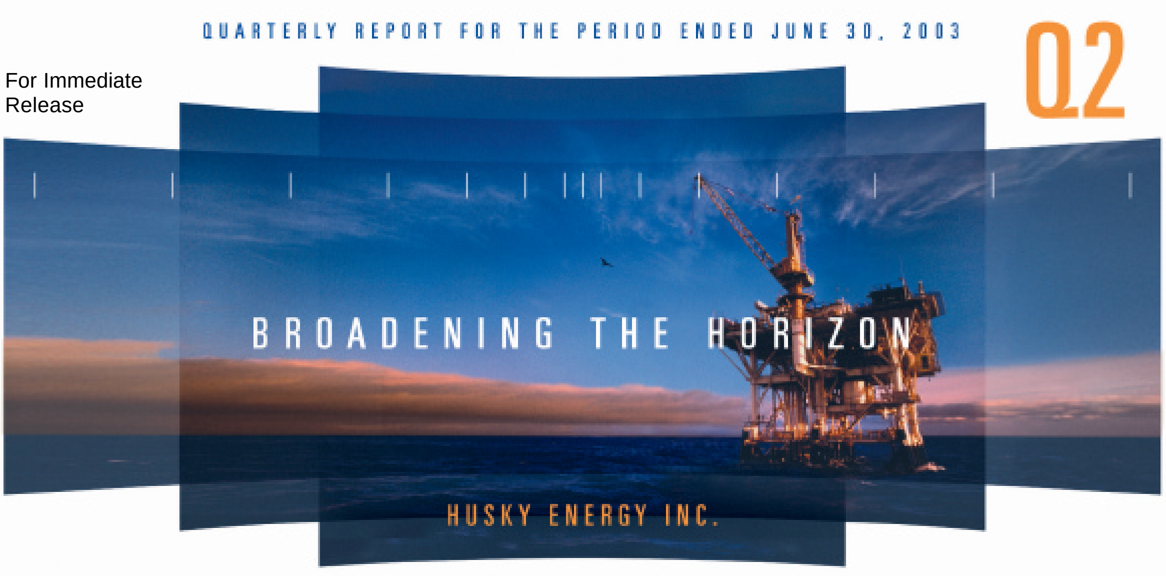
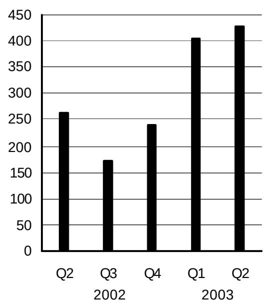
For Immediate Release

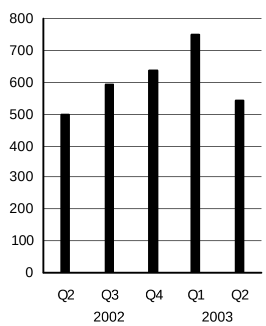


HUSKY ENERGY ANNOUNCES STRONG SECOND QUARTER RESULTS

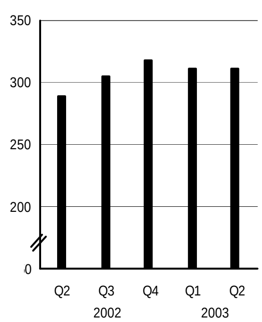
Net Earnings
($ millions)



Cash Flow from Operations
($ millions)



Total Production
(mboe/day)



(Calgary, Alberta) Husky Energy Inc. reported net earnings of $427 million or $1.05 per share (diluted) in the second quarter of 2003 compared with $263 million or $0.64 per share (diluted) in the second quarter of 2002, an increase of 62.4 percent. Cash flow from operations was $540 million or $1.27 per share (diluted) in the second quarter of 2003, up from $498 million or $1.17 per share (diluted) in the second quarter of 2002.

The main contributors to the Company's financial performance were strong commodity prices, foreign exchange gains on U.S. denominated debt translation and lower tax provisions due to federal and provincial tax rate reductions. Net earnings for the second quarter included a net gain of $66 million or $0.16 per share on U.S. denominated debt translation and a positive adjustment of $161 million or $0.38 per share related to tax rate changes. Comparing with the second quarter of 2002, there was a net gain of $50 million or $0.12 per share related to U.S. denominated debt translation and a positive adjustment of $17 million or $0.04 per share related to tax rate changes.

"Husky Energy continues to deliver strong earnings and cash flow from operations and we are pleased with the progress of existing major projects," stated John C.S. Lau, President and Chief Executive Officer.

Production in the second quarter of 2003 was 310,600 barrels of oil equivalent a day compared with 288,900 barrels of oil equivalent a day in the second quarter of 2002. Comparing the second quarter of 2003 with the second quarter of 2002, light crude oil and natural gas liquids production was up 34 percent to 209,000 barrels of oil a day, heavy crude oil production was up two percent to 94,700 barrels per day and natural gas production was up seven percent to 609.4 million cubic feet per day.

Production in the first six months of 2003 averaged 311,300 boe a day compared with 288,800 barrels of oil equivalent a day in the same period in 2002. Light crude oil and natural gas liquids production was up 34 percent to 74,600 barrels a day and heavy crude oil production was up four percent to 96,300 barrels a day. Natural gas production was up six percent to 600.4 million cubic feet a day.

Husky's net earnings for the first six months of 2003 were $833 million or $2.06 per share (diluted), compared with $389 million or $0.93 per share (diluted) for the same period in 2002, an increase of 114 percent. Cash flow from operations for the first six months of 2003 was $1,287 million or $3.03 per share (diluted) compared with $871 million or $2.04 per share (diluted) for the same period of 2002.

"Husky's strong balance sheet and record cash flows and earnings provide the company a solid base for future growth," said John C.S. Lau. "With our financial discipline, we expect that the Company is able to fund all existing projects by our cash flow from operations."

Highlights *(millions of dollars, except per share amounts)*		Three months ended June 30 **2003**	2002	% Change	Six months ended June 30 **2003**	2002	% Change
Sales and operating revenues, net of royalties		**$ 1,769**	$ 1,659	⇧ 7	**$ 3,987**	$ 3,018	⇧ 32
Cash flow from operations		**540**	498	⇧ 8	**1,287**	871	⇧ 48
Per share - Basic		**1.27**	1.18	⇧ 8	**3.04**	2.05	⇧ 48
- Diluted		**1.27**	1.17	⇧ 9	**3.03**	2.04	⇧ 49
Segmented earnings							
Upstream		**$ 359**	$ 178	⇧ 102	**$ 666**	$ 272	⇧ 145
Midstream		**49**	30	⇧ 63	**98**	86	⇧ 14
Refined Products		**2**	13	⇩ 85	**2**	17	⇩ 88
Corporate and eliminations		**17**	42	⇩ 60	**67**	14	⇧ 379
Net earnings		**$ 427**	$ 263	⇧ 62	**$ 833**	$ 389	⇧ 114
Per share - Basic		**$ 1.06**	$ 0.64	⇧ 66	**$ 2.07**	$ 0.93	⇧ 123
- Diluted		**1.05**	0.64	⇧ 64	**2.06**	0.93	⇧ 122
Dividend paid per share		**0.09**	0.09	-	**0.18**	0.18	-
Daily production, before royalties							
Light crude oil & NGL	*(mbbls/day)*	**74.9**	56.1	⇧ 34	**74.6**	55.5	⇧ 34
Medium crude oil	*(mbbls/day)*	**39.4**	44.6	⇩ 12	**40.4**	45.6	⇩ 11
Heavy crude oil *	*(mbbls/day)*	**94.7**	92.8	⇧ 2	**96.3**	92.9	⇧ 4
Total crude oil & NGL	*(mbbls/day)*	**209.0**	193.5	⇧ 8	**211.3**	194.0	⇧ 9
Natural gas	*(mmcf/day)*	**609.4**	571.8	⇧ 7	**600.4**	569.0	⇧ 6
Barrels of oil equivalent (6:1)	*(mboe/day)*	**310.6**	288.9	⇧ 8	**311.3**	288.8	⇧ 8

* *Includes a disposition of 3 mbbls in the second quarter 2003.*

Highlights

UPSTREAM
Production

Total production in the second quarter of 2003 averaged 310,600 barrels of oil equivalent per day, an increase of eight percent compared with the second quarter of 2002. During the second quarter of 2003:

- production of crude oil was two percent lower than the first quarter of 2003. Crude oil production in the second quarter of 2003 was affected by weather related production delays in the Lloydminster heavy oil area and by oil property divestitures.
- in Western Canada 66 net oil wells were completed.
- in the Lloydminster area, Husky drilled 49 primary and thermal heavy oil wells.
- light crude oil production from Terra Nova averaged 19,000 barrels per day compared with 15,700 barrels per day in the second quarter of 2002.

