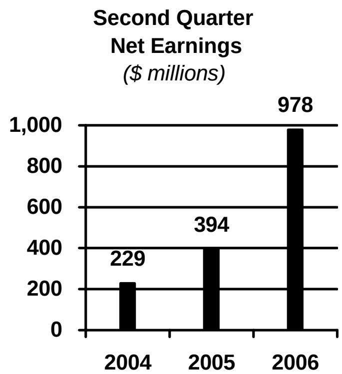
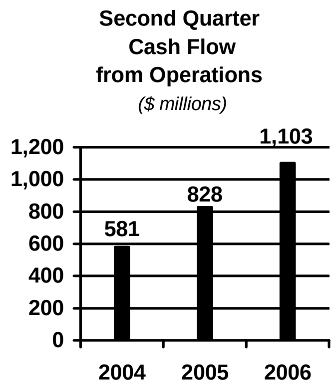
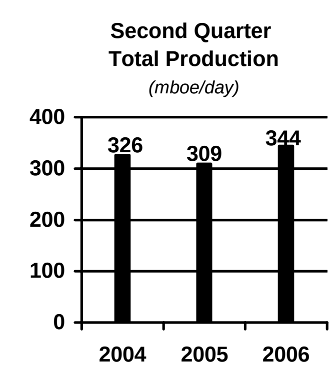
HUSKY ENERGY ANNOUNCES 2006 SECOND QUARTER RESULTS







Calgary, Alberta - Husky Energy Inc. reported net earnings of $978 million or $2.31 per share (diluted) in the second quarter of 2006, up 148 percent from $394 million or $0.93 per share (diluted) in the second quarter of 2005. Net earnings for the second quarter of 2006 included tax benefits due to tax rate reductions of $328 million or $0.77 per share (diluted). Cash flow from operations in the second quarter was $1.1 billion or $2.60 per share (diluted), a 33 percent increase compared with $828 million or $1.95 per share (diluted) for the same period in 2005. Sales and operating revenues, net of royalties, were $3.0 billion in the second quarter of 2006, compared with $2.4 billion in the second quarter of 2005.

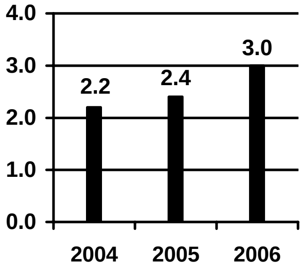
"We are pleased with Husky's exploration success and White Rose project execution," said Mr. John C.S. Lau, President & Chief Executive Officer, Husky Energy Inc. "With a solid balance sheet and cash flow, Husky will continue to benefit from its integrated business strategy and quality asset base in this strong price environment."

Production in the second quarter of 2006 was 344,000 barrels of oil equivalent per day, compared with 308,900 barrels of oil equivalent per day in the second quarter of 2005. Total crude oil and natural gas liquids production was 231,800 barrels per day, compared with 194,000 barrels per day in the second quarter of 2005. Natural gas production was 672.8 million cubic feet per day, compared with 689.3 million cubic feet per day in the second quarter of 2005.

Husky's Tucker Oil Sands Project at Cold Lake, Alberta is on schedule and on budget. Construction of the facility which will use steam-assisted drainage technology (SAGD) is substantially complete. First steam is planned in August of 2006 with first oil targeted for the fourth quarter. During the production cycle, Husky expects to produce approximately 350 million barrels of bitumen with peak production of more than 30,000 barrels per day.

At the Sunrise Oil Sands Project, work is progressing on the front-end engineering design and Husky is continuing its evaluation of alternatives for the downstream portion of the project.

Second Quarter
Sales and Operating
Revenues
($ billions)



Husky successfully acquired an additional 14,560 acres of oil sands lease adjacent to its Saleski property. The acquisition increases Husky's land holdings in Saleski from 178,560 acres to 193,120 acres and the potential resources in Saleski to approximately 20.8 billion barrels of original bitumen in place.

At the White Rose oil field, the fifth production well began producing oil at the end of June and has increased reservoir production capacity to approximately 110,000 barrels of oil per day. A sixth production well is scheduled to come on stream at the end of 2006 and will further increase reservoir production capacity to 125,000 barrels of oil per day.

In June, Husky made a hydrocarbon discovery at the White Rose O-28 delineation well in the western section of the White Rose oil field. Based on the Company's current interpretation, the discovery at the O-28 well could contain an additional potential recoverable resource of 40 to 90 million barrels of oil. The proved plus probable reserves in the White Rose field were estimated at 240 million barrels (174 million barrels Husky's share).

In the South China Sea, Husky made a significant hydrocarbon discovery on the Liwan 3-1-1, Block 29/26. In accordance with the Company's current interpretation of the 2-D seismic and drilling results, the discovery could contain a potential recoverable resource of four to six trillion cubic feet of natural gas. As such, it would be one of the largest natural gas discoveries offshore China.

Offshore Indonesia, Husky was awarded the East Bawean II Block in the East Java Sea, increasing its holdings in the region by 4,255 square kilometres. The East Bawean II Block is located in the North East Java Basin approximately 200 kilometres north of the Company's BD gas field in the Madura Strait, offshore Indonesia. The acquisition of the East Bawean ll Block increases Husky's total holdings in Indonesia to 7,049 square kilometres or approximately 1.8 million acres. Husky holds a 100 percent interest in the Madura Strait and East Bawean II blocks.

Construction of Husky's Lloydminster Ethanol Plant in Lloydminster, Saskatchewan is essentially complete and commissioning activities have commenced with full production expected in the third quarter of 2006. In Minnedosa, Manitoba construction of the new ethanol plant is progressing on schedule with start-up planned in the third quarter of 2007.

For the first six months of 2006, Husky's net earnings were $1.5 billion or $3.54 per share (diluted), compared with $778 million or $1.84 per share (diluted) for the same period in 2005, an increase of 93 percent. Cash flow from operations for the first six months of 2006 was $2.1 billion or $4.88 per share (diluted), compared with $1.6 billion or $3.88 per share (diluted) for the same period in 2005.

Production in the first six months of 2006 was 348,700 barrels of oil equivalent per day, compared with 314,200 barrels of oil equivalent per day in the same period in 2005. Total crude oil and natural gas liquids production was 235,500 barrels per day, compared with 200,400 barrels per day during the first six months of 2005. Natural gas production was 679.0 million cubic feet per day, compared with 682.8 million cubic feet per day in the first six months of 2005.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

July 19, 2006

This MD&A should be read in conjunction with the Consolidated Financial Statements and related Notes. Readers are also encouraged to refer to Husky's MD&A and Consolidated Financial Statements and 2005 Annual Information Form filed in 2006 with Canadian regulatory agencies and Form 40-F filed with the Securities and Exchange Commission ("SEC"), the U.S. regulatory agency. These documents are available at www.sedar.com and at www.sec.gov.

Forward-looking Statements

This MD&A contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. The reader is advised to refer to Section 14.0 "Forward-looking Statements or Information" for additional information.

Use of Pronouns and Other Terms Denoting Husky

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended June 30, 2006 are compared with results for the three months ended June 30, 2005 and results for the six months ended June 30, 2006 are compared with results for the six months ended June 30, 2005. Discussions with respect to Husky's financial position as at June 30, 2006 are compared with its financial position at December 31, 2005.

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.

1.0 SUMMARY OF QUARTERLY RESULTS

Husky's net earnings for the second quarter of 2006 were $978 million, up $584 million compared with the second quarter of 2005. Included in net earnings during the second quarter of 2006 are tax benefits amounting to $328 million. These benefits relate to tax rate reductions by the governments of Canada, Alberta and Saskatchewan that were all substantively enacted during the quarter.

The White Rose oil field, which commenced operations in the fourth quarter of 2005, contributed significantly to the positive variance in the second quarter of 2006 as did higher crude oil prices. Unrealized gains from foreign currency translation and lower stock-based compensation also contributed to the higher net earnings in the second quarter. The positive variance in the second quarter was partially offset by higher cash taxes, lower natural gas prices, lower production volumes from the Terra Nova and Wenchang oil fields and lower upgrading differentials.

Financial Summary		Three months ended							
		June 30	March 31	Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30
(millions of dollars, except per share amounts and ratios)		**2006**	2006	2005	2005	2005	2005	2004	2004
Sales and operating revenues, net of royalties		**$ 3,040**	$ 3,104	$ 3,207	$ 2,594	$ 2,350	$ 2,094	$ 2,018	$ 2,191
Segmented earnings									
Upstream		**$ 822**	$ 412	$ 533	$ 445	$ 307	$ 239	$ 112	$ 161
Midstream		**140**	150	135	61	130	169	77	50
Refined Products		**52**	16	17	27	20	18	(3)	18
Corporate and eliminations		**(36)**	(54)	(16)	23	(63)	(42)	39	68
Net earnings		**$ 978**	$ 524	$ 669	$ 556	$ 394	$ 384	$ 225	$ 297
Per share	- Basic	**$ 2.31**	$ 1.24	$ 1.58	$ 1.31	$ 0.93	$ 0.91	$ 0.53	$ 0.70
	- Diluted	**2.31**	1.24	1.58	1.31	0.93	0.91	0.53	0.70
Cash flow from operations		**1,103**	967	1,197	944	828	816	469	571
Per share	- Basic	**2.60**	2.28	2.82	2.23	1.95	1.93	1.11	1.34
	- Diluted	**2.60**	2.28	2.82	2.23	1.95	1.93	1.11	1.34
Dividends per common share		**0.25**	0.25	0.25	0.14	0.14	0.12	0.12	0.12
Special dividend per common share		**-**	-	1.00	-	-	-	0.54	-
Total assets		**16,405**	15,859	15,797	14,712	14,058	13,690	13,240	12,901
Total long-term debt including current portion		**1,722**	1,838	1,886	1,896	2,192	2,290	2,103	2,096
Return on equity [(1)]	*(percent)*	**34.8**	29.6	29.2	22.9	20.2	18.3	17.0	17.7
Return on average capital employed [(1)]	*(percent)*	**28.2**	23.2	22.8	17.9	15.3	13.9	13.0	13.4

[(1)] *Calculated for the twelve months ended for the periods shown.*

Western Canada crude oil production for the second quarter of 2006 remained at the same level as compared with the first quarter of 2006. Natural gas sales volume decreased by 13 mmcf/day from the first quarter of 2006 to the second quarter of 2006. This decrease was primarily due to a higher number of plant turnarounds and repairs, pipeline and sales restrictions and tie-in delays.

