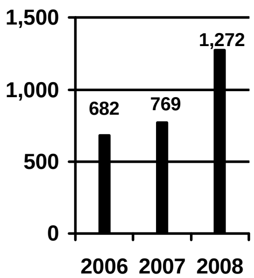
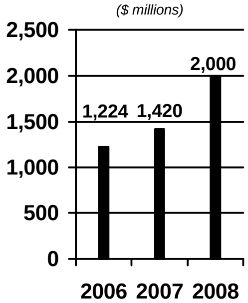
Quarterly Report to the Shareholders for the period ended September 30, 2008

HUSKY ENERGY REPORTS 2008 THIRD QUARTER RESULTS

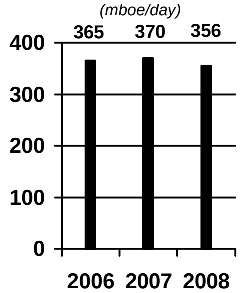
Third Quarter
Net Earnings
($ millions)



Third Quarter
Cash Flow
from Operations
($ millions)



Third Quarter
Total Production
(mboe/day)



Calgary, Alberta – Husky Energy Inc. (TSX - HSE) reported net earnings of $1.27 billion or $1.50 per share (diluted) in the third quarter of 2008, an increase of 65 percent from $769 million or $0.91 per share (diluted) in the same quarter of 2007. Cash flow from operations in the third quarter of 2008 was $2.0 billion or $2.36 per share (diluted), a 41 percent increase compared with $1.4 billion or $1.67 per share (diluted) in the same quarter of 2007. Sales and operating revenues, net of royalties, were $7.7 billion in the third quarter of 2008, an increase of 77 percent compared with $4.4 billion in the same quarter of 2007.

"Husky's strong earnings and cash flow allow the Company to finance its current capital program, redeem debt and accumulate cash, positioning the Company for further investment opportunities," said John C.S. Lau, President & Chief Executive Officer of Husky Energy Inc. "Husky's focus on financial discipline in respect of costs and project execution over the years has positioned the Company to perform well in these volatile financial and commodity markets."

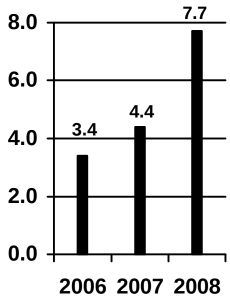
In the third quarter of 2008, total production averaged 355,900 barrels of oil equivalent per day, compared with 369,900 barrels of oil equivalent per day in the third quarter of 2007, a reduction of four percent. Total crude oil and natural gas liquids production was 256,200 barrels per day, compared with 266,500 barrels per day in 2007. Natural gas production was 598 million cubic feet per day, compared with 620 million cubic feet per day in the same period of 2007. The decrease in production of barrels of oil equivalent is generally in line with Husky's updated guidance as reported in the second quarter of 2008.

For the first nine months of 2008, Husky's net earnings were $3.5 billion or $4.15 per share (diluted), compared with $2.1 billion or $2.52 per share (diluted) in the first nine months of 2007. Cash flow from operations was $5.6 billion or $6.63 per share (diluted) in the first nine months of 2008, compared with $4.0 billion or $4.71 per share (diluted) in the same period of 2007. Sales and operating revenues, net of royalties, were $20.0 billion in the first nine months of 2008, compared with $10.8 billion in the first nine months of 2007.

Production for the first nine months of 2008 was 355,100 barrels of oil equivalent per day, compared with 379,600 barrels of oil equivalent per day in the same period in 2007. Crude oil and natural gas liquids production was 254,700 barrels per day, compared with 275,400 barrels per day in the first nine months of 2007. This reflects the severe ice pack and iceberg winter conditions off the East Coast of Canada and the previously disclosed delay in ramp up of production at the Tucker Oil Sands Project.

Natural gas production was 602 million cubic feet per day as compared with 625 million cubic feet per day during the same period of 2007.

Third Quarter Sales and Operating Revenues
($ billions)



In the third quarter, Husky signed a joint venture agreement acquiring a 50 percent working interest in 844,000 net acres of leasehold ownership and wells in the Columbia River Basin in the states of Washington and Oregon, for a consideration of approximately U.S. $100 per acre for 422,000 acres.

During the third quarter, work progressed at the Sunrise Oil Sands Project on area infrastructure and site preparation. Phase one production is expected to commence approximately four years following project sanction.

In the White Rose satellite developments off Canada's East Coast, engineering work has progressed well and drilling of stratigraphic wells commenced during the third quarter. In September, the eighth producing well in the White Rose field commenced production. Husky has also been successful in acquiring two exploration blocks on the Labrador Shelf off the coast of Labrador.

Offshore China, Husky's contracted deep water drilling rig *West Hercules* continued with commissioning and acceptance testing in Korea. Delivery of the rig is expected at the end of October 2008 and we expect to commence appraisal drilling at the Liwan field in November. Husky initially plans to drill four delineation wells on the Liwan discovery and two exploration wells on satellite prospects in the area. Additionally, two shallow water rigs are currently being contracted to drill a total of four exploration wells in the South China Sea, East China Sea and Yingge Hai basin. Husky expects to commence drilling the first well in December 2008.

In Indonesia, the Madura BD field development plan was approved in July 2008 and Husky expects approval of the Madura Production Sharing Contract (PSC) extension from the regulatory authorities prior to year-end. On the East Bawean II PSC, Husky has secured a jack up drilling rig to drill two exploration wells in 2009. Husky has been awarded a PSC from the government of Indonesia for a 100 percent interest in the North Sambawa II Block in the East Java Sea.

Third Quarter Financial Highlights 2008 versus 2007

- Earnings per share to $1.50 from $0.91
- Cash flow per share to $2.36 from $1.67
- Return on equity to 36.6% from 26.6%
- Return on average capital employed to 31.6% from 22.3%
- Debt to capital employed ratio to 11% from 21%
- Debt to cash flow ratio to 0.2 from 0.6

In the downstream business, refining crack spread margins during the start of the quarter were low with pressure on gasoline cracks partially offset by firmer distillate spreads. Crude supply disruptions associated with hurricanes Gustav, Hanna and Ike widened spreads later in the quarter but impacted crude oil feedstock availability. These two factors resulted in slightly lower refinery throughput than the same period in 2007. The Lima Refinery had a high on-stream reliability during the quarter. The Toledo Refinery was limited in its ability to capitalize on wider sweet/sour differentials as production was also impacted by turnaround activities. Husky has completed the conceptual stage of reconfiguring the Lima Refinery to process heavier feedstocks.

Husky's earnings are largely determined by realized prices for crude oil and natural gas, including the effects of changes to the U.S./Canadian exchange rate. Recently, changes in the crude oil and natural gas pricing and the exchange rate have moved together, with changes in the exchange rate providing partial offset to changes in crude oil and natural gas pricing. As at October 20, 2008 crude oil (WTI) and natural gas (NYMEX) prices had fallen to U.S. $74.25 per barrel (26 percent) and U.S. $6.74 per million British Thermal Units (nine percent) respectively from September 30, 2008, partially offset by a 12 percent reduction in the exchange rate to $0.835 U.S. dollar per Canadian dollar at the same date.

Husky continues to strengthen its financial position and has a very strong balance sheet. Total long-term debt including current portion at September 30, 2008 was $1,719 million compared with $2,814 million at December 31, 2007. The total debt was substantially offset by cash and cash equivalents of $966 million resulting in net debt of $753 million at September 30, 2008. Debt to cash flow from operations decreased to 0.2 times at the end of the third quarter compared with 0.5 times at the 2007 year-end. The ratio of debt to capital employed improved to 11 percent at September 30, 2008 from 19 percent at December 31, 2007.

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

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1. Summary of Quarterly Financial Results

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

	Three months ended							
	Sept. 30	June 30	March 31	Dec. 31	Sept. 30	June 30	March 31	Dec. 31
(millions of dollars, except per share amounts and ratios)	**2008**	2008	2008	2007	2007	2007	2007	2006
Sales and operating revenues, net of royalties	**$ 7,715**	$ 7,199	$ 5,086	$ 4,760	$ 4,351	$ 3,163	$ 3,244	$ 3,084
Net earnings by sector								
Upstream	**$ 1,079**	$ 1,239	$ 717	$ 864	$ 516	$ 636	$ 580	$ 453
Midstream	**100**	153	144	218	129	77	111	105
Downstream	**(9)**	194	38	103	121	53	20	10
Corporate and eliminations	**102**	(223)	(12)	(111)	3	(45)	(61)	(26)
Net earnings	**$ 1,272**	$ 1,363	$ 887	$ 1,074	$ 769	$ 721	$ 650	$ 542
Per share - Basic and diluted	**$ 1.50**	$ 1.61	$ 1.04	$ 1.26	$ 0.91	$ 0.85	$ 0.77	$ 0.64
Cash flow from operations	**2,000**	2,090	1,541	1,425	1,420	1,257	1,324	1,207
Per share - Basic and diluted	**2.36**	2.46	1.82	1.68	1.67	1.48	1.56	1.42
Ordinary quarterly dividend per common share	**0.50**	0.40	0.33	0.33	0.25	0.25	0.25	0.25
Special dividend per common share	**-**	-	-	-	-	-	0.25	-
Total assets	**26,292**	25,296	24,391	21,697	20,718	17,969	17,781	17,933
Cash and cash equivalents	**966**	536	366	208	7	133	-	442
Total long-term debt including current portion	**1,719**	2,129	3,019	2,814	2,835	1,423	1,527	1,611
Return on equity [(1)] *(percent)*	**36.6**	34.9	31.2	30.2	26.6	27.1	32.1	31.8
Return on average capital employed [(1)] *(percent)*	**31.6**	30.9	26.5	25.7	22.3	23.8	27.3	27.0

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

- Financial position remains strong, financing capital programs and retiring debt with cash generated from operating activities
- Production consistent with second quarter guidance

- Average commodity price environment remained strong during the quarter
- Refined product margins were low compared with the same period in the previous year due to weak demand for products combined with supply disruptions in both Canada and the U.S.A.
- Marketing margins in the third quarter of 2008 were impacted by declines in commodity prices at the end of the quarter resulting in lower broker profits

2. Business Environment

Average Benchmarks

		Three months ended					
		Sept. 30 2008	June 30 2008	March 31 2008	Dec. 31 2007	Sept. 30 2007	June 30 2007
WTI crude oil [1]	*(U.S. $/bbl)*	**117.98**	123.98	97.90	90.68	75.38	65.03
Brent crude oil [2]	*(U.S. $/bbl)*	**114.78**	121.38	96.90	88.70	74.87	68.76
Canadian light crude 0.3% sulphur	*($/bbl)*	**122.53**	126.73	98.20	87.19	80.70	72.61
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**96.17**	89.70	64.23	42.03	43.61	39.02
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**10.24**	10.93	8.03	6.97	6.16	7.55
NIT natural gas	*($/GJ)*	**8.76**	8.86	6.76	5.69	5.31	6.99
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**18.34**	21.95	21.81	34.06	23.50	20.36
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**10.96**	14.50	10.09	8.23	11.91	24.18
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.960**	0.990	0.996	1.018	0.957	0.911

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

Oil and Gas Prices

Our earnings are largely determined by realized prices for crude oil and natural gas including the effects of changes in the U.S./Canadian dollar exchange rate. During the third quarter of 2008 our upstream industry segment contributed 85% to consolidated net earnings. Significant fluctuations in our earnings are related to the volatility of oil and gas prices which are determined by market forces over which we have no control.

During the first nine months of 2008, the near-month price of WTI averaged U.S. $113.52/bbl and peaked above U.S. $145 in mid July before declining to U.S. $91.15/bbl during September. The average for the third quarter was U.S. $117.98/bbl and the price at the end of September was U.S. $100.64/bbl and by October 20th was U.S. $74.25/bbl.

During the third quarter of 2008 the light/heavy crude oil differential averaged 16% of WTI compared with 31% of WTI in the third quarter of 2007. Higher demand for heavy crude was in response to lower crack spreads and increased demand for distillates.

Natural gas prices quoted on the NYMEX rose sharply through the first half of 2008 and were, on average, 37% higher than the same period in 2007 based on lower storage levels and higher demand. During the third quarter of 2008, natural gas prices plummetted as natural gas storage levels increased, surpassing five-year average levels by mid August. At the end of the third quarter of 2008, natural gas inventory in underground storage in the United States was 2% higher than the five year average and 4% lower than the same date in 2007. The NYMEX near-month price ended the third quarter of 2008 at U.S. $7.44/mmbtu and by October 20th was U.S. $6.74/mmbtu.

Foreign Exchange

The majority of our revenues are denominated in U.S. dollars. A weakening of the Canadian dollar against the U.S. dollar positively impacts our revenue stream, offsetting the impact of lower oil and natural gas prices.

