008, the operator of the refinery reported adjustments to capital expenditures, inventory, inventory related payables and other items contributed to the downstream LLC on March 31, 2008. As a result, BP's revised contributions were capital expenditures of U.S. $11 million, inventories of U.S. $388 million, other net assets of U.S. $3 million, less inventory related payables of U.S. $23 million and adjusted earnings of U.S. $39 million. The adjustments resulted in an increase to the contribution payable from Husky of U.S. $79 million.

Both joint ventures are being accounted for using proportionate consolidation. The amounts recorded in the financial statements represent the Company's 50% interest in the joint ventures.

b) CNOOC Southeast Asia Limited

In April 2008, a subsidiary of the Company, Husky Oil Madura Partnership ("HOMP"), entered into an agreement with CNOOC Southeast Asia Limited ("CNOOCSE"), which resulted in the acquisition by CNOOCSE of a 50% equity interest in Husky Oil (Madura) Limited, a subsidiary of HOMP, for a consideration of $127 million (U.S. $125 million) resulting in a gain of $69 million included in other - net in the Consolidated Statements of Earnings and Comprehensive Income. Husky Oil (Madura)

Limited holds a 100% interest in the Madura Strait Production Sharing Contract. The resulting joint venture arrangement is being accounted for using the proportionate consolidation method.

Note 7 Cash Flows - Change in Non-cash Working Capital

	Three months ended June 30		Six months ended June 30	
	2008	2007	**2008**	2007
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ (211)**	$ 147	**$ (535)**	$ 149
Inventories	**(238)**	(99)	**(486)**	(91)
Prepaid expenses	**(35)**	(143)	**(36)**	(144)
Accounts payable and accrued liabilities	**461**	(374)	**581**	(959)
Change in non-cash working capital	**$ (23)**	$ (469)	**$ (476)**	$(1,045)
Relating to:				
Operating activities	**$ (29)**	$ (114)	**$ (326)**	$ (752)
Financing activities	**64**	(162)	**73**	56
Investing activities	**(58)**	(193)	**(223)**	(349)
b) Other cash flow information:				
Cash taxes paid	**$ 110**	$ 72	**$ 281**	$ 840
Cash interest paid	**41**	39	**82**	62

Note 8 Goodwill

	Three months ended June 30		Six months ended June 30	
	2008	2007	**2008**	2007
Balance at beginning of period	**$ 680**	$ 160	**$ 660**	$ 160
Foreign currency translation of goodwill in self-sustaining U.S. operations	**(5)**	-	**15**	-
Balance at June 30	**$ 675**	$ 160	**$ 675**	$ 160

Note 9 Bank Operating Loans

At June 30, 2008, the Company had unsecured short-term borrowing lines of credit with banks totalling $270 million (December 31, 2007 - $270 million). As at June 30, 2008 and December 31, 2007, there were no bank operating loans outstanding. As of June 30, 2008, letters of credit under these lines of credit totalled $82 million (December 31, 2007 - $73 million).

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. As at June 30, 2008, there was no balance outstanding under this credit facility.

Note 10 Long-term Debt

	Maturity	June 30 **2008**	Dec. 31 2007	June 30 **2008**	Dec. 31 2007
		Cdn $ Amount		*U.S. $ Denominated*	
Long-term debt					
Medium-term notes	2009	**$ 203**	$ 203	**$ -**	$ -
6.25% notes	2012	**407**	395	**400**	400
7.55% debentures	2016	**204**	198	**200**	200
6.20% notes	2017	**306**	296	**300**	300
6.15% notes	2019	**306**	296	**300**	300
8.90% capital securities	2028	**-**	223	**-**	225
6.80% notes	2037	**458**	445	**450**	450
Debt issue costs [(1)]		**(18)**	(20)	**-**	-
Unwound interest rate swaps		**34**	37	**-**	-
		$ 1,900	$ 2,073	**$ 1,650**	$ 1,875
Long-term debt due within one year					
Bridge financing	2008	**$ -**	$ 741	**$ -**	$ 750
8.90% capital securities	2008	**229**	-	**225**	-
		$ 229	$ 741	**$ 225**	$ 750

[(1)] *Calculated using the effective interest rate method.*

On June 12, 2008, Husky initiated a cash tender offer to purchase any and all of the 8.90% capital securities. As of June 12, 2008, there were U.S. $225 million of capital securities outstanding. The full tender offer consideration for the capital securities was U.S. $1,010 per U.S. $1,000 principal amount of capital securities plus accrued and unpaid interest. The tender offer expired on July 11, 2008 at which date U.S. $214 million or 95% of the capital securities had been tendered. The settlement date occurred July 11, 2008. The remaining capital securities will be redeemed on August 14, 2008.

