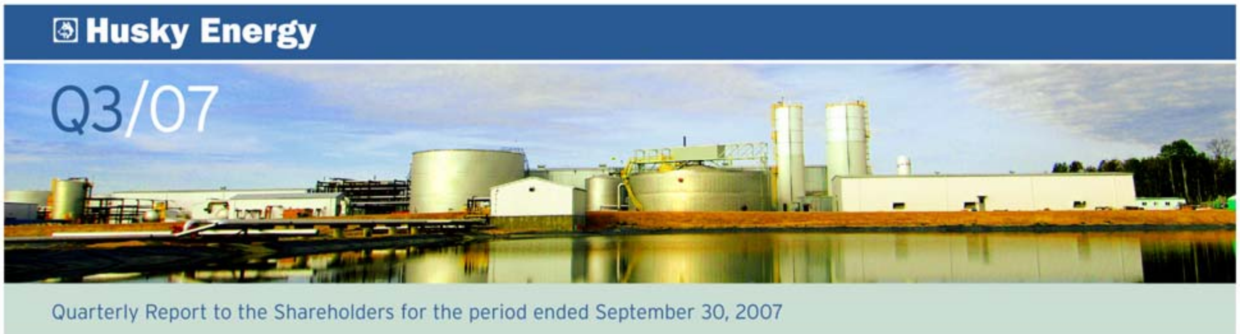
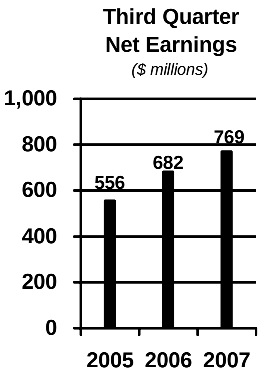
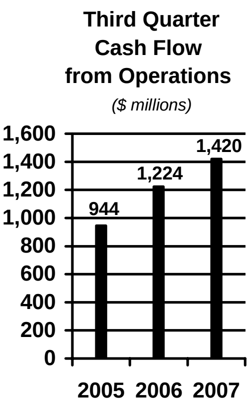
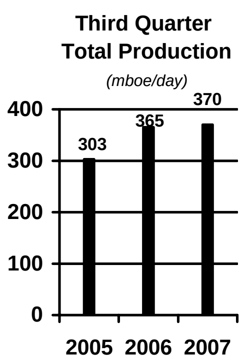


HUSKY ENERGY REPORTS 2007 THIRD QUARTER RESULTS







Calgary, Alberta – Husky Energy Inc. reported net earnings of $769 million or $0.91 per share (diluted) in the third quarter of 2007, an increase of 13% compared with $682 million or $0.80 per share (diluted) in the same quarter of 2006. Cash flow from operations in the third quarter was $1.4 billion or $1.67 per share (diluted), a 16% increase compared with $1.2 billion or $1.44 per share (diluted) in the same quarter of 2006. Sales and operating revenues, net of royalties, were $4.4 billion in the third quarter of 2007, up 27% compared with $3.4 billion in the third quarter of 2006.

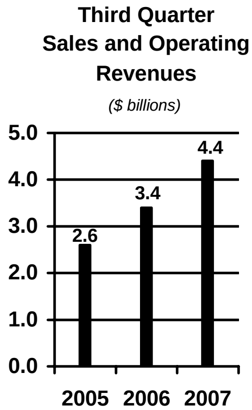
"We are very pleased with the results for the third quarter. Net earnings and cash flow reflect the strong performance of the White Rose oil field and contribution from the U.S. refining operations," said Mr. John C.S. Lau, President & Chief Executive Officer. "The acquisition of the 165,000 barrel per day U.S. refinery at Lima, Ohio gives Husky upgrading and refining integration with its upstream oil production."

Production in the third quarter of 2007 averaged 369,900 barrels of oil equivalent per day, compared with 364,700 barrels of oil equivalent per day in the third quarter of 2006. Total crude oil and natural gas liquids production was 266,500 barrels per day and natural gas production was 620.1 million cubic feet per day.

Production at the White Rose oil field in the third quarter averaged gross 110,000 barrels per day (Husky's share 79,200 barrels per day), reflecting a 16-day planned turnaround completed in July. During the third quarter, Husky negotiated an agreement in principle with the Government of Newfoundland and Labrador regarding fiscal terms for the satellite developments. Under the proposed agreement, the government confirmed its adherence to the generic fiscal terms for the existing White Rose project.

In August 2007, an application was submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board to develop the North Amethyst field. The South White Rose Extension development amendment plan was approved by the federal and provincial governments in September 2007.

At the Tucker Oil Sands project, we continued to steam either the injection well or the production well of the 32 well pairs during the third quarter. The well pairs that have attained steam-assisted gravity drainage mode are continuing to experience growth in their production rates as the steam chamber grows. During the third quarter, extension and acceleration of the project started with the initiation of drilling of an additional eight well pairs on the Pad "C" location. As



per our development schedule, we plan to drill and complete a new pad of eight well pairs in 2008 on Pad “D”.

The Sunrise Oil Sands project is on schedule to complete front-end engineering design work in the fourth quarter of 2007. The first phase of the project will have a design rate of 60,000 barrels per day of bitumen with successive phases to a production level of 200,000 barrels per day.

In Greenland, Husky was awarded a 43.75% interest in a third offshore exploration licence. The block covers an area of 13,213 square kilometres and is located approximately 30 kilometres offshore the west coast of Disko Island. Esso Exploration Greenland Limited holds a 43.75% interest and is the operator, and Nunaoil A/S holds the remaining 12.5%.

In the South China Sea, Husky continued with a seismic program over Block 29/26 that contains the Liwan natural gas discovery and the adjacent Block 29/06. The program will evaluate exploration leads for future drilling locations. The West Hercules deep water drilling rig is 78% complete and is expected to arrive in the field in the second half of 2008.

In Indonesia, Husky signed heads of agreements for the sale of natural gas production from the Madura BD field. Husky expects to sign formal gas sales agreements and file a plan of development with the Indonesian Government by the end of 2007.

Effective July 1, 2007, Husky completed its acquisition of the Lima refinery at a purchase price of U.S. $1.9 billion plus net working capital. An additional U.S. $540 million was paid for the estimated cost of feedstock and product inventory. Husky will review options with respect of reconfiguring and expanding this refinery to process heavy crude oil and bitumen as primary feedstocks.

At the Lloydminster Upgrader, debottlenecking was completed and capacity increased from 77,000 to 82,000 barrels per day in the third quarter of 2007. Front-end engineering design for a potential expansion of the Upgrader is complete and a decision regarding the project is expected in the fourth quarter of 2007.

In Minnedosa, construction of the new 130 million litre per annum ethanol production facility is 90% complete with commissioning and startup expected in the fourth quarter of 2007.

For the first nine months of 2007, Husky’s net earnings were $2.1 billion or $2.52 per share (diluted), compared with $2.2 billion or $2.57 per share (diluted) for the same period in 2006. The decrease in net earnings in the first nine months of 2007 resulted primarily from the effect of tax rate reductions of $328 million recorded in 2006. Earnings before income taxes were $3.1 billion in the first nine months of 2007 compared with $2.7 billion in the first nine months of 2006. Cash flow from operations for the first nine months of 2007 was $4.0 billion or $4.71 per share (diluted), compared with $3.3 billion or $3.88 per share (diluted) for the same period in 2006.

Production in the first nine months of 2007 was 379,600 barrels of oil equivalent per day, compared with 354,100 barrels of oil equivalent per day in the same period in 2006. Total crude oil and natural gas liquids production was 275,400 barrels per day, compared with 241,500 barrels per day during the first nine

Third Quarter Financial Highlights 2007 versus 2006

- Earnings per share to $0.91 from $0.80
- Cash flow per share to $1.67 from $1.44
- Return on equity to 26.6% from 34.2%
- Return on average capital employed to 22.3% from 28.7%
- Debt to cash flow ratio to 0.6 from 0.4
- Debt to capital employed ratio to 21% from 16%
- Market capitalization increased to $35 billion from $31 billion

months of 2006. Natural gas production was 625.2 million cubic feet per day, compared with 675.7 million cubic feet per day in the first nine months of 2006.

Our current forecast for 2007 oil production remains in the guidance range while gas production is expected to be approximately 6% below the lower end of the guidance range. This is a result of low gas prices, high operating costs and the redeployment of capital and delayed capital projects.

Husky's financial position remains strong. Including the Lima refinery acquisition, Husky's debt to cash flow ratio was 0.6 to 1 and debt to capital was 21% at September 30, 2007. During the quarter, Husky completed a successful public offering in the United States of U.S. $300 million of 6.20% 10-year notes due September 15, 2017 and U.S. $450 million of 6.80% 30-year notes due September 15, 2037.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") OCTOBER 17, 2007

TABLE OF CONTENTS

1.0 QUARTERLY FINANCIAL RESULTS

Husky's net earnings for the third quarter of 2007 were $769 million, an increase of $87 million or 13% compared with the third quarter of 2006.

Third Quarter

Higher net earnings in the third quarter of 2007 were mainly related to the inclusion of the Lima refinery operations effective July 1, 2007, higher light oil production and prices, strong margins from asphalt products and crude oil marketing, higher ethanol income and a wider upgrading differential.

Positive earnings factors were partially offset by lower prices and volume for heavy crude oil, natural gas, medium crude oil, higher royalties on White Rose production, higher unit operating costs and depreciation, depletion and amortization and lower synthetic crude sales volume.

Cash flow from operations was $1.4 billion in the third quarter of 2007 compared with $1.2 billion in the third quarter of 2006.

Nine Months

Net earnings for the first nine months of 2007 were $2.1 billion compared with $2.2 billion during the first nine months of 2006. The decrease in net earnings in the first nine months of 2007 resulted primarily from the effect of tax rate reductions of $328 million recorded in 2006.

Earnings before income taxes were $3.1 billion in the first nine months of 2007 compared with $2.7 billion in the first nine months of 2006. The increase in earnings before income taxes in 2007 resulted from the same factors that affected the third quarter, except that light oil prices were lower in the first nine months of 2007 than in the comparable period in 2006.

Cash flow from operations was $4.0 billion in the first nine months of 2007 compared with $3.3 billion in the first nine months of 2006.

Financial Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except per share amounts and ratios)	**2007**	2006	**2007**	2006
Segmented earnings				
Upstream	**$ 516**	$ 608	**$ 1,732**	$ 1,842
Midstream	**129**	87	**317**	377
Downstream	**121**	28	**194**	96
Corporate and eliminations	**3**	(41)	**(103)**	(131)
Net earnings	**$ 769**	$ 682	**$ 2,140**	$ 2,184
Per share - Basic and diluted [(1)]	**$ 0.91**	$ 0.80	**$ 2.52**	$ 2.57
Cash flow from operations	**1,420**	1,224	**4,001**	3,294
Per share - Basic and diluted [(1)]	**1.67**	1.44	**4.71**	3.88
Ordinary quarterly dividend per common share [(1)]	**0.25**	0.25	**0.75**	0.50
Special dividend per common share [(1)]	**-**	-	**0.25**	-
Total assets	**20,718**	17,324	**20,718**	17,324
Total long-term debt including current portion	**2,835**	1,722	**2,835**	1,722
Return on equity [(2)] *(percent)*	**26.6**	34.2	**26.6**	34.2
Return on average capital employed [(2)] *(percent)*	**22.3**	28.7	**22.3**	28.7

[(1)] Reflects a two-for-one share split on June 27, 2007, which has been applied retroactively. Refer to Note 10 to the Consolidated Financial Statements.
[(2)] Calculated for the 12 months ended for the dates shown.

2.0 CORE BUSINESS STRATEGY

Our core business strategy was presented in our 2006 annual Management's Discussion and Analysis, which is available from the Canadian Securities Administrators' web site, www.sedar.com, the U.S. Securities and Exchange Commission's web site, www.sec.gov or our web site www.huskyenergy.ca.

In summary, our strategy is to continue to exploit our conventional oil and gas asset base in Western Canada while expanding into new areas with large scale growth projects. Our plans include projects in the Alberta oil sands, the basins off the East Coast of Canada, the central Mackenzie River Valley, the South China Sea and the Madura Strait and East Java Sea in Indonesia. Our plans for the Midstream and Downstream segments involve enhancing performance and capturing new value throughout the value chain by further integrating existing operations and the Lima refinery, optimizing our plant operations and expanding plant and infrastructure operations where warranted.

3.0 CAPABILITY TO DELIVER RESULTS

Our current capacity to deliver results was also provided in our recently filed MD&A and in our Annual Information Form that are available from www.sedar.com and www.sec.gov. In order to deliver competitive results, we must continually identify and develop an inventory of projects and opportunities that will provide a satisfactory return on investment. The major projects that are currently at varying stages of development are discussed below.

3.1 UPSTREAM

WHITE ROSE OIL FIELD

In early September 2007, the second gas injection well was completed. The completion of this well will provide additional gas storage capacity and concludes our 18-well development plan for the South Avalon portion of the White Rose oil field.

SEAROSE FPSO TIE-BACK PROGRAM

The South White Rose Extension development amendment plan was approved by the federal and provincial governments in September. In August 2007, we submitted an application to the Canada-Newfoundland and Labrador Offshore Petroleum Board to develop the North Amethyst field.

During the third quarter of 2007, the glory hole excavation into the seabed at the North Amethyst drill centre was completed. Front-end engineering design ("FEED") studies to support the tie-back of the White Rose satellite reservoirs and required *SeaRose FPSO* modifications progressed. Overall, FEED was approximately 65% complete as of September 30, 2007.

EAST COAST CANADA EXPLORATION AND WHITE ROSE DELINEATION

A side track of the C-30 delineation well was drilled in the third quarter of 2007. This delineation well and side track will allow us to further evaluate reservoir quality and reserves in the West White Rose area.

Evaluation of 3-D seismic data acquired in 2005 and 2006 over Exploration Licences 1067 and 1011 is on-going.

TUCKER OIL SANDS PROJECT

At the Tucker Oil Sands project, we continued to steam either the injection well or the production well of the 32 well pairs during the third quarter. The well pairs that have attained SAGD mode are continuing to experience growth in their production rates as the steam chamber grows. Extension and acceleration of the project started during the third quarter with the initiation of drilling of an additional eight well pairs on the Pad "C" location. As per our development schedule, we plan to drill and complete a new pad of eight well pairs in 2008 on Pad "D".

SUNRISE OIL SANDS PROJECT

The FEED for the Sunrise Oil Sands project is approximately 85% complete and is expected to be fully completed by the end of the year. The first phase of the project will have a design rate of 60 mbbls/day of bitumen with successive phases to a production level of 200 mbbls/day.

In the field, early site preparation work centered around clearing various development areas. This included central plant rough grading and development of field facility roads and well pads. This work will continue into the second quarter of 2008. Proposals for expansion of the drilling camp and procurement of accommodations for construction workers are currently under review. The winter 2008 drilling program includes 50 stratigraphic test wells as well as five water source and five observation wells. Planning for the SAGD horizontal well pairs is underway with the first rig due to start drilling by mid 2008.

Area infrastructure projects are proceeding with the aerodrome expected to be operational by late 2007. Business discussions on permanent road access and a power transmission line are continuing, as are discussions with regulatory authorities and other area stakeholders.

CARIBOU

The overall FEED progress for the Caribou demonstration project is currently approximately 80% complete. We have now identified 12 stratigraphic test locations for the 2008 winter drilling program following the completion of geological modeling and simulation studies. Discussions and negotiations are continuing with regulatory authorities and various stakeholder groups on the development application to the Energy and Utilities Board and Alberta Environment.

SALESKI

Following the completion of geological mapping and cross sections we currently have 12 locations for the 2008 winter drilling program. Planning is also underway for the acquisition of additional seismic this winter. Work on an all season access road into Saleski is in the early planning stages. In addition, we continue to examine the technical merits of various production processes for Saleski.

NORTHWEST TERRITORIES EXPLORATION

In the Northwest Territories, Husky increased its holdings by approximately 26% in three exploration licenses and freehold lands totalling 227,700 acres in the Central Mackenzie Valley during the third quarter of 2007. Husky plans to drill two exploration wells in the first quarter of 2008 on Exploration License 423, located approximately 60 kilometres southeast of the Summit Creek B-44 and the Stewart Creek D-57 discoveries. Husky has a 75% working interest in Exploration License 423.

