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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER

Pursuant to Rule 13a-16 or 15d-16
Under the Securities Exchange Act of 1934

RECD S.E.C.
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For the month of March 2003

Commission File Number: 1-04307

PROCESSED
MAR 27 2003
THOMSON
FINANCIAL

Husky Energy Inc.
(Translation of registrant's name into English)

707 8th Avenue S.W., Calgary, Alberta, Canada T2P 1H5
(Address of principal executive offices)

PE 3/3/03

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F ____ Form 40-F _X_

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1). _X__

Note: Regulation S-T Rule 101(b)(1) only permits the submission in paper of a Form 6-K if submitted solely to provide an attached annual report to security holders.

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): _____

Note: Regulation S-T Rule 101(b)(7) only permits the submission in paper of a Form 6-K if submitted to furnish a report or other document that the registrant foreign private issuer must furnish and make public under the laws of the jurisdiction in which the registrant is incorporated, domiciled or legally organized (the registrant's "home country"), or under the rules of the home country exchange on which the registrant's securities are traded, as long as the report or other document is not a press release, is not required to be and has not been distributed to the registrant's security holders, and, if discussing a material event, has already been the subject of a Form 6-K submission or other Commission filing on EDGAR.

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes ________ No __X_

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-______.

On March 26, 2003, Husky Energy Inc. filed, and mailed to its stockholders, its annual report for the fiscal year ended December 31, 2002. The annual report is attached hereto as Exhibit A.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

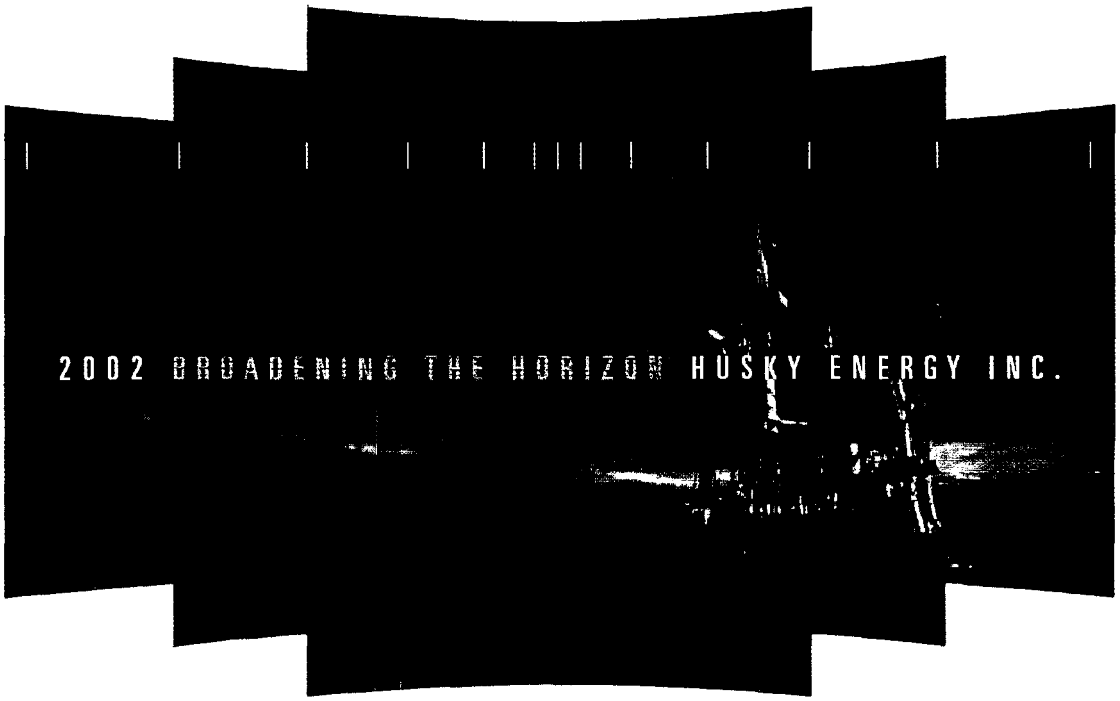
HUSKY ENERGY INC.

By: ______________________
Neil D. McGee
Vice President & Chief
Financial Officer

By: ______________________
James D. Girgulis
Vice President, Legal &
Corporate Secretary

Date: March 26, 2003

EXHIBIT A



ANNUAL REPORT HUSKY ENERGY INC. 2002

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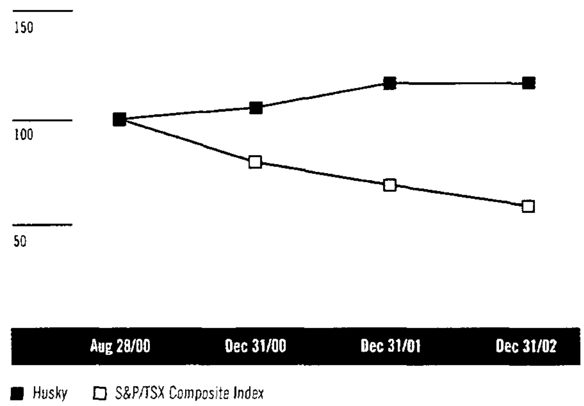
HUSKY SHARE PRICE PERFORMANCE



CORPORATE PROFILE Over the last decade Husky has grown into an integrated energy and energy-related company and one of Canada's largest producers of oil and gas. The Company's businesses comprise three distinct segments: upstream, midstream and refined products. Integration of these business segments generates cost efficiency and provides a more stable stream of earnings and cash flow.

The upstream segment includes the exploration, development and production of light, medium and heavy crude oil and natural gas. Operations are focused in Western Canada and offshore the Canadian East Coast as well as in the South China Sea and other international areas.

The midstream business includes the upgrading of heavy oil into premium quality synthetic crude together with infrastructure and marketing activities such as pipeline transportation, gas storage, power generation and the marketing of crude oil, natural gas, sulphur and petroleum coke.

Refined products activities include the refining, marketing and distribution of asphalt and a wide range of petroleum and other products. The refined products group includes 571 retail outlets across Canada and the wholesaling of both fuel and asphalt in Canada and in the United States.

Husky Energy Inc. is headquartered in Calgary, Alberta, Canada and is listed on the Toronto Stock Exchange under the symbol HSE.

HUSKY AT A GLANCE

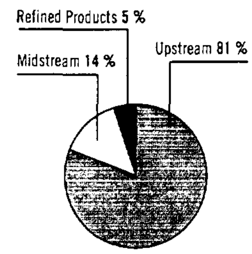
Segment	Business Focus	Strategic Focus
Upstream	Upstream activities include the exploration, development and production of oil and natural gas. We are active in Western Canada, offshore the Canadian East Coast and internationally.	Five-year production target of 500,000 barrels of oil equivalent per day, an annual average growth rate of 10 percent.
	Western Canada □ Exploration is focused on natural gas and crude oil in the Western Canada Sedimentary Basin □ Heavy oil continues to deliver excellent growth in cold and thermal heavy oil production □ Appraisal and development of our Cold Lake and Athabasca oil sands holdings	□ Increase oil and gas production through exploitation and exploration in key areas □ Optimize and expand Lloydminster heavy oil operations □ Fully load infrastructure and reduce costs in Western Canada □ Initiate development of in-situ bitumen resources commencing with Tucker and Kearl in northern Alberta
	Canadian East Coast □ A 12.51 percent interest in the producing Terra Nova oil field □ Operator with a 72.5 percent interest in the White Rose oil field development project □ 2.1 million acres of exploration acreage	□ Continue offshore exploration and expand production off the East Coast of Canada
	International □ A 40 percent interest in the Wenchang 13-1 and 13-2 producing oil fields in the South China Sea □ Expanded exploration portfolio in the South China Sea	□ Continue exploration and expand production in the South China Sea

Midstream	*The midstream business includes:*
	□ The Lloydminster heavy oil upgrader with processing capacity of 77,000 barrels of oil per day
	□ Extensive infrastructure and marketing assets, including a
	  □ 1,900 kilometre pipeline system
	  □ 50 percent interest in the 215-megawatt Meridian cogeneration facility at Lloydminster
	  □ 50 percent interest in the 90-megawatt power generation facility at Rainbow Lake
	  □ 20 bcf of gas storage capacity
	  □ commodity marketing business
		□ Optimize core assets by enhancing upgrader/refinery integration and pipeline system
		□ Continue to reduce unit operating costs
		□ Expand the commodity marketing business
		□ Continue developing complementary business opportunities

Refined Products	Refined products includes: □ The 25,000-barrel per day Lloydminster asphalt refinery and marketing business □ The 10,000-barrel per day light oil refinery at Prince George, which supplies 20 percent of the fuel sold by our retail outlets. The remainder is supplied under long-term third party arrangements and open market purchases □ A retail network of 571 Husky and Mohawk outlets across Canada	□ Grow asphalt business through increasing sales volumes and margins, development of new income streams and reducing operating costs □ Optimize product supply agreements □ Enhance the retail network by automation improvements, upgrading of facilities, increased throughput and ancillary store sales and strategic alliances

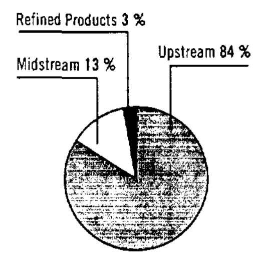
2002 Achievements	2003 Plans
Production increased by 10 percent to 300,000 barrels of oil equivalent per day.	2003 production is estimated to average between 305,000 and 325,000 barrels of oil equivalent per day.
▫ Shackleton discovery and development added reserves and production of natural gas ▫ Initiated regulatory approval process for Husky's proposed Tucker in-situ project ▫ Completed swap of interests in the Kearl in-situ properties	▫ Drill 60 exploratory wells in the Foothills, Deep Basin, northeast British Columbia and northwest Plains ▫ Drill 100 Shackleton gas wells and expand facilities. Drill and tie-in 300 shallow gas wells in northwest Alberta ▫ Increase primary and thermal heavy oil production from Bolney/Celtic ▫ Commence detailed engineering design and submit commercial application for the Tucker in-situ project ▫ Continue delineation of Kearl and commence front-end engineering design and Environmental Impact Assessment
▫ Terra Nova production commenced in January ▫ White Rose development approved. Construction under way	▫ Continue development drilling in Terra Nova and increase production ▫ Continue construction of White Rose and commence development drilling ▫ Evaluate exploration leads and prospects in Grand Banks for future drilling
▫ Wenchang project on schedule and on budget with first oil in July ▫ Acquired three additional exploration blocks in the South China Sea	▫ Drilled two exploration wells in the Wenchang 39/05 block. Proceed with exploration assessment of the prospects and leads on new blocks
▫ Lloydminster Upgrader exceeded three million person-hours without a lost-time accident ▫ Completed a scheduled plant turnaround at the Lloydminster Upgrader ▫ Commodity marketing achieved record volumes and profits	▫ Increase Upgrader capacity to 82,000 barrels per day by end of 2004 through debottlenecking projects ▫ Revenue enhancements through alternative feedstocks, products and waste product conversions ▫ Move upgrader residual to asphalt refinery for processing to obtain yield increases ▫ Focus on pipeline optimization in the short-term and expansion for long-term growth ▫ Expand marketing activities in bitumen/heavy oil corridor
▫ Delivered record asphalt sales despite weaker demand in Canada and the United States ▫ Increased retail throughput per site by 4.2 percent ▫ Opened two new car and truck stops and rolled out the first of the new Husky Market stores	▫ Evaluate and make decision on upgrading Prince George refinery to meet new environmental regulations ▫ Increase throughput per outlet through technology and site image upgrade program, branding recognition and ethanol enhanced fuels ▫ Increase revenues per customer through cross merchandising and loyalty programs ▫ Expand asphalt marketing business by entering into new geographical regions and pursue synergies with Upgrader to increase throughput and reduce asphalt costs

2002 Segment Contribution



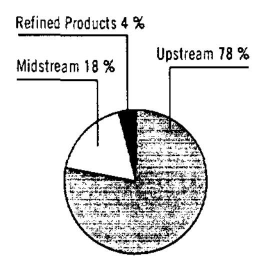
Total Assets

$10.2 billion [1]



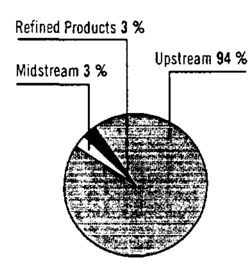
Cash Flow

$2.2 billion [1]



Earnings

$881 million [1]



Capital Expenditures

$1.7 billion [1]

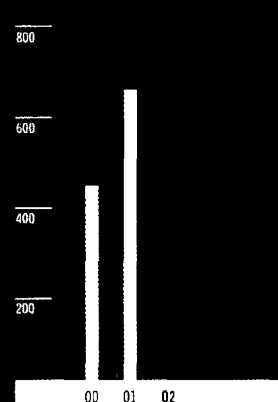
[1] *Excluding corporate segment.*

FINANCIAL AND OPERATING HIGHLIGHTS

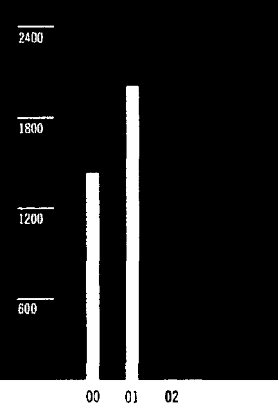
Year ended December 31 (millions of dollars except where indicated)			2002	2001	2000
Financial Highlights	Sales and operating revenues, net of royalties		**6,384**	6,596	5,066
	Cash flow from operations		**2,096**	1,946	1,399
	Per share *(dollars)* – Basic		**4.94**	4.60	4.26
	– Diluted		**4.92**	4.57	4.26
	Net earnings		**804**	654	438
	Per share *(dollars)* – Basic		**1.88**	1.49	1.28
	– Diluted		**1.88**	1.48	1.28
	Capital expenditures [1]		**1,692**	1,473	803
	Return on average capital employed [2]	*(percent)*	**12.2**	10.9	12.4
	Return on equity [3]	*(percent)*	**16.7**	15.4	19.4
	Debt to capital employed	*(percent)*	**32**	33	37
	Debt to cash flow from operations	*(times)*	**1.1**	1.1	1.7

[1] Excludes corporate acquisitions.
[2] Capital employed for purposes of this calculation has been weighted for 2000.
[3] Equity for purposes of this calculation has been weighted for 2000 and includes amounts due to shareholders prior to August 25, 2000.

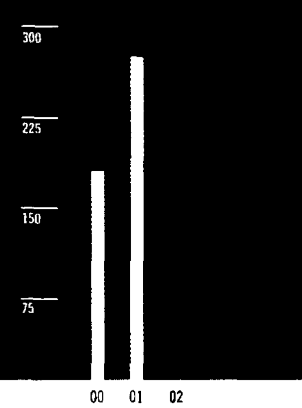
Year ended December 31			2002	2001	2000
Operating Highlights	Daily production, before royalties				
	Light/medium crude oil & NGL	*(mbbls/day)*	**125.9**	112.0	63.6
	Lloydminster heavy crude oil	*(mbbls/day)*	**79.4**	65.4	53.5
			205.3	177.4	117.1
	Natural gas	*(mmcf/day)*	**569**	573	358
	Barrels of oil equivalent	*(mboe/day)*	**300.2**	272.8	176.8
	Proved reserves, before royalties				
	Light/medium crude oil & NGL	*(mmbbls)*	**388**	430	440
	Lloydminster heavy crude oil	*(mmbbls)*	**181**	169	114
	Natural gas	*(bcf)*	**2,095**	1,966	1,909
	Barrels of oil equivalent	*(mmboe)*	**918**	927	872
	Synthetic crude oil sales	*(mbbls/day)*	**59.3**	59.5	60.6
	Pipeline throughput	*(mbbls/day)*	**457**	537	528
	Light oil sales	*(million litres/day)*	**7.7**	7.6	7.4
	Asphalt product sales	*(mbbls/day)*	**20.8**	21.4	20.2
	Refinery throughput	*(mbbls/day)*	**32.1**	33.9	32.6



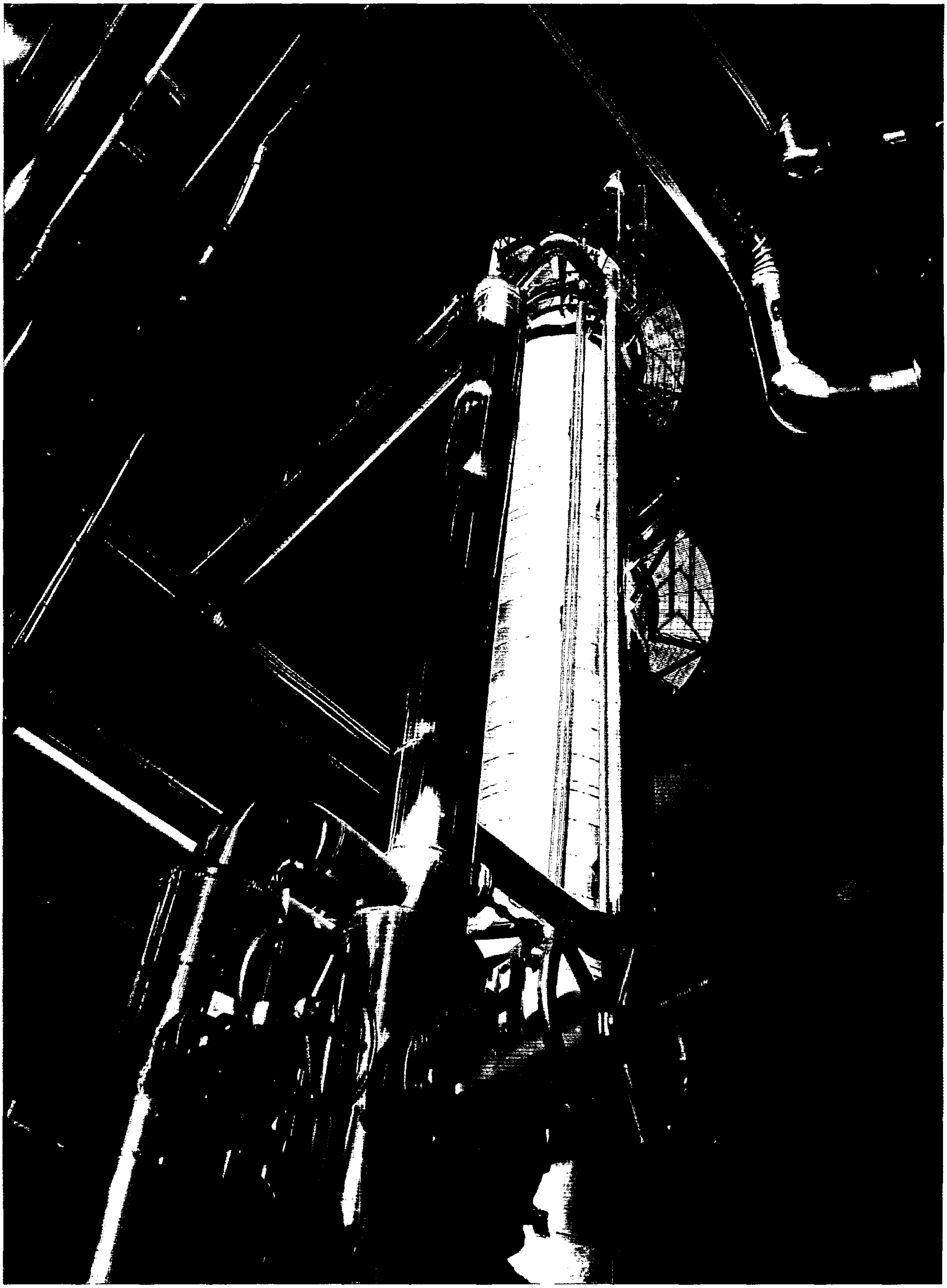
Net Earnings
($ millions)



Cash Flow from Operations
($ millions)



Daily Production, before Royalties
(mboe/day)



REPORT TO OUR SHAREHOLDERS

Husky Energy

We achieved a number of significant operational milestones in 2002 including first oil production from Terra Nova and Wenchang and the commencement of the White Rose oil field development project.

BROADENING THE HORIZON

We are pleased to report that 2002 has been another year of success for Husky Energy.

Net earnings in 2002 were $804 million or $1.88 per share, a 23 percent increase over 2001. Cash flow from operations was $2.1 billion, an eight percent increase over the prior year, and annual production of 300,000 barrels of oil equivalent per day, was an increase of 10 percent. Our return on shareholders' equity was 16.7 percent.

Our results benefited from increased crude oil production and prices, and a strengthening of natural gas prices late in the year, while our midstream business continued to mitigate the impact of volatile commodity prices and differentials.

In addition to our strong financial performance in 2002, we achieved a number of significant operational milestones:

- The Terra Nova oil field offshore Canada's East Coast came on stream in January, and has achieved 95 percent on-stream efficiency. We have a 12.51 percent working interest in the field, and our share of production is expected to average 16,000 barrels per day in 2003.
- In March the owners sanctioned the development of the White Rose oil field, offshore Canada's East Coast. We are the operator and a 72.5 percent working interest owner in the project, which is expected to come on stream in late 2005. White Rose is expected to make a major contribution to our production as we project our share from the field could reach 67,000 barrels of oil per day by the end of 2006.
- The Wenchang oil field in the South China Sea came on stream in July, on time and on budget. Our working interest in Wenchang is 40 percent and our share of production is expected to average 20,000 barrels per day in 2003. Following the success of Wenchang, we have acquired three additional exploration blocks in this new core growth area.
- In September we filed a public disclosure document for our proposed Tucker oil sands project where we hold a 100 percent working interest. We increased our interest in the Kearl oil sands lease to 100 percent in the in-situ project area and we carried out further evaluation work during the year.

NET EARNINGS, CASH FLOW FROM OPERATIONS AND PRODUCTION WERE ALL RECORDS

Husky Energy

We were recognized as oil producer of the year by Oilweek Magazine in 2002.

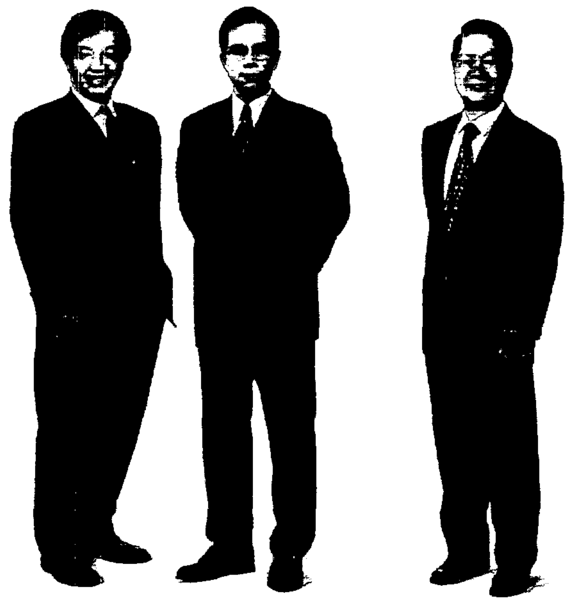
- In October we commenced the expansion of our heavy oil thermal recovery project in the Bolney/Celtic area.
- In October we commenced development of the Shackleton gas discovery at Swift Current, Saskatchewan. By December the field was producing 23 million cubic feet of gas per day, and we expect to produce an average of 40 million cubic feet per day in 2003.
- In our midstream and refined products businesses, we achieved record volumes of over 850,000 barrels of oil equivalent per day and a new record for asphalt sales.
- We received a number of awards for our performance in the areas of health, safety and the environment. The Lloydminster Upgrader exceeded three million person-hours without a lost-time accident.

Looking forward to 2003, we expect the current uncertain economic and political climate to continue and the year will likely be characterized by further volatility in commodity prices. Key events will be the outcome of any hostilities in the Middle East, the extent of economic recovery in the developed nations, and the ability of OPEC to maintain production discipline amongst its members. All of these events remain difficult to predict.

Natural gas prices are expected to remain strong. Gas consumption in North America in recent years has exceeded reserve replacement, mainly due to the demand for gas-fired power generation. Despite a continued slow-down in the U.S. economy, this will likely continue until new supplies from offshore or northern Canada and Alaska can be brought to market.

We expect Husky will increase production of both oil and gas in 2003, and we are well placed to benefit from strong commodity prices. At the same time, the integration of our business provides some protection against volatility in commodity prices and differentials. This enables us to broaden the horizon on growing shareholder value, and focus our capital expenditures on development projects at White Rose and the oil sands.