Interest - net consisted of:

	Three months ended June 30 **2008**	2007	Six months ended June 30 **2008**	2007
Long-term debt	**$ 43**	$ 26	**$ 91**	$ 54
Short-term debt	**1**	2	**2**	3
	44	28	**93**	57
Amount capitalized	**-**	(5)	**-**	(8)
	44	23	**93**	49
Interest income	**(3)**	(1)	**(6)**	(6)
	$ 41	$ 22	**$ 87**	$ 43

Foreign exchange consisted of:

	Three months ended June 30		Six months ended June 30	
	2008	2007	**2008**	2007
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ (10)**	$ (101)	**$ 34**	$ (115)
Cross currency swaps	**3**	32	**(11)**	36
Contribution receivable	**11**	-	**11**	-
Other (gains) losses	**2**	33	**(18)**	42
Loss (gain)	**$ 6**	$ (36)	**$ 16**	$ (37)

Note 11 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Six months ended June 30	
	2008	2007
Asset retirement obligations at beginning of year	**$ 662**	$ 622
Liabilities incurred	**29**	16
Liabilities disposed	**(2)**	(14)
Liabilities settled	**(24)**	(21)
Accretion	**27**	22
Asset retirement obligations at June 30	**$ 692**	$ 625

At June 30, 2008, the estimated total undiscounted inflation-adjusted amount required to settle outstanding asset retirement obligations was $5.2 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 30 years into the future. This amount has been discounted using credit-adjusted risk free rates ranging from 6.2% to 6.8%.

Note 12 Commitments and Contingencies

The Company has no material litigation other than various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

Note 13 Share Capital

The Company's authorized share capital consists of an unlimited number of no par value common and preferred shares.

Common Shares

Changes to issued common shares were as follows:

	Six months ended June 30			
	2008		2007	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of year	848,960,310	$ 3,551	848,537,018	$ 3,533
Options exercised	183,000	8	311,592	14
Balance at June 30	**849,143,310**	**$ 3,559**	848,848,610	$ 3,547

Stock Options

In accordance with the Company's stock option plan, common share options may be granted to officers and certain other employees. The stock option plan is a tandem plan that provides the stock option holder with the right to exercise the option or surrender the option for a cash payment. The exercise price of the option is equal to the weighted average trading price of the Company's common shares during the five trading days prior to the date of the award. When the option is surrendered for cash, the cash payment is the difference between the weighted average trading price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option.

Under the terms of the original stock option plan, the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year. Amendments to the Company's stock option plan in 2007 also provided for performance vesting of stock options. Performance options granted may vest in up to one-third increments if the Company's annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to its industry peer group. The ultimate number of performance options that vest will depend upon the Company's performance measured over three calendar years. If the Company's performance is below the specified level compared with its industry peer group, the performance options awarded will be forfeited. If the Company's performance is at or above the specified level compared with its industry peer group, the number of performance options exercisable shall be determined by the Company's relative ranking.

The following tables cover all stock options granted by the Company for the periods shown.

	Six months ended June 30			
	2008		2007	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of year	30,131	$ 37.18	11,656	$ 16.40
Granted	2,029	$ 40.62	25,211	$ 41.66
Exercised for common shares	(183)	$ 12.95	(311)	$ 11.93
Surrendered for cash	(3,355)	$ 22.48	(3,712)	$ 13.32
Forfeited	(1,084)	$ 41.40	(639)	$ 38.79
Outstanding at June 30	**27,538**	**$ 39.22**	32,205	$ 36.07
Options exercisable at June 30	**7,479**	**$ 33.99**	5,435	$ 12.43

	June 30, 2008				
	Outstanding Options			Options Exercisable	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices
\$11.67 - \$11.99	1,761	\$ 11.74	1	1,761	\$ 11.74
\$12.00 - \$17.99	80	\$ 15.56	1	80	\$ 15.56
\$18.00 - \$27.99	300	\$ 25.92	2	53	\$ 25.81
\$28.00 - \$36.99	681	\$ 35.24	3	236	\$ 35.19
\$37.00 - \$39.99	896	\$ 39.45	4	58	\$ 38.20
\$40.00 - \$40.99	2,441	\$ 40.88	5	-	\$ -
\$41.00 - \$42.57	21,379	\$ 41.69	4	5,291	\$ 41.66
	27,538	**\$ 39.22**	**4**	**7,479**	**\$ 33.99**