During the third quarter the Canadian dollar weakened 3.9% against the U.S. dollar, closing at $0.944 U.S. per Canadian dollar at September 30, 2008 and by October 20th had further weakened to $0.835 U.S. per Canadian dollar. The average exchange rate for the quarter was $0.96 U.S. per Canadian dollar compared to $0.99 U.S. per Canadian dollar in the second quarter of 2008.

Refinery Crack Spreads

The 3:2:1 crack spread is the key indicator for refining margins as refinery gasoline output is approximately twice the distillate output. This crack spread is equal to the price of two-thirds of a barrel of gasoline plus one-third of a barrel of diesel (distillate) less one barrel of crude oil. Prices are based on NYMEX near-month contract averages.

During the third quarter of 2008, the U.S. New York Harbor crack spread averaged U.S. $10.96/bbl compared with U.S. $11.91/bbl in the third quarter of 2007 due to lower demand for motor fuel, particularly gasoline, partially offset in September by hurricane related refinery outages.

Actual crack spreads achieved are also impacted by the timing of delivery of crude oil purchases, accounted for on a FIFO basis which is consistent with Canadian GAAP.

Cost Environment

The oil and gas industry is experiencing an increase in costs in excess of the general rate of inflation. These increases affect the cost of operating our oil and gas properties, processing plants and refineries. They also affect our capital projects which are susceptible to cost volatility.

Global Financial Crisis

The current global financial crisis has reduced liquidity in financial markets, restricted access to financing and caused significant volatility in commodity prices. These will impact the performance of the economy going forward. However, companies with strong cash generation from operations, availability of cash and cash equivalents, low debt with long maturities and unused committed credit facilities will be better positioned to manage through this crisis.

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 third quarter of 2008. Each item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis	2008 Third Quarter Average	Increase	Effect on Annual Pre-tax Cash Flow [7]		Effect on Annual Net Earnings [7]	
			($ millions)	*($/share)* [8]	*($ millions)*	*($/share)* [8]
Upstream and Midstream						
WTI benchmark crude oil price	$ 117.98	*U.S. $1.00/bbl*	75	0.09	53	0.06
NYMEX benchmark natural gas price [1]	$ 10.24	*U.S. $0.20/mmbtu*	25	0.03	18	0.02
WTI/Lloyd crude blend differential [2]	$ 18.34	*U.S. $1.00/bbl*	(9)	(0.01)	(7)	(0.01)
Downstream						
Light oil margins	$ 0.027	*Cdn $0.005/litre*	15	0.02	10	0.01
Asphalt margins	$ 10.33	*Cdn $1.00/bbl*	13	0.01	8	0.01
New York Harbor 3:2:1 crack spread [3]	$ 10.96	*U.S. $1.00/bbl*	67	0.08	42	0.05
Consolidated						
Exchange rate (U.S. $ per Cdn $) [4]	$ 0.960	*U.S. $0.01*	(98)	(0.12)	(70)	(0.08)
Interest rate [5]		*100 basis points*	-	-	-	-
Period end translation of U.S. $ debt (U.S. $ per Cdn $)	$ 0.944 [6]	*U.S. $0.01*	-	-	12	0.01

[1] *Includes decrease in net earnings related to natural gas consumption.*
[2] *Includes impact of upstream and upgrading operations only.*
[3] *Relates to U.S. Refining & Marketing.*
[4] *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*
[5] *An interest rate change would not have an impact as Husky did not have variable rate debt outstanding as of September 30, 2008.*
[6] *U.S./Canadian dollar exchange rate at September 30, 2008.*
[7] *Excludes derivatives.*
[8] *Based on 849.3 million common shares outstanding as of September 30, 2008.*

3. Results of Operations

3.1 Upstream

Upstream Net Earnings Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2008**	2007	**2008**	2007
Gross revenues	**$ 3,032**	$ 1,803	**$ 8,366**	$ 5,394
Royalties	**691**	307	**1,772**	740
Net revenues	**2,341**	1,496	**6,594**	4,654
Operating and administration expenses	**407**	371	**1,200**	1,038
Depletion, depreciation and amortization	**369**	413	**1,111**	1,219
Other	**24**	(39)	**(28)**	(88)
Income taxes	**462**	235	**1,276**	753
Net earnings	**$ 1,079**	$ 516	**$ 3,035**	$ 1,732

Third Quarter

During the third quarter of 2008, upstream net revenues increased by $845 million compared with the same period in 2007. Higher crude oil, natural gas and sulphur prices more than offset lower sales volumes and higher royalties.

During the third quarter of 2008, our realized heavy crude oil and bitumen prices averaged 83% of our realized light crude oil and NGL prices versus 57% during the same period in 2007.

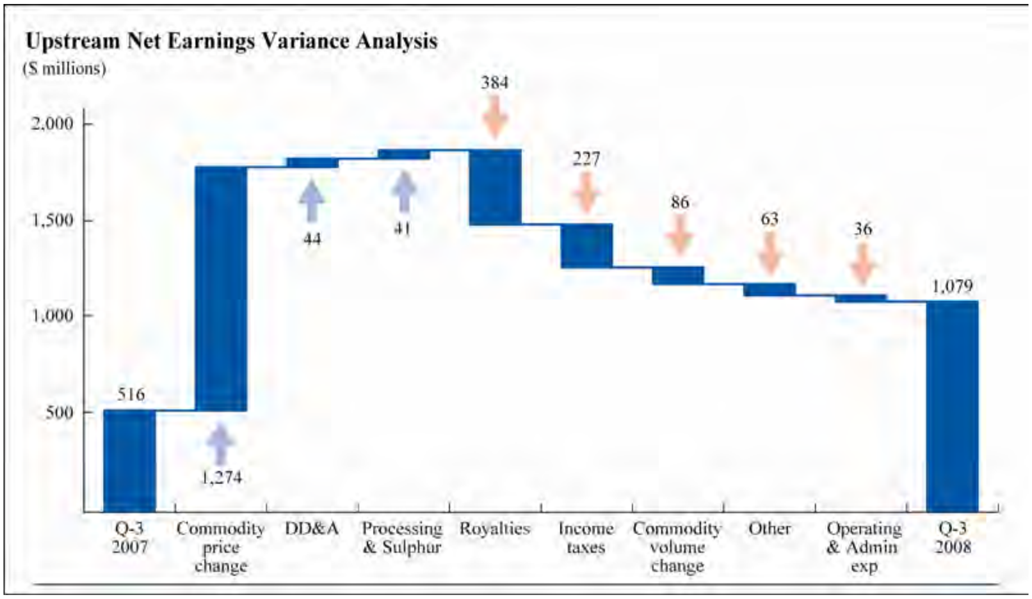
Nine Months

For the nine months ended September 30, 2008, upstream net revenues increased by $1,940 million compared with the same period in 2007. Higher crude oil, natural gas and sulphur prices more than offset lower volumes and higher royalties.

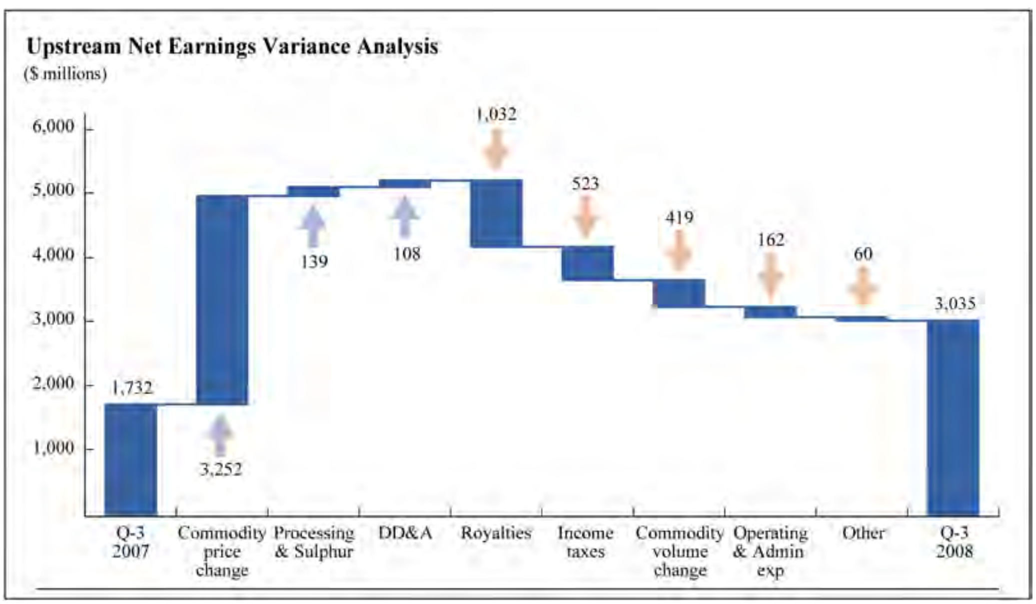
During the first nine months of 2008, our realized heavy crude oil and bitumen prices averaged 75% of our realized light crude oil and NGL prices versus 57% during the same period in 2007.

Upstream Net Earnings Variance Analysis

Third Quarter



Nine Months



Pricing

Average Sales Prices Realized		Three months ended Sept. 30		Nine months ended Sept. 30	
		2008	2007	**2008**	2007
Crude Oil	*($/bbl)*				
Light crude oil & NGL		**$ 114.85**	$ 76.00	**$ 110.72**	$ 70.49
Medium crude oil		**103.60**	54.55	**93.32**	49.69
Heavy crude oil & bitumen		**95.55**	43.64	**83.13**	39.84
Total average		**105.57**	60.91	**97.42**	56.59
Natural Gas	*($/mcf)*				
Average		**8.66**	5.18	**8.30**	6.34

Oil and Gas Production

Daily Gross Production		Three months ended Sept. 30		Nine months ended Sept. 30	
		2008	2007	**2008**	2007
Crude oil & NGL	*(mbbls/day)*				
Western Canada					
Light crude oil & NGL		**24.4**	25.1	**24.6**	26.8
Medium crude oil		**26.9**	26.7	**26.9**	27.1
Heavy crude oil & bitumen		**107.6**	106.5	**105.8**	106.6
		158.9	158.3	**157.3**	160.5
East Coast Canada					
White Rose - light crude oil		**72.7**	79.2	**71.9**	86.3
Terra Nova - light crude oil		**12.6**	16.3	**13.4**	15.4
China					
Wenchang - light crude oil & NGL		**12.0**	12.7	**12.1**	13.2
Total crude oil & NGL		**256.2**	266.5	**254.7**	275.4
Natural gas	*(mmcf/day)*	**598.3**	620.1	**602.2**	625.2
Total	*(mboe/day)*	**355.9**	369.9	**355.1**	379.6

Crude Oil and NGL Production

Third Quarter

In the third quarter of 2008, crude oil and NGL production decreased by 4% compared with the same period in 2007. On the East Coast, light oil production was lower due to the delayed start up of the eighth producing well at White Rose, which was a result of ice conditions in the second quarter, and a 4-day shut down due to offloading operational restrictions combined with tanker availability. At Terra Nova operational and maintenance issues also resulted in reduced production. White Rose was shut down for 16 days for scheduled maintenance in the third quarter of 2007.

Nine Months

In the first nine months of 2008, crude oil and NGL production decreased by 8% compared with the same period of the previous year. Production from the White Rose field was shut down for 11 days in April due to the encroachment of severe ice pack and iceberg conditions. In June 2008, Terra Nova was shut down for 14 days for a scheduled maintenance turnaround compared to near capacity production in the nine month period in 2007.

During the first nine months of 2008, crude oil and NGL production from Western Canada was down 2% compared with the first nine months of 2007 primarily due to high reservoir decline, development delays and shut-in facilities.

Natural Gas Production

Third Quarter

Production of natural gas decreased by 4% compared with the same period of the previous year. In 2007 a strategic decision was made to reduce drilling for natural gas in response to low natural gas prices and pending higher Alberta gas royalties. Higher reservoir declines were also a factor.

In the third quarter of 2008, 59% 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.

Nine Months

In addition to the factors affecting the third quarter, natural gas production was 4% lower in the first nine months of the year compared with the same period in 2007 due to severe cold weather in Western Canada in the first quarter of 2008.

Production Guidance

2008 Gross Production Guidance		Guidance	Nine months ended Sept. 30	Year ended Dec. 31
		2008	**2008**	2007
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		139 - 148	**122**	139
Medium crude oil		28 - 29	**27**	27
Heavy crude oil & bitumen		114 - 124	**106**	107
		281 - 301	**255**	273
Natural gas	*(mmcf/day)*	625 - 655	**602**	623
Total barrels of oil equivalent	*(mboe/day)*	385 - 410	**355**	377

Production for 2008 is expected to be 358 to 366 mbbls per day, five to seven percent below our guidance range.

Royalties

In the third quarter of 2008, royalty rates in Western Canada averaged 19% as a percentage of gross revenue, up from 15% in the third quarter of 2007.

In March 2008, the Tier II incremental royalty rate became effective for White Rose. As a result, East Coast offshore royalty rates averaged 31% as a percentage of gross revenue in the third quarter compared with 21% in the third quarter of 2007.

Royalty rates for the first nine months of 2008 averaged 17% in Western Canada and 29% offshore the East Coast compared with 15% and 11% respectively in 2007.

Unit Operating Costs

Third Quarter

In the third quarter of 2008, operating costs in Western Canada averaged $13.58/boe compared with $11.47/boe in the same period in 2007. Increasing operating costs in Western Canada are generally related to the nature of exploitation necessary to manage production from maturing fields and new more extensive but less prolific reservoirs. Western Canada operations require increasing amounts of infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive pipeline systems, crude and water trucking and more complex natural gas compression systems. These factors in turn require higher energy consumption, workovers and generally more material costs. In addition, higher levels of industry activity lead naturally to competition for resources and consequential higher service rates and unit costs. Our efforts are focused on managing rising operating costs with initiatives such as the establishment of a logistics support division to control the costs of transporting production. We strive to keep our infrastructure, including gas plants, crude processing plants, transportation systems, compression systems, lease access and other infrastructure fully utilized.

Operating costs at the East Coast offshore operations were $8 million lower in the third quarter of 2008 compared with the third quarter of 2007 and averaged $4.93/bbl compared with $5.34/bbl. In 2007 White Rose was shut down for 16 days for scheduled maintenance. Operating costs at the South China Sea offshore operations averaged $3.77/bbl in the third quarter of 2008 compared with $3.18/bbl in the same period in 2007, as a result of higher maintenance costs for the maturing field.

Nine Months

Total upstream unit operating costs in the first nine months of 2008 averaged $10.96/boe compared with $8.93/boe in the same period in 2007. In addition to the factors affecting the third quarter, operating costs were adversely affected in the first quarter by extreme cold weather in Western Canada, which resulted in increased costs for gas well servicing and methanol injection to deal with gas well freeze ups. In the second quarter operating costs increased compared with the previous year due to additional resources required to manage ice encroachment and subsurface mechanical issues on the East Coast.

Unit Depletion, Depreciation and Amortization

Third Quarter

Total unit DD&A averaged $11.27/boe in the third quarter of 2008 compared with $12.14/boe in the third quarter of 2007. In Canada, unit DD&A was $11.27/boe, a decrease of 4% from the third quarter of 2007. The lower DD&A rate in Canada was primarily due to the disposition of 50% of the Sunrise oil sands asset, which reduced the full cost base by approximately $1.6 billion or $1.72/boe in the third quarter of 2008. The Sunrise oil sands project currently does not have any proved reserves attributed to it.

Nine Months

For the first nine months of 2008, total unit DD&A averaged $11.43/boe compared with $11.76/boe during the same period in 2007. This was primarily due to the effect of the Sunrise disposition partially offset by a higher full cost base during the first nine months of 2008 compared with the first nine months of 2007.

Netback Analysis	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	**2008**	2007
	$	$	**$**	$
Total				
Crude oil equivalent *(per boe)* [(1)]				
Gross price	**90.54**	52.30	**83.95**	51.50
Royalties	**20.35**	9.02	**17.81**	7.13
Net sales price	**70.19**	43.28	**66.14**	44.37
Operating costs [(2)]	**11.20**	9.60	**10.96**	8.93
Operating netback	**58.99**	33.68	**55.18**	35.44
DD&A	**11.27**	12.14	**11.43**	11.76
Administration expenses and other [(2)]	**0.71**	(0.55)	**0.24**	(0.30)
Earnings before income taxes	**47.01**	22.09	**43.51**	23.98
Western Canada				
Crude oil *(per boe)* [(1)]				
Light crude oil				
Gross price	**98.38**	62.29	**92.02**	59.41
Royalties	**14.19**	7.39	**12.68**	6.61
Net sales price	**84.19**	54.90	**79.34**	52.80
Operating costs [(2)]	**8.75**	12.39	**13.11**	12.68
Operating netback	**75.44**	42.51	**66.23**	40.12
Medium crude oil				
Gross price	**100.95**	53.38	**90.92**	49.12
Royalties	**17.91**	9.45	**16.29**	8.60
Net sales price	**83.04**	43.93	**74.63**	40.52
Operating costs [(2)]	**15.72**	15.12	**15.48**	13.73
Operating netback	**67.32**	28.81	**59.15**	26.79
Heavy crude oil & bitumen				
Gross price	**94.88**	43.43	**82.57**	39.82
Royalties	**16.25**	5.52	**12.27**	5.07
Net sales price	**78.63**	37.91	**70.30**	34.75
Operating costs [(2)]	**16.41**	12.80	**15.77**	12.53
Operating netback	**62.22**	25.11	**54.53**	22.22
Natural gas *(per mcfge)* [(3)]				
Gross price	**8.99**	5.48	**8.66**	6.51
Royalties	**1.84**	0.95	**1.71**	1.26
Net sales price	**7.15**	4.53	**6.95**	5.25
Operating costs [(2)]	**1.82**	1.48	**1.60**	1.39
Operating netback	**5.33**	3.05	**5.35**	3.86
East Coast				
Light crude oil *(per boe)* [(1)]				
Gross price	**117.65**	76.97	**113.72**	72.32
Royalties [(4)]	**35.97**	16.07	**33.08**	7.89
Net sales price	**81.68**	60.90	**80.64**	64.43
Operating costs [(2)]	**4.93**	5.34	**5.22**	4.12
Operating netback	**76.75**	55.56	**75.42**	60.31
International				
Light crude oil *(per boe)* [(1)]				
Gross price	**114.80**	77.48	**115.19**	73.54
Royalties	**39.42**	14.24	**34.22**	12.97
Net sales price	**75.38**	63.24	**80.97**	60.57
Operating costs [(2)]	**4.12**	3.18	**4.64**	3.72
Operating netback	**71.26**	60.06	**76.33**	56.85

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

Other Items

During the third quarter of 2008, a $24 million loss was recorded on an embedded derivative related to a drilling rig contract requiring payment in U.S. currency. This compares with a $39 million gain in the third quarter of 2007. A loss of $41 million was recorded in the first nine months of 2008 compared with a gain of $88 million for the same period in 2007. The payments required under this contract are expected to occur over the three-year period from late 2008. The amount will fluctuate with the U.S./Canadian forward exchange rate until actual contract settlement. Contracts to purchase U.S. currency had been entered into to offset approximately 60% of this derivative. During the third quarter of 2008, the Company unwound one of the contracts realizing a gain of $12 million. At September 30, 2008, the remaining contracts offset approximately 40% of the derivative (Refer to Note 16 to the Consolidated Financial Statements).

Other items also include a gain of $69 million on the sale of 50% of Husky Oil (Madura) Limited to CNOOC Ltd. in the second quarter of 2008.

Upstream Capital Expenditures

At September 30, 2008, our overall upstream capital expenditures were 78% of the 2008 capital expenditure guidance. Our major upstream projects remain essentially on schedule and their ultimate completion dates are expected to be maintained.

Capital Expenditures Summary [1]	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2008**	2007	**2008**	2007
Exploration				
Western Canada	**$ 167**	$ 97	**$ 476**	$ 338
East Coast Canada and Frontier	**49**	28	**94**	33
Northwest United States	**50**	-	**50**	-
International	**53**	21	**115**	46
	319	146	**735**	417
Development				
Western Canada	**407**	354	**1,270**	1,099
East Coast Canada	**257**	45	**398**	161
International	**-**	-	**3**	5
	664	399	**1,671**	1,265
	$ 983	$ 545	**$ 2,406**	$ 1,682

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

During the first nine months of 2008, capital expenditures were $1,746 million (73%) in Western Canada, $492 million (20%) off the East Coast of Canada, $50 million (2%) in the Northwest United States and $118 million (5%) offshore China and Indonesia.

The following table discloses the number of gross and net exploration and development wells we completed in Western Canada and the oil sands during the periods indicated. Ninety-one percent of the net exploration wells and 96% of the net development wells we drilled in the third quarter of 2008 resulted in wells capable of commercial production as compared with 95% and 97% respectively in the third quarter of 2007.

Western Canada and Oil Sands Wells Drilled		Three months ended Sept. 30				Nine months ended Sept. 30			
		2008		2007		**2008**		2007	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**10**	**10**	23	23	**38**	**36**	56	56
	Gas	**17**	**11**	16	13	**81**	**64**	85	72
	Dry	**3**	**2**	3	2	**23**	**21**	13	12
		30	**23**	42	38	**142**	**121**	154	140
Development	Oil	**262**	**211**	221	203	**455**	**388**	417	387
	Gas	**157**	**88**	67	54	**292**	**192**	241	195
	Dry	**13**	**13**	7	7	**16**	**16**	19	19
		432	**312**	295	264	**763**	**596**	677	601
Total		**462**	**335**	337	302	**905**	**717**	831	741

Western Canada - Excluding Oil Sands

During the first nine months of 2008, we invested $1,489 million on exploration and development throughout the Western Canada Sedimentary Basin excluding oil sands. Of this, $386 million was invested on oil development and $246 million was invested on natural gas development. We drilled 709 net wells in the basin during the first nine months of 2008, resulting in 416 net oil wells and 256 net natural gas wells. In addition, $128 million was spent on production optimization and operating cost reduction initiatives. Capital spending on facilities, land acquisition and retention and environmental protection amounted to $168 million. During the first nine months of 2008, $294 million was spent to acquire producing properties.

Our high impact exploration program is conducted along the foothills of Alberta and British Columbia and in the deep basin region of Alberta. In the first nine months of 2008, we invested $241 million on drilling in these natural gas prone areas. During this period we drilled 26 net exploration wells in the foothills and deep basin regions; 19 were cased as natural gas wells. The remaining 95 net exploration wells were drilled primarily in the shallow regions of the Western Canada Sedimentary Basin.

Oil Sands

Oil sands capital expenditures totalled $257 million during the first nine months of 2008. At Tucker, we spent $107 million on drilling new well pairs, facility modification and new pad preparation. At Sunrise, we spent $108 million on engineering design, site preparation and facilities and equipment requisitions. At Caribou and Saleski we spent $42 million on project development.

East Coast Development

During the first nine months of 2008, we spent $398 million primarily for the North Amethyst and West White Rose tie-back development projects and the completion of an infill production well and other capital enhancements at White Rose. Construction commenced on North Amethyst and long lead equipment was procured. Engineering design began for the West White Rose development and infill drilling commenced at the White Rose South Avalon field.

East Coast and Northwest Territories Exploration

During the first nine months of 2008, we spent $94 million on two exploration wells in the Central Mackenzie Valley and on our East Coast seismic program.

Northwest United States

On September 30, 2008, we invested $50 million to acquire petroleum and natural gas rights in the Columbia River Basin located in southeastern Washington and northeast Oregon and a 50% interest in an exploration well currently being drilled.

International

During the first nine months of 2008, we spent $115 million on exploration drilling in the South China Sea and seismic data acquisition on the East Bawean II exploration block in the Java Sea.

2008 Guidance

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

2008 Capital Expenditure Guidance *[(1)] [(2)]*

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

[(1)] Excludes capitalized administrative costs and capitalized interest.
[(2)] Upstream capital expenditures for the nine months ended September 30 were $2,406 million.