In the second quarter of 2006, we drilled 45 gross (26 net) exploration wells in the Western Canada Sedimentary Basin ("WCSB") resulting in 8 gross (8 net) oil wells and 34 gross (16 net) gas wells. In the natural gas prone deep basin, foothills and northern plains areas we drilled 9 gross (5.5 net) wells resulting in 8 gross (5.1 net) natural gas wells. At June 30, 2006, 6 gross (3.5 net) wells were drilling or suspended in these regions.

Following successful completion of a fourth production well in May 2006, Husky achieved 100 mbbls/day (72.5 mbbls/day Husky's share) of production from the White Rose field. The field's production rates were kept at an average rate of 85 mbbls/day (62 mbbls/day Husky's share) until the fifth production well came on stream at the end of the quarter. The addition of the fifth production well has increased the field's productive capacity by 25 mbbls/day to 110 mbbls/day (80 mbbls/day Husky's share).

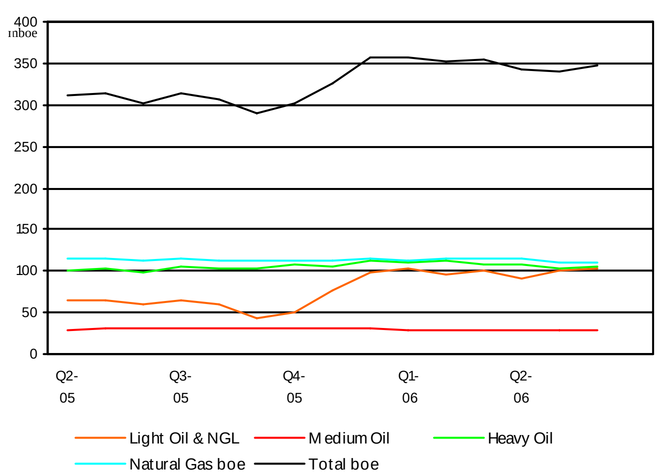
Terra Nova oil field production was 6.5 mbbls/day lower in the second quarter of 2006 compared with the first quarter of 2006 as a result of mechanical failure of components in the gearbox of both of the vessel's main power generators. The FPSO subsequently suspended production operations in early May and began preparing to disconnect from the riser buoy prior to disembarking for dry dock and commencement of the 2006 turnaround. Production operations are expected to resume in late September 2006.

Wenchang oil field production declined by 1.4 mbbls/day in the second quarter of 2006 compared with the first quarter of 2006 reflecting natural reservoir decline.

Daily Gross Production

		Three months ended				
		June 30 2006	March 31 2006	Dec. 31 2005	Sept. 30 2005	June 30 2005
Crude oil and NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**29.8**	31.3	30.1	31.8	31.7
Medium crude oil		**28.5**	29.4	31.0	30.3	30.6
Heavy crude oil		**105.6**	109.5	109.5	103.3	100.9
		163.9	170.2	170.6	165.4	163.2
East Coast Canada						
White Rose - light crude oil		**53.0**	46.4	19.0	-	-
Terra Nova - light crude oil		**2.8**	9.3	12.2	10.2	13.5
China						
Wenchang - light crude oil		**12.1**	13.5	14.1	14.4	17.3
		231.8	239.4	215.9	190.0	194.0
Natural gas	*(mmcf/day)*	**672.8**	685.4	675.3	679.2	689.3
Total	*(mboe/day)*	**344.0**	353.6	328.5	303.2	308.9

Production



During the first six months of 2006 White Rose was further developed and Husky's share averaged 49.7 mbbls/day. This increase in production of light crude was partially offset because the Terra Nova oil field was shut-in to prepare to move the FPSO to dry dock.

2.0 STRATEGIC PLANS AND CAPABILITIES

We have several major projects that are at various stages of development and, upon completion, are expected to result in sustained growth in enterprise value.

Upstream

- East Coast Exploration and Development
- Oil Sands Development
- Mackenzie River Valley Exploration
- China and Indonesia Exploration and Development

Midstream

- Upgrader Expansion

Refined Products

- Refinery Modifications
- Ethanol Plant Construction

2.1 UPSTREAM

Gross Production		Six months ended June 30 **2006**	Full Year Forecast 2006	Six months ended June 30 2005	Year ended Dec. 31 2005
Crude oil & NGL	*(mbbls/day)*				
Light crude oil & NGL		**99.0**	103 - 116	63.3	64.6
Medium crude oil		**29.0**	29 - 32	31.5	31.1
Heavy crude oil		**107.5**	115 - 120	105.6	106.0
		235.5	247 - 268	200.4	201.7
Natural gas	*(mmcf/day)*	**679.0**	680 - 730	682.8	680.0
Total barrels of oil equivalent	*(mboe/day)*	**348.7**	360 - 390	314.2	315.0

Our foundation assets in the WCSB currently provide the majority of the funding required to finance our strategic plans including our strategy with respect to the optimal exploitation of the significant remaining resources in the WCSB.

These exploitation activities involve increased drilling of infill and step-out wells, the installation of various types of enhanced recovery techniques, including thermal recovery of heavy oil and emerging technologies such as alkaline surfactant polymer floods. In addition, increased production from coalbed methane deposits is augmenting natural gas production.

We also plan to maintain exploration activities focused on natural gas prospects in the deep basin and the foothills and northern regions of Alberta and British Columbia where natural gas reservoirs are deeper and have been larger and prolific.

White Rose Oil Field

Following successful completion of a fourth production well, the White Rose oil field achieved 100 mbbls/day (72.5 mbbls/day Husky's share) of total production. Production rates were kept at an average rate of 85 mbbls/day (62 mbbls/day Husky's share) until the fifth production well came on production at the end of the quarter. The addition of the fifth producer has increased reservoir productive capacity to 110 mbbls/day total (80 mbbls/day Husky's share). A sixth production well, which is scheduled to come on stream at the end of 2006, will further increase reservoir productive capacity to 125 mbbls/day total (91 mbbls/day Husky's share).

Actual production will depend on the FPSO throughput capacity limitation, which will be evaluated during the third quarter of 2006.

On June 20, 2006 we announced a hydrocarbon discovery at the White Rose O-28 delineation well in the western section of the White Rose oil field. The O-28 well was drilled on Significant Discovery Licence 1024 to depths of up to 3,342 metres. The well revealed a 280 metre oil column in a multi-layered reservoir in the Ben Nevis Avalon formation. An additional side-track well is being drilled and logged to provide further information about reservoir quality, continuity and hydrocarbon contacts. Based on our current interpretation of the 3-D seismic and the O-28 well results, the discovery could contain a potential recoverable gross resource of 40 to 90 million barrels of oil. Our share of this potential recoverable resource will augment our proved and probable reserves which were approximately 173 million barrels of oil at the end of 2005. Husky plans to tie this western extension of the oil field back to the *SeaRose FPSO*.

East Coast Canada Exploration

In the West Bonne Bay region of the Jeanne d'Arc Basin on Significant Discovery Licence ("SDL") 1040, exploration drilling began during the second quarter. West Bonne Bay is located just to the northeast of the Terra Nova oil field. Under the terms of a farm-in agreement with Norsk Hydro, who currently hold a 90 percent interest, we will earn a 25 percent interest in SDL 1040 and an additional 7.5 percent interest in the North Ben Nevis SDL 1008 where we hold a 65.6 percent interest.

A seismic vessel has been contracted to finish the 3-D seismic program in the Jeanne d'Arc Basin that was halted last fall due to inclement weather. This program, along with additional 3-D seismic shooting in the vicinity of the White Rose and Terra Nova oil fields, will commence early July.

Tucker Oil Sands Project

At the Tucker Oil Sands project, construction is substantially complete and is on schedule to begin steam injection in August of 2006. Drilling and well completions are 100 percent complete. Operational readiness has been achieved with fully trained staff on-site. The project remains on schedule to produce first oil in the fourth quarter of 2006.

Sunrise Oil Sands Project

During the second quarter of 2006 progress at Sunrise included commencement of front-end engineering design, which is targeted to be complete by the third quarter of 2007. Various facility configuration studies are ongoing and collaborative work continued with various industry participants on regional infrastructure, including an access highway and airport. Modeling of the source water is ongoing and we plan to drill five source water evaluation wells prior to year-end. An additional 10 source water evaluation wells and 29 stratigraphic test wells are planned for the winter drilling season. Pad locations and trajectories for phase one horizontal wells are currently being determined.

Caribou and Saleski

During the second quarter we began evaluating core from stratigraphic test well programs completed at Saleski and Caribou during the winter and spring. Development planning is underway including water source and disposal studies for both projects and determination of the appropriate bitumen recovery process for Saleski.

Husky acquired one oil sands lease in the Saleski area of northern Alberta at the July 12, 2006 Alberta land sale (Lease L0402 located in Ranges 20 & 21, Township 87 W4M). The lease totals 14,560 acres and is estimated to contain 1.3 billion barrels of bitumen in place within the Grosmont and Nisku carbonate. The acquired lands are adjacent to Husky's existing holdings in the Saleski area and resulted in an increase in Husky's total land holdings from 178,560 acres to 193,120 acres (or from 279 sections to 302 sections) and increased Husky's bitumen in place estimate for Saleski from 19.5 billion barrels to 20.8 billion barrels.

Northwest Territories Exploration

In May 2006 Husky announced a natural gas discovery at the Stewart D-57 well. The D-57 discovery was drilled on Tulita District Land Corporation Freehold Block M-38. The well was drilled to a depth of 3,147 metres, cased to total depth and suspended. On open-hole testing, natural gas flowed from two Cretaceous intervals to the surface at a combined rate of 5 million cubic feet per day, confirming a hydrocarbon bearing column of at least 50 metres. This is the first successful Cretaceous hydrocarbon discovery in the Central Mackenzie region.

Husky also concluded its winter drilling program in the Summit Creek area approximately 26 kilometres northwest of the Stewart D-57 discovery. The program consisted of the Summit Creek K-44 well, an appraisal and deeper pool exploration well adjacent to the Summit Creek B-44 discovery well. Summit Creek K-44 was drilled on Exploration License ("EL") 397, 1.4 kilometres northeast of the B-44 discovery well. The well was drilled to a depth of 3,130 metres, cased to total depth and suspended. The results are being evaluated.

During the second quarter of 2006 we were awarded EL 441 (Block CMV-6), flanking the eastern boundary of EL 397. The licence area contains extensions of several plays from EL 397, including the Cretaceous natural gas play recently confirmed by our Stewart D-57 well. The licence requires a work commitment of $10.5 million over the next four years. We now hold interests in approximately 3,275 square kilometers in the Central Mackenzie Valley area.

Approximately 200 kilometres of seismic is being shot to better identify prospects for this winter's drilling program on EL 397.

China Exploration

On June 14, 2006 we announced a significant hydrocarbon discovery at Liwan 3-1-1, in the South China Sea.

Liwan 3-1-1 was drilled in a water depth of 1,500 metres on Block 29/26 in the Pearl River Mouth Basin and is the first deep water discovery made offshore China. The block is located approximately 250 kilometres south of Hong Kong. The well was drilled on existing 2-D seismic data to a total depth of 3,843 metres on a large structure with 60 square kilometres of closure and encountered 56 metres of net gas pay on logs over two zones. The 2-D seismic interpretation prior to drilling the well indicated a direct hydrocarbon response at the Liwan 3-1-1 location, which is present over a majority of the 60 square kilometre closure currently mapped. The porosity encountered in the pay zones averaged approximately 20 percent, based on petrophysical interpretation.

The Liwan 3-1-1 well will be sidetracked for further evaluation of the pay zone and we are currently planning a 3-D seismic survey for the near future to assess a number of similar structures which have been identified on 2-D seismic data. Further drilling on the block will follow after the evaluation of the 3-D data. Based on our current interpretation of the 2-D seismic and the Liwan 3-1-1 well results, the discovery could contain a potential recoverable resource of four to six trillion cubic feet of natural gas. China National Offshore Oil Corporation has the right to participate in the development of any discoveries up to a 51 percent working interest.

Also, in China, we are seeking tenders on a rig to drill an exploration well on Block 04/35 in the East China Sea. The well is planned for late 2006.

Indonesia Natural Gas Development

At Madura, Indonesia, the conceptual design for the BD natural gas field development has been submitted to the Indonesian regulatory agency, BPMIGAS, for consideration. Negotiations on a gas sales agreement and extension of the production sharing agreement continued through the second quarter of 2006. Completion of this project is contingent on the timing of government approval.

During the second quarter of 2006 we were awarded the Bawean II Block. This block is located in the same basin as the Madura BD natural gas field and contains similar prospects. We have committed to shoot 1,400 square kilometres of seismic and drill two wells in the first exploration phase.

2.2 MIDSTREAM

We are currently implementing various pipeline and terminal expansion initiatives coincident with the increasing level of upstream activity, particularly in the heavy oil/bitumen corridor and south to the main pipeline shipping systems at Hardisty, Alberta.

Lloydminster Upgrader

At the Lloydminster Upgrader the front-end engineering design with respect to plans to expand throughput capacity from approximately 80 to 150 mbbls/day of synthetic crude oil and diluent commenced. The plans also include modifications to the Upgrader that will permit processing of a 67 percent Cold Lake bitumen feedstock mix. During the second quarter of 2006 negotiations were completed and agreements executed with various process licensors. Front-end engineering design work is expected to be completed by the third quarter of 2007. Subject to project sanction, completion of the expansion could be achieved by the end of 2010.

2.3 REFINED PRODUCTS

Prince George Refinery Low Sulphur Upgrade

At the Prince George refinery the second phase of modifications to produce low sulphur diesel fuel is complete. The refinery now produces both low sulphur gasoline and ultra low sulphur diesel consistent with marketplace requirements. The refinery's design rate capacity is now 12 mbbls/day of low sulphur fuel, a 20 percent increase based on previously stated capacity.

Lloydminster and Minnedosa Ethanol Plants

To meet the increasing demand for ethanol blended gasoline, which currently ranges from 10 percent E-10 to 85 percent E-85 ethanol, we are currently constructing two motor fuel grade ethanol plants. One plant is located adjacent to our Upgrader at Lloydminster, Saskatchewan and the other at Minnedosa, Manitoba, the site of our existing ethanol plant. Each plant will have the same throughput capacity, producing 130 million litres of ethanol per year.

Construction of the Lloydminster plant is essentially complete and is in the final stages of commissioning.

Construction of the Minnedosa plant is approximately 20 percent complete. The plant is expected to be ready for start-up during the third quarter of 2007.

3.0 BUSINESS ENVIRONMENT

Husky's financial results are significantly influenced by its business environment. Average quarterly market prices were:

Average Benchmark Prices and U.S. Exchange Rate		Three months ended				
		June 30 2006	March 31 2006	Dec. 31 2005	Sept. 30 2005	June 30 2005
WTI crude oil [1]	*(U.S. $/bbl)*	**70.70**	63.48	60.02	63.10	53.17
Brent crude oil [2]	*(U.S. $/bbl)*	**69.62**	61.75	56.90	61.54	51.58
Canadian par light crude 0.3% sulphur	*($/bbl)*	**78.97**	69.40	71.65	77.04	66.43
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**48.65**	26.25	29.60	44.13	27.95
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**6.79**	8.98	12.97	8.49	6.73
NIT natural gas	*($/GJ)*	**5.95**	8.79	11.08	7.75	6.99
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**17.99**	29.20	24.24	18.90	21.27
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.891**	0.866	0.852	0.833	0.804

(1) Prices quoted are near-month contract prices for settlement during the next month.

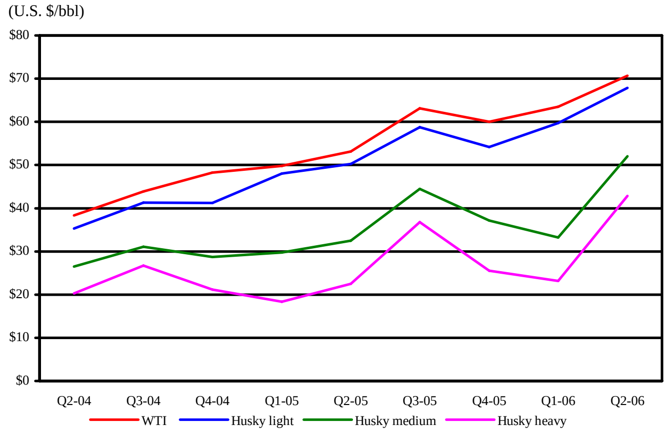
(2) Dated Brent prices which are dated less than 15 days prior to loading for delivery.

3.1 COMMODITY PRICE RISK

Our earnings depend largely on the profitability of our upstream business segment which is most significantly affected by fluctuations in oil and gas prices. Commodity prices have been, and are expected to continue to be, volatile due to a number of factors beyond our control. The effect of any single risk is not determinable with certainty as these are interdependent and our future course of action depends upon our assessment of all information available at any given time.

Crude Oil

WTI and Husky Average Crude Oil Prices



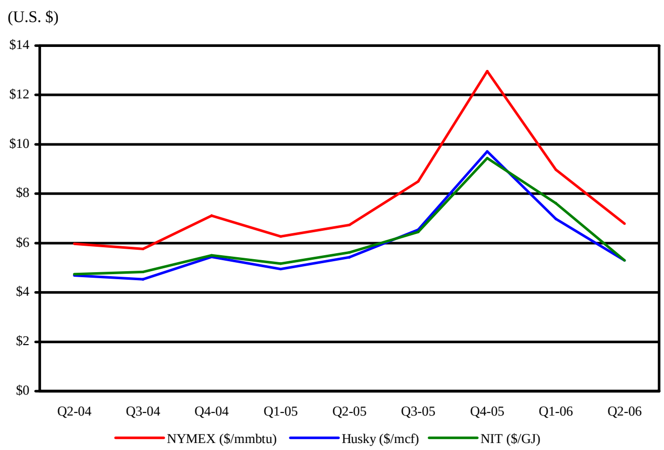
WTI, the benchmark crude price, has escalated throughout the period reported with some fluctuations, closely followed by Husky's light crude prices.

The prices received for our crude oil and NGL are related to the price of crude oil in world markets. Prices for heavy crude oil and other lesser quality crudes trade at a discount or differential to light crude oil due to the additional processing costs.

Following the typical seasonal lull in crude oil prices in the fourth quarter of 2005 prices recovered to and then exceeded the U.S. $70.00/bbl level ending the second quarter with a spot price of U.S. $73.94/bbl. The environment for crude oil prices, in the near-term, remains unchanged as a result of continued geopolitical strife and unpredictable weather patterns.

Natural Gas

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



Both U.S. and Canadian benchmark natural gas prices have decreased in 2006. Husky's natural gas prices, which are dominated by floating prices, followed suit.

The price of natural gas in North America is affected by regional supply and demand factors, particularly those affecting the United States such as weather conditions, pipeline delivery capacity, production disruptions, the availability of alternative sources of less costly energy supply, inventory levels and general industry activity levels. Periodic imbalances between supply and demand for natural gas are common and result in volatile pricing.

NYMEX natural gas prices peaked at the end of 2005, primarily as a result of hurricane related shut-in production, after which mild winter weather, high gas storage levels and mandatory draw downs caused prices to decline rapidly through the first quarter of 2006. Prices during the second quarter of 2006 fluctuated in the range of U.S. $6.00/mmbtu and U.S. $7.50/mmbtu and ended the quarter at U.S. $5.89/mmbtu for July deliveries.

Other Business Environment Risks

Please refer to our 2005 MD&A for a discussion about other business environment risks.

3.2 SENSITIVITY ANALYSIS

The following table indicates the relative annual effect of changes in certain key variables on our pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the second quarter of 2006. 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.

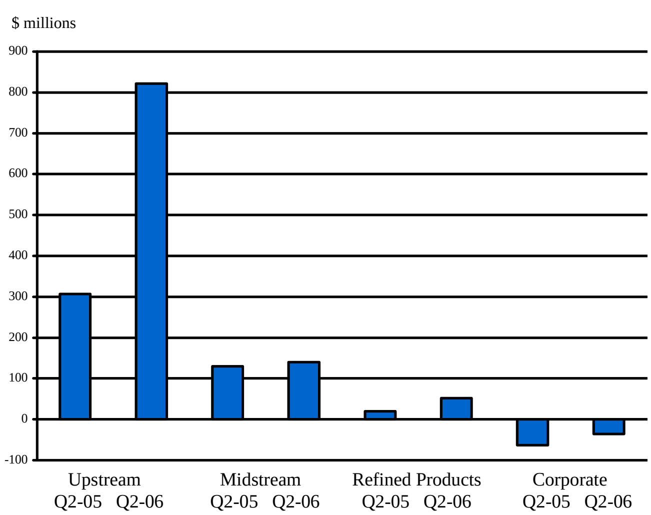
Sensitivity Analysis

	2006 Second 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	70.70	*U.S. $1.00/bbl*	82	0.19	55	0.13
NYMEX benchmark natural gas price [1]	6.79	*U.S. $0.20/mmbtu*	34	0.08	23	0.05
WTI/Lloyd crude blend differential [2]	17.99	*U.S. $1.00/bbl*	(29)	(0.07)	(19)	(0.04)
Exchange rate (U.S. $ per Cdn $) [3]	0.89	*U.S. $0.01*	(68)	(0.16)	(46)	(0.11)
Refined Products						
Light oil margins	0.05	*Cdn $0.005/litre*	16	0.04	10	0.02
Asphalt margins	12.51	*Cdn $1.00/bbl*	9	0.02	6	0.01
Consolidated						
Period end translation of U.S. $ debt (U.S. $ per Cdn $)	0.90 [4]	*U.S. $0.01*			8	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 June 30, 2006.*
(5) *Based on June 30, 2006 common shares outstanding of 424.2 million.*

4.0 RESULTS OF OPERATIONS

Quarterly Segmented Earnings



Husky's profitability is largely dependant on Upstream operations, partially supported by upgrading results during times when light/heavy crude oil differentials are wider.

4.1 UPSTREAM

Second Quarter

Upstream earnings were $515 million higher in the second quarter of 2006 than in the second quarter of 2005 as a result of the following factors:

- higher sales volume of light and heavy crude oil;
- higher light, medium and heavy crude oil prices; and
- lower income taxes resulting from rate reductions.

Partially offset by:

- lower sales volume of medium crude oil and natural gas;
- lower natural gas prices;
- higher unit operating costs; and
- higher unit depletion, depreciation and amortization.

Six Months

The factors that affected results for the second quarter were primarily responsible for variances in results for the six months ended June 30, 2006 except for natural gas prices, which were higher during the six month period in 2006 compared with the same period in 2005.

Upstream Earnings Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2006**	2005	**2006**	2005
Gross revenues	**$ 1,658**	$ 1,154	**$ 3,151**	$ 2,194
Royalties	**207**	178	**413**	330
Net revenues	**1,451**	976	**2,738**	1,864
Operating and administration expenses	**308**	249	**619**	489
Depletion, depreciation and amortization	**354**	278	**705**	551
Income taxes	**(33)**	142	**180**	278
Earnings	**$ 822**	$ 307	**$ 1,234**	$ 546

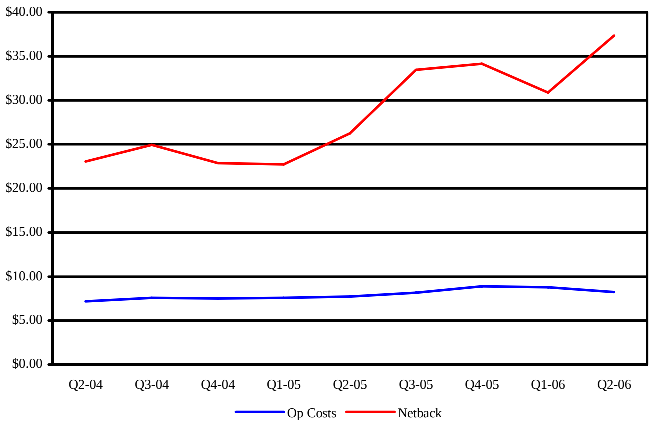
Net Revenue Variance Analysis

(millions of dollars)	Crude oil & NGL	Natural gas	Other	Total
Three months ended June 30, 2005	$ 624	$ 332	$ 20	$ 976
Price changes	353	(49)	-	304
Volume changes	205	(10)	-	195
Royalties	(60)	31	-	(29)
Processing and sulphur	-	-	5	5
Three months ended June 30, 2006	**$ 1,122**	**$ 304**	**$ 25**	**$ 1,451**
Six months ended June 30, 2005	$ 1,197	$ 631	$ 36	$ 1,864
Price changes	490	75	-	565
Volume changes	384	(4)	-	380
Royalties	(84)	-	-	(84)
Processing and sulphur	-	-	13	13
Six months ended June 30, 2006	**$ 1,987**	**$ 702**	**$ 49**	**$ 2,738**

Unit Operating Costs

Unit operating costs were six percent higher in the second quarter of 2006 compared with the same period in 2005 due to higher costs for energy, labour, servicing natural gas compression, higher natural gas well count and production declines. The high level of industry activity has created increased demand for, and consequently, higher prices for oil field materials and services.

NETBACK AND UNIT OPERATING COST



Higher netbacks resulting from higher crude oil prices are only marginally offset by increases in operating costs.

Unit Depletion, Depreciation and Amortization

Unit depletion, depreciation and amortization expense increased 15 percent in the second quarter of 2006 compared with the same period in 2005. The increase was primarily due to net growth of the capital base in 2006 as a result of increased requirements for production maintenance capital for our properties in the WCSB, and the start-up of the White Rose oil field, which, since it is an offshore development, has a higher ratio of capital to reserves. In addition, the higher energy costs, as with operating costs, increased the cost of materials and services embedded in our capital costs.

Average Sales Prices		Three months ended June 30		Six months ended June 30	
		2006	2005	**2006**	2005
Crude Oil	*($/bbl)*				
Light crude oil & NGL		**$ 73.74**	$ 59.51	**$ 70.35**	$ 57.95
Medium crude oil		**58.42**	40.45	**48.29**	38.42
Heavy crude oil		**48.12**	27.95	**26.73**	25.13
Total average		**60.18**	40.09	**52.54**	37.59
Natural Gas	*($/mcf)*				
Average		**5.95**	6.76	**7.01**	6.42

Effective Royalty Rates	Three months ended June30		Six months ended June 30	
Percentage of upstream sales revenues	**2006**	2005	**2006**	2005
Crude oil & NGL	**12%**	13%	**11%**	13%
Natural gas	**15%**	20%	**18%**	20%
Total	**13%**	16%	**13%**	15%

Upstream Revenue Mix	Three months ended June 30		Six months ended June 30	
Percentage of upstream sales revenues, after royalties	**2006**	2005	**2006**	2005
Light crude oil & NGL	**41%**	31%	**42%**	31%
Medium crude oil	**8%**	10%	**8%**	10%
Heavy crude oil	**28%**	23%	**23%**	23%
Natural gas	**23%**	36%	**27%**	36%
	100%	100%	**100%**	100%

Operating Netbacks

	WCSB		East Coast		International		Total	
Three months ended June 30	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
Light Crude Oil *(per boe)* [(1)]								
Sales Price	**$ 62.34**	$ 57.50	**$ 76.57**	$ 58.11	**$ 77.80**	$ 66.11	**$ 72.56**	$ 60.20
Royalties	**7.14**	7.64	**1.82**	2.86	**16.35**	6.16	**5.21**	6.09
Operating costs	**12.88**	11.26	**4.97**	3.29	**2.41**	2.39	**6.95**	6.91
	42.32	38.60	**69.78**	51.96	**59.04**	57.56	**60.40**	47.20
Medium Crude Oil *(per boe)* [(1)]								
Sales Price	**57.34**	40.61	**-**	-	**-**	-	**57.34**	40.61
Royalties	**10.76**	6.98	**-**	-	**-**	-	**10.76**	6.98
Operating costs	**11.52**	10.05	**-**	-	**-**	-	**11.52**	10.05
	35.06	23.58	**-**	-	**-**	-	**35.06**	23.58
Heavy Crude Oil *(per boe)* [(1)]								
Sales Price	**47.92**	28.09	**-**	-	**-**	-	**47.92**	28.09
Royalties	**6.34**	3.09	**-**	-	**-**	-	**6.34**	3.09
Operating costs	**10.28**	9.48	**-**	-	**-**	-	**10.28**	9.48
	31.30	15.52	**-**	-	**-**	-	**31.30**	15.52
Total Crude Oil *(per boe)* [(1)]								
Sales Price	**52.08**	35.64	**76.57**	58.11	**77.80**	66.11	**59.28**	39.96
Royalties	**7.28**	4.65	**1.82**	2.86	**16.35**	6.16	**6.44**	4.66
Operating costs	**10.95**	9.90	**4.97**	3.29	**2.41**	2.39	**9.07**	8.79
	33.85	21.09	**69.78**	51.96	**59.04**	57.56	**43.77**	26.51
Natural Gas *(per mcfge)* [(2)]								
Sales Price	**6.23**	6.81	**-**	-	**-**	-	**6.23**	6.81
Royalties	**1.16**	1.51	**-**	-	**-**	-	**1.16**	1.51
Operating costs	**1.09**	1.00	**-**	-	**-**	-	**1.09**	1.00
	3.98	4.30	**-**	-	**-**	-	**3.98**	4.30
Equivalent Unit *(per boe)* [(1)]								
Sales Price	**46.13**	37.81	**76.57**	58.11	**77.80**	66.11	**52.19**	40.29
Royalties	**7.15**	6.49	**1.82**	2.86	**16.35**	6.16	**6.61**	6.31
Operating costs	**9.17**	8.26	**4.97**	3.29	**2.41**	2.39	**8.24**	7.74
	$ 29.81	$ 23.06	**$ 69.78**	$ 51.96	**$ 59.04**	$ 57.56	**$ 37.34**	$ 26.24

(1) *Includes associated co-products converted to boe.*

(2) *Includes associated co-products converted to mcfge.*

Operating Netbacks (continued)

Six months ended June 30	WCSB 2006	WCSB 2005	East Coast 2006	East Coast 2005	International 2006	International 2005	Total 2006	Total 2005
Light Crude Oil *(per boe)* [1]								
Sales Price	**$ 61.50**	$ 53.92	**$ 73.14**	$ 59.42	**$ 75.58**	$ 62.42	**$ 70.06**	$ 57.61
Royalties	**6.27**	6.23	**2.75**	2.94	**10.83**	5.78	**4.85**	5.37
Operating costs	**12.32**	10.53	**6.15**	3.61	**3.11**	2.38	**7.55**	6.70
	42.91	37.16	**64.24**	52.87	**61.64**	54.26	**57.66**	45.54
Medium Crude Oil *(per boe)* [1]								
Sales Price	**47.83**	38.49	**-**	-	**-**	-	**47.83**	38.49
Royalties	**8.51**	6.69	**-**	-	**-**	-	**8.51**	6.69
Operating costs	**12.02**	10.30	**-**	-	**-**	-	**12.02**	10.30
	27.30	21.50	**-**	-	**-**	-	**27.30**	21.50
Heavy Crude Oil *(per boe)* [1]								
Sales Price	**37.34**	25.28	**-**	-	**-**	-	**37.34**	25.28
Royalties	**4.71**	2.62	**-**	-	**-**	-	**4.71**	2.62
Operating costs	**10.76**	9.35	**-**	-	**-**	-	**10.76**	9.35
	21.87	13.31	**-**	-	**-**	-	**21.87**	13.31
Total Crude Oil *(per boe)* [1]								
Sales Price	**43.32**	32.95	**73.14**	59.42	**75.58**	62.42	**52.12**	37.36
Royalties	**5.66**	4.06	**2.75**	2.94	**10.83**	5.78	**5.25**	4.13
Operating costs	**11.25**	9.75	**6.15**	3.61	**3.11**	2.38	**9.60**	8.69
	26.41	19.14	**64.24**	52.87	**61.64**	54.26	**37.27**	24.54
Natural Gas *(per mcfge)* [2]								
Sales Price	**7.15**	6.50	**-**	-	**-**	-	**7.15**	6.50
Royalties	**1.54**	1.45	**-**	-	**-**	-	**1.54**	1.45
Operating costs	**1.04**	0.97	**-**	-	**-**	-	**1.04**	0.97
	4.57	4.08	**-**	-	**-**	-	**4.57**	4.08
Equivalent Unit *(per boe)* [1]								
Sales Price	**43.14**	35.36	**73.14**	59.42	**75.58**	62.42	**49.14**	37.94
Royalties	**7.09**	5.91	**2.75**	2.94	**10.83**	5.78	**6.53**	5.77
Operating costs	**9.24**	8.19	**6.15**	3.61	**3.11**	2.38	**8.52**	7.67
	$ 26.81	$ 21.26	**$ 64.24**	$ 52.87	**$ 61.64**	$ 54.26	**$ 34.09**	$ 24.50

(1) *Includes associated co-products converted to boe.*

(2) *Includes associated co-products converted to mcfge.*

Upstream Capital Expenditures

Capital Expenditures Summary [1] *(millions of dollars)*	Three months ended June 30 **2006**	Three months ended June 30 2005	Six months ended June 30 **2006**	Six months ended June 30 2005
Exploration				
Western Canada	**$ 153**	$ 153	**$ 320**	$ 314
East Coast Canada and Frontier	**4**	14	**25**	18
International	**36**	19	**37**	23
	193	186	**382**	355
Development				
Western Canada	**244**	223	**757**	594
East Coast Canada	**111**	126	**163**	246
International	**6**	1	**9**	3
	361	350	**929**	843
	$ 554	$ 536	**$ 1,311**	$ 1,198

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

Upstream capital expenditures totaled $1,311 million, 84 percent of total consolidated capital expenditures during the first six months of 2006 compared with $1,198 million or 91 percent of the total, during the first six months of 2005.

Western Canada Wells Drilled [1] [2]		Three months ended June 30 **2006** Gross	**2006** Net	2005 Gross	2005 Net	Six months ended June 30 **2006** Gross	**2006** Net	2005 Gross	2005 Net
Exploration	Oil	**8**	**8**	10	10	**30**	**30**	35	32
	Gas	**34**	**16**	36	21	**196**	**100**	132	93
	Dry	**3**	**2**	5	5	**19**	**17**	19	19
		45	**26**	51	36	**245**	**147**	186	144
Development	Oil	**70**	**59**	65	58	**196**	**171**	131	119
	Gas	**30**	**22**	47	44	**254**	**216**	278	265
	Dry	**2**	**2**	5	5	**11**	**11**	15	15
		102	**83**	117	107	**461**	**398**	424	399
Total		**147**	**109**	168	143	**706**	**545**	610	543

[1] *Excludes stratigraphic test wells.*
[2] *Includes non-operated wells.*

4.2 MIDSTREAM

Second Quarter

Upgrading earnings decreased in the second quarter of 2006 by $18 million compared with the second quarter of 2005 due to:

- narrower upgrading differential; and
- lower sales volume of synthetic crude oil due to an outage for compressor repairs.

Partially offset by:

- lower natural gas and steam costs; and
- lower income taxes and adjustment for tax rate reductions.

Six Months

The factors that affected results for the second quarter were primarily responsible for variances in the results for the six months ended June 30, 2006.

Upgrading Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2006**	2005	**2006**	2005
Gross margin		**$ 136**	$ 195	**$ 344**	$ 402
Operating costs		**53**	53	**119**	103
Other recoveries		**(2)**	(2)	**(3)**	(3)
Depreciation and amortization		**6**	4	**12**	9
Income taxes		**-**	43	**44**	89
Earnings		**$ 79**	$ 97	**$ 172**	$ 204
Selected operating data:					
Upgrader throughput [(1)]	*(mbbls/day)*	**68.8**	71.3	**70.1**	71.7
Synthetic crude oil sales	*(mbbls/day)*	**56.9**	60.1	**60.2**	62.0
Upgrading differential	*($/bbl)*	**$ 22.73**	$ 31.05	**$ 28.73**	31.51
Unit margin	*($/bbl)*	**$ 26.35**	$ 35.64	**$ 31.61**	35.80
Unit operating cost [(2)]	*($/bbl)*	**$ 8.39**	$ 8.12	**$ 9.33**	7.91

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

Upgrading Earnings Variance Analysis

(millions of dollars)	
Three months ended June 30, 2005	$ 97
Volume	(10)
Margin	(49)
Operating costs - energy related	5
Operating costs - non-energy related	(5)
Depreciation and amortization	(2)
Income taxes	43
Three months ended June 30, 2006	**$ 79**
Six months ended June 30, 2005	$ 204
Volume	(12)
Margin	(46)
Operating costs - energy related	(4)
Operating costs - non-energy related	(12)
Depreciation and amortization	(3)
Income taxes	45
Six months ended June 30, 2006	**$ 172**

Second Quarter

Infrastructure and marketing earnings increased by $28 million in the second quarter of 2006 compared with the second quarter of 2005 due to:

- higher income associated with marketing natural gas and blended heavy crude oil;
- higher pipeline margins; and
- lower income taxes including an adjustment for tax rate reductions.

Six Months

The factors that affected results for the second quarter were primarily responsible for variances in the results for the six months ended June 30, 2006 except that earnings from marketing blended heavy crude oil were lower than the comparable six month period in 2005.

Infrastructure and Marketing Earnings Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)	**2006**	2005	**2006**	2005
Gross margin - pipeline	**$ 28**	$ 22	**$ 54**	$ 47
- other infrastructure and marketing	**52**	39	**120**	116
	80	61	**174**	163
Other expenses	**3**	2	**5**	5
Depreciation and amortization	**5**	6	**11**	11
Income taxes	**11**	20	**40**	52
Earnings	**$ 61**	$ 33	**$ 118**	$ 95
Selected operating data:				
Aggregate pipeline throughput *(mbbls/day)*	**480**	488	**490**	499

Midstream Capital Expenditures

Midstream capital expenditures totaled $87 million in the first six months of 2006; $75 million at the Lloydminster Upgrader, primarily for debottleneck and reliability projects and $12 million on pipelines and infrastructure.

4.3 Refined Products

Second Quarter

Refined products earnings increased by $32 million in the second quarter of 2006 compared with the second quarter of 2005 due to:

- higher marketing margins for gasoline and distillates; and
- higher sales volume of asphalt products.

Partially offset by:

- higher depreciation expense for the Prince George refinery and marketing outlets.

Six Months

The factors that affected results for the second quarter were primarily responsible for variances in the results for the six months ended June 30, 2006.

Refined Products Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2006**	2005	**2006**	2005
Gross margin - fuel sales		**$ 57**	$ 24	**$ 79**	$ 53
- ancillary sales		**8**	9	**16**	16
- asphalt sales		**32**	28	**53**	47
		97	61	**148**	116
Operating and other expenses		**19**	19	**35**	36
Depreciation and amortization		**13**	11	**23**	20
Income taxes		**13**	11	**22**	22
Earnings		**$ 52**	$ 20	**$ 68**	$ 38
Selected operating data:					
Number of fuel outlets				**506**	521
Light oil sales	*(million litres/day)*	**8.6**	8.8	**8.6**	8.6
Light oil retail sales per outlet	*(thousand litres/day)*	**12.2**	12.2	**12.5**	12.3
Prince George refinery throughput	*(mbbls/day)* [1]	**3.7**	9.5	**6.5**	9.8
Asphalt sales	*(mbbls/day)*	**24.9**	19.7	**21.3**	18.7
Lloydminster refinery throughput	*(mbbls/day)*	**25.4**	21.6	**26.2**	24.3

[1] *Prince George throughput decreased in the second quarter of 2006 as a result of a plant shutdown for the commissioning of the low sulphur diesel modifications.*

Refined Products Capital Expenditures

Refined Products capital expenditures totaled $143 million in the first six months of 2006; $32 million at the Prince George refinery, $64 million at the Lloydminster ethanol plant and $40 million at the Minnedosa ethanol plant.

4.4 CORPORATE

Second Quarter

Corporate expense decreased by $27 million in the second quarter of 2006 compared with the second quarter of 2005 due to:

- gains on translation of U.S. denominated debt in the second quarter 2006 compared with losses in the second quarter of 2005; and
- lower stock-based compensation expense during the second quarter of 2006.

Partially offset by:

- lower capitalized interest due to start-up of the White Rose oil field; and
- higher profit elimination on inventory on-hand at the end of the second quarter of 2006.

Six Months

The factors that affected results for the second quarter were primarily responsible for variances in the results for the six months ended June 30, 2006.

Corporate Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars) income (expense)	**2006**	2005	**2006**	2005
Intersegment eliminations - net	**$ (23)**	$ 14	**$ (14)**	$ (9)
Administration expenses	**(8)**	(5)	**(12)**	(11)
Stock-based compensation	**(15)**	(77)	**(85)**	(98)
Accretion	**(1)**	(1)	**(1)**	(1)
Other - net	**(4)**	(3)	**(8)**	(6)
Depreciation and amortization	**(5)**	(5)	**(11)**	(11)
Interest on debt	**(32)**	(37)	**(70)**	(72)
Interest capitalized	**10**	31	**21**	55
Interest income	**-**	-	**-**	1
Foreign exchange - realized	**(8)**	(1)	**19**	5
Foreign exchange - unrealized	**40**	(19)	**18**	(32)
Income taxes	**10**	40	**53**	74
Loss	**$ (36)**	$ (63)	**$ (90)**	$ (105)

Foreign Exchange Rates	Three months ended June 30		Six months ended June 30	
	2006	2005	**2006**	2005
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.857**	U.S. $0.827	**U.S. $0.858**	U.S. $0.831
At end of period	**U.S. $0.897**	U.S. $0.816	**U.S. $0.897**	U.S. $0.816

Consolidated Income Taxes

During the second quarter of 2006 consolidated income taxes consisted of $210 million of current taxes and a recovery of future taxes of $229 million compared with current taxes of $75 million and future taxes of $101 million in the same period of 2005.

The recovery of future taxes in the second quarter of 2006 resulted from recording non-recurring tax benefits of $328 million that arose due to changes in the tax rates for the governments of Canada ($198 million), Alberta ($90 million) and Saskatchewan ($40 million). All of this tax legislation received royal assent and was, therefore, substantively enacted in the second quarter of 2006.

The increase in current taxes in the second quarter of 2006 compared with the second quarter of 2005 was due to higher taxable income.

Corporate Capital Expenditures

Corporate capital expenditures totaled $13 million in the first six months of 2006 primarily for various office and information system upgrades.

5.0 LIQUIDITY AND CAPITAL RESOURCES

During the second quarter cash flow from operating activities financed all of our capital requirements and dividend payment. At June 30, 2006 we had $1.4 billion in unused committed credit facilities.

5.1 Operating Activities

In the second quarter of 2006, cash generated from operating activities amounted to $1,302 million compared with $771 million in the second quarter of 2005. Higher cash flow from operating activities was primarily due to higher commodity prices, higher production volumes and a higher change in non-cash working capital.

5.2 Financing Activities

In the second quarter of 2006, cash used in financing activities amounted to $339 million compared with $192 million in the second quarter of 2005. During the second quarter of 2006, higher dividends and non-cash working capital associated with financing activities primarily resulted in a higher use of cash compared with the second quarter of 2005. The change in non-cash working capital mainly related to a reduction of $108 million in outstanding accounts receivable that had been sold under our securitization program. 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 second quarter of 2006, cash used in investing activities amounted to $773 million compared with $585 million in the second quarter of 2005. Cash was used primarily for capital expenditures and provisions for turnarounds partially offset by proceeds from asset sales.

5.4 SOURCES OF CAPITAL

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash to fund capital programs necessary to maintain and increase production and proved developed reserves, to acquire strategic oil and gas assets, repay maturing debt and pay dividends. Husky's upstream capital programs are funded principally by cash provided from operating activities. During times of low oil and gas prices, part of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining our production, it may be necessary to utilize alternative sources of capital to continue our strategic investment plan during periods of low commodity prices. As a result we 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.

Sources and Uses of Cash	Six months ended June 30	Year ended December 31
(millions of dollars)	**2006**	2005
Cash sourced		
Cash flow from operations [1]	**$ 2,070**	$ 3,785
Asset sales	**33**	74
Proceeds from exercise of stock options	**1**	6
Proceeds from monetization of financial instruments	**-**	39
	2,104	3,904
Cash used		
Capital expenditures	**1,543**	3,068
Debt repayment - net	**96**	215
Special dividend on common shares	**-**	424
Ordinary dividends on common shares	**212**	276
Settlement of asset retirement obligations	**14**	41
Other	**13**	32
	1,878	4,056
Net cash (deficiency)	**226**	(152)
Increase (decrease) in non-cash working capital	**(281)**	394
Increase (decrease) in cash and cash equivalents	**(55)**	242
Cash and cash equivalents - beginning of period	**249**	7
Cash and cash equivalents - end of period	**$ 194**	$ 249

[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.*

Working capital is the amount by which current assets exceed current liabilities. At June 30, 2006, our working capital deficiency was $854 million compared with $1.0 billion at December 31, 2005. These 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.

At June 30, 2006, we had unused committed long and short-term credit facilities totalling $1.4 billion. A total of $12 million of our borrowing credit facilities were used in support of outstanding letters of credit and an additional $54 million of letters of credit were outstanding at June 30, 2006 and supported by dedicated credit lines. During the second quarter of 2006 our long-term revolving credit facilities were extended from three to five year maturities.

Credit Ratings

During the second quarter, Standard & Poor's Ratings Services placed the Company's long-term corporate credit and senior unsecured debt ratings on CreditWatch with positive implications. As at June 30, 2006 the Company's senior unsecured debt was rated Baa2 by Moody's Investors Service, BBB by Standard & Poor's Ratings Services, BBB (high) by Dominion Bond Rating Service and BBB+ by Fitch Ratings.

Financial Ratios	Three months ended June 30		Six months ended June 30	
(millions of dollars, except ratios)	**2006**	2005	**2006**	2005
Cash flow - operating activities	**$ 1,302**	$ 771	**$ 2,426**	$ 1,500
- financing activities	**$ (339)**	$ (192)	**$ (848)**	$ (253)
- investing activities	**$ (773)**	$ (585)	**$ (1,633)**	$ (1,251)
Debt to capital employed *(percent)*			**16.3**	24.5
Corporate reinvestment ratio [(1) (2)]			**0.8**	1.0

(1) *Calculated for the12 months ended for the periods shown.*

(2) *Reinvestment ratio is based on net capital expenditures including corporate acquisitions.*

5.5 CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

Refer to Husky's 2005 annual Management's Discussion and Analysis under the caption "Cash Requirements" which summarizes contractual obligations and commercial commitments. There has been no material change in these amounts as at June 30, 2006.

5.6 OFF BALANCE SHEET ARRANGEMENTS

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

We engage, in the ordinary course of business, in the securitization of accounts receivable. At June 30, 2006, we had sold $242 million of accounts receivable 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.

6.0 TRANSACTIONS WITH RELATED PARTIES

We did not have any significant transactions with related parties during the first six months of 2006 or during the year ended December 31, 2005.

7.0 SIGNIFICANT CUSTOMERS

We did not have any customers that constituted more than 10 percent of total sales and operating revenues during the first six months of 2006.

8.0 FINANCIAL AND DERIVATIVE INSTRUMENTS

Husky is exposed to market risks related to commodity prices, interest rates and foreign exchange rates as discussed under Section 3.0 "Business Environment". From time to time, we use financial and derivative instruments to manage our exposure to these risks.

8.1 POWER CONSUMPTION

At June 30, 2006, we had hedged power consumption as follows:

(millions of dollars, except where indicated)	Notional Volumes *(MW)*	Term	Price	Unrecognized Gain (Loss)
Fixed price purchase	19.0	July to Aug. 2006	$ 62.50/MWh	$ -
	19.0	July to Sept. 2006	$ 63.00/MWh	(0.1)
	38.0	Oct. to Dec. 2006	$ 62.95/MWh	0.3
				$ 0.2

8.2 INTEREST RATE RISK MANAGEMENT

In the first six months of 2006, interest rate risk management activities resulted in a decrease to interest expense of $1 million.

The cross currency swaps resulted in an addition to interest expense of $5 million in the first six months of 2006.

Husky has interest rate swaps on $200 million of long-term debt effective February 8, 2002 whereby 6.95 percent was swapped for CDOR + 175 bps until July 14, 2009. During the first six months of 2006, 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 $5 million offset to interest expense in the first six months of 2006.

8.3 FOREIGN CURRENCY RISK MANAGEMENT

Please refer to note 11 of the Consolidated Financial Statements.

9.0 APPLICATION OF 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, 2005 available at www.sedar.com.

10.0 NEW ACCOUNTING STANDARDS

Effective January 1, 2006, we adopted the revised recommendations of the Canadian Institute of Chartered Accountants section 3831, "Non-monetary Transactions" which replaced section 3830 of the same name. The new recommendations require that all non-monetary transactions are measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business. The guidance was effective for all non-monetary transactions initiated in periods beginning on or after January 1, 2006.

11.0 OUTSTANDING SHARE DATA

(in thousands, except per share amounts)		Six months ended June 30 **2006**	Year ended December 31 2005
Share price [(1)]	High	**$ 75.64**	$ 69.95
	Low	**$ 58.00**	$ 32.30
	Close at end of period	**$ 70.06**	$ 59.00
Average daily trading volume		**624**	664
Weighted average number of common shares outstanding			
	Basic	**424,163**	423,964
	Diluted	**424,163**	423,964
Issued and outstanding at end of period [(2)]			
Number of common shares		**424,187**	424,125
Number of stock options		**6,783**	7,285
Number of stock options exercisable		**3,145**	1,533

(1) 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.

(2) 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 June 30, 2006 to July 11, 2006.

12.0 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:

(millions of dollars)		Six months ended June 30 **2006**	Year ended December 31 2005
Non-GAAP	Cash flow from operations	**$ 2,070**	$ 3,785
	Settlement of asset retirement obligations	**(14)**	(41)
	Change in non-cash working capital	**370**	(72)
GAAP	Cash flow - operating activities	**$ 2,426**	$ 3,672

13.0 TERMS AND 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* (1)
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*
OPEC	*Organization of Petroleum Exporting Countries*
WCSB	*Western Canada Sedimentary Basin*
SAGD	*Steam-assisted gravity drainage*
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*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital*
Equity	*Shares and retained earnings*
Total Debt	*Long-term debt including current portion and bank operating loans*
hectare	*One hectare is equal to 2.47 acres*
initial reserves	*Remaining reserves plus cumulative production*
feedstock	*Raw materials which are processed into petroleum products*
design rate capacity	*The maximum continuous rated output of a plant based on its design*

(1) *NOVA Inventory Transfer is an exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline.*

Natural gas converted on the basis that six mcf equals one barrel of oil.

In this report, the terms "Husky Energy Inc.", "Husky", "we", "our" or "the Company" mean Husky Energy Inc. and its subsidiaries and partnership interests on a consolidated basis.

14.0 FORWARD-LOOKING STATEMENTS OR INFORMATION

Certain statements in this Interim Report are forward-looking statements or information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, and 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 forward-looking statements made in this Interim Report. 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 may be 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 and information include: our steam injection and production plans for the Tucker in-situ oil sands project, our White Rose drilling, development and production plans, our West Bonne Bay drilling plans, our Lloydminster ethanol plant production plans, our Minnedosa ethanol plant commissioning plans, our throughput capacity projections for the ethanol plants, our East Coast seismic program, our Sunrise oil sands project design schedule, and water evaluation and stratigraphic drilling plans, our South China Sea drilling and seismic evaluation plans, our East China Sea drilling plans, and our Lloydminster Upgrader expansion design plans. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Interim Report. Among the key factors that have a direct bearing on the Company's results of operations are the nature of the Company's involvement in the business of exploration, development and production of oil and natural gas reserves and the fluctuation of the exchange rate between the Canadian dollar and the United States dollar. These and other factors are discussed herein under "Management's Discussion and Analysis".

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Company made by or on behalf of the Company, 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:

- *fluctuations in commodity prices;*
- *the accuracy of our oil and gas reserve estimates and estimated production levels as they are affected by our success at exploration and development drilling and related activities and estimated decline rates;*
- *the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures;*
- *changes in general economic, market and business conditions;*
- *fluctuations in supply and demand for our products;*
- *fluctuations in the cost of borrowing;*
- *our use of derivative financial instruments to hedge exposure to changes in commodity prices and fluctuations in interest rates and foreign currency exchange rates;*
- *political and economic developments, expropriations, royalty and tax increases, retroactive tax claims and changes to import and export regulations and other foreign laws and policies in the countries in which we operate;*
- *our ability to receive timely regulatory approvals;*
- *the integrity and reliability of our capital assets;*
- *the cumulative impact of other resource development projects;*
- *the maintenance of satisfactory relationships with unions, employee associations and joint venturers;*
- *competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy;*
- *actions by governmental authorities, including changes in environmental and other regulations that may impose restrictions in areas where we operate;*
- *the ability and willingness of parties with whom we have material relationships to fulfill their obligations; and*
- *the occurrence 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.*

Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement or statements 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 statements.

15.0 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 well head.

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 those 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" at page 2 of our Annual Information Form for the year ended December 31, 2005 filed with securities regulatory authorities for further information.

16.0 CAUTIONARY NOTE TO U.S. INVESTORS

The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated with actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms in this release and Interim Report, such as "probable reserves" and "recoverable resource", that the SEC's guidelines strictly prohibit us from including in filings with the SEC. U.S. investors should refer to our Annual Report on Form 40-F available from us or the SEC for further reserve disclosure.

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of dollars)	**June 30 2006**	December 31 2005
	(unaudited)	*(audited)*
Assets		
Current assets		
Cash and cash equivalents	**$ 194**	$ 249
Accounts receivable	**747**	856
Inventories	**465**	471
Prepaid expenses	**70**	40
	1,476	1,616
Property, plant and equipment - (full cost accounting)	**23,881**	22,375
Less accumulated depletion, depreciation and amortization	**9,166**	8,416
	14,715	13,959
Goodwill	**160**	160
Other assets	**54**	62
	$ 16,405	$ 15,797
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 2,063**	$ 2,391
Long-term debt due within one year *(note 5)*	**267**	274
	2,330	2,665
Long-term debt *(note 5)*	**1,455**	1,612
Other long-term liabilities *(note 6)*	**717**	730
Future income taxes	**3,089**	3,270
Commitments and contingencies *(note 8)*		
Shareholders' equity		
Common shares *(note 9)*	**3,527**	3,523
Retained earnings	**5,287**	3,997
	8,814	7,520
	$ 16,405	$ 15,797
Common shares outstanding *(millions) (note 9)*	**424.2**	424.1

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

Consolidated Statements of Earnings

(millions of dollars, except per share amounts) (unaudited)	Three months ended June 30 **2006**	Three months ended June 30 2005	Six months ended June 30 **2006**	Six months ended June 30 2005
Sales and operating revenues, net of royalties	**$ 3,040**	$ 2,350	**$ 6,144**	$ 4,444
Costs and expenses				
Cost of sales and operating expenses	**1,638**	1,331	**3,465**	2,482
Selling and administration expenses	**50**	40	**77**	69
Stock-based compensation	**15**	77	**85**	98
Depletion, depreciation and amortization	**383**	304	**762**	602
Interest - net *(note 5)*	**22**	6	**49**	16
Foreign exchange *(note 5)*	**(32)**	20	**(37)**	27
Other - net	**5**	2	**8**	5
	2,081	1,780	**4,409**	3,299
Earnings before income taxes	**959**	570	**1,735**	1,145
Income taxes *(note 7)*				
Current	**210**	75	**414**	142
Future	**(229)**	101	**(181)**	225
	(19)	176	**233**	367
Net earnings	**$ 978**	$ 394	**$ 1,502**	$ 778
Earnings per share				
Basic	**$ 2.31**	$ 0.93	**$ 3.54**	$ 1.84
Diluted	**$ 2.31**	$ 0.93	**$ 3.54**	$ 1.84
Weighted average number of common shares outstanding *(millions)*				
Basic	**424.2**	423.9	**424.2**	423.8
Diluted	**424.2**	423.9	**424.2**	423.8

Consolidated Statements of Retained Earnings

(millions of dollars) (unaudited)	Three months ended June 30 **2006**	Three months ended June 30 2005	Six months ended June 30 **2006**	Six months ended June 30 2005
Beginning of period	**$ 4,415**	$ 3,027	**$ 3,997**	$ 2,694
Net earnings	**978**	394	**1,502**	778
Dividends on common shares	**(106)**	(59)	**(212)**	(110)
End of period	**$ 5,287**	$ 3,362	**$ 5,287**	$ 3,362

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

Consolidated Statements of Cash Flows

(millions of dollars) (unaudited)	Three months ended June 30 **2006**	Three months ended June 30 2005	Six months ended June 30 **2006**	Six months ended June 30 2005
Operating activities				
Net earnings	**$ 978**	$ 394	**$ 1,502**	$ 778
Items not affecting cash				
Accretion *(note 6)*	**9**	9	**18**	17
Depletion, depreciation and amortization	**383**	304	**762**	602
Future income taxes *(note 7)*	**(229)**	101	**(181)**	225
Foreign exchange	**(41)**	17	**(42)**	24
Other	**3**	3	**11**	(2)
Settlement of asset retirement obligations	**(6)**	(9)	**(14)**	(14)
Change in non-cash working capital *(note 4)*	**205**	(48)	**370**	(130)
Cash flow - operating activities	**1,302**	771	**2,426**	1,500
Financing activities				
Bank operating loans financing - net	**(62)**	(48)	**-**	(15)
Long-term debt issue	**251**	1,029	**1,226**	2,451
Long-term debt repayment	**(300)**	(1,150)	**(1,322)**	(2,393)
Proceeds from exercise of stock options	**-**	3	**1**	4
Proceeds from monetization of financial instruments	**-**	30	**-**	30
Dividends on common shares	**(106)**	(59)	**(212)**	(110)
Change in non-cash working capital *(note 4)*	**(122)**	3	**(541)**	(220)
Cash flow - financing activities	**(339)**	(192)	**(848)**	(253)
Available for investing	**963**	579	**1,578**	1,247
Investing activities				
Capital expenditures	**(683)**	(613)	**(1,543)**	(1,304)
Asset sales	**1**	14	**33**	57
Other	**(12)**	(2)	**(13)**	(2)
Change in non-cash working capital *(note 4)*	**(79)**	16	**(110)**	(2)
Cash flow - investing activities	**(773)**	(585)	**(1,633)**	(1,251)
Increase (decrease) in cash and cash equivalents	**190**	(6)	**(55)**	(4)
Cash and cash equivalents at beginning of period	**4**	9	**249**	7
Cash and cash equivalents at end of period	**$ 194**	$ 3	**$ 194**	$ 3

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

Notes to the Consolidated Financial Statements

Six months ended June 30, 2006 *(unaudited)*

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 1 Segmented Financial Information

	Upstream		Midstream				Refined Products		Corporate and Eliminations [1]		Total	
			Upgrading		Infrastructure and Marketing							
	2006	2005	2006	2005	2006	2005	2006	2005	2006	2005	2006	2005
Three months ended June 30												
Sales and operating revenues, net of royalties	$ 1,451	$ 976	$ 404	$ 393	$ 2,267	$ 1,611	$ 674	$ 560	$ (1,756)	$ (1,190)	$ 3,040	$ 2,350
Costs and expenses												
Operating, cost of sales, selling and general	308	249	319	249	2,190	1,552	596	518	(1,705)	(1,118)	1,708	1,450
Depletion, depreciation and amortization	354	278	6	4	5	6	13	11	5	5	383	304
Interest - net	-	-	-	-	-	-	-	-	22	6	22	6
Foreign exchange	-	-	-	-	-	-	-	-	(32)	20	(32)	20
	662	527	325	253	2,195	1,558	609	529	(1,710)	(1,087)	2,081	1,780
Earnings (loss) before income taxes	789	449	79	140	72	53	65	31	(46)	(103)	959	570
Current income taxes	156	69	29	(2)	20	(4)	3	(1)	2	13	210	75
Future income taxes	(189)	73	(29)	45	(9)	24	10	12	(12)	(53)	(229)	101
Net earnings (loss)	$ 822	$ 307	$ 79	$ 97	$ 61	$ 33	$ 52	$ 20	$ (36)	$ (63)	$ 978	$ 394
Capital expenditures - Three months ended June 30	$ 554	$ 536	$ 38	$ 30	$ 11	$ 7	$ 79	$ 43	$ 7	$ 4	$ 689	$ 620
Six months ended June 30												
Sales and operating revenues, net of royalties	$ 2,738	$ 1,864	$ 809	$ 746	$ 4,731	$ 3,063	$ 1,220	$ 997	$ (3,354)	$ (2,226)	$ 6,144	$ 4,444
Costs and expenses												
Operating, cost of sales, selling and general	619	489	581	444	4,562	2,905	1,107	917	(3,234)	(2,101)	3,635	2,654
Depletion, depreciation and amortization	705	551	12	9	11	11	23	20	11	11	762	602
Interest - net	-	-	-	-	-	-	-	-	49	16	49	16
Foreign exchange	-	-	-	-	-	-	-	-	(37)	27	(37)	27
	1,324	1,040	593	453	4,573	2,916	1,130	937	(3,211)	(2,047)	4,409	3,299
Earnings (loss) before income taxes	1,414	824	216	293	158	147	90	60	(143)	(179)	1,735	1,145
Current income taxes	299	122	53	9	39	(11)	12	(2)	11	24	414	142
Future income taxes	(119)	156	(9)	80	1	63	10	24	(64)	(98)	(181)	225
Net earnings (loss)	$ 1,234	$ 546	$ 172	$ 204	$ 118	$ 95	$ 68	$ 38	$ (90)	$ (105)	$ 1,502	$ 778
Capital employed - As at June 30	$ 9,400	$ 7,878	$ 538	$ 490	$ 311	$ 570	$ 577	$ 399	$ (290)	$ (234)	$ 10,536	$ 9,103
Capital expenditures - Six months ended June 30	$ 1,311	$ 1,198	$ 75	$ 47	$ 12	$ 13	$ 143	$ 48	$ 13	$ 8	$ 1,554	$ 1,314
Total assets - As at June 30	$ 13,436	$ 11,575	$ 912	$ 751	$ 718	$ 871	$ 1,005	$ 727	$ 334	$ 134	$ 16,405	$ 14,058

[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.*

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, 2005, 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, 2005.

Note 3 Change in Accounting Policies

Non-monetary Transactions

Effective January 1, 2006, the Company adopted the revised recommendations of the Canadian Institute of Chartered Accountants section 3831, "Non-monetary Transactions" which replaced section 3830 of the same name. The new recommendations require that all non-monetary transactions are measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business. The guidance was effective for all non-monetary transactions initiated in periods beginning on or after January 1, 2006.

Note 4 Cash Flows - Change in Non-cash Working Capital

	Three months ended June 30		Six months ended June 30	
	2006	2005	**2006**	2005
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ 5**	$ 25	**$ 109**	$ (20)
Inventories	**(26)**	(86)	**6**	(140)
Prepaid expenses	**(23)**	(7)	**(19)**	(18)
Accounts payable and accrued liabilities	**48**	39	**(377)**	(174)
Change in non-cash working capital	**4**	(29)	**(281)**	(352)
Relating to:				
Financing activities	**(122)**	3	**(541)**	(220)
Investing activities	**(79)**	16	**(110)**	(2)
Operating activities	**$ 205**	$ (48)	**$ 370**	$ (130)
b) Other cash flow information:				
Cash taxes paid	**$ 44**	$ 76	**$ 173**	$ 159
Cash interest paid	**$ 47**	$ 43	**$ 79**	$ 73

Note 5 Long-term Debt

	Maturity	**June 30 2006**	Dec 31 2005	**June 30 2006**	Dec 31 2005
		Cdn $ Amount		*U.S. $ Denominated*	
Long-term debt					
7.125% notes	2006	**$ 167**	$ 175	**$ 150**	$ 150
6.25% notes	2012	**446**	467	**400**	400
7.55% debentures	2016	**223**	233	**200**	200
6.15% notes	2019	**335**	350	**300**	300
8.45% senior secured bonds		**-**	99	**-**	85
Medium-term notes	2007-9	**300**	300	**-**	-
8.90% capital securities	2028	**251**	262	**225**	225
Total long-term debt		**1,722**	1,886	**$1,275**	$1,360
Amount due within one year		**(267)**	(274)		
		$1,455	$1,612		

Interest - net consisted of:

	Three months ended June 30 **2006**	2005	Six months ended June 30 **2006**	2005
Long-term debt	**$ 31**	$ 36	**$ 68**	$ 70
Short-term debt	**2**	1	**3**	2
	33	37	**71**	72
Amount capitalized	**(10)**	(31)	**(21)**	(55)
	23	6	**50**	17
Interest income	**(1)**	-	**(1)**	(1)
	$ 22	$ 6	**$ 49**	$ 16

Foreign exchange consisted of:

	Three months ended June 30 **2006**	2005	Six months ended June 30 **2006**	2005
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ (66)**	$ 22	**$ (67)**	$ 31
Cross currency swaps	**27**	(4)	**26**	(6)
Other losses	**7**	2	**4**	2
	$ (32)	$ 20	**$ (37)**	$ 27

Note 6 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Six months ended June 30	
	2006	2005
Asset retirement obligations at beginning of period	**$ 557**	$ 509
Liabilities incurred	**10**	8
Liabilities disposed	**-**	(7)
Liabilities settled	**(14)**	(14)
Accretion	**18**	17
Asset retirement obligations at end of period	**$ 571**	$ 513

At June 30, 2006, the estimated total undiscounted inflation adjusted amount required to settle the asset retirement obligations was $3.4 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend up to 50 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2 to 6.4 percent.

Note 7 Income Taxes

The recovery of future taxes in the second quarter of 2006 resulted from recording non-recurring tax benefits of $328 million that arose due to changes in the tax rates for the governments of Canada ($198 million), Alberta ($90 million) and Saskatchewan ($40 million). All of this tax legislation received royal assent and was, therefore, substantively enacted in the second quarter of 2006. There were no similar tax rate benefits recorded in the first quarter of 2006 or during the first six months of 2005.

Note 8 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 9 Share Capital

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

Common Shares

Changes to issued common shares were as follows:

	Six months ended June 30			
	2006		2005	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of period	424,125,078	$ 3,523	423,736,414	$ 3,506
Exercised - options and warrants	62,265	4	246,341	9
Balance at June 30	**424,187,343**	**$ 3,527**	423,982,755	$ 3,515

Stock Options

A summary of the status of the Company's stock option plan is presented below:

	Six months ended June 30			
	2006		2005	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of period	7,285	$ 25.81	9,964	$ 22.61
Granted	567	$ 69.33	175	$ 35.29
Exercised for common shares	(62)	$ 20.97	(217)	$ 16.27
Surrendered for cash	(834)	$ 22.84	(1,646)	$ 18.10
Forfeited	(173)	$ 40.18	(281)	$ 24.46
Outstanding at June 30	**6,783**	**$ 29.49**	7,995	$ 23.92
Options exercisable at June 30	**3,145**	**$ 23.59**	2,281	$ 21.98

	June 30, 2006				
	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
$13.96 - $14.99	92	$ 14.56	2	92	$ 14.56
$15.00 - $22.99	173	$ 19.75	2	97	$ 18.78
$23.00 - $23.99	5,194	$ 23.83	3	2,876	$ 23.83
$24.00 - $39.99	352	$ 32.07	3	80	$ 31.39
$40.00 - $55.99	440	$ 51.96	4	-	$ -
$56.00 - $73.80	532	$ 70.26	5	-	$ -
	6,783	**$ 29.49**	**3**	**3,145**	**$ 23.59**

Note 10 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended June 30		Six months ended June 30	
	2006	2005	**2006**	2005
Employer current service cost	**$ 5**	$ 5	**$ 9**	$ 9
Interest cost	**3**	3	**5**	5
Expected return on plan assets	**(2)**	(2)	**(3)**	(4)
Amortization of net actuarial losses	**-**	-	**-**	1
	$ 6	$ 6	**$ 11**	$ 11

Note 11 Financial Instruments and Risk Management

Unrecognized gains (losses) on derivative instruments were as follows:

	June 30 2006	Dec. 31 2005
Commodity price risk management		
Power consumption	**$ -**	$ -
Interest rate risk management		
Interest rate swaps	**2**	7
Foreign currency risk management		
Foreign exchange contracts	**(27)**	(32)

Commodity Price Risk Management

Power Consumption

At June 30, 2006, the Company had hedged power consumption as follows:

	Notional Volumes *(MW)*	Term	Price
Fixed price purchase	19.0	July to Aug. 2006	$62.50/MWh
	19.0	July to Sept. 2006	$63.00/MWh
	38.0	Oct. to Dec. 2006	$62.95/MWh

The impact of the hedge program during the first six months of 2006 was a loss of $1.0 million (2005 - loss of $0.1 million).

Natural Gas Contracts

At June 30, 2006, the unrecognized gains (losses) on external offsetting physical purchase and sale natural gas contracts were as follows:

	Volumes *(mmcf)*	Unrecognized Gain (Loss)
Physical purchase contracts	32,747	$ (1)
Physical sale contracts	(32,747)	$ 5

Interest Rate Risk Management

During the first six months of 2006, the Company realized a gain of $1 million (2005 - gain of $9 million) from interest rate risk management activities.

Foreign Currency Risk Management

During the first six months of 2006, the Company realized a loss of $21 million (2005 - gain of $7 million) from all foreign currency risk management activities.

Sale of Accounts Receivable

The Company has a securitization program to sell, on a revolving basis, accounts receivable to a third party up to $350 million. As at June 30, 2006, $242 million in outstanding accounts receivable had been sold under the program, a reduction of $108 million in the second quarter compared with $350 million in outstanding account receivable sold at December 31, 2005. In July 2006, the program to sell accounts receivable was further reduced by $17 million to $225 million.

Husky Energy will release its second quarter financial results after markets close on Wednesday, July 19, 2006. A conference call for analysts and investors will be held on Thursday, July 20, 2006 at 4:15 p.m. (EST).

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

Media are invited to listen to the conference call by dialing 1-800-377-5794 beginning at 4:05 p.m. (EST). Those unable to listen to the call live may listen to a recording by dialing 1-800-558-5253 one hour after the completion of the call, approximately 6:15 p.m. (EST), then dialing reservation number 21298690. The PostView will be available until Thursday, August 17, 2006.

Husky Energy is a Canadian based, integrated energy and energy-related company headquartered in Calgary, Alberta. Husky Energy is publicly traded on the Toronto Stock Exchange under the symbol HSE.

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