Note 14 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended June 30		Six months ended June 30	
	2008	2007	**2008**	2007
Employer current service cost	**\$ 8**	\$ 6	**\$ 15**	\$ 12
Interest cost	**3**	3	**6**	5
Expected return on plan assets	**(3)**	(3)	**(6)**	(5)
Amortization of net actuarial losses	**1**	1	**2**	2
	\$ 9	\$ 7	**\$ 17**	\$ 14

Note 15 Related Party Transactions

TransAlta Power, L.P. ("TAPLP") is under the indirect control of Husky's principal shareholders. TAPLP is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLP"), which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLP. These natural gas sales are related party transactions and have been measured at the exchange amount. For the six months ended June 30, 2008, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was \$64 million. At June 30, 2008, the total value of accounts receivable related to these transactions was \$8 million.

Note 16 Financial Instruments and Risk Management

Details of the Company's significant accounting policies for the recognition and measurement of financial instruments and the basis for which income and expense are recognized are disclosed in Note 3 of the Company's 2007 consolidated financial statements.

Risk Management Overview

The Company is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. In certain instances, the Company uses derivative instruments to manage the Company's exposure to these risks.

The Company employs risk management strategies and policies to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels. Risk management is ultimately established by the Company's Board of Directors and is implemented by senior management and monitored by the risk management function within the Company.

Fair Value of Financial Instruments

The Company's financial instruments as at June 30, 2008 included cash and cash equivalents, accounts receivable, contribution receivable, bank operating loans, accounts payable and accrued liabilities, contribution payable, long-term debt, the derivative portion of cash flow and fair value hedges and freestanding and embedded derivatives.

The carrying value of cash and cash equivalents, accounts receivable, bank operating loans, accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of these investments.

At June 30, 2008, the carrying value of the contribution receivable and contribution payable was $1.2 billion and $1.3 billion respectively. The fair value of these financial instruments is not readily determinable due to uncertainties regarding timing of the cash flows. Refer to Note 6, "Joint Ventures."

The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability.

The fair value of long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates. These fair value determinations are compared to quotes received from financial institutions to ensure reasonability. The estimated fair value of long-term debt at the dates shown was:

	June 30, 2008		December 31, 2007	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$ 2,129**	**$ 2,153**	$ 2,814	$ 2,903

Market Risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk and other price risk, for example, commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns.

In certain instances, the Company uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

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

A change in the value of the Canadian dollar against the U.S. dollar will also result in an increase or decrease in the Company's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as the related interest expense. In order to mitigate the Company's exposure to long-term debt affected by the

U.S./Canadian dollar exchange rate, the Company has entered into cash flow hedges using cross currency debt swaps. In addition, a portion of our U.S. dollar denominated debt has been designated as a hedge of a net investment in a self-sustaining foreign operation and the unrealized foreign exchange gain is recorded in Other Comprehensive Income.

To mitigate risk related to interest rates, the Company enters into fair value hedges using interest rate swaps. The Company's objectives, processes and policies for managing market risk have not changed from the previous year.

Commodity Price Risk Management

Natural Gas Contracts

At June 30, 2008, the Company had the following third party offsetting physical purchase and sale natural gas contracts, which met the definition of a derivative instrument:

	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	30,972	$ 19
Physical sale contracts	(30,972)	$ (18)

These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain or loss has been recorded in other expenses in the consolidated statement of earnings.

Interest Rate Risk Management

At June 30, 2008, the Company had entered into a fair value hedge using interest rate swap arrangements whereby the fixed interest rate coupon on the medium-term notes was swapped to floating rates with the following terms:

Debt	Amount	Swap Maturity	Swap Rate *(percent)*	Fair Value
6.95% medium-term notes	$ 200	July 14, 2009	CDOR + 175 bps	$ 3

This contract has been recorded at fair value in other assets. During the six months ended June 30, 2008, the Company recognized a loss of less than $1 million (2007 - gain of $1 million) on the interest rate swap arrangements.

Embedded Derivative

The Company entered into a contract with a Norwegian-based company for drilling services offshore China. The contract currency is U.S. dollars, which is not the functional currency of either transacting party. As a result, this contract has been identified as containing an embedded derivative requiring bifurcation and separate accounting treatment at fair value. This embedded derivative has been recorded at fair value in accounts receivable and other assets and the resulting unrealized loss has been recorded in other expenses in the consolidated statement of earnings. At June 30, 2008, the fair value of the embedded derivative was $84 million (December 31, 2007 - $101 million). In the first six months of 2008, the impact was an unrealized loss on the embedded derivative of $17 million.