3.2 Midstream

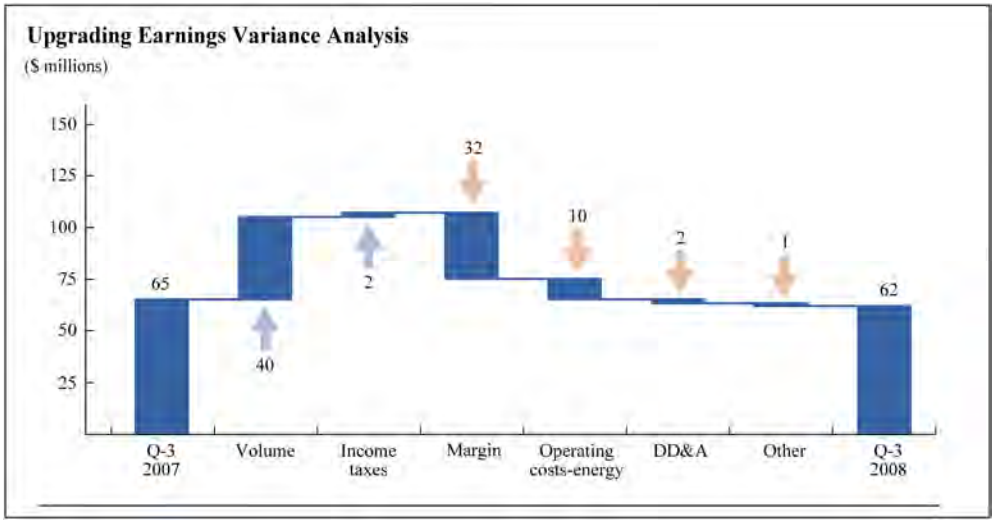
Upgrading Net Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2008**	2007	**2008**	2007
Gross margin		**$ 163**	$ 155	**$ 502**	$ 382
Operating and administration expenses		**65**	55	**195**	160
Other recoveries		**-**	(1)	**(2)**	(3)
Depreciation and amortization		**9**	7	**22**	17
Income taxes		**27**	29	**86**	63
Net earnings		**$ 62**	$ 65	**$ 201**	$ 145
Selected operating data:					
Upgrader throughput [(1)]	*(mbbls/day)*	**79.3**	67.4	**66.8**	57.5
Synthetic crude oil sales	*(mbbls/day)*	**69.1**	55.1	**58.8**	48.6
Upgrading differential	*($/bbl)*	**$ 26.09**	$ 30.41	**$ 27.94**	$ 27.94
Unit margin	*($/bbl)*	**$ 25.60**	$ 30.63	**$ 31.10**	$ 28.78
Unit operating cost [(2)]	*($/bbl)*	**$ 8.93**	$ 8.93	**$ 10.62**	$ 10.21

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

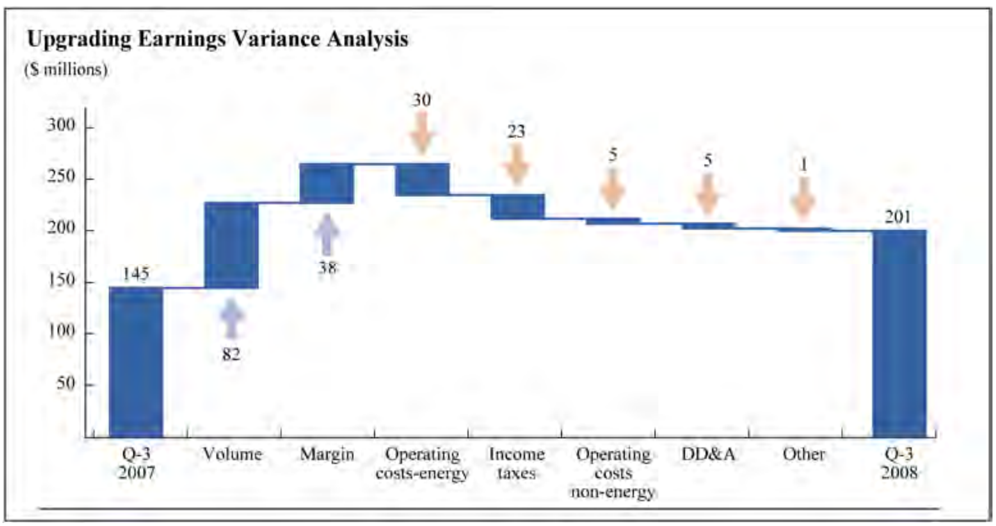
The upgrading business segment adds value by processing heavy sour crude oil into high value synthetic crude oil and low sulphur distillates. The upgrader profitability is primarily dependent on the differential between the cost of heavy crude feedstock and the sales price of synthetic crude oil.

Upgrading Net Earnings Variance Analysis

Third Quarter



Nine Months



Third Quarter

During the third quarter of 2008, the upgrading differential averaged $26.09/bbl, a decrease of $4.32 compared with the same period in 2007. The differential is equal to Husky Synthetic Blend, which sells at a premium to West Texas Intermediate, less Lloyd Heavy Blend. During the third quarter of 2008, the overall unit margin was 16% lower than the previous year due to the lower upgrading differential, partially offset by the addition of higher value low sulphur off-road diesel to the upgrader's product stream and higher sulphur prices.

Upgrader throughput was 18% higher in the third quarter of 2008 compared with the same period in 2007. In 2007, the upgrader was operating one hydrocracker train at lower rates due to maintenance requirements. Unit operating costs were unchanged in the third quarter of 2008 compared with 2007.

Nine Months

During the first nine months of 2008, upgrading earnings were 39% higher than the year earlier. In addition to the factors affecting the third quarter, upgrader throughput was 16% higher in the nine-month period of 2008 compared with the same period in 2007. In 2007, throughput was lower due to a 49-day scheduled turnaround and installation of new coke drums during the second quarter. Throughput was below capacity during 2008 due to a temporary shutdown to replace the hydrogen plant catalyst during the second quarter.

Infrastructure and Marketing Net Earnings Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)	**2008**	2007	**2008**	2007
Gross margin - pipeline	**$ 32**	$ 33	**$ 101**	$ 87
- other infrastructure and marketing	**34**	71	**213**	191
	66	104	**314**	278
Operating and administration expenses	**3**	3	**10**	7
Depreciation and amortization	**8**	7	**23**	21
Income taxes	**17**	30	**85**	78
Net earnings	**$ 38**	$ 64	**$ 196**	$ 172
Selected operating data:				
Aggregate pipeline throughput *(mbbls/day)*	**494**	506	**512**	502

Third Quarter

Infrastructure and marketing net earnings in the third quarter of 2008 were $38 million compared with $64 million in the third quarter of 2007. Lower earnings were primarily due to lower brokering margins on crude oil and natural gas, as commodity prices decreased through the latter part of the third quarter of 2008, and declining gas storage spreads. The pipeline and infrastructure business was a stabilizing factor with consistent margins year over year.

Nine Months

During the first nine months of 2008, infrastructure and marketing earnings were 14% higher than the previous year primarily due to higher brokering margins on crude oil and sulphur during the first half of 2008.

Midstream Capital Expenditures

Midstream capital expenditures totalled $112 million in the first nine months of 2008. At the Lloydminster upgrader we spent $76 million, primarily for contingent consideration and facility reliability projects. The remaining $36 million was spent on the pipeline extension between Lloydminster and Hardisty, Alberta.

3.3 Downstream

Canadian Refined Products Net Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2008**	2007	**2008**	2007
Gross margin - fuel sales		**$ 30**	$ 39	**$ 118**	$ 144
- ancillary sales		**9**	12	**33**	31
- asphalt sales		**37**	82	**84**	131
		76	133	**235**	306
Operating and administration expenses		**19**	19	**45**	57
Depreciation and amortization		**21**	16	**61**	47
Income taxes		**11**	31	**39**	62
Net earnings		**$ 25**	$ 67	**$ 90**	$ 140
Selected operating data:					
Number of fuel outlets				**496**	502
Light oil sales	*(million litres/day)*	**8.3**	9.0	**8.0**	8.8
Light oil retail sales per outlet	*(thousand litres/day)*	**13.4**	13.8	**13.1**	13.2
Prince George refinery throughput	*(mbbls/day)*	**7.9**	10.8	**9.9**	10.1
Asphalt sales	*(mbbls/day)*	**33.9**	25.9	**24.9**	20.9
Lloydminster refinery throughput	*(mbbls/day)*	**27.3**	29.0	**25.2**	24.1
Ethanol production	*(thousand litres/day)*	**598.2**	323.5	**615.7**	317.0

Canadian Refined Products

Third Quarter

Throughput at the Prince George refinery was 27% lower in the third quarter of 2008 compared with the third quarter of 2007 due to the scheduled shut down in September 2008 for maintenance. Sales volumes were further impacted due to supply shortages from our third party suppliers caused by refinery outages.

Third quarter 2008 ethanol production increased 85% due to the start-up of the Minnedosa ethanol plant, which commenced operations at the end of 2007. This was offset by a 38% reduction in margins in 2008 due to the increase in corn prices, reduced demand and higher natural gas prices.

Asphalt sales volumes were 31% higher in the third quarter of 2008 compared with the same period in 2007 as a result of higher demand and good weather. This was more than offset by a decrease in product margins of approximately 55% due to the increase in heavy crude oil feedstock costs. Additional value was captured in the quarter from higher volumes of residuals and distillates produced at the Lloydminster refinery and processed at the Lloydminster upgrader into low sulphur off-road diesel and synthetic crude oil.

Nine Months

During the first nine months of 2008, earnings from gasoline and diesel were lower when compared to the same period in 2007 as a result of the same factors affecting the third quarter. Earnings from ethanol sales were higher than the previous year due to higher sales volume partially offset by lower margins. Margins on asphalt products were lower than those of the same period in the previous year due to rising crude oil feedstock costs.

U.S. Refining and Marketing Net Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2008**	2007	**2008**	2007
Gross refining margin		**$ 105**	$ 155	**$ 590**	$ 155
Processing costs		**110**	45	**269**	45
Operating and administration expenses		**5**	-	**7**	-
Interest - net		**1**	1	**2**	1
Depreciation and amortization		**42**	22	**104**	22
Income taxes		**(19)**	33	**75**	33
Net earnings		**$ (34)**	$ 54	**$ 133**	$ 54
Selected operating data:					
Lima Refinery throughput	*(mbbls/day)*	**132.8**	140.3	**136.4**	140.3 [(2)]
Toledo Refinery throughput	*(mbbls/day)*	**53.8**	-	**59.9 [(1)]**	-

[(1)] *The Toledo Refinery operating results are included from March 31, 2008, the date the acquisition was completed. Throughput represents six months of operations.*
[(2)] *The Lima Refinery operating results are included from July 1, 2007, the date the acquisition was completed. Throughput represents three months of operations.*

U.S. Refining and Marketing

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

On March 31, 2008, we completed a transaction that resulted in the formation of two joint entities forming an integrated oil sands business. The downstream entity is a 50% interest in the BP Toledo Refinery, which has a crude distillation capacity of 150 mbbls/day. The second and third quarters of 2008 are the first periods that the BP/Husky Toledo Refinery's results of operations have been reflected in our earnings.

Third Quarter

Refining crack spread margins at the start of the quarter were low with pressure on gasoline crack spreads partially offset by firmer distillate spreads. Low gasoline margins resulted in lower crude throughputs at Lima. Crude supply disruptions associated with hurricanes Gustav, Hanna and Ike widened spreads but impacted crude oil feedstock availability. Toledo was also limited in its ability to capitalize on wider sweet/sour differentials as production was impacted by planned process unit outages to complete priority maintenance and turnaround activities.

Nine Months

During the first nine months of 2008, earnings from the U.S. Refining and Marketing segment reflect a full nine months of operations from the Lima Refinery and operations from the Toledo Refinery from April 1, 2008.

In the downstream sector, the drop in demand for motor fuels that began in mid-2007 continued through the first nine months of 2008, in line with U.S. economic conditions and record high fuel prices. Lower consumption combined with higher product stocks resulted in narrow refinery crack spreads. Crack spreads improved in the second quarter primarily on distillates, which were in high demand globally. In the third quarter distillate margins continued to be stronger than gasoline margins and we continued to optimize refinery throughput toward distillate production to maximize margins.

Downstream Capital Expenditures

Downstream capital expenditures totalled $155 million during the first nine months of 2008.

In Canada capital expenditures totalled $92 million, $58 million for retail network remodelling, automation and facility upgrades, $18 million for upgrades and environmental protection at the Prince George and Lloydminster refineries, $13 million for upgrades at the Minnedosa and Lloydminster ethanol plants and $3 million for asphalt distribution and processing upgrades.

In the United States capital expenditures totalled $63 million, $28 million at the Lima Refinery for the front-end engineering design for an isocracker debottleneck project and for various environmental protection and facility upgrades. At the Toledo Refinery capital expenditures totalled $35 million primarily for environmental protection and facility upgrades.

3.4 Corporate

Corporate Summary	Three months ended Sept.30		Nine months ended Sept. 30	
(millions of dollars) income (expense)	**2008**	2007	**2008**	2007
Intersegment eliminations - net	**$ 123**	$ 23	**$ (14)**	$ (35)
Administration expenses	**5**	(3)	**(85)**	(96)
Depreciation and amortization	**(8)**	(6)	**(22)**	(18)
Interest - net	**(28)**	(46)	**(114)**	(89)
Foreign exchange	**76**	20	**60**	57
Income taxes	**(66)**	15	**42**	78
Net earnings (loss)	**$ 102**	$ 3	**$ (133)**	$ (103)

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

In the third quarter of 2008, administration expenses included a stock-based compensation recovery of $44 million compared with a $16 million recovery in the same period in 2007. The decrease in net interest expense during the third quarter of 2008 compared with a year earlier was primarily due to retirement of debt in the second and third quarters of 2008. Additional debt was issued during 2007 for the acquisition of the Lima Refinery.