Natural gas production averaged 609.4 million cubic feet per day, an increase of seven percent compared with the second quarter of 2002. The increase in natural gas production was mainly attributable to:

- the 2003 second quarter drilling program that resulted in 75 net natural gas completions combined with 280 net natural gas completions from the first quarter. In the Boyer/Cherpeta area in north central Alberta, 250 shallow gas wells were drilled and 210 wells were tied-in during the winter drilling program. Wells brought on stream in this area during the second quarter of 2003 added approximately 27 million cubic feet per day to production.
- well completions and tie-ins in the Alberta foothills area added 17 million cubic feet per day to production.

Shackleton Natural Gas

Husky drilled 32 wells in the Shackleton area during the second quarter of 2003. At the end of June 2003, 140 natural gas wells were on stream in the Shackleton area and 50 wells were in the process of being equipped and tied-in. Gross sales volume averaged 40 million cubic feet per day during the second quarter of 2003, an increase of approximately 9 million cubic feet per day over the first quarter. During the second quarter Husky commenced the next phase of an in-fill and step-out drilling program and expects to drill approximately 40 wells during the third quarter of 2003.

Bolney/Celtic Thermal

As part of stage two of this development, five horizontal well pairs were drilled and completed during the second quarter of 2003 at Celtic. During the second quarter of 2003 contracts were awarded for the heat integration systems at Bolney.

Oil Sands - Alberta

Tucker

During the second quarter of 2003 Husky continued with its project application to the Alberta Energy and Utilities Board and its environmental impact assessment submitted to Alberta Environment. Work on the project progressed with the design basis for the plant and facilities. Husky proposes to develop a 30,000 barrel per day in-situ bitumen project utilizing steam assisted gravity drainage technology.

Kearl

Husky completed core logging on the 212 stratigraphic test wells drilled as part of the preliminary assessment. The development of a detailed geological model of the reservoir and preliminary data gathering for the environmental impact assessment are currently underway.

Exploration

Western Canada

During the second quarter of 2003 Husky drilled 15 net exploration wells, which included one net oil well completion and 11 net natural gas well completions. During the second quarter seven wells suspended at the end of the first quarter were completed.

Second quarter exploration activity focussed primarily in the foothills region of Alberta. At Bighorn in the Alberta foothills region, three wells were cased for Mississippian natural gas potential and are expected to be completed during the third quarter. During the second quarter, two exploratory wells were spudded in the Bighorn area with natural gas targets in the Mississippian sands.

China

During the second quarter of 2003, a 3-D seismic program commenced in the South China Sea. The program covers 1,000 square kilometres on the shallow water Block 23/15 in the Beibu Wan Basin located between Hainan Island and the mainland. We expect the 3-D seismic will improve sub-surface imaging and consequently the identification of appropriate drilling locations.

On the deep water Block 40/30 in the Pearl River Basin, a prospective structure has been identified and rig selection is underway.

Major Project Update

East Coast, Canada Offshore

White Rose

During the second quarter of 2003 the turret for the floating production, storage and offloading vessel (“FPSO”) was tested in Abu Dhabi and is to be delivered to Korea to be installed on the FPSO. The hull for the FPSO is on schedule to depart Korea in early 2004 for delivery to the integration yard in Newfoundland. Progress at the White Rose oilfield was on schedule during the second quarter of 2003. The first of three glory holes scheduled to be completed in 2003 is substantially complete. The semi-submersible drilling rig Glomar Grand Banks has arrived on the East Coast of Canada and has completed final testing and sea trials prior to commencing development drilling.

MIDSTREAM

Husky Lloydminster Upgrader

At the Husky Lloydminster Upgrader, a review of remaining debottle-neck projects has been completed and engineering of identified debottle-neck projects is nearing completion. This project is expected to increase the plant's productive capacity from 77,000 barrels per day to 82,000 barrels per day by the end of 2004.

In response to the Saskatchewan Government’s requirement for ethanol blended gasoline commencing in 2004, Husky is conducting front end engineering and design for an ethanol plant with a 130 million litre per year capacity. The plant will be located at the Husky Lloydminster Upgrader.

REFINED PRODUCTS

During the second quarter of 2003, Husky commenced construction on a car/truck stop in Belmont, Ontario. Completion is scheduled toward the end of 2003.

StorePoint, an integrated point of sale system, was installed at 51 outlets during the quarter bringing the total StorePoint systems installed to 274.

Husky expanded its asphalt distribution network with the commissioning of a new facility in Winnipeg, Manitoba. The facility is equipped to store and distribute asphalt and road maintenance supplies as well as manufacture various emulsion products.

Management's Discussion & Analysis

Management's Discussion and Analysis should be read in conjunction with the unaudited consolidated financial statements of the Company for the six months ended June 30, 2003 and the audited consolidated financial statements and management's discussion and analysis for the year ended December 31, 2002, which are included in the Company's annual report for the year ended December 31, 2002. All comparisons refer to the second quarter of 2003 compared with the second quarter of 2002 and the first six months of 2003 compared with the first six months of 2002, unless otherwise indicated. All dollar amounts, except per share data, are in millions of Canadian dollars, unless otherwise indicated.

The calculation of barrels of oil equivalent ("boe") and thousands of cubic feet of gas equivalent ("mcfge") are based on a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. All production volumes quoted are gross, the Company's working interest share before royalties, and realized prices include the effect of hedging gains and losses, unless otherwise indicated. Crude oil has been classified as the following: light crude oil has an API gravity of 30 degrees or more; medium crude oil has an API gravity of 21 degrees or more and less than 30 degrees; heavy crude oil has an API gravity of less than 21 degrees.

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 from operating activities as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as an indicator of the Company's financial performance. Husky's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations generated by each business segment represents a measurement of financial performance for which each reporting business segment is responsible. The other items required to arrive at cash flow from operating activities are considered to be a corporate responsibility.

Quarterly Comparison

		Three months ended				
		June 30	March 31	Dec. 31	Sept. 30	June 30
		2003	2003	2002	2002	2002
Sales and operating revenues, net of royalties		**$ 1,769**	$ 2,218	$ 1,697	$ 1,669	$ 1,659
Cash flow from operations		**540**	747	635	590	498
Net earnings		**427**	406	242	173	263
Per share - Basic		**1.06**	1.01	0.57	0.38	0.64
- Diluted		**1.05**	1.00	0.57	0.38	0.64
Daily production, before royalties						
Light crude oil & NGL	*(mbbls/day)*	**74.9**	74.3	78.8	71.9	56.1
Medium crude oil	*(mbbls/day)*	**39.4**	41.4	43.5	44.4	44.6
Heavy crude oil	*(mbbls/day)*	**94.7**	97.8	99.4	95.2	92.8
Natural gas	*(mmcf/day)*	**609.4**	591.2	577.4	561.6	571.8
Barrels of oil equivalent (6:1)	*(mboe/day)*	**310.6**	312.1	317.9	305.1	288.9

Consolidated Results Summary

Husky's net earnings for the second quarter of 2003 were $427 million or $1.05 per share (diluted) compared with net earnings of $263 million or $0.64 per share (diluted) during the second quarter of 2002. Higher earnings in the second quarter of 2003 compared with the second quarter of 2002 were mainly the result of the following factors:

- higher natural gas prices and production
- higher light crude oil production
- higher realized prices for light and medium crude oil and NGL
- higher upgrading netbacks
- higher synthetic crude oil sales volume
- changes in the federal and Alberta income tax rates

partially offset by:

- lower heavy crude oil prices
- higher per unit operating costs and depletion, depreciation and amortization expense
- lower refined product margins
- higher current taxes

Husky's net earnings for the first six months of 2003 were $833 million or $2.06 per share (diluted) compared with net earnings of $389 million or $0.93 per share (diluted) during the comparable period of 2002. Higher earnings in the first six months of 2003 compared with the same period in 2002 were mainly the result of the following factors:

- higher natural gas and crude oil prices
- higher light and heavy crude oil and natural gas production
- higher upgrading netbacks
- higher cogeneration income
- foreign exchange gains on U.S. dollar denominated long-term debt

partially offset by:

- higher royalties
- higher operating costs and depletion, depreciation and amortization expense
- lower medium crude oil production
- lower refined products margins
- higher income taxes, partially offset by reduced rates

Cash flow from operating activities for the second quarter of 2003 was $523 million compared with $496 million in the same quarter last year. The non-recurring benefits from changes to income tax legislation did not affect cash flow and, as a result, the increase in cash flow from operating activities was five percent compared with a 62 percent increase in net earnings. Cash flow from operating activities amounted to $1,425 million in the first six months of 2003, an increase of 67 percent compared with $855 million in the same period in 2002.