Foreign Currency Risk Management

The Company manages its exposure to foreign exchange fluctuations by balancing the U.S. dollar denominated cash flows with U.S. dollar denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency.

At June 30, 2008, the Company had a cash flow hedge using the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate *(percent)*	Fair Value
6.25% notes	U.S. $ 150	$ 212	June 15, 2012	7.41	$ (73)
6.25% notes	U.S. $ 75	$ 90	June 15, 2012	5.65	$ (13)
6.25% notes	U.S. $ 50	$ 59	June 15, 2012	5.67	$ (7)
6.25% notes	U.S. $ 75	$ 88	June 15, 2012	5.61	$ (10)

These contracts have been recorded at fair value in other long-term liabilities. The portion of the fair value of the derivative related to foreign exchange losses has been recorded in earnings to offset the foreign exchange on the translation of the underlying debt. The remaining loss of $8 million, net of tax of $4 million, has been included in other comprehensive income. At June 30, 2008, the balance in accumulated other comprehensive income was $9 million, net of tax of $4 million. For the six months ended June 30, 2008, the Company recognized a foreign exchange gain of $11 million (2007 - loss of $4 million) on the cross currency debt swaps.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. During the first six months of 2008, the impact of these contracts was a loss of $1 million (2007 - gain of $2 million).

The Company entered into forward purchases of U.S. dollars to partially offset the fluctuations in foreign exchange related to the contract for drilling services offshore China, which contains an embedded derivative. At June 30, 2008, the following foreign exchange transactions had been entered into:

Date	Forward Purchases	Canadian Equivalent	Fair Value
October 5, 2007	U.S. $ 119	$ 117	$ 4
October 11, 2007	U.S. $ 119	$ 116	$ 5
October 29, 2007	U.S. $ 119	$ 115	$ 7

These forward contracts have been recorded at fair value in accounts receivable and other assets and the resulting gain has been recorded in other expenses in the consolidated statement of earnings. During the first six months of 2008, the impact was a gain of $8 million.

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 and marketing operations, which are considered self-sustaining. During the second quarter of 2008, the Company repaid its bridge financing of U.S. $750 million. As a result, the Company's net investment hedge is limited to the remaining U.S. $750 million. As at June 30, 2008, the unrealized foreign exchange loss of $40 million, net of tax of $7 million, arising from the translation of the debt is recorded in other comprehensive income.

Sensitivity Analysis

This sensitivity analysis has been calculated by increasing or decreasing the interest rate or foreign currency exchange rate, as appropriate, in the fair value methodologies described in the "Fair Value of Financial Instruments" section of this note. These sensitivities represent the effect resulting from changing the relevant rates with all other variables held constant and have been applied only to financial instruments. The Company's process for determining these sensitivities has not changed from the previous quarter.

The Company is exposed to interest rate risk on its interest rate swaps. As at June 30, 2008, had interest rates been 50 basis points higher or lower and assuming all other variables remained constant, the impact to fair value would have been less than $1 million. The impact to net earnings would have been nil.

The Company is exposed to interest rate and foreign currency risk on its cross currency debt swaps. Had the Canadian dollar been 1% stronger versus the U.S. dollar and assuming all other variables remained constant, the impact to other comprehensive income would have been $6 million lower. As at June 30, 2008, had the Canadian dollar been 1% weaker versus the U.S. dollar and assuming all other variables remained constant, the impact to other comprehensive income would have been $4 million higher. As at June 30, 2008, had the interest rates been 50 basis points higher and assuming all other variables remained constant, the impact to other comprehensive income would have been $2 million higher. An equal and offsetting impact would have occurred had the interest rates been 50 basis points lower and assuming all other variables remained constant.

The Company is exposed to foreign currency risk on its embedded derivative and its forward purchases of U.S. dollars to partially offset the fluctuations in foreign exchange related to the embedded derivative. As at June 30, 2008, had the Canadian dollar been 1% stronger relative to the U.S. dollar and assuming all other variables remained constant, the impact to net earnings would have been $6 million higher for the embedded derivative and $4 million lower for the forward purchases of U.S. dollars. Equal and offsetting impacts would have occurred had the Canadian dollar been 1% weaker relative to the U.S. dollar and assuming all other variables remained constant.