Foreign Exchange Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2008**	2007	**2008**	2007
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**$ 35**	$ (73)	**$ 69**	$ (188)
Cross currency swaps	**(14)**	23	**(25)**	59
Contribution receivable	**(48)**	-	**(37)**	-
Other (gains) losses	**(49)**	30	**(67)**	72
	$ (76)	$ (20)	**$ (60)**	$ (57)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.982**	U.S. $0.940	**U.S. $1.012**	U.S. $0.858
At end of period	**U.S. $0.944**	U.S. $1.004	**U.S. $0.944**	U.S. $1.004

Corporate Capital Expenditures

Corporate capital expenditures totalled $33 million in the first nine months of 2008 primarily for office and information system upgrades.

Consolidated Income Taxes

During the third quarter of 2008, consolidated income taxes consisted of $266 million of current taxes and $298 million of future taxes compared with current taxes of $99 million and future taxes of $244 million in the same period of 2007. The increase in current taxes in the third quarter of 2008 compared with the third quarter of 2007 was due to the deferral of White Rose income in 2007. The increase in future taxes in the third quarter of 2008 compared with the same period in 2007 was due to an increase in earnings.

4. Liquidity and Capital Resources

During the third quarter of 2008, cash flow from operating activities financed all of our capital requirements, dividend payment and repayment of debt. Husky maintained its strong position with debt of $1.7 billion offset by cash on hand of $966 million for $753 million of net debt. In addition, at September 30, 2008 we had $1.5 billion in unused committed credit facilities.

Cash Flow Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except ratios)	**2008**	2007	**2008**	2007
Cash flow - operating activities	**$ 2,091**	$ 1,298	**$ 5,372**	$ 3,106
- financing activities	**$ (751)**	$ 1,725	**$ (2,069)**	$ 1,049
- investing activities	**$ (910)**	$ (3,149)	**$ (2,545)**	$ (4,590)
Financial Ratios				
Debt to capital employed *(percent)*			**10.8**	20.9
Corporate reinvestment ratio *(percent)* (1) (2)			**48**	90

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

4.1 Operating Activities

In the third quarter of 2008, cash generated from operating activities amounted to $2.1 billion compared with $1.3 billion in the third quarter of 2007. Higher cash flow from operating activities was primarily due to higher upstream commodity prices, upgrading sales volumes and lower interest. This was partially offset by lower U.S. refining and marketing income, crude oil and sulphur brokering income, higher cost of sales, operating and administrative expenses and cash taxes.

4.2 Financing Activities

In the third quarter of 2008, cash used in financing activities was $751 million compared with cash provided by financing activities of $1.7 billion in the third quarter of 2007. $474 million was used to repay capital securities and debt. In July 2007, cash provided was used to acquire the Lima Refinery. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

4.3 Investing Activities

In the third quarter of 2008, cash used in investing activities amounted to $910 million compared with $3.1 billion in the third quarter of 2007. Cash invested in both periods was used primarily for capital expenditures, with $2.6 billion in 2007 for the Lima Refinery.

4.4 Sources of Capital

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

Working capital is the amount by which current assets exceed current liabilities. At September 30, 2008, our working capital was $1.8 billion compared with a working capital deficiency of $51 million at December 31, 2007. In addition to increases in cash balances, working capital increased due to higher feedstock and refined product inventories, higher accounts receivable at our U.S. refining operations due to the inclusion of the Toledo Refinery and higher accounts receivable for our Canadian crude oil production. The higher working capital from cash, accounts receivable and inventories was partially offset by higher accounts payable, primarily for U.S. refinery feedstock purchases and higher income taxes payable resulting from higher taxable income.

(millions of dollars)	**Sept. 30 2008**	Dec. 31 2007	Change	
Current assets				
Cash and cash equivalents	**$ 966**	$ 208	$ 758	Strong earnings and cash flow
Accounts receivable	**2,152**	1,622	530	Higher crude oil prices
Inventories	**1,629**	1,190	439	Inclusion of Toledo inventory; increased Lima inventory
Prepaid expenses	**60**	28	32	
	4,807	3,048	1,759	
Current liabilities				
Accounts payable	**1,779**	1,460	(319)	Higher crude oil and gas prices; higher royalties; inclusion of Toledo Refinery
Accrued interest payable	**24**	20	(4)	
Income taxes payable	**301**	36	(265)	Higher taxable income
Other accrued liabilities	**930**	842	(88)	Higher dividend payable offset by lower stock compensation liability
Long-term debt due within one year	**-**	741	741	Repayment of bridge financing
	3,034	3,099	65	
Working capital (deficiency)	**$ 1,773**	$ (51)	$ 1,824	

Capital Structure

(millions of dollars)	September 30, 2008 Outstanding	Available
Total short-term and long-term debt	$ 1,719	$ 1,641
Common shares, retained earnings and accumulated other comprehensive income	$ 14,256	

At September 30, 2008, we had unused committed long and short-term borrowing credit facilities totalling $1.5 billion. A total of $129 million of our short-term borrowing credit facilities were used in support of outstanding letters of credit.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility available of $10 million for general purposes. Our 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 period that the prospectus was effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of the date of this MD&A, U.S. $750 million of debt securities had been issued under this shelf prospectus.

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

On August 29, 2008, Husky redeemed the 6.95% medium-term notes - Series E due July 14, 2009. The principal amount was $200 million and the redemption price, including accrued interest, totalled $208 million.

During September 2008, Husky repurchased U.S. $43 million of the outstanding U.S. $450 million 6.80% notes due September 2037. On October 8, 2008, an additional U.S. $20 million was repurchased.

4.5 Credit Ratings

On March 31, 2008, DBRS upgraded our Senior Unsecured Notes and Debentures to A (low).

Our other credit ratings, which remain unchanged, are available in our 2007 filed Annual Information Form at www.sedar.com.

4.6 Contractual Obligations and Commercial Commitments

Refer to Husky's 2007 annual and 2008 interim Management's Discussion and Analysis under the caption "Liquidity and Capital Resources," which summarizes contractual obligations and commercial commitments. At September 30, 2008, we had $435 million of additional contractual obligations, which are expected to be settled in the following periods: 2009 - $202 million; 2010 - $56 million; 2011 - $43 million; 2012 - $14 million and thereafter - $120 million. Exploration and development offshore Newfoundland accounted for 86% of these contractual obligations.

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

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

4.8 Transactions with Related Parties

TransAlta Power, L.P. is an indirect subsidiary of Cheung Kong Infrastructure Holdings Ltd., which is majority owned by Hutchison Whampoa Limited, which owns 100% of U.F. Investments (Barbados) Ltd., a 34.58% shareholder in Husky. TransAlta Power, L.P. is a 49.99% owner of TransAlta Cogeneration, L.P., our partner in the Meridian cogeneration plant in Lloydminster, Saskatchewan. We sell natural gas to the Meridian cogeneration plant and other cogeneration plants owned by TransAlta Power, L.P. We received the market price or negotiated medium-term contracts based on market-related terms for these commodities. During the first nine months of 2008, we sold $31 million of natural gas to TransAlta Power, L.P.

5. Capability to Deliver Results and the Strategic Plan

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

In summary, our strategy is to continue to exploit oil and gas assets in Western Canada while expanding into new areas with large scale sustainable growth potential. Our plans include projects in Canada (the

Alberta oil sands, the basins offshore Canada's East Coast and in the Central Mackenzie River Valley), Asia (the South China Sea, the Madura Strait and the East Java Sea) and offshore Greenland. In the midstream and downstream sectors we are enhancing performance and maximizing the value chain through integrating our businesses, optimizing plant operations and expanding plant and infrastructure.

6. Key Growth Highlights

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

Upstream

White Rose Development and Delineation

At the North Amethyst tie-back development project, the *Henry Goodrich* semi-submersible rig completed drilling a delineation well in early October. The *Henry Goodrich* has moved to the West White Rose tie-back project to drill a further stratigraphic test well. The South White Rose extension, the smaller of the satellite tie-back developments, was approved by the federal and provincial governments in September 2007 and is expected to augment production following completion of the North Amethyst and West White Rose tie-back projects.

East Coast Exploration

In September 2008, we acquired two exploration blocks on the Labrador Shelf off the coast of Labrador. Parcel NL07-2-1 is 585,580 acres with a work commitment of $10.2 million (100% Husky working interest) and Parcel NL07-2-3 is 557,502 acres with a work commitment of $120.2 million (75% Husky working interest). The work commitment will be undertaken during the first six years of the nine-year term of the Exploration Licence. We also hold a 17.1% interest in the Bjarni and North Bjarni Significant Discovery Licences ("SDL"), which are located adjacent to the NL07-2-3 parcel and the Gudrid SDL, which is located adjacent to the NL07-2-1 parcel.

Our 3-D seismic program covering 2,150 square kilometres in the Jeanne d'Arc Basin was completed and the results are being evaluated.

Drilling of an exploration well (35% working interest) in the Flemish Pass Basin, Exploration Licence ("EL") 1049, is expected to commence in the fourth quarter of 2008 following completion of the West White Rose stratigraphic test well.

Offshore Greenland

The acquisition of 7,000 kilometres of 2-D seismic on Blocks 5 and 7 is now complete. Husky is the operator and holds an 87.5% interest in these two blocks. We also hold a 43.75% working interest in Block 6. The acquisition of 3,000 kilometres of 2-D seismic on this block is now complete. The hi-resolution aero-gravity and magnetic survey covering Husky's blocks has been postponed for the year due to weather issues. The survey was approximately 77% complete and is expected to resume in 2009.

Offshore China Exploration

The *West Hercules* deep water drilling rig, currently undergoing commissioning and acceptance trials is expected to be delivered by the end of October and is expected to commence drilling at the Liwan field on Block 29/26 in the South China Sea in November 2008. The initial drilling program will include four delineation wells and two exploration wells. Due to the late arrival of the *West Hercules* rig, previous plans to drill an exploration well on Block 39/05 have been rescheduled.

Processing of 3-D seismic data acquired on Block 29/26, including the Liwan vicinity, and Block 29/06, is expected to be completed in the fourth quarter. Front-end engineering design activity at Liwan is currently being tendered and we expect to commence work prior to year-end. We are working to secure a shallow water drilling rig for a multi-well program on Blocks 35/18 and 50/14, which are located west of Hainan Island in the Yingge Hai Basin.

In August 2008, we relinquished all but 58 square kilometres of Block 39/05, which surrounds the Wenchang oil fields, and secured an extension of Phase III exploration commitments. We are currently securing a semi-submersible drilling rig for this well and expect to commence drilling in December 2008.

Subsequent to the evaluation of the Wushi 23-2-1 exploration well and fulfillment of our Phase II exploration commitments on Block 23/15 in the Beibu Wan Basin, we will not proceed with Phase III and have relinquished the remainder of this block.

Indonesia Exploration and Development

In April 2008, we completed an agreement with CNOOC Ltd. to jointly develop the Madura BD gas and natural gas liquids field located offshore East Java, Indonesia. Under the agreement, CNOOC Ltd. acquired a 50% equity interest and operatorship of Husky Oil (Madura) Limited, which holds a 100% interest in the Madura Strait Production Sharing Contract ("PSC"). The agreement covers the development and further exploration of the Madura Strait PSC. The Madura BD field development plan has been approved by the government of Indonesia and we expect the Madura PSC extension to be approved by the end of the fourth quarter.

In the East Bawean II PSC, in which we hold a 100% interest, the *Transocean Adriatic XI* jack up rig has been secured to drill two exploration wells in the second quarter of 2009.

Husky has been awarded a PSC from the government of Indonesia for a 100% interest in the North Sambawa II Block in the East Java Sea.

United States

On September 30, 2008 we entered into a joint venture agreement to acquire a 50% working interest in 844,000 net acres of leasehold ownership and wells in the Columbia River Basin in southeast Washington and northeast Oregon for consideration of approximately U.S. $100 per acre for 422,000 acres. The basin is characterized by over-pressure, tight sand natural gas formations.

Tucker Oil Sands Project

Optimization strategies to enhance the ramp-up of production continued in the third quarter. Three wells on Pad A, modified to improve the effectiveness of steam heating of the reservoir, commenced steaming during the third quarter. Pad C commenced production from six of the eight new well pairs. Two of the pairs commenced production in July and four in September. Steaming on the two remaining well pairs on Pad C is continuing. Drilling on the new Pad D is planned in 2009 utilizing experience gained from work currently underway on Pads A and C.

Sunrise Oil Sands Project

The development of the Sunrise oil sands project (Husky 50%) will proceed in multiple phases. The first development phase will produce 60 mbbls/day of bitumen. Phase one production is expected to commence approximately four years following project sanction. The second and third phases are targeted to increase the production capacity to approximately 200 mbbls/day of bitumen by 2015 to 2020, subject to corporate sanction.

McMullen Development

Planning for the development of the McMullen property located in the west central region of the Athabasca oil sands of northern Alberta is progressing. We received approval to drill 18 cold production wells and began drilling in October. In addition, we began drilling test wells in early October as part of a pilot project to test thermal recovery techniques.

Western Canada

Husky's Alkaline Surfactant Polymer ("ASP") enhanced oil recovery program, which currently includes ASP developments at Gull Lake and Fosterton, Saskatchewan and operating ASP applications at Warner and Crowsnest, Alberta, continues to move forward. Start up of the Gull Lake project is planned for the second quarter of 2009. The front-end engineering design for the Fosterton ASP project has been approved and sanctioned in the third quarter of 2008. Husky holds a 62.4% working interest.

Drilling at the Trident coal bed methane development (50% working interest) has resumed after weather related delays. During the first nine months of 2008, 60 gross wells were completed. We expect to complete our 100 to 120 gross well program by year-end or during the first quarter of 2009.

In the Lloydminster heavy oil producing area, we continue to test various enhanced recovery techniques. In August we began CO_2 injection at our second cold solvent pilot project. This pilot project is designed to test oil recovery and production rates utilizing CO_2 and propane.

Downstream

Lima, Ohio Refinery

An engineering evaluation has been completed to determine the reconfiguration of the Lima Refinery to increase its capacity to process heavier, less costly, crude oil feedstocks; realize complex refining processes to enhance margins; and increase flexibility in product outputs. The current configuration at the Lima Refinery allows it to process a predominantly light sweet crude oil feedstock. This limits our ability to process a lower cost heavier crude feedstock to meet seasonal and longer term market demands.

Toledo, Ohio Refinery

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

7. Risk Management

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

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

Interest Rate Risk Management

In the first nine months of 2008, interest rate risk management activities resulted in an increase 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 nine months of 2008, these swaps resulted in an offset to interest expense amounting to less than $1 million. The interest rate swaps were discontinued as a fair value hedge on August 29, 2008 given the $200 million medium-term notes were redeemed. For the remainder of 2008, the fair value changes will be included in other expenses.

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

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

Foreign Currency Risk Management

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

- U.S. $150 million at 6.25% swapped at $1.41 to $212 million at 7.41% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.19 to $90 million at 5.65% until June 15, 2012.
- U.S. $50 million at 6.25% swapped at $1.17 to $59 million at 5.67% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.17 to $88 million at 5.61% until June 15, 2012.

At September 30, 2008, we had the following freestanding derivatives in place where Husky had entered into forward purchases of U.S. dollars to partially offset exposure on an embedded derivative (refer to Note 16 to the Consolidated Financial Statements):

- U.S. $107 million bought at $0.9854 for $117 million from January 2008 to June 2011.
- U.S. $107 million bought at $0.9772 for $116 million from January 2008 to June 2011.

At September 30, 2008, the cost of a U.S. dollar in Canadian currency was $1.0599.

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 September 30, 2008, 100% or $1.7 billion of our long-term debt was denominated in U.S. dollars. The percentage of our long-term debt exposed to the U.S./Canadian exchange rate decreases to 78% when cross currency swaps are considered.

Effective July 1, 2007, our U.S. $1.5 billion of debt financing related to the Lima acquisition was designated as a hedge of the net investment in the U.S. refining operations, which are considered self-sustaining. During the second quarter of 2008, we repaid our bridge financing of U.S. $750 million. In the third quarter of 2008, the Company repurchased U.S. $43 million of bonds that were classified as a net investment hedge. As a result, the net investment hedge is limited to the remaining U.S. $707 million. As at September 30, 2008, unrealized foreign exchange losses arising from the translation of the debt were $66 million, net of tax of $12 million which was recorded in "Other Comprehensive Income."

8. Critical Accounting Estimates

Certain of our accounting policies require that we make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. For a discussion about those accounting policies, please refer to our Management's Discussion and Analysis for the year ended December 31, 2007, available at www.sedar.com.

9. Accounting Policies

New Accounting Standards Adopted

As disclosed in Management's Discussion and Analysis for the year ended December 31, 2007, on January 1, 2008, we adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3031 "Inventories", Section 3863 "Financial Instruments – Presentation", Section 3862

"Financial Instruments – Disclosures" and Section 1535 "Capital Disclosures." The adoption of these standards has had no material impact on Husky's net earnings or cash flows. Additional information on the effects of the adoption of these standards can be found in Notes 3, 4 and 5 to the Interim Consolidated Financial Statements.

Recent Accounting Pronouncements

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 recognizes costs as assets in accordance with CICA Section 1000, "Financial Statement Concepts." Moreover, Section 3064 will eliminate the current practice of recognizing as assets, items that do not meet the Section 1000 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. The Company is currently determining the impact of this standard.

In January 2006, the Canadian Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of the AcSB's strategic plan, Canadian publicly accountable entities will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian generally accepted accounting principles ("GAAP") for years beginning on or after January 1, 2011. An omnibus exposure draft was issued by the AcSB in the second quarter of 2008, which incorporates IFRS into the CICA Handbook and prescribes the transitional provisions for adopting IFRS. Currently, we are assessing the effects of adoption and developing a plan accordingly. We will continue to monitor any changes in the adoption of IFRS and will update plans as necessary.

10. Outstanding Share Data

(in thousands)	October 17 2008	December 31 2007
Issued and outstanding		
Number of common shares	849,329	848,960
Number of stock options	29,875	30,131
Number of stock options exercisable	7,013	4,494

11. Reader Advisories

This MD&A should be read in conjunction with the Consolidated Financial Statements and related Notes. Readers are encouraged to refer to Husky's MD&A and Consolidated Financial Statements and 2007 Annual Information Form filed in 2008 with Canadian regulatory agencies and Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and at www.huskyenergy.com.

Use of Pronouns and Other Terms Denoting Husky

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended September 30, 2008 are compared with results for the three months ended September 30, 2007 and results for the nine months ended September 30, 2008 are compared with results for the nine months ended September 30, 2007. Discussions with respect to Husky's financial position as at September 30, 2008 are compared with its financial position at December 31, 2007.

Additional Reader Guidance

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

Non-GAAP Measures

Disclosure of Cash Flow from Operations

Management's Discussion and Analysis contains the term "cash flow from operations," which should not be considered an alternative to, or more meaningful than "cash flow - operating activities" as determined in accordance with generally accepted accounting principles, as an indicator of our financial performance. Cash flow from operations or earnings is presented in our financial reports to assist management and investors in analyzing operating performance by business in the stated period. Our determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items.

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

		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)		**2008**	2007	**2008**	2007
Non-GAAP	Cash flow from operations	**$ 2,000**	$ 1,420	**$ 5,631**	$ 4,001
	Settlement of asset retirement obligations	**(13)**	(14)	**(37)**	(35)
	Change in non-cash working capital	**104**	(108)	**(222)**	(860)
GAAP	Cash flow - operating activities	**$ 2,091**	$ 1,298	**$ 5,372**	$ 3,106

Disclosure of Operating Netback

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

Cautionary Note Required by National Instrument 51-101

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

Husky's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to Husky by Canadian securities regulatory authorities, which permits Husky to provide disclosure required by and consistent with the requirements of the United States Securities and Exchange Commission and the Financial Accounting Standards Board in the United States in place of much of the disclosure expected by National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Please refer to "Disclosure of Exemption Under National Instrument 51-101" on page 2 of our Annual Information Form for the year ended December 31, 2007 filed with securities regulatory authorities for further information.

Abbreviations

bbls	*barrels*
bps	*basis points*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mmbbls	*million barrels*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
bcf	*billion cubic feet*
tcf	*trillion cubic feet*
boe	*barrels of oil equivalent*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mmboe	*million barrels of oil equivalent*
mcfge	*thousand cubic feet of gas equivalent*
GJ	*gigajoule*
mmbtu	*million British Thermal Units*
mmlt	*million long tons*
NGL	*natural gas liquids*
WTI	*West Texas Intermediate*
NYMEX	*New York Mercantile Exchange*
NIT	*NOVA Inventory Transfer*
LIBOR	*London Interbank Offered Rate*
CDOR	*Certificate of Deposit Offered Rate*
SEDAR	*System for Electronic Document Analysis and Retrieval*
FPSO	*Floating production, storage and offloading vessel*
FEED	*Front-end engineering design*

Terms

Bitumen	*A naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. It is more viscous than 10 degrees API*
Capital Employed	*Short- and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital*
Corporate Reinvestment Ratio	*Net capital expenditures (capital expenditures net of proceeds from asset sales) plus corporate acquisitions (net assets acquired) divided by cash flow from operations*
Dated Brent	*Prices which are dated less than 15 days prior to loading for delivery*
Debt to Capital Employed	*Total debt divided by total debt and shareholders' equity*
Delineation Well	*A well in close proximity to an oil or gas discovery well that helps determine the areal extent of the reservoir*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
Embedded Derivative	*Implicit or explicit term(s) in a contract that affects some or all of the cash flows or the value of other exchanges required by the contract*
Equity	*Shares, retained earnings and accumulated other comprehensive income*
Feedstock	*Raw materials which are processed into petroleum products*
Front-end Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Glory Hole	*An excavation in the seabed where the wellheads and other equipment are situated to protect them from scouring icebergs*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which an interest is owned. Net refers to the sum of the fractional working interests owned by a company*

Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Hectare	*One hectare is equal to 2.47 acres*
Near-month Prices	*Prices quoted for contracts for settlement during the next month*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Return on Capital Employed	*Net earnings plus after tax interest expense divided by average capital employed*
Return on Shareholders' Equity	*Net earnings divided by average shareholders' equity*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Three Dimensional (3-D) Seismic	*Seismic imaging which uses a grid of numerous cables rather than a few lines stretched in one line*
Total Debt	*Long-term debt including current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

12. Forward-Looking Statements and Information

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

In particular, forward-looking statements in this release and Interim Report include, but are not limited to: our 2008 revised production guidance and capital spending guidance, our development plans for the North Amethyst, West White Rose oil fields and South White Rose oil field extension, and our plans to participate in an exploration well in the Flemish Pass Basin, our production optimization plans for the Tucker in-situ oil sands project, our Sunrise multiphase development plans, our development plans for the McMullen property, our exploration and delineation drilling plans for the South China Sea, the receipt of an extension of the PSC for the Madura BD natural gas and NGL field and two-well work program for the East Bawean II exploration block, our plans to install various enhanced recovery schemes and drilling programs in Western Canada and our review options in respect of reconfiguring and expanding the Lima Refinery and our plans to modify the Toledo Refinery.

- *Although we believe that the expectations reflected by the forward-looking statements presented in this release and Interim Report are reasonable, our forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to us about ourselves and the businesses in which we operate. Information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources.*
- *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.*

These risks, uncertainties, material assumptions and other factors that could affect actual results are discussed in our Annual Information Form, our Form 40-F, Interim Reports and other documents available at www.sedar.com and www.sec.gov, respectively.

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

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of dollars, except share data)	**September 30 2008**	December 31 2007
	(unaudited)	
Assets		
Current assets		
Cash and cash equivalents	**$ 966**	$ 208
Accounts receivable	**2,152**	1,622
Inventories	**1,629**	1,190
Prepaid expenses	**60**	28
	4,807	3,048
Property, plant and equipment *(note 6)*	**32,291**	29,407
Less accumulated depletion, depreciation and amortization	**12,920**	11,602
	19,371	17,805
Goodwill *(note 8)*	**696**	660
Contribution receivable *(note 6)*	**1,238**	-
Other assets	**180**	184
	$ 26,292	$ 21,697
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 3,034**	$ 2,358
Long-term debt due within one year *(note 10)*	**-**	741
	3,034	3,099
Long-term debt *(note 10)*	**1,719**	2,073
Contribution payable *(note 6)*	**1,414**	-
Other long-term liabilities *(note 11)*	**957**	918
Future income taxes	**4,912**	3,957
Shareholders' equity		
Common shares *(note 13)*	**3,567**	3,551
Retained earnings	**10,654**	8,176
Accumulated other comprehensive income	**35**	(77)
	14,256	11,650
	$ 26,292	$ 21,697
Common shares outstanding *(millions) (note 13)*	**849.3**	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 Sept. 30 **2008**	2007	Nine months ended Sept. 30 **2008**	2007
Sales and operating revenues, net of royalties	**$ 7,715**	$ 4,351	**$ 20,000**	$ 10,758
Costs and expenses				
Cost of sales and operating expenses	**5,403**	2,735	**13,376**	6,215
Selling and administration expenses	**92**	58	**214**	148
Stock-based compensation *(note 13)*	**(44)**	(16)	**27**	48
Depletion, depreciation and amortization	**457**	471	**1,343**	1,344
Interest - net *(note 10)*	**29**	47	**116**	90
Foreign exchange *(note 10)*	**(76)**	(20)	**(60)**	(57)
Other - net	**18**	(36)	**(57)**	(81)
	5,879	3,239	**14,959**	7,707
Earnings before income taxes	**1,836**	1,112	**5,041**	3,051
Income taxes				
Current	**266**	99	**725**	237
Future	**298**	244	**794**	674
	564	343	**1,519**	911
Net earnings	**1,272**	769	**3,522**	2,140
Other comprehensive income				
Derivatives designated as cash flow hedges, net of tax *(note 16)*	**(4)**	-	**(9)**	4
Cumulative foreign currency translation adjustment	**122**	(140)	**187**	(140)
Hedge of net investment, net of tax *(note 16)*	**(26)**	91	**(66)**	91
	92	(49)	**112**	(45)
Comprehensive income	**$ 1,364**	$ 720	**$ 3,634**	$ 2,095
Earnings per share				
Basic and diluted	**$ 1.50**	$ 0.91	**$ 4.15**	$ 2.52
Weighted average number of common shares outstanding *(millions)*				
Basic and diluted	**849.2**	848.9	**849.1**	848.7

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 Sept. 30 **2008**	Three months ended Sept. 30 2007	Nine months ended Sept. 30 **2008**	Nine months ended Sept. 30 2007
Common shares				
Beginning of period	**$ 3,559**	$ 3,547	**$ 3,551**	$ 3,533
Options exercised	**8**	2	**16**	16
End of period	**3,567**	3,549	**3,567**	3,549
Retained earnings				
Beginning of period	**9,806**	6,826	**8,176**	6,087
Net earnings	**1,272**	769	**3,522**	2,140
Dividends on common shares				
Ordinary	**(424)**	(213)	**(1,044)**	(637)
Special	**-**	-	**-**	(212)
Adoption of financial instruments	**-**	-	**-**	4
End of period	**10,654**	7,382	**10,654**	7,382
Accumulated other comprehensive income				
Beginning of period	**(57)**	(14)	**(77)**	-
Adoption of financial instruments	**-**	-	**-**	(18)
Other comprehensive income *(note 16)*				
Derivatives designated as cash flow hedges, net of tax	**(4)**	-	**(9)**	4
Cumulative foreign currency translation adjustment	**122**	(140)	**187**	(140)
Hedge of net investment, net of tax	**(26)**	91	**(66)**	91
	92	(49)	**112**	(45)
End of period	**35**	(63)	**35**	(63)
Shareholders' equity	**$ 14,256**	$ 10,868	**$ 14,256**	$ 10,868

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 Sept. 30 **2008**	Three months ended Sept. 30 2007	Nine months ended Sept. 30 **2008**	Nine months ended Sept. 30 2007
Operating activities				
Net earnings	**$ 1,272**	$ 769	**$ 3,522**	$ 2,140
Items not affecting cash				
Accretion *(note 11)*	**13**	13	**40**	35
Depletion, depreciation and amortization	**457**	471	**1,343**	1,344
Future income taxes	**298**	244	**794**	674
Foreign exchange	**(27)**	(48)	**7**	(127)
Other	**(13)**	(29)	**(75)**	(65)
Settlement of asset retirement obligations *(note 11)*	**(13)**	(14)	**(37)**	(35)
Change in non-cash working capital *(note 7)*	**104**	(108)	**(222)**	(860)
Cash flow - operating activities	**2,091**	1,298	**5,372**	3,106
Financing activities				
Bank operating loans financing - net	**-**	44	**-**	44
Long-term debt issue	**202**	4,755	**949**	6,622
Long-term debt repayment	**(673)**	(3,154)	**(2,185)**	(5,121)
Debt issue costs	**-**	(8)	**-**	(8)
Proceeds from exercise of stock options	**3**	-	**5**	4
Proceeds from monetization of financial instruments	**12**	-	**12**	-
Dividends on common shares	**(424)**	(213)	**(1,044)**	(849)
Other	**5**	-	**(3)**	-
Change in non-cash working capital *(note 7)*	**124**	301	**197**	357
Cash flow - financing activities	**(751)**	1,725	**(2,069)**	1,049
Available for investing	**1,340**	3,023	**3,303**	4,155
Investing activities				
Capital expenditures	**(1,094)**	(710)	**(2,672)**	(2,091)
Corporate acquisition	**-**	(2,589)	**-**	(2,589)
Joint venture arrangement *(note 6)*	**-**	-	**127**	-
Asset sales	**(1)**	5	**33**	332
Other	**(5)**	(4)	**-**	(42)
Change in non-cash working capital *(note 7)*	**190**	149	**(33)**	(200)
Cash flow - investing activities	**(910)**	(3,149)	**(2,545)**	(4,590)
Increase (decrease) in cash and cash equivalents	**430**	(126)	**758**	(435)
Cash and cash equivalents, beginning of period	**536**	133	**208**	442
Cash and cash equivalents, end of period	**$ 966**	$ 7	**$ 966**	$ 7

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

Notes to the Consolidated Financial Statements

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

Note 1 Segmented Financial Information

	Upstream		Midstream				Downstream				Corporate and Eliminations [1]		Total	
			Upgrading		Infrastructure and Marketing		Canadian Refined Products		U.S. Refining and Marketing					
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Three months ended September 30														
Sales and operating revenues, net of royalties	**$ 2,341**	$ 1,496	**$ 859**	$ 406	**$ 4,077**	$ 2,524	**$ 1,187**	$ 831	**$ 2,446**	$ 1,043	**$(3,195)**	$ (1,949)	**$ 7,715**	$ 4,351
Costs and expenses														
Operating, cost of sales, selling and general	**431**	332	**761**	305	**4,014**	2,423	**1,130**	717	**2,456**	933	**(3,323)**	(1,969)	**5,469**	2,741
Depletion, depreciation and amortization	**369**	413	**9**	7	**8**	7	**21**	16	**42**	22	**8**	6	**457**	471
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**1**	1	**28**	46	**29**	47
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**(76)**	(20)	**(76)**	(20)
	800	745	**770**	312	**4,022**	2,430	**1,151**	733	**2,499**	956	**(3,363)**	(1,937)	**5,879**	3,239
Earnings (loss) before income taxes	**1,541**	751	**89**	94	**55**	94	**36**	98	**(53)**	87	**168**	(12)	**1,836**	1,112
Current income taxes	**197**	56	**27**	4	**31**	5	**7**	(2)	**(28)**	14	**32**	22	**266**	99
Future income taxes	**265**	179	**-**	25	**(14)**	25	**4**	33	**9**	19	**34**	(37)	**298**	244
Net earnings (loss)	**$ 1,079**	$ 516	**$ 62**	$ 65	**$ 38**	$ 64	**$ 25**	$ 67	**$ (34)**	$ 54	**$ 102**	$ 3	**$ 1,272**	$ 769
Capital expenditures - Three months ended Sept. 30 [2]	**$ 983**	$ 545	**$ 26**	$ 51	**$ 21**	$ 36	**$ 45**	$ 77	**$ 22**	$ 5	**$ 7**	$ 8	**$ 1,104**	$ 722
Nine months ended September 30														
Sales and operating revenues, net of royalties	**$ 6,594**	$ 4,654	**$ 1,990**	$ 994	**$11,088**	$ 7,600	**$ 2,891**	$ 2,158	**$ 6,328**	$ 1,043	**$(8,891)**	$ (5,691)	**$20,000**	$10,758
Costs and expenses														
Operating, cost of sales, selling and general	**1,172**	950	**1,681**	769	**10,784**	7,329	**2,701**	1,909	**6,014**	933	**(8,792)**	(5,560)	**13,560**	6,330
Depletion, depreciation and amortization	**1,111**	1,219	**22**	17	**23**	21	**61**	47	**104**	22	**22**	18	**1,343**	1,344
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**2**	1	**114**	89	**116**	90
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**(60)**	(57)	**(60)**	(57)
	2,283	2,169	**1,703**	786	**10,807**	7,350	**2,762**	1,956	**6,120**	956	**(8,716)**	(5,510)	**14,959**	7,707
Earnings (loss) before income taxes	**4,311**	2,485	**287**	208	**281**	250	**129**	202	**208**	87	**(175)**	(181)	**5,041**	3,051
Current income taxes	**462**	81	**63**	5	**89**	50	**20**	13	**9**	14	**82**	74	**725**	237
Future income taxes	**814**	672	**23**	58	**(4)**	28	**19**	49	**66**	19	**(124)**	(152)	**794**	674
Net earnings (loss)	**$ 3,035**	$ 1,732	**$ 201**	$ 145	**$ 196**	$ 172	**$ 90**	$ 140	**$ 133**	$ 54	**$ (133)**	$ (103)	**$ 3,522**	$ 2,140
Capital expenditures - Nine months ended Sept. 30 [2]	**$ 2,406**	$ 1,682	**$ 76**	$ 173	**$ 36**	$ 77	**$ 92**	$ 160	**$ 63**	$ 5	**$ 33**	$ 24	**$ 2,706**	$ 2,121
Goodwill additions - Nine months ended Sept. 30	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ 503	**$ -**	$ -	**$ -**	$ 503
Total assets - As at September 30	**$14,724**	$14,085	**$ 1,481**	$ 1,354	**$ 1,802**	$ 1,016	**$ 1,562**	$ 1,212	**$ 5,507**	$ 2,915	**$ 1,216**	$ 136	**$26,292**	$20,718

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

Geographical Financial Information

	Canada		United States		Other International		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Three months ended September 30								
Sales and operating revenues, net of royalties	**$ 4,762**	$ 2,984	**$ 2,869**	$ 1,293	**$ 84**	$ 74	**$ 7,715**	$ 4,351
Capital expenditures [(1)]	**979**	696	**72**	5	**53**	21	**1,104**	722
Nine months ended September 30								
Sales and operating revenues, net of royalties	**$12,289**	$ 8,648	**$ 7,444**	$ 1,891	**$ 267**	$ 219	**$20,000**	$10,758
Capital expenditures [(1)]	**2,475**	2,065	**113**	5	**118**	51	**2,706**	2,121
As at September 30								
Property, plant and equipment, net	**$15,511**	$15,631	**$ 3,461**	$ 1,450	**$ 399**	$ 356	**$19,371**	$17,437
Goodwill	**160**	160	**536**	476	**-**	-	**696**	636

[(1)] *Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.*

Note 2 Significant Accounting Policies

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

Note 3 Changes in Accounting Policies

Inventories

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

Note 4 New Disclosures

a) Financial Instruments - Disclosure and Presentation

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

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

b) Capital Disclosures

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

Note 5 Pending Accounting Pronouncements

Goodwill and Intangible Assets

In February 2008, the CICA issued CICA section 3064, “Goodwill and Intangible Assets,” which will replace CICA section 3062 of the same name. As a result of issuing this guidance, CICA section 3450, “Research and Development Costs,” and Emerging Issues Committee Abstract No. 27, “Revenues and Expenditures during the Pre-Operating Period,” will be withdrawn. This new guidance recognizes costs as assets in accordance with CICA section 1000, “Financial Statement Concepts.” Moreover, section 3064 will eliminate the current practice of recognizing as assets, items that do not meet the section 1000 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. The Company is currently determining the impact of this standard.

Note 6 Joint Ventures

a) BP

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

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

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

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

During the third quarter of 2008, Husky recorded adjustments to capital expenditures contributed to the upstream joint venture on March 31, 2008. As a result, revised capital spending for the three-month period ended March 31, 2008, was $18 million. The adjustment resulted in a decrease in the contribution receivable from BP of $23 million.

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

b) CNOOC Southeast Asia Limited

In April 2008, a subsidiary of the Company, Husky Oil Madura Partnership (“HOMP”), entered into an agreement with CNOOC Southeast Asia Limited (“CNOOCSE”), which resulted in the acquisition by CNOOCSE of a 50% equity interest in Husky Oil (Madura) Limited, a subsidiary of HOMP, for a consideration of $127 million (U.S. $125 million) resulting in a gain of $69 million included in other - net in the Consolidated Statements of Earnings and Comprehensive Income. Husky Oil (Madura) Limited holds a 100% interest in the Madura Strait Production Sharing Contract. The resulting joint venture arrangement is being accounted for using the proportionate consolidation method.

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

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	**2008**	2007
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ 78**	$ (213)	**$ (457)**	$ (64)
Inventories	**306**	(7)	**(180)**	(98)
Prepaid expenses	**7**	122	**(29)**	(22)
Accounts payable and accrued liabilities	**27**	440	**608**	(519)
Change in non-cash working capital	**$ 418**	$ 342	**$ (58)**	$ (703)
Relating to:				
Operating activities	**$ 104**	$ (108)	**$ (222)**	$ (860)
Financing activities	**124**	301	**197**	357
Investing activities	**190**	149	**(33)**	(200)
b) Other cash flow information:				
Cash taxes paid	**$ 209**	$ 25	**$ 490**	$ 865
Cash interest paid	**45**	43	**127**	105

Note 8 Goodwill

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	**2008**	2007
Balance at beginning of period	**$ 675**	$ 160	**$ 660**	$ 160
Acquired during the period	**-**	503	**-**	503
Foreign currency translation of goodwill in self-sustaining U.S. operations	**21**	(27)	**36**	(27)
Balance at September 30	**$ 696**	$ 636	**$ 696**	$ 636

Note 9 Bank Operating Loans

At September 30, 2008, the Company had unsecured short-term borrowing lines of credit with banks totalling $370 million (December 31, 2007 - $270 million). As at September 30, 2008 and December 31, 2007, there were no bank operating loans outstanding. As of September 30, 2008, letters of credit under these lines of credit totalled $129 million (December 31, 2007 - $73 million).

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

Note 10 Long-term Debt

	Maturity	Sept. 30 **2008**	Dec. 31 2007	Sept. 30 **2008**	Dec. 31 2007
		Cdn $ Amount		*U.S. $ Denominated*	
Long-term debt					
Medium-term notes	2009	**$ -**	$ 203	**$ -**	$ -
6.25% notes	2012	**424**	395	**400**	400
7.55% debentures	2016	**212**	198	**200**	200
6.20% notes	2017	**318**	296	**300**	300
6.15% notes	2019	**318**	296	**300**	300
8.90% capital securities	2028	**-**	223	**-**	225
6.80% notes	2037	**431**	445	**407**	450
Debt issue costs [(1)]		**(17)**	(20)	**-**	-
Unwound interest rate swaps		**33**	37	**-**	-
		$ 1,719	$ 2,073	**$ 1,607**	$ 1,875
Long-term debt due within one year					
Bridge financing	2008	**$ -**	$ 741	**$ -**	$ 750

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

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

On August 29, 2008, Husky redeemed the 6.95% medium-term notes - Series E due July 14, 2009. The principal amount was $200 million and the redemption price, including accrued interest, totalled $208 million.

During September 2008, Husky repurchased U.S. $43 million of the outstanding U.S. $450 million 6.80% notes due September 2037.

Interest - net consisted of:

	Three months ended Sept. 30 **2008**	Three months ended Sept. 30 2007	Nine months ended Sept. 30 **2008**	Nine months ended Sept. 30 2007
Long-term debt	**$ 35**	$ 52	**$ 126**	$ 106
Short-term debt	**2**	2	**4**	5
	37	54	**130**	111
Amount capitalized	**-**	(5)	**-**	(13)
	37	49	**130**	98
Interest income	**(8)**	(2)	**(14)**	(8)
	$ 29	$ 47	**$ 116**	$ 90

Foreign exchange consisted of:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	**2008**	2007
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ 35**	$ (73)	**$ 69**	$ (188)
Cross currency swaps	**(14)**	23	**(25)**	59
Contribution receivable	**(48)**	-	**(37)**	-
Other (gains) losses	**(49)**	30	**(67)**	72
Gain	**$ (76)**	$ (20)	**$ (60)**	$ (57)

Note 11 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Nine months ended Sept. 30	
	2008	2007
Asset retirement obligations at beginning of year	**$ 662**	$ 622
Liabilities incurred	**41**	42
Liabilities disposed	**(2)**	(14)
Liabilities settled	**(37)**	(35)
Accretion	**40**	35
Asset retirement obligations at September 30	**$ 704**	$ 650

At September 30, 2008, the estimated total undiscounted inflation-adjusted amount required to settle outstanding asset retirement obligations was $5.3 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 30 years into the future. This amount has been discounted using credit-adjusted risk free rates ranging from 6.2% to 6.8%.

Note 12 Commitments and Contingencies

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

Details of the Company's commitments as at December 31, 2007 are disclosed in Note 15 of the consolidated financial statements in the Company's annual report for the year ended December 31, 2007. In the first nine months of 2008, the Company had additional contractual obligations to purchase goods and services totalling $1,585 million. These contracts are expected to be settled in the following periods: 2008 - $687 million; 2009 - $533 million; 2010 - $188 million; thereafter - $177 million.

Note 13 Share Capital

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

Common Shares

Changes to issued common shares were as follows:

	Nine months ended September 30			
	2008		2007	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of year	848,960,310	$ 3,551	848,537,018	$ 3,533
Options exercised	368,250	16	372,574	16
Balance at September 30	**849,328,560**	**$ 3,567**	848,909,592	$ 3,549

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.

	Nine months ended September 30			
	2008		2007	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of year	30,131	$ 37.18	11,656	$ 16.40
Granted	6,140	$ 43.57	25,716	$ 41.68
Exercised for common shares	(368)	$ 13.68	(372)	$ 11.87
Surrendered for cash	(3,892)	$ 23.13	(4,535)	$ 13.35
Forfeited	(2,000)	$ 41.51	(2,040)	$ 40.70
Outstanding at September 30	**30,011**	**$ 40.31**	30,425	$ 36.58
Options exercisable at September 30	**7,079**	**$ 35.05**	4,781	$ 13.07

	September 30, 2008				
	Outstanding Options			Options Exercisable	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices
$11.67 - $11.99	1,379	$ 11.74	1	1,379	$ 11.74
$12.00 - $17.99	71	$ 15.52	1	71	$ 15.52
$18.00 - $27.99	231	$ 26.36	2	98	$ 24.94
$28.00 - $36.99	670	$ 35.22	3	315	$ 35.50
$37.00 - $39.99	861	$ 39.48	4	57	$ 38.20
$40.00 - $40.99	2,425	$ 40.88	4	-	$ -
$41.00 - $45.02	24,374	$ 42.24	4	5,159	$ 41.68
	30,011	**$ 40.31**	**4**	**7,079**	**$ 35.05**

Note 14 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	**2008**	2007
Employer current service cost	**$ 7**	$ 5	**$ 22**	$ 17
Interest cost	**4**	2	**10**	7
Expected return on plan assets	**(3)**	(2)	**(9)**	(7)
Amortization of net actuarial losses	**1**	2	**3**	4
	$ 9	$ 7	**$ 26**	$ 21

Note 15 Related Party Transactions

TransAlta Power, L.P. ("TAPLP") is under the indirect control of Husky's principal shareholders. TAPLP is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLP"), which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLP. These natural gas sales are related party transactions and have been measured at the exchange amount. For the nine months ended September 30, 2008, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $31 million. At September 30, 2008, the total value of accounts receivable related to these transactions was $5 million.

Note 16 Financial Instruments and Risk Management

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

Risk Management Overview

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

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

Fair Value of Financial Instruments

The Company's financial instruments as at September 30, 2008 included cash and cash equivalents, accounts receivable, contribution receivable, bank operating loans, accounts payable and accrued liabilities, contribution payable, long-term debt, the derivative portion of cash flow 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 September 30, 2008, the carrying value of the contribution receivable and contribution payable was $1.2 billion and $1.4 billion respectively. The fair value of these financial instruments is not readily determinable due to uncertainties regarding timing of the cash flows. Refer to Note 6, "Joint Ventures."

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

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

	September 30, 2008		December 31, 2007	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$ 1,719**	**$ 1,579**	$ 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 may enter 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 September 30, 2008, the Company had the following third party offsetting physical purchase and sale natural gas contracts, which met the definition of a derivative instrument:

	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	23,386	$ -
Physical sale contracts	(23,386)	$ 3

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 September 30, 2008, the Company had a freestanding derivative that requires us to pay amounts based on a fixed interest rate in exchange for receipt of payments based on a floating interest rate with the following terms:

Notional	Swap Maturity	Swap Rate *(percent)*	Fair Value
$ 200	July 14, 2009	CDOR + 175 bps	$ 2

This contract has been recorded at fair value in accounts receivable. Prior to August 29, 2008, this derivative was a hedging item in a fair value hedge, and a gain of $4 million was recorded through interest expense. On August 29, 2008, the underlying debt was redeemed and the fair value hedge was discontinued. The loss of $1 million subsequent to August 29, 2008 has been recorded in other expenses.

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 September 30, 2008, the fair value of the embedded derivative was $60 million (December 31, 2007 - $101 million). In the first nine months of 2008, the impact was an unrealized loss on the embedded derivative of $41 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 September 30, 2008, the Company had a cash flow hedge using the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate *(percent)*	Fair Value
6.25% notes	U.S. $ 150	$ 212	June 15, 2012	7.41	$ (69)
6.25% notes	U.S. $ 75	$ 90	June 15, 2012	5.65	$ (11)
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 and the remaining loss has been included in other comprehensive income. As at September 30, 2008, the unrealized foreign exchange loss of $9 million, net of tax of $4 million is recorded in other comprehensive income. At September 30, 2008, the balance in accumulated other comprehensive income was $12 million, net of tax of $5 million. For the nine months ended September 30, 2008, the Company recognized a foreign exchange gain of $25 million (2007 - loss of $59 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 nine months of 2008, the impact of these contracts was a loss of $7 million (2007 - gain of $5 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. During the third quarter of 2008, the Company unwound one of the forward purchases realizing a gain of $12 million recorded in other expenses in the consolidated statement of earnings. At September 30, 2008, the following foreign exchange transactions had been entered into:

Date	Forward Purchases	Canadian Equivalent	Fair Value
October 5, 2007	U.S. $ 119	$ 117	$ 8
October 11, 2007	U.S. $ 119	$ 116	$ 8

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 nine months of 2008, the impact was a gain of $9 million.

Effective July 1, 2007, the Company's U.S. $1.5 billion of debt financing related to the Lima acquisition was designated as a hedge of the Company's net investment in the U.S. refining and marketing operations, which are considered self-sustaining. During the second quarter of 2008, the Company repaid its bridge financing of U.S. $750 million. In the third quarter of 2008, the Company repurchased U.S. $43 million of bonds that were classified as a net investment hedge. As a result, the Company's net investment hedge is limited to the remaining U.S. $707 million. As at September 30, 2008, the unrealized foreign exchange loss of $66 million, net of tax of $12 million, arising from the translation of the debt is recorded in other comprehensive income.

Sensitivity Analysis

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

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

The Company is exposed to interest rate and foreign currency risk on its cross currency debt swaps. As at September 30, 2008, 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 $5 million lower. An equal and offsetting impact would have occurred had the Canadian dollar been 1% weaker versus the U.S. dollar and assuming all other variables remained constant. As at September 30, 2008, had the interest rates been 50 basis points higher and assuming all other variables remained constant, the impact to other comprehensive income would have been $2 million higher. Had the interest rates been 50 basis points lower and assuming all other variables remained constant, the impact to other comprehensive income would have been $8 million lower.

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 September 30, 2008, had the Canadian dollar been 1% stronger relative to the U.S. dollar and assuming all other variables remained constant, the impact to net earnings would have been $6 million higher for the embedded derivative and $2 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 September 30, 2008:

Financial Liability	Less than 1 Year	1 to less than 2 Years	2 to less than 5 Years	Thereafter
Accounts payable and accrued liabilities	$ 3,034	$ -	$ -	$ -
Cross currency swaps	-	-	447	-
Long-term debt and interest on fixed rate debt	111	111	744	2,244
Other long-term liabilities	5	-	-	-
Total	$ 3,150	$ 111	$1,191	$ 2,244

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

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

Credit Risk

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

Cash and cash equivalents include cash bank balances and short-term deposits maturing in less than 90 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	**Sept. 30, 2008**
Current	**$ 1,939**
Past due (1 - 30 days)	**182**
Past due (31 - 60 days)	**8**
Past due (61 - 90 days)	**3**
Past due (more than 90 days)	**14**
Total	**$ 2,146**

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

Balance at January 1, 2008	$ 10
Provisions and revisions	24
Balance at September 30, 2008	**$ 34**

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

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

Sale of Accounts Receivable

The Company has a securitization program to sell, on a revolving basis, accounts receivable to a third party up to $350 million. As at September 30, 2008, no accounts receivable had been sold under the program (December 31, 2007 - nil). The program expires on January 31, 2009.

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 September 30, 2008, the amount the Company would be contractually required to pay under the cross currency swaps at maturity was $353 million higher (December 31, 2007 - $341 million higher) than their carrying amount.

Note 17 Capital Disclosures

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

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

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

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

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

Husky Energy Inc. will host a conference call for analysts and investors on Wednesday, October 22, 2008, at 4:15 p.m. Eastern time to discuss Husky's third quarter results. To participate please dial 1-800-319-4610 beginning at 4:05 p.m. Eastern time.

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

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

Media are invited to listen to the conference call.

- Dial 1-800-597-1419 beginning at 4:05 p.m. (Eastern time)

A recording of the call will be available at approximately 5:30 p.m. (Eastern time)

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

The Postview will be available until January 21, 2009.

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