CHINA EXPLORATION

The seismic program currently being conducted over Block 29/26, which contains the Liwan natural gas discovery, and the adjacent Block 29/06 is approximately 80% complete. The program will cover a total of 3,300 square kilometres and will evaluate exploration leads for future drilling locations. Delineation of Liwan is planned to commence in the second half of 2008 upon the arrival of the West Hercules deep water drilling rig, which is currently being constructed. The West Hercules is expected to arrive in the South China Sea during the second quarter of 2008. At September 30, 2007, the West Hercules was 78% complete and we have secured it for three years. Conceptual engineering studies for production facilities are underway.

Current drilling plans include an exploration well on Block 23/15, which we expect to spud in November 2007. This well will complete our Phase II commitment. The China National Offshore Oil Company has approved a one year extension to our Phase I drilling commitment on Block 04/35. We continue to pursue additional rigs for our drilling commitment on Block 04/35 and Phase III drilling commitment on Block 39/04.

INDONESIA NATURAL GAS DEVELOPMENT AND EXPLORATION

In August 2007, we announced the signing of heads of agreements for the sale of natural gas production from the Madura BD field. Husky intends to submit the Plan of Development for the BD field in the fourth quarter of 2007. Environmental impact studies are also underway and are expected to be completed by year-end. Additionally, Husky has commenced discussions with the Indonesian Government regarding an extension of the Madura Strait Production Sharing Contract ("PSC").

On the East Bawean II PSC, we have contracted the acquisition of 1,400 square kilometers of 3-D seismic data, which will commence in the fourth quarter of 2007.

OFFSHORE GREENLAND

In June 2007, we were awarded 87.5% interest in exploration licences for two blocks (blocks 5 and 7) covering an area of 21,067 square kilometres located 120 kilometres offshore the west coast of Disko Island, Greenland. We were awarded 43.75% of a third block (Block 6) covering 13,213 square kilometres in October. We will operate blocks 5 and 7 and Esso will operate Block 6. In July we began acquisition of an aero-gravity and magnetics survey over the blocks.

3.2 MIDSTREAM

LLOYDMINSTER TO HARDISTY PIPELINE EXPANSION

Construction of the second phase of our pipeline expansion is approximately 98% complete and is on schedule to be finished during the fourth quarter of 2007. The third and final phase around the Lloydminster area is expected to be complete by the end of June 2008.

LLOYDMINSTER UPGRADER EXPANSION

During the Upgrader turnaround in the third quarter of 2007, the Upgrader debottleneck project was completed increasing daily throughput capacity to 82,000 bbls/day.

The overall FEED for the potential expansion of the Lloydminster Upgrader is complete and a decision on whether to proceed with the expansion is expected by the end of 2007.

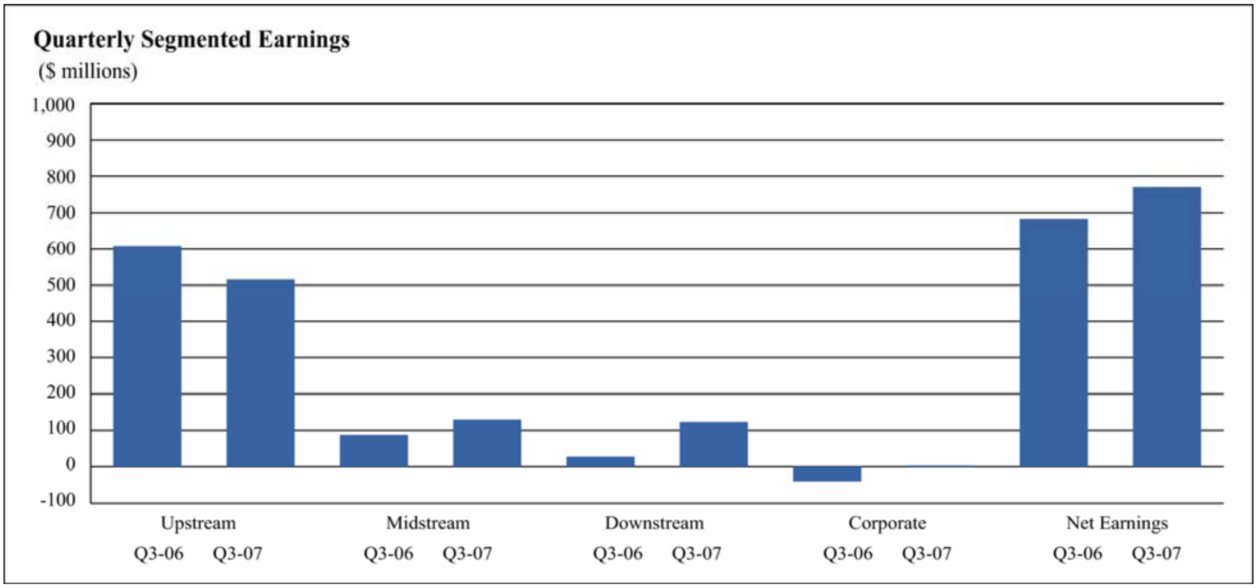
3.3 DOWNSTREAM

MINNEDOSA ETHANOL PLANT

In Minnedosa, construction of the new 130 million litre per annum ethanol production facility is 90% complete, with commissioning and start-up expected in the fourth quarter of 2007.

4.0 RESULTS OF OPERATIONS

The following graphically illustrates comparative earnings by business segment and includes corporate expenses and intersegment profit elimination amounts, the total of which is equal to consolidated net earnings.



4.1 UPSTREAM

Upstream Earnings Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2007**	2006	**2007**	2006
Gross revenues	**$ 1,803**	$ 1,816	**$ 5,394**	$ 4,967
Royalties	**307**	216	**740**	629
Net revenues	**1,496**	1,600	**4,654**	4,338
Operating and administration expenses	**371**	329	**1,038**	948
Depletion, depreciation and amortization	**413**	382	**1,219**	1,087
Other	**(39)**	-	**(88)**	-
Income taxes	**235**	281	**753**	461
Earnings	**$ 516**	$ 608	**$ 1,732**	$ 1,842

THE UPSTREAM BUSINESS ENVIRONMENT

Commodity Prices

The average prices we realized during the third quarter and nine months of 2007 compared with the third quarter and nine months of 2006 are illustrated below.

Average Sales Prices		Three months ended Sept. 30		Nine months ended Sept. 30	
		2007	2006	**2007**	2006
Crude Oil	*($/bbl)*				
Light crude oil & NGL		**$ 76.00**	$ 74.05	**$ 70.49**	$ 71.74
Medium crude oil		**54.55**	57.35	**49.69**	51.28
Heavy crude oil		**43.69**	49.62	**39.93**	41.45
Total average		**60.91**	61.79	**56.59**	55.81
Natural Gas	*($/mcf)*				
Average		**5.18**	5.69	**6.34**	6.57

The prices received for our crude oil production are determined by global economic factors including the Canadian versus U.S. dollar exchange rate. The grade of our crude oil also affects the price we receive. The economics of refining crude oil into finished products such as gasoline and distillates favours light sweet crude oil over heavy sour crude oil because the light sweet feedstock yields a higher proportion of more valuable motor fuels, such as gasoline, without the need to incur additional processing costs.

Natural gas prices are not affected as much by global economics, but rather by local supply and demand. Based on the last three years, approximately 85% of natural gas imported into the United States is transported by pipelines and the remainder by LNG vessel.

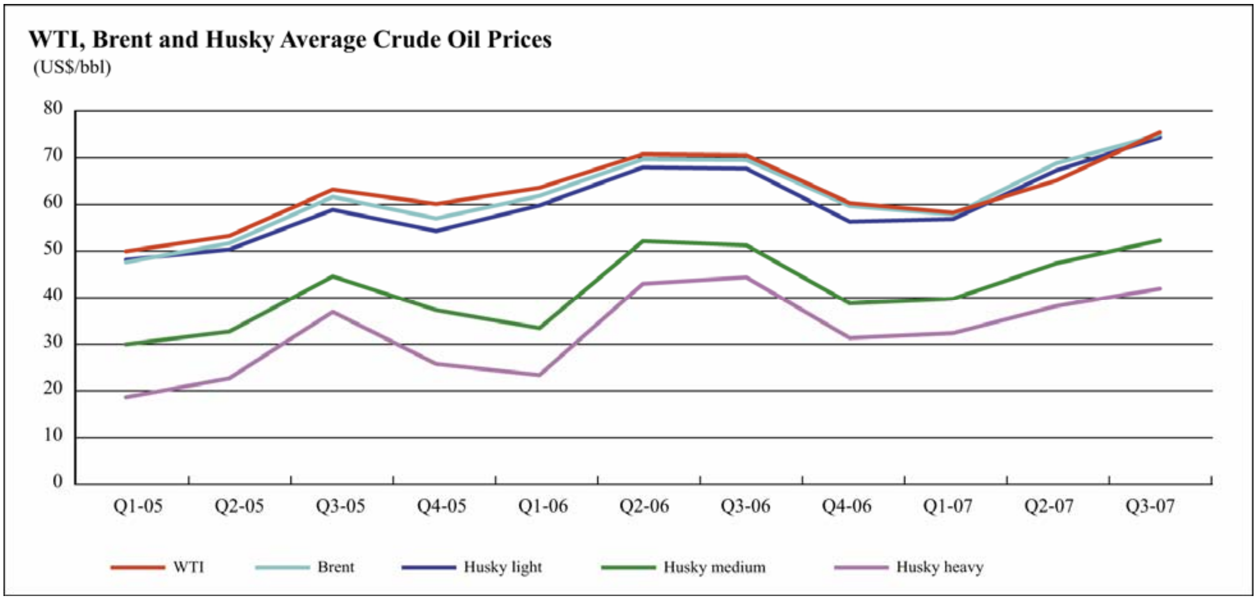
Our Upstream results are significantly influenced by commodity prices. The following table shows certain select average quarterly market benchmark prices:

Average Benchmark Prices and U.S. Exchange Rate		Three months ended				
		Sept. 30 2007	June 30 2007	March 31 2007	Dec. 31 2006	Sept. 30 2006
WTI crude oil [1]	*(U.S. $/bbl)*	**75.38**	65.03	58.16	60.21	70.48
Brent crude oil [2]	*(U.S. $/bbl)*	**74.87**	68.76	57.75	59.68	69.49
Canadian light crude 0.3% sulphur	*($/bbl)*	**80.70**	72.61	67.76	65.12	79.65
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**43.61**	39.02	38.25	35.24	49.61
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**6.16**	7.55	6.77	6.56	6.58
NIT natural gas	*($/GJ)*	**5.31**	6.99	7.07	6.03	5.72
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**23.50**	20.36	17.32	21.75	19.24
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.957**	0.911	0.854	0.878	0.892

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

Crude Oil

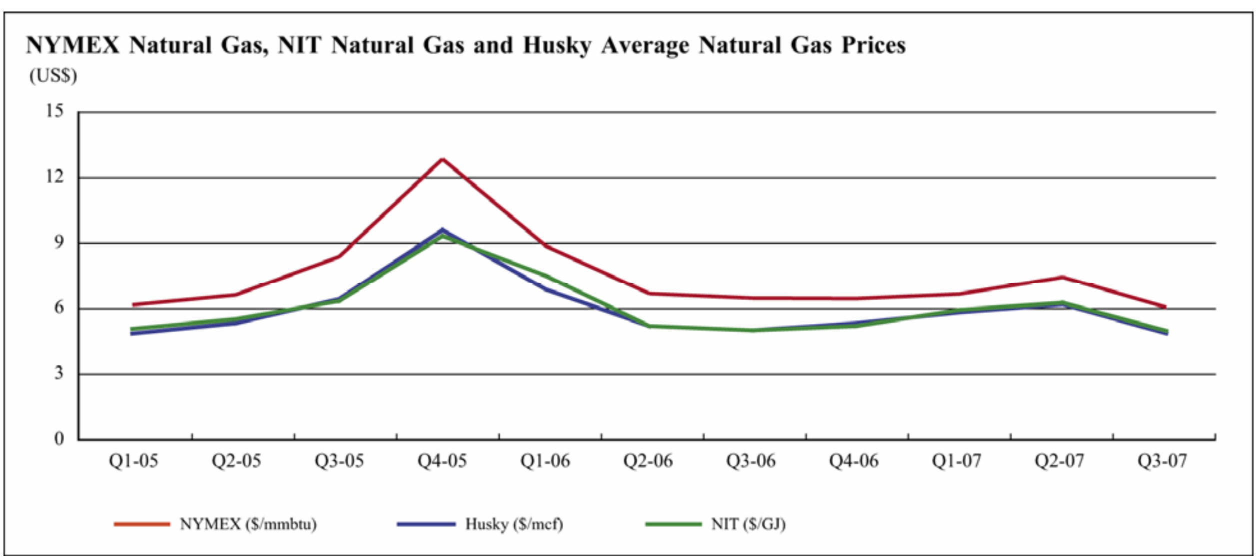
The following graph illustrates the relative changes over several quarters in the realized prices of our three main crude oil categories expressed in U.S. dollars, West Texas Intermediate ("WTI"), the main benchmark crude oil, and Brent.



During the third quarter of 2007, WTI continued its up trend from the beginning of 2007 averaging U.S. $66.19/bbl during the nine months ended September 30, 2007, slightly lower than the average during 2006 of U.S. $66.22/bbl. WTI average for the nine months ended September 30, 2007 was abnormally low as a result of refinery maintenance and outages leading to an oversupply of WTI. This downward pressure on WTI prices began in February and was relieved at the end of July when it again surpassed the price of Brent. During this period, Brent crude became the global benchmark and averaged U.S. $67.13/bbl during the nine months ended September 30, 2007, higher than the average during 2006 of U.S. $65.14/bbl.

Natural Gas

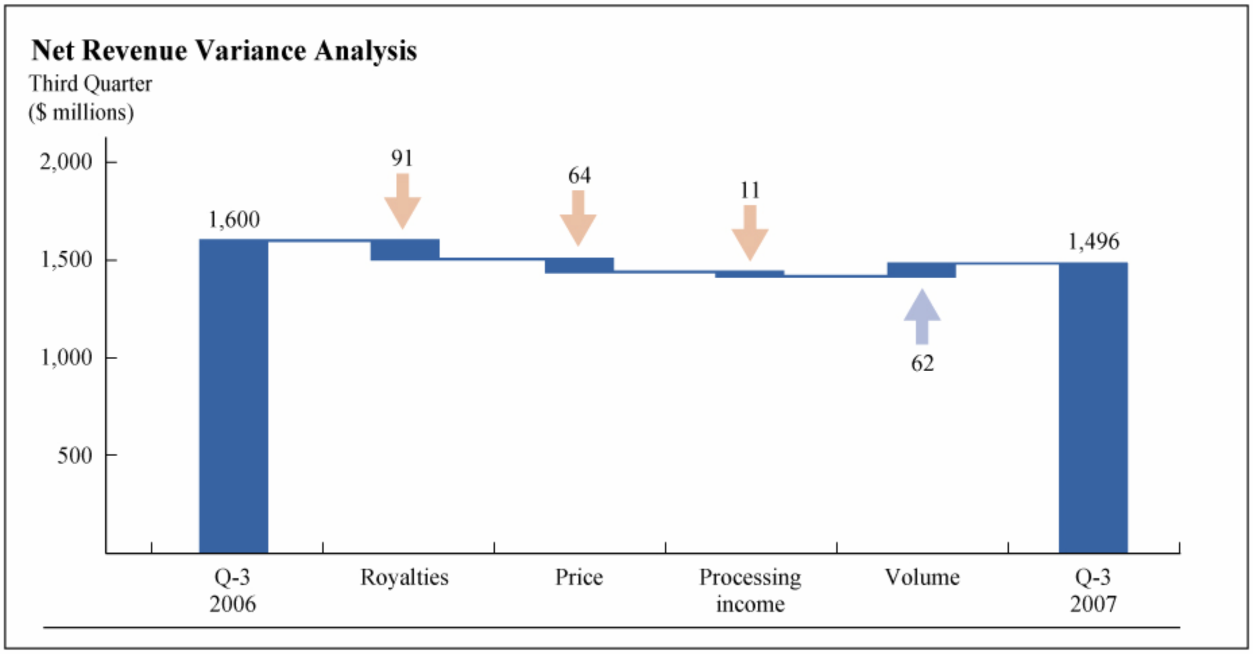
The following graph illustrates the relative changes over several quarters in our realized natural gas price, expressed in U.S. dollars, compared with two major benchmark prices.



In the United States, the high level of stored natural gas and no hurricane related damage to infrastructure in the third quarter continued to keep prices fluctuating around the U.S. $6/mmbtu level. Lower natural gas consumption resulted from moderate temperatures in the major natural gas market areas, with some short lived heat waves that spiked demand and price. The NYMEX price for near month settlement averaged U.S. $6.16/mmbtu during the third quarter of 2007 compared with U.S. $6.58/mmbtu during the third quarter of 2006.

Revenue

Third Quarter

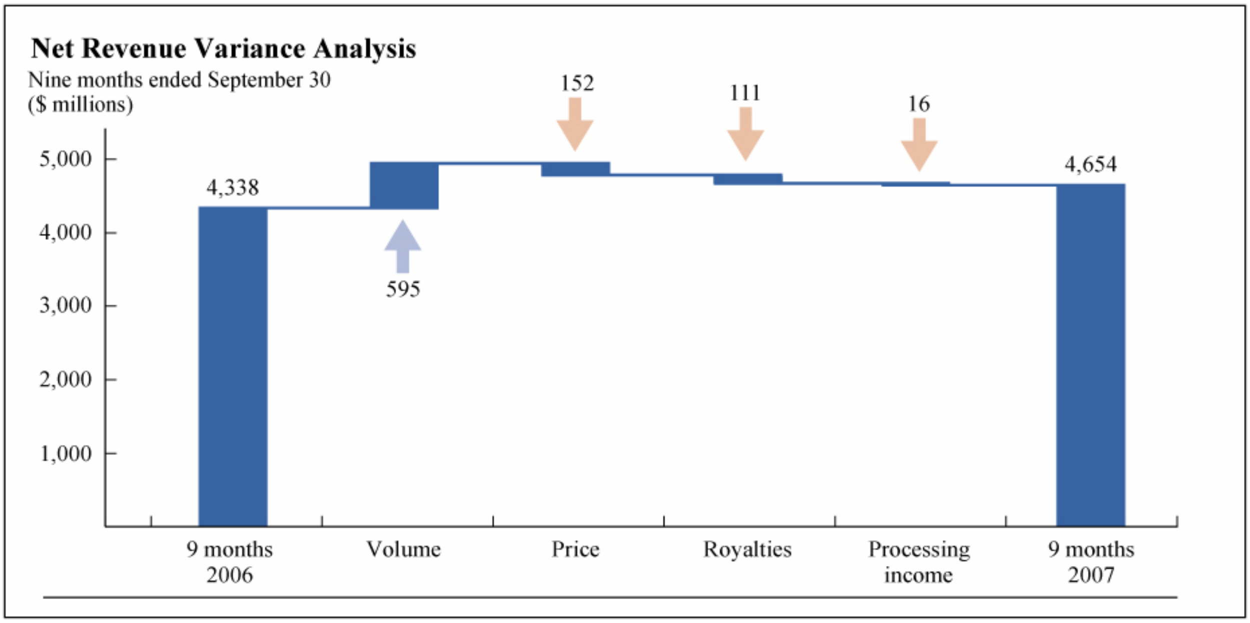


During the third quarter of 2007, our upstream net revenues were $1.5 billion, compared with $1.6 billion in the third quarter of 2006.

In the third quarter of 2007, Western Canada was the source of 60% of our crude oil and 100% of our natural gas production, resulting in 58% of upstream revenue before royalties. East Coast Canada contributed 37% of our crude oil production, 78% of our light crude oil production and resulted in 39% of upstream revenue before royalties. China contributed 5% of revenue.

In the third quarter of 2006, Western Canada was the source of 66% of our crude oil and 100% of our natural gas production, resulting in 66% of upstream revenue before royalties. East Coast Canada contributed 30% of our crude oil production, 71% of our light crude oil production and resulted in 30% of upstream revenue before royalties. China contributed 4% of revenue.

Nine Months



During the first nine months of 2007, our upstream net revenues were $4.7 billion, compared with $4.3 billion in the corresponding period of 2006.

In the first nine months of 2007, Western Canada was the source of 58% of our crude oil and 100% of our natural gas production, resulting in 57% of upstream revenue before royalties. East Coast Canada contributed 37% of our crude oil production, 77% of our light crude oil production and resulted in 38% of upstream revenue before royalties. China contributed 5% of revenue.

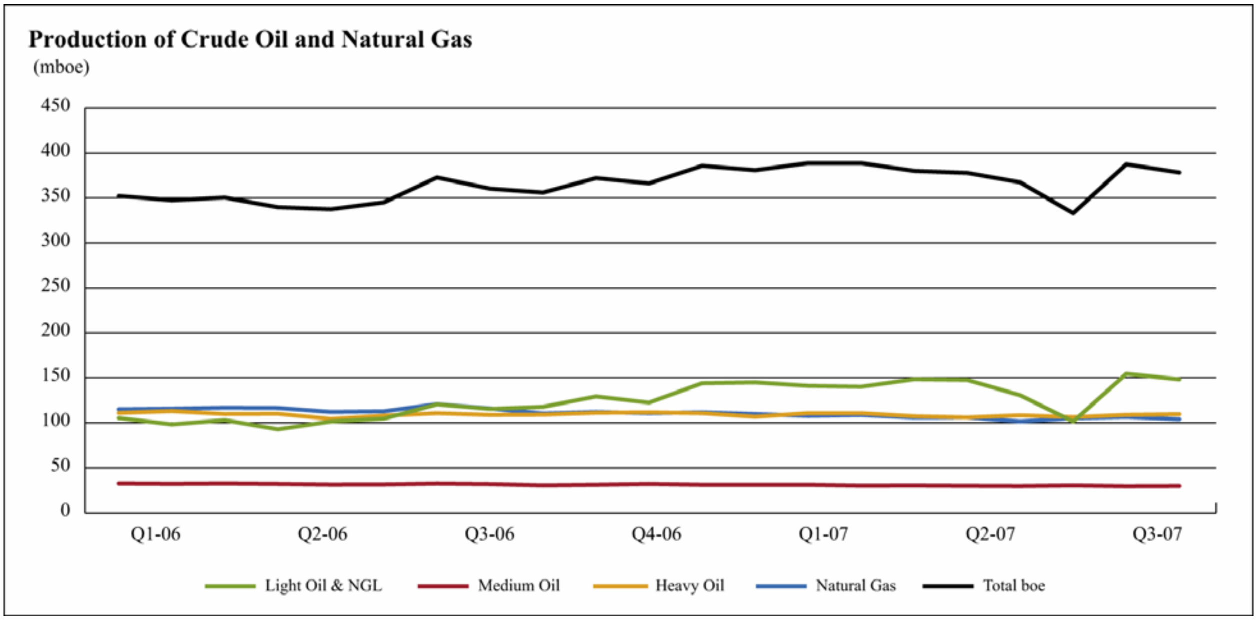
In the nine months of 2006, Western Canada was the source of 69% of our crude oil and 100% of our natural gas production resulting in 69% of upstream revenue before royalties. East Coast Canada contributed 24% of our crude oil production, 63% of our light crude oil production and resulted in 26% of upstream revenue before royalties. China contributed 5% of revenue.

Effective Royalty Rates

Royalties per unit of production and percentage of upstream gross revenues	Three months ended Sept. 30				Nine months ended Sept. 30			
	2007		2006		**2007**		2006	
	$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Crude oil & NGL								
Light crude oil & NGL	**15.20**/*bbl*	**20**	5.53/*bbl*	7	**8.97**/*bbl*	**13**	6.18/*bbl*	9
Medium crude oil	**9.78**/*bbl*	**18**	10.12/*bbl*	18	**8.71**/*bbl*	**18**	9.07/*bbl*	18
Heavy crude oil & bitumen	**5.56**/*bbl*	**13**	6.74/*bbl*	14	**5.09**/*bbl*	**13**	5.36/*bbl*	13
Natural gas	**0.75**/*mcf*	**14**	1.03/*mcf*	18	**1.06**/*mcf*	**17**	1.19/*mcf*	18
Total	**9.04**/*boe*	**17**	6.44/*boe*	12	**7.14**/*boe*	**14**	6.47/*boe*	13

Upstream Revenue Mix	Three months ended Sept. 30		Nine months ended Sept. 30	
Percentage of upstream net revenues	**2007**	2006	**2007**	2006
Crude oil & NGL				
Light crude oil & NGL	**50**	47	**51**	44
Medium crude oil	**7**	7	**7**	8
Heavy crude oil & bitumen	**25**	27	**22**	24
	82	81	**80**	76
Natural gas	**18**	19	**20**	24
	100	100	**100**	100

OIL AND GAS PRODUCTION



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

Daily Gross Production

		Three months ended				
		Sept. 30 2007	June 30 2007	March 31 2007	Dec. 31 2006	Sept. 30 2006
Crude oil and NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**25.1**	25.3	30.1	30.4	30.2
Medium crude oil		**26.7**	26.8	27.5	28.0	28.1
Heavy crude oil & bitumen		**106.5**	105.4	108.0	109.5	107.9
		158.3	157.5	165.6	167.9	166.2
East Coast Canada						
White Rose - light crude oil		**79.2**	90.3	89.4	79.4	75.9
Terra Nova - light crude oil		**16.3**	15.5	14.7	6.7	-
China						
Wenchang - light crude oil & NGL		**12.7**	13.2	13.6	11.7	11.1
		266.5	276.5	283.3	265.7	253.2
Natural gas	*(mmcf/day)*	**620.1**	615.7	640.0	662.2	669.1
Total	*(mboe/day)*	**369.9**	379.1	390.0	376.1	364.7

2007 Gross Production Guidance

		Original Guidance 2007	Nine months ended Sept. 30 **2007**	Year ended Dec. 31 2006
Crude oil & NGL	*(mbbls/day)*	**278 - 295**	**276**	248
Natural gas	*(mmcf/day)*	**670 - 690**	**625**	672
Total barrels of oil equivalent	*(mboe/day)*	**390 - 410**	**380**	360

Our current forecast for 2007 oil production remains in the guidance range while gas production is expected to be approximately 6% below the lower end of the guidance range. This is a result of low gas prices, high operating costs and the redeployment of capital and delayed capital projects.

Crude Oil Production

In the third quarter of 2007, Western Canada crude oil and NGL production declined 5% compared with the third quarter of 2006. The decline in production was mainly due to a protracted spring break-up combined with capital project delays and the disposition of properties in April 2007. Plans are being implemented to increase field work.

Light crude oil production from the White Rose and Terra Nova oil fields off the East Coast of Canada averaged 95.5 mbbls/day during the third quarter of 2007 compared with 75.9 mbbls/day during the third quarter of 2006. At White Rose, approval to produce 50 mmbbls of light oil per year (36 mmbbls per year Husky share) was received in July 2007. White Rose may now produce at a maximum of 140 mbbls/day (102 mbbls/day Husky share) or an annual sustained average of 120 mbbls/day to 125 mbbls/day (87 mbbls/day to 91 mbbls/day Husky share). White Rose was shut down for 16 days during July 2007 for a scheduled turnaround when a number of facility inspections, equipment replacements and general maintenance activities were undertaken. Our interest in Terra Nova production averaged 16.3 mbbls/day in the third quarter of 2007.

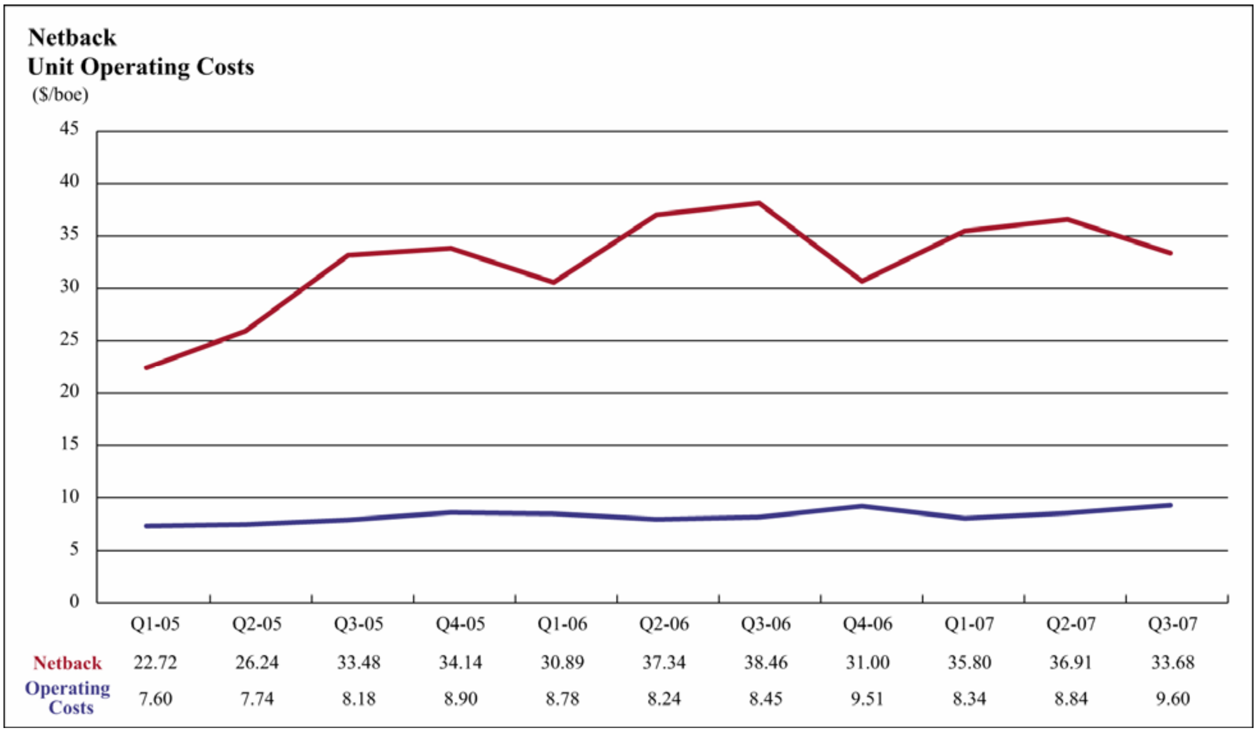
At Wenchang in the South China Sea, production was 14% higher in the third quarter of 2007 compared with the same period in 2006. New production wells and well workovers in the fourth quarter of 2006 boosted production levels. NGL production also augmented crude oil production with the installation of gas liquid extraction facilities, which became operational in October 2006.

Natural Gas Production

All of our natural gas is produced in Western Canada. In the third quarter of 2007, the foothills of Alberta and British Columbia, the deep basin of Alberta and the plains of northeast British Columbia and northwest Alberta were the source of 57% of our natural gas production; the remainder was from east central and southern Alberta and southern Saskatchewan.

Production of natural gas was down approximately 7% in the third quarter of 2007 compared with the third quarter of 2006, primarily due to redeployment of capital, capital project delays, property divestitures, infrastructure maintenance, as well as restrictions due to an early spring break-up and high decline.

OPERATING COSTS



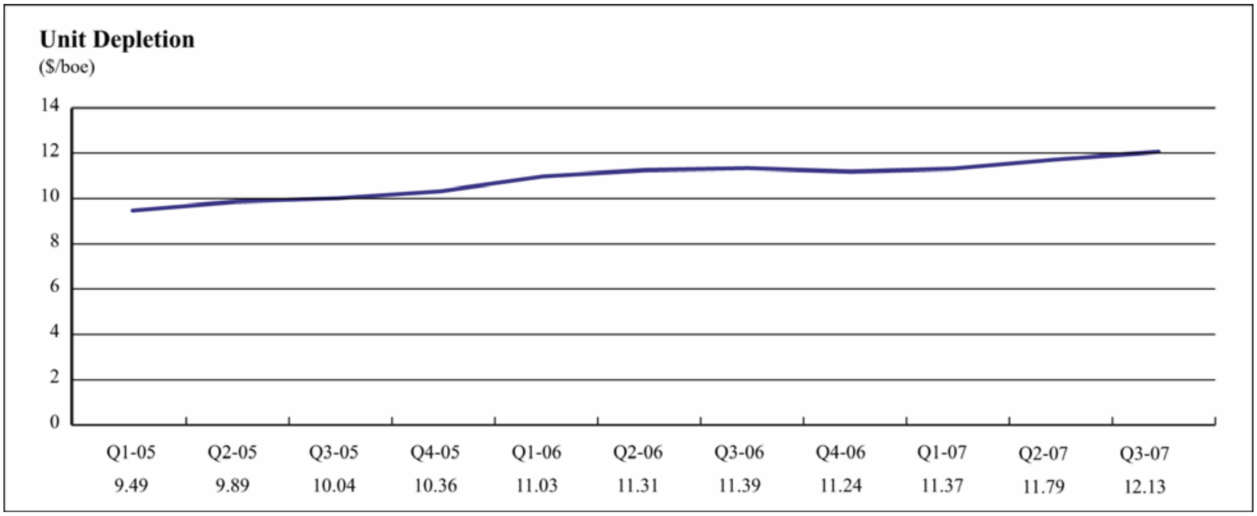
Operating costs in Western Canada averaged $11.47/boe in the third quarter of 2007 compared with $9.29/boe in the corresponding period in 2006, an increase of 23%.

The trend of increasing operating costs in Western Canada is related to the nature of exploitation necessary to manage production from maturing fields and new but more extensive and less prolific reservoirs. Western Canadian operations require increasing amounts of infrastructure including more wells, more extensive pipeline systems, crude oil and water trucking, more extensive natural gas compression systems and complex tertiary recovery schemes. Cyclic steam and SAGD heavy oil and bitumen recovery schemes involve processes requiring higher energy consumption, workovers and generally more material costs. In the current quarter, higher unit operating costs were also influenced by Tucker, which is in the early production phase. In addition, higher levels of industry activity increase competition for resources and inflate costs. In managing rising operating costs, we attempt to keep our infrastructure, including gas plants, crude oil processing plants, transportation systems, compression systems, lease access and other infrastructure fully utilized and optimized.

Operating costs at the East Coast offshore operations averaged $5.34/bbl in the third quarter of 2007 compared with $6.03/bbl in the third quarter of 2006. Unit operating costs in the third quarter of 2007 benefited from higher production volume from both White Rose and Terra Nova.

Operating costs at the South China Sea offshore operations averaged $3.18/bbl in the third quarter of 2007 compared with $3.57/bbl in the same period in 2006. Increased unit operating costs resulted from the maturing of the reservoir and the addition of liquids extraction to the operation in the third quarter of 2006.

DEPLETION, DEPRECIATION AND AMORTIZATION



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

The Canadian cost centre DD&A averaged $12.16/boe in the third quarter of 2007 compared with $11.35/boe in the third quarter of 2006, an increase of 7%. The increase in DD&A results primarily from higher capital costs and lower reserve booking. Increasing capital is due to increased drilling and associated infrastructure in Western Canada and large capital investment developing offshore reserves off the East Coast of Canada.

OTHER

During the third quarter, we recorded a $39 million gain on an embedded derivative related to a contract requiring payment in U.S. currency. The payments are expected to occur over the three-year period from mid 2008. This amount will fluctuate with the U.S./Cdn forward exchange rate until the actual contract settlement.

Operating Netbacks

	Western Canada		East Coast		International		Total	
Three months ended Sept. 30	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
Light Crude Oil *(per boe)* [(1)]								
Sales price	**$ 62.29**	$ 62.61	**$ 76.97**	$ 75.78	**$ 77.48**	$ 77.07	**$ 74.39**	$ 72.58
Royalties [(2)]	**7.39**	9.43	**16.07**	0.77	**14.24**	16.80	**14.34**	4.52
Operating costs	**12.39**	7.40	**5.34**	6.03	**3.18**	4.24	**6.39**	6.20
	42.51	45.78	**55.56**	68.98	**60.06**	56.03	**53.66**	61.86
Medium Crude Oil *(per boe)* [(1)]								
Sales price	**53.38**	56.35	**-**	-	**-**	-	**53.38**	56.35
Royalties	**9.45**	10.02	**-**	-	**-**	-	**9.45**	10.02
Operating costs	**15.12**	12.99	**-**	-	**-**	-	**15.12**	12.99
	28.81	33.34	**-**	-	**-**	-	**28.81**	33.34
Heavy Crude Oil & Bitumen *(per boe)* [(1)]								
Sales price	**43.43**	49.41	**-**	-	**-**	-	**43.43**	49.41
Royalties	**5.52**	6.71	**-**	-	**-**	-	**5.52**	6.71
Operating costs	**12.80**	10.69	**-**	-	**-**	-	**12.80**	10.69
	25.11	32.01	**-**	-	**-**	-	**25.11**	32.01
Total Crude Oil *(per boe)* [(1)]								
Sales price	**47.95**	52.94	**76.97**	75.78	**77.48**	77.07	**59.70**	60.79
Royalties	**6.48**	7.77	**16.07**	0.77	**14.24**	16.80	**10.27**	6.09
Operating costs	**13.14**	10.52	**5.34**	6.03	**3.18**	4.24	**9.89**	8.91
	28.33	34.65	**55.56**	68.98	**60.06**	56.03	**39.54**	45.79
Natural Gas *(per mcfge)* [(3)]								
Sales price	**5.48**	5.99	**-**	-	**-**	-	**5.48**	5.99
Royalties	**0.95**	1.21	**-**	-	**-**	-	**0.95**	1.21
Operating costs	**1.48**	1.23	**-**	-	**-**	-	**1.48**	1.23
	3.05	3.55	**-**	-	**-**	-	**3.05**	3.55
Equivalent Unit *(per boe)* [(1)]								
Sales price	**42.07**	46.24	**76.97**	75.78	**77.48**	77.07	**52.30**	53.35
Royalties	**6.19**	7.56	**16.07**	0.77	**14.24**	16.80	**9.02**	6.44
Operating costs	**11.47**	9.29	**5.34**	6.03	**3.18**	4.24	**9.60**	8.45
	$ 24.41	$ 29.39	**$ 55.56**	$ 68.98	**$ 60.06**	$ 56.03	**$ 33.68**	$ 38.46

(1) *Includes associated co-products converted to boe.*
(2) *During the third quarter of 2007, White Rose royalties increased to 16% because the project, off the East Coast, achieved payout status for Tier 1 royalties.*
(3) *Includes associated co-products converted to mcfge.*

Operating Netbacks (continued)

Nine months ended Sept. 30	Western Canada 2007	Western Canada 2006	East Coast 2007	East Coast 2006	International 2007	International 2006	Total 2007	Total 2006
Light Crude Oil *(per boe)* [(1)]								
Sales price	**$ 59.41**	$ 61.86	**$ 72.32**	$ 74.22	**$ 73.54**	$ 76.05	**$ 70.11**	$71.01
Royalties [(2)]	**6.61**	7.37	**7.89**	1.94	**12.97**	12.68	**8.14**	4.73
Operating costs	**12.68**	10.59	**4.12**	6.10	**3.72**	3.46	**5.62**	7.03
	40.12	43.90	**60.31**	66.18	**56.85**	59.91	**56.35**	59.25
Medium Crude Oil *(per boe)* [(1)]								
Sales price	**49.12**	50.65	**-**	-	**-**	-	**49.12**	50.65
Royalties	**8.60**	9.01	**-**	-	**-**	-	**8.60**	9.01
Operating costs	**13.73**	12.34	**-**	-	**-**	-	**13.73**	12.34
	26.79	29.30	**-**	-	**-**	-	**26.79**	29.30
Heavy Crude Oil & Bitumen *(per boe)* [(1)]								
Sales price	**39.82**	41.42	**-**	-	**-**	-	**39.82**	41.42
Royalties	**5.07**	5.39	**-**	-	**-**	-	**5.07**	5.39
Operating costs	**12.53**	10.74	**-**	-	**-**	-	**12.53**	10.74
	22.22	25.29	**-**	-	**-**	-	**22.22**	25.29
Total Crude Oil *(per boe)* [(1)]								
Sales price	**44.49**	46.57	**72.32**	74.22	**73.54**	76.05	**56.11**	55.19
Royalties	**5.93**	6.37	**7.89**	1.94	**12.97**	12.68	**6.98**	5.55
Operating costs	**12.76**	11.00	**4.12**	6.10	**3.72**	3.46	**9.15**	9.35
	25.80	29.20	**60.31**	66.18	**56.85**	59.91	**39.98**	40.29
Natural Gas *(per mcfge)* [(3)]								
Sales price	**6.51**	6.76	**-**	-	**-**	-	**6.51**	6.76
Royalties	**1.26**	1.43	**-**	-	**-**	-	**1.26**	1.43
Operating costs	**1.39**	1.10	**-**	-	**-**	-	**1.39**	1.10
	3.86	4.23	**-**	-	**-**	-	**3.86**	4.23
Equivalent Unit *(per boe)* [(1)]								
Sales price	**42.38**	44.18	**72.32**	74.22	**73.54**	76.05	**51.50**	50.59
Royalties	**6.55**	7.25	**7.89**	1.94	**12.97**	12.68	**7.13**	6.50
Operating costs	**11.04**	9.25	**4.12**	6.10	**3.72**	3.46	**8.93**	8.50
	$ 24.79	$ 27.68	**$ 60.31**	$ 66.18	**$ 56.85**	$ 59.91	**$ 35.44**	$ 35.59

(1) *Includes associated co-products converted to boe.*
(2) *During the third quarter of 2007, White Rose royalties increased to 16% because the project, off the East Coast, achieved payout status for Tier 1 royalties.*
(3) *Includes associated co-products converted to mcfge.*

UPSTREAM CAPITAL EXPENDITURES

Capital expenditures during the first nine months of 2007 were funded primarily with internally generated cash flow.

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

2007 Capital Expenditure Guidance [(1)]

(millions of dollars)	
Western Canada - oil & gas	**$ 1,840**
- oil sands	**330**
East Coast Canada	**290**
International	**160**
	$ 2,620

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

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

Capital Expenditures Summary [(1)]

(millions of dollars)	Three months ended Sept. 30 **2007**	Three months ended Sept. 30 2006	Nine months ended Sept. 30 **2007**	Nine months ended Sept. 30 2006
Exploration				
Western Canada	**$ 97**	$ 140	**$ 338**	$ 460
East Coast Canada and Frontier	**28**	16	**33**	41
International	**21**	32	**46**	69
	146	188	**417**	570
Development				
Western Canada	**354**	325	**1,099**	1,082
East Coast Canada	**45**	88	**161**	251
International	**-**	11	**5**	20
	399	424	**1,265**	1,353
	$ 545	$ 612	**$ 1,682**	$ 1,923

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

During the first nine months of 2007, upstream capital expenditures were $1,682 million, $1,437 million (85%) in Western Canada, $194 million (12%) off the East Coast of Canada and $51 million (3%) offshore China, Indonesia and other international areas.

Western Canada

During the first nine months of 2007, we invested $117 million on exploration in the foothills, deep basin and northern plains. We drilled six net wells in these regions resulting in six net natural gas wells. In the Lloydminster area of Alberta and Saskatchewan, from which the majority of our heavy crude oil is produced, we invested $393 million, primarily for exploitation and optimization.

We invested $169 million in the oil sands areas during the first nine months of 2007, $65 million at Tucker and $55 million on the Sunrise project. Front-end engineering design of the Sunrise project is currently 87% complete. We invested $49 million at our other oil sands areas, principally at Saleski, where we acquired additional lands, began to acquire seismic data and drilled several evaluation wells.

We also drilled 44 stratigraphic test wells, water source and disposal evaluation wells and acquired seismic data at Caribou.

The following table discloses the number of gross and net exploration and development wells we completed during the third quarter and nine months ended September 30, 2007 and 2006. The data indicates that during the third quarter of 2007, 95% of the net exploration wells and 97% of the net development wells we drilled resulted in wells cased for production.

Western Canada Wells Drilled		Three months ended Sept. 30				Nine months ended Sept. 30			
		2007		2006		**2007**		2006	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**23**	**23**	42	41	**56**	**56**	71	70
	Gas	**16**	**13**	84	46	**85**	**72**	278	150
	Dry	**3**	**2**	6	5	**13**	**12**	24	22
		42	**38**	132	92	**154**	**140**	373	242
Development	Oil	**221**	**203**	201	174	**417**	**387**	380	334
	Gas	**67**	**54**	120	115	**241**	**195**	382	331
	Dry	**7**	**7**	9	6	**19**	**19**	20	17
		295	**264**	330	295	**677**	**601**	782	682
Total		**337**	**302**	462	387	**831**	**741**	1,155	924

Off the East Coast of Canada

During the first nine months of 2007, capital expenditures in the region off the East Coast of Canada totalled $194 million. The North Amethyst glory hole was successfully completed in August 2007. FEED is continuing on the White Rose satellite tie-backs. The C-30 delineation well was drilled to further assess reservoir quality and reserves in the West White Rose field, with a side track that was drilled during the third quarter. During September 2007, the second gas injection well at the White Rose oil field was completed.

International

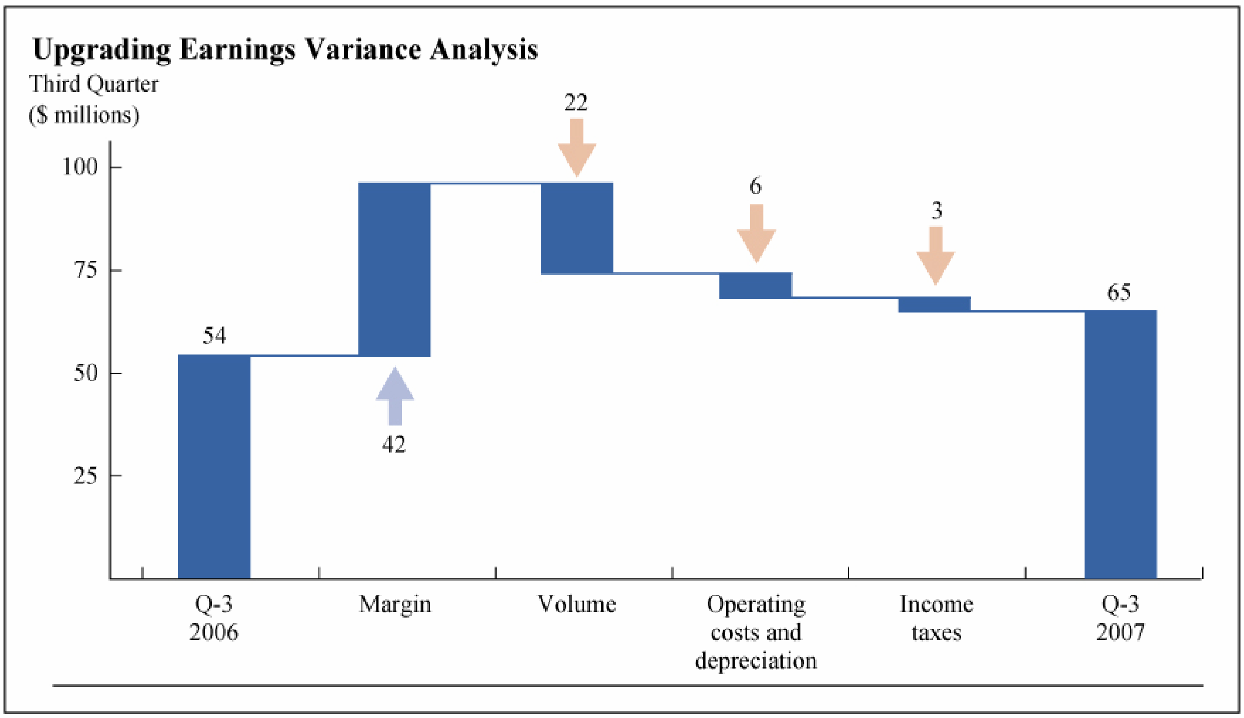
During the first nine months of 2007, we invested $51 million on international exploration for seismic acquisition and evaluations for the South and East China Seas and on the East Bawean II exploration block in the Java Sea. Capital expenditures on development were $4 million in the first nine months of 2007, primarily to advance the Madura natural gas and liquids project in Indonesia.

4.2 MIDSTREAM

Upgrading Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2007**	2006	**2007**	2006
Gross margin		**$ 155**	$ 135	**$ 382**	$ 479
Operating costs		**55**	50	**160**	169
Other recoveries		**(1)**	(1)	**(3)**	(4)
Depreciation and amortization		**7**	6	**17**	18
Income taxes		**29**	26	**63**	70
Earnings		**$ 65**	$ 54	**$ 145**	$ 226
Selected operating data:					
Upgrader throughput [(1)]	*(mbbls/day)*	**67.4**	73.1	**57.5**	71.0
Synthetic crude oil sales	*(mbbls/day)*	**55.1**	65.7	**48.6**	62.0
Upgrading differential	*($/bbl)*	**$ 30.41**	$ 23.75	**$ 27.94**	$ 27.04
Unit margin	*($/bbl)*	**$ 30.63**	$ 22.38	**$ 28.78**	$ 28.31
Unit operating cost [(2)]	*($/bbl)*	**$ 8.93**	$ 7.62	**$ 10.21**	$ 8.73

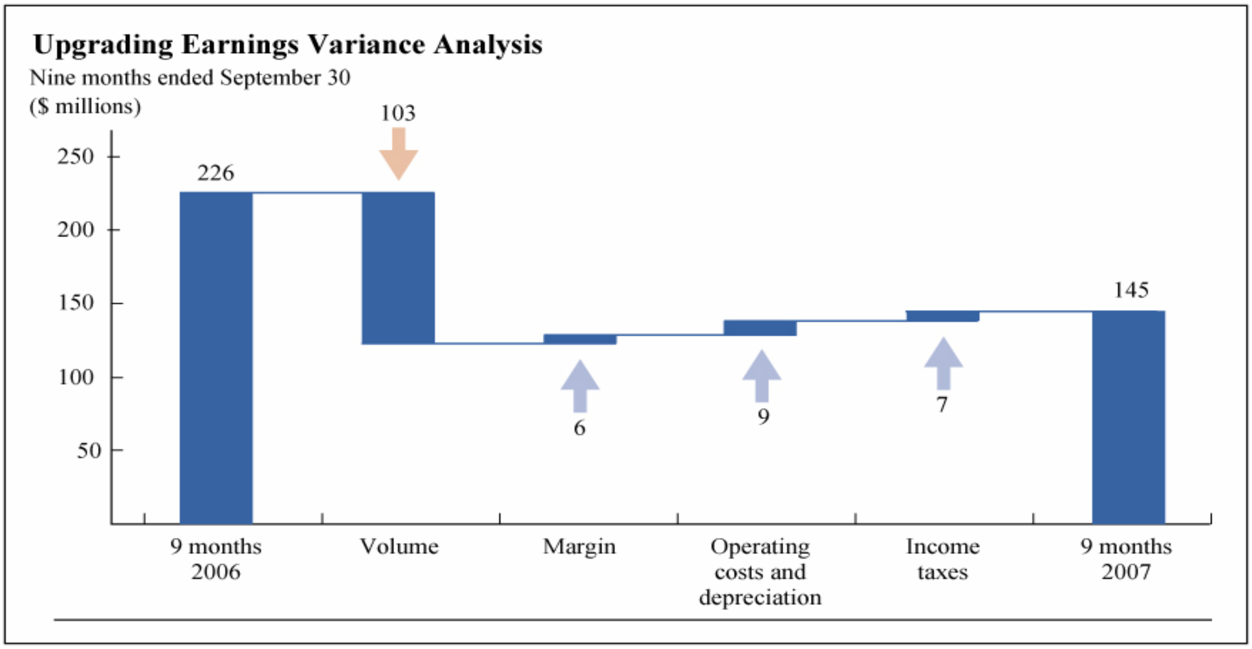
[(1)] *Throughput includes diluent returned to the field.*
[(2)] *Based on throughput.*

Third Quarter



Upgrading earnings in the third quarter of 2007 were $65 million, an increase of $11 million from the third quarter of 2006 due primarily to a higher upgrading differential partially offset by lower sales volume. The lower volumes were due to operating one hydrocracker train at lower rates to complete some unplanned maintenance. Operating costs during the third quarter of 2007 were $8.93/bbl compared with $7.62/bbl in the same quarter in 2006.

Nine Months



Upgrading earnings were lower in the first nine months of 2007 than the corresponding period in 2006 due to lower sales volume. A turnaround, which shut the plant down for 49 days from May 10 to June 28, resulted in lower throughput in the second quarter of 2007 compared with the same quarter in 2006. The turnaround time was extended from 40 days to install two new coke drums. Operating costs during the first nine months of 2007 were $10.21/bbl compared with $8.73/bbl in the same period in 2006.

Infrastructure and Marketing Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2007**	2006	**2007**	2006
Gross margin	- pipeline	**$ 33**	$ 26	**$ 87**	$ 80
	- other infrastructure and marketing	**71**	32	**191**	152
		104	58	**278**	232
Other expenses		**3**	3	**7**	8
Depreciation and amortization		**7**	6	**21**	17
Income taxes		**30**	16	**78**	56
Earnings		**$ 64**	$ 33	**$ 172**	$ 151
Selected operating data:					
Aggregate pipeline throughput *(mbbls/day)*		**506**	457	**502**	479

Third Quarter

Infrastructure and marketing earnings in the third quarter of 2007 increased by $31 million compared with the third quarter of 2006, largely due to higher commodity marketing margins and higher facilities utilization, including pipelines and processing facilities.

Nine Months

Infrastructure and marketing earnings in the first nine months of 2007 were $21 million higher than the same period in 2006. The increase in earnings was primarily due to higher third quarter commodity marketing margins, particularly Lloyd Blend, and higher third quarter pipelines earnings.

MIDSTREAM CAPITAL EXPENDITURES

Midstream capital expenditures totalled $250 million in the first nine months of 2007. $173 million was spent at the Lloydminster Upgrader, including front-end engineering design for a proposed expansion, a small debottleneck project and reliability projects. The remaining $77 million was primarily for a pipeline extension between Lloydminster and Hardisty, Alberta.

4.3 DOWNSTREAM

Refined Products Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2007**	2006	**2007**	2006
Gross margin - fuel sales		**$ 39**	$ 42	**$ 144**	$ 121
- ancillary sales		**12**	10	**31**	26
- asphalt sales		**82**	18	**131**	71
		133	70	**306**	218
Operating and other expenses		**19**	18	**57**	53
Depreciation and amortization		**16**	11	**47**	34
Income taxes		**31**	13	**62**	35
Earnings		**$ 67**	$ 28	**$ 140**	$ 96
Selected operating data:					
Number of fuel outlets				**502**	504
Light oil sales	*(million litres/day)*	**9.0**	9.1	**8.8**	8.7
Light oil retail sales per outlet	*(thousand litres/day)*	**13.8**	13.6	**13.2**	12.8
Prince George refinery throughput	*(mbbls/day)*	**10.8**	11.6	**10.1**	8.2
Asphalt sales	*(mbbls/day)*	**25.9**	30.0	**20.9**	24.2
Lloydminster refinery throughput	*(mbbls/day)*	**29.0**	27.9	**24.1**	26.8
Ethanol production	*(thousand litres/day)*	**323.5**	26.8	**317.0**	26.0

Third Quarter

Refined Products earnings in the third quarter of 2007 were $67 million compared with $28 million in the third quarter of 2006, primarily due to strong asphalt products margins, the addition of ethanol sales from the new Lloydminster ethanol plant, lower fuel margins and higher depreciation.

Nine Months

Refined Products earnings in the first nine months of 2007 were $140 million compared with $96 million during the same period in 2006. Higher earnings resulted from strong margins for asphalt products, the inclusion of ethanol sales from the Lloydminster ethanol plant and higher depreciation.

U.S. Refining Earnings Summary		Three months ended September 30
(millions of dollars, except where indicated)		**2007**
Gross refining margin		**$ 155**
Processing costs		**45**
Interest - net		**1**
Depreciation and amortization		**22**
Income taxes		**33**
Earnings		**$ 54**
Selected operating data:		
Refinery throughput	*(mbbls/day)*	
Crude oil		**120.2**
Other feedstock		**19.8**
Yield	*(mbbls/day)*	
Gasoline		**79.7**
Middle distillates		**42.5**
Other fuel and feedstock		**18.1**
Margins	*($/bbl crude throughput)*	
Gross refining margin		**13.56**
Unit operating costs	*($/bbl of yield)*	**3.50**
Refined product sales	*(mbbls/day)*	
Gasoline		**74.0**
Middle distillates		**39.6**
Other fuel and feedstock		**10.9**

Third Quarter

The U.S. refining operations were acquired effective July 1, 2007 and consist of a refinery in Lima, Ohio with a nameplate capacity of 165 mbbls/day of crude oil feedstock. The refinery currently processes predominantly light sweet crude oil but we plan to examine various options to integrate the Lima refinery with our heavy oil and future bitumen production. The refinery is well situated geographically in respect of both feedstock access and product distribution. The acquisition of the refining operations has established a new operating business segment.

During the three months ended September 30, 2007, the Lima refinery's earnings were $54 million. The refinery operated normally during the third quarter except for 16 days in July and early August when it operated at a reduced rate as a result of an electrical transformer outage. During September, the crude oil throughput averaged 155 mbbls/day.

DOWNSTREAM CAPITAL EXPENDITURES

Refined Products capital expenditures totalled $160 million during the first nine months of 2007. The Minnedosa ethanol plant currently under construction accounted for $86 million, $50 million for marketing location upgrades and construction and $24 million for debottleneck and upgrade projects at the Lloydminster asphalt refinery, Prince George refinery, Lloydminster ethanol plant and asphalt distribution facilities.

U.S. refining operations capital expenditures totalled $5 million for various facilities upgrades.

4.4 CORPORATE

Corporate Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars) income (expense)	**2007**	2006	**2007**	2006
Intersegment eliminations - net	**$ 23**	$ (2)	**$ (35)**	$ (16)
Administration expenses	**(12)**	(7)	**(33)**	(19)
Stock-based compensation	**16**	(18)	**(48)**	(103)
Accretion	**(2)**	(1)	**(4)**	(2)
Other - net	**(5)**	(11)	**(11)**	(19)
Depreciation and amortization	**(6)**	(6)	**(18)**	(17)
Interest on debt	**(51)**	(28)	**(102)**	(98)
Interest capitalized	**5**	9	**13**	30
Foreign exchange - realized	**(13)**	-	**(42)**	19
Foreign exchange - unrealized	**33**	(5)	**99**	13
Income taxes	**15**	28	**78**	81
Earnings (loss)	**$ 3**	$ (41)	**$ (103)**	$ (131)

Foreign Exchange Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2007**	2006	**2007**	2006
(Gain) loss on translation of U.S. dollar denominated long-term debt				
Realized	**$ -**	$ (1)	**$ -**	$ (31)
Unrealized	**(73)**	1	**(188)**	(36)
	(73)	-	**(188)**	(67)
Cross currency swaps	**23**	-	**59**	26
Other losses	**30**	5	**72**	9
	$ (20)	$ 5	**$ (57)**	$ (32)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.940**	U.S. $0.897	**U.S. $0.858**	U.S. $0.858
At end of period	**U.S. $1.004**	U.S. $0.897	**U.S. $1.004**	U.S. $0.897

CORPORATE CAPITAL EXPENDITURES

During the first nine months of 2007, corporate capital expenditures amounted to $24 million for various office space and facilities upgrades.

CONSOLIDATED INCOME TAXES

During the third quarter of 2007, consolidated income taxes consisted of $99 million of current taxes and $244 million of future taxes compared with current taxes of $210 million and future taxes of $98 million in the same period of 2006.

Lower current income taxes and higher future income taxes in the third quarter of 2007 were due to the deferral of White Rose income.

Quarterly Financial Summary

	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)	**2007**	2007	2007	2006	2006	2006	2006	2005
Sales and operating revenues, net of royalties	**$ 4,351**	$ 3,163	$ 3,244	$ 3,084	$ 3,436	$ 3,040	$ 3,104	$ 3,207
Segmented earnings								
Upstream	**$ 516**	$ 636	$ 580	$ 453	$ 608	$ 822	$ 412	$ 533
Midstream	**129**	77	111	105	87	140	150	135
Downstream	**121**	53	20	10	28	52	16	17
Corporate and eliminations	**3**	(45)	(61)	(26)	(41)	(36)	(54)	(16)
Net earnings	**$ 769**	$ 721	$ 650	$ 542	$ 682	$ 978	$ 524	$ 669
Per share - Basic and diluted [(1)]	**$ 0.91**	$ 0.85	$ 0.77	$ 0.64	$ 0.80	$ 1.15	$ 0.62	$ 0.79
Cash flow from operations	**1,420**	1,257	1,324	1,207	1,224	1,103	967	1,197
Per share - Basic and diluted [(1)]	**1.67**	1.48	1.56	1.42	1.44	1.30	1.14	1.41
Ordinary quarterly dividend per common share [(1)]	**0.25**	0.25	0.25	0.25	0.25	0.125	0.125	0.125
Special dividend per common share [(1)]	**-**	-	0.25	-	-	-	-	0.50
Total assets	**20,718**	17,969	17,781	17,933	17,324	16,328	15,855	15,716
Total long-term debt including current portion	**2,835**	1,423	1,527	1,611	1,722	1,722	1,838	1,886
Return on equity [(2)] *(percent)*	**26.6**	27.1	32.1	31.8	34.2	34.8	29.6	29.2
Return on average capital employed [(2)] *(percent)*	**22.3**	23.8	27.3	27.0	28.7	28.2	23.2	22.8

[(1)] *Amounts prior to June 30, 2007 as restated. Refer to Note 10 to the Consolidated Financial Statements.*
[(2)] *Calculated for the 12 months ended for the dates shown.*

4.5 SENSITIVITY ANALYSIS

The following table indicates the relative annual effect of changes in certain key variables on our pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the third quarter of 2007. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis	2007 Third Quarter Average	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
			($ millions)	*($/share)* [5]	*($ millions)*	*($/share)* [5]
Upstream and Midstream						
WTI benchmark crude oil price	$ 75.38	*U.S. $1.00/bbl*	84	0.10	58	0.07
NYMEX benchmark natural gas price [1]	$ 6.16	*U.S. $0.20/mmbtu*	34	0.04	24	0.03
WTI/Lloyd crude blend differential [2]	$ 23.50	*U.S. $1.00/bbl*	(27)	(0.03)	(19)	(0.02)
Exchange rate (U.S. $ per Cdn $) [3]	$ 0.957	*U.S. $0.01*	(110)	(0.13)	(74)	(0.09)
Downstream						
Light oil margins	$ 0.04	*Cdn $0.005/litre*	17	0.02	11	0.01
Asphalt margins	$ 31.06	*Cdn $1.00/bbl*	10	0.01	6	0.01
New York Harbor 3:2:1 crack spread	$ 11.90	*U.S. $1.00/bbl*	42	0.05	26	0.03
Consolidated						
Period end translation of U.S. $ debt (U.S. $ per Cdn $)	$ 1.004 [4, 6]	*U.S. $0.01*			19	0.02

[1] Includes decrease in earnings related to natural gas consumption.
[2] Includes impact of upstream and upgrading operations only.
[3] Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items.
[4] U.S./Canadian dollar exchange rate at September 30, 2007.
[5] Based on 848.9 million common shares outstanding as of September 30, 2007.
[6] Excludes derivatives.

5.0 LIQUIDITY AND CAPITAL RESOURCES

During the third quarter of 2007, cash flow from operating activities financed all of our capital expenditures and dividend payment. The acquisition of the Lima refinery was funded with short-term bridge financing, half of which was refinanced with the issue of U.S. $750 million of long-term notes in September. At September 30, 2007, 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)	**2007**	2006	**2007**	2006
Cash flow - operating activities	**$ 1,298**	$ 1,473	**$ 3,106**	$ 3,903
- financing activities	**$ 1,725**	$ (333)	**$ 1,049**	$ (1,181)
- investing activities	**$ (3,149)**	$ (713)	**$ (4,590)**	$ (2,346)
Financial Ratios				
Debt to capital employed *(percent)*			**20.9**	15.6
Corporate reinvestment ratio *(percent)* [1] [2]			**0.5**	0.7

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

5.1 OPERATING ACTIVITIES

In the third quarter of 2007, cash generated from operating activities amounted to $1.3 billion compared with $1.5 billion in the third quarter of 2006. Lower cash flow from operating activities was mainly due to a change in non-cash working capital.

5.2 FINANCING ACTIVITIES

In the third quarter of 2007, cash provided by financing activities amounted to $1.7 billion compared with cash used in financing activities of $333 million in the third quarter of 2006. During the third quarter of 2007, cash was generated predominantly from debt issued to facilitate closing the acquisition of the Lima refinery. Change in non-cash working capital was primarily related to the sale of receivables offset by dividends paid in the quarter. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

5.3 INVESTING ACTIVITIES

In the third quarter of 2007, cash used in investing activities amounted to $3.1 billion compared with $713 million in the third quarter of 2006. Cash invested in the third quarter of 2007 of $2.6 billion was for the Lima refinery acquisition, including feedstock and product inventory. Additionally, cash invested in both periods was used primarily for capital expenditures, partially offset by asset sales.

5.4 SOURCES OF CAPITAL

We are currently able to fund our capital programs principally by cash provided from operating activities. We also maintain access to sufficient capital via capital debt markets commensurate with the strength of our balance sheet and continually examine our options with respect to sources of long and short-term capital resources. In addition, from time to time we engage in hedging a portion of our revenue to protect cash flow.

Working capital is the amount by which current assets exceed current liabilities. At September 30, 2007, our working capital deficiency was $358 million compared with $495 million at December 31, 2006. Working capital deficits are primarily the result of accounts payable related to capital expenditures for exploration and development. Settlement of these current liabilities is funded by cash provided by operating activities and, to the extent necessary, by bank borrowings. This position is a common characteristic of the oil and gas industry which, by the nature of its business, spends large amounts of capital.

(millions of dollars)	**Sept. 30 2007**	Dec. 31 2006	Change	
Current assets				
Cash and cash equivalents	**$ 7**	$ 442	$ (435)	Tax payment
Accounts receivable	**1,344**	1,284	60	Inclusion of Lima receivables offset by sale of accounts receivable
Inventories	**1,079**	428	651	Inclusion of Lima inventory and higher gas storage
Prepaid expenses	**43**	25	18	
	2,473	2,179	294	
Current liabilities				
Bank operating loans	**43**	-	(43)	Short-term loans
Accounts payable	**1,329**	1,268	(61)	Lower capital and natural gas product accruals offset by Lima payables
Accrued interest payable	**30**	27	(3)	
Income taxes payable	**-**	615	615	Tax payment made
Other accrued liabilities	**682**	664	(18)	Higher accruals due to Lima
Long-term debt due within one year	**747**	100	(647)	Bridge financing for Lima acquisition
	2,831	2,674	(157)	
Working capital	**$ (358)**	$ (495)	$ 137	

Sources and Uses of Cash *(millions of dollars)*	Nine months ended Sept. 30 **2007**	Year ended December 31 2006
Cash sourced		
Cash flow from operations [1]	**$ 4,001**	$ 4,501
Debt issue	**6,666**	1,226
Asset sales	**332**	34
Proceeds from exercise of stock options	**4**	3
	11,003	5,764
Cash used		
Capital expenditures	**2,091**	3,171
Corporate acquisition	**2,589**	-
Debt repayment	**5,121**	1,493
Special dividend on common shares	**212**	-
Ordinary dividends on common shares	**637**	636
Settlement of asset retirement obligations	**35**	36
Settlement of cross currency swap	**-**	47
Other	**50**	13
	10,735	5,396
Net cash	**268**	368
Decrease in non-cash working capital	**(703)**	(94)
Increase (decrease) in cash and cash equivalents	**(435)**	274
Cash and cash equivalents - beginning of period	**442**	168
Cash and cash equivalents - end of period	**$ 7**	$ 442

[1] *Cash flow from operations represents net earnings plus items not affecting cash, which include accretion, depletion, depreciation and amortization, future income taxes and foreign exchange.*

Capital Structure

(millions of dollars)	September 30, 2007 Outstanding (U.S. $)	(Cdn $)	Available (Cdn $)
Short-term bank debt	$ -	$ 43	$ 156
Long-term bank debt			
Syndicated credit facility	-	-	1,250
Bilateral credit facilities	-	-	150
Bridge facility	750	747	
Medium-term notes (1)	-	200	
Capital securities	225	224	
U.S. public notes	1,650	1,644	
	2,625	2,858	1,556
Fair value adjustment (1)	-	2	
Debt issue costs (2)	-	(20)	
Unwound interest rate swaps (3)	-	38	
Total short-term and long-term debt	$ 2,625	$ 2,878	$ 1,556
Common shares, retained earnings and accumulated other comprehensive income		$ 10,868	

(1) *The carrying value of the medium-term notes has been adjusted to fair value to meet the accounting requirements for a fair value hedge. Refer to Notes 3 and 12 to the Consolidated Financial Statements.*

(2) *Debt issue costs have been reclassified to long-term debt with the adoption of financial instruments. Previously these deferred costs were included in other assets. Refer to Notes 3 and 7 to the Consolidated Financial Statements.*

(3) *The unamortized portion of the gain on previously unwound interest rate swaps that would be designated as fair value hedges is required to be included in the carrying value of long-term debt with the adoption of financial instruments. Refer to Notes 3 and 7 to the Consolidated Financial Statements.*

At September 30, 2007, we had unused committed long and short-term borrowing credit facilities totalling $1.5 billion. A total of $71 million of our borrowing credit facilities were used in support of outstanding letters of credit and an additional $30 million of letters of credit were outstanding at September 30, 2007 and supported by dedicated letters of credit lines.

At a special meeting of the shareholders on June 27, 2007, the shareholders approved a two-for-one share split of our issued and outstanding common shares. On June 27, 2007, the Company filed Articles of Amendment to effect the share split. All references to common share amounts, including common shares issued and outstanding, basic and diluted earnings per share, dividend per share, weighted average number of common shares outstanding and stock options granted, exercised, surrendered and forfeited have been retroactively restated to reflect the impact of the two-for-one share split. The common shares commenced trading on the Toronto Stock Exchange reflecting this split on July 9, 2007.

During the second quarter of 2007, we arranged short-term bridge financing from several banks to facilitate closing the acquisition of the Lima refinery on July 3, 2007. The bridge financing provided U.S. $1.5 billion while the remaining funds required were drawn under existing credit facilities.

In September 2007, we issued U.S. $300 million of 6.20% 10-year notes due September 15, 2017 and U.S. $450 million of 6.80% 30-year notes due September 15, 2037 under a shelf prospectus dated September 21, 2006. The net proceeds of these notes were used to repay part of the U.S. $1.5 billion short-term bridge financing for the acquisition of the Lima refinery. Total net proceeds from these issues were U.S. $743 million or $775 million at the then effective exchange rate. The remaining amount that is eligible for issue under our shelf prospectus is U.S. $250 million until October 21, 2008. During the remaining period that the prospectus remains effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale.

5.5 CREDIT RATINGS

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

5.6 CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

Refer to Husky's 2006 annual Management's Discussion and Analysis under the caption "Cash Requirements," which summarizes contractual obligations and commercial commitments. In September 2007, we issued U.S. $300 million of 6.20% notes and U.S. $450 million of 6.80% notes. Interest of U.S. $18.6 million will be paid in respect of the 6.20% notes for 10 years and U.S. $30.6 million for 30 years on the 6.80% notes.

5.7 OFF BALANCE SHEET ARRANGEMENTS

We engage, in the ordinary course of business, in the securitization of accounts receivable. At September 30, 2007, $350 million of accounts receivable have been sold under the securitization program. The securitization program permits the sale of a maximum $350 million of accounts receivable on a revolving basis. The accounts receivable are sold to an unrelated third party and in accordance with the agreement we must provide a loss reserve to replace defaulted receivables. The securitization agreement expires on January 31, 2009.

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

5.8 TRANSACTIONS WITH RELATED PARTIES

We did not have any significant transactions with related parties during the first nine months of 2007 or during the year ended December 31, 2006.

5.9 SIGNIFICANT CUSTOMERS

We did not have any customers that constituted more than 10% of total sales and operating revenues during the first nine months of 2007.

6.0 RISKS AND RISK MANAGEMENT

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

6.1 FINANCIAL RISKS

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 2007, interest rate risk management activities resulted in a decrease to interest expense of $1 million.

Cross currency swaps resulted in an addition to interest expense of $4 million in the first nine months of 2007.

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 2007, these swaps resulted in an offset to interest expense amounting to $1 million.

The amortization of previous interest rate swap terminations resulted in an additional $4 million offset to interest expense in the first nine months of 2007.

FOREIGN CURRENCY RISK MANAGEMENT

At September 30, 2007, 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, 2007, the cost of a U.S. dollar in Canadian currency was $0.9963.

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, 2007, 93% or $2.6 billion of our long-term debt was denominated in U.S. dollars. The percentage of our long-term debt exposed to the Cdn/U.S. exchange rate decreases to 80% when cross currency swaps are considered.

CHANGES TO FEDERAL AND PROVINCIAL LAWS AND REGULATIONS

Changes in laws and regulations, including those in respect of the fiscal regimes that govern our activities, could affect our results of operations. On September 18, 2007, the Alberta royalty review panel released its recommended amendments to the Alberta provincial royalty and tax regime. The Government of Alberta indicated that it expects to respond to these recommendations by mid-October 2007. It is not possible to predict which of the recommendations will be implemented by the Alberta Government, if any.

VOLATILITY OF REFINING MARGINS

On July 1, 2007, we established a new operating business segment through the acquisition of a refinery in Lima, Ohio. The U.S. Refining operating business segment is subject to the same risks inherent with all of our plant operations. In addition, we are now sensitive to the volatility of U.S. refining margins, which can be affected by the availability, cost and quality of crude oil feedstock, changes in the supply of refined products in the market, changes in the market demand for refined products and changes in refinery operating costs, including labour and energy costs. We expect U.S. refining margins to continue to be volatile.

7.0 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, 2006 available at www.sedar.com.

8.0 CHANGES IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") section 3855, "Financial Instruments - Recognition and Measurement," section 3865, "Hedges," section 1530, "Comprehensive Income" and section 3861, "Financial Instruments - Disclosure and Presentation." These standards have been adopted prospectively. See Note 3a) to the Consolidated Financial Statements.

ACCOUNTING CHANGES

In July 2006, the AcSB issued a revised CICA section 1506, "Accounting Changes." These amendments were made to harmonize section 1506 with current International Financial Reporting Standards. The changes covered by this section include changes in accounting policy, changes in accounting estimates and correction of errors. Under CICA section 1506, voluntary changes in accounting policy are only permitted if they result in financial statements that provide more reliable and relevant information. When a change in accounting policy is made, this change is applied retrospectively unless impractical. Changes in accounting estimates are generally applied prospectively and material prior period errors are corrected retrospectively. This section also outlines additional disclosure requirements when accounting changes are applied including justification for voluntary changes, complete description of the policy, primary source of GAAP and detailed effect on financial statement line items. CICA section 1506 is effective for fiscal years beginning on or after January 1, 2007.

9.0 OUTSTANDING SHARE DATA [1]

(in thousands, except per share amounts)		Nine months ended Sept. 30 **2007**	Year ended December 31 2006
Share price [2]	High	**$ 46.65**	$ 41.50
	Low	**$ 35.01**	$ 29.00
	Close at end of period	**$ 41.45**	$ 39.02
Average daily trading volume		**1,021**	1,210
Weighted average number of common shares outstanding			
	Basic and diluted	**848,718**	848,412
Issued and outstanding at end of period [3]			
Number of common shares		**848,910**	848,538
Number of stock options		**30,425**	11,656
Number of stock options exercisable		**4,781**	4,464

(1) 2006 amounts as restated. Refer to Note 10 to the Consolidated Financial Statements.
(2) Trading in the common shares of Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite, S&P/TSX Canadian Energy Sector and in the S&P/TSX 60 indices.
(3) There were no significant issuances of common shares, stock options or any other securities convertible into, or exercisable or exchangeable for common shares during the period from September 30, 2007 to October 11, 2007. During this period, 36 thousand stock options were exercised for shares, 65 thousand options were surrendered for cash and 131 thousand options were forfeited. At October 11, 2007, the Company had 848,946 thousand common shares outstanding and there were 30,193 thousand stock options outstanding, of which 4,681 thousand were exercisable.

10.0 NON-GAAP MEASURES

DISCLOSURE OF CASH FLOW FROM OPERATIONS

Management's Discussion and Analysis contains the term "cash flow from operations," which should not be considered an alternative to, or more meaningful than "cash flow - operating activities" as determined in accordance with generally accepted accounting principles as an indicator of our financial performance.

Our determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items.

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

		Nine months ended Sept. 30	Year ended December 31
(millions of dollars)		**2007**	2006
Non-GAAP	Cash flow from operations	**$ 4,001**	$ 4,501
	Settlement of asset retirement obligations	**(35)**	(36)
	Change in non-cash working capital	**(860)**	544
GAAP	Cash flow - operating activities	**$ 3,106**	$ 5,009

11.0 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 2006 Annual Information Form filed in 2007 with Canadian regulatory agencies and Form 40-F filed with the U.S. 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.ca.

Use of Pronouns and Other Terms Denoting Husky

In this MD&A, unless the context indicates otherwise, 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, 2007 are compared with results for the three months ended September 30, 2006 and results for the nine months ended September 30, 2007 are compared with results for the nine months ended September 30, 2006. Discussions with respect to Husky's financial position as at September 30, 2007 are compared with its financial position at December 31, 2006.

Additional Reader Guidance

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

Internal Control over Financial Reporting and Disclosure Controls and Procedures Related to the Acquisition of the Lima Refinery

Effective July 1, 2007, we acquired a refinery in Lima, Ohio from Valero Energy Corporation for a purchase price of U.S. $1.9 billion.

Valero Energy Corporation, a company subject to the certification requirements of sections 302 and 906 of the Sarbanes-Oxley Act of 2002, reported in its Form 10-Q for the period ended March 31, 2007 that there had been no changes in their internal control over financial reporting that had occurred during their last fiscal quarter that materially affected, or was reasonably likely to materially affect their internal control over financial reporting.

The operations of the Lima refinery are currently being integrated into our operations, including assessing and designing internal controls over financial reporting and disclosure controls and procedures for the Lima refinery operations.

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, 2006 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*
MW	*megawatt*
MWh	*megawatt-hour*
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*
OPEC	*Organization of Petroleum Exporting Countries*
WCSB	*Western Canada Sedimentary Basin*
SAGD	*Steam-assisted gravity drainage*

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*
Carbonate	*Sedimentary rock primarily composed of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite) which forms many petroleum reservoirs*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non- cash working capital*
Coalbed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Contingent Resource	*Are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations but not currently economic*
Dated Brent	*Prices which are dated less than 15 days prior to loading for delivery*
Design Rate Capacity	*Maximum continuous rated output of a plant based on its design*
Discovered Resource	*Are those quantities of oil and gas estimated on a given date to be remaining in, plus those quantities already produced from, known accumulations. Discovered resources are divided into economic and uneconomic categories, with the estimated future recoverable portion classified as reserves and contingent resources, respectively*
Equity	*Shares and retained earnings*
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*
Heads of Agreement	*A non-binding document that outlines the main issues relevant to a tentative formal agreement*
Hectare	*One hectare is equal to 2.47 acres*
Nameplate Capacity	*The maximum rated output at which a plant or other equipment was designed and constructed to safely and efficiently operate under specified conditions*
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*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
Possible Reserves	*Are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves*
Surfactant	*A substance that tends to reduce the surface tension of a liquid in which it is dissolved*
Total Debt	*Long-term debt including current portion and bank operating loans*

12.0 FORWARD-LOOKING STATEMENTS

Certain statements in this release and Interim Report are forward-looking statements or information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The Company is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in these forward-looking statements. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intend," "plan," "projection," "could," "vision," "goals," "objective" and "outlook") are not historical facts and are forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. In particular, forward-looking statements include: our general strategic plans, our production guidance, our White Rose and East Coast drilling, development and production plans, our production *plans for the Tucker in-situ oil sands project, our Sunrise oil sands project production plan, design schedule and drilling schedule, our Northwest Territories drilling program, the schedule of our offshore China geophysical and drilling programs, the timing for the signing of agreements and filing of development plans for Indonesia, our Minnedosa plant commissioning and startup schedule, the schedule and our plans for expanding our heavy crude oil mainline, schedule of our Lloydminster Upgrader expansion design plans, our plans to review options in respect of reconfiguring and expanding the Lima refinery and plans for assessing internal controls over financial reporting and disclosure controls and procedures for the Lima refinery operations. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this release and Interim Report. Among the key factors that have a direct bearing on our results of operations are the nature of our involvement in the business of exploration for, and development and production of crude oil and natural gas reserves and the fluctuation of the exchange rates between the Canadian and United States dollar.*

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

- *the prices we receive for our crude and natural gas production;*
- *demand for our products and our cost of operations;*
- *our ability to replace our proved oil and gas reserves in a cost-effective manner;*
- *competitive actions of other companies, including increased competition from other oil and gas companies;*
- *business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us and that may or may not be financially recoverable;*
- *foreign exchange risk;*
- *actions by governmental authorities, including changes in environmental and other regulations that may impose operating costs or restrictions in areas where we operate; and*
- *the accuracy of our reserve estimates and estimated production levels.*

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

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

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of dollars, except share data)	**September 30 2007**	December 31 2006
	(unaudited)	
Assets		
Current assets		
Cash and cash equivalents	**$ 7**	$ 442
Accounts receivable	**1,344**	1,284
Inventories	**1,079**	428
Prepaid expenses	**43**	25
	2,473	2,179
Property, plant and equipment - (full cost accounting)	**28,577**	25,552
Less accumulated depletion, depreciation and amortization	**11,140**	10,002
	17,437	15,550
Goodwill	**636**	160
Other assets	**172**	44
	$ 20,718	$ 17,933
Liabilities and Shareholders' Equity		
Current liabilities		
Bank operating loans *(note 6)*	**$ 43**	$ -
Accounts payable and accrued liabilities	**2,041**	2,574
Long-term debt due within one year *(note 7)*	**747**	100
	2,831	2,674
Long-term debt *(note 7)*	**2,088**	1,511
Other long-term liabilities *(note 8)*	**873**	756
Future income taxes	**4,058**	3,372
Commitments and contingencies *(note 9)*		
Shareholders' equity		
Common shares *(note 10)*	**3,549**	3,533
Retained earnings	**7,382**	6,087
Accumulated other comprehensive income	**(63)**	-
	10,868	9,620
	$ 20,718	$ 17,933
Common shares outstanding *(millions) (note 10)*	**848.9**	848.5

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

Consolidated Statements of Earnings and Comprehensive Income

	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except share data) (unaudited)	**2007**	2006	**2007**	2006
Sales and operating revenues, net of royalties	**$ 4,351**	$ 3,436	**$ 10,758**	$ 9,580
Costs and expenses				
Cost of sales and operating expenses	**2,735**	1,944	**6,215**	5,409
Selling and administration expenses	**58**	38	**148**	115
Stock-based compensation	**(16)**	18	**48**	103
Depletion, depreciation and amortization	**471**	411	**1,344**	1,173
Interest - net *(note 7)*	**47**	19	**90**	68
Foreign exchange *(note 7)*	**(20)**	5	**(57)**	(32)
Other - net	**(36)**	11	**(81)**	19
	3,239	2,446	**7,707**	6,855
Earnings before income taxes	**1,112**	990	**3,051**	2,725
Income taxes				
Current	**99**	210	**237**	624
Future	**244**	98	**674**	(83)
	343	308	**911**	541
Net earnings	**769**	682	**2,140**	2,184
Other comprehensive income *(note 3)*				
Derivatives designated as cash flow hedges, net of tax	**-**	-	**4**	-
Cumulative foreign currency translation adjustment	**(140)**	-	**(140)**	-
Hedge of net investment, net of tax	**91**	-	**91**	-
	(49)	-	**(45)**	-
Comprehensive income *(note 3)*	**$ 720**	$ 682	**$ 2,095**	$ 2,184
Earnings per share				
Basic and diluted *(note 10)*	**$ 0.91**	$ 0.80	**$ 2.52**	$ 2.57
Weighted average number of common shares outstanding *(millions)*				
Basic and diluted *(note 10)*	**848.9**	848.5	**848.7**	848.4

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

Consolidated Statements of Retained Earnings and Accumulated Other Comprehensive Income

	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars) (unaudited)	**2007**	2006	**2007**	2006
Retained earnings, beginning of period	**$ 6,826**	$ 5,287	**$ 6,087**	$ 3,997
Net earnings	**769**	682	**2,140**	2,184
Dividends on common shares - ordinary	**(213)**	(212)	**(637)**	(424)
- special	**-**	-	**(212)**	-
Adoption of financial instruments *(notes 3, 12)*	**-**	-	**4**	-
Retained earnings, end of period	**$ 7,382**	$ 5,757	**$ 7,382**	$ 5,757
Accumulated other comprehensive income, beginning of period	**$ (14)**	$ -	**$ -**	$ -
Adoption of financial instruments *(notes 3, 12)*	**-**	-	**(18)**	-
Other comprehensive income *(note 3)*				
Derivatives designated as cash flow hedges, net of tax	**-**	-	**4**	-
Cumulative foreign currency translation adjustment	**(140)**	-	**(140)**	-
Hedge of net investment, net of tax	**91**	-	**91**	-
	(49)	-	**(45)**	-
Accumulated other comprehensive income, end of period	**$ (63)**	$ -	**$ (63)**	$ -

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

Consolidated Statements of Cash Flows

	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars) (unaudited)	**2007**	2006	**2007**	2006
Operating activities				
Net earnings	**$ 769**	$ 682	**$ 2,140**	$ 2,184
Items not affecting cash				
Accretion *(note 8)*	**13**	16	**35**	34
Depletion, depreciation and amortization	**471**	411	**1,344**	1,173
Future income taxes	**244**	98	**674**	(83)
Foreign exchange	**(48)**	-	**(127)**	(42)
Other	**(29)**	17	**(65)**	28
Settlement of asset retirement obligations	**(14)**	(10)	**(35)**	(24)
Change in non-cash working capital *(note 5)*	**(108)**	259	**(860)**	633
Cash flow - operating activities	**1,298**	1,473	**3,106**	3,903
Financing activities				
Bank operating loans financing - net	**44**	-	**44**	-
Long-term debt issue	**4,755**	-	**6,622**	1,226
Long-term debt repayment	**(3,154)**	-	**(5,121)**	(1,322)
Debt issue costs	**(8)**	-	**(8)**	-
Proceeds from exercise of stock options	**-**	2	**4**	3
Dividends on common shares	**(213)**	(212)	**(849)**	(424)
Change in non-cash working capital *(note 5)*	**301**	(123)	**357**	(664)
Cash flow - financing activities	**1,725**	(333)	**1,049**	(1,181)
Available for investing	**3,023**	1,140	**4,155**	2,722
Investing activities				
Capital expenditures	**(710)**	(746)	**(2,091)**	(2,289)
Corporate acquisition *(note 4)*	**(2,589)**	-	**(2,589)**	-
Asset sales	**5**	1	**332**	34
Other	**(4)**	1	**(42)**	(12)
Change in non-cash working capital *(note 5)*	**149**	31	**(200)**	(79)
Cash flow - investing activities	**(3,149)**	(713)	**(4,590)**	(2,346)
Increase (decrease) in cash and cash equivalents	**(126)**	427	**(435)**	376
Cash and cash equivalents, beginning of period	**133**	117	**442**	168
Cash and cash equivalents, end of period	**$ 7**	$ 544	**$ 7**	$ 544

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, 2007 *(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		Refined Products		U.S. Refining					
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
Three months ended September 30														
Sales and operating revenues, net of royalties	**$ 1,496**	$ 1,600	**$ 406**	$ 485	**$ 2,524**	$ 2,451	**$ 831**	$ 776	**$ 1,043**	$ -	**$(1,949)**	$(1,876)	**$ 4,351**	$ 3,436
Costs and expenses										-				
Operating, cost of sales, selling and general	**332**	329	**305**	399	**2,423**	2,396	**717**	724	**933**	-	**(1,969)**	(1,837)	**2,741**	2,011
Depletion, depreciation and amortization	**413**	382	**7**	6	**7**	6	**16**	11	**22**	-	**6**	6	**471**	411
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**1**	-	**46**	19	**47**	19
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**(20)**	5	**(20)**	5
	745	711	**312**	405	**2,430**	2,402	**733**	735	**956**	-	**(1,937)**	(1,807)	**3,239**	2,446
Earnings (loss) before income taxes	**751**	889	**94**	80	**94**	49	**98**	41	**87**	-	**(12)**	(69)	**1,112**	990
Current income taxes	**56**	158	**4**	31	**5**	18	**(2)**	5	**14**	-	**22**	(2)	**99**	210
Future income taxes	**179**	123	**25**	(5)	**25**	(2)	**33**	8	**19**	-	**(37)**	(26)	**244**	98
Net earnings (loss)	**$ 516**	$ 608	**$ 65**	$ 54	**$ 64**	$ 33	**$ 67**	$ 28	**$ 54**	$ -	**$ 3**	$ (41)	**$ 769**	$ 682
Capital expenditures - Three months ended Sept. 30 [(2)]	**$ 545**	$ 612	**$ 51**	$ 44	**$ 36**	$ 29	**$ 77**	$ 59	**$ 5**	$ -	**$ 8**	$ 10	**$ 722**	$ 754
Nine months ended September 30														
Sales and operating revenues, net of royalties	**$ 4,654**	$ 4,338	**$ 994**	$ 1,294	**$ 7,600**	$ 7,182	**$ 2,158**	$ 1,996	**$ 1,043**	$ -	**$(5,691)**	$(5,230)	**$10,758**	$ 9,580
Costs and expenses														
Operating, cost of sales, selling and general	**950**	948	**769**	980	**7,329**	6,958	**1,909**	1,831	**933**	-	**(5,560)**	(5,071)	**6,330**	5,646
Depletion, depreciation and amortization	**1,219**	1,087	**17**	18	**21**	17	**47**	34	**22**	-	**18**	17	**1,344**	1,173
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**1**	-	**89**	68	**90**	68
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**(57)**	(32)	**(57)**	(32)
	2,169	2,035	**786**	998	**7,350**	6,975	**1,956**	1,865	**956**	-	**(5,510)**	(5,018)	**7,707**	6,855
Earnings (loss) before income taxes	**2,485**	2,303	**208**	296	**250**	207	**202**	131	**87**	-	**(181)**	(212)	**3,051**	2,725
Current income taxes	**81**	457	**5**	84	**50**	57	**13**	17	**14**	-	**74**	9	**237**	624
Future income taxes	**672**	4	**58**	(14)	**28**	(1)	**49**	18	**19**	-	**(152)**	(90)	**674**	(83)
Net earnings (loss)	**$ 1,732**	$ 1,842	**$ 145**	$ 226	**$ 172**	$ 151	**$ 140**	$ 96	**$ 54**	$ -	**$ (103)**	$ (131)	**$ 2,140**	$ 2,184
Capital employed - As at September 30	**$ 9,732**	$ 9,264	**$ 974**	$ 636	**$ 588**	$ 468	**$ 656**	$ 711	**$ 2,485**	$ -	**$ (688)**	$ (68)	**$13,747**	$11,011
Capital expenditures - Nine months ended Sept. 30 [(2)]	**$ 1,682**	$ 1,923	**$ 173**	$ 119	**$ 77**	$ 41	**$ 160**	$ 202	**$ 5**	$ -	**$ 24**	$ 23	**$ 2,121**	$ 2,308
Total assets - As at September 30 [(3)]	**$14,085**	$13,531	**$1,354**	$ 1,076	**$ 1,016**	$ 960	**$ 1,212**	$ 1,070	**$ 2,915**	$ -	**$ 136**	$ 687	**$20,718**	$17,324

[(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.*

[(3)] *2007 includes goodwill on the Lima refinery acquisition related to Downstream - U.S. Refining.*

Geographical Financial Information

	Canada		United States		Other International		Total	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006
Three months ended September 30								
Sales and operating revenues, net of royalties	**$ 2,984**	$ 3,076	**$ 1,293**	$ 297	**$ 74**	$ 63	**$ 4,351**	$ 3,436
Capital expenditures [1]	**696**	711	**5**	-	**21**	43	**722**	754
Nine months ended September 30								
Sales and operating revenues, net of royalties	**$ 8,648**	$ 8,356	**$ 1,891**	$ 1,010	**$ 219**	$ 214	**$10,758**	$ 9,580
Capital expenditures [1]	**2,065**	2,219	**5**	-	**51**	89	**2,121**	2,308
As at September 30								
Property, plant and equipment, net	**$15,631**	$14,710	**$ 1,450**	$ 3	**$ 356**	$ 352	**$17,437**	$15,065
Goodwill	**160**	160	**476**	-	**-**	-	**636**	160

[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, 2006, 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, 2006. Certain prior years' amounts have been reclassified to conform with current presentation.

Note 3 Changes in Accounting Policies

a) Financial Instruments and Hedging Activities

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") section 3855, "Financial Instruments - Recognition and Measurement," section 3865, "Hedges," section 1530, "Comprehensive Income" and section 3861, "Financial Instruments - Disclosure and Presentation." The Company has adopted these standards prospectively and the comparative interim consolidated financial statements have not been restated. Transition amounts have been recorded in retained earnings or accumulated other comprehensive income.

i) Financial Instruments

All financial instruments must initially be recognized at fair value on the balance sheet. The Company has classified each financial instrument into the following categories: held for trading financial assets and financial liabilities, loans or receivables, held to maturity investments, available for sale financial assets, and other financial liabilities. Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on held for trading financial instruments are recognized in earnings. Gains and losses on available for sale financial assets are recognized in other comprehensive income and are transferred to earnings when the asset is derecognized. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method.

Upon adoption and with any new financial instrument, an irrevocable election is available that allows entities to classify any financial asset or financial liability as held for trading, even if the financial instrument does not meet the criteria to designate it as held for trading. The Company has not elected to classify any financial assets or financial liabilities as held for trading unless they meet the held for trading criteria. A held for trading financial instrument is not a loan or receivable and includes one of the following criteria:

- is a derivative, except for those derivatives that have been designated as effective hedging instruments;
- has been acquired or incurred principally for the purpose of selling or repurchasing in the near future; or
- is part of a portfolio of financial instruments that are managed together and for which there is evidence of a recent actual pattern of short-term profit taking.

For financial assets and financial liabilities that are not classified as held for trading, the transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are added to the fair value initially recognized for that financial instrument. These costs are expensed to earnings using the effective interest rate method.

ii) Derivative Instruments and Hedging Activities

Derivative instruments are utilized by the Company to manage market risk against the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company may choose to designate derivative instruments as hedges. Hedge accounting continues to be optional.

At the inception of a hedge, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between the hedged items and hedging items and the method for testing the effectiveness of the hedge, which must be reasonably assured over the term of the hedge. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company formally assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

All derivative instruments are recorded on the balance sheet at fair value in either accounts receivable, other assets, accounts payable and accrued liabilities, or other long-term liabilities. Freestanding derivative instruments are classified as held for trading financial instruments. Gains and losses on these instruments are recorded in other expenses in the consolidated statement of earnings in the period they occur. Derivative instruments that have been designated and qualify for hedge accounting have been classified as either fair value or cash flow hedges. For fair value hedges, the gains or losses arising from adjusting the derivative to its fair value are recognized immediately in earnings along with the gain or loss on the hedged item. For cash flow hedges, the effective portion of the gains and losses is recorded in other comprehensive income until the hedged transaction is recognized in earnings. When the earnings impact of the underlying hedged transaction is recognized in the consolidated statement of earnings, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Any hedge ineffectiveness is immediately recognized in earnings. For any hedging relationship that has been determined to be ineffective, hedge accounting is discontinued on a prospective basis.

The Company may enter into commodity price contracts to hedge anticipated sales of crude oil and natural gas production to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream oil and gas revenues as the related sales occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers to retain market prices while meeting customer or supplier pricing requirements. Gains and losses from these contracts are recognized in midstream revenues or costs of sales.

The Company may enter into power price contracts to hedge anticipated purchases of electricity to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream operating expenses as the related purchases occur.

The Company may enter into interest rate swap agreements to hedge its fixed and floating interest rate mix on long-term debt. Gains and losses from these contracts are recognized as an adjustment to the interest expense on the hedged debt instrument.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments related to foreign exchange are recorded in the foreign exchange expense in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The remaining portion of the gain or loss is recorded in accumulated other comprehensive income and is adjusted for changes in the fair value of the instrument over the life of the debt.

The Company may enter into foreign exchange forwards and foreign exchange collars to hedge anticipated U.S. dollar denominated crude oil and natural gas sales. Gains and losses on these instruments are recognized as an adjustment to upstream oil and gas revenues when the sale is recorded.

For cash flow hedges that have been terminated or cease to be effective, prospective gains or losses on the derivative are recognized in earnings. Any gain or loss that has been included in accumulated other comprehensive income at the time the hedge is discontinued continues to be deferred in accumulated other comprehensive income until the original hedged transaction is recognized in earnings. However, if the likelihood of the original hedged transaction occurring is no longer probable, the entire gain or loss in accumulated other comprehensive income related to this transaction is immediately reclassified to earnings.

Fair values of the derivatives are based on quoted market prices where available. The fair values of swaps and forwards are based on forward market prices. If a forward price is not available for a commodity based forward, a forward price is estimated using an existing forward price adjusted for quality or location.

iii) Embedded Derivatives

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract when their economic characteristics and risks are not clearly and closely related to those of the host contract, the terms of the embedded derivatives are the same as those of a freestanding derivative and the combined contract is not classified as held for trading or designated at fair value. The Company has selected January 1, 2003 as its transition date for accounting for any potential embedded derivatives.

iv) Comprehensive Income

Comprehensive income consists of net earnings and other comprehensive income ("OCI"). OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge and the change in fair value of any available for sale financial instruments. Amounts included in OCI are shown net of tax. Accumulated other comprehensive income is a new equity category comprised of the cumulative amounts of OCI.

b) Lima Refinery Acquisition

Due to the Lima refinery acquisition, effective July 1, 2007, the following accounting policies have been implemented:

i) Financial Instruments and Hedging Activities - Net Investment Hedges

The Company may designate certain U.S. dollar denominated debt as a hedge of its net investment in self-sustaining foreign operations. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in other comprehensive income, net of tax and are limited to the translation gain or loss on the net investment.

ii) Foreign Currency Translation

The accounts of self-sustaining foreign operations are translated using the current rate method. Assets and liabilities are translated at the period-end exchange rate and revenues and expenses are translated at the average exchange rates for the period. Gains and losses on the translation of self-sustaining foreign operations are included in a separate component of accumulated other comprehensive income.

iii) Precious Metals

The Company uses precious metals in conjunction with catalyst as part of the refining process at the Lima refinery. These precious metals remain intact; however, there is a loss during the reclamation process. The estimated loss is amortized to operating expenses over the period that the precious metal is in use, which is approximately two to five years. After the reclamation process, the actual loss is compared to the estimated loss and any difference is recognized in earnings.

c) Accounting Changes

Effective January 1, 2007, the Company adopted the revised recommendations of CICA section 1506, "Accounting Changes."

The new recommendations permit voluntary changes in accounting policy only if they result in financial statements which provide more reliable and relevant information. Accounting policy changes are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively and changes in accounting estimates are applied prospectively by including these changes in earnings. The guidance was effective for all changes in accounting polices, changes in accounting estimates and corrections of prior period errors initiated in periods beginning on or after January 1, 2007.

d) Inventories

The Company has assessed CICA section 3031, "Inventories," which is effective January 1, 2008 and has determined that there will be no impact to the financial statements.

Note 4 Corporate Acquisition

Effective July 1, 2007, the Company acquired a refinery in Lima, Ohio from Valero Energy Corporation through the purchase of all of the issued and outstanding shares of Lima Refining Company ("Lima"). The total cash consideration was U.S. $1.9 billion plus net working capital, which is currently being finalized. An additional U.S. $540 million was paid for the estimated cost of feedstock and product inventory. The results of Lima are included in the consolidated financial statements of the Company from its acquisition date.

Prior to the acquisition of Lima, the Company's business was conducted through three major business segments - Upstream, Midstream and Refined Products. The Refined Products segment has been renamed "Downstream" and includes refining in Canada of crude oil and marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products (Refined Products) and refining in the U.S. of primarily light sweet crude oil to produce and market gasoline and diesel fuels that meet U.S. clean fuels standards (U.S. Refining). The Lima operations have been included in the Downstream - U.S. Refining segment in note 1, Segmented Financial Information.

The allocation of the aggregate purchase price based on the estimated fair values of the net assets of Lima on its acquisition date was as follows:

	U.S. $	Cdn $
Net assets acquired		
Working capital	$ -	$ -
Property, plant and equipment	1,459	1,546
Goodwill (1)	475	503
Other assets	25	26
Other long-term liabilities	(55)	(58)
	1,904	2,017
Feedstock and product inventory acquired	540	572
Total	$ 2,444	$ 2,589

(1) *Allocated to U.S. Refining in the Company's downstream segment and deductible for U.S. income tax purposes. Refer to note 1, Segmented Financial Information.*

The allocation of the purchase price is preliminary and subject to any final adjustments.

Note 5 Cash Flows - Change in Non-cash Working Capital

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	**2007**	2006
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ (213)**	$ (255)	**$ (64)**	$ (146)
Inventories	**(7)**	28	**(98)**	34
Prepaid expenses	**122**	(1)	**(22)**	(20)
Accounts payable and accrued liabilities	**440**	395	**(519)**	22
Change in non-cash working capital	**$ 342**	$ 167	**$ (703)**	$ (110)
Relating to:				
Operating activities	**$ (108)**	$ 259	**$ (860)**	$ 633
Financing activities	**301**	(123)	**357**	(664)
Investing activities	**149**	31	**(200)**	(79)
b) Other cash flow information:				
Cash taxes paid	**$ 25**	$ (10)	**$ 865**	$ 163
Cash interest paid	**43**	22	**105**	101

Note 6 Bank Operating Loans

At September 30, 2007, the Company had unsecured short-term borrowing lines of credit with banks totalling $270 million (December 31, 2006 - $220 million). As at September 30, 2007, bank operating loans were $43 million (December 31, 2006 - nil) and letters of credit under these lines of credit totalled $71 million (December 31, 2006 - $19 million).

Note 7 Long-term Debt

	Maturity	Sept. 30 2007	Dec. 31 2006	Sept. 30 2007	Dec. 31 2006
		Cdn $ Amount		*U.S. $ Denominated*	
Long-term debt					
Bridge financing [1]	2008	**$ 747**	$ -	**$ 750**	$ -
Medium-term notes [2]	2009	**202**	300	**-**	-
6.25% notes	2012	**399**	466	**400**	400
7.55% debentures	2016	**199**	233	**200**	200
6.20% notes	2017	**299**	-	**300**	-
6.15% notes	2019	**299**	350	**300**	300
8.90% capital securities	2028	**224**	262	**225**	225
6.80% notes	2037	**448**	-	**450**	-
Debt issue costs [3]		**(20)**	-	**-**	-
Unwound interest rate swaps [4]		**38**	-	**-**	-
Total long-term debt		**2,835**	1,611	**$2,625**	$ 1,125
Amount due within one year [1]		**(747)**	(100)		
		$ 2,088	$ 1,511		

(1) The Company has the right to extend the maturity of the bridge financing to June 26, 2009 by providing 30 days' notice.
(2) The carrying value of the medium-term notes has been adjusted to fair value to meet the accounting requirements for a fair value hedge. Refer to note 12, Financial Instruments and Risk Management.
(3) Debt issue costs have been reclassified to long-term debt with the adoption of financial instruments. Previously, these deferred costs were included in other assets.
(4) The unamortized portion of the gain on previously unwound interest rate swaps that would be designated as fair value hedges is required to be included in the carrying value of long-term debt with the adoption of financial instruments.

In July 2007, the Company obtained short-term bridge financing from several banks to facilitate closing the acquisition of the Lima refinery. The bridge financing provided U.S. $1.5 billion while the remaining funds required were drawn under existing credit facilities. On September 11, 2007, the Company refinanced U.S. $750 million of the bridge financing by issuing U.S. $300 million of 6.20% notes due September 15, 2017 and U.S. $450 million of 6.80% notes due September 15, 2037. This was the first offering by Husky under a base shelf prospectus dated September 21, 2006 filed with securities regulatory authorities in Canada and the United States. The notes are redeemable at the option of the Company at any time, subject to a make whole provision. Interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of Husky's other unsecured and unsubordinated indebtedness.

Interest - net consisted of:

	Three months ended Sept. 30 2007	Three months ended Sept. 30 2006	Nine months ended Sept. 30 2007	Nine months ended Sept. 30 2006
Long-term debt	**$ 52**	$ 32	**$ 106**	$ 100
Short-term debt	**2**	1	**5**	4
	54	33	**111**	104
Amount capitalized	**(5)**	(9)	**(13)**	(30)
	49	24	**98**	74
Interest income	**(2)**	(5)	**(8)**	(6)
	$ 47	$ 19	**$ 90**	$ 68

Foreign exchange consisted of:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	**2007**	2006
Gain on translation of U.S. dollar denominated long-term debt	**$ (73)**	$ -	**$ (188)**	$ (67)
Cross currency swaps	**23**	-	**59**	26
Other losses	**30**	5	**72**	9
	$ (20)	$ 5	**$ (57)**	$ (32)

Note 8 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Nine months ended Sept. 30	
	2007	2006
Asset retirement obligations at beginning of period	**$ 622**	$ 557
Liabilities incurred	**42**	29
Liabilities disposed	**(14)**	-
Liabilities settled	**(35)**	(24)
Accretion	**35**	34
Asset retirement obligations at end of period	**$ 650**	$ 596

At September 30, 2007, the estimated total undiscounted inflation-adjusted amount required to settle outstanding asset retirement obligations was $4.5 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 6.5%.

Note 9 Commitments and Contingencies

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

Note 10 Share Capital

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

On June 27, 2007, the Company filed Articles of Amendment to implement a two-for-one share split of its issued and outstanding common shares. The share split was approved at a special meeting of the shareholders on June 27, 2007. All references to common share amounts, including common shares issued and outstanding, basic and diluted earnings per share, dividend per share, weighted average number of common shares outstanding and stock options granted, exercised, surrendered and forfeited have been retroactively restated to reflect the impact of the two-for-one share split.

Common Shares

Changes to issued common shares were as follows:

	Nine months ended September 30			
	2007		2006	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of period	848,537,018	$ 3,533	848,250,156	$ 3,523
Options exercised	372,574	16	259,530	9
Balance at September 30	**848,909,592**	**$ 3,549**	848,509,686	$ 3,532

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. Effective February 26, 2007, the Board of Directors approved amendments to the Company's stock option plan to also provide for performance vesting of stock options. Shareholder ratification was obtained at the Annual and Special Meeting of Shareholders on April 19, 2007. Performance options granted may vest in 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 exercisable 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			
	2007		2006	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of period	11,656	$ 16.40	14,570	$ 12.91
Granted	25,716	$ 41.68	1,484	$ 35.13
Exercised for common shares	(372)	$ 11.87	(260)	$ 11.09
Surrendered for cash	(4,535)	$ 13.35	(3,283)	$ 11.76
Forfeited	(2,040)	$ 40.70	(436)	$ 20.24
Outstanding at September 30	**30,425**	**$ 36.58**	12,075	$ 15.73
Options exercisable at September 30	**4,781**	**$ 13.07**	4,681	$ 12.07

	September 30, 2007				
	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
$6.81 - $9.99	52	$ 7.22	1	52	$ 7.22
$10.00 - $10.99	29	$ 10.32	1	29	$ 10.32
$11.00 - $12.99	4,319	$ 11.74	2	4,319	$ 11.74
$13.00 - $19.99	299	$ 16.07	2	68	$ 15.21
$20.00 - $29.99	509	$ 26.03	3	99	$ 24.66
$30.00 - $39.99	1,280	$ 35.89	4	214	$ 35.62
$40.00 - $42.57	23,937	$ 41.68	5	-	$ -
	30,425	**$ 36.58**	**4**	**4,781**	**$ 13.07**

As a result of the special $0.25 per share dividend that was declared in February 2007, a downward adjustment of $0.175 was made to the exercise price of all outstanding stock options effective February 28, 2007, in accordance with the terms of the stock option plan under which the options were issued.

Note 11 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	**2007**	2006
Employer current service cost	**$ 5**	$ 4	**$ 17**	$ 13
Interest cost	**2**	2	**7**	7
Expected return on plan assets	**(2)**	(1)	**(7)**	(4)
Amortization of net actuarial losses	**2**	-	**4**	-
	$ 7	$ 5	**$ 21**	$ 16

Note 12 Financial Instruments and Risk Management

As described in note 3a), on January 1, 2007, the Company adopted the new CICA requirements relating to financial instruments. The following table summarizes the prospective adoption adjustments that were required as at January 1, 2007.

	December 31, 2006 (As Reported)	Adoption Adjustment	January 1, 2007 (As Restated)
Consolidated Balance Sheets			
Assets			
Accounts receivable	$ 1,284	$ 6	$ 1,290
Prepaid expenses	25	(2)	23
Other assets	44	(7)	37
Liabilities and Shareholders' Equity			
Accounts payable and accrued liabilities	2,574	(5)	2,569
Long-term debt due within one year	100	(2)	98
Long-term debt	1,511	34	1,545
Other long-term liabilities	756	(10)	746
Future income taxes	3,372	(6)	3,366
Retained earnings	6,087	4	6,091
Accumulated other comprehensive income	-	(18)	(18)

Commodity Price Risk Management

Natural Gas Contracts

At September 30, 2007, 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	25,663	$ 2
Physical sale contracts	(25,663)	$ 1

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

Interest Rate Risk Management

At September 30, 2007, the Company had entered into a fair value hedge using interest rate swap arrangements whereby the fixed interest rate coupon on the medium-term notes was swapped to floating rates with the following terms:

Debt	Amount	Swap Maturity	Swap Rate *(percent)*	Fair Value
6.95% medium-term notes	$ 200	July 14, 2009	CDOR + 175 bps	$ 2

This contract has been recorded at fair value in other assets.

During the first nine months of 2007, the Company realized a gain of $1 million (2006 - gain of $1 million) from interest rate risk management activities.

Foreign Currency Risk Management

At September 30, 2007, 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	$ (81)
6.25% notes	U.S. $ 75	$ 90	June 15, 2012	5.65	$ (15)
6.25% notes	U.S. $ 50	$ 59	June 15, 2012	5.67	$ (9)
6.25% notes	U.S. $ 75	$ 88	June 15, 2012	5.61	$ (12)

These contracts have been recorded at fair value in other long-term liabilities. The portion of the fair value of the derivative related to foreign exchange losses has been recorded in earnings to offset the foreign exchange on the translation of the underlying debt. The remainder of the loss has been included in other comprehensive income.

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 2007, the impact of these contracts was a gain of $5 million (2006 - gain of $3 million).

Effective July 1, 2007, the Company's U.S. $1.5 billion of debt financing related to the Lima acquisition has been designated as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. The unrealized foreign exchange gain arising from the translation of the debt of $91 million, net of tax of $17 million, is recorded in other comprehensive income, net of tax.

Embedded Derivatives

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 other assets and the resulting unrealized gain has been recorded in other expenses in the consolidated statement of earnings for the period. In the first nine months of 2007, the impact was an unrealized gain on embedded derivatives of $88.3 million.

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, 2007, $350 million of accounts receivable had been sold under the program (December 31, 2006 - nil).

Husky Energy Inc. will host a conference call for analysts and investors on Thursday, October 18, 2007 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.ca, under Investor Relations. The webcast will be archived for approximately 90 days.

Those unable to listen to the call live may listen to a recording by dialing 1-800-319-6413 one hour after the completion of the call, approximately 6:15 p.m. (EST), then dialing reservation number 8622. The Postview will be available until November 18, 2007.

Media are invited to listen to the conference call by dialing 1-800-597-1419 beginning at 4:05 p.m. Eastern time.

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For further information, please contact:

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