Liquidity Risk

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

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

The following are the contractual maturities of financial liabilities as at June 30, 2008:

Financial Liability	Less than 1 Year	1 to less than 2 Years	2 to less than 5 Years	Thereafter
Accounts payable and accrued liabilities	$ 2,945	$ -	$ -	$ -
Cross currency swaps	-	-	447	-
Long-term debt and interest on fixed rate debt	361	317	724	2,298
Other long-term liabilities	5	-	-	-
Total	$ 3,311	$ 317	$1,171	$ 2,298

The Company's contribution payable to the joint venture with BP (refer to Note 6) is payable between June 30, 2008 and December 31, 2015 with the final balance due and payable by December 31, 2015.

The Company's objectives, processes and policies for managing liquidity risk have not changed from the previous year.

Credit Risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial instrument, in owing an amount to the Company, fail to meet or discharge their obligation to the Company. The Company's accounts receivables are predominantly with customers in the energy industry and are subject to normal industry credit risks. The Company's policy to mitigate credit risk is to primarily deal with major financial institutions and investment grade rated entities. The Company did not have any customers that constituted more than 10% of total sales and operating revenues during the second quarter of 2008.

Cash and cash equivalents include cash bank balances and short-term deposits maturing in less than 30 days. The Company manages the credit exposure related to short-term investments by monitoring exposures daily on a per issuer basis relative to predefined investment limits.

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure.

The Company considers its accounts receivable excluding income taxes receivable and doubtful accounts to be aged as follows:

Aging	**June 30, 2008**
Current	**$ 1,939**
Past due (1 - 30 days)	**217**
Past due (31 - 60 days)	**6**
Past due (61 - 90 days)	**4**
Past due (more than 90 days)	**17**
Total	**$ 2,183**

The movement in the Company's allowance for doubtful accounts for the first six months of 2008 was as follows:

Balance at January 1, 2008	$ 10
Provisions and revisions	2
Balance at June 30, 2008	**$ 12**

For the first six months of 2008, the Company wrote off $1 million of uncollectible receivables.

The Company's objectives, processes and policies for managing credit risk have not changed from the previous year.

Sale of Accounts Receivable

The Company has a securitization program to sell, on a revolving basis, accounts receivable to a third party up to $350 million. As at June 30, 2008, no accounts receivable had been sold under the program (December 31, 2007 - nil).

Held-for-Trading Financial Liabilities

The Company's cross currency swaps have been designated as a cash flow hedge and the derivative component of the hedge meets the definition of a held-for-trading financial liability. The cross currency swap counterparties' credit profiles have not materially changed since the past year or since inception. As a result, the amount of change during the period and cumulatively in the fair value of the cross currency swaps has not been materially impacted by changes resulting from credit risk. At June 30, 2008, the amount the Company would be contractually required to pay under the cross currency swaps at maturity was $344 million higher (December 31, 2007 - $341 million higher) than their carrying amount.

Note 17 Capital Disclosures

The Company's objectives when managing capital are: (i) to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk; and (ii) to maintain investor, creditor and market confidence to sustain the future development of the business.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of our underlying assets. The Company considers its capital structure to include shareholders' equity, debt and working capital. To maintain or adjust the capital structure, the Company may from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors capital based on the current and projected ratios of debt to cash flow and debt to capital employed. The Company's objective is to maintain a debt to cash flow from operations ratio of less than two times. The ratio may increase at certain times as a result of acquisitions. To facilitate the management of this ratio, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company's share capital is not subject to external restrictions; however the bilateral credit facilities and the syndicated credit facility include a debt to cash flow covenant. The Company was fully compliant with this covenant at June 30, 2008.

There were no changes in the Company's approach to capital management from the previous year.

Husky Energy Inc. will host a conference call for analysts and investors on Thursday, July 24, 2008 at 5:15 p.m. Eastern time to discuss Husky's second quarter results. To participate please dial 1-800-319-4610 beginning at 5:05 p.m. Eastern time.

Mr. John C.S. Lau, President & Chief Executive Officer, and other officers will be participating in the call.

A live audio webcast of the conference call will be available via Husky's website, www.huskyenergy.com under Investor Relations. The webcast will be archived for approximately 90 days.

Media are invited to listen to the conference call

- Dial 1-800-597-1419 beginning at 5:05 p.m. (Eastern time)

A recording of the call will be available at approximately 7:30 p.m. (Eastern time)

- Dial 1-800-319-6413 (dial reservation # 2658)

The Postview will be available until October 24, 2008.

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For further information, please contact:

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