Capital expenditures in the six months ended June 30, 2003 amounted to $802 million, which was substantially the same as in the first six months of 2002.

Total debt at June 30, 2003 amounted to $1,995 million compared with $2,385 million at December 31, 2002. The ratio of net debt to total net debt plus equity at June 30, 2003 was 20 percent compared with 29 percent at December 31, 2002. Interest expense totalled $41 million for the six months ended June 30, 2003 compared with $51 million in the first six months of 2002.

2003 Production Forecast

Husky provided its production forecast for 2003 in the First Quarter 2003 Report; the forecast remains unchanged. Overall production is expected to average between 310 and 330 mboe/day. Production of light crude oil and NGL is anticipated to average between 70 and 75 mbbls/day. Production of medium crude oil is anticipated to average between 40 and 45 mbbls/day and heavy crude oil production is anticipated to average between 100 and 110 mbbls/day. Natural gas production is anticipated to average between 590 and 620 mmcf/day.

Business Environment

During the second quarter of 2003 the price for West Texas Intermediate crude oil ("WTI") fell below U.S. $26 per barrel as factors leading to market disruption prevailing during the first quarter abated. Production from Venezuela and Nigeria returned to normalized levels, production in-transit from Iraq prior to the war was still entering the United States and increased production from Saudi Arabia effectively offset the shortfall from the cessation of exports from Iraq. This combined with the expectation that production from Iraq would return to normal led to lower prices for WTI despite historically low crude oil inventory levels. In June, 2003 WTI rose above U.S. $30 per barrel as crude oil inventories declined with the arrival of the driving season at the beginning of June and the announcement by OPEC that production quotas would remain at existing levels. In addition, the uncertain prospect of a return to large-scale production in Iraq and uncertainty associated with Nigeria and Venezuela also buoyed WTI prices.

Low storage levels of natural gas persisted into the second quarter of 2003, which supported NYMEX prices at historically higher levels. Continued higher natural gas prices will depend on whether industrial and electrical power generation demand detracts from natural gas available for injection into storage before the next heating season.

Industry Benchmarks *(averages)*

		Three months ended				
		June 30 2003	March 31 2003	Dec. 31 2002	Sept. 30 2002	June 30 2002
West Texas Intermediate ("WTI")	*(U.S. $/bbl)*	**$ 28.91**	$ 33.86	$ 28.15	$ 28.27	$ 26.25
NYMEX natural gas	*(U.S. $/mmbtu)*	**$ 5.39**	$ 6.60	$ 3.99	$ 3.26	$ 3.37
AECO natural gas	*($/GJ)*	**$ 6.63**	$ 7.51	$ 4.98	$ 3.08	$ 4.19
WTI/Lloyd Blend differential	*(U.S. $/bbl)*	**$ 6.98**	$ 8.12	$ 8.14	$ 5.99	$ 6.04
U.S./Canadian dollar exchange rate	*(U.S. $)*	**$ 0.716**	$ 0.663	$ 0.638	$ 0.640	$ 0.643

Risk Management

Husky's results of operations are affected by market based factors beyond its control. Most significant among these are commodity prices, interest rates and foreign exchange rates. Husky uses various financial instruments to hedge exposure to changes in the price of crude oil and natural gas and fluctuations in interest rates and foreign exchange rates.

The Company implemented a corporate hedging program for 2003 to manage volatility of natural gas and crude oil prices.

Natural Gas

At June 30, 2003, 240 mmcf per day of natural gas was hedged from July to October 2003 and 100 mmcf per day in November and December 2003 at an average price of U.S. $5.33 per mmbtu. At June 30, 2003, the marked to market value of the contracts was a loss of U.S. $4.2 million.

The program's natural gas hedges were in effect during April, May and June. During that period Husky recorded net payments totalling $2.3 million on these contracts.

Crude Oil

At June 30, 2003, 85 mbbls per day was hedged from July to December 2003 at U.S. $29.25 per barrel. At June 30, 2003, the marked to market value of the contracts was a gain of U.S. $5.1 million.

The crude oil hedges were in effect from January to June 2003. During that period Husky recorded net payments totalling $6.0 million on these contracts.

Husky has entered into a put option contract in effect from July to December 2003 on 3,680,000 barrels of crude oil with a strike price of U.S. $27 per barrel. The contract is a full term settlement contract such that if the average price for WTI is below U.S. $27 per barrel the differential will be paid to Husky. Husky paid U.S. $6.1 million for the contract that will be charged to earnings over the contract period. At June 30, 2003 the fair value of the contract was a benefit of U.S. $2.3 million.

Foreign Exchange

In the first half of 2003 Husky entered into three cross currency swaps the terms of which are as follows:

- U.S. $150 million at 6.875 percent swapped at $1.5250 to $229 million at 8.50 percent until November 15, 2003
- U.S. $150 million at 7.125 percent swapped at $1.4500 to $218 million at 8.74 percent until November 15, 2006
- U.S. $150 million at 6.250 percent swapped at $1.4100 to $212 million at 7.41 percent until June 15, 2012

At June 30, 2003 the actual U.S./Canadian exchange was $1.3553. The out of the money differential resulted in an offset to foreign currency gains recorded in the first half of 2003 on U.S. denominated long-term debt of $48 million.

In the first half of 2003 the three cross currency swaps resulted in an addition to interest expense amounting to $6.7 million.

Interest Rates

Husky has an interest rate swap 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 half of 2003 this swap resulted in an offset to interest expense amounting to $2.2 million.

Husky has an interest rate swap on U.S. $200 million of long-term debt effective February 12, 2002 whereby 7.55 percent was swapped for an average U.S. LIBOR + 194 bps until November 15, 2011. During the first half of 2003, this swap resulted an offset to interest expense amounting to U.S. $4.2 million.

Results of Operations

UPSTREAM
Earnings and Production

Second Quarter

Earnings from Husky's upstream business segment increased $181 million to $359 million in the second quarter of 2003 from $178 million in the same quarter in 2002. The higher earnings were due primarily to the following:

- higher realized natural gas prices, net of a hedging loss of $0.07 per mcf
- higher light crude oil production including the Wenchang oil field coming on stream in July 2002 and higher production from the Terra Nova oil field
- higher realized prices for light and medium gravity crude oil and NGL, including a hedging gain of $2.29 per barrel

partially offset by:

- higher unit operating costs reflecting increased energy and energy related costs and higher maintenance costs partially offset by lower unit operating costs at Wenchang and Terra Nova
- lower heavy crude oil prices, which were not hedged
- lower medium crude oil production primarily due to divestitures and declines at mature water flood fields
- higher unit depletion, depreciation and amortization expense related to capital expenditures associated with offshore producing properties and increased capital requirements to maintain production in the mature oil fields and shallow natural gas fields in Western Canada

Six Months

Earnings from Husky's upstream business segment increased $394 million to $666 million in the first half of 2003 from $272 million in the same period in 2002. The higher earnings were due primarily to the following:

- higher realized prices for natural gas and crude oil
- higher production of light and heavy crude oil and natural gas production

partially offset by:

- higher royalties
- higher unit operating costs and depletion, depreciation and amortization expense
- lower production of medium crude oil

Production in the Second Quarter of 2003 Compared with the First Quarter of 2003

Production of crude oil and NGL from Husky's properties in Western Canada averaged 165 mbbls per day in the second quarter of 2003, down four percent from the 172 mbbls per day in the first quarter of 2003. Lower crude oil and NGL production in the second quarter was primarily due to wet weather conditions in the Lloydminster heavy oil area, divestitures of light and medium crude oil properties during the first half of 2003 and natural declines at mature oil fields.

Production of natural gas from Husky's properties in Western Canada averaged 609 mmcf per day in the second quarter of 2003, up three percent from 591 mmcf per day in the first quarter of 2003. Increased production of natural gas in the second quarter compared with the first quarter reflects the results of the winter drilling program. The natural gas drilling program was primarily focussed on the Boyer/Cherpeta area in the northern Alberta plains, the foothills area of Alberta and the Shackleton/Lacadena area of southwestern Saskatchewan.

Production from the Terra Nova oil field offshore the East Coast of Canada averaged 19 mbbls per day in the second quarter of 2003, up from 16 mbbls per day in the first quarter. Production levels were impacted by damage caused by adverse weather conditions in the first quarter.

Production from the Wenchang oil field offshore south China averaged 24 mbbls per day in the second quarter of 2003, a decrease of three percent over the first quarter due to expected natural reservoir decline.

Upstream Earnings Summary

	Three months ended June 30		Six months ended June 30	
	2003	2002	**2003**	2002
Gross revenues	**$ 891**	$ 750	**$ 2,071**	$ 1,336
Royalties	**137**	115	**337**	190
Hedging	**(6)**	-	**10**	-
Net revenues	**760**	635	**1,724**	1,146
Operating and administrative expenses	**212**	171	**435**	334
Depletion, depreciation and amortization ("DD&A")	**233**	202	**462**	402
Income taxes	**(44)**	84	**161**	138
Earnings	**$ 359**	$ 178	**$ 666**	$ 272

Net Revenue Variance Analysis

	Crude oil & NGL	Natural gas	Other	Total
Three months ended June 30, 2002	$ 466	$ 161	$ 8	$ 635
Price changes	(15)	13	-	(2)
Volume changes	51	84	-	135
Royalties	4	(26)	-	(22)
Hedging	10	(4)	-	6
Processing and sulphur	-	-	8	8
Three months ended June 30, 2003	**$ 516**	**$ 228**	**$ 16**	**$ 760**
Six months ended June 30, 2002	$ 834	$ 295	$ 17	$1,146
Price changes	259	335	-	594
Volume changes	104	20	-	124
Royalties	(45)	(102)	-	(147)
Hedging	(6)	(4)	-	(10)
Processing and sulphur	-	-	17	17
Six months ended June 30, 2003	**$1,146**	**$ 544**	**$ 34**	**$1,724**

Average Realized Prices

		Three months ended June 30		Six months ended June 30	
		2003	2002	**2003**	2002
Before commodity hedging					
Light crude oil & NGL	*($/bbl)*	**$ 35.58**	$ 33.96	**$ 41.36**	$ 31.25
Medium crude oil	*($/bbl)*	**$ 30.48**	$ 30.90	**$ 34.24**	$ 27.81
Heavy crude oil	*($/bbl)*	**$ 25.13**	$ 27.75	**$ 29.12**	$ 24.37
Natural gas	*($/mcf)*	**$ 5.50**	$ 3.98	**$ 6.63**	$ 3.54
After commodity hedging					
Light crude oil & NGL	*($/bbl)*	**$ 36.30**	$ 33.96	**$ 41.17**	$ 31.25
Medium crude oil	*($/bbl)*	**$ 32.05**	$ 30.90	**$ 33.75**	$ 27.81
Heavy crude oil	*($/bbl)*	**$ 25.13**	$ 27.75	**$ 29.12**	$ 24.37
Natural gas	*($/mcf)*	**$ 5.43**	$ 3.98	**$ 6.59**	$ 3.54

Royalty Rates

	Three months ended June 30		Six months ended June 30	
Percentage of upstream sales revenues, before royalties	**2003**	2002	**2003**	2002
Crude oil & NGL	**11**	13	**13**	13
Natural gas	**23**	21	**23**	19
Total	**15**	15	**16**	14

Daily Production, Before Royalties

		Three months ended June 30		Six months ended June 30	
		2003	2002	**2003**	2002
Light crude oil & NGL	*(mbbls/day)*	**74.9**	56.1	**74.6**	55.5
Medium crude oil	*(mbbls/day)*	**39.4**	44.6	**40.4**	45.6
Heavy crude oil	*(mbbls/day)*	**94.7**	92.8	**96.3**	92.9
Total crude oil & NGL	*(mbbls/day)*	**209.0**	193.5	**211.3**	194.0
Natural gas	*(mmcf/day)*	**609.4**	571.8	**600.4**	569.0
Barrels of oil equivalent (6:1)	*(mboe/day)*	**310.6**	288.9	**311.3**	288.8

Product Mix

	Three months ended June 30		Six months ended June 30	
Percentage of upstream sales revenues, net of royalties	**2003**	2002	**2003**	2002
Crude oil & NGL	**68**	73	**67**	73
Natural gas	**32**	27	**33**	27
	100	100	**100**	100

Operating Netbacks

Western Canada

Light Crude Oil Netbacks [1]

	Three months ended June 30		Six months ended June 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 38.90**	$ 34.56	**$ 43.11**	$ 31.28
Royalties	**6.45**	4.23	**8.25**	3.69
Hedging	**(1.62)**	-	**0.41**	-
Operating costs	**9.20**	9.52	**10.01**	9.69
Netback	**$ 24.87**	$ 20.81	**$ 24.44**	$ 17.90

Medium Crude Oil Netbacks [1]

	Three months ended June 30		Six months ended June 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 30.77**	$ 30.54	**$ 34.43**	$ 27.61
Royalties	**5.28**	5.63	**6.07**	4.71
Hedging	**(1.51)**	-	**0.48**	-
Operating costs	**9.66**	6.73	**9.41**	6.76
Netback	**$ 17.34**	$ 18.18	**$ 18.47**	$ 16.14

Heavy Crude Oil Netbacks [1]

	Three months ended June 30		Six months ended June 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 25.17**	$ 27.68	**$ 29.23**	$ 24.24
Royalties	**2.42**	3.04	**3.28**	2.50
Operating costs	**9.24**	6.82	**9.65**	6.73
Netback	**$ 13.51**	$ 17.82	**$ 16.30**	$ 15.01

Natural Gas Netbacks [2]

	Three months ended June 30		Six months ended June 30	
Per mcfge	**2003**	2002	**2003**	2002
Sales revenues	**$ 5.34**	$ 4.05	**$ 6.52**	$ 3.62
Royalties	**1.28**	0.95	**1.56**	0.77
Hedging	**0.07**	-	**0.04**	-
Operating costs	**0.78**	0.71	**0.78**	0.64
Netback	**$ 3.21**	$ 2.39	**$ 4.14**	$ 2.21

Total Western Canada Upstream Netbacks [1]

	Three months ended June 30		Six months ended June 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 30.14**	$ 27.86	**$ 35.26**	$ 24.89
Royalties	**5.30**	4.58	**6.53**	3.78
Hedging	**(0.25)**	-	**0.20**	-
Operating costs	**7.57**	6.25	**7.80**	6.11
Netback	**$ 17.52**	$ 17.03	**$ 20.73**	$ 15.00

Terra Nova Crude Oil Netbacks				
	Three months ended June 30		Six months ended June 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 32.16**	$ 34.22	**$ 39.08**	$ 32.90
Royalties	**0.83**	0.34	**0.66**	0.33
Operating costs	**3.09**	5.00	**3.21**	4.20
Netback	**$ 28.24**	$ 28.88	**$ 35.21**	$ 28.37

Wenchang Crude Oil Netbacks				
	Three months ended June 30		Six months ended June 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 38.42**	$ -	**$ 43.46**	$ -
Royalties	**3.03**	-	**3.52**	-
Operating costs	**1.16**	-	**1.62**	-
Netback	**$ 34.23**	$ -	**$ 38.32**	$ -

Total Upstream Segment Netbacks [(1)]				
	Three months ended June 30		Six months ended June 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 30.92**	$ 28.21	**$ 36.13**	$ 25.25
Royalties	**4.84**	4.35	**5.96**	3.63
Hedging	**(0.21)**	-	**0.17**	-
Operating costs	**6.80**	6.19	**7.05**	6.03
Netback	**$ 19.49**	$ 17.67	**$ 22.95**	$ 15.59

[(1)] *Includes associated co-products converted to boe.*
[(2)] *Includes associated co-products converted to mcfge.*

MIDSTREAM

Second Quarter

Earnings from Husky's midstream business segment were $49 million in the second quarter of 2003 compared with $30 million in the same quarter in 2002. The increase in midstream earnings resulted primarily from a $19 million increase in upgrading earnings, which increased as a result of the following:

- higher upgrading margins primarily due to a wider average differential between heavy and light crude oil
- higher sales of synthetic crude oil, higher on stream days in the second quarter of 2003 due to a plant turnaround performed in June 2002 and improved plant reliability

partially offset by:

- higher unit operating costs due primarily to increased energy costs

Earnings from infrastructure and marketing operations were $23 million in the second quarter of 2003, the same as the second quarter in 2002. Higher earnings in the second quarter of 2003 from pipelines and cogeneration operations were offset by lower commodity marketing earnings.

Six Months

Earnings from Husky's midstream business segment were $98 million in the first half of 2003 compared with $86 million in the same period in 2002. The increase in midstream earnings was due to the following:

- higher upgrading netbacks and sales of synthetic crude oil
- higher cogeneration income
- higher pipeline income

partially offset by:

- higher upgrading operating costs
- lower commodity marketing income

Upgrading

		Three months ended June 30		Six months ended June 30	
		2003	2002	**2003**	2002
Gross margin		**$ 79**	$ 49	**$ 160**	$ 124
Operating costs		**52**	38	**110**	74
Other expenses (recoveries)		**(1)**	(2)	**(2)**	(3)
DD&A		**5**	4	**10**	9
Income taxes		**(3)**	2	**4**	12
Earnings		**$ 26**	$ 7	**$ 38**	$ 32
Selected operating data:					
Upgrader throughput [1]	*(mbbls/day)*	**74.0**	58.9	**72.6**	67.7
Synthetic crude oil sales	*(mbbls/day)*	**66.5**	51.3	**63.0**	61.2
Upgrading differential	*($/bbl)*	**12.65**	10.43	**13.21**	9.94
Unit margin	*($/bbl)*	**13.12**	10.55	**14.04**	11.20
Unit operating cost [2]	*($/bbl)*	**7.80**	7.13	**8.38**	6.01

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

Upgrading Earnings Variance Analysis

Three months ended June 30, 2002	$ 7
Volume	15
Differential	15
Operating costs - energy related	(12)
Operating costs - non-energy related	(2)
Other	(1)
DD&A	(1)
Income taxes	5
Three months ended June 30, 2003	**$ 26**
Six months ended June 30, 2002	$ 32
Volume	4
Differential	32
Operating costs - energy related	(33)
Operating costs - non-energy related	(3)
Other	(1)
DD&A	(1)
Income taxes	8
Six months ended June 30, 2003	**$ 38**

Infrastructure and Marketing		Three months ended June 30		Six months ended June 30	
		2003	2002	**2003**	2002
Gross margin	- pipeline	**$ 16**	$ 14	**$ 33**	$ 30
	- other infrastructure and marketing	**26**	30	**76**	72
		42	44	**109**	102
Other expenses		**3**	2	**5**	4
DD&A		**5**	5	**10**	9
Income taxes		**11**	14	**34**	35
Earnings		**$ 23**	$ 23	**$ 60**	$ 54
Selected operating data:					
Aggregate pipeline throughput	*(mbbls/day)*	**480**	448	**479**	458

REFINED PRODUCTS

Earnings from Husky's refined products business segment were $2 million in the second quarter of 2003 compared with $13 million in the same period in 2002. The decline in refined products earnings was primarily a result of a write-down of inventory in the second quarter of 2003 of $9 million that was reflected in lower sales margins for motor fuels and asphalt products, lower results in the first quarter of 2003 for the asphalt winter fill program partially offset by higher motor fuel sales volume.

Earnings in the six months ended June 30, 2003 were $2 million compared with $17 million in the same period in 2002. The lower earnings in 2003 resulted from factors similar to those that affected the second quarter of 2003.

Refined Products		Three months ended June 30		Six months ended June 30	
		2003	2002	**2003**	2002
Gross margin	- fuel sales	**$ 9**	$ 24	**$ 32**	$ 36
	- ancillary sales	**8**	6	**14**	12
	- asphalt sales	**12**	13	**10**	20
		29	43	**56**	68
Operating and other expenses		**17**	13	**34**	24
DD&A		**9**	8	**18**	16
Income taxes		**1**	9	**2**	11
Earnings		**$ 2**	$ 13	**$ 2**	$ 17
Selected operating data:					
Number of fuel outlets				**568**	575
Light oil sales	*(million litres/day)*	**7.8**	7.4	**8.1**	7.3
Prince George refinery throughput	*(mbbls/day)*	**11.0**	7.7	**10.8**	9.3
Asphalt sales	*(mbbls/day)*	**20.7**	20.5	**18.9**	19.1
Lloydminster refinery throughput	*(mbbls/day)*	**25.4**	19.9	**25.1**	22.5

CORPORATE

Selling and Administration Expenses

Selling and administration expenses were $31 million in the second quarter of 2003 compared with $18 million in the second quarter of 2002. In the first half of 2003 selling and administration expenses totalled $58 million compared with $38 million in the period of 2002. The increase in selling and administration expenses in 2003 was related to higher staff levels and compensation costs.

Interest Expense

Interest expense, net of interest income and interest capitalized, was $20 million in the second quarter of 2003 compared with $24 million in the second quarter of 2002. Interest capitalized in the second quarter amounted to $13 million compared with $4 million in the second quarter of 2002. Higher capitalization of interest was related to the progress of the White Rose oil field development project. Interest income was the same in the second quarters of 2003 and 2002.

Foreign Exchange

Foreign exchange gains recorded in the second quarter of 2003 totalled $72 million compared with $65 million in the second quarter of 2002. Foreign exchange gains in the second quarter of 2003 comprised $126 million of gains on U.S. denominated debt translation partially offset by $40 million of cross currency swap losses and a $14 million loss on working capital and other monetary items. Foreign exchange gains in the second quarter of 2002 comprised $71 million of gains on U.S. denominated debt translation partially offset by a $6 million loss on working capital and other monetary items.

Income Taxes

During the second quarter of 2003 Husky's total provision for income taxes amounted to a recovery of $16 million compared with an income tax expense of $89 million in the same period in 2002.

During the second quarter of 2003 a non-recurring benefit of $141 million was recorded in respect of substantively enacted changes pursuant to Bill C-48, an Act to amend the Income Tax Act. The changes will reduce the rate on resource income by seven percent, provide for the deduction of crown royalties and eliminate the resource allowance over a five-year period. In addition, a non-recurring benefit of $20 million was recorded relating to an Alberta rate reduction, Bill 41, The Alberta Corporate Tax Amendment Act, 2003. Both adjustments impacted future taxes. During the second quarter of 2002 a non-recurring benefit of $34 million was recorded resulting from a reduction to the Alberta corporate income tax rate. The current tax provision in the second quarter was $42 million, just over half of which was related to income from the Wenchang operation.

Sensitivity Analysis

The following table shows the annual effect on net earnings and cash flow of changes in certain key variables. The analysis is based on business conditions and production volumes during the second quarter of 2003. Each separate item in the sensitivity analysis assumes the others 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

Item	*Increase*	*Effect on Pre-tax Cash Flow*		*Effect on Net Earnings*	
		($ millions)	*($/share)[5]*	*($ millions)*	*($/share)[5]*
WTI benchmark crude oil price					
Excluding hedges	*U.S. $1.00/bbl*	94	0.22	62	0.15
Including hedges	*U.S. $1.00/bbl*	49	0.12	31	0.07
NYMEX benchmark natural gas price [1]					
Excluding hedges	*U.S. $0.20/mmbtu*	32	0.08	19	0.05
Including hedges	*U.S. $0.20/mmbtu*	9	0.02	3	0.01
Light/heavy crude oil differential [2]	*Cdn. $1.00/bbl*	(23)	(0.05)	(14)	(0.03)
Light oil margins	*Cdn. $0.005/litre*	14	0.03	9	0.02
Asphalt margins	*Cdn. $1.00/bbl*	8	0.02	5	0.01
Exchange rate (U.S. $ per Cdn. $) [3]					
Including hedges	*U.S. $0.01*	(49)	(0.12)	(32)	(0.08)
Interest rate [4]	*1%*	(6)	(0.02)	(4)	(0.01)

[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. $ denominated long-term debt and other monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $10 million in net earnings based on June 30, 2003 U.S. $ denominated debt levels.
[4] Interest rate sensitivity based on annual weighted obligations.
[5] Based on June 30, 2003 common shares outstanding of 418.8 million.

Liquidity and Capital Resources

SUMMARY

	Three months ended June 30		Six months ended June 30	
	2003	2002	**2003**	2002
Cash flow from operating activities	**$ 523**	$ 496	**$ 1,425**	$ 855
Cash flow from financing activities	**3**	69	**(376)**	124
Cash flow from investing activities	**(365)**	(393)	**(858)**	(807)
Increase in cash and cash equivalents	**$ 161**	$ 172	**$ 191**	$ 172

INVESTING ACTIVITIES

During the first half of 2003 cash flow available for investing totalled $1,049 million compared with $979 million in the same period in 2002.

Capital expenditures in the first half of 2003 amounted to $802 million compared with $787 million in the first half of 2002.

Capital Expenditures

	Three months ended June 30		Six months ended June 30	
	2003	2002	**2003**	2002
Upstream				
Exploration				
Western Canada	**$ 56**	$ 37	**$ 185**	$ 159
East Coast Canada	**3**	-	**3**	15
International	**2**	-	**12**	1
	61	37	**200**	175
Development				
Western Canada	**129**	119	**370**	342
East Coast Canada	**87**	154	**191**	177
International	**-**	22	**-**	41
	216	295	**561**	560
	277	332	**761**	735
Midstream				
Upgrader	**6**	12	**10**	21
Infrastructure and marketing	**3**	3	**5**	10
	9	15	**15**	31
Refined Products	**9**	9	**17**	13
Corporate	**7**	5	**9**	8
	$ 302	$ 361	**$ 802**	$ 787

Upstream

During the first half of 2003 capital expenditures for exploration and development in Western Canada totalled $555 million compared with $501 million a year earlier.

Total development spending in Western Canada during the first half of 2003 amounted to $370 million compared with $342 million during the same period in 2002. In the first half of 2003 development expenditures were directed to the following areas:

- Alberta northwest plains area, $143 million for shallow natural gas drilling, completions and installation of facilities in the Boyer/Cherpeta districts
- Lloydminster heavy oil area, $84 million for continued exploitation and optimization including work on the Bolney/Celtic thermal project

- east central and southern Alberta and southeastern Saskatchewan, $89 million primarily for in-fill drilling and facilities optimization and continuing work on the Shackleton/Lacadena natural gas project in southeastern Saskatchewan
- Alberta foothills area, $52 million for facilities optimization and in-fill drilling.

Exploration expenditures in the Western Canada Sedimentary Basin in the first half of 2003 amounted to $185 million compared with $159 million in the first half of 2002. In 2003 the primary exploration targets were natural gas prospects in the Alberta foothills as well as step-out drilling throughout Husky's properties in the basin. Capital spending during the first half of 2003 on the oilsands projects at Kearl and Tucker, Alberta amounted to $25 million.

Drilling results during the first half of 2003 included a higher number of uncommercial or dry wells compared to the same period in 2002 primarily as a result of drilling toward the edge of shallow natural gas reservoirs in northern Alberta.

Capital expenditures for exploration and development offshore the East Coast of Canada amounted to $194 million in the first half of 2003, $179 million for White Rose, $12 million for Terra Nova and the balance on exploration prospects.

Wells Drilled [(1)]

		Three months ended June 30				Six months ended June 30			
		2003		2002		**2003**		2002	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Western Canada									
Exploration	Oil	**1**	**1**	6	6	**5**	**4**	12	11
	Gas	**15**	**11**	19	18	**91**	**81**	107	101
	Dry	**3**	**3**	1	1	**21**	**20**	10	10
		19	**15**	26	25	**117**	**105**	129	122
Development	Oil	**67**	**65**	120	112	**187**	**172**	172	156
	Gas	**67**	**64**	14	10	**286**	**274**	240	226
	Dry	**6**	**6**	6	6	**40**	**38**	25	24
		140	**135**	140	128	**513**	**484**	437	406
		159	**150**	166	153	**630**	**589**	566	528

[(1)] *Excludes stratigraphic test wells.*

Midstream

In the first half of 2003 capital expenditures at the Husky Lloydminster Upgrader amounted to $10 million compared with $21 million in the same period in 2002. Spending was primarily directed toward the continuing optimization of the plant. Spending on the midstream infrastructure operations amounted to $5 million primarily for pipeline improvements.

Refined Products

Capital expenditures in the first half of 2003 amounted to $17 million compared with $13 million in the first half of 2002. During 2003, $8 million was spent on marketing outlet construction and improvements, $6 million on refinery improvements and the balance primarily on expanding asphalt distribution facilities.

FINANCING ACTIVITIES

At June 30, 2003 Husky's total debt, net of cash and cash equivalents was $1,498 million compared with $2,079 million at December 31, 2002, a reduction of $581 million. The reduction in Husky's net debt was comprised of repayments totalling $140 million, foreign exchange gain at June 30, 2003 totalling $250 million and an increase in cash and cash equivalents of $191 million.

During the first quarter of 2003 Husky reduced its syndicated credit facility from $940 million to $830 million. At June 30, 2003 there were no drawings under this facility. During the first quarter of 2003 Husky added a revolving facility with a Canadian financial institution for $100 million that carries essentially the same terms as the $830 million syndicated credit facility.

During the first quarter of 2003 Husky terminated its agreement to continually sell up to $200 million of net trade receivables.

Common Share Information

(thousands of shares, except per share amounts)		**Six months ended June 30 2003**	Year ended December 31 2002
Share price [1]	High	**$ 18.14**	$ 17.98
	Low	**$ 16.03**	$ 14.00
	Close at end of period	**$ 17.50**	$ 16.47
Average daily trading volume		**343**	463
Weighted average number of common shares outstanding			
	Basic	**418,352**	417,425
	Diluted	**420,159**	419,334
Number of common shares outstanding at end of period		**418,801**	417,874

(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.*

This document contains certain forward-looking statements relating, but not limited, to our operations, anticipated financial performance, business prospects and strategies and which are based on our current expectations, estimates, projections and assumptions and were made by us in light of our experience and our perception of historical trends. All statements that address expectations or projections about the future, including statements about our strategy for growth, expected expenditures, commodity prices, costs, schedules and production volumes, operating or financial results, are forward-looking statements. Some of our forward-looking statements may be identified by words like "expects", "anticipates", "plans", "intends", "believes", "projects", "indicates", "could", "vision", "goal", "objective" and similar expressions. Our business is subject to risks and uncertainties, some of which are similar to other energy companies and some of which are unique to us. Our actual results may differ materially from those expressed or implied by our forward-looking statements as a result of known and unknown risks, uncertainties and other factors.

You are cautioned not to place undue reliance on our forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, that 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 our actual results include, but are not limited to:

- ***changes in general economic, market and business conditions;***
- ***fluctuations in supply and demand for our products;***
- ***fluctuations in commodity prices;***
- ***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 currency exchange rates;***
- ***political and economic developments, expropriation, 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 accuracy of our reserve estimates, production estimates and production levels and our success at exploration and development drilling and related activities;***
- ***the maintenance of satisfactory relationships with unions, employee associations, joint venturers and partners;***

- ***competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy;***
- ***the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures;***
- ***actions by governmental authorities, including changes in environmental and other regulations;***
- ***the ability and willingness of parties with whom we have material relationships to fulfill their obligations to us; 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.***

We caution that the foregoing list of important factors is not exhaustive. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements.

CONSOLIDATED BALANCE SHEETS

(millions of dollars)	**June 30 2003**	December 31 2002
	(unaudited)	*(audited)*
Assets		
Current assets		
Cash and cash equivalents	**$ 497**	$ 306
Accounts receivable	**865**	572
Inventories	**253**	243
Prepaid expenses	**30**	23
	1,645	1,144
Property, plant and equipment - (full cost accounting)	**15,075**	14,450
Less accumulated depletion, depreciation and amortization	**5,476**	5,103
	9,599	9,347
Other assets	**88**	84
	$ 11,332	$ 10,575
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 977**	$ 811
Long-term debt due within one year *(note 4)*	**456**	421
	1,433	1,232
Long-term debt *(note 4)*	**1,539**	1,964
Site restoration and other long-term liabilities	**319**	249
Future income taxes *(note 6)*	**2,166**	2,003
Shareholders' equity		
Capital securities and accrued return	**312**	364
Common shares *(note 5)*	**3,415**	3,406
Retained earnings	**2,148**	1,357
	5,875	5,127
	$ 11,332	$ 10,575
Commitments *(note 7)*		
Common shares outstanding *(millions)* *(note 5)*	**418.8**	417.9

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

CONSOLIDATED STATEMENTS OF EARNINGS

(unaudited)

(millions of dollars, except per share amounts)	Three months ended June 30		Six months ended June 30	
	2003	2002	**2003**	2002
Sales and operating revenues, net of royalties	**$ 1,769**	$ 1,659	**$ 3,987**	$ 3,018
Costs and expenses				
Cost of sales and operating expenses	**1,119**	1,105	**2,478**	2,008
Selling and administration expenses	**31**	18	**58**	38
Depletion, depreciation and amortization	**258**	223	**511**	444
Interest - net *(note 4)*	**20**	24	**41**	51
Foreign exchange	**(72)**	(65)	**(172)**	(57)
Other - net	**2**	2	**2**	(1)
	1,358	1,307	**2,918**	2,483
Earnings before income taxes	**411**	352	**1,069**	535
Income taxes *(note 6)*				
Current	**42**	6	**90**	34
Future	**(58)**	83	**146**	112
	(16)	89	**236**	146
Net earnings	**$ 427**	$ 263	**$ 833**	$ 389
Earnings per share *(note 9)*				
Basic	**$ 1.06**	$ 0.64	**$ 2.07**	$ 0.93
Diluted	**$ 1.05**	$ 0.64	**$ 2.06**	$ 0.93
Weighted average number of common shares outstanding *(millions)* *(note 9)*				
Basic	**418.5**	417.4	**418.4**	417.2
Diluted	**420.3**	419.6	**420.2**	419.3

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(unaudited)

(millions of dollars)	Three months ended June 30		Six months ended June 30	
	2003	2002	**2003**	2002
Beginning of period	**$ 1,743**	$ 805	**$ 1,357**	$ 722
Net earnings	**427**	263	**833**	389
Dividends on common shares	**(38)**	(37)	**(75)**	(75)
Return on capital securities (net of related taxes and foreign exchange)	**16**	6	**33**	1
End of period	**$ 2,148**	$ 1,037	**$ 2,148**	$ 1,037

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

(millions of dollars)	Three months ended June 30 2003	Three months ended June 30 2002	Six months ended June 30 2003	Six months ended June 30 2002
Operating activities				
Net earnings	**$ 427**	$ 263	**$ 833**	$ 389
Items not affecting cash				
Depletion, depreciation and amortization	**258**	223	**511**	444
Future income taxes	**(58)**	83	**146**	112
Foreign exchange - non-cash	**(86)**	(71)	**(202)**	(70)
Other	**(1)**	-	**(1)**	(4)
Cash flow from operations	**540**	498	**1,287**	871
Change in non-cash working capital *(note 8)*	**(17)**	(2)	**138**	(16)
Cash flow - operating activities	**523**	496	**1,425**	855
Financing activities				
Bank operating loans financing - net	**-**	(120)	**-**	(100)
Long-term debt issue	**-**	772	**-**	972
Long-term debt repayment	**-**	(535)	**(140)**	(646)
Return on capital securities payment	**-**	-	**(15)**	(16)
Debt issue costs	**-**	(7)	**-**	(7)
Proceeds from exercise of stock options	**3**	1	**9**	4
Proceeds from interest swaps monetization	**44**	-	**44**	-
Dividends on common shares	**(38)**	(37)	**(75)**	(75)
Change in non-cash working capital *(note 8)*	**(6)**	(5)	**(199)**	(8)
Cash flow - financing activities	**3**	69	**(376)**	124
Available for investing	**526**	565	**1,049**	979
Investing activities				
Capital expenditures	**(302)**	(361)	**(802)**	(787)
Asset sales	**42**	5	**49**	17
Other	**2**	(10)	**4**	(10)
Change in non-cash working capital *(note 8)*	**(107)**	(27)	**(109)**	(27)
Cash flow - investing activities	**(365)**	(393)	**(858)**	(807)
Increase in cash and cash equivalents	**161**	172	**191**	172
Cash and cash equivalents at beginning of period	**336**	-	**306**	-
Cash and cash equivalents at end of period	**$ 497**	$ 172	**$ 497**	$ 172

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, 2003 *(unaudited)*

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

Note 1 Segmented Financial Information

	Upstream		Midstream				Refined Products		Corporate and Eliminations [(1)]		Total	
			Upgrading		Infrastructure and Marketing							
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002
Three months ended June 30												
Sales and operating revenues, net of royalties	**$ 760**	$ 635	**$ 256**	$ 195	**$1,205**	$ 958	**$ 352**	$ 322	**$ (804)**	$ (451)	**$ 1,769**	$ 1,659
Costs and expenses												
Operating, cost of sales, selling and general	**212**	171	**228**	182	**1,166**	916	**340**	292	**(794)**	(436)	**1,152**	1,125
Depletion, depreciation and amortization	**233**	202	**5**	4	**5**	5	**9**	8	**6**	4	**258**	223
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**20**	24	**20**	24
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(72)**	(65)	**(72)**	(65)
	445	373	**233**	186	**1,171**	921	**349**	300	**(840)**	(473)	**1,358**	1,307
Earnings (loss) before income taxes	**315**	262	**23**	9	**34**	37	**3**	22	**36**	22	**411**	352
Current income taxes	**39**	1	**-**	-	**(4)**	4	**3**	1	**4**	-	**42**	6
Future income taxes	**(83)**	83	**(3)**	2	**15**	10	**(2)**	8	**15**	(20)	**(58)**	83
Net earnings (loss)	**$ 359**	$ 178	**$ 26**	$ 7	**$ 23**	$ 23	**$ 2**	$ 13	**$ 17**	$ 42	**$ 427**	$ 263
Six months ended June 30												
Sales and operating revenues, net of royalties	**$1,724**	$1,146	**$ 532**	$ 416	**$2,637**	$1,910	**$ 736**	$ 553	**$ (1,642)**	$ (1,007)	**$ 3,987**	$ 3,018
Costs and expenses												
Operating, cost of sales, selling and general	**435**	334	**480**	363	**2,533**	1,812	**714**	509	**(1,624)**	(973)	**2,538**	2,045
Depletion, depreciation and amortization	**462**	402	**10**	9	**10**	9	**18**	16	**11**	8	**511**	444
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**41**	51	**41**	51
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(172)**	(57)	**(172)**	(57)
	897	736	**490**	372	**2,543**	1,821	**732**	525	**(1,744)**	(971)	**2,918**	2,483
Earnings (loss) before income taxes	**827**	410	**42**	44	**94**	89	**4**	28	**102**	(36)	**1,069**	535
Current income taxes	**77**	21	**-**	-	**1**	12	**8**	1	**4**	-	**90**	34
Future income taxes	**84**	117	**4**	12	**33**	23	**(6)**	10	**31**	(50)	**146**	112
Net earnings (loss)	**$ 666**	$ 272	**$ 38**	$ 32	**$ 60**	$ 54	**$ 2**	$ 17	**$ 67**	$ 14	**$ 833**	$ 389
Capital employed - As at June 30 [(2)]	**$6,111**	$ 6,001	**$ 468**	$ 324	**$ 442**	$ 194	**$ 425**	$ 383	**$ 424**	$ 233	**$ 7,870**	$ 7,135
Total assets - As at June 30	**$8,541**	$ 7,860	**$ 655**	$ 657	**$ 945**	$ 736	**$ 607**	$ 523	**$ 584**	$ 189	**$11,332**	$ 9,965

[(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)] *Capital employed is defined as short- and long-term debt and shareholders' equity.*

Note 2 Significant Accounting Polices

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, 2002. 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, 2002.

Note 3 Financial Instruments and Risk Management

Upstream Commodity Price Risk

In January and February 2003, the Company hedged crude oil averaging 85,000 bbls/day from April to December 2003 at an average fixed price of U.S. $29.42/bbl. In addition, the Company executed a put option program in February 2003 for approximately 3.7 mmbbls from July to December 2003 at a strike price of U.S. $27.00/bbl. The cost of the put option program of U.S. $6.1 million is deferred and will be amortized over the term of the options.

In February and May 2003, the Company hedged 230 mmcf/day of natural gas for April to June 2003, 240 mmcf/day for July to October 2003 and 100 mmcf/day for November and December 2003 at an average price of U.S. $5.33/mcf.

Foreign Currency Rate Risk

In the first six months of 2003, the Company entered into the following cross currency swaps:

Debt	Swap Amount *(millions)*	Swap Maturity	Canadian Equivalent *(millions)*
6.875% notes	U.S. $150	November 15, 2003	$229
7.125% notes	U.S. $150	November 15, 2006	$218
6.25% notes	U.S. $150	June 15, 2012	$212

Interest Rate Risk

The Company has interest rate swap arrangements whereby the fixed interest rate coupon on certain debt has been swapped to floating rates with the following terms as at June 30, 2003:

Debt	Swap Amount *(millions)*	Swap Maturity	Swap Rate *(percent)*
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps
7.55% debentures	U.S. $200	November 15, 2011	U.S. LIBOR + 194 bps

During the first six months of 2003, the Company unwound the following interest rate swaps:

Debt	Swap Amount *(millions)*	Swap Maturity	Gross Proceeds *(millions)*
6.875% notes	U.S. $35	November 15, 2003	U.S. $2
7.125% notes	U.S. $150	November 15, 2006	U.S. $12
6.25% senior notes	U.S. $150	June 15, 2012	U.S. $16

The proceeds have been deferred and will be amortized over the term of the debt.

Sale of Accounts Receivable

The Company terminated its agreement to sell net trade receivables of up to $200 million on a continual basis on March 31, 2003.

Note 4 Long-term Debt

			Maturity	June 30 2003	Dec. 31 2002
Long-term debt					
6.25% notes	*-2003 & 2002*	*U.S. $400*	2012	**$ 542**	$ 632
6.875% notes	*-2003 & 2002*	*U.S. $150*	2003	**203**	237
7.125% notes	*-2003 & 2002*	*U.S. $150*	2006	**203**	237
7.55% debentures	*-2003 & 2002*	*U.S. $200*	2016	**271**	316
8.45% senior secured bonds	*-2003*	*U.S. $157*			
	-2002	*U.S. $162*	2003-12	**213**	256
Private placement notes	*-2003*	*U.S. $47*			
	-2002	*U.S. $68*	2003-5	**63**	107
Medium-term notes			2004-9	**500**	600
Total long-term debt				**1,995**	2,385
Amount due within one year				**(456)**	(421)
				$ 1,539	$ 1,964

At June 30, 2003, the Company did not have any borrowings under the Company's $830 million syndicated credit facility or its $100 million credit facility. Interest rates under the syndicated credit facility vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected, credit ratings assigned by certain rating agencies to the Company's senior unsecured debt and whether the facility is revolving or non-revolving. The $100 million credit facility has substantially the same terms as the syndicated credit facility.

Interest - net consisted of:

	Three months ended June 30		Six months ended June 30	
	2003	2002	**2003**	2002
Long-term debt	**$ 34**	$ 29	**$ 66**	$ 60
Short-term debt	**1**	1	**1**	2
	35	30	**67**	62
Amount capitalized	**(13)**	(4)	**(22)**	(10)
	22	26	**45**	52
Interest income	**(2)**	(2)	**(4)**	(1)
	$ 20	$ 24	**$ 41**	$ 51

Note 5 Share Capital

The Company's authorized share capital consists of an unlimited number of no par value common and preferred shares. Changes to issued share capital were as follows:

	Six months ended June 30			
	2003		2002	
	Number of Common Shares	Amount	Number of Common Shares	Amount
Balance at beginning of period	417,873,601	$ 3,406	416,878,093	$ 3,397
Exercised for cash - options and warrants	927,082	9	593,465	4
Balance at June 30	**418,800,683**	**$ 3,415**	417,471,558	$ 3,401

The fair values of all common share options granted are estimated on the date of grant using the Modified Black-Scholes option-pricing model. The weighted average fair market value of options granted during the year and the assumptions used in their determination are as noted below:

	Three months ended June 30		Six months ended June 30	
	2003	2002	**2003**	2002
Weighted average fair market value per option	**$ 3.59**	$ 6.02	**$ 3.76**	$ 5.99
Risk-free interest rate *(percent)*	**3.9**	3.5	**3.9**	3.5
Volatility *(percent)*	**23**	45	**24**	45
Expected life *(years)*	**5**	5	**5**	5
Expected annual dividend per share	**$ 0.36**	$ 0.36	**$ 0.36**	$ 0.36

The Company follows the intrinsic value method of accounting for stock-based compensation for its fixed stock option plan, under which compensation cost is not recognized. If the Company applied the fair value method at the grant dates for options granted after January 1, 2002 and also to all options granted, the Company's net earnings and earnings per share would have been as follows:

	Three months ended June 30		Six months ended June 30	
	2003	2002	**2003**	2002
Compensation cost - options granted after January 1, 2002	**$ 1**	$ -	**$ 1**	$ -
Compensation cost - all options granted	**$ 4**	$ 3	**$ 7**	$ 6
Net earnings available to common shareholders				
As reported	**$ 443**	$ 269	**$ 865**	$ 389
Options granted after January 1, 2002	**$ 442**	$ 269	**$ 864**	$ 389
All options granted	**$ 439**	$ 266	**$ 858**	$ 383
Weighted average number of common shares outstanding *(millions)*				
Basic	**418.5**	417.4	**418.4**	417.2
Diluted	**420.3**	419.6	**420.2**	419.3
Basic earnings per share				
As reported	**$ 1.06**	$ 0.64	**$ 2.07**	$ 0.93
Options granted after January 1, 2002	**$ 1.06**	$ 0.64	**$ 2.07**	$ 0.93
All options granted	**$ 1.05**	$ 0.64	**$ 2.05**	$ 0.92
Diluted earnings per share				
As reported	**$ 1.05**	$ 0.64	**$ 2.06**	$ 0.93
Options granted after January 1, 2002	**$ 1.05**	$ 0.64	**$ 2.06**	$ 0.93
All options granted	**$ 1.04**	$ 0.63	**$ 2.04**	$ 0.91

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

	Six months ended June 30			
	2003		2002	
Fixed Options	Number of Shares *(thousands)*	Weighted Average Exercise Prices	Number of Shares *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of period	7,920	$13.91	8,602	$13.78
Granted	326	$16.85	329	$16.32
Exercised	(705)	$13.74	(243)	$13.58
Forfeited	(70)	$14.52	(379)	$14.19
Outstanding, June 30	**7,471**	**$14.05**	8,309	$13.87
Options exercisable at June 30	4,314	$13.81	2,742	$13.79

At June 30, 2003, the options outstanding had exercise prices ranging from $11.16 to $17.46 with a weighted average contractual life of 2.4 years.

Shares potentially issuable on the settlement of the capital securities have not been included in the determination of diluted earnings as the Company has neither the obligation nor intention to settle amounts due through the issue of shares.

Note 6 Income Taxes

Income tax expense in the first six months of 2003 included a non-recurring adjustment to future income taxes of $20 million resulting from a change in the Alberta corporate income tax rate. Additionally, on June 13, 2003 Bill C-48, an Act to amend the Income Tax Act (natural resources), was substantively enacted and resulted in a non-recurring tax benefit of $141 million. The resource tax changes include a change in the federal tax rate, deductibility of crown royalties and elimination of the resource allowance, to be phased in over the next five years. Income tax expense in the first six months of 2002 included a non-recurring adjustment to future income taxes of $44 million resulting from changes to the British Columbia and Alberta corporate income tax rates, a reduction in the federal corporate income tax rate for non-resource income and the recognition of additional tax deductions relating to foreign exchange losses of prior years.

Note 7 Commitments

The Company has awarded various contracts for the construction of the floating production, storage and offloading vessel and several other components of the White Rose development project with expected completion dates in 2005. The Company's share of the total value of contractual obligations at June 30, 2003 was $1.1 billion. As at June 30, 2003, the Company had spent $468 million on these contracts.

Note 8 Cash Flows - Change in Non-cash Working Capital

	Three months ended June 30		Six months ended June 30	
	2003	2002	**2003**	2002
a) Changes in non-cash working capital were as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ 58**	$ 115	**$ (293)**	$ (38)
Inventories	**(23)**	(17)	**(10)**	(18)
Prepaid expenses	**(13)**	4	**(7)**	2
Accounts payable and accrued liabilities	**(152)**	(136)	**140**	3
Change in non-cash working capital	**(130)**	(34)	**(170)**	(51)
Relating to:				
Financing activities	**(6)**	(5)	**(199)**	(8)
Investing activities	**(107)**	(27)	**(109)**	(27)
Operating activities	**$ (17)**	$ (2)	**$ 138**	$ (16)
b) Other cash flow information:				
Cash taxes paid	**$ 49**	$ -	**$ 65**	$ 14
Cash interest paid	**$ 45**	$ 35	**$ 68**	$ 70

Note 9 Net Earnings Per Common Share

	Three months ended June 30		Six months ended June 30	
	2003	2002	**2003**	2002
Net earnings	**$ 427**	$ 263	**$ 833**	$ 389
Return on capital securities (net of related taxes and foreign exchange)	**16**	6	**32**	-
Net earnings available to common shareholders	**$ 443**	$ 269	**$ 865**	$ 389
Weighted average number of common shares outstanding - Basic *(millions)*	**418.5**	417.4	**418.4**	417.2
Effect of dilutive stock options and warrants	**1.8**	2.2	**1.8**	2.1
Weighted average number of common shares outstanding - Diluted *(millions)*	**420.3**	419.6	**420.2**	419.3
Net earnings				
Per share - Basic	**$ 1.06**	$ 0.64	**$ 2.07**	$ 0.93
- Diluted	**$ 1.05**	$ 0.64	**$ 2.06**	$ 0.93

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
NGL	natural gas liquids
LIBOR	London Interbank Offered Rate
CDOR	Certificate of Deposit Offered Rate
hectare	1 hectare is equal to 2.47 acres
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 change in non-cash working capital
Equity	Capital securities and accrued return, shares and retained earnings
Net Debt	Total debt net of cash and cash equivalents
Total Debt	Long-term debt including current portion and bank operating loans

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

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

Husky Energy will host a conference call for analysts and investors on Thursday, July 24, 2003 at 4:15 p.m. Eastern time to discuss Husky's second quarter results. To participate, please dial 1 (800) 377-5794 beginning at 4:05 p.m. Eastern time. Media are invited to participate in the call on a listen-only basis by dialing 1 (800) 440-1782 beginning at 4:05 p.m.

Those who are unable to listen to the call live may listen to a recording of the call by dialing 1 (800) 558-5253 one hour after the completion of the call, approximately 6:15 p.m. Eastern time, then dialing reservation number 21154465. The PostView will be available until Thursday, August 7, 2003.

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