We have implemented a hedging program to take advantage of strong commodity prices and lock in revenues and cash flow levels well in excess of our business plan for the year. At February 14, 2003 we



Husky Energy

Mr. Canning K. N. Fok (left)
Co-Chairman

Mr. Victor T. K. Li (middle)
Co-Chairman

Mr. John C. S. Lau (right)
President & CEO

had hedged 34 percent of our estimated 2003 crude oil production at an average WTI price of U.S. $29.50 per barrel and 17 percent of our estimated gas production at an average NYMEX price of U.S. $5.20 per million British Thermal Units.

In 2003 we will be placing increased emphasis on corporate governance practices. The full impact of the U.S. Sarbanes-Oxley Act on Husky is being reviewed. It is anticipated that similar legislation will follow in Canada. The Board of Directors has established a Corporate Governance Committee with specific responsibility for monitoring compliance.

We will continue with our initiatives that have already reduced greenhouse gases substantially since 2000, and we will continue to review the provisions of the Kyoto Protocol in 2003. In the absence of a legislative and implementation plan from the Federal Government, it is difficult to determine the full extent of Kyoto's impact on our operations, or to develop a strategy for compliance.

In conclusion, 2002 has been a successful year for us, financially and operationally. In recognition of our achievements, we were named oil producer of the year by *Oilweek* magazine. Our success would not have been possible without the support of our Board of Directors and the hard work and dedication of our management team and employees. In particular, we would like to thank Ron Greene and Wil Matthews, who will not be standing for re-election as directors, for their significant contributions during our period of rapid growth, and we take this opportunity to wish them well in the future.

We look forward with confidence to another successful year in 2003.

Victor T. K. Li	Canning K. N. Fok	John C. S. Lau
Co-Chairman	*Co-Chairman*	*President & Chief Executive Officer*

February 5, 2003

QUESTIONS AND ANSWERS

Husky Energy

ANSWERS FROM OUR PRESIDENT & CEO

Question What is Husky Energy's strategy for value creation?

Answer Our strategy is to build a solid foundation for profitable growth by exploiting and developing an integrated portfolio of assets. We also look for synergistic opportunities to enhance shareholder value.

Our business is divided into three integrated segments representing upstream, midstream, and refined products. Our corporate culture is fiscally disciplined, enforcing strict cost control and focus on economic returns.

We have a five-year production target of 500,000 barrels of oil equivalent per day, which represents an annual average growth rate of 10 percent. Much of this growth will come from exploiting our existing assets including White Rose and the Tucker and Kearl oil sands properties.

We aim for an average five-year return on equity in excess of 15 percent and return on capital employed of at least 10 percent.

Question In the 2001 Annual Report you said that you saw Husky Energy as both a buyer and seller of assets in 2002. Can you comment on results for 2002 and plans for 2003?

Answer Our strategy is to improve the quality of our portfolio by disposing of non-core properties and acquiring quality assets in our core areas. In 2002, we disposed of non-core properties representing 8,000 barrels of oil equivalent per day and are in the process of finalizing a second disposition representing 3,500 barrels of oil equivalent per day. No further significant dispositions are planned in 2003.

We were also active in reviewing several potential property and corporate acquisitions, although none came to fruition in what was a seller's market. In 2003, we will continue to look for acquisition opportunities that enhance shareholder value.

Question What are your production estimates for 2003? Can you comment on 2004 and beyond?

Answer Our production estimate for 2003 is 305,000 to 325,000 barrels of oil equivalent per day. This includes light and medium oil and natural gas liquids of 120,000 to 130,000 barrels, heavy oil of 85,000 to 90,000 barrels and natural gas of 580 to 620 million cubic feet.

Beyond 2003, and before taking into account our major development projects offshore and in the oil sands, we expect steady growth in our heavy oil and natural gas production and stable production in light and medium oil, and natural gas liquids.

Question What is your current policy regarding hedging? Do you have any commodity hedges in place?

Answer Our position is to review opportunities to lock in prices on a portion of production during periods of high commodity prices that we believe may not be sustainable.

All transactions are authorized by the President & CEO, in line with the corporate strategy approved by the Board of Directors.

At February 14, 2003 we had hedged 26 million barrels of crude oil production from April through to December 2003 at an average WTI price of U.S. $29.50 per barrel. We had also hedged 37 billion cubic feet of natural gas production, primarily in the second and third quarters of 2003 at an average NYMEX gas price of U.S. $5.20 per million British Thermal Units. This production hedging amounts to 34 percent of our estimated crude oil production and 17 percent of our natural gas production for 2003.

Question Can you comment on Husky Energy's requirement to comply with the Sarbanes-Oxley Act?

Answer The Sarbanes-Oxley Act was enacted in July 2002. It represents an expansion of U.S. Securities law in the areas of corporate governance, disclosure, reporting and accounting requirements and penalties.

We have U.S. public debt securities, and file 6-K and 40-F reports pursuant to the multijurisdictional disclosure system (MJDS) between the United States and Canada.

As our common shares are listed on the Toronto Stock Exchange, we are only required to comply with certain provisions of the Sarbanes-Oxley Act, in particular, those governing companies that have filed registration statements in the U.S. or are required to file periodic reports in the U.S.

We will comply on an ongoing basis with those provisions of the Act that relate to us.

Question Please comment on the likely impact of Kyoto on your current operations.

Answer Husky has been addressing the issue of Greenhouse Gas emissions since before Kyoto. We have already achieved reductions of over two million tonnes of carbon dioxide equivalents per year from existing operations. We have also won five awards from the Voluntary Challenge Registry for our reporting and reduction efforts. Based on success to date, we recently updated our corporate reduction target to a more aggressive level of five million tonnes per year by 2006.

In December 2002, the Government of Canada provided assurances to industry, including oil and gas producers, designed to limit the cost of complying with Kyoto. However, there is still considerable uncertainty with regard to the future impact of Kyoto and the costs of compliance and administration.

Question Natural gas production growth has not materialized as expected. Has this changed your strategy towards natural gas exploration?

Answer Natural gas production growth has been a challenge for the whole industry and we have been relatively successful in maintaining our production levels in 2002.

A number of factors contributed to lower production growth than anticipated, including higher decline rates and tie-in delays. Notwithstanding these issues, natural gas production grew towards the end of the year.

Our strategy in Western Canada is unchanged and will remain focused on deep gas in the Foothills Deep Basin, northeast British Columbia and northwest Plains regions and shallow gas in the southern Plains and northern Alberta.

ANSWERS FROM OUR PRESIDENT & CEO

Question

You have announced a capital expenditure budget for 2003 of $1.8 billion with approximately $1.66 billion allocated to the upstream business segment. Production growth is estimated at two to nine percent. This appears to be low in proportion to the capital budget. Please comment.

Answer

Over one-third of the capital expenditure budget for 2003 is for long-term projects that will only result in production increases in later years. $515 million relates to the White Rose field and $65 million to oil sands development. No proved reserves have been booked for these projects which are expected to come into production in 2005/2006.

$975 million will be invested in Western Canada where spending focus is on gas and oil in the high netback areas of the British Columbia Foothills and northwest Alberta Plains.

Question

What are your plans for the oil sands?

Answer

Our goals for oil sands development are to establish thermal production of 30,000 barrels of oil per day at Tucker by 2006 and to grow Husky's oil sands business to 100,000 barrels of oil per day by 2010 through development of the Kearl leases.

A commercial development application for Tucker was filed in February 2003. At Kearl, 97 test wells were drilled in 2002 to assess the bitumen potential. A further 200 wells are planned this year.

Question

Cost control and keeping on schedule have been difficult for recent large scale projects in the industry. Can you comment on the steps you have taken with respect to the White Rose project?

Answer

We have conducted extensive work on the White Rose development and believe we have a good understanding of what is required during the construction and production phases of the project. The White Rose critical path and cost analysis are a direct benefit of using experienced personnel from our other major projects, including the recently completed Terra Nova development.

Over 90 percent of the key project costs are covered under fixed price contracts with firm delivery dates. These contracts include incentives for remaining on schedule and penalties for delays. This should help to ensure our contractors remain on schedule.

Activities planned for 2003 include continuing construction of the Floating Production Storage and Offloading vessel (FPSO) hull and turret, and fabrication of the topsides, as well as development drilling and a sub-sea facilities integration test.

Question

You have now acquired a total of four exploration blocks in the South China Sea. What are your plans for this area in 2003 and the next few years?

Answer

We expect the South China Sea to become a core growth area for Husky. China is currently undergoing significant change and restructuring to conform to World Trade Organization standards. This is attracting interest from many foreign companies. Demand for crude oil and natural gas is likely to exceed domestic supply in the coming years.

The South China Sea has numerous sedimentary basins with good exploration potential for oil and gas. The fiscal regime in China is favourable and operating costs are low. Our current Wenchang production is a good example. It has a five percent value added tax, a 33 percent corporate income tax rate, and royalties and other taxes of three to six percent.

Two unsuccessful exploration wells were drilled this year. We plan to evaluate additional prospects for possible drilling in 2004.

Question What is the Company's strategy regarding its refined products business?

Answer Our refined products business is an integral part of our hydrocarbon value chain. It provides a steady source of cash flow and a reliable market for upstream production.

In our retail business, we have established a strong presence in specialized markets, particularly car and truck stops, cardlocks, and ethanol-blended fuels.

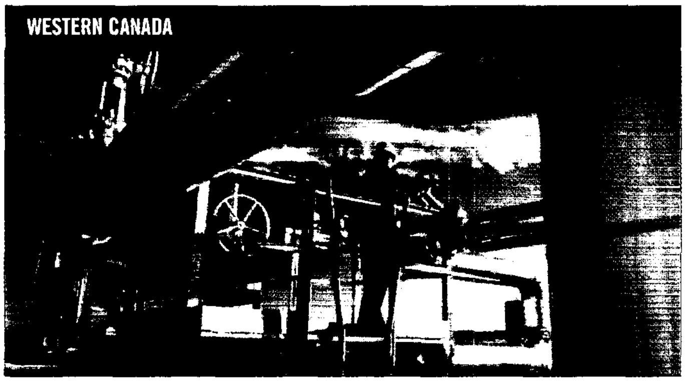
We will continue to look for growth opportunities which enhance shareholder value.

Question Can you update your plans for expansion of the Lloydminster Upgrader?

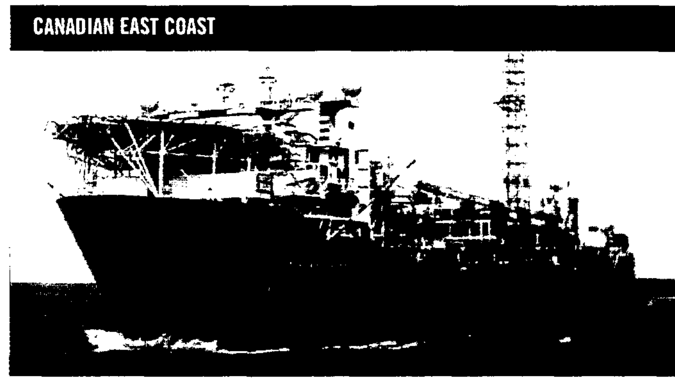
Answer Although Husky completed the first conceptual engineering phase of the Front-End Engineering and Development study in 2002, we do not have definite plans for when the Upgrader expansion project will proceed. We need more certainty that costs, including the costs of implementing Kyoto, can be controlled, and that the construction schedule can be met to ensure that an economic return can be achieved. Meanwhile, we are proceeding with a debottlenecking project to increase throughput capacity by six percent to 82,000 barrels per day by the end of 2004.

Question After several years of record earnings are there any plans to increase the dividend?

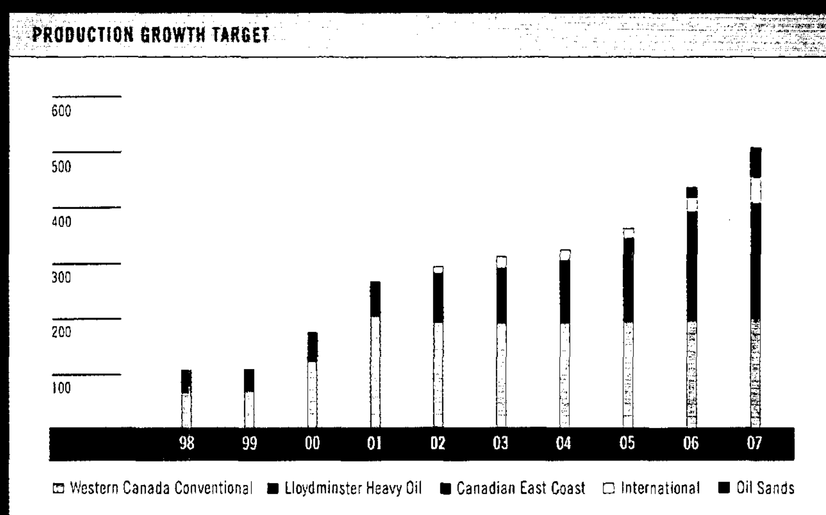
Answer The Board of Directors review our dividend policy from time to time. The current annual dividend of $0.36 per share provides the highest yield in our peer group.



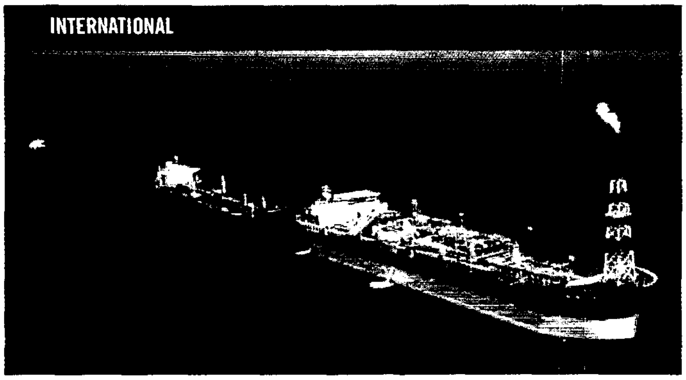
WESTERN CANADA

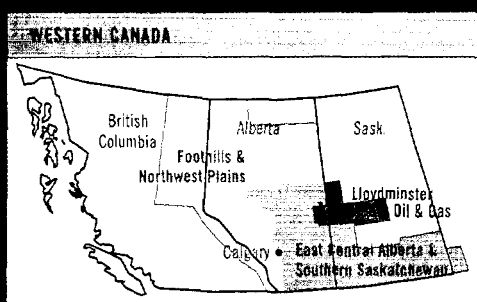


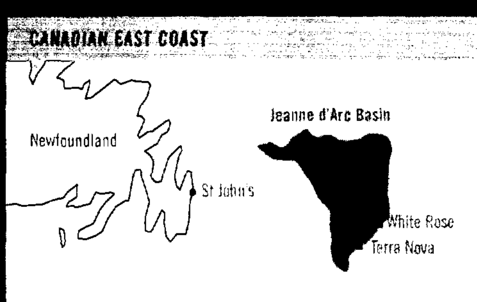
CANADIAN EAST COAST

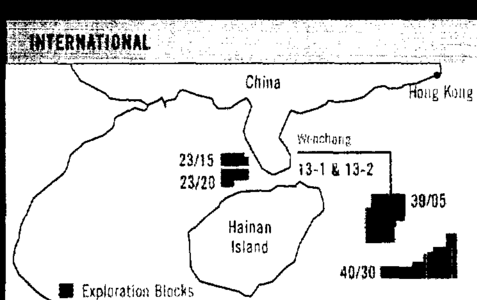


BROADENING THE HORIZON









REPORT ON OPERATIONS

In the last three years, Husky has grown from a privately held company into a major integrated oil and gas enterprise with more than $10 billion in assets. Our portfolio of high quality assets provides diversity and balance between risk and reward and between short- and long-term objectives. Our goal is to grow shareholder value and this will be achieved through:

- Integrated operations under which our business segments complement and support each other
- Focusing on opportunities in natural gas and heavy oil exploration and production in Western Canada to provide near- and medium-term growth in cash flow
- Developing longer-term projects in Alberta's oil sands, offshore the East Coast, in the South China Sea and internationally
- Strong financial discipline and adherence to strict rate of return targets for new investments

2002 has been an exciting year as many of the projects we implemented in earlier years came to fruition while new projects made significant steps forward, broadening our horizon and providing a platform for the future.

CANADA'S EAST COAST

Our strategy is to continue to grow offshore production and Canada's East Coast is a key element in achieving our long-term growth targets. Our plan is to increase oil production from our existing fields at Terra Nova and White Rose while developing new leads and prospects on our exploration acreage.

WHITE ROSE The development of the White Rose oil field is our second major project offshore the East Coast. White Rose will be a major contributor to our future growth. We, as operator, hold a 72.5 percent working interest in this project.

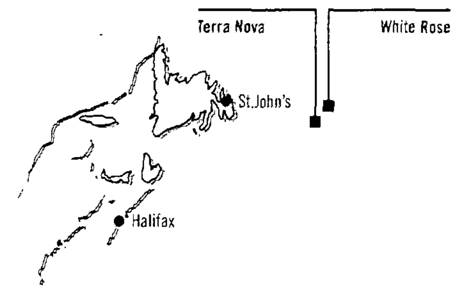
White Rose is located 350 kilometres east of St. John's, Newfoundland in the Jeanne d'Arc Basin. Discovered in 1984 and delineated in 1999 and 2000, the field has three known pools. Initial development is focused on the South Avalon pool, but future potential exists in the North and West Avalon pools.

Following a comprehensive development application process, the Federal and Provincial governments gave regulatory approval in December of 2001. Project sanction by the owners followed in March 2002.

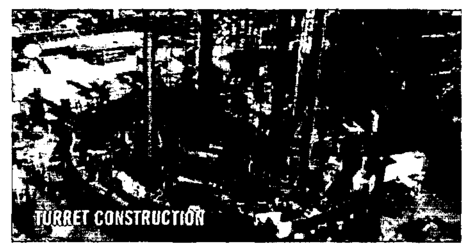
White Rose will be developed using a purpose-built Floating Production, Storage and Offloading vessel (FPSO) attached to a sub-sea production infrastructure. Construction contracts for the FPSO and the sub-sea facilities are in place. To ensure rigorous attention to project cost management, these contracts contain incentives for early completion within budget, and penalties for delays and cost overruns. First production is expected by year-end 2005.

TERRA NOVA Terra Nova achieved first oil production in January 2002. We have a 12.51 percent working interest in the field which has achieved sustained gross production rates of 125,000 barrels per day and exceeded 95 percent on-stream efficiency. The operator received regulatory approval to increase production to 150,000 barrels per day in November 2002, and in February 2003, this was further increased to 180,000 barrels per day.

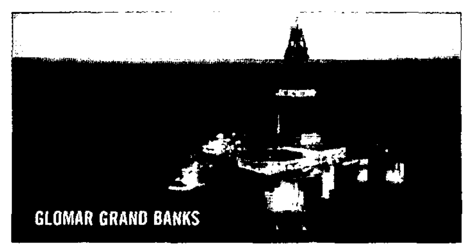
EXPLORATION We continue to be encouraged by exploration opportunities on the Grand Banks and believe the area holds potential beyond White Rose and Terra Nova. We hold nine other East Coast Exploration Licenses and have participated in several other discoveries.



CANADA'S EAST COAST



TURRET CONSTRUCTION



GLOMAR GRAND BANKS

TERRA NOVA FPSO

WHITE ROSE PROJECT SANCTIONED

W H I T E   R O S E

Construction of the FPSO hull began in late 2002 in South Korea. ▼

OUTLOOK

Our share of production from Terra Nova is expected to average at least 16,000 barrels per day in 2003. Our plans include:

- *Continued evaluation of the South Whale and North Jeanne d'Arc Basins in anticipation of exploration drilling in 2004/2005;*
- *Continuation of construction of the White Rose FPSO hull, turret and topsides;*
- *Commencement of White Rose development drilling and construction and testing of the sub-sea production system.*

WHITE ROSE PROJECT SUMMARY

Working interest - 72.5 percent
Probable reserves[1] - gross 200-250 million bbls
Probable reserves[1] - Husky share 145-181 million bbls
Peak production - gross 92,000 bbls/day
Peak production - Husky share 67,000 bbls/day
Number of wells - 19-21
Field life - 10-15 years
First oil - 2005
Development cost - gross $2.35 billion

[1] *No proved reserves will be booked until the development is substantially complete*

INTERNATIONAL

Our strategy for international growth is to first establish a production base in a new country and to subsequently increase our asset base through exploration, exploitation and acquisitions. This strategy has been successfully implemented in China, and we continually review new opportunities in China and in selected other countries.

WENCHANG Our Wenchang joint venture with the China National Offshore Oil Company (CNOOC) was our second major development project to come on stream in 2002. The project was on time and on budget, achieving first oil on July 7, 2002.

Wenchang comprises two high quality oil fields located in the Pearl River Mouth Basin in the South China Sea, 400 kilometres southwest of Hong Kong. The field produces 35 degree API crude similar in quality to Minas, the Indonesian benchmark blend.

The fields produce from wells tied into two fixed platforms in water 120 metres deep. Production is pipelined to the FPSO vessel stationed between the two platforms. The FPSO contains processing and power generation facilities, oil storage capacity of 850,000 barrels and provides accommodation for the workforce.

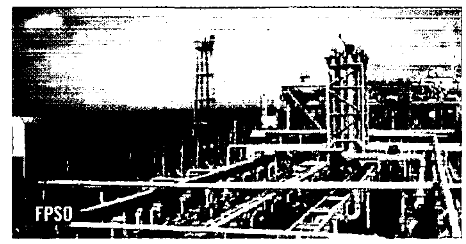
The economics of the Wenchang project are very attractive. Operating costs at peak production are approximately U.S. $2.00 per barrel. Fiscal terms include a five percent value added tax, royalties and other taxes of three to six percent and a corporate income tax rate of 33 percent.

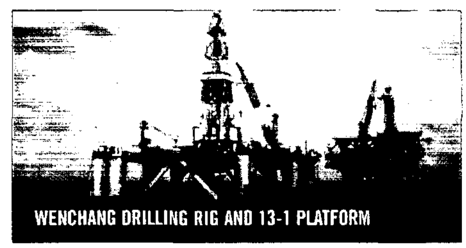
EXPLORATION We have a 100 percent working interest in four exploration blocks in the South China Sea:

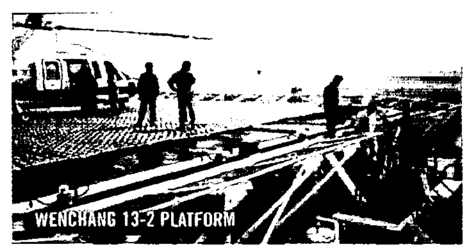
- Block 39/05 – 5,700 km^2 (1.41 million acres)
- Block 23/15 – 1,327 km^2 (0.33 million acres)
- Block 23/20 – 1,543 km^2 (0.38 million acres)
- Block 40/30 – 6,704 km^2 (1.66 million acres)

Each block has a single well commitment in the first three years and CNOOC has the right to participate in any development on the blocks with a 51 percent interest.

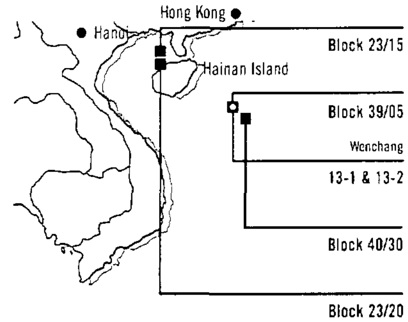
INTERNATIONAL


FPSO


WENCHANG DRILLING RIG AND 13-1 PLATFORM

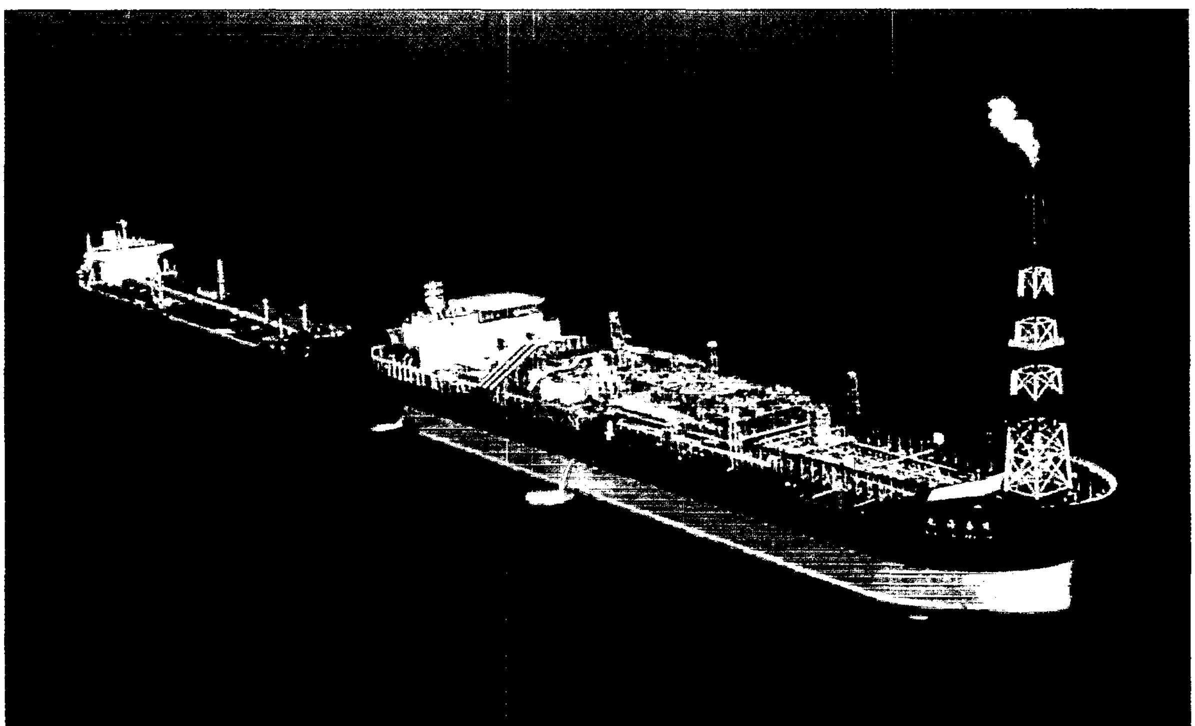

WENCHANG 13-2 PLATFORM

SUCCESSFUL IMPLEMENTATION OF INTERNATIONAL GROWTH STRATEGY



WENCHANG

The Wenchang field achieved first oil in July 2002. ▼



OUTLOOK

Our share of production from Wenchang is expected to average 20,000 barrels per day in 2003.

Our plans for 2003 are to evaluate additional prospects for possible drilling in 2004.

WENCHANG PROJECT SUMMARY

Working interest - 40 percent
Reserves - gross[1] 92 million bbls
Reserves - Husky share 37 million bbls
Peak production - gross 60,000 bbls/day
Peak production - Husky share 24,000 bbls/day
Number of wells - 21
Field life - 10-12 years
First oil - July 2002
FPSO storage capacity - 850,000 bbls
Development cost gross - U.S. $327 million

[1] *Proved plus probable reserves of which 11 million produced to December 31, 2002*

NATURAL GAS

Our natural gas strategy in Western Canada is to capitalize on the rich potential of the Western Canada Sedimentary Basin through the drilling of a portfolio of low-risk shallow gas prospects in the northwest Alberta Plains and southern Saskatchewan areas and higher-risk deep wells in the British Columbia and Alberta foothills. Our goal is to create at least one new core growth area every year.

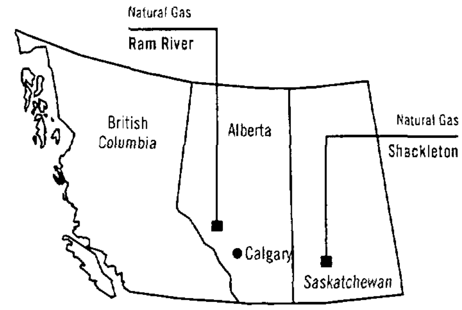
SHACKLETON Central to our natural gas strategy is the Shackleton discovery northwest of Swift Current, Saskatchewan. After establishing commerciality in 2001, we drilled 130 wells in the second half of 2002, and added two gathering and compression systems. By December, the Shackleton field was a new core area producing 23 million cubic feet of gas per day, and is expected to produce an average of 40 million cubic feet per day in 2003. Successful area development could increase Husky's reserves to 250 billion cubic feet over the next two to three years.

RAM RIVER Our Ram River plant in the central Alberta foothills is the focal point of our natural gas strategy in this part of the basin. Ram River is one of the largest gas processing facilities of its kind in Canada, and is capable of processing more than 600 million cubic feet per day of raw gas and 2,800 tonnes per day of sulphur.

We are operator of the plant. The surrounding infrastructure comprises 1,100 kilometres of pipelines and compression and dehydration facilities connecting sour gas fields from as far away as 145 kilometres. This creates a natural core area for both development and exploration activities.

EXPLORATION Outside of the Shackleton shallow gas area, we have focused our gas exploration on the higher impact plays of the Foothills, Deep Basin and northeastern British Columbia regions. These regions are characterized by multi-zone potential, with higher average well deliverabilities and longer-life reserves than the more mature portions of the Western Canada Basin.

In 2002, we drilled 58 wells in these exploration regions, achieving an 88 percent success rate. Significant new discoveries were made at Lynx/Copton in the Foothills, Kiskiu and Minehead in the Deep Basin, and Ekwan/Bovouac in northeastern British Columbia. In 2003, a 60-well drilling program is planned for the exploration area.

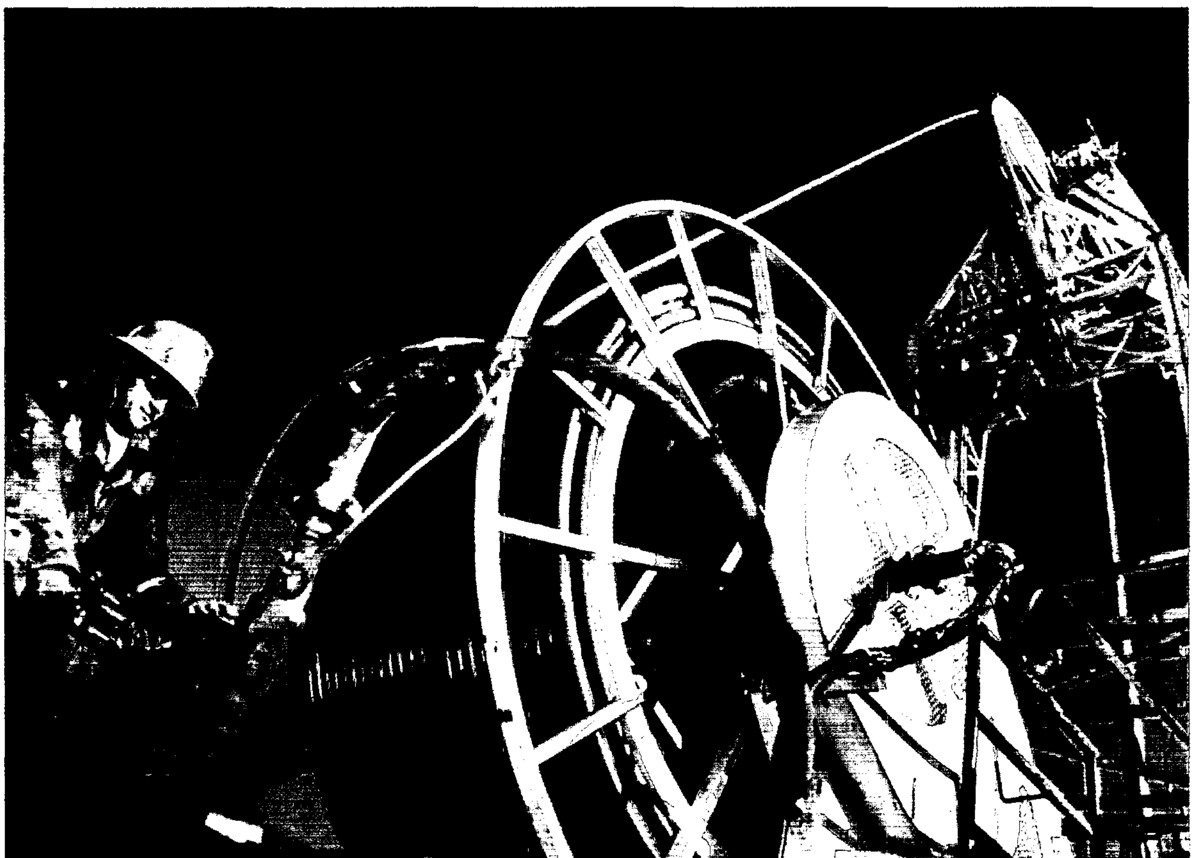


NATURAL GAS

FOCUSED ON NATURAL GAS

S H A C K L E T O N

Shackleton discovery northwest of Swift Current, Saskatchewan. ▼



OUTLOOK

We expect natural gas production for 2003 to average 580 to 620 million cubic feet per day.

Our plans are to continue to focus our exploration in areas of long-life reserves and areas that have the highest remaining undiscovered potential. Our development efforts will be directed towards shallow gas in the northwest Alberta Plains and southern Saskatchewan areas.

SHACKLETON PROJECT SUMMARY

Working interest - 100 percent

First production - October 2002

Proved reserve additions - 82 bcf

Peak production - 45 mmcf/day

Landholdings - 250,000 acres

HEAVY OIL

Our heavy oil development and growth strategy is focused on the Lloydminster area where our upstream operations enjoy the full benefit of integration with our refining and upgrading assets. Our strategy is to grow through the drilling of primary heavy oil wells, and the development of new thermal recovery projects.

LLOYDMINSTER We hold a significant land position with high working interests in the Lloydminster area. As operator, we control almost 98 percent of our production. In conjunction with our upgrader and 1,900-kilometre pipeline system, our integrated asset portfolio gives us control over production, transportation, conversion and refining and allows us to optimize the value chain.

This infrastructure provides our rapidly growing commodity group with the opportunity to market our oil and significant volumes of third party production in both Canada and the United States.

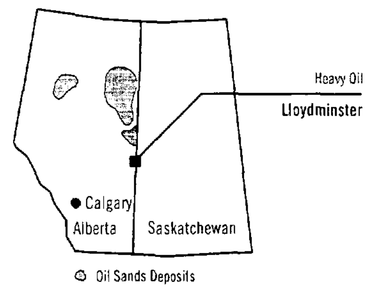
Our strategy to drill 300-400 primary heavy oil wells each year continued to prove successful in 2002. We drilled 340 primary oil wells with a success rate of 95 percent and added proved reserves of 39 million barrels at an average finding and development cost of $6.60 per barrel.

BOLNEY/CELTIC Following our acquisition of the Bolney heavy oil assets in the Lloydminster area in 2001, we developed a three-stage plan for development of Bolney with our thermal assets in the Celtic area.

In 2002, we completed phase one of the project. This included the drilling of eight new Steam Assisted Gravity Drainage (SAGD) well pairs in the Celtic reservoir and the construction of new steam and emulsion lines between Celtic and the Bolney steam and emulsion treating facilities.

Celtic production began in October 2002, reaching 3,000 barrels per day by year end. Full production of 6,000 barrels per day is projected by April 2003.

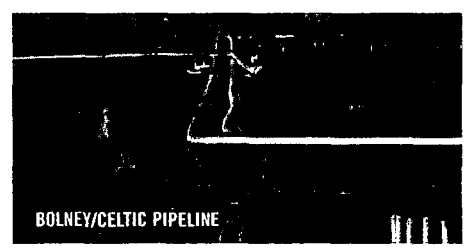
Stage two of the project includes further drilling and heat integration at the processing site, and stage three will include expansion of the steam production capability and further drilling. This project has excellent potential to support a cogeneration facility, which will be evaluated in 2003. Peak production from the project is expected to reach 14,000 barrels per day, with 6,000 barrels per day from Bolney and 8,000 barrels per day from Celtic.



HEAVY OIL


SINGLE WELL MONITORING


BOLNEY/CELTIC PUMPJACKS


BOLNEY/CELTIC PIPELINE

HEAVY OIL GROWTH CONTINUES

L L O Y D M I N S T E R

A key business for over 50 years. ▼

OUTLOOK

We expect heavy oil production to average 85 to 90 thousand barrels per day in 2003.

We will continue to exploit our heavy oil lands by drilling 300 to 400 primary heavy oil wells each year, and look for other opportunities to implement thermal recovery technology.

LLOYDMINSTER ASSETS

Heavy Oil Production Assets:
– Landholdings - 1.5 million acres
– Average working interest - 98 percent
– 2002 production - 79,400 bbls/day
– Proved reserves[1] - 181 million bbls
Other Assets:
– Pipelines - 1,900 kms

[1] *at December 31, 2002*

OIL SANDS

Western Canada's oil sands deposits are one of our targeted growth areas. We believe that bitumen and synthetic crude production will increase significantly over the next 15 years and support growth in Canada's overall crude oil production. To capitalize on this opportunity we have acquired significant land positions in the Athabasca and Cold Lake areas.

TUCKER Our initial project in the oil sands is at Tucker, located 30 kilometres northwest of the town of Cold Lake. Tucker is characterized by clean high porosity sandstone with pay zones up to 45 metres thick.

Our plan is to develop Tucker using SAGD technology. Initial production will be from four well pads, with an additional four to eight pads required to reach full production. Each well pad will be connected to centralized treating and water handling facilities.

We have completed front-end engineering design and a baseline environmental study in the area. In September 2002, we commenced the public disclosure process and followed this with an environmental impact assessment. A commercial development application was submitted in February 2003.

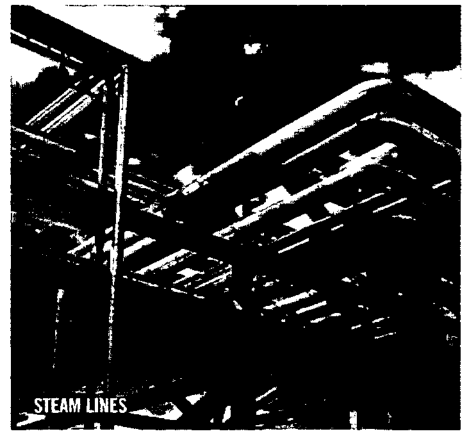
KEARL Our major oil sands project at Kearl is located in the Athabasca region of northern Alberta.

In 2002 we increased our interest in the Kearl in-situ lease to 100 percent through an asset exchange. As a result, we increased our share of possible reserves to 2.25 billion barrels.

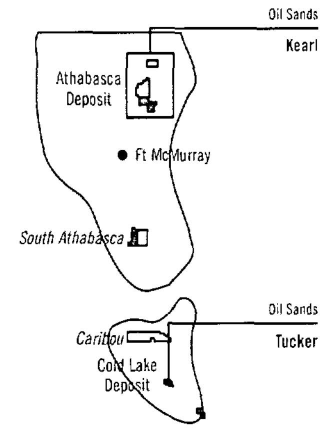
In 2002 we drilled 97 test wells to assess the bitumen potential. We also commenced an environmental impact assessment and conceptual engineering. For 2003, we are planning a further 200 wells and our goal is to submit a commercial application for regulatory approval in late 2003 or early 2004.

OTHER OIL SANDS LEASES We have varying interests in a number of other leases with estimated bitumen in place of 15 billion barrels. These leases are currently under evaluation to determine their commercial potential.

OIL SANDS



WELL POSITIONED IN OIL SANDS



T U C K E R Located 30 kilometres northwest of the town of Cold Lake, Alberta. ▼

OUTLOOK

Our oil sands strategy is to establish thermal bitumen production of 30,000 barrels per day from Tucker by 2006 and to grow production to 100,000 barrels per day by 2010 with the addition of production from Kearl in staged increments commencing in 2006/2007.

PROJECT SUMMARY

Tucker:

– Working interest - 100 percent

– First production - 2005/2006

– Reserves [1] - 250 million bbls

– Peak production - 30,000 bbls/day

– Landholdings - 10,080 acres

Kearl:

– Working interest - 100 percent

– First production - 2006/2007

– Possible reserves - 2.25 billion bbls

– Peak production - 100,000 bbls/day

– Landholdings - 56,800 acres

[1] *Includes probable and possible*

UPGRADING AND REFINING

Our upgrading and refining assets play an important role in our strategy of integrating our operations from production to market. This allows us to capture synergies and value from all segments of the business and reduce the volatility of our earnings and cash flow.

THE LLOYDMINSTER UPGRADER Our Lloydminster heavy oil Upgrader is at the heart of our upgrading and refining operations. The Upgrader processes feedstock into premium quality synthetic crude and diluent. The synthetic crude is then sold to refiners. The diluent is returned to the field for heavy oil blending. Approximately 85 percent of the upgrader and asphalt refinery feedstock is from our own production. We have over 100,000 barrels per day of processing capability in the Lloydminster area.

Located on the Upgrader site is a 215-megawatt, natural gas fired cogeneration plant that provides 10 percent of Saskatchewan's power as well as 100 percent of the Upgrader's process steam requirements. We operate the plant through a joint venture with Transalta.

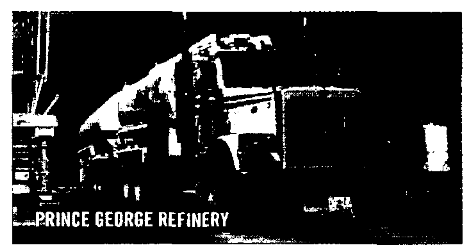
The Upgrader substantially removes our exposure to heavy/light oil differentials in respect of our heavy oil production, and provides an opportunity for our commodity-marketing group to add to the value chain.

In 2002, facility throughput was 65,400 barrels per day. This was nine percent lower than 2001 due to a scheduled plant turnaround in June 2002 and operational problems in the summer.

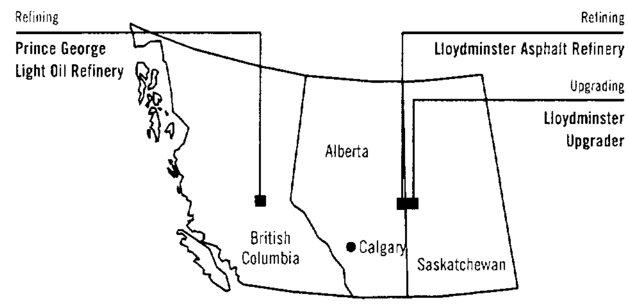
ASPHALT REFINERY Our Lloydminster refinery processes heavy crude into asphalt products used in road construction and maintenance and in the manufacture of building products. The facility has a total throughput capacity of 25,000 barrels per day and also produces a lighter distillate used by the upgrader, and a condensate stream used to blend with heavy oil production.

LIGHT OIL REFINERY Our light oil refinery at Prince George, British Columbia has a throughput capacity of 10,000 barrels per day. The refinery produces unleaded gasoline, diesel fuel and heavy fuel oil.

UPGRADING AND REFINING



UPGRADING AND REFINING – KEY TO THE VALUE CHAIN



LLOYDMINSTER UPGRADER

Lloydminster Upgrader, a key asset in the midstream business. ▼

OUTLOOK

In 2003 and 2004, we are planning a number of debottlenecking projects aimed at increasing the Upgrader's throughput to 82,000 barrels per day. In the longer-term, there are opportunities to double the current capacity of the facility through the addition of a new plant.

Normal levels of throughput are anticipated at our Lloydminster and Prince George refineries in 2003.

UPGRADING AND REFINING CAPACITY

- Upgrader - 77,000 bbls/day
- Asphalt refinery - 25,000 bbls/day
- Light oil refinery - 10,000 bbls/day

HUSKY RETAIL NETWORK

Our retail business consists of a network of service stations, truck stops and bulk distribution facilities stretching from Vancouver Island to eastern Ontario. These outlets are located on primary urban roads and major highways in order to offer a full range of products and services to the motoring public under the Husky and Mohawk brands.

HUSKY TRAVEL CENTRES Consumers expect clean, bright and safe locations, with standardized products and fast, easy service, both at the pump and in our Husky Market stores and Husky House restaurants. In response, we have initiated a systematic upgrade of all our car and truck stops, convenience stores and restaurants, to provide customers with one-stop shopping for all their travel requirements.

As part of this initiative, we will promote a more balanced image among our traditional customer group of professional travelers, as well as families and other recreational travelers. In 2002, we opened two new car and truck stops with restaurants in Saskatoon and Mississauga and a new Husky Market store in Calgary.

Several other outlets are in the process of being upgraded, and the initiative should take three to five years to implement.

In 2002, our throughput per outlet increased by 4.2 percent.

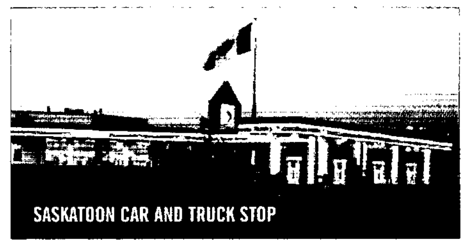
MINNEDOSA ETHANOL PLANT To better protect the environment and improve vehicle performance we market an ethanol-blended gasoline known as "Mother Nature's gasoline" – at all our Husky and Mohawk retail outlets.

Our ethanol plant at Minnedosa, Manitoba produces 90 percent of the ethanol used in these blends. This equates to 10 million litres of ethanol per year.

Ethanol is produced from grain, and is used in blending with gasoline to produce a high-octane, environmentally friendly automotive fuel. It also helps prevent freezing in fuel lines.

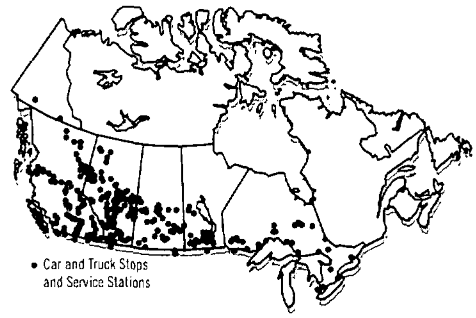
HUSKY RETAIL NETWORK

ETHANOL BLENDED GASOLINE


SASKATOON CAR AND TRUCK STOP


HUSKY HOUSE RESTAURANT

BUILDING CUSTOMER SERVICE



RETAIL OUTLETS

Our new Husky Market store. ▼

OUTLOOK

We will continue to upgrade our existing outlets to appeal to a wider range of potential customers and grow unit throughput.

RETAIL OUTLETS

Service stations - 503
Car and truck stops - 43
Bulk distributors - 25
Total outlets - 571
Cardlocks* - 62
Convenience stores* - 438
Husky House restaurants* - 45

* *Included in outlet total*

HUSKY AND THE COMMUNITY

We recognize our responsibility to support the communities in which we live and conduct our operations. In 2002, we fulfilled this commitment in three broad categories:

ABORIGINAL AFFAIRS Our aboriginal affairs program started in 1992. The program is designed to promote environmental stewardship and cross-cultural awareness between the business community and First Nations people. The program also provides business and employment opportunities, and support for education. We administer this program through formal cooperative agreements with First Nation groups.

In 2002 we entered into a cooperative agreement with the Bigstone Cree Nation and we now have formal programs and five memorandums of understanding in place with seven First Nations.

EDUCATION We believe in educating the youth to provide for the future. We are long-term supporters of several educational institutions including:

- The University of Calgary
- The University of Lethbridge
- Mount Royal College – Calgary
- The University of Northern British Columbia
- The University of Beijing

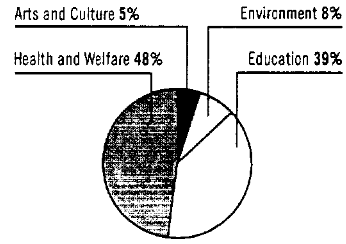
We support these institutions through scholarships, sponsoring academic chairs, and direct funding of facilities such as the Bituminous Materials Chair at the University of Calgary.

GIVING Our annual Charitable Donations Program is one of the ways we support our community. Under this program, selected charitable donations from our employees are matched by contributions from the Company.

Our donations committee has the responsibility for the distribution of the funds with emphasis on health and welfare, education, arts and culture and the environment.

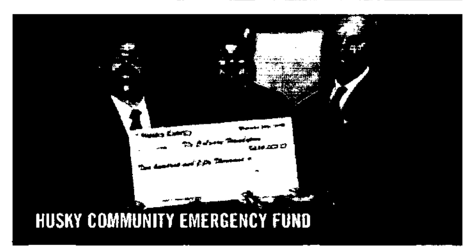
We provide direct support to the communities in which we operate. In 2002, we donated $200,000 to the Give to Feel Good Campaign in St. John's, Newfoundland. The donation from Husky, combined with the 2:1 match from the Government of Newfoundland and Labrador will be used for the purchase of three ultrasound units – two for the General Hospital and one for St. Clare's Mercy Hospital.

In November we established the Husky Community Emergency Fund with an endowment of $250,000 to The Calgary Foundation, providing an immediate emergency resource for Calgary and the surrounding area. This fund will be administered by The Calgary Foundation. To date, this is the largest corporate gift The Calgary Foundation has received.



Giving in the Right Places

HUSKY AND THE COMMUNITY



INVESTING IN COMMUNITIES

ABORIGINAL AFFAIRS

Husky has a formal cooperative agreement with Frog Lake First Nation. ▼

OUTLOOK

We are committed to long-term support of the community, education and aboriginal affairs.

HUSKY AND THE COMMUNITY

- Aboriginal affairs programs
- Supporter of several educational institutions
- Donated funds towards ultrasound units
- Established Husky Community Emergency Fund

HEALTH, SAFETY AND ENVIRONMENT

We are committed to a high level of health, safety and environmental protection for our employees, contractors, the public and the environment, and we have put in place the necessary management and control systems to ensure this commitment is met.

HEALTH AND SAFETY

Health and Safety Performance Our injury frequency statistics have improved significantly compared with 2001. Employee lost-time accidents fell from 11 in 2001 to five in 2002, a 55 percent reduction. However, contractor safety performance continues to lag behind employee performance, and therefore will continue to be an area where we implement new programs for improvement.

ENVIRONMENT

Greenhouse Gas (GHG) Emissions For a number of years, we have been actively pursuing programs to reduce our GHG emission intensity index and we will continue to support further reductions in GHG emissions.

In 2001, we set a target of reducing our total GHG emissions by 2.3 million tonnes of carbon dioxide equivalents per year from existing operations, by the year 2005. Our progress towards this goal has been faster than anticipated, and we have therefore set a new, more aggressive target of reducing emissions by five million tonnes per year from existing operations by 2006.

We expect that this target will increase further as the full impact of Canada's ratification of Kyoto and associated industry regulations unfolds.

Environmental Impact Whenever possible, we seek to minimize the environmental impact of our operations. For example, we have reduced the impact of wellsites through planning, site selection, and adopting innovative approaches such as below ground wellsites.

Wildlife Protection We are extensively involved with the public, industry and government on a number of wildlife protection, water and land use issues through direct participation and sponsorship in various research initiatives.

HEALTH, SAFETY AND ENVIRONMENT


SAFETY INSPECTIONS


BELOW GROUND WELLSITE


CARIBOU PROTECTION

COMMITTED TO HEALTH, SAFETY AND ENVIRONMENT

AN OUTSTANDING SAFETY RECORD

OUTLOOK

Health, Safety and Environment is a key component in our Corporate strategic planning process and we have committees at both the Senior Management and Board of Directors levels.

HEALTH, SAFETY AND ENVIRONMENT AWARDS

In 2002, we were recognized for our health, safety and environmental performance through the following:

- Voluntary Challenge Registry award
- Canadian Association of Petroleum Producers award
- Workers' Compensation Board
- Canadian National Railway Safe Handling award for products
- Canadian Gas Processors Association award
- Certificate of Recognition in Alberta's Partnerships in Health and Safety Program

CORPORATE GOVERNANCE

Husky Energy

Our corporate governance practices are the responsibility of the Board of Directors. The Board of Directors has delegated some of its responsibilities to monitor and enhance the Company's governance practices to the Corporate Governance Committee. The Board believes that good corporate governance is of fundamental importance to the success of the Company. In 2002, with the encouragement of the Board, the Company made substantial progress in strengthening its governance practices and has responded effectively to changes in the market place. The Company's governance practices are consistent with the guidelines for effective corporate governance published by the Toronto Stock Exchange (the TSX Guidelines).

As a foreign registrant with the U.S. Securities and Exchange Commission, we are required to comply with certain of the provisions of the U.S. Sarbanes-Oxley Act of 2002 as they come into effect. Our Corporate Governance Committee, under its mandate from the Board of Directors, will continue to review our corporate governance practices with the intent of ensuring our standards are in compliance.

The Management Information Circular issued in connection with the 2003 Annual Meeting contains a complete description of our corporate governance practices and a comparison to the TSX Guidelines.

DUTIES AND RESPONSIBILITIES OF THE BOARD OF DIRECTORS

The primary duties and responsibilities of the Board of Directors are:

- The strategic planning process;
- Risk identification and mitigation;
- Approval of the annual corporate budget;
- Overseeing the integrity of internal control and management information systems;
- Overseeing effective communication with shareholders.

COMPOSITION OF THE BOARD OF DIRECTORS

Our Board is currently comprised of eight unrelated directors and seven related directors. An unrelated director is one who is independent of management and is free from any interest and any business or other relationship that could, or could reasonably be perceived to, materially interfere with the director's ability to act in the best interests of the Company.

COMMITTEES OF THE BOARD OF DIRECTORS

The Board has delegated certain of its responsibilities to four committees, each of which has specific roles and responsibilities as defined by the Board. All of the members of each committee are non-management directors. These committees are as follows:

Audit Committee

The members of the Audit Committee are M.J.G. Glynn (Chairman), T.C.Y. Hui, W.L. Matthews and W.E. Shaw.

The Audit Committee is responsible for review and approval of the quarterly and annual financial statements, recommending to the Board the appointment and remuneration of the external auditors, and the scope and extent of both internal and external audit work. The committee also has overall responsibility for the internal control systems that management has established.

The Audit Committee met six times in 2002.

Compensation Committee

The members of the Compensation Committee are C.K.N. Fok (Chairman), R.G. Greene, H. Kluge, E.L. Kwok and F.J. Sixt.

The Compensation Committee determines the total compensation and benefits of the President & CEO. On recommendation of the President & CEO, the Compensation Committee determines the general compensation structure and policies and programs for the Company and the compensation and benefit levels for the other senior officers. The Committee's mandate is to ensure the overall compensation programs are designed to maintain the Company's desired competitive positioning in the oil and gas industry.

The Compensation Committee met once in 2002.

Health, Safety and Environment Committee

The members of the Health, Safety and Environment Committee are H. Kluge (Chairman), B.D. Kinney, and S.T.L. Kwok.

The overall responsibility of this committee is the review and recommendation for approval by the Board of Directors of updates to the health, safety and environmental policy, the development with management of specific environmental objectives and targets, and to monitor compliance with the Company's environmental policies and achievement of environmental objectives and targets.

The Health, Safety and Environment Committee met twice in 2002.

Corporate Governance Committee

The members of the Corporate Governance Committee are H. Kluge (Chairman), E.L. Kwok and W.L. Matthews.

This committee, formed in 2002, is responsible for reviewing the effectiveness of the corporate governance practices of the Company, periodically reviewing the composition of the Board and its committees and their respective terms of reference, as well as reporting to the Board on its effectiveness and the contribution of individual directors. In conjunction with the Co-Chairmen, the committee develops the annual performance objectives for the President & CEO and assists in evaluating the performance of the President & CEO. The committee is also responsible for ensuring appropriate structures and procedures are in place so that the Board can function independently of management.

The Corporate Governance Committee met once in 2002.

CONTENTS

MANAGEMENT'S DISCUSSION & ANALYSIS AND FINANCIAL STATEMENTS

Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements and Auditors' Report included in this Annual Report. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada. The effect of significant differences between Canadian and United States accounting principles is disclosed in note 16 of the Consolidated Financial Statements. The following discussion and analysis refers primarily to 2002 compared with 2001, unless otherwise indicated. An abridged discussion and analysis of the salient variances between 2001 and 2000 is provided on page 57. All dollar amounts 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.

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 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.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

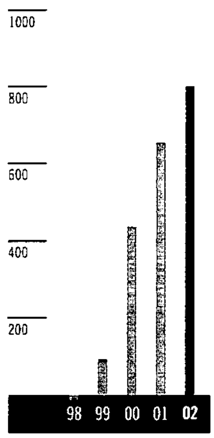
The Company's Chief Executive Officer and Chief Financial Officer (its principal executive officer and principal financial officer, respectively) have concluded, based on their evaluation as of a date within 90 days prior to the filing of this Annual Report (the "evaluation date"), that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by it in reports filed or submitted by it under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Security and Exchange Commission's rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by it in such reports is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

CHANGES TO INTERNAL CONTROLS AND PROCEDURES FOR FINANCIAL REPORTING

There have been no significant changes to Husky's internal controls or in other factors that could significantly affect these controls subsequent to the evaluation date and the filing date of this Annual Report.

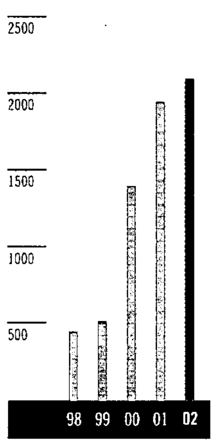
FORWARD LOOKING STATEMENTS

Certain of the statements set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report including statements which may contain words such as "could", "expect", "believe", "will" and similar expressions and statements relating to matters that are not historical facts are forward-looking and are based upon Husky's current belief as to the outcome and timing of such future events. There are numerous risks and uncertainties that can affect the outcome and timing of such events, including many factors beyond the control of Husky. These factors include, but are not limited to, the matters described under the heading "Business Environment". Should one or more of these risks or uncertainties occur, or should any of the underlying assumptions prove incorrect, Husky's actual results and plans for 2003 and beyond could differ materially from those expressed in the forward-looking statements.



Net Earnings
($ millions)

Earnings grew 23 percent in 2002, setting a new record



Cash Flow from Operations
($ millions)

In 2002 cash flow set a new record

OVERVIEW

Husky's operations are organized into three major business segments:

- The upstream segment includes the exploration for and the development and production of crude oil and natural gas in Western Canada, offshore the Canadian East Coast and offshore Southern China and other international areas.
- The midstream segment is organized into two reportable business segments; heavy crude oil upgrading operations, and infrastructure and commodity marketing operations. The infrastructure and commodity marketing segment comprises heavy crude oil pipeline and processing operations, natural gas storage, cogeneration operations and crude oil and natural gas marketing.
- The refined products segment consists of refining of crude oil and marketing of refined petroleum products including asphalt products.

Year ended December 31 ($ millions, except per share amounts and production)		2002	% Change	2001 [1]	% Change	2000 [1]
Net earnings		$ **804**	23	$ 654	49	$ 438
Per share - Basic		**1.88**	26	1.49	16	1.28
- Diluted		**1.88**	27	1.48	16	1.28
Cash flow from operations		**2,096**	8	1,946	39	1,399
Per share - Basic		**4.94**	7	4.60	8	4.26
- Diluted		**4.92**	8	4.57	7	4.26
Sales and operating revenues, net of royalties		**6,384**	(3)	6,596	30	5,066
Daily production, before royalties						
Light/medium crude oil & NGL	*(mbbls/day)*	**125.9**	12	112.0	76	63.6
Lloydminster heavy crude oil	*(mbbls/day)*	**79.4**	21	65.4	22	53.5
Natural gas	*(mmcf/day)*	**569.2**	(1)	572.6	60	358.0
Barrels of oil equivalent (6:1)	*(mboe/day)*	**300.2**	10	272.8	54	176.8

[1] 2001 and 2000 amounts as restated. Refer to note 3 of the Consolidated Financial Statements.

CONSOLIDATED RESULTS SUMMARY

Total consolidated revenue during 2002 was three percent lower than in 2001 primarily as a result of lower natural gas prices. The effect of lower natural gas prices was most noticeable in the infrastructure and marketing segment with respect to natural gas marketing revenues.

Higher net earnings and cash flow in 2002 compared with 2001 were attributable to increased earnings from:

- the upstream business segment
- the commodity marketing and infrastructure business segment

partially offset by lower earnings from:

- the upgrading business segment
- the refined products business segment

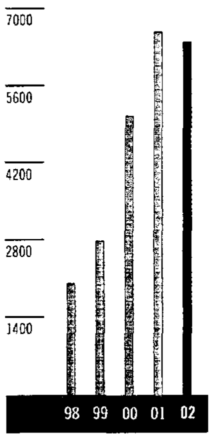
Upstream

Earnings from the upstream segment increased by $206 million to $688 million in 2002 compared with $482 million in 2001 due to:

- higher realized oil prices
- higher crude oil production
- lower natural gas royalties

partially offset by:

- lower prices for natural gas
- higher operating costs



Sales and Operating Revenues, Net of Royalties
($ millions)

In 2002 revenues declined slightly due to lower gas prices

Midstream

Earnings from the midstream segment decreased by $95 million to $161 million in 2002 compared with $256 million in 2001 due to:

- narrower upgrading differentials
- lower pipeline throughput

partially offset by:

- higher oil and gas commodity marketing income
- higher cogeneration income
- lower energy related upgrading operating costs

Refined Products

Earnings from the refined products segment decreased by $31 million to $32 million in 2002 compared with $63 million in 2001 due to:

- lower margins on asphalt sales

partially offset by:

- improved gasoline and distillate margins

Corporate

Corporate charges decreased by $70 million to $77 million in 2002 from $147 million in 2001, due to:

- lower foreign exchange losses on translation of U.S. dollar denominated long-term debt

partially offset by:

- higher intersegment profit eliminations
- higher corporate asset depreciation
- higher net interest expense

BUSINESS ENVIRONMENT

Husky's financial results are significantly influenced by its business environment, in particular, by crude oil and natural gas prices, the costs to find, develop, produce and deliver crude oil and natural gas, the demand for and ability to deliver natural gas, the exchange rate between the Canadian dollar and the U.S. dollar, refined product margins, the demand for Husky's pipeline capacity, the demand for refined petroleum products, government regulation and the cost of borrowing.

AVERAGE BENCHMARK PRICES

		2002	2001	2000
West Texas Intermediate ("WTI")	*(U.S. $/bbl)*	**$ 26.08**	$ 25.97	$ 30.20
NYMEX natural gas	*(U.S. $/mmbtu)*	**$ 3.25**	$ 4.38	$ 3.91
AECO natural gas	*($/GJ)*	**$ 3.86**	$ 5.97	$ 4.76
WTI/Lloyd blend differential	*(U.S. $/bbl)*	**$ 6.47**	$ 10.74	$ 8.20
U.S./Canadian dollar exchange rate	*(U.S. $)*	**$ 0.637**	$ 0.646	$ 0.673

Commodity Prices

Husky's earnings depend largely on the profitability of its upstream business, which is significantly affected by fluctuations of oil and gas prices. Commodity prices have been, and are expected to be, volatile due to a number of factors beyond Husky's control. The prices received for the crude oil and NGL sold by Husky 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 sweet crude oil.

Average benchmark oil prices were marginally higher during 2002 after rising throughout most of the year. The price for West Texas Intermediate ("WTI") crude oil began the year at U.S. $21.13/bbl and ended at U.S. $31.21/bbl, averaging U.S. $26.08/bbl for the year, slightly higher than U.S. $25.97/bbl in 2001 and significantly less than the U.S. $30.20/bbl in 2000.

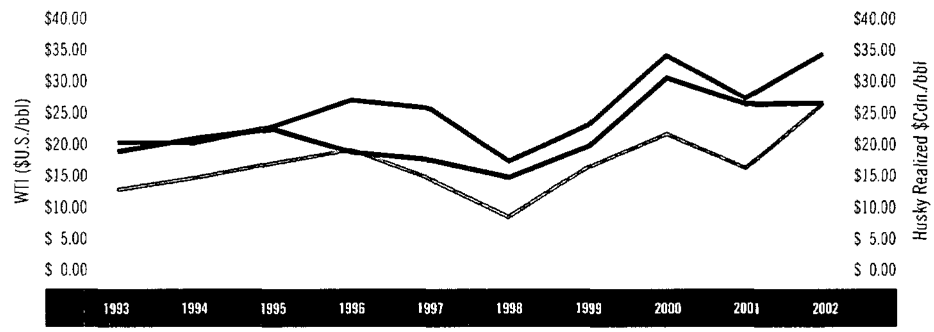
The opposite trend occurred for average heavy crude oil differentials, which averaged U.S. $6.47/bbl for WTI/Lloyd blend during 2002 compared with U.S. $10.74/bbl during 2001. The narrower differential tends to improve Husky's financial results as the Company's crude oil production is weighted toward heavier gravity crudes. In periods of wider differentials, Husky's upgrader offsets some of the effect of lower heavy crude prices. Husky's realized price for light/medium crude oil and NGL averaged $33.28/bbl in 2002 compared with $27.19/bbl in 2001 and heavy crude oil averaged $26.09/bbl in 2002 compared with $15.85/bbl in 2001.

Toward the end of 2002 the Organization of Petroleum Exporting Countries ("OPEC") announced cuts to their production that were intended to keep prices within a U.S. $22 and $28/bbl price band. OPEC has maintained their production discipline for the past three years and prices have fluctuated within the price band. World crude oil prices increased toward the end of 2002 and into 2003 as a result of a number of events in addition to OPEC's decision to cut actual production: colder than normal temperatures; uncertainty over the near-term in respect of Iraq; and, the crippling strikes in Venezuela. On February 11, 2003 WTI was U.S. $35.43/bbl.

The price of natural gas is affected by regional supply and demand factors in North America, particularly those affecting the United States such as weather patterns, pipeline delivery capacity, 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. The price of natural gas, unlike crude oil, is not subject to the influence of an organization like OPEC.

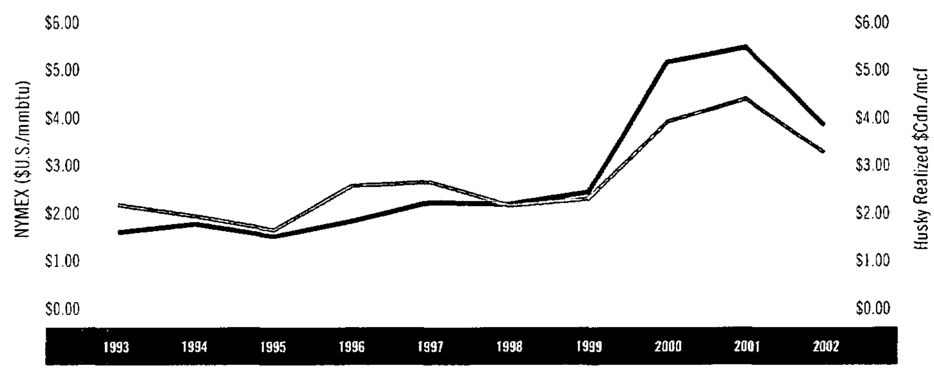
Natural gas prices realized by Husky are based either on fixed price contracts, spot prices or the New York Mercantile Exchange ("NYMEX") or other United States or domestic regional market prices. The NYMEX near-month price for natural gas ended 2002 at U.S. $4.79/mmbtu and was U.S. $5.98/mmbtu on February 11, 2003.

WTI AND HUSKY REALIZED CRUDE OIL PRICE



	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
West Texas Intermediate ("WTI") (U.S. $)	$18.48	$20.61	$22.01	$18.40	$17.18	$14.43	$19.24	$30.20	$25.97	$26.08
Husky realized heavy crude oil price	$12.48	$14.33	$16.65	$18.75	$14.16	$ 8.26	$16.00	$21.26	$15.85	$26.09
Husky realized light/medium crude oil price	$20.00	$19.91	$22.47	$26.62	$25.31	$16.99	$22.63	$33.56	$26.87	$33.86

NYMEX NATURAL GAS AND HUSKY REALIZED NATURAL GAS PRICE



	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
NYMEX natural gas (U.S. $)	$2.16	$1.92	$1.63	$2.55	$2.63	$2.14	$2.27	$3.91	$4.38	$3.25
Husky realized natural gas price	$1.59	$1.76	$1.50	$1.82	$2.21	$2.17	$2.41	$5.16	$5.47	$3.83

The margins realized by Husky for refined products are affected by crude oil price fluctuations, which affect refinery feedstock costs, and third-party refined product purchases. Husky's ability to maintain refined product margins in an environment of higher feedstock costs is contingent upon its ability to pass higher costs on to its customers.

The profitability of Husky's heavy oil upgrading operations is dependent upon the amount by which revenues from the synthetic crude oil produced exceed the costs of the heavy oil feedstock plus the related operating costs. An increase in the price of blended heavy crude oil feedstock which is not accompanied by an equivalent increase in the price of synthetic crude oil would reduce the profitability of Husky's upgrading operations. Husky has significant crude oil production that trades at a discount to light crude oil, and any negative effect of a narrower differential on upgrading operations would be more than offset by a positive effect on revenues in the upstream segment.

Husky's portfolio of light, medium and heavy crude oil and natural gas reserves and the efficient operation of its upgrader, refineries and other infrastructure provide opportunities to take advantage of any increases in commodity prices while assisting in managing price volatility.

Foreign Exchange

Husky's results are affected by the exchange rate between the Canadian and U.S. dollars. The majority of Husky's revenues are received in U.S. dollars or from the sale of commodities that receive prices determined by reference to U.S. benchmark prices. Accordingly, a change in the value of the Canadian dollar relative to the U.S. dollar has the effect of increasing or decreasing revenues unlike many of Husky's expenditures, which are in Canadian dollars. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as in the related interest expense. At December 31, 2002, 78 percent or $2.1 billion of Husky's long-term debt and capital securities were denominated in U.S. dollars. At the end of 2002, U.S. $20 million of forward foreign exchange collars were in place with an average cap of $1.54 and floor of $1.49. The terms of the collars range from March 2003 to September 2004. The U.S./Cdn. exchange rate at the end of 2002 was $1.58. On January 23, 2003, the Company executed an arrangement under which it swapped its U.S. $150 million 6.875 percent notes due November 2003. The notes were effectively swapped to $229 million 8.5 percent notes, at an effective exchange rate of $1.525. Refer to note 15 of the Consolidated Financial Statements for further disclosure on the Company's use of derivative financial instruments to manage foreign currency risk.

Interest Rates

Husky is exposed to interest rate fluctuations on its floating rate debt and derivative financial instruments with sensitivity to interest rates. The Company maintains a portion of its total debt in floating rate facilities. The Company will occasionally fix its floating rate debt or create a variable rate for its fixed rate debt using derivative financial instruments.

At December 31, 2002 substantially all of Husky's outstanding long-term debt was at fixed rates, however U.S. $535 million had been swapped to floating rates at an average of London Inter Bank Offered Rate ("LIBOR") plus 1.62 percent. These arrangements mature as follows:

- U.S. $35 million in November 2003
- U.S. $150 million in November 2006
- U.S. $200 million in November 2011
- U.S. $150 million in June 2012

In January, 2003 Husky unwound the U.S. $35 million swap due November 2003. The proceeds amounted to $2.0 million and will be recognized in income over the period to November 2003. In addition $200 million of fixed rate debt was swapped into floating rate debt at Canadian Bankers' Acceptance Rate ("CDOR") plus 1.75 percent until July 2009.

Husky's average effective interest rate during 2002 was 6.70 percent before interest rate swaps and 5.48 percent after swaps. Refer to note 15 of the Consolidated Financial Statements for further disclosure on the Company's use of derivative financial instruments to manage interest rate risk.

Environmental Regulation

Most aspects of Husky's business are subject to environmental laws and regulations. Similar to other companies in the oil and gas industry, Husky incurs costs for preventive and corrective actions. Changes to regulations could have an adverse effect on Husky's results of operations and financial condition.

International Operations

Husky's international operations may be affected by a variety of factors including political and economic developments, expropriation, exchange controls, currency fluctuations, royalty and tax increases, retroactive tax claims, import and export regulations and other foreign laws or policies affecting foreign trade or investment.

Risk Management

Husky uses derivative financial instruments when deemed appropriate to hedge exposure to changes in the price of crude oil and natural gas and fluctuations in interest rates and foreign currency exchange rates. Husky does not engage in transactions involving derivative financial instruments for trading or other speculative purposes. Refer to note 15 of the Consolidated Financial Statements for further disclosure on the Company's use of derivative financial instruments.

BUSINESS PLAN

Husky's 2003 business plan assumes that:

- WTI will average U.S. $24.00/bbl and the WTI/Lloyd blend differential will average U.S. $6.25/bbl
- NYMEX natural gas price will average U.S. $3.75/mcf
- the Canadian dollar will average U.S. $0.65
- U.S. $ LIBOR will average 2.50 percent
- Husky's total production will average 305 to 325 mboe/day. The composition is estimated to be 120 to 130 bbls/day light crude oil & NGL, 85 to 90 mbbls/day heavy crude oil and 580 to 620 mmcf/day natural gas

Husky plans to invest capital in the following segments in 2003:

Year ended December 31 ($ millions)	2003 Estimate
Upstream	
Western Canada	$ 1,040
East Coast Canada	560
International	55
	1,655
Midstream	100
Refined Products	60
Corporate	25
	$ 1,840

Strategic Plan

The 2003 capital program will continue to implement Husky's long-term strategic plan of increasing reserves and production in the upstream business segment and expansion and optimization of the midstream and refined products businesses.

The light crude oil potential of the Western Canada Sedimentary Basin, although considerable, is diminishing since discovery of large accumulations of light crude oil is becoming less probable. Declining production from Husky's light and medium crude oil producing properties in Western Canada is planned to be more than offset by further exploitation of heavy oil in the Lloydminster region of Alberta and Saskatchewan, continued development of oil sands potential in Alberta, production from the White Rose offshore project and further increases of production from new projects in China. Activities related to the development of oil sands in 2003 include submission of an environmental impact assessment and project application for the Tucker and Kearl, Alberta in-situ projects and the drilling of more than 200 stratigraphic test wells at Kearl. Activities in China include evaluation of the newly acquired exploration blocks in the South China Sea. The White Rose development project is progressing and a semi-submersible drilling rig has been secured for development drilling in 2002.

The undiscovered natural gas potential of the Western Canada Sedimentary Basin is considered to be very good and is concentrated in the western portion of the basin. Husky's natural gas production is expected to increase as a result of exploration and development activities concentrated in the foothills and deep basin region west of the fifth meridian in Alberta and British Columbia as well as the northern plains district of Alberta.

During 2003 Husky intends to invest:

- in excess of $1 billion on upstream capital programs located throughout the Western Canada Sedimentary Basin
- approximately $100 million in the midstream segment primarily for further debottlenecking of the Lloydminster Upgrader
- approximately $60 million in the refined products segment primarily for further upgrading of the marketing outlet system

Husky has implemented a corporate hedging plan to protect cash flow and earnings in 2003. The most critical aspect of the plan is to hedge commodity price realizations. The parameters of the plan are as follows:

- crude oil forward sales at a minimum of U.S. $29.00/bbl
- natural gas forward sales at a minimum of U.S. $5.00/mmbtu in non-heating or inventory building months and U.S. $5.25/mmbtu during heating or inventory draw-down months
- no more than 50 percent of annual forecast production will be hedged

There is no plan currently to hedge the Canadian dollar or crude oil differentials.

At February 14, 2003 the Company had hedged 26 mmbbls of crude oil primarily from April through to December 2003 at an average price of U.S. $29.50/bbl. At February 14, 2003 the Company had hedged 37 bcf of natural gas primarily in the second and third quarters of 2003 at an average price of U.S. $5.20/mmbtu. This amounts to 34 percent of Husky's estimated crude oil production and 17 percent of its estimated natural gas production during 2003. In addition, Husky executed a put option program for approximately 3.7 mmbbls from July to December 2003 at a strike price of U.S. $27.00/bbl. The cost of the program was U.S. $6.1 million.

RESULTS OF OPERATIONS - *UPSTREAM*

UPSTREAM EARNINGS SUMMARY

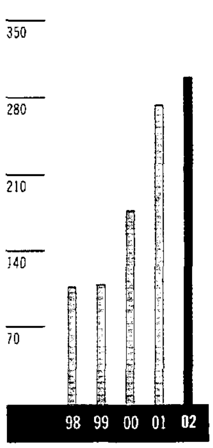
Year ended December 31 ($ millions)	2002	2001	2000
Gross revenues	**$ 3,120**	$ 2,667	$ 2,055
Royalties	**460**	502	351
Hedging (gain)/loss	**(5)**	-	155
Net revenues	**2,665**	2,165	1,549
Operating and administrative expenses	**729**	648	375
Depletion, depreciation and amortization	**851**	728	407
Income taxes	**397**	307	315
Earnings	**$ 688**	$ 482	$ 452

NET REVENUE VARIANCE ANALYSIS

($ millions)	Light/ Medium Crude Oil & NGL	Lloydminster Heavy Crude Oil	Natural Gas	Other	Total
Year ended December 31, 2000					
Net revenues	$ 632	$ 357	$ 534	$ 26	$ 1,549
Price changes	(348)	(253)	59	(8)	(550)
Volume changes	632	114	404	-	1,150
Royalties	(52)	29	(128)	-	(151)
Hedging	49	102	4	-	155
Processing	-	-	-	12	12
Year ended December 31, 2001					
Net revenues	913	349	873	30	2,165
Price changes	276	297	(342)	8	239
Volume changes	138	81	(7)	-	212
Royalties	(16)	(56)	113	-	41
Hedging	5	-	-	-	5
Processing	-	-	-	3	3
Year ended December 31, 2002					
Net revenues	**$ 1,316**	**$ 671**	**$ 637**	**$ 41**	**$ 2,665**

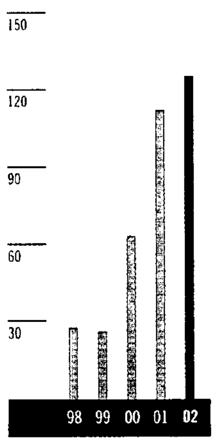
DAILY PRODUCTION, BEFORE ROYALTIES

Year ended December 31		2002	2001	2000
Light/medium crude oil & NGL	*(mbbls/day)*	**125.9**	112.0	63.6
Lloydminster heavy crude oil	*(mbbls/day)*	**79.4**	65.4	53.5
Natural gas	*(mmcf/day)*	**569.2**	572.6	358.0
Barrels of oil equivalent (6:1)	*(mboe/day)*	**300.2**	272.8	176.8



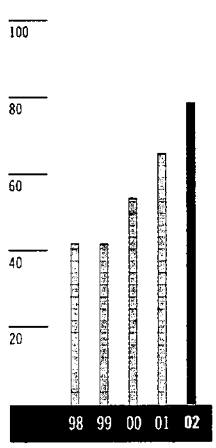
Daily Production, before Royalties - Total
(mboe/day)

10 percent production growth in 2002 was in line with our five-year target



Daily Production, before Royalties - Light/Medium Crude Oil & NGL
(mbbls/day)

New production from Terra Nova and Wenchang drove a 12 percent increase in 2002



Daily Production, before Royalties - Lloydminster Heavy Crude Oil
(mbbls/day)

A successful exploitation program resulted in a 21 percent increase in 2002

AVERAGE REALIZED PRICES

Year ended December 31		2002	2001	2000
Light/medium crude oil & NGL	*($/bbl)*	$ 33.16	$ 27.19	$ 35.88
Hedging (gain)/loss		(0.12)	-	2.46
Light/medium crude oil & NGL price realized		$ 33.28	$ 27.19	$ 33.42
Lloydminster heavy crude oil	*($/bbl)*	$ 26.09	$ 15.85	$ 26.45
Hedging (gain)/loss		-	-	5.19
Lloydminster heavy crude oil price realized		$ 26.09	$ 15.85	$ 21.26
Natural gas price	*($/mcf)*	$ 3.83	$ 5.47	$ 5.18
Hedging (gain)/loss		-	-	0.02
Natural gas price realized		$ 3.83	$ 5.47	$ 5.16

PRODUCT MIX

Year ended December 31	2002	2001	2000
Percentage of upstream sales revenues, after royalties			
Light/medium crude oil & NGL	49%	42%	40%
Lloydminster heavy crude oil	25%	16%	23%
Natural gas	26%	42%	37%
	100%	100%	100%

ROYALTY RATES

Year ended December 31	2002	2001	2000
Percentage of upstream sales revenues, before royalties			
Light/medium crude oil & NGL	15%	19%	20%
Lloydminster heavy crude oil	11%	8%	15%
Natural gas	18%	23%	19%
Total	15%	19%	19%

2002 compared with 2001

Husky's earnings from the upstream segment increased by $206 million (43 percent) to $688 million in 2002 from $482 million in 2001.

Husky's total revenues from upstream operations were $3,120 million in 2002 compared with $2,667 million in 2001 as a result of:

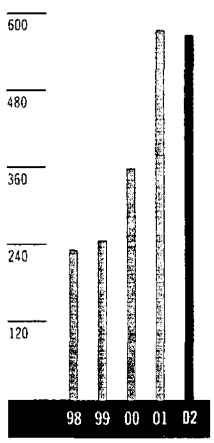
- higher sales volume and price realization for crude oil

the effect of which was offset partially by:

- lower natural gas prices

Higher production volumes of crude oil were due to:

- the ongoing Lloydminster heavy oil development programs
- Terra Nova and Wenchang commencing production in January and July, respectively



Daily Production, before Royalties - Natural Gas
(mmcf/day)

New production from Shackleton in 2002 offset declines in other areas

Operating costs per unit of production increased three percent in 2002 compared with 2001 as a result of:

- light/medium crude oil properties under secondary and tertiary recovery schemes in Western Canada
- extensive shallow gas production in Western Canada

partially offset by:

- lower unit operating costs at Terra Nova, Wenchang and at the heavy oil operations at Lloydminster

Depletion, depreciation and amortization ("DD&A") increased to $7.76/boe in 2002 from $7.31/boe in 2001 and resulted from:

- higher maintenance capital for properties under secondary and tertiary recovery and shallow natural gas and offshore operations requiring large infrastructure capital

Income taxes increased in 2002 compared with 2001 reflecting higher pre-tax earnings offset in part by rate reductions in British Columbia and Alberta.

Operating Netbacks [1]

Western Canada

LIGHT/MEDIUM CRUDE OIL NETBACKS [2]

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	**$ 31.10**	$ 27.39	$ 35.68
Royalties	**5.25**	4.87	6.42
Hedging (gain)/loss	**(0.15)**	-	2.46
Operating costs	**8.50**	7.47	6.23
Netback	**$ 17.50**	$ 15.05	$ 20.57

LLOYDMINSTER HEAVY CRUDE OIL NETBACKS [2]

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	**$ 26.02**	$ 16.00	$ 26.45
Royalties	**2.97**	1.27	3.00
Hedging (gain)/loss	**-**	-	5.19
Operating costs	**7.03**	7.60	6.15
Netback	**$ 16.02**	$ 7.13	$ 12.11

NATURAL GAS NETBACKS [3]

Year ended December 31 (per mcfge)	2002	2001	2000
Sales revenues	**$ 3.96**	$ 5.39	$ 5.28
Royalties	**0.82**	1.30	1.18
Hedging (gain)/loss	**-**	-	0.02
Operating costs	**0.70**	0.58	0.49
Netback	**$ 2.44**	$ 3.51	$ 3.59

(1) 2001 and 2000 amounts as restated. Refer to note 3 of the Consolidated Financial Statements.
(2) Includes associated co-products converted to boe.
(3) Includes associated co-products converted to mcfge.

TOTAL WESTERN CANADA UPSTREAM NETBACKS [1]

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	$ 27.04	$ 26.42	$ 31.41
Royalties	4.45	5.04	5.42
Hedging (gain)/loss	(0.05)	-	2.40
Operating costs	6.55	6.08	5.27
Netback	$ 16.09	$ 15.30	$ 18.32

TERRA NOVA LIGHT/MEDIUM CRUDE OIL NETBACKS

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	$ 35.47	$ -	$ -
Royalties	0.36	-	-
Operating costs	3.62	-	-
Netback	$ 31.49	$ -	$ -

WENCHANG LIGHT/MEDIUM CRUDE OIL NETBACKS

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	$ 44.36	$ -	$ -
Royalties	2.65	-	-
Operating costs	2.15	-	-
Netback	$ 39.56	$ -	$ -

TOTAL UPSTREAM NETBACKS [1]

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	$ 28.12	$ 26.42	$ 31.41
Royalties	4.20	5.04	5.42
Hedging (gain)/loss	(0.05)	-	2.40
Operating costs	6.24	6.08	5.27
Netback	$ 17.73	$ 15.30	$ 18.32

[1] *Includes associated co-products converted to boe.*

Upstream Capital Expenditures

Year ended December 31 ($ millions)	2002	2001	2000
Exploration			
Western Canada	$ 304	$ 236	$ 118
East Coast Canada	41	81	63
International	9	5	-
	354	322	181
Development			
Western Canada	730	786	301
East Coast Canada	417	110	131
International	66	99	87
	1,213	995	519
	$ 1,567	$ 1,317	$ 700

Proved Reserves - Light/Medium Crude Oil & NGL
(mmbbls)

2002 reserves do not yet reflect any reserves from White Rose

Western Canada

Capital expenditures reflect exploration and exploitation of properties in central and southern Alberta, southern Saskatchewan, the foothills, deep basin and northern region of Alberta and north eastern British Columbia and the increasing pace of development in the Lloydminster heavy oil area. Many of the properties located in Alberta and Saskatchewan are crude oil properties under secondary pressure maintenance schemes or shallow natural gas properties, which require extensive optimization and rationalization.

Capital expenditures in the Lloydminster heavy oil areas of Alberta and Saskatchewan in the last two years were $273 million and $324 million, respectively. Husky drilled 369 wells in the Lloydminster area in 2002 compared with 490 wells in 2001 resulting in 327 and 415 oil well completions and 25 and 39 natural gas well completions in 2002 and 2001, respectively. In 2002, expansion of the heavy oil thermal project at Bolney/Celtic, Saskatchewan continued. Capital spending on the project totalled $36 million and productive capacity had been increased from 3,000 bbls/day to 5,000 bbls/day by year-end. Capital spending for the natural gas development in the Shackleton area of southern Saskatchewan totalled $61 million and 2002 exit production volume was approximately 30 mmcf/day.

Exploration spending in Western Canada increased by $68 million to $304 million in 2002 from $236 million in 2001 and $118 million in 2000. Exploration spending remains focused on natural gas prone areas in the deep basin areas of western Alberta and the foothills and northern plains of Alberta and British Columbia.

East Coast Canada

Husky's 2002 capital spending in the Jeanne d'Arc Basin totalled $458 million. Capital spending on the White Rose development project amounted to $395 million (including $24 million of capitalized interest). The Terra Nova oil field development was commissioned in January 2002. Additional development capital spending for Terra Nova amounted to $22 million during the year. The remaining $41 million was for other Jeanne d'Arc Basin exploration.

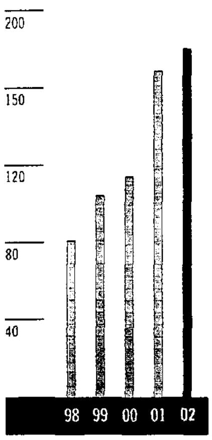
International

Internationally, Husky's capital expenditures totalled $75 million during 2002, $66 million of which was spent on the Wenchang oil field development in the South China Sea. Wenchang was commissioned in July 2002. The remainder was spent on an exploration program in the South China Sea, which began in late 2002. The Qionghai 18-1-3 well in the South China Sea was plugged and abandoned in January 2003 without testing and the Wenchang 8-1-1 was plugged and abandoned without testing in February 2003.

RESERVE ADDITIONS

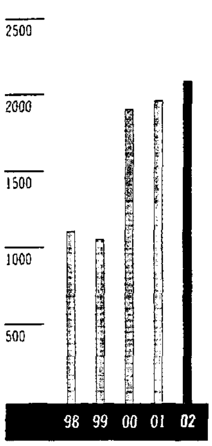
The efficient replacement of the Company's oil and gas productive capacity is the fundamental key to the growth of value. During the three years ended December 31, 2002, Husky has replaced an average of 120 percent of production on a boe basis, exclusive of acquisitions and divestitures. Over the three years ended December 31, 2002 reserves were added at an average cost of $10.12/boe.

During 2002, extensions of proved acreage and improved recovery added 44 mmbbls to proved reserves of crude oil and NGL, 19 mmbbls of which was from Terra Nova. Technical revisions added 12 mmbbls to crude oil and NGL reserves, primarily from Bolney/Celtic. Net divestitures amounted to 11 mmbbls. During 2002, discoveries, extensions and improved recovery added 387 bcf to proved reserves of natural gas. The larger additions were 133 bcf from Boyer in northern Alberta, 82 bcf from Shackleton in southern Saskatchewan and 36 bcf from discoveries in Kiskiu and Ansell in the Alberta foothills and deep basin. Net divestitures of non-core properties amounted to 13 bcf and technical revisions amounted to negative 37 bcf.



Proved Reserves - Lloydminster Heavy Crude Oil
(mmbbls)

Heavy oil reserves continued to grow in 2002



Proved Reserves - Natural Gas
(bcf)

Reserve growth in 2002 benefited from the additions at Shackleton

At December 31, 2002, the present value of future net cash flows after tax from the Company's proved oil and gas reserves, based on prices and costs in effect at year-end and discounted at 10 percent, was $7.2 billion compared with $2.8 billion at the end of 2001.

McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers was engaged to evaluate 65 percent of Husky's proved oil and gas reserves. The firm's aggregate proved reserve estimates were approximately 10 percent lower than Husky's estimates which are set out below.

Summary of Reserves

LIGHT/MEDIUM CRUDE OIL & NGL RESERVES

Year ended December 31 (mmbbls)	2002		2001		2000	
	Gross	Net	Gross	Net	Groos	Net
Proved developed	**323**	**280**	329	287	338	283
Proved undeveloped	**65**	**52**	101	89	102	88
Total proved	**388**	**332**	430	376	440	371

LLOYDMINSTER HEAVY CRUDE OIL RESERVES

Year ended December 31 (mmbbls)	2002		2001		2000	
	Gross	Net	Gross	Net	Groos	Net
Proved developed	**116**	**109**	96	92	65	63
Proved undeveloped	**65**	**60**	73	72	49	47
Total proved	**181**	**169**	169	164	114	110

NATURAL GAS RESERVES

Year ended December 31 (bcf)	2002		2001		2000	
	Gross	Net	Gross	Net	Groos	Net
Proved developed	**1,547**	**1,273**	1,577	1,342	1,580	1,276
Proved undeveloped	**548**	**440**	389	332	329	269
Total proved	**2,095**	**1,713**	1,966	1,674	1,909	1,545

BARRELS OF OIL EQUIVALENT

Year ended December 31 (mmboe)	2002		2001		2000	
	Gross	Net	Gross	Net	Groos	Net
Proved developed	**697**	**601**	688	603	666	559
Proved undeveloped	**221**	**185**	239	216	206	180
Total proved	**918**	**786**	927	819	872	739

RESERVE LIFE INDEX [1]

Year ended December 31 (years)	2002	2001	2000
Light/medium crude oil & NGL	**8.5**	10.5	10.2
Lloydminster heavy crude oil	**6.2**	7.0	5.4
Natural gas	**10.0**	9.4	9.0
Barrels of oil equivalent	**8.4**	9.3	8.7

[1] *Includes total proved reserves.*

Finding and Development Costs

TOTAL [1]

Year ended December 31	2000-2002	2002	2001	2000
Total capitalized costs *($ millions)*	$ 3,314.9	$ 1,505.1	$ 1,172.0	$ 637.8
Proved reserve additions and revisions *(mmboe)*	327.6	114.5	120.4	92.7
Average cost per boe	$ 10.12	$ 13.14	$ 9.73	$ 6.88

WESTERN CANADA [2]

Year ended December 31	2000-2002	2002	2001	2000
Total capitalized costs *($ millions)*	$ 2,298.7	$ 978.5	$ 920.1	$ 400.1
Proved reserve additions and revisions *(mmboe)*	256.9	94.8	112.9	49.2
Average cost per boe	$ 8.95	$ 10.32	$ 8.15	$ 8.13

[1] *Excludes acquisitions/divestitures.*
[2] *Excludes oil sands and acquisitions/divestitures.*

Production Replacement

TOTAL

Year ended December 31	2000-2002	2002	2001	2000
Production *(mmboe)*	273.9	109.6	99.6	64.7
Proved reserve additions and revisions *(mmboe)*	327.6	114.5	120.4	92.7
Production replacement ratio (excluding acquisitions/divestitures) *(percent)*	120	104	121	143
Proved reserve additions and revisions (including acquisitions/divestitures) *(mmboe)* [1]	372.6	100.9	154.5	117.2
Production replacement ratio (including acquisitions/divestitures) *(percent)* [1]	136	92	155	181

WESTERN CANADA [2]

Year ended December 31	2000-2002	2002	2001	2000
Production *(mmboe)*	264.3	100.2	99.5	64.6
Proved reserve additions and revisions *(mmboe)*	256.9	94.8	112.9	49.2
Production replacement ratio (excluding acquisitions/divestitures) *(percent)*	97	95	113	76
Proved reserve additions and revisions (including acquisitions/divestitures) *(mmboe)* [1]	301.9	81.2	147.0	73.7
Production replacement ratio (including acquisitions/divestitures) *(percent)* [1]	114	81	148	114

[1] *Excludes 2000 Renaissance acquisition.*
[2] *Excludes oil sands.*

Recycle Ratio

The recycle ratio measures the efficiency of Husky's capital program by comparing the cost of finding and developing proved reserves with the netback from production. The ratio is calculated by dividing the netback by the proved finding and development cost on a boe basis. Netback is defined as upstream net sales revenues less operating and administrative costs per boe of production.

TOTAL

Year ended December 31	2000-2002	2002	2001	2000
Netback *($/boe)*	$ 16.89	$ 17.66	$ 15.23	$ 18.15
Proved finding and development cost *($/boe)*	$ 10.12	$ 13.14	$ 9.73	$ 6.88
Recycle ratio	1.67	1.34	1.57	2.64

WESTERN CANADA [1]

Year ended December 31	2000-2002	2002	2001	2000
Netback *($/boe)*	$ 16.29	$ 16.07	$ 15.21	$ 18.30
Proved finding and development cost *($/boe)*	$ 8.95	$ 10.32	$ 8.15	$ 8.13
Recycle ratio	1.82	1.56	1.87	2.25

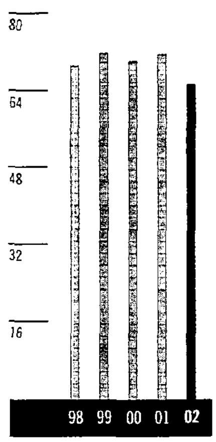
[1] *Excludes oil sands.*

WESTERN CANADA DRILLING

Year ended December 31 (wells)		2002		2001		2000	
		Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	21	20	78	76	16	13
	Gas	139	131	102	90	30	20
	Dry	15	14	36	34	9	9
		175	165	216	200	55	42
Development	Oil	497	453	594	542	411	363
	Gas	485	453	251	221	92	70
	Dry	58	55	68	63	30	28
		1,040	961	913	826	533	461
Total		1,215	1,126	1,129	1,026	588	503

UNDEVELOPED LAND HOLDINGS

Year ended December 31 (thousands of acres)	2002		2001	
	Gross	Net	Gross	Net
Western Canada				
Alberta	5,416	4,907	5,980	5,373
Saskatchewan	2,098	1,986	2,066	1,921
British Columbia	314	273	188	141
Manitoba	13	13	76	75
	7,841	7,179	8,310	7,510
Northwest Territories and Arctic	463	175	1,538	409
Eastern Canada	2,414	2,104	1,878	1,471
Total Canada	10,718	9,458	11,726	9,390
International	4,464	2,066	1,425	697
Total	15,182	11,524	13,151	10,087



Upgrader Throughput
(mbbls/day)

2002 throughput fell due to a plant turnaround and subsequent operational problems

RESULTS OF OPERATIONS - *MIDSTREAM*

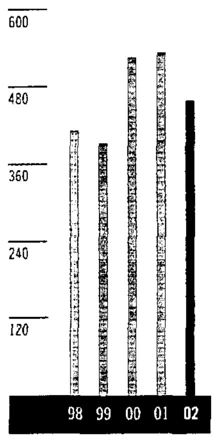
UPGRADING EARNINGS SUMMARY

Year ended December 31 ($ millions, except where indicated)		2002	2001	2000
Gross margin		$ 246	$ 428	$ 321
Operating costs		154	192	158
Other expenses (recoveries)		(6)	(12)	5
DD&A		18	17	16
Income taxes		26	73	54
Earnings		$ 54	$ 158	$ 88
Upgrader throughput [1]	*(mbbls/day)*	65.4	71.7	70.0
Synthetic crude oil sales	*(mbbls/day)*	59.3	59.5	60.6
Upgrading differential	*($/bbl)*	$ 10.81	$ 17.91	$ 13.77
Unit operating cost [2]	*($/bbl)*	$ 6.48	$ 7.35	$ 6.17

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

UPGRADING EARNINGS VARIANCE ANALYSIS

($ millions)	
Year ended December 31, 2000	$ 88
Volume	(8)
Differential	115
Operating costs - energy related	(29)
Operating costs - non-energy related	(5)
Other	17
DD&A	(1)
Income taxes	(19)
Year ended December 31, 2001	158
Volume	(1)
Differential	(181)
Operating costs - energy related	39
Operating costs - non-energy related	(1)
Other	(6)
DD&A	(1)
Income taxes	47
Year ended December 31, 2002	**$ 54**



Pipeline Throughput
(mbbls/day)

The lower level of throughput in 2002 reflected increased competition

INFRASTRUCTURE AND MARKETING EARNINGS SUMMARY

Year ended December 31 ($ millions, except where indicated)	2002	2001	2000
Gross margin			
Pipeline	$ 55	$ 86	$ 87
Other infrastructure and marketing	147	111	30
	202	197	117
Other expenses	10	10	1
DD&A	20	17	15
Income taxes	65	72	45
Earnings	$ 107	$ 98	$ 56
Aggregate pipeline throughput *(mbbls/day)*	457	537	528

2002 compared with 2001

Total midstream earnings decreased by $95 million (37 percent) to $161 million in 2002 from $256 million in 2001 due to:

- upgrading differential narrowing to average $10.81/bbl in 2002 versus $17.91/bbl in 2001

partially offset by:

- lower energy related operating costs

Lower throughput in 2002 compared with 2001 was due to a plant turnaround in June and subsequent operational problems. However synthetic crude oil sales in 2002 were augmented by sales of third party product.

Infrastructure and marketing operations earnings increased nine percent in 2002 due to:

- improved crude oil and natural gas commodity margins
- higher cogeneration income

partially offset by:

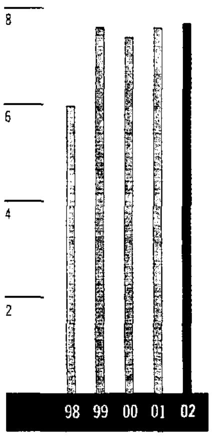
- reduced heavy crude pipeline throughput

Lower income taxes in 2002 compared with 2001 related to lower pre-tax earnings and rate reductions in British Columbia and Alberta and federal rate reductions for non-resource income.

Midstream Capital Expenditures

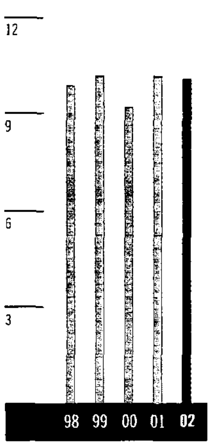
Midstream capital expenditures in 2002 were primarily for upgrader, pipeline and cogeneration plant upgrades and upgrader debottlenecking front-end engineering.

Year ended December 31 ($ millions)	2002	2001	2000
Upgrader	$ 41	$ 47	$ 12
Infrastructure and marketing	17	58	47
	$ 58	$ 105	$ 59



Light Oil Products Sales Volume
(million litres/day)

2002 was a record year for the commodity marketing business



Prince George Refinery Throughput
(mbbls/day)

Prince George continued to operate near peak levels in 2002

RESULTS OF OPERATIONS - *REFINED PRODUCTS*

REFINED PRODUCTS EARNINGS SUMMARY

Year ended December 31 ($ millions, except where indicated)		2002	2001	2000
Gross margin				
Fuel sales		$ **81**	$ 69	$ 55
Ancillary sales		**26**	27	26
Asphalt sales		**45**	106	38
		152	202	119
Operating and other expenses		**64**	59	60
DD&A		**34**	31	28
Income taxes		**22**	49	15
Earnings		$ **32**	$ 63	$ 16
Number of fuel outlets		**571**	580	579
Refined product sales volume				
Light oil products	*(million litres/day)*	**7.7**	7.6	7.4
Asphalt products	*(mbbls/day)*	**20.8**	21.4	20.2
Refinery throughput				
Lloydminster refinery	*(mbbls/day)*	**22.0**	23.7	23.4
Prince George refinery	*(mbbls/day)*	**10.1**	10.2	9.2

2002 compared with 2001

Total refined products earnings decreased by $31 million (49 percent) to $32 million in 2002 from $63 million in 2001. Earnings from asphalt product operations were lower in 2002 due to higher heavy crude oil feedstock costs. Light oil refined product earnings increased primarily due to improved fuel margins.

Refined Products Capital Expenditures

In 2002, capital expenditures of $28 million were directed toward marketing outlet improvements, the remainder was spent on refinery maintenance.

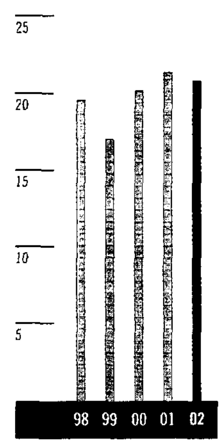
RESULTS OF OPERATIONS - *CORPORATE*

Interest

Interest expense less interest income and capitalized interest was $104 million in 2002 compared with $101 million in 2001. Interest capitalized in 2002 was $26 million compared with $51 million in 2001 reflecting the completion of the Terra Nova development project and the resultant cessation of interest being capitalized to the project. Interest continued to be capitalized to the White Rose development project in 2002. Interest income was $1 million in both 2002 and 2001. Total interest paid on short- and long-term debt in 2002 was $131 million compared with $153 million in 2001 reflecting lower interest rates in 2002. Husky's effective interest rate for 2002 after the effect of swaps was 5.48 percent compared with 6.86 percent during 2001.

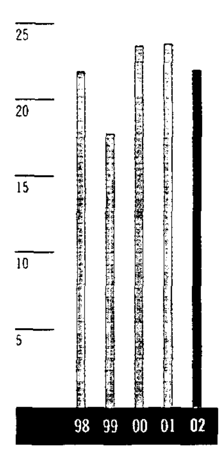
Foreign Exchange

Foreign exchange losses during 2002 comprised $13 million of cash losses and $11 million of non-cash realized losses on long-term debt offset by $11 million of unrealized gains on long-term debt. Foreign exchange cash losses were related to other monetary items, primarily foreign exchange collars.



Asphalt Products Sales Volume
(mbbls/day)

Record sales to the United States in 2002 were offset by lower demand in Canada



Lloydminster Refinery Throughput
(mbbls/day)

Operational problems caused lower throughput in 2002

In June 2002, U.S. $400 million of 10-year debt securities were issued. The Canadian dollar equivalent on issue was $617 million based on an exchange rate of $1.5432. On December 31, 2002 the exchange rate was $1.5796 generating a loss of approximately $15 million, and offsetting gains on other U.S. dollar denominated debt.

Effective January 1, 2002, due to a change in Canadian generally accepted accounting principles, foreign exchange gains and losses on long-term monetary items are no longer deferred and amortized but, as is the practice in the United States, are reflected in earnings in the period they occur. Results from prior periods have been restated to reflect this change. The U.S./Canadian exchange rates expressed in Canadian dollars at December 31, 2002, 2001, 2000 and 1999 were $1.5796, $1.5926, $1.5002 and $1.4433, respectively.

Income Taxes

Income tax expense in 2002 amounted to $420 million, substantially unchanged from 2001. Income tax in 2002 reflected the effect of the British Columbia and Alberta corporate income tax rate reductions and a reduction of the federal corporate income tax rate for non-resource income. Current taxes in 2002 comprised $41 million on Wenchang earnings, $18 million of capital tax and the remainder for other taxes.

At December 31, 2002 Husky's tax pools consisted of the following:

($ millions)	
Canadian Development Expense	$ 960
Canadian Oil and Gas Property Expense	942
Foreign Exploration and Development Expense	247
Undepreciated Capital Costs	1,515
Other	36
	$ 3,700

Corporate Capital Expenditures

Corporate capital expenditures amounted to $23 million in 2002 and $22 million in 2001 and were primarily for computer hardware and software and office furniture and equipment.

SENSITIVITY ANALYSIS

The following table shows the effect on net earnings and cash flow of changes in certain key variables. The analysis is based on business conditions and production volumes during 2002. 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 ($ millions)	($/share) [6]	Effect on Net Earnings ($ millions)	($/share) [6]
WTI benchmark crude oil price [1]	U.S. $1.00/bbl	101	0.24	64	0.15
NYMEX benchmark natural gas price [2]	U.S. $0.20/mmbtu	39	0.09	23	0.05
Light/heavy crude oil differential [3]	Cdn. $1.00/bbl	(28)	(0.07)	(17)	(0.04)
Light oil margins	Cdn. $0.005/litre	14	0.03	8	0.02
Asphalt margins	Cdn. $1.00/bbl	8	0.02	5	0.01
Exchange rate (U.S. $ per Cdn. $) [4]	U.S. $0.01	(41)	(0.10)	(26)	(0.06)
Interest rate [5]	1%	(12)	(0.03)	(8)	(0.02)

[1] *Excludes the impact of hedging. Hedged oil volumes at December 31, 2002 were immaterial.*

[2] *Includes decrease in earnings related to natural gas consumption.*

[3] *Includes impact of upstream and upgrading operations only.*

[4] *Assumes no foreign exchange gains or losses on U.S. $ denominated long-term debt and other monetary items. In 2002 a new accounting standard eliminates the deferral of foreign exchange gains and losses on long-term monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $19 million in net earnings based on December 31, 2002 U.S. $ denominated debt levels.*

[5] *Interest rate sensitivity based on annual weighted obligations.*

[6] *Based on December 31, 2002 common shares outstanding of 417.9 million.*

LIQUIDITY AND CAPITAL RESOURCES

FINANCIAL RATIOS

Year ended December 31	**2002**	2001	2000
Cash flow - operating activities *($ millions)*	**$ 1,892**	$ 1,930	$ 1,209
- financing activities *($ millions)*	**$ 3**	$ (423)	$ (558)
- investing activities *($ millions)*	**$ (1,589)**	$ (1,507)	$ (651)
Debt to capital employed *(percent)*	**31.8**	32.8	37.4
Debt to cash flow from operations	**1.1**	1.1	1.7
Corporate reinvestment ratio [1]	**0.8**	0.8	0.6

[1] *Capital and investment expenditures divided by cash flow from operations.*

In 2002 cash generated by operating activities was $1,892 million, a decrease of $38 million from the $1,930 million recorded in 2001 and an increase of $683 million from the $1,209 million in 2000. Lower cash from operating activities in 2002 was primarily due to higher accounts receivable and inventories. Cash used in investing activities amounted to $1,589 million in 2002, an increase of $82 million from the $1,507 million in 2001 and an increase of $938 million from the $651 million in 2000.

In 2002 cash provided from financing activities comprised $972 million from the issuance of long-term debt and $9 million of proceeds from the exercise of stock options. Cash utilized by financing activities in 2002 comprised $778 million for debt repayment, $151 million for dividends on common shares, $31 million for return on capital securities payment, $9 million for debt issue costs and a change of $9 million in non-cash working capital.

In 2001 financing activities utilized a net $423 million comprising debt repayments, net of issues, of $290 million, dividends of $150 million, return on capital securities payment of $30 million and reduction of site restoration provision of $4 million partially offset by a change of $42 million in non-cash working capital and proceeds of $9 million from the exercise of stock options.

In 2002 investing activities comprised $1,695 million for capital expenditures and acquisition costs partially offset by asset sales of $93 million and other adjustments of $13 million. In 2001 investing activities comprised $1,598 million of capital expenditures and acquisition costs partially offset by asset sales of $67 million and other adjustments of $24 million.

Cash and cash equivalents at December 31, 2002 totalled $306 million compared with a nil balance at the beginning of the year. During January 2003, $200 million of the cash was utilized to settle the accounts under the Company's receivable sales agreement outstanding at the end of the year. Total debt, net of cash and cash equivalents was $2,079 million at December 31, 2002.

Financing Activities

As at December 31, 2002 Husky's outstanding long-term debt totalled $2,385 million, including amounts due within one year, compared with $2,092 million at December 31, 2001.

At December 31, 2002 there were no drawings under the Company's $940 million revolving syndicated credit facility. Interest rates on this facility vary and are 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.

At December 31, 2002 the Company had utilized in support of letters of credit $12 million of its $195 million in short-term credit facilities. The interest rates applicable to these facilities vary and are based on Canadian prime, Bankers' Acceptance, money market rates or U.S. dollar equivalents.

Effective June 14, 2002, the Company issued U.S. $400 million of 6.25 percent notes under a U.S. $1 billion base shelf prospectus dated June 6, 2002. See note 9 of the Consolidated Financial Statements.

Effective January 23, 2003 the Company swapped the U.S. $150 million 6.875 percent notes due November 2003 to $229 million 8.5 percent debt due November 2003. This transaction effectively fixes the exchange rate on the U.S. notes at $1.525. As a result there will be no future foreign exchange gains or losses on these notes up to their maturity date.

The Company has an agreement to sell up to $200 million of net trade receivables on a continual basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates, to be paid on an ongoing basis. The average effective rate in 2002 was approximately 2.8 percent (2001 - 4.7 percent). The Company has potential exposure to an immaterial amount of credit loss under this agreement. As at December 31, 2002 $200 million of net trade receivables had been sold.

The Company believes that, based on its current forecast for commodity prices for 2003, together with the corporate hedging plan, its capital program of $1.8 billion will be funded by operating activities and, to the extent required, available lines of credit. In the event of significantly lower cash flow the Company is able to defer certain of its capital spending programs without penalty.

The Company declared dividends aggregating $0.36 per share ($151 million) in 2002. The board of directors of Husky has established a dividend policy that pays quarterly dividends of $0.09 ($0.36 annually) per common share. However, there can be no assurance that further dividends will be declared. The declaration of dividends will be at the discretion of the Board of Directors which will consider earnings, capital requirements, financial condition of the Company and other relevant factors.

At December 31, 2002 Husky had the following credit ratings:

	Rating	Debt Rated
Standard and Poor's Rating Service	BBB	Senior unsecured debt
	BB+	Capital securities
	BBB	8.45% senior secured bonds
Moody's Investor Service	Baa2	Senior unsecured debt
	Ba1	Capital securities
	Baa2	8.45% senior secured bonds
Dominion Bond Rating Service	BBB (high)	Senior unsecured long-term notes
	BBB	Capital securities

SIGNIFICANT ACCOUNTING POLICIES

The preparation of financial statements in accordance with generally accepted accounting principles requires that management make appropriate decisions with respect to the selection of accounting policies and in formulating estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses. The following is included in Management's Discussion and Analysis to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results being reported depending on management's assumptions and changes in prevailing conditions which affect the application of these policies and practices. Significant accounting policies are disclosed in note 3 of the Consolidated Financial Statements. Inherent in the application of a number of these policies is the requirement of management to make certain assumptions and interpretations that affect the determination of assets, liabilities, revenues and expenses. Accordingly, the emergence of new information and changed circumstances can cause material changes in reported financial results.

The following assessment of significant accounting policies is not meant to be exhaustive. Materially different results might occur from the application of the entire series of accounting policies to which the Company might be subject. Additionally, the Company might realize different results from the application of new accounting standards promulgated by various rule-making bodies.

Proved Oil and Gas Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas liquids including condensate and natural gas that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered proved if they can be produced economically as demonstrated by either actual production or conclusive formation tests. Reserves which must be produced through the application of enhanced recovery techniques are included in the proved category only after successful testing by a pilot project or operation of an installed program in the same reservoir that provides support for the engineering analysis on which the project was based. Proved developed reserves are expected to be produced through existing wells and with existing facilities and operating methods.

The estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's plans. The effect of changes in proved oil and gas reserves on the financial results and position of the Company is described under the heading "Full Cost Accounting for Oil and Gas Activities."

Full Cost Accounting for Oil and Gas Activities

Depletion Expense

The Company uses the Full Cost Method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs, estimated future development costs and estimated removal and site restoration costs is amortized using the unit of production method based on estimated proved oil and gas reserves.

An increase in estimated proved oil and gas reserves will result in a corresponding reduction in depletion expense. A decrease in estimated future development costs will result in a corresponding reduction in depletion expense.

Withheld Costs

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Ceiling Test

The Full Cost Method of accounting requires the calculation of a ceiling test which limits the net capital costs carried to an amount that is equal to or less than the estimated future net cash inflows from the Company's oil and gas properties, including net cost less impairment of unproved properties. The test is a cost recovery test and is not intended to represent an estimate of fair market value. The test is performed quarterly. If the net carrying cost of the oil and gas properties exceeds the indicated limit then the difference is charged to earnings.

Impairment of Long-lived Assets

In addition to testing the permitted limits of oil and gas asset carrying costs, the Company is required to review the carrying value of all other property, plant and equipment for potential impairment. The review for impairment compares the carrying cost to the estimated fair value of the long-lived asset and if the carrying cost exceeds the fair value the difference is charged to earnings.

Asset Retirement Obligations

The Company is required to provide for future removal and site restoration costs, net of expected recoveries. The Company must estimate these costs in accordance with existing laws, contracts or other policies and must estimate the expected recoveries, which is generally the salvage value or residual value of an asset. These estimated net costs are charged to earnings and the appropriate liability account over the expected service life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

Legal, Environmental Remediation and Other Contingent Matters

The Company is required to both determine whether a loss is probable based on judgement and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. The Company's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstance.

Income Tax Accounting

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, actual income tax liability may differ significantly from that estimated and recorded by management.

New Accounting Standards

In June 2001 the Financial Accounting Standards Board issued Statement No. 143 "Accounting for Asset Retirement Obligations". Financial Accounting Statement ("FAS") 143 requires an entity to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When initially recorded, the liability is added to the related property, plant and equipment, subsequently increasing depletion, depreciation and amortization expense. In addition, the liability is accreted for the change in present value in each period. Upon adoption of FAS 143 the Company will adjust its existing future removal and site restoration liability using the cumulative-effect approach. FAS 143 is effective for fiscal years commencing on or after January 1, 2003. The Canadian Institute of Chartered Accountants issued an exposure draft entitled "Asset Retirement Obligations" in April 2002 that is substantially the same as FAS 143 and is effective for fiscal years beginning on or after January 1, 2004.

The Company has estimated that the cumulative effect will be an increase of the future removal and site restoration liability of $58 million, an increase of related net property, plant and equipment of $56 million, a decrease to the future income tax liability of $1 million and a decrease in retained earnings of $1 million.

RESULTS OF OPERATIONS FOR 2001 COMPARED WITH 2000

Upstream

The increase in upstream revenues for 2001 was due to:

- higher production of crude oil and natural gas from the acquisition of Renaissance
- heavy oil exploitation programs in the Lloydminster heavy oil area
- higher realized natural gas prices

partially offset by:

- lower crude oil and NGL prices

Operating costs per unit of production increased 13 percent in 2001 as a result of:

- increased production of heavier gravity crude oil
- the operation of mature properties under waterflood and a higher proportion of low pressure shallow natural gas

Total DD&A per boe was $7.31 in 2001 compared with $6.28 in 2000. The increase in the DD&A rate was primarily due to a full year of operations for the Renaissance properties.

Midstream

Higher earnings in 2001 were primarily due to wider upgrading differentials and improved crude oil and natural gas commodity marketing volumes and margins partially offset by higher energy related operating costs.

Refined Products

Asphalt product operations accounted for most of the improved earnings in 2001 due to the lower cost of feedstock and increased sales volume.

Corporate

Capitalized interest was primarily in respect of Terra Nova and White Rose projects. Interest paid in 2000 included $9 million in respect of the partial redemption of the Husky Terra Nova 8.45 percent senior secured bonds. Husky's average interest rate in 2001 was approximately 6.9 percent compared with 7.5 percent in 2000.

QUARTERLY FINANCIAL SUMMARY

($ millions, except where indicated)	2002				2001			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Sales and operating revenues, net of royalties	$ 1,697	$ 1,669	$ 1,659	$ 1,359	$ 1,615	$ 1,470	$ 1,731	$ 1,780
Net earnings	$ 242	$ 173	$ 263	$ 126	$ 45	$ 118	$ 299	$ 192
Net earnings per share								
- Basic	$ 0.57	$ 0.38	$ 0.64	$ 0.29	$ 0.09	$ 0.25	$ 0.74	$ 0.42
- Diluted	$ 0.57	$ 0.38	$ 0.64	$ 0.29	$ 0.09	$ 0.24	$ 0.73	$ 0.42
Cash flow from operations	$ 635	$ 590	$ 498	$ 373	$ 287	$ 478	$ 561	$ 620
Cash flow from operations per share								
- Basic	$ 1.50	$ 1.39	$ 1.18	$ 0.88	$ 0.67	$ 1.13	$ 1.33	$ 1.47
- Diluted	$ 1.50	$ 1.39	$ 1.17	$ 0.87	$ 0.66	$ 1.12	$ 1.32	$ 1.46
Share price								
- High	$ 17.20	$ 17.00	$ 17.98	$ 17.80	$ 20.25	$ 20.95	$ 17.30	$ 15.80
- Low	$ 15.43	$ 14.00	$ 15.85	$ 14.20	$ 15.06	$ 14.65	$ 13.10	$ 13.20
- Close (end of period)	$ 16.47	$ 16.70	$ 16.66	$ 17.10	$ 16.47	$ 17.85	$ 16.22	$ 13.25
Shares traded *(thousands)*	20,478	30,620	31,159	34,383	59,251	46,993	25,333	25,280
Number of weighted average common shares outstanding *(thousands)*								
- Basic	417,748	417,497	417,393	416,939	416,545	416,025	415,878	415,805
- Diluted	419,567	419,136	419,558	418,951	419,367	419,153	418,337	417,555

MANAGEMENT'S REPORT

The management of Husky Energy Inc. is responsible for the financial information and operating data presented in this annual report.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgements. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this annual report has been prepared on a basis consistent with that in the financial statements.

Husky Energy Inc. maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. The system of internal controls is further supported by an internal audit function.

The Audit Committee of the Board of Directors, composed of non-management Directors, meets regularly with management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy, financial reporting matters and reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

The consolidated financial statements have been audited by KPMG, the independent auditors, in accordance with generally accepted auditing standards on behalf of the shareholders. KPMG have full and free access to the Audit Committee.

John C. S. Lau
President & Chief Executive Officer

Neil McGee
Vice President &
Chief Financial Officer

Calgary, Alberta
February 5, 2003

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Husky Energy Inc., as at December 31, 2002, 2001 and 2000 and the consolidated statements of earnings, retained earnings (deficit), and cash flows for each of the years in the three-year period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with Canadian generally accepted auditing standards and auditing standards generally accepted in the United States of America. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002, 2001 and 2000 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Calgary, Alberta, Canada
Chartered Accountants

February 5, 2003

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of dollars)		2002		2001		2000
Assets						
Current assets						
Cash and cash equivalents	$	**306**	$	-	$	-
Accounts receivable		**572**		376		715
Inventories *(note 4)*		**243**		226		186
Prepaid expenses		**23**		24		27
		1,144		626		928
Property, plant and equipment, net *(notes 1, 5)* (full cost accounting)		**9,347**		8,715		7,841
Other assets *(note 9)*		**84**		29		60
	$	**10,575**	$	9,370	$	8,829
Liabilities and Shareholders' Equity						
Current liabilities						
Bank operating loans *(note 8)*	$	**-**	$	100	$	34
Accounts payable and accrued liabilities		**811**		821		1,076
Long-term debt due within one year *(note 9)*		**421**		144		33
		1,232		1,065		1,143
Long-term debt *(note 9)*		**1,964**		1,948		2,311
Site restoration provision *(note 5)*		**249**		212		178
Future income taxes *(note 10)*		**2,003**		1,659		1,212
Shareholders' equity						
Capital securities and accrued return *(note 12)*		**364**		367		344
Common shares *(note 11)*		**3,406**		3,397		3,388
Retained earnings		**1,357**		722		253
		5,127		4,486		3,985
Commitments and contingencies *(note 14)*						
	$	**10,575**	$	9,370	$	8,829

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2001 and 2000 amounts as restated (note 3).

On behalf of the Board:

John C. S. Lau
Director

Martin J. G. Glynn
Director

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31 (millions of dollars, except per share amounts)		2002		2001		2000
Sales and operating revenues, net of royalties	$	**6,384**	$	6,596	$	5,066
Costs and expenses						
Cost of sales and operating expenses		**4,009**		4,425		3,492
Selling and administration expenses		**94**		88		67
Depletion, depreciation and amortization *(notes 1, 5)*		**939**		807		481
Interest - net *(note 9)*		**104**		101		101
Foreign exchange		**13**		94		39
Other - net		**1**		7		85
		5,160		5,522		4,265
Earnings before income taxes		**1,224**		1,074		801
Income taxes *(note 10)*						
Current		**66**		20		12
Future		**354**		400		351
		420		420		363
Net earnings	$	**804**	$	654	$	438
Earnings per share *(note 11)*						
Basic	$	**1.88**	$	1.49	$	1.28
Diluted	$	**1.88**	$	1.48	$	1.28

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (DEFICIT)

Year ended December 31 (millions of dollars)		2002		2001		2000
Beginning of year	$	**722**	$	253	$	(295)
Net earnings		**804**		654		438
Dividends on common shares		**(151)**		(150)		-
Return on capital securities *(note 12)*		**(29)**		(53)		(43)
Related future income taxes *(note 10)*		**11**		18		16
Reduction of stated capital		**-**		-		160
Foreign exchange (retroactive adjustment) *(note 3)*		**-**		-		(15)
Employee future benefits *(note 13)*		**-**		-		(8)
End of year	$	**1,357**	$	722	$	253

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2001 and 2000 amounts as restated (note 3).

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars, except per share amounts)	2002	2001	2000
Operating activities			
Net earnings	$ 804	$ 654	$ 438
Items not affecting cash			
Depletion, depreciation and amortization	939	807	481
Future income taxes	354	400	351
Foreign exchange - non-cash *(note 3)*	-	82	44
Other	(1)	3	85
Cash flow from operations	2,096	1,946	1,399
Change in non-cash working capital *(note 7)*	(204)	(16)	(190)
	1,892	1,930	1,209
Financing activities			
Bank operating loans financing - net	(100)	66	3
Long-term debt issue	972	-	535
Long-term debt repayment	(678)	(356)	(800)
Redemption of preferred shares	-	-	(364)
Return on capital securities payment	(31)	(30)	(30)
Debt issue costs	(9)	-	-
Deferred credits	-	(4)	(4)
Proceeds from exercise of stock options	9	9	-
Dividends on common shares	(151)	(150)	-
Change in non-cash working capital *(note 7)*	(9)	42	102
	3	(423)	(558)
Available for investing	1,895	1,507	651
Investing activities			
Capital expenditures	(1,692)	(1,473)	(803)
Corporate acquisitions	(3)	(125)	(38)
Asset sales	93	67	2
Other	(20)	6	80
Change in non-cash working capital *(note 7)*	33	18	108
	(1,589)	(1,507)	(651)
Increase in cash and cash equivalents	306	-	-
Cash and cash equivalents at beginning of year	-	-	-
Cash and cash equivalents at end of year	$ 306	$ -	$ -
Cash flow from operations per share *(note 11)*			
Basic	$ 4.94	$ 4.60	$ 4.26
Diluted	$ 4.92	$ 4.57	$ 4.26

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2001 and 2000 amounts as restated (note 3).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

Note 1 Segmented Financial Information

	2002	2001	2000	2002	2001	2000
	Upstream			Midstream Upgrading		
Year ended December 31						
Sales and operating revenues, net of royalties	**$ 2,665**	$ 2,165	$ 1,549	**$ 909**	$ 886	$ 1,006
Costs and expenses						
Operating, cost of sales, selling and general	**729**	648	375	**811**	638	848
Depletion, depreciation and amortization	**851**	728	407	**18**	17	16
Interest - net	**-**	-	-	**-**	-	-
Foreign exchange	**-**	-	-	**-**	-	-
	1,580	1,376	782	**829**	655	864
Earnings (loss) before income taxes	**1,085**	789	767	**80**	231	142
Current income taxes	**55**	17	10	**1**	1	1
Future income taxes	**342**	290	305	**25**	72	53
Net earnings (loss)	**$ 688**	$ 482	$ 452	**$ 54**	$ 158	$ 88
Capital employed - As at December 31 [2]	**$ 6,040**	$ 5,715	$ 5,398	**$ 319**	$ 320	$ 352
Property, plant and equipment - As at December 31						
Cost						
Canada	**$ 11,525**	$ 10,353	$ 9,023	**$ 998**	$ 958	$ 912
International	**469**	394	290	**-**	-	-
	$ 11,994	$ 10,747	$ 9,313	**$ 998**	$ 958	$ 912
Accumulated depletion, depreciation and amortization						
Canada	**$ 3,894**	$ 3,272	$ 2,622	**$ 372**	$ 354	$ 337
International	**185**	147	139	**-**	-	-
	$ 4,079	$ 3,419	$ 2,761	**$ 372**	$ 354	$ 337
Net						
Canada	**$ 7,631**	$ 7,081	$ 6,401	**$ 626**	$ 604	$ 575
International	**284**	247	151	**-**	-	-
	$ 7,915	$ 7,328	$ 6,552	**$ 626**	$ 604	$ 575
Total assets - As at December 31						
Canada	**$ 7,883**	$ 7,160	$ 6,584	**$ 658**	$ 644	$ 613
International	**337**	247	151	**-**	-	-
	$ 8,220	$ 7,407	$ 6,735	**$ 658**	$ 644	$ 613

(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.

Midstream Infrastructure and Marketing			Refined Products			Corporate and Eliminations [1]			Total		
2002	2001	2000	2002	2001	2000	2002	2001	2000	2002	2001	2000
$ 4,230	$ 4,380	$ 2,309	$ 1,310	$ 1,349	$ 1,347	$ (2,730)	$ (2,184)	$ (1,145)	$ 6,384	$ 6,596	$ 5,066
4,038	4,193	2,193	1,222	1,206	1,288	(2,696)	(2,165)	(1,060)	4,104	4,520	3,644
20	17	15	34	31	28	16	14	15	939	807	481
-	-	-	-	-	-	104	101	101	104	101	101
-	-	-	-	-	-	13	94	39	13	94	39
4,058	4,210	2,208	1,256	1,237	1,316	(2,563)	(1,956)	(905)	5,160	5,522	4,265
172	170	101	54	112	31	(167)	(228)	(240)	1,224	1,074	801
6	1	-	4	1	1	-	-	-	66	20	12
59	71	45	18	48	14	(90)	(81)	(66)	354	400	351
$ 107	$ 98	$ 56	$ 32	$ 63	$ 16	$ (77)	$ (147)	$ (174)	$ 804	$ 654	$ 438
$ 431	$ 395	$ 312	$ 338	$ 329	$ 351	$ 384	$ (81)	$ (50)	$ 7,512	$ 6,678	$ 6,363
$ 591	$ 575	$ 510	$ 702	$ 655	$ 628	$ 165	$ 143	$ 108	$ 13,981	$ 12,684	$ 11,181
-	-	-	-	-	-	-	-	-	469	394	290
$ 591	$ 575	$ 510	$ 702	$ 655	$ 628	$ 165	$ 143	$ 108	$ 14,450	$ 13,078	$ 11,471
$ 184	$ 165	$ 148	$ 360	$ 330	$ 302	$ 108	$ 95	$ 82	$ 4,918	$ 4,216	$ 3,491
-	-	-	-	-	-	-	-	-	185	147	139
$ 184	$ 165	$ 148	$ 360	$ 330	$ 302	$ 108	$ 95	$ 82	$ 5,103	$ 4,363	$ 3,630
$ 407	$ 410	$ 362	$ 342	$ 325	$ 326	$ 57	$ 48	$ 26	$ 9,063	$ 8,468	$ 7,690
-	-	-	-	-	-	-	-	-	284	247	151
$ 407	$ 410	$ 362	$ 342	$ 325	$ 326	$ 57	$ 48	$ 26	$ 9,347	$ 8,715	$ 7,841
$ 850	$ 862	$ 1,000	$ 534	$ 428	$ 487	$ 313	$ 29	$ (6)	$ 10,238	$ 9,123	$ 8,678
-	-	-	-	-	-	-	-	-	337	247	151
$ 850	$ 862	$ 1,000	$ 534	$ 428	$ 487	$ 313	$ 29	$ (6)	$ 10,575	$ 9,370	$ 8,829

Note 2

Nature of Operations and Organization

HUSKY ENERGY INC. ("Husky" or "the Company") is a publicly traded, integrated energy and energy-related company headquartered in Calgary, Alberta.

Management has segmented the Company's business based on differences in products and services and management strategy and responsibility. The Company's business is conducted predominantly through three major business segments – upstream, midstream and refined products.

Upstream includes exploration for, development and production of crude oil, natural gas and natural gas liquids. The Company's upstream operations are located primarily in Western Canada, offshore Eastern Canada (East Coast), South China Sea (Wenchang), with some interests outside Canada (International).

Midstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading); marketing of the Company's and other producers' crude oil, natural gas, natural gas liquids, sulphur and petroleum coke; and pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas and cogeneration of electrical and thermal energy (Infrastructure and marketing).

Refined products includes refining of crude oil and marketing of refined petroleum products including gasoline, alternative fuels and asphalt.

Note 3

Significant Accounting Policies

These financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which, in the case of the Company, differ in certain respects from those in the United States. These differences are described in note 16, Reconciliation to Accounting Principles Generally Accepted in the United States.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

The consolidated financial statements include the accounts of the Company and its subsidiaries.

A significant part of the Company's activities is conducted jointly with third parties and accordingly the accounts reflect the Company's proportionate interest in these activities.

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

In 2001 and previously, the Company presented certain crown charges as a component of operating expenses. These charges have been reclassified as royalties for 2002 and for all comparative periods presented in these financial statements. There is no impact on the net earnings or cash flow of the Company as a result of this change.

a) *Cash and Cash Equivalents*

   Cash and cash equivalents consist of cash on hand and deposits with a maturity of less than three months.

b) *Inventory Valuation*

   Crude oil, natural gas, refined petroleum products and purchased sulphur inventories are valued at the lower of cost, on a first-in, first-out basis, or net realizable value. Materials and supplies are stated at average cost. Cost consists of raw material, labour, direct overhead and transportation. Intersegment profits are eliminated.

c) Property, Plant and Equipment

i) Oil and Gas

The Company employs the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves are capitalized and accumulated within cost centres on a country-by-country basis. Such costs include land acquisition, geological and geophysical, drilling of productive and non-productive wells, carrying costs directly related to unproved properties and administrative costs directly related to exploration and development activities. Interest is capitalized on certain major capital projects based on the Company's long-term cost of borrowing.

The provision for depletion of oil and gas properties and depreciation of associated production facilities is calculated using the unit of production method, based on proved oil and gas reserves as estimated by the Company's engineers, for each cost centre. Depreciation of gas plants and certain other oil and gas facilities is provided using the straight-line method based on their estimated useful lives. In the normal course of operations, retirements of oil and gas interests are accounted for by charging the asset cost, net of any proceeds, to accumulated depletion or depreciation.

Costs of acquiring and evaluating significant unproved oil and gas interests are excluded from costs subject to depletion and depreciation until it is determined that proved oil and gas reserves are attributable to such interests or until impairment occurs. Costs of major development projects are excluded from costs subject to depletion and depreciation until the earliest of when a portion of the property becomes capable of production, or when development activity ceases, or when impairment occurs.

The aggregate carrying values of oil and gas interests are subject to cost recovery ceiling tests. Net capitalized costs in each cost centre are limited to the estimated future net revenues from proved oil and gas reserves, at prices and costs in effect at year-end, plus the cost of unproved properties and major development projects, less impairment. In addition, the net capitalized costs of all cost centres, less related future income taxes, are limited to the estimated future net revenues from all cost centres plus the net cost of major development projects and unproved properties less future removal and site restoration costs, administrative expenses, financing costs and income taxes. Any amounts in excess of these limits are charged to earnings.

ii) Other Plant and Equipment

Depreciation for substantially all other plant and equipment, except upgrading assets, is provided using the straight-line method based on estimated useful lives of assets. Depreciation for upgrading assets is provided using the unit of production method, based on the plant's estimated productive life. When the net carrying amount of other plant and equipment, less related accumulated provisions for future removal and site restoration costs and future income taxes, exceeds the net recoverable amount, the excess is charged to earnings. Repairs and maintenance costs, other than major turnaround costs, are charged to earnings as incurred. Major turnaround costs are deferred when incurred and amortized over the estimated period of time to the next scheduled turnaround. At the time of disposition of plant and equipment, accounts are relieved of the asset values and accumulated depreciation and any resulting gain or loss is reflected in earnings.

iii) Future Removal and Site Restoration Costs

Future removal and site restoration costs net of expected recoveries, where they are probable and can be reasonably estimated, are provided for using the method of depletion or depreciation related to the asset. Costs are estimated by the Company's engineers based on current regulations, costs, technology and industry standards. The annual charge is included in the provision for depletion, depreciation and amortization. Removal and site restoration expenditures are charged to the accumulated provision as incurred.

d) *Financial Instruments*

Gains and losses related to financial instruments designated as hedges are deferred and recognized in the period and in the same financial statement category in which the revenues or expenses associated with the hedged transactions are recognized.

In November 2001, the Accounting Standards Board ("AcSB") of the Canadian Institute of Chartered Accountants ("CICA") issued an Accounting Guideline "Hedging Relationships" that establishes standards for the documentation and effectiveness of hedging activities that are substantially similar to the corresponding requirements in Financial Accounting Standards Board ("FASB") Statement No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). The new recommendations will be effective January 1, 2004. Note 16 discloses the impact of FAS 133 on the financial statements for 2002.

e) *Revenue Recognition*

Revenues from the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recorded on a gross basis when title passes to an external party. Sales between the business segments of the Company are eliminated from sales and operating revenues and cost of sales. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

f) *Foreign Currency Translation*

Results of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars using average rates for the year for revenue and expenses, except depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Monetary assets are translated at current exchange rates and non-monetary assets are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in earnings. Capital securities are adjusted to the current rate of exchange and included in retained earnings.

Effective January 1, 2002, the Company retroactively adopted the revised recommendations of the CICA on Foreign Currency Translation. The new recommendations eliminated the deferral and amortization of foreign exchange gains and losses on long-term monetary items. This change resulted in a reduction of retained earnings at January 1, 2000 of $15 million and a reduction of earnings after tax of $47 million and $26 million for the years ended December 31, 2001 and 2000, respectively. This change also resulted in a reduction to other assets of $133 million, a reduction to the future income tax liability of $36 million and an increase to capital securities of $17 million as at December 31, 2001.

g) Stock-based Compensation Plans

In accordance with the Company's stock option plan, common share options are granted to directors, officers and certain other employees. The Company does not recognize compensation expense on the issuance of common share options under this plan because the exercise price of the share options is equal to the market value of the common shares when they are granted. In accordance with CICA section 3870 "Stock-based Compensation and Other Stock-based Payments", note 11 discloses the impact on the financial statements for options granted after January 1, 2002. The standards are substantially similar to those in FASB Statement No. 123 "Accounting for Stock-based Compensation" ("FAS 123"). Note 16 presents the disclosures required by FAS 123 in the financial statements.

h) Earnings Per Share

Basic common shares outstanding are the weighted average number of common shares outstanding for each period. Diluted common shares outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back common shares at the average market price for the period. In addition, diluted common shares also include the effect of the potential exercise of any outstanding warrants.

i) Impairment or Disposal of Long-term Assets

In December 2002, the AcSB of the CICA approved new standards for the impairment and disposal of long-lived assets that are substantially equivalent to those in FASB Statement No. 144 "Accounting for the Impairment or Disposal of Long-term Assets" ("FAS 144"). Note 16 presents the disclosures required by FAS 144 in the financial statements.

Note 4

Inventories

	2002	2001	2000
Crude oil and refined petroleum products	$ 166	$ 140	$ 132
Natural gas	50	69	41
Materials, supplies and other	27	17	13
	$ 243	$ 226	$ 186

Note 5

Property, Plant and Equipment

Refer to note 1 "Segmented Financial Information" which presents the Company's property, plant and equipment by segment.

Costs of oil and gas properties, including major development projects, excluded from costs subject to depletion and depreciation at December 31 were as follows:

	2002	2001	2000
Canada	$ 1,318	$ 1,226	$ 1,073
International	37	235	137
	$ 1,355	$ 1,461	$ 1,210

The Company has estimated future removal and site restoration costs of $703 million at December 31, 2002 (2001 - $653 million; 2000 - $619 million). During 2002 actual removal and site restoration expenditures amounted to $17 million (2001 - $18 million; 2000 - $10 million).

Note 6

Plan of Arrangement

On June 18, 2000 Husky Oil Limited and Renaissance Energy Ltd. ("Renaissance") agreed to a Plan of Arrangement whereby Husky Oil Limited and its principal subsidiary, Husky Oil Operations Limited ("HOOL"), would merge with Renaissance and continue as HOOL. The Plan of Arrangement also included the incorporation of a new company, Husky Energy Inc. Husky is the parent company of HOOL and is publicly traded. The transaction became effective August 25, 2000 and the results of Husky include those of Renaissance from that date forward.

The allocation of the aggregate purchase price based on the estimated fair values of the Renaissance net assets at August 25, 2000 were as follows:

	Allocation
Net assets acquired	
Working capital	$ 84
Property, plant and equipment	3,514
Marketing and transportation	(131)
Other assets	23
Acquisition costs	(51)
Site restoration provision	(70)
Future income taxes	(60)
Long-term debt	(1,211)
	$ 2,098
Consideration	
Common shares exchanged	$ 1,734
Preferred shares issued	364
	$ 2,098

Note 7

Cash Flows - Change in Non-cash Working Capital

a) Changes in non-cash working capital were as follows:

	2002	2001	2000
Decrease (increase) in non-cash working capital			
Accounts receivable	$ (153)	$ 361	$ (254)
Inventories	(17)	(40)	(38)
Prepaid expenses	1	3	2
Accounts payable and accrued liabilities	(11)	(280)	310
Change in non-cash working capital	(180)	44	20
Relating to:			
Financing activities	(9)	42	102
Investing activities	33	18	108
Operating activities	$ (204)	$ (16)	$ (190)

b) Other cash flow information:

	2002	2001	2000
Cash taxes paid	$ 20	$ 13	$ 9
Cash interest paid	$ 139	$ 145	$ 138

Note 8

Bank Operating Loans

At December 31, 2002 the Company had short-term borrowing lines of credit with banks totalling $195 million (2001 - $195 million; 2000 - $234 million), of which $12 million (2001 - $102 million; 2000 - $84 million) had been used for bank operating loans and letters of credit. Interest payable is based on Bankers' Acceptance, money market, or prime rates. During 2002, the weighted average interest rate on short-term borrowings was approximately 2.9 percent.

Note 9

Long-term Debt

		Maturity	2002	2001	2000
Long-term debt					
Revolving syndicated credit facility					
	- 2001 U.S. $116		$ -	$ 185	$ 174
Non-revolving syndicated credit facility			-	-	300
6.25% notes	- U.S. $400	2012	**632**	-	-
6.875% notes	- U.S. $150	2003	**237**	239	225
7.125% notes	- U.S. $150	2006	**237**	239	225
7.55% debentures	- U.S. $200	2016	**316**	318	300
8.45% senior secured bonds	- 2002 U.S. $162	2003-12	**256**	276	268
	- 2001 U.S. $173				
	- 2000 U.S. $179				
Private placement notes	- 2002 U.S. $68	2003-5	**107**	135	152
	- 2001 U.S. $85				
	- 2000 U.S. $101				
Medium-term notes		2003-9	**600**	700	700
Total long-term debt			**2,385**	2,092	2,344
Amount due within one year			**(421)**	(144)	(33)
			$ 1,964	$ 1,948	$ 2,311

Interest - net for the years ended December 31 were as follows:

	2002	2001	2000
Long-term debt	**$ 128**	$ 148	$ 144
Short-term debt	**3**	5	4
	131	153	148
Amount capitalized	**(26)**	(51)	(43)
	105	102	105
Interest income	**(1)**	(1)	(4)
	$ 104	$ 101	$ 101

As at December 31, 2002, other assets included $23 million (2001 - $17 million; 2000 - $20 million) of deferred debt issue costs.

The revolving syndicated credit facility allows the Company to borrow up to $940 million in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a one-year committed revolving credit facility, extendible annually. In the event that the lenders do not consent to such extension, the revolving credit facility will convert to a four-year non-revolving amortizing term loan. Interest rates 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 credit rating agencies to the Company's rated senior unsecured debt and whether the Company borrows under the revolving or non-revolving condition.

The 6.25 percent notes were issued June 14, 2002 and rank on equal footing with other unsecured indebtedness of the Company. The notes mature June 15, 2012 and are redeemable at the option of the Company at any time. Interest is payable semi-annually. The notes were issued under a base shelf prospectus dated June 6, 2002 filed with securities regulatory authorities in Canada and the United States. The prospectus permits Husky to offer for sale, from time to time, up to U.S. $1 billion of debt securities during the 25 months from June 6, 2002.

The 6.875 percent notes, the 7.125 percent notes and the 7.55 percent debentures represent unsecured securities issued under a trust indenture dated October 31, 1996. Such securities mature in 2003, 2006 and 2016, respectively. The 6.875 percent and 7.125 percent notes are not redeemable prior to maturity. The 7.55 percent debentures are redeemable, at the option of the Company, at any time and at a price determinable at the time of redemption. Interest is payable semi-annually.

The 8.45 percent senior secured bonds represent securities issued by a subsidiary under a trust indenture dated July 20, 1999. These securities amortize semi-annually with final maturity in 2012 and are redeemable prior to maturity under certain circumstances. Such securities were issued in connection with the financing of the Company's share of the costs for the exploration and development of the Terra Nova oil field located off the East Coast of Canada. Interest is payable semi-annually. Although the Company commenced principal payments on August 1, 2001 ($8 million) it has the option of subsequently delaying the repayment schedule by one year. The Company, through a wholly owned partnership, owns 12.51 percent of the oil field and associated facilities. The repayment of the securities is contracted to be made solely from revenue from the oil field. There is also a charge created by the partnership on its interest in the assets of the oil field and associated facilities in favour of the security holders. In addition, certain financial obligations require letters of credit or cash equivalents as collateral.

The private placement notes are issued under two separate note agreements dated January 31, 2001. The notes are unsecured and redeemable at any time by the Company at a price determinable at the time of redemption. Interest is payable semi-annually or quarterly, depending on the particular note.

The medium-term notes Series B and C represent unsecured securities issued under a trust indenture dated February 3, 1997 and the Series D and E notes represent unsecured securities issued under a trust indenture dated May 4, 1999. The amounts, rates and maturities are as follows:

Issue	Amount	Interest Rate	Maturity Date
Series B	$ 100	6.85%	February 2007
Series C	100	5.75%	February 2003
Series D	200	6.30%	June 2004
Series E	200	6.95%	July 2009
	$ 600		

Interest is payable semi-annually on all series. The Series B and E notes are redeemable at any time at the option of the Company, at a price determinable at the time of redemption.

Aggregate maturities of long-term debt for the next five years are: 2003 - $421 million; 2004 - $272 million; 2005 - $74 million; 2006 - $276 million; and 2007 - $132 million.

Note 10

Income Taxes

The combined provisions for income taxes in the Consolidated Statements of Earnings and Retained Earnings (Deficit) reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31 were accounted for as follows:

	2002	2001	2000
Earnings before taxes	$ 1,224	$ 1,074	$ 801
Statutory income tax rate *(percent)*	41.6	43.7	44.7
Expected income tax	509	469	358
Effect on income tax of:			
Change in statutory tax rate	(31)	(52)	-
Ownership charges	-	-	15
Return on capital securities	(11)	(18)	(16)
Royalties, lease rentals and mineral taxes payable to the crown	159	184	141
Resource allowance on Canadian production income	(212)	(219)	(175)
Non-deductible capital taxes	18	20	12
Gains and losses on foreign exchange	-	20	9
Other - net	(23)	(2)	3
	$ 409	$ 402	$ 347
Charged (credited) to:			
Income tax expense	$ 420	$ 420	$ 363
Retained earnings	(11)	(18)	(16)
	$ 409	$ 402	$ 347

The future income taxes liability at December 31 comprised the tax effect of temporary differences as follows:

	2002	2001	2000
Future tax liabilities			
Property, plant and equipment	$ 2,199	$ 1,882	$ 1,467
Other temporary differences	30	7	2
	2,229	1,889	1,469
Future tax assets			
Loss carryforwards	7	28	103
Foreign exchange losses deductible on realization	28	26	7
Site restoration and other deferred credits	105	93	81
Provincial royalty rebates	48	46	45
Other temporary differences	38	37	21
	226	230	257
	$ 2,003	$ 1,659	$ 1,212

Note 11

Share Capital

The Company's authorized share capital is as follows:

Common shares - an unlimited number of no par value.
Preferred shares - an unlimited number of no par value.

Changes to issued share capital were as follows:

Common Shares

	Number of Shares	Dollars
January 1, 2000	-	$ -
Issued for Renaissance shares	145,530,429	1,734
Issued for Husky Oil Limited shares	270,272,654	1,654
December 31, 2000	415,803,083	3,388
Options and warrants exercised	1,075,010	9
December 31, 2001	416,878,093	3,397
Options and warrants exercised	995,508	9
December 31, 2002	**417,873,601**	**$ 3,406**

Preferred Shares

In 2000, the Company issued 145.5 million preferred shares to former shareholders of Renaissance. These shares were subsequently redeemed for total proceeds of $364 million. At December 31, 2002, 2001 and 2000, there were no outstanding preferred shares.

Restructuring

As part of the restructuring that occurred in 2000, all previously issued preferred shares of Husky Oil Limited were exchanged, redeemed or cancelled on the capitalization of Husky Energy Inc. All previously issued common and preferred shares were recorded at a value of $1 per share. In addition, the previously outstanding subordinated shareholders' loans, which bore interest payable at 9.05 percent per annum, were converted to Class C preferred shares prior to their cancellation.

In August 2000, $150 million Class A preferred shares and $190 million Class B preferred shares were exchanged for $340 million of Husky Energy Inc. common shares. In addition, $1,306 million Class C preferred shares were cancelled on amalgamation for $1,306 million Husky Energy Inc. common shares. Husky Energy Inc. common shares issued for Husky Oil Limited shares as at December 31, 2000 were $1,654 million which included $8 million of paid in capital.

Stock Options

The following options to purchase common shares have been awarded to directors, officers and certain other employees. At December 31, 2002, 29.2 million common shares were reserved for issuance under the Company stock option plan. The exercise price of the option is equal to the average market price of the Company's common shares during the five trading days prior to the date of the award. Under the stock option plan the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year.

	Number of Shares *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Options Exercisable *(thousands)*
January 1, 2000	-	$ -	-	-
Granted	8,995	$ 13.61	5	
Assumed on Renaissance acquisition	1,372	$ 15.77	2	
Forfeited	(606)	$ 13.61	5	
December 31, 2000	9,761	$ 13.91	4	1,372
Granted	664	$ 15.60	4	
Exercised	(656)	$ 13.99	3	
Forfeited	(1,167)	$ 15.81	2	
December 31, 2001	8,602	$ 13.78	4	2,853
Granted	568	$ 16.11	5	
Exercised	(608)	$ 13.63	2	
Forfeited	(642)	$ 14.37	3	
December 31, 2002	**7,920**	**$ 13.91**	**3**	**4,822**

At December 31, 2002, the options outstanding had exercise prices ranging from $11.16 to $19.76.

In 2000, the Company granted 1.4 million Renaissance replacement options to purchase common shares of Husky in exchange for certain share purchase options to purchase common shares of Renaissance previously held by employees of Renaissance. The former shareholders of Husky Oil Limited were also granted warrants to acquire, for no additional consideration, 1.86 common shares of the Company for each common share issued on the exercise of a Renaissance replacement option. The warrants are exercisable only if and when the Renaissance replacement options are exercised and provide for the issue of a maximum of 2.5 million common shares. As at December 31, 2002, there were 815 thousand common shares remaining which could potentially be issued as a result of the exercise of these warrants.

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:

	2002	2001	2000
Weighted average fair market value per option	**$ 5.19**	$ 5.70	$ 5.03
Risk-free interest rate *(percent)*	**3.6**	3.5	5.5
Volatility *(percent)*	**43**	45	30
Expected life *(years)*	**5**	5	5
Expected annual dividend per share	**$ 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 in 2002 and also to all options granted, the Company's net earnings and earnings per share would have been as follows:

	2002	2001	2000
Compensation cost - options granted in 2002	$ -	$ -	$ -
Compensation cost - all options granted	$ 13	$ 13	$ 4
Net earnings available to common shareholders			
As reported	$ 787	$ 620	$ 410
Options granted in 2002	$ 787	$ 620	$ 410
All options granted	$ 774	$ 607	$ 406
Weighted average number of common shares outstanding *(millions)*			
Basic	417.4	416.1	321.2
Diluted	419.3	418.6	321.2
Basic earnings per share			
As reported	$ 1.88	$ 1.49	$ 1.28
Options granted in 2002	$ 1.88	$ 1.49	$ 1.28
All options granted	$ 1.86	$ 1.46	$ 1.26
Diluted earnings per share			
As reported	$ 1.88	$ 1.48	$ 1.28
Options granted in 2002	$ 1.88	$ 1.48	$ 1.28
All options granted	$ 1.85	$ 1.45	$ 1.26

Per Share Amounts

The calculation of basic net earnings and cash flow from operations per common share is based on the net earnings and cash flow from operations after deducting return on capital securities, net of applicable income taxes, divided by the weighted average number of common shares outstanding.

Diluted net earnings and cash flow from operations per common share include the dilutive impact of options and warrants outstanding under the employee stock option plan calculated using the "treasury stock method". Shares potentially issuable on the settlement of the capital securities have not been included in the determination of diluted earnings and cash flow from operations per common share, as the Company has neither the obligation nor intention to settle amounts due through the issue of shares.

The number of antidilutive options and warrants at December 31, 2002, 2001 and 2000 were nil, nil and 11.7 million, respectively.

During 2002 the Company declared dividends of $0.36 per common share (2001 - $0.36 per common share).

Note 12

Capital Securities

The Company issued U.S. $225 million unsecured capital securities under an indenture dated August 10, 1998. Such securities rank junior to all senior debt and other financial debt of the Company. They yield an annual return of 8.9 percent, payable semi-annually until August 15, 2008 and mature in 2028. The capital securities are redeemable, in whole or in part, by the Company at any time prior to August 15, 2008 at a price determinable at the time of redemption. They are redeemable at par, in whole but not in part, by the Company on or after August 15, 2008. If not redeemed in whole, commencing on August 15, 2008, the annual return changes to a floating rate equal to U.S. LIBOR plus 5.50 percent payable semi-annually. The Company has the right at any time prior to maturity to defer payment of the return on the securities. Since the Company also has the unrestricted ability to settle its deferred return, principal and redemption obligations through the issuance of common or preferred shares, the principal amount of the capital securities, net of issue costs, has been classified as equity. The return amounts, net of income taxes, are classified as distributions of equity. Return on capital securities comprises the return and foreign exchange on the capital securities.

The amounts disclosed as capital securities in shareholders' equity at December 31 were as follows:

	2002	2001	2000
Capital securities - *U.S. $225*	**$ 355**	$ 358	$ 338
Unamortized costs of issue	**(3)**	(3)	(5)
Accrued return	**12**	12	11
	$ 364	$ 367	$ 344

Note 13

Pension Plans and Other Post-retirement Benefits

The Company currently provides a defined contribution pension plan for all qualified employees. The Company also maintains a defined benefit pension plan, which is closed to new entrants, and all current participants are vested. The Company also provides certain medical and dental coverage to its retirees which are accrued over the working lives of the employees.

Weighted average long-term assumptions used for the defined benefit pension plan and other post-retirement benefits were as follows:

	2002	2001	2000
Discount rate *(percent)*	**6.3**	7.3	7.3
Long-term rate of increase in compensation levels *(percent)*	**5.0**	5.0	5.0
Long-term rate of return on plan assets *(percent)*	**8.0**	8.0	8.0

The status of the defined benefit plan and accrued benefit liability at December 31 were as follows:

	2002	2001	2000
Plan assets at fair market value, principally marketable debt and equity securities and cash equivalents	**$ 77**	$ 85	$ 90
Projected benefit obligation	**(108)**	(95)	(93)
Excess assets (excess obligation)	**(31)**	(10)	(3)
Unrecognized past service cost	**1**	-	-
Unrecognized (gains) losses	**27**	6	(2)
Accrued benefit liability	**$ (3)**	$ (4)	$ (5)

The Company's other post-retirement benefits program is not funded and at December 31, 2002, the obligation was $21 million, $17 million of which was accrued. The obligation and accrual at December 31, 2001 and 2000 was $16 million and $13 million, respectively. At December 31, 2002 the discount rate was changed to 6.3 percent from 7.3 percent.

Note 14

Commitments and Contingencies

Certain former owners of interests in the upgrading assets retained a 20-year upside financial interest expiring in 2014 which would require payments to them, should certain product price conditions be met.

The Company has firm commitments for transportation services that require the payment of tariffs. The Company has sufficient production to utilize these transmission services.

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 December 31, 2002 was $1.1 billion. As at December 31, 2002 the Company had spent $322 million on these contracts.

The Company is involved in 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.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time and management believes that it has adequately provided for current and future income taxes.

Note 15

Financial Instruments and Risk Management

The nature of the Company's operations, including the issuance of long-term debt, exposes the Company to fluctuations in commodity prices, foreign currency exchange rates and interest rates. The Company monitors these risks and, when appropriate, utilizes derivative financial instruments to manage its exposure to these risks. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes.

Carrying Values and Estimated Fair Values of Financial Instruments

The carrying value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of those instruments. The estimated fair values of other financial instruments at December 31 were as follows:

ASSETS (LIABILITIES)

	2002		2001		2000	
	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ (2,385)	$ (2,579)	$ (2,092)	$ (2,143)	$ (2,344)	$ (2,348)
Foreign exchange contracts	-	(7)	-	(29)	-	(5)
Foreign exchange forwards	-	(5)	-	-	-	-
Interest rate swaps	-	86	-	4	-	5
Natural gas contracts	-	(4)	-	15	-	5
Crude oil contracts	-	6	-	-	-	-
Fixed physical sales contracts	-	111	-	114	-	-
Fixed physical purchase contracts	-	(122)	-	(88)	-	-

Upstream Commodity Price Risk

The Company, from time to time, employs financial and physical arrangements intended to manage its exposure to price fluctuations. The Company may use physical fixed price product arrangements, futures contracts, swaps, collars and put options to hedge its commodity prices. A portion of the upstream segment price risk may be managed through the forward selling of oil and gas production combined with the forward selling of U.S. dollars.

At December 31, 2002 the Company had hedged 7.5 mmcf of natural gas per day at NYMEX for the years 2003-2005 at an average price of U.S. $1.92 per mcf.

During 2002 the impact was insignificant (2001 - insignificant; 2000 - loss of $150 million) from upstream hedges.

Commodity Marketing Activities

The Company also uses commodity derivatives to manage price risk associated with marketing activities. Derivative instruments provide methods to meet customer pricing requirements while achieving a price structure consistent with the Company's overall pricing strategy. Under this "brokering" strategy substantially all derivative transactions are concurrently offset by a physical purchase or sale arrangement that matches the volume, duration and sales point at which the transactions are priced. In this manner the Company is able either to fix a spread between the price paid to the third party producer and the price received from the financial counterparty or convert a fixed price to floating.

During 2002, the Company entered into variable price physical forward sales with respect to crude oil of 20,000 bbls per day for October and November 2002. The physical sales were hedged by a number of financial transactions in which Husky pays the same variable pricing but receives fixed pricing. The average fixed price that Husky received under financial transactions for October and November production was U.S. $30.51 per bbl and U.S. $30.18 per bbl, respectively. A gain of $5 million was recognized in 2002.

In December 2002 and January 2003 the Company entered into variable price physical forward sales with respect to crude oil of 20,000 bbls per day for January 2003, 30,000 bbls per day for February to May 2003 and 20,000 bbls per day for June 2003. The average fixed price Husky receives under the financial transactions for January is U.S. $30.41 per bbl, February and March U.S. $30.45 per bbl, April and May U.S. $30.38 per bbl and for June U.S. $30.30 per bbl. Also, the Company hedged 30 mmcf per day of natural gas for April to October 2003 at an average price of U.S. $5.04.

In addition, the Company has a portfolio of fixed price offsetting physical forward purchase and sale natural gas contracts. The objective of these contracts is to "lock in" a positive spread between the physical purchase and sales contract prices. At December 31, 2002 the Company had entered into offsetting fixed price physical arrangements to concurrently sell and purchase natural gas for 12 mmcf per day for 2003 through October 2004 to receive an average fixed margin of $0.24 per mcf. In addition, the Company had entered into fixed price physical forward sales with respect to natural gas inventory held in storage for 26 mmcf per day through April 2004 to receive an average fixed margin of $0.92 per mcf.

At December 31, 2002 the Company had also entered into a number of arrangements, consistent with the strategies described above, the impact of which is insignificant to the Company's operations.

Foreign Currency Rate Risk

The Company manages its exposure to exchange rate fluctuations by balancing the U.S. denominated cash flows from operations with U.S. denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency. In addition, Husky has hedged a percentage of its exposure to fluctuations in the U.S. dollar with collar arrangements.

At December 31, 2002 the Company had hedged the exchange rate on U.S. dollars through currency collars up to U.S. $20 million per month at an average floor exchange rate of $1.49 and an average ceiling exchange rate of $1.54 for varying periods up to 2004.

During 2002 the Company realized a loss of $11 million (2001 - loss of $4 million; 2000 - loss of $5 million) from foreign currency risk management activities.

In January 2003, the Company used a currency swap to convert the 6.875 percent notes of U.S. $150 million due November 15, 2003 to Canadian $229 million. The exchange rate of the swap was $1.525 and will result in a foreign exchange gain of $8 million (before tax). The interest rate on the swap is 8.50 percent.

Foreign Exchange Forwards

The Company hedged U.S. dollar revenues for various amounts and maturities to 2005 through the use of foreign exchange forwards. The total amount hedged is U.S. $104 million at an average forward rate of $1.5576.

Interest Rate Risk

The majority of the Company's long-term debt has fixed interest rates and various maturities. The Company periodically uses interest rate swaps to manage its financing costs. At December 31, 2002 the Company had entered into interest rate swap arrangements whereby the fixed interest rate coupon on certain debt was swapped to floating rates with the following terms:

Debt	Amount	Swap Maturity	Swap Rate *(percent)*
6.875% notes	U.S. $ 35	November 15, 2003	U.S. LIBOR - 13 bps
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps
7.125% notes	U.S. $150	November 15, 2006	U.S. LIBOR + 235 bps
7.55% debentures	U.S. $200	November 15, 2011	U.S. LIBOR + 194 bps
6.25% senior notes	U.S. $150	June 15, 2012	U.S. LIBOR + 88 bps

During 2002 the Company realized a gain of $29 million (2001 - gain of $2 million; 2000 - gain of $1 million) from interest rate risk management activities.

In January 2003, the Company unwound the interest rate swap on the 6.875 percent notes due November 15, 2003. The proceeds were U.S. $2 million and will be deferred and amortized into income during 2003.

Credit Risk

Accounts receivable are predominantly with customers in the energy industry and are subject to normal industry credit risks. In addition, the Company is exposed to credit related losses in the event of non-performance by counterparties to its financial instruments. The Company primarily deals with major financial institutions and investment grade rated entities to mitigate these risks.

Sale of Accounts Receivable

The Company has an agreement to sell net trade receivables up to $200 million on a continual basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates to be paid on an ongoing basis. The average effective rate for 2002 was approximately 2.8 percent (2001 - 4.7 percent; 2000 - 6.0 percent). The Company has potential exposure to an immaterial amount of credit loss under this agreement.

Note 16

Reconciliation to Accounting Principles Generally Accepted in the United States

The Company's consolidated financial statements have been prepared in accordance with GAAP in Canada, which differ in some respects to GAAP in the United States. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements were insignificant except as described on the following page:

CONSOLIDATED STATEMENTS OF EARNINGS

	2002	2001	2000
Net earnings	$ **804**	$ 654	$ 438
Adjustments			
Full cost accounting [a]	**88**	(544)	26
Related income taxes	**(37)**	235	(12)
Foreign currency translation on capital securities [b]	**3**	(20)	(13)
Related income taxes	**(1)**	5	4
Post-retirement benefits [c]	**-**	-	(4)
Related income taxes	**-**	-	2
Return on capital securities [d]	**(32)**	(33)	(30)
Related income taxes	**11**	14	13
Gain (loss) on energy trading contracts [e]	**(2)**	20	-
Related income taxes	**1**	(8)	-
Derivatives and hedging [e]	**22**	(20)	-
Related income taxes	**(9)**	8	-
Accounting for income taxes [f]	**(37)**	(14)	23
Net earnings under U.S. GAAP	$ **811**	$ 297	$ 447
Weighted average number of common shares outstanding under U.S. GAAP *(millions)*			
- Basic	**417.4**	416.1	321.2
- Diluted	**419.3**	418.6	321.2
Net earnings per share under U.S. GAAP			
- Basic	$ **1.94**	$ 0.71	$ 1.39
- Diluted	$ **1.93**	$ 0.71	$ 1.39

2001 and 2000 amounts as restated (notes 3 and 16 (b)).

CONDENSED CONSOLIDATED BALANCE SHEETS

	2002		2001		2000	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets [e]	$ **1,144**	$ **1,292**	$ 626	$ 756	$ 928	$ 939
Property, plant and equipment, net [a]	**9,347**	**8,670**	8,715	7,950	7,841	7,620
Other assets [b] [d] [j]	**84**	**89**	29	33	60	65
	$ **10,575**	$ **10,051**	$ 9,370	$ 8,739	$ 8,829	$ 8,624
Current liabilities [c] [d] [e] [j]	$ **1,232**	$ **1,318**	$ 1,065	$ 1,203	$ 1,143	$ 1,165
Long-term debt [d] [e]	**1,964**	**2,406**	1,948	2,306	2,311	2,648
Site restoration provision	**249**	**249**	212	212	178	178
Future income taxes [a] [b] [c] [d] [e] [f] [j]	**2,003**	**1,772**	1,659	1,361	1,212	1,135
Capital securities and accrued return [d]	**364**	**-**	367	-	344	-
Share capital and contributed surplus [g] [h]	**3,406**	**3,640**	3,397	3,631	3,388	3,622
Accumulated other comprehensive income [e] [j]	**-**	**(17)**	-	3	-	-
Retained earnings (deficit)	**1,357**	**683**	722	23	253	(124)
	$ **10,575**	$ **10,051**	$ 9,370	$ 8,739	$ 8,829	$ 8,624

2001 and 2000 amounts as restated (notes 3 and 16 (b)).

CONDENSED CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (DEFICIT) AND COMPREHENSIVE INCOME

	2002		2001		2000	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Retained earnings (deficit), beginning of year	$ 722	$ 23	$ 253	$ (124)	$ (295)	$ (571)
Net earnings	804	811	654	297	438	447
Dividends on common shares and other	(151)	(151)	(150)	(150)	152	-
Capital securities, net of tax and foreign exchange (d)	(18)	-	(35)	-	(27)	-
Foreign exchange (b)	-	-	-	-	(15)	-
Retained earnings (deficit), end of year	$ 1,357	$ 683	$ 722	$ 23	$ 253	$ (124)
Other comprehensive income, beginning of year	$ -	$ 3	$ -	$ -	$ -	$ -
Cumulative effect of change in accounting, net of tax (e)	-	-	-	(10)	-	-
Cash flow hedges, net of tax (e)	-	(10)	-	13	-	-
Minimum pension liability, net of tax (i)	-	(10)	-	-	-	-
Other comprehensive income, end of year	$ -	$ (17)	$ -	$ 3	$ -	$ -

2001 and 2000 amounts as restated (notes 3 and 16 (b)).

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS

	2002		2001		2000	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Sales and operating revenues (e) (i)	$ 6,384	$ 5,778	$ 6,596	$ 5,606	$ 5,066	$ 4,628
Costs and expenses (b) (d) (e) (i)	4,117	3,488	4,614	3,654	3,683	3,263
Depletion, depreciation and amortization (a)	939	851	807	1,351	481	455
Interest, net (d)	104	136	101	134	101	131
Earnings before income taxes	1,224	1,303	1,074	467	801	779
Income taxes (a) (b) (c) (d) (e) (f)	420	492	420	176	363	332
Net earnings, before cumulative effect of change in accounting	804	811	654	291	438	447
Change in accounting, net of tax (e)	-	-	-	6	-	-
Net earnings	$ 804	$ 811	$ 654	$ 297	$ 438	$ 447

2001 and 2000 amounts as restated (notes 3 and 16 (b)).

The increases or decreases noted above refer to the following differences between U.S. GAAP and Canadian GAAP:

(a) The Company performs a cost recovery ceiling test for each cost centre which limits net capitalized costs to the undiscounted estimated future net revenue from proved oil and gas reserves plus the cost of unproved properties less impairment, using year-end prices or average prices in that year if appropriate. In addition, the aggregate value of all cost centres is further limited by including financing costs, administration expenses, future removal and site restoration costs and income taxes. Under U.S. GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves using a discount factor of 10 percent. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable year-end. Financing and administration costs are excluded from the calculation under U.S. GAAP. At December 31, 2001 the Company recognized a U.S. GAAP ceiling test write down of $334 million after tax.

(b) Effective January 1, 2002, the Company retroactively adopted the revised recommendations of the CICA on Foreign Currency Translation (note 3). The new recommendations eliminated the deferral and amortization of foreign exchange gains and losses on long-term monetary items. The Company records the gain or loss on the capital securities as a charge to retained earnings. Under U.S. GAAP, gains or losses on translation of foreign denominated long-term monetary items, including those on capital securities, are credited or charged to earnings immediately.

(c) Prior to 2000 the Company expensed costs related to medical and dental post-retirement benefits as incurred. Effective January 1, 2000 the Company retroactively adopted, without restatement, the new recommendations issued by the CICA on accounting for employee future benefits which are consistent with those under U.S. GAAP, which requires use of the projected benefit method prorated based on service.

(d) The Company records the capital securities as a component of equity and the return thereon as a charge to retained earnings. Under U.S. GAAP, the capital securities, the accrued return thereon and costs of issue would be classified outside of shareholders' equity and the related return would be charged to earnings.

(e) Effective January 1, 2001, the Company adopted the provisions of FAS 133, "Accounting for Derivative Instruments and Hedging Activities". On initial adoption of FAS 133, the Company recorded additional assets and liabilities of $20.3 million and $10.0 million, respectively, and a resulting cumulative catch-up adjustment to increase earnings by $5.7 million, net of tax, for the fair value of derivatives which did not qualify as hedges on January 1, 2001. The Company also recorded assets and liabilities of $3.8 million and $23.0 million, respectively, and a resulting reduction of other comprehensive income within shareholders' equity of $10.6 million, net of tax, for the fair value of derivatives designated as hedges against variability in future cash flows from the sale of natural gas. An additional asset of $7.4 million for the fair value of derivatives designated as hedges against changes in the fair value of certain firm commitments and an offsetting liability for the difference between carrying and fair values of the hedged items was also recorded. The effect of the cumulative catch-up adjustment was to increase net earnings per share under U.S. GAAP by $0.01 (basic and diluted).

At December 31, 2002 the Company recorded additional assets and liabilities for U.S. GAAP purposes of $110.6 million and $122.1 million, respectively, for the fair values of derivative financial instruments. During 2002, a gain of $11.0 million, net of tax, was included in income for U.S. GAAP purposes for unrealized gains on foreign currency derivatives and natural gas basis swaps that did not qualify for hedge accounting under FAS 133. The Company also recorded a gain of $1.3 million, net of tax, in revenue for U.S. GAAP purposes with respect to derivatives designated as hedges of change in the fair value of certain fixed price commodity contracts and offsetting changes in the fair value of those contracts. In addition, the amount included in other comprehensive income was adjusted by a $10.1 million gain, net of tax, for changes in the fair values of the derivatives designated as hedges of cash flows relating to commodity price risk, foreign exchange derivatives and the transfer to income of amounts applicable to cash flows occurring in 2002.

Under U.S. GAAP, energy trading contracts entered into and physical energy trading inventories purchased on or before October 26, 2002 have been recorded at fair value. These contracts include derivatives as well as energy trading contracts that do not meet the definition of derivatives. Effective October 26, 2002, non-derivative energy trading contracts and inventories purchased after the effective date are no longer recorded at fair value in accordance with Emerging Issues Task Force ("EITF") 02-03 "Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities". Under Canadian GAAP, the impact of energy trading contracts is recorded as they settle. Under U.S. GAAP, the Company recorded additional assets and liabilities of $37.0 million and $19.3 million, respectively, at December 31, 2002 and included the resulting unrealized gain in earnings for the year.

Under U.S. GAAP, gains and losses on energy trading contracts have been netted against sales and operating revenues. All prior periods have been reclassified to conform with this change.

(f) The Canadian GAAP liability method of accounting for income taxes requires the measurement of future income tax liabilities and assets using income tax rates that reflect enacted income tax rate reductions, provided it is more likely than not that the Company will be eligible for such rate reductions in the period of reversal. U.S. GAAP allows recording of such rate reductions only when claimed.

(g) As a result of the reorganization of the capital structure which occurred on August 25, 2000, the deficit of Husky Oil Limited was eliminated. Elimination of the deficit would not be permitted under U.S. GAAP.

(h) The Company recorded interest waived on subordinated shareholders' loans and dividends waived on Class C shares as a reduction of ownership charges. Under U.S. GAAP, waