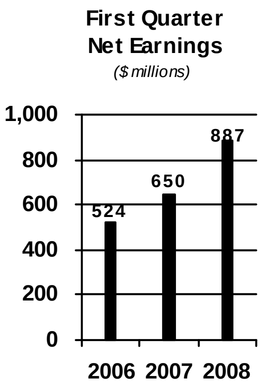
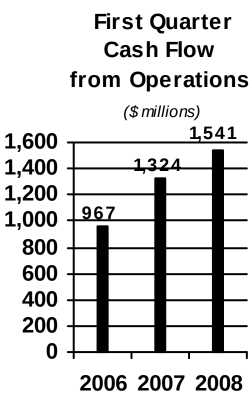
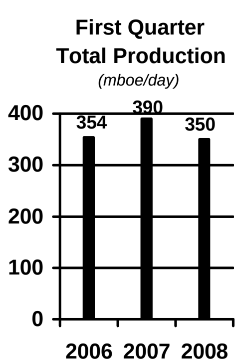
HUSKY ENERGY REPORTS 2008 FIRST QUARTER RESULTS







Calgary, Alberta – Husky Energy Inc. reported net earnings of $887 million or $1.04 per share (diluted) in the first quarter of 2008, an increase of 36% from $650 million or $0.77 per share (diluted) in the same quarter of 2007. Cash flow from operations in the first quarter was $1,541 million or $1.82 per share (diluted), a 16% increase compared with $1,324 million or $1.56 per share (diluted) in the same quarter of 2007. Sales and operating revenues, net of royalties, were $5.1 billion in the first quarter of 2008, up 57% compared with $3.2 billion in the first quarter of 2007.

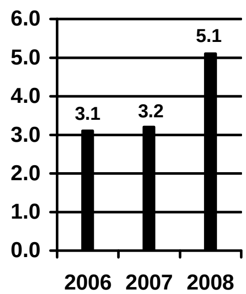
"Husky has continued to achieve good financial results in revenue, net earnings and cash flow from operations in a high oil commodity price environment," said Mr. John C.S. Lau, President & Chief Executive Officer of Husky Energy Inc. "In the first quarter, we are pleased to have closed the transaction with BP on schedule, creating an integrated oil sands/refining joint venture and to have received government and regulatory approvals to proceed with the development of the North Amethyst oil field offshore Canada's East Coast."

In the first quarter of 2008, total production averaged 350,100 barrels of oil equivalent per day compared with 390,000 barrels of oil equivalent per day in the first quarter of 2007. Total crude oil and natural gas liquids production was 251,700 barrels per day, compared with 283,300 barrels per day in the first quarter of 2007. The decline is due primarily to a 13-day turnaround at the White Rose oil field in late January and early February and the sale of some non-core properties in Western Canada. Natural gas production was 590.4 million cubic feet per day compared with 640.0 million cubic feet per day in the same period of 2007, which reflects the decrease in wells drilled in 2007 as a result of weak gas prices.

On March 31, 2008, Husky and BP completed all agreements required to form an integrated oil sands joint venture. The transaction consists of a 50/50 partnership to develop the Sunrise oil sands project in Canada, which Husky will operate, and a 50/50 limited liability company for the existing Toledo refinery in Ohio, USA, which BP will operate. The development of the Sunrise oil sands project is expected to proceed in three phases. The first development phase will produce 60,000 barrels per day of bitumen starting in 2012 and the second and third phases are targeted to increase the Sunrise production capacity to approximately 200,000 barrels per day of bitumen by 2015 to 2020. The Toledo refinery will be modified to process approximately 120,000 barrels per day of bitumen feedstock by 2015, matching the first two phases of the Sunrise oil sands development.

Agreement to purchase 110,000 contiguous acres of oil sands leases at McMullen, located in the west central Athabasca oil sands deposit, for $105 million was closed in the first quarter. Husky has a 100% working interest in these oil sands leases. This land lies adjacent to oil sands leases that we currently hold.

First Quarter
Sales and Operating Revenues
($ billions)



In April 2008, the Company received approval from the federal and provincial governments and regulators for the North Amethyst satellite development near the White Rose oil field. The North Amethyst oil field is the first of three satellite oil pools to be developed adjacent to the White Rose oil field in the Jeanne d'Arc Basin, with first oil planned for late 2009 or early 2010. Husky's working interest in this development is 68.875%.

Husky entered into contracts for two offshore drilling rigs in the first quarter to drill several development wells in the White Rose and satellite oil fields as well as exploration prospects in the Jeanne d'Arc Basin. In January 2008, Husky announced that it had contracted the GSF Grand Banks semi-submersible drilling rig until January 2011. In March 2008, agreement was reached with our partners to bring the semi-submersible drilling rig, Henry Goodrich, to the Newfoundland and Labrador offshore region. The rig will be available for approximately 17 months for Husky operated wells.

First Quarter
Financial Highlights
2008 versus 2007

- Earnings per share to $1.04 from $0.77
- Cash flow per share to $1.82 from $1.56
- Return on equity to 26.8% from 32.1%
- Return on average capital employed to 22.3% from 27.3%
- Debt to capital employed ratio to 20% from 14%
- Debt to cash flow ratio to 0.5 from 0.3

In March 2008 we reached an agreement to participate in an exploration well to be drilled later in 2008 in the Flemish Pass Basin off the east coast of Newfoundland and Labrador on Exploration Licence 1049 operated by StatoilHydro. Husky has a 35% working interest in this licence.

Internationally, Husky completed the interpretation of the 3-D seismic data acquired over the Liwan natural gas discovery offshore China in preparation for the arrival of the West Hercules deep water drilling rig in mid-2008. Husky plans to drill one shallow water exploration well on Block 39/05 before moving the rig to Block 29/26 to commence delineation drilling of the Liwan discovery. Elsewhere in China, Husky has spudded an exploration well in the Beibu Basin on Block 23/15 and we should soon complete the acquisition of 750 square kilometres of 3-D seismic data on Block 35/18 in the Yinggehai Basin.

In April 2008, the Company 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 in Husky Oil (Madura) Limited for a consideration of U.S. $125 million. Husky Oil (Madura) Limited 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. Husky has drilled 10 wells in this area since 1984 and made two discoveries, the Madura BD and MDA gas fields.

At the Lima Refinery, Husky has completed the acquisition transaction and assumed responsibility for all operations and administrative, marketing and trading services. In addition, a sales and marketing office has been established in Columbus, Ohio, USA to manage product sales and movements in our U.S. operations.

In Minnedosa, the ethanol plant that was commissioned in December 2007 reached its design capacity of 130 million litres per year during the first quarter.

Husky continues to strengthen its balance sheet and financial position. Total long-term debt including current portion at March 31, 2008 was $3,019 million compared with $2,814 million at December 31, 2007. Debt to cash flow ratio and debt to capital employed ratio remained low at 0.5 and 20% respectively at March 31, 2008.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") APRIL 21, 2008

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Husky's Businesses

Husky is a Canadian-based energy and energy-related company with total assets greater than $24 billion and over 4,000 employees.

Husky is integrated through the three industry sectors: upstream, midstream and downstream.

- In the upstream sector, we explore for, develop and produce crude oil and natural gas *(upstream business segment)*.
- In the midstream sector, we upgrade heavy crude oil *(upgrading business segment)*, process and pipeline heavy crude oil, maintain interests in two cogeneration plants as well as store and market crude oil and natural gas *(infrastructure and marketing business segment)*.
- In the downstream sector, we distribute motor fuel and ancillary and convenience products, manufacture and market asphalt products, produce ethanol and operate two regional refineries in Canada *(Canadian refined products business segment)* and refine crude oil in two refineries in Ohio and market refined products in the U.S. Midwest *(U.S. refining and marketing business segment)*.

1. Quarterly Financial Results

Quarterly Financial Summary

	Three months ended							
	March 31	Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30	June 30
(millions of dollars, except per share amounts and ratios)	**2008**	2007	2007	2007	2007	2006	2006	2006
Sales and operating revenues, net of royalties	**$ 5,086**	$ 4,760	$ 4,351	$ 3,163	$ 3,244	$ 3,084	$ 3,436	$ 3,040
Segmented net earnings								
Upstream	**$ 717**	$ 864	$ 516	$ 636	$ 580	$ 453	$ 608	$ 822
Midstream	**144**	218	129	77	111	105	87	140
Downstream	**38**	103	121	53	20	10	28	52
Corporate and eliminations	**(12)**	(111)	3	(45)	(61)	(26)	(41)	(36)
Net earnings	**$ 887**	$ 1,074	$ 769	$ 721	$ 650	$ 542	$ 682	$ 978
Per share - Basic and diluted	**$ 1.04**	$ 1.26	$ 0.91	$ 0.85	$ 0.77	$ 0.64	$ 0.80	$ 1.15
Cash flow from operations	**1,541**	1,425	1,420	1,257	1,324	1,207	1,224	1,103
Per share - Basic and diluted	**1.82**	1.68	1.67	1.48	1.56	1.42	1.44	1.30
Ordinary quarterly dividend per common share	**0.33**	0.33	0.25	0.25	0.25	0.25	0.25	0.125
Special dividend per common share	**-**	-	-	-	0.25	-	-	-
Total assets	**24,391**	21,697	20,718	17,969	17,781	17,933	17,324	16,328
Total long-term debt including current portion	**3,019**	2,814	2,835	1,423	1,527	1,611	1,722	1,722
Return on equity [(1)] *(percent)*	**26.8**	30.2	26.6	27.1	32.1	31.8	34.2	34.8
Return on average capital employed [(1)] *(percent)*	**22.3**	25.7	22.3	23.8	27.3	27.0	28.7	28.2

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

2. Capability to Deliver Results and Strategic Plan

Our current capacity to deliver results and strategic plan are described in our recently filed 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 the Alberta oil sands, the basins off the East Coast of Canada, the central Mackenzie River Valley, the South China Sea, Madura Strait, 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 Performance Drivers

To achieve corporate strategic objectives and provide our shareholders with a good return on investment, we need to capture opportunities that will drive corporate performance and enhance our position to continue to capture future opportunities. During the first quarter of 2008, key performance drivers that emerged or were advanced are noted below:

3.1 Across Segments

Integrated Oil Sands Joint Development

On March 31, 2008, Husky and BP completed contracts that formed an integrated oil sands joint venture. The transaction consists of a 50/50 partnership to develop the Sunrise oil sands project in the Athabasca oil sands deposit, which Husky will operate, and the formation of a 50/50 limited liability company for the existing Toledo, Ohio BP refinery, which BP will operate. The development of the Sunrise oil sands project is expected to proceed in three phases. The first development phase will produce 60 mbbls/day of bitumen starting in 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. The Toledo refinery will be modified to process approximately 120 mbbls/day of bitumen feedstock (diluted as required for transportation purposes) by 2015, matching the first two phases of the Sunrise oil sands development.

3.2 Upstream

White Rose Development and Delineation

Approval of the North Amethyst development application by the Canada - Newfoundland and Labrador Offshore Petroleum Board ("CNLOPB") and the provincial and federal governments was received in April 2008. The front-end engineering design and the glory hole to accommodate the subsea facilities are complete. A drilling rig has been secured and procurement of long lead equipment is underway. West White Rose delineation results continue to be analyzed and infrastructure details and the glory hole location are being determined. The South White Rose extension development plan was approved by the federal and provincial governments in September 2007.

In March 2008, agreement was reached with our partners, StatoilHydro and Petro-Canada, to bring the semi-submersible drilling rig Henry Goodrich to the Newfoundland and Labrador offshore region. The rig will be available to us and our partners for 27 months, of which approximately 17 months is for Husky operated wells. We have also contracted the GSF Grand Banks semi-submersible drilling rig until January 2011. These rigs will drill several development wells in the White Rose and satellite fields, including the North Amethyst and West White Rose fields as well as exploration prospects in the Jeanne d'Arc Basin. The Henry Goodrich is also scheduled to drill two development wells in the Terra Nova field.

East Coast Exploration

Acquisition of 3-D seismic covering 2,500 square kilometres around the White Rose field and on Exploration Licences 1090 and 1091 is scheduled for mid-2008.

In March 2008, we reached an agreement to participate in an exploration well to be drilled later in 2008 on Exploration Licence 1049 in the Flemish Pass Basin off the east coast of Newfoundland and Labrador. StatoilHydro is the operator of this licence and we hold a 35% working interest.

Tucker Oil Sands Project

Optimization strategies intended to remedy performance issues are continuing on the existing well pads. The drilling of eight new well pairs on Pad C is complete and a new D pad with well pairs placed in an optimized position in the reservoir is being planned.

Sunrise Oil Sands Project

At Sunrise, work on area infrastructure and site preparation progressed during the first quarter. Front-end engineering design activities for Phase 1 are now complete and the project is being readied for sanction. The winter stratigraphic well drilling program is complete and analysis of results is underway. Regulatory amendment approval and the Sunrise project corporate sanction are expected later in 2008.

Caribou

Technical and field work is continuing on the 10 mbbls/day demonstration project including water source and disposal well and stratigraphic test wells. Regulatory approval for the project is expected in 2008.

Saleski

The winter drilling program was completed and consisted of a water source and disposal well and seven observation and stratigraphic test wells. We are continuing to work on reservoir characterization and evaluation of various recovery processes.

Northwest Territories Exploration

Husky holds interests in 4,380 square kilometres in the Central Mackenzie Valley. Two exploration wells were drilled on Exploration License ("EL") 423. The Dahadinni B-20 and the Keele River L-52 wells have both been abandoned without testing. EL 423 is located approximately 60 kilometres southeast of the Summit Creek B-44 and the Stewart Creek D-57 discovery wells. We hold a 75% working interest in EL 423.

China Exploration

A four well delineation program of the Liwan area on Block 29/26 is on schedule to commence in mid-2008 upon the arrival of the West Hercules deep water drilling rig, which is nearing completion in South Korea and is expected to commence sea trials in May.

Three exploration wells are planned to be drilled in the shallow waters of the South and East China seas. The Wushi 23-2-1 well was spudded on March 27, 2008 on Block 23/15 in the Beibu Wan Basin of the South China Sea north of Hainan Island. The second well is expected to spud on Block 39/05 southwest of the Wenchang oil field in the South China Sea before the end of 2008. The third well is slated to be drilled on Block 4/35 in the East China Sea.

In February, we commenced acquiring 750 square kilometres of 3-D seismic data on Block 35/18, which is west of Hainan Island in the Yinggehai Basin. In April 2008, we commenced acquiring 725 square kilometres of 3-D seismic on Block 29/06 adjacent to the eastern boundary of Block 29/26 and resumed the acquisition of the remaining 200 square kilometres of 3-D seismic of a 2,615 square kilometre program that was started in 2007 in the Liwan area.

Indonesia Exploration and Development

We have submitted the Madura BD field development plan and Production Sharing Licence extension to the Indonesian regulatory authorities for approval. Front-end engineering design for the project will begin upon receipt of these regulatory approvals.

In April 2008, the Company 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 in Husky Oil (Madura) Limited for a consideration of U.S. $125 million. Husky Oil (Madura) Limited 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.

Analysis is progressing on 1,410 square kilometres of 3-D seismic data recently acquired from the East Bawean II block in the East Java Sea. Currently, two exploration wells are planned for 2009.

Land Acquisition Offshore Greenland

We hold interests in 34,280 square kilometres in three blocks offshore Greenland. Acquisition of 2-D seismic data is planned for 2008. A hi-resolution aero-gravity and magnetic survey is scheduled for completion in 2008.

3.3 Downstream

Lima Refinery in Ohio

An engineering evaluation is underway to determine the optimal reconfiguration of the Lima refinery to increase its capacity to process heavier crude feedstocks.

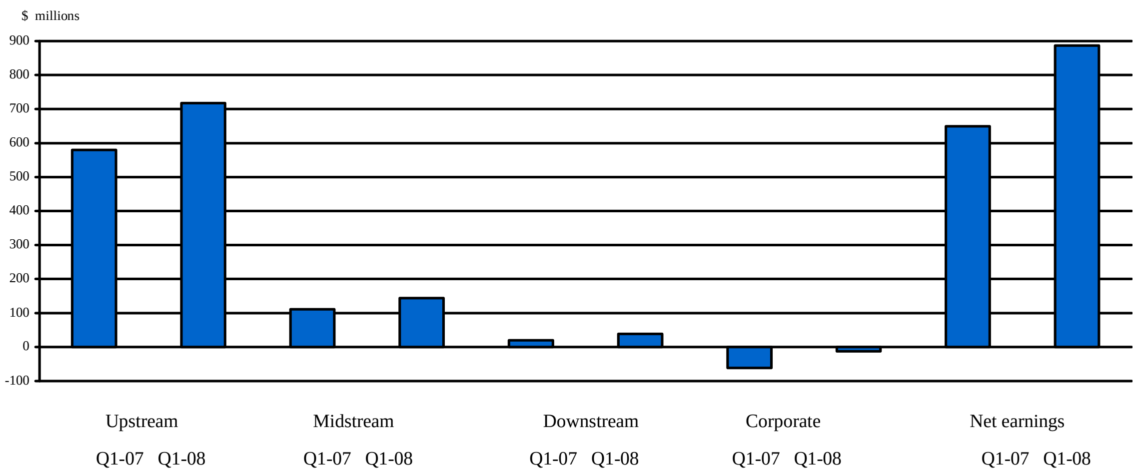
BP/Husky Toledo Refinery

The acquisition of a 50% interest in the BP Toledo refinery was closed on March 31, 2008. The refinery has the capacity to process 150 mbbls/day of crude oil including 60 mbbls/day of blended heavy sour crude. 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. Results of Operations

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

Quarterly Segmented Net Earnings

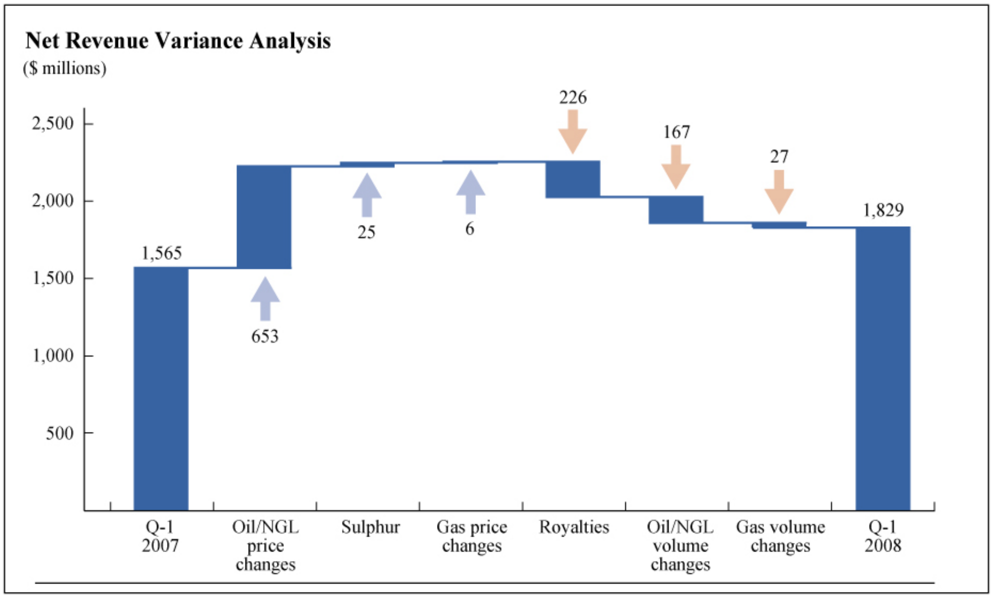


4.1 Upstream

Upstream Net Earnings Summary	Three months ended March 31	
(millions of dollars)	**2008**	2007
Gross revenues	**$ 2,253**	$ 1,763
Royalties	**424**	198
Net revenues	**1,829**	1,565
Operating and administration expenses	**384**	323
Depletion, depreciation and amortization	**390**	399
Other	**29**	-
Income taxes	**309**	263
Net earnings	**$ 717**	$ 580

Net Revenue

During the first quarter of 2008, upstream net revenues increased by $264 million compared with the same period in 2007. Higher crude oil and natural gas prices more than offset lower sales volume during the first quarter of 2008.



The Upstream Business Environment

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 more 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.

Average Benchmark Prices and U.S. Exchange Rate

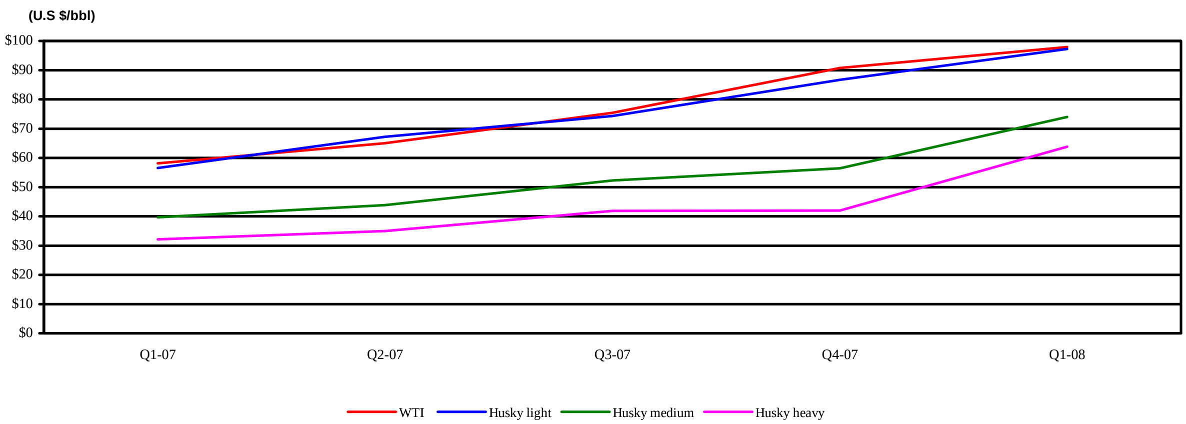
		Three months ended				
		March 31 2008	Dec. 31 2007	Sept. 30 2007	June 30 2007	March 31 2007
WTI crude oil [1]	*(U.S. $/bbl)*	**97.90**	90.68	75.38	65.03	58.16
Brent crude oil [2]	*(U.S. $/bbl)*	**96.90**	88.70	74.87	68.76	57.75
Canadian light crude 0.3% sulphur	*($/bbl)*	**98.20**	87.19	80.70	72.61	67.76
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**64.23**	42.03	43.61	39.02	38.25
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**8.03**	6.97	6.16	7.55	6.77
NIT natural gas	*($/GJ)*	**6.76**	5.69	5.31	6.99	7.07
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**21.81**	34.06	23.50	20.36	17.32
U.S./Canadian dollar exchange rate	*(U.S. $)*	**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.*

Crude Oil

The following graph illustrates the relative changes over several quarters in the realized prices of our three main crude oil categories expressed in U.S. dollars and West Texas Intermediate ("WTI"), the main benchmark crude oil.

WTI and Husky Average Crude Oil Prices

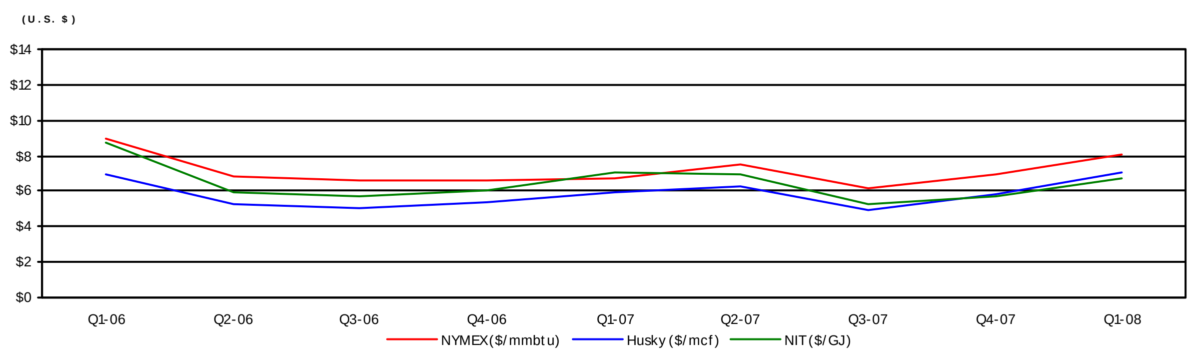


The majority of our crude oil production is marketed in North America. The slow economic growth in the United States during the first quarter of 2008 has marginally reduced consumption of petroleum, however, tight production surplus has continued to push crude oil prices to new highs. During March 2008, WTI averaged $105.42/bbl. From December 2007 to March 2008 our monthly average heavy oil prices increased by approximately 52%.

Natural Gas

The following graph illustrates the relative changes over several quarters in our natural gas price realized compared with two major benchmark prices.

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices



Natural gas prices quoted on the NYMEX rose through the first quarter of 2008 and were, on average, 19% higher than the same period in 2007. Higher prices in the first quarter of 2008 are largely attributed to colder weather compared with last winter in the major natural gas consumption regions. At the end of the first quarter of 2008 natural gas stocks in underground storage in the United States were 20% lower than at the same date in 2007.

The average prices realized during the first quarter of 2008 compared with the first quarter of 2007 are illustrated below.

Average Sales Prices		Three months ended March 31	
		2008	2007
Crude Oil	*($/bbl)*		
Light crude oil & NGL		**$ 95.20**	$ 64.88
Medium crude oil		**74.30**	46.40
Heavy crude oil & bitumen		**63.91**	37.63
Total average		**79.98**	52.70
Natural Gas	*($/mcf)*		
Average		**7.04**	6.94

Oil and Gas Production

The following table shows our gross daily production rate by location and product type for five sequential quarters.

Daily Gross Production		Three months ended				
		March 31 2008	Dec. 31 2007	Sept. 30 2007	June 30 2007	March 31 2007
Crude oil & NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**25.4**	25.8	25.1	25.3	30.1
Medium crude oil		**26.9**	27.0	26.7	26.8	27.5
Heavy crude oil & bitumen		**104.3**	107.8	106.5	105.4	108.0
		156.6	160.6	158.3	157.5	165.6
East Coast Canada						
White Rose - light crude oil		**67.5**	81.1	79.2	90.3	89.4
Terra Nova - light crude oil		**14.9**	11.6	16.3	15.5	14.7
China						
Wenchang - light crude oil & NGL		**12.7**	11.2	12.7	13.2	13.6
		251.7	264.5	266.5	276.5	283.3
Natural gas	*(mmcf/day)*	**590.4**	617.8	620.1	615.7	640.0
Total	*(mboe/day)*	**350.1**	367.5	369.9	379.1	390.0

Crude Oil and NGL Production

Crude oil and NGL production in the first quarter of 2008 decreased by 11% compared with the same period in 2007. Production from the White Rose field was shut down for 13 days in the quarter while scheduled maintenance was performed on the *SeaRose FPSO*. Production from White Rose averaged 67 mbbls/day at an average realized price of $97.96/bbl during the first quarter of 2008 compared with 89 mbbls/day at an average realized price of $66.69/bbl during the same period in 2007. In March 2008, the Tier II incremental royalty rate became effective for White Rose. The Tier II status increases royalty rates by 10%.

During the first quarter of 2008, crude oil and NGL production from Western Canada was down 5% compared with the first quarter of 2007 primarily due to the disposition of non-core oil properties.

Natural Gas Production

In the first quarter of 2008, 58% 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.

Production of natural gas was down approximately 8% in the first quarter of 2008 compared with the first quarter of 2007. In 2007, management reduced natural gas drilling activity in response to low natural gas prices and pending higher Alberta gas royalties.

2008 Gross Production Guidance		Guidance	Three months ended Mar. 31	Year ended Dec. 31
		2008	**2008**	2007
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		139 - 148	**120.5**	139
Medium crude oil		28 - 29	**26.9**	27
Heavy crude oil & bitumen		114 - 124	**104.3**	107
		281 - 301	**251.7**	273
Natural gas	*(mmcf/day)*	625 - 655	**590.4**	623
Total barrels of oil equivalent	*(mboe/day)*	385 - 410	**350.1**	377

Upstream Revenue Mix	Three months ended March 31	
Percentage of upstream net revenues	**2008**	2007
Crude oil & NGL		
Light crude oil & NGL	**44**	51
Medium crude oil	**8**	6
Heavy crude oil & bitumen	**29**	21
	81	78
Natural gas	**19**	22
	100	100

Unit Operating Costs

Operating costs in Western Canada averaged $12.85/boe in the first quarter of 2008 compared with $10.55/boe in the same period in 2007. Extreme cold weather for part of the quarter increased costs for gas well servicing and methanol injection to deal with gas well freeze ups. 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, 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. 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 $5.27/bbl in the first quarter of 2008 compared with $3.03/bbl in the first quarter of 2007. The higher unit operating cost in 2008 was due to lower production combined with higher maintenance costs resulting from the *SeaRose FPSO* turnaround.

Operating costs at the South China Sea offshore operations averaged $4.63/bbl in the first quarter of 2008 compared with $4.28/bbl in the same period in 2007.

Unit Depletion, Depreciation and Amortization

Depletion, depreciation and amortization ("DD&A") under the full cost method of accounting for oil and gas activities is calculated on a country-by-country basis. The DD&A rate is calculated by dividing the capital costs subject to DD&A by the proved oil and gas reserves expressed as an equivalent barrel. The resultant dollar per barrel of oil equivalent is assigned to each barrel of oil equivalent that is produced to determine the DD&A expense for the period.

Total unit DD&A averaged $12.25/boe in the first quarter of 2008 compared with $11.37/boe in the first quarter of 2007. In Canada, unit DD&A was $12.34/boe, an increase of 9% over the first quarter of 2007. The higher DD&A rate in Canada was primarily due to a larger capital base. Increased capital spending is required in Western Canada for a greater number of wells to maintain production including more extensive field infrastructure. Off the East Coast of Canada large capital investment is required to develop oil reserves.

Embedded Derivative

During the first quarter of 2008, a $28 million loss was recorded on an embedded derivative related to a drilling rig contract requiring payment in U.S. currency (refer to Note 15 to the Consolidated Financial Statements). 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.

Netback Analysis

	Three months ended March 31			
	2008		2007	
	$	**%** [(1)]	$	% [(1)]
Total				
Crude oil equivalent *(per boe)* [(2)]				
Gross price	**69.37**		49.67	
Royalties	**13.19**	**19**	5.63	11
Net sales price	**56.18**		44.04	
Operating costs [(3)]	**10.75**	**15**	8.34	17
Operating netback	**45.43**		35.70	
DD&A	**12.25**	**18**	11.37	23
Administration expenses & other [(3)]	**0.96**	**1**	0.33	1
Earnings before income taxes	**32.22**	**47**	24.00	48
Canada				
Crude oil equivalent *(per boe)* [(2)]				
Gross price	**68.23**		48.99	
Royalties	**12.70**	**19**	5.45	11
Net sales price	**55.53**		43.54	
Operating costs [(3)]	**10.98**	**16**	8.49	17
Operating netback	**44.55**		35.05	
Western Canada				
Crude oil *(per boe)* [(2)]				
Light crude oil				
Gross price	**78.12**		57.00	
Royalties	**10.20**	**13**	6.20	11
Net sales price	**67.92**		50.80	
Operating costs [(3)]	**16.59**	**21**	11.95	21
Operating netback	**51.33**		38.85	
Medium crude oil				
Gross price	**72.82**		46.19	
Royalties	**13.39**	**18**	7.96	17
Net sales price	**59.43**		38.23	
Operating costs [(3)]	**14.55**	**20**	13.56	29
Operating netback	**44.88**		24.67	
Heavy crude oil & bitumen				
Gross price	**63.50**		37.67	
Royalties	**8.22**	**13**	4.72	13
Net sales price	**55.28**		32.95	
Operating costs [(3)]	**14.95**	**24**	11.84	31
Operating netback	**40.33**		21.11	
Natural gas *(per mcfge)* [(4)]				
Gross price	**7.45**		7.01	
Royalties	**1.42**	**19**	1.44	21
Net sales price	**6.03**		5.57	
Operating costs [(3)]	**1.53**	**21**	1.33	19
Operating netback	**4.50**		4.24	
East Coast				
Light crude oil *(per boe)* [(2)]				
Gross price	**97.86**		66.46	
Royalties [(5)]	**23.84**	**24**	2.11	3
Net sales price	**74.02**		64.35	
Operating costs [(3)]	**5.27**	**5**	3.03	5
Operating netback	**68.75**		61.32	
International				
Light crude oil *(per boe)* [(2)]				
Gross price	**100.44**		68.25	
Royalties	**26.54**	**26**	10.35	15
Net sales price	**73.90**		57.90	
Operating costs [(3)]	**4.63**	**5**	4.90	7
Operating netback	**69.27**		53.00	

(1) *Percent of gross price.*
(2) *Includes associated co-products converted to boe.*
(3) *Operating costs exclude accretion, which is included in administration expenses & other.*
(4) *Includes associated co-products converted to mcfge.*
(5) *During the third quarter of 2007, White Rose royalties increased to 16% because the project, off the East Coast, achieved payout status for Tier 1 royalties.*

Upstream Capital Expenditures

Our 2008 Upstream Capital expenditure guidance remains unchanged from that reported in our recently filed 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.*

The following table summarizes our capital expenditures for the periods presented.

Capital Expenditures Summary [1]

	Three months ended March 31	
(millions of dollars)	**2008**	2007
Exploration		
Western Canada	**$ 206**	$ 165
East Coast Canada and Frontier	**25**	5
International	**30**	5
	261	175
Development		
Western Canada	**469**	388
East Coast Canada	**68**	54
	537	442
	$ 798	$ 617

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

During the first quarter of 2008, capital expenditures were $675 million (84%) in Western Canada, $93 million (12%) off the East Coast of Canada and $30 million (4%) offshore China, Indonesia and other international areas.

Western Canada

In Western Canada, we invested $595 million on exploration and development on conventional areas, which produce variously light, medium, heavy crude oil or natural gas throughout the Western Canada Sedimentary Basin, $330 million was invested on properties in Alberta, northeast British Columbia and southern Saskatchewan primarily to further develop properties with proved reserves. We drilled 194 net wells in these regions resulting in 104 oil wells and 87 natural gas wells. In the Lloydminster area of Alberta and Saskatchewan, from which the majority of our heavy crude oil is produced, we invested $222 million, again mainly to extend proved properties. Our principal exploration program is conducted along the foothills of Alberta and British Columbia and in the deep basin region of Alberta. In the first quarter of 2008, we invested $43 million drilling in these natural gas prone areas. During the first quarter of 2008, we drilled 15 net exploration wells in the foothills/deep basin regions; 10 were cased as natural gas wells.

Oil sands capital expenditures totalled $80 million during the first quarter of 2008. At Tucker, we spent $17 million, at Sunrise $41 million and $22 million at our other oil sands areas, Caribou and Saleski.

The following table discloses the number of gross and net exploration and development wells we completed during the quarter ended March 31, 2008 and the same quarter in 2007. Seventy-nine percent of the net exploration wells and 98% of the net development wells we drilled resulted in wells capable of commercial production.

Western Canada Wells Drilled		Three months ended March 31			
		2008		2007	
		Gross	**Net**	Gross	Net
Exploration	Oil	**23**	**23**	20	20
	Gas	**57**	**49**	65	56
	Dry	**20**	**19**	9	9
		100	**91**	94	85
Development	Oil	**120**	**104**	138	130
	Gas	**116**	**87**	168	137
	Dry	**3**	**3**	10	10
		239	**194**	316	277
Total		**339**	**285**	410	362

White Rose Development

During the first quarter of 2008, we spent $68 million primarily for *SeaRose FPSO* tie-back projects and White Rose betterments.

East Coast and Northwest Territories Exploration

During the first quarter of 2008, we spent $25 million on two exploration wells in the Central Mackenzie Valley and on preliminary planning for our East Coast exploration program.

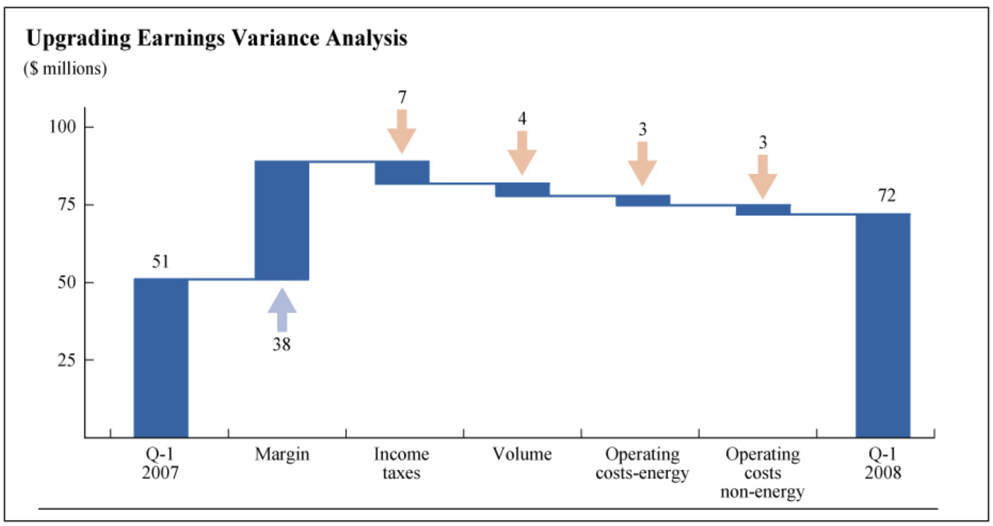
International

During the first quarter of 2008, we spent $30 million on exploration drilling in the South China Sea and seismic on the East Bawean II exploration block in the Java Sea.

4.2 Midstream

Upgrading Net Earnings Summary		Three months ended March 31	
(millions of dollars, except where indicated)		**2008**	2007
Gross margin		**$ 171**	$ 138
Operating costs		**63**	58
Other recoveries		**(1)**	(1)
Depreciation and amortization		**6**	6
Income taxes		**31**	24
Net earnings		**$ 72**	$ 51
Selected operating data:			
Upgrader throughput [1]	*(mbbls/day)*	**62.8**	69.0
Synthetic crude oil sales	*(mbbls/day)*	**55.6**	57.8
Upgrading differential	*($/bbl)*	**$ 28.53**	$ 24.11
Unit margin	*($/bbl)*	**$ 33.84**	$ 26.44
Unit operating cost [2]	*($/bbl)*	**$ 10.98**	$ 9.30

(1) Throughput includes diluent returned to the field.
(2) Based on throughput.



Upgrading Business Environment

During the first quarter of 2008, the upgrading differential averaged $28.53/bbl, 18% higher 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 first quarter of 2008, the overall unit margin was 28% higher than a year earlier, in part, due to the addition of low sulphur off-road diesel to the upgrader's product stream.

Upgrader throughput was 9% lower in the first quarter of 2008 compared with the same period in 2007 due to temporary operational issues. Unit operating costs increased by 18% in the first quarter of 2008 compared with a year earlier due primarily to higher consumption of steam and higher natural gas prices.

Infrastructure and Marketing Net Earnings Summary		Three months ended March 31	
(millions of dollars, except where indicated)		**2008**	2007
Gross margin	- pipeline	**$ 25**	$ 26
	- other infrastructure and marketing	**89**	72
		114	98
Other expenses		**3**	4
Depreciation and amortization		**8**	7
Income taxes		**31**	27
Net earnings		**$ 72**	$ 60
Selected operating data:			
Aggregate pipeline throughput	*(mbbls/day)*	**504**	493

Infrastructure and marketing net earnings in the first quarter of 2008 were $72 million compared with $60 million in the first quarter of 2007. Crude oil marketing and cogeneration earnings were also higher during the first quarter of 2008 compared with the first quarter of 2007.

Midstream Capital Expenditures

Midstream capital expenditures totalled $32 million in the first three months of 2008: $22 million was spent at the Lloydminster upgrader, primarily for contingent consideration and facility reliability projects. The remaining $10 million was spent on the pipeline extension between Lloydminster and Hardisty, Alberta.

4.3 Downstream

Canadian Refined Products Net Earnings Summary		Three months ended March 31	
(millions of dollars, except where indicated)		**2008**	2007
Gross margin	- fuel sales	**$ 38**	$ 42
	- ancillary sales	**10**	9
	- asphalt sales	**19**	13
		67	64
Operating and other expenses		**4**	18
Depreciation and amortization		**20**	16
Income taxes		**13**	10
Net earnings		**$ 30**	$ 20
Selected operating data:			
Number of fuel outlets		**501**	506
Light oil sales	*(million litres/day)*	**7.9**	8.9
Light oil retail sales per outlet	*(thousand litres/day)*	**13.1**	13.1
Prince George refinery throughput	*(mbbls/day)*	**11.4**	11.1
Asphalt sales	*(mbbls/day)*	**17.8**	17.3
Lloydminster refinery throughput	*(mbbls/day)*	**22.0**	24.7
Ethanol production	*(thousand litres/day)*	**649.1**	318.1

Canadian Refined Products Business Environment

The Canadian refined products business segment acquires refined product primarily at rack prices from third party refiners. During the first quarter of 2008 we benefited from higher throughput at the Prince George refinery, which produces a high gasoline yield. Product sales from the Prince George refinery, which accounted for 23% of our total Canadian refined product requirement, provided an offset to first quarter margin declines.

During the first quarter of 2008 asphalt product margins were approximately 40% higher than a year earlier. Asphalt sales were primarily from lower cost 2007 inventory. 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.

First quarter 2008 ethanol margins were down 9% from last year, slightly better than conventional fuel margins. Ethanol is a high octane clean burning blending stock that adds value to low octane gasoline and receives government incentives. Ethanol sales during the first quarter of 2008 were double those in the same period in 2007. The new Minnedosa ethanol plant commenced operation at the end of 2007.

U.S. Refining and Marketing Net Earnings Summary		Three months ended March 31
(millions of dollars, except where indicated)		**2008**
Gross refining margin		**$ 87**
Processing costs		**53**
Operating and other expenses		**1**
Interest - net		**1**
Depreciation and amortization		**19**
Income taxes		**5**
Net earnings		**$ 8**
Selected operating data:		
Refinery throughput	*(mbbls/day)*	
Crude oil and other feedstock		**138.4**
Yield	*(mbbls/day)*	
Gasoline		**74.2**
Middle distillates		**49.5**
Other fuel and feedstock		**11.4**
Gross refining margin	*($/bbl crude throughput)*	**6.91**
Unit operating costs	*($/bbl of yield)*	**4.33**
Refined product sales	*(mbbls/day)*	
Gasoline		**86.4**
Middle distillates		**45.9**
Other fuel and feedstock		**10.1**

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

U.S. Refining and Marketing Business Environment

In the downstream sector the drop in demand for motor fuels that began in mid 2007 was more pronounced in the first quarter of 2008 and in line with U.S. economic conditions and the traditional weak first quarter refining margin environment. Lower consumption combined with higher product stocks resulted in narrow refinery crack spreads.

The 3:2:1 crack spread is the key proxy for refining margins since, on average, refinery gasoline output is around twice the distillate output. This crack spread is equal to the price of 2/3 barrel of gasoline plus 1/3 barrel of diesel (distillate) less 1 barrel of crude oil. During the first quarter of 2008 the New York Harbour 3:2:1 crack spread averaged U.S. $10.09/bbl, 11% lower than a year earlier. March margins continued to grow with market fundamentals strengthening entering the spring driving season.

Downstream Capital Expenditures

Refined Products capital expenditures totalled $19 million during the first quarter 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.

4.4 Corporate

Corporate Summary	Three months ended March 31	
(millions of dollars) income (expense)	**2008**	2007
Intersegment eliminations - net	**$ (9)**	$ (25)
Administration expenses	**49**	(38)
Depreciation and amortization	**(7)**	(5)
Interest - net	**(45)**	(21)
Foreign exchange	**(10)**	1
Income taxes	**10**	27
Net earnings (loss)	**$ (12)**	$ (61)

In the first quarter of 2008, administration expenses reflected a recovery of stock-based compensation expense. The increase in net interest expense during the first 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 March 31	
(millions of dollars)	**2008**	2007
(Gain) loss on translation of U.S. dollar denominated long-term debt		
Unrealized	**$ 44**	$ (14)
	44	(14)
Cross currency swaps	**(14)**	4
Other (gains) losses	**(20)**	9
	$ 10	$ (1)
U.S./Canadian dollar exchange rates:		
At beginning of period	**U.S. $1.012**	U.S. $0.858
At end of period	**U.S. $0.973**	U.S. $0.867

Corporate Capital Expenditures

Corporate capital expenditures totaled $12 million in the first three months of 2008 primarily for various office and information system upgrades.

Consolidated Income Taxes

During the first quarter of 2008, consolidated income taxes consisted of $225 million of current taxes and $154 million of future taxes compared with current taxes of $72 million and future taxes of $225 million in the same period of 2007. The increase in current taxes and decrease in future taxes in the first quarter of 2008 compared with the first quarter of 2007 was due to the deferral of White Rose income.

4.5 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 first 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 First Quarter Average	Increase	Effect on Pre-tax Cash Flow [6]		Effect on Net Earnings [6]	
			($ millions)	*($/share)* [7]	*($ millions)*	*($/share)* [7]
Upstream and Midstream						
WTI benchmark crude oil price	$ 97.90	*U.S. $1.00/bbl*	74	0.09	52	0.06
NYMEX benchmark natural gas price [1]	$ 8.03	*U.S. $0.20/mmbtu*	25	0.03	17	0.02
WTI/Lloyd crude blend differential [2]	$ 21.81	*U.S. $1.00/bbl*	(28)	(0.03)	(19)	(0.02)
Downstream						
Light oil margins	$ 0.04	*Cdn $0.005/litre*	14	0.02	9	0.01
Asphalt margins	$ 10.99	*Cdn $1.00/bbl*	7	0.01	4	-
New York Harbor 3:2:1 crack spread [3]	$ 10.09	*U.S. $1.00/bbl*	48	0.06	30	0.04
Consolidated						
Exchange rate (U.S. $ per Cdn $) [4]	$ 0.996	*U.S. $0.01*	(76)	(0.09)	(55)	(0.06)
Interest rate		*1%*	(10)	(0.01)	(7)	(0.01)
Period end translation of U.S. $ debt (U.S. $ per Cdn $)	$ 0.973 [5]	*U.S. $0.01*			20	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 the Lima, Ohio refinery.
(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 March 31, 2008.
(6) Excludes derivatives.
(7) Based on 849.0 million common shares outstanding as of March 31, 2008.

5. Liquidity and Capital Resources

During the first quarter of 2008, cash flow from operating activities financed all of our capital requirements and dividend payment. At March 31, 2008 we had $1.4 billion in unused committed credit facilities.

Cash Flow Summary	Three months ended March 31	
(millions of dollars, except ratios)	**2008**	2007
Cash flow - operating activities	**$ 1,227**	$ 672
- financing activities	**$ (101)**	$ (222)
- investing activities	**$ (968)**	$ (892)
Financial Ratios		
Debt to capital employed *(percent)*	**19.7**	14.1
Corporate reinvestment ratio *(percent)* [1] [2]	**58**	63

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

5.1 Operating Activities

In the first quarter of 2008, cash generated from operating activities amounted to $1.2 billion compared with $672 million in the first quarter of 2007.

5.2 Financing Activities

In the first quarter of 2008, cash used in financing activities was $101 million compared with $222 million in the first quarter of 2007. During the first quarter of 2008, cash provided by a change in non-cash working capital associated with financing activities and lower dividends primarily resulted in a lower use of cash compared with the first quarter of 2007. The change in non-cash working capital mainly related to a decrease in dividends payable due to the special dividend of $0.25 per common share declared in February 2007. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

5.3 Investing Activities

In the first quarter of 2008, cash used in investing activities amounted to $968 million compared with $892 million in the first quarter of 2007. Cash invested in both periods was used primarily for capital expenditures.

5.4 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 capital 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. In addition, from time to time we engage in hedging a portion of our revenue to protect cash flow.

Working capital is the amount by which current assets exceed current liabilities. At March 31, 2008, our working capital was $595 million compared with a working capital deficiency of $51 million at December 31, 2007. The increase in working capital was related to feedstock and refined product inventories and higher accounts receivable at our U.S. refining operations and higher accounts receivable for our Canadian crude oil production. The higher working capital from accounts receivable and inventories was partially offset by higher accounts payable primarily for U.S. refinery feedstock purchases.

(millions of dollars)	March 31 2008	Dec. 31 2007	Change	
Current assets				
Cash and cash equivalents	**$ 366**	$ 208	$ 158	
Accounts receivable	**1,957**	1,622	335	Higher crude oil prices
Inventories	**1,651**	1,190	461	Inclusion of Toledo inventory; increased Lima inventory
Prepaid expenses	**27**	28	(1)	
	4,001	3,048	953	
Current liabilities				
Bank operating loans	**77**	-	(77)	
Accounts payable	**1,629**	1,460	(169)	Higher crude oil prices and higher royalties
Accrued interest payable	**29**	20	(9)	
Income taxes payable	**112**	36	(76)	Timing of tax payments
Other accrued liabilities	**788**	842	54	
Long-term debt due within one year	**771**	741	(30)	Foreign exchange impact on U.S. dollar denominated debt
	3,406	3,099	(307)	
Working capital	**$ 595**	$ (51)	$ 646	

Capital Structure

(millions of dollars)	March 31, 2008 Outstanding	Available
Total short-term and long-term debt	$ 3,096	$ 1,422
Common shares, retained earnings and accumulated other comprehensive income	$ 12,300	

At March 31, 2008, we had unused committed long and short-term borrowing credit facilities totalling $1.4 billion. A total of $71 million of our borrowing credit facilities were used in support of outstanding letters of credit and an additional $21 million of letters of credit were outstanding at March 31, 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. The Company's proportionate share is $5 million.

We currently have a shelf prospectus dated September 21, 2006 that enabled us to offer up to U.S. $1.0 billion of debt securities in the United States until October 21, 2008. During the 25 months 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 Management's Discussion and Analysis, 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.

5.5 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.

5.6 Contractual Obligations and Commercial Commitments

Refer to Husky's 2007 annual Management's Discussion and Analysis under the caption "Cash Requirements," which summarizes contractual obligations and commercial commitments as at December 31, 2007.

At March 31, 2008, we had additional contractual obligations to purchase goods and services totalling $1,150 million. These contracts are expected to be settled in the following periods: 2008 - $687 million; 2009 - $331 million; and 2010 - $132 million. Our East Coast exploration and development program accounts for 62% of the total value of these additional contracts and the remaining amounts are for refined petroleum product purchases.

5.7 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 March 31, 2008, we had no accounts receivable sold under the securitization program. The securitization program permits the sale of a maximum $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.

5.8 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. During the first quarter of 2008, we sold $31 million of natural gas to TransAlta Power, L.P.

6. Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks see our Annual Information Form recently 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 three 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 three 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 three months of 2008.

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

Foreign Currency Risk Management

At March 31, 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 March 31, 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 15 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 March 31, 2008 the cost of a U.S. dollar in Canadian currency was $1.0279.

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 March 31, 2008, 90% or $2.7 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 78% when cross currency swaps are considered.

Effective July 1, 2007, the Company's U.S. $1.5 billion of debt financing related to the Lima acquisition was designated as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. As at March 31, 2008, unrealized foreign exchange loss arising from the translation of the debt was $51 million, net of tax of $9 million which was recorded in "Other Comprehensive Income."

7. 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.

8. 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.

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 15 to the Consolidated Financial Statements for the additional disclosures under section 3862.

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 16 to the Consolidated Financial Statements.

9. Outstanding Share Data

(in thousands)	March 31 **2008**	December 31 2007
Issued and outstanding at end of period [(1)]		
Number of common shares	**849,044**	848,960
Number of stock options	**31,086**	30,131
Number of stock options exercisable	**3,887**	4,494

[(1)] *There were no significant issuances of common shares, stock options or any other securities convertible into, or exercisable or exchangeable for common shares during the period from March 31, 2008 to April 11, 2008. During this period, 7 thousand stock options were exercised for shares and 24 thousand stock options were surrendered for cash. At April 11, 2008, the Company had 849,051 thousand common shares outstanding and there were 31,055 thousand stock options outstanding, of which 3,856 thousand were exercisable.*

10. 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 March 31, 2008 are compared with results for the three months ended March 31, 2007. Discussions with respect to Husky's financial position as at March 31, 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 generally accepted accounting principles ("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. 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:

		Three months ended March 31	
(millions of dollars)		**2008**	2007
Non-GAAP	Cash flow from operations	**$ 1,541**	$ 1,324
	Settlement of asset retirement obligations	**(17)**	(14)
	Change in non-cash working capital	**(297)**	(638)
GAAP	Cash flow - operating activities	**$ 1,227**	$ 672

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*

Forward-Looking Statements or Information

Certain statements in this release and Interim Report are forward-looking statements or information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The Company is hereby providing cautionary statements identifying important factors that could cause the Company's 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" and "outlook") are not historical facts and are forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. In particular, forward-looking statements include, but are not limited to: our 2008 production and capital spending guidance, our annualized sensitivity analysis of the effect of changes in key variables on our pre-tax cash flow and net earnings, our East Coast exploration and White Rose delineation and SeaRose FPSO tie-back plans, our development plans for the North Amethyst oil field, our production optimization plans for the Tucker in-situ oil sands project, our Sunrise phased development plans, our Caribou and Saleski oil sands projects plans and development application schedule, our Northwest Territories exploration program, the schedule and results of our offshore China geophysical and drilling programs, the Liwan natural gas discovery delineation and development plans, the receipt of approvals for and commencement of production at the Madura BD natural gas and NGL field, the results of our seismic data analysis from the East Bawean II exploration block in the East Java Sea, our work programs for offshore Greenland and our plans to review options in respect of reconfiguring and expanding the Lima refinery and our plans to modify the Toledo refinery. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this release. Among the key factors that have a direct bearing on our results of operations are the nature of our involvement in the business of exploration for, and development and production of crude oil and natural gas reserves and the fluctuation of the exchange rates between the Canadian and United States dollar.

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;*
- *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;*
- *foreign exchange risk;*
- *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 accuracy of our reserve estimates and estimated production levels.*

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

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of dollars, except share data)	**March 31 2008** *(unaudited)*	December 31 2007
Assets		
Current assets		
Cash and cash equivalents	**$ 366**	$ 208
Accounts receivable	**1,957**	1,622
Inventories	**1,651**	1,190
Prepaid expenses	**27**	28
	4,001	3,048
Property, plant and equipment	**30,417**	29,407
Less accumulated depletion, depreciation and amortization	**12,055**	11,602
	18,362	17,805
Goodwill	**680**	660
Contribution receivable *(note 6)*	**1,177**	-
Other assets	**171**	184
	$ 24,391	$ 21,697
Liabilities and Shareholders' Equity		
Current liabilities		
Bank operating loans *(note 8)*	**$ 77**	$ -
Accounts payable and accrued liabilities	**2,558**	2,358
Long-term debt due within one year *(note 9)*	**771**	741
	3,406	3,099
Long-term debt *(note 9)*	**2,248**	2,073
Contribution payable *(note 6)*	**1,290**	-
Other long-term liabilities *(note 10)*	**912**	918
Future income taxes	**4,235**	3,957
Commitments and contingencies *(note 11)*		
Shareholders' equity		
Common shares *(note 12)*	**3,555**	3,551
Retained earnings	**8,783**	8,176
Accumulated other comprehensive income	**(38)**	(77)
	12,300	11,650
	$ 24,391	$ 21,697
Common shares outstanding *(millions) (note 12)*	**849.0**	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 March 31 **2008**	2007
Sales and operating revenues, net of royalties	**$ 5,086**	$ 3,244
Costs and expenses		
Cost of sales and operating expenses	**3,307**	1,779
Selling and administration expenses	**51**	38
Stock-based compensation	**(43)**	21
Depletion, depreciation and amortization	**450**	433
Interest - net *(note 9)*	**46**	21
Foreign exchange *(note 9)*	**10**	(1)
Other - net	**(1)**	6
	3,820	2,297
Earnings before income taxes	**1,266**	947
Income taxes		
Current	**225**	72
Future	**154**	225
	379	297
Net earnings	**887**	650
Other comprehensive income		
Derivatives designated as cash flow hedges, net of tax	**(2)**	2
Cumulative foreign currency translation adjustment	**92**	-
Hedge of net investment, net of tax	**(51)**	-
Comprehensive income	**$ 926**	$ 652
Earnings per share		
Basic and diluted	**$ 1.04**	$ 0.77
Weighted average number of common shares outstanding *(millions)*		
Basic and diluted	**849.0**	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 March 31 **2008**	2007
Common shares		
Beginning of period	**$ 3,551**	$ 3,533
Options exercised	**4**	3
End of period	**3,555**	3,536
Retained earnings		
Beginning of period	**8,176**	6,087
Net earnings	**887**	650
Dividends on common shares		
Ordinary	**(280)**	(212)
Special	**-**	(212)
Adoption of financial instruments	**-**	4
End of period	**8,783**	6,317
Accumulated other comprehensive income		
Beginning of period	**(77)**	-
Adoption of financial instruments	**-**	(18)
Other comprehensive income		
Derivatives designated as cash flow hedges, net of tax	**(2)**	2
Cumulative foreign currency translation adjustment	**92**	-
Hedge of net investment, net of tax	**(51)**	-
	39	2
End of period	**(38)**	(16)
Shareholders' equity	**$ 12,300**	$ 9,837

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

Consolidated Statements of Cash Flows

(millions of dollars) (unaudited)	Three months ended March 31 **2008**	2007
Operating activities		
Net earnings	**$ 887**	$ 650
Items not affecting cash		
Accretion *(note 10)*	**13**	12
Depletion, depreciation and amortization	**450**	433
Future income taxes	**154**	225
Foreign exchange	**31**	(10)
Other	**6**	14
Settlement of asset retirement obligations *(note 10)*	**(17)**	(14)
Change in non-cash working capital *(note 7)*	**(297)**	(638)
Cash flow - operating activities	**1,227**	672
Financing activities		
Bank operating loans financing - net	**77**	83
Long-term debt issue	**375**	435
Long-term debt repayment	**(275)**	(535)
Proceeds from exercise of stock options	**1**	1
Dividends on common shares	**(280)**	(424)
Other	**(8)**	-
Change in non-cash working capital *(note 7)*	**9**	218
Cash flow - financing activities	**(101)**	(222)
Available for investing	**1,126**	450
Investing activities		
Capital expenditures	**(852)**	(734)
Asset sales	**30**	-
Other	**19**	(2)
Change in non-cash working capital *(note 7)*	**(165)**	(156)
Cash flow - investing activities	**(968)**	(892)
Increase (decrease) in cash and cash equivalents	**158**	(442)
Cash and cash equivalents, beginning of period	**208**	442
Cash and cash equivalents, end of period	**$ 366**	$ -

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

Notes to the Consolidated Financial Statements

Three months ended March 31, 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 March 31														
Sales and operating revenues, net of royalties	**$ 1,829**	$ 1,565	**$ 483**	$ 359	**$ 3,102**	$ 2,555	**$ 722**	$ 618	**$ 1,329**	$ -	**$(2,379)**	$ (1,853)	**$ 5,086**	$ 3,244
Costs and expenses														
Operating, cost of sales, selling and general	**413**	323	**374**	278	**2,991**	2,461	**659**	572	**1,296**	-	**(2,419)**	(1,790)	**3,314**	1,844
Depletion, depreciation and amortization	**390**	399	**6**	6	**8**	7	**20**	16	**19**	-	**7**	5	**450**	433
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**1**	-	**45**	21	**46**	21
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**10**	(1)	**10**	(1)
	803	722	**380**	284	**2,999**	2,468	**679**	588	**1,316**	-	**(2,357)**	(1,765)	**3,820**	2,297
Earnings (loss) before income taxes	**1,026**	843	**103**	75	**103**	87	**43**	30	**13**	-	**(22)**	(88)	**1,266**	947
Current income taxes	**166**	22	**22**	1	**30**	16	**6**	8	**(22)**	-	**23**	25	**225**	72
Future income taxes	**143**	241	**9**	23	**1**	11	**7**	2	**27**	-	**(33)**	(52)	**154**	225
Net earnings (loss)	**$ 717**	$ 580	**$ 72**	$ 51	**$ 72**	$ 60	**$ 30**	$ 20	**$ 8**	$ -	**$ (12)**	$ (61)	**$ 887**	$ 650
Capital expenditures - Three months ended March 31	**$ 798**	$ 617	**$ 22**	$ 48	**$ 10**	$ 36	**$ 19**	$ 40	**$ 7**	$ -	**$ 12**	$ 5	**$ 868**	$ 746
Goodwill additions - Three months ended March 31	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -
Total assets - As at March 31	**$ 13,114**	$14,168	**$1,434**	$1,177	**$ 1,322**	$ 1,057	**$ 1,396**	$ 1,180	**$ 6,574**	$ -	**$ 551**	$ 199	**$24,391**	$17,781

[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.*

Geographical Financial Information

	Canada		United States		Other International		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Three months ended March 31								
Sales and operating revenues, net of royalties	**$ 3,384**	$ 2,836	**$ 1,618**	$ 336	**$ 84**	$ 72	**$ 5,086**	$ 3,244
Capital expenditures (1)	**831**	741	**7**	-	**30**	5	**868**	746
As at March 31								
Property, plant and equipment, net	**$ 16,511**	$ 15,513	**$ 1,460**	$ 3	**$ 391**	$ 341	**$ 18,362**	$ 15,857
Goodwill (2)	**160**	160	**520**	-	**-**	-	**680**	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 15, "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 16, "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 Venture with 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 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.

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.

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

	Three months ended March 31	
	2008	2007
a) Change in non-cash working capital was as follows:		
Decrease (increase) in non-cash working capital		
Accounts receivable	**$ (324)**	$ 2
Inventories	**(248)**	8
Prepaid expenses	**(1)**	(1)
Accounts payable and accrued liabilities	**120**	(585)
Change in non-cash working capital	**$ (453)**	$ (576)
Relating to:		
Operating activities	**$ (297)**	$ (638)
Financing activities	**9**	218
Investing activities	**(165)**	(156)
b) Other cash flow information:		
Cash taxes paid	**$ 171**	$ 768
Cash interest paid	**41**	23

Note 8 Bank Operating Loans

At March 31, 2008, the Company had unsecured short-term borrowing lines of credit with banks totalling $270 million (December 31, 2007 - $270 million). As at March 31, 2008, bank operating loans were $77 million (December 31, 2007 - nil). As of March 31, 2008, letters of credit under these lines of credit totalled $71 million (December 31, 2007 - $73 million).

The Sunrise Oil Sands Partnership has an unsecured demand credit facility available of $10 million for general purposes. The Company's proportionate share is $5 million. As at March 31, 2008, there was no balance outstanding under this credit facility.

Note 9 Long-term Debt

	Maturity	March 31 2008	Dec. 31 2007	March 31 2008	Dec. 31 2007
		Cdn $ Amount		*U.S. $ Denominated*	
Long-term debt					
Medium-term notes	2009	**$ 205**	$ 203	**$ -**	$ -
Bilateral credit facilities	2012	**100**	-	**-**	-
6.25% notes	2012	**411**	395	**400**	400
7.55% debentures	2016	**205**	198	**200**	200
6.20% notes	2017	**308**	296	**300**	300
6.15% notes	2019	**308**	296	**300**	300
8.90% capital securities	2028	**231**	223	**225**	225
6.80% notes	2037	**463**	445	**450**	450
Debt issue costs [(1)]		**(19)**	(20)	**-**	-
Unwound interest rate swaps		**36**	37	**-**	-
		$ 2,248	$ 2,073	**$ 1,875**	$ 1,875
Long-term debt due within one year					
Bridge financing [(2)]	2008	**$ 771**	$ 741	**$ 750**	$ 750

[(1)] *Calculated using the effective interest rate method.*
[(2)] *The Company has the right to extend the maturity of the bridge financing to June 26, 2009 by providing 30 days' notice.*

Interest - net consisted of:

	Three months ended March 31 2008	Three months ended March 31 2007
Long-term debt	**$ 48**	$ 28
Short-term debt	**1**	1
	49	29
Amount capitalized	**-**	(3)
	49	26
Interest income	**(3)**	(5)
	$ 46	$ 21

Foreign exchange consisted of:

	Three months ended March 31 2008	Three months ended March 31 2007
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ 44**	$ (14)
Cross currency swaps	**(14)**	4
Other (gains) losses	**(20)**	9
Loss (gain)	**$ 10**	$ (1)

Note 10 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Three months ended March 31	
	2008	2007
Asset retirement obligations at beginning of year	**$ 662**	$ 622
Liabilities incurred	**18**	8
Liabilities disposed	**(1)**	-
Liabilities settled	**(17)**	(14)
Accretion	**13**	12
Asset retirement obligations at end of year	**$ 675**	$ 628

At March 31, 2008, the estimated total undiscounted inflation-adjusted amount required to settle outstanding asset retirement obligations was $5.1 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 11 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 12 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:

	Three months ended March 31			
	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	83,922	4	75,596	3
Balance at March 31	**849,044,232**	**$ 3,555**	848,612,614	$ 3,536

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.

	Three months ended March 31			
	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	-	$ -
Exercised for common shares	(84)	$ 11.81	(76)	$ 12.00
Surrendered for cash	(747)	$ 13.12	(767)	$ 12.06
Forfeited	(243)	$ 41.46	(244)	$ 34.56
Outstanding at March 31	**31,086**	**$ 38.02**	10,569	$ 16.15
Options exercisable at March 31	**3,887**	**$ 15.33**	3,877	$ 13.50

	March 31, 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
$7.23 - $11.99	3,157	$ 11.70	1	3,157	$ 11.70
$12.00 - $17.99	115	$ 15.94	2	96	$ 15.62
$18.00 - $27.99	390	$ 26.17	3	144	$ 26.57
$28.00 - $36.99	942	$ 35.15	3	390	$ 34.63
$37.00 - $39.99	939	$ 39.39	4	100	$ 38.20
$40.00 - $40.99	2,447	$ 40.88	5	-	$ -
$41.00 - $42.57	23,096	$ 41.69	4	-	$ -
	31,086	**$ 38.02**	**4**	**3,887**	**$ 15.33**

Note 13 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended March 31	
	2008	2007
Employer current service cost	**$ 7**	$ 6
Interest cost	**3**	2
Expected return on plan assets	**(3)**	(2)
Amortization of net actuarial losses	**1**	1
	$ 8	$ 7

Note 14 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 three months ended March 31, 2008, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $31 million. At March 31, 2008, the total value of accounts receivable related to these transactions was $6 million.

Note 15 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 March 31, 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 March 31, 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 Venture with BP."

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:

	March 31, 2008		December 31, 2007	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$3,019**	**$2,997**	$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 March 31, 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	29,149	$ 10
Physical sale contracts	(29,149)	$ (9)

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 March 31, 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	$ 5

This contract has been recorded at fair value in other assets. During the three months ended March 31, 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 March 31, 2008, the fair value of the embedded derivative was $73 million (December 31, 2007 - $101 million). In the first quarter of 2008, the impact was an unrealized loss on the embedded derivative of $28 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 March 31, 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	$ (71)
6.25% notes	U.S. $ 75	$ 90	June 15, 2012	5.65	$ (10)
6.25% notes	U.S. $ 50	$ 59	June 15, 2012	5.67	$ (6)
6.25% notes	U.S. $ 75	$ 88	June 15, 2012	5.61	$ (8)

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 $5 million, net of tax of

$2 million, has been included in other comprehensive income. At March 31, 2008, the balance in accumulated other comprehensive income was $4 million, net of tax of $3 million. For the three months ended March 31, 2008, the Company recognized a foreign exchange gain of $14 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 three months of 2008, the impact of these contracts was a loss of $2 million (2007 - gain of less than $1 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 March 31, 2008, the following foreign exchange transactions had been entered into:

Date	Forward Purchases	Canadian Equivalent	Fair Value
October 5, 2007	U.S. $ 119	$ 117	$ 7
October 11, 2007	U.S. $ 119	$ 116	$ 7
October 29, 2007	U.S. $ 119	$ 115	$ 9

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 three months of 2008, the impact was a gain of $15 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. As at March 31, 2008, the unrealized foreign exchange loss of $51 million, net of tax of $9 million, arising from the translation of the debt is recorded in other comprehensive income.

Sensitivity Analysis

The Company is exposed to interest rate risk on its interest rate swaps. As at March 31, 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 $4 million lower. As at March 31, 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 $6 million higher. As at March 31, 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 March 31, 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 March 31, 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	$ 2,558	$ -	$ -	$ -
Bank operating loans	77	-	-	-
Cross currency swaps	-	-	447	-
Long-term debt and interest on fixed rate debt	916	338	905	2,887
Other long-term liabilities	5	-	-	-
Total	$ 3,556	$338	$1,352	$ 2,887

The Company's contribution payable to the joint venture with BP (refer to Note 6) is payable between March 31, 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 first 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	March 31, 2008
Current	**$ 1,695**
Past due (1 - 30 days)	**223**
Past due (31 - 60 days)	**-**
Past due (61 - 90 days)	**6**
Past due (more than 90 days)	**20**
Total	**$ 1,944**

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

Balance at January 1, 2008	$ 10
Provisions and revisions	1
Balance at March 31, 2008	**$ 11**

For the first quarter of 2008, the Company wrote off less than $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 March 31, 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 March 31, 2008, the amount the Company would be contractually required to pay under the cross currency swaps at maturity was $352 million higher (December 31, 2007 - $341 million higher) than their carrying amount.

Note 16 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, the syndicated credit facility and the bridge credit facility all include a debt to cash flow covenant. The Company was fully compliant with this covenant at March 31, 2008.

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

Note 17 Subsequent Event

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 U.S. $125 million. Husky Oil (Madura) Limited holds a 100% interest in the Madura Strait Production Sharing Contract. The resulting joint venture arrangement will be accounted for using the proportionate consolidation method.

Husky Energy Inc. will host a conference call for analysts and investors on Tuesday, April 22, 2008 at 8:30 a.m. Eastern time to discuss Husky's first quarter results. To participate please dial 1-800-319-4610 beginning at 8:15 a.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 8:20 a.m. (Eastern time)

A recording of the call will be available at approximately 9:30 a.m. (Eastern time)

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

The Postview will be available until May 22, 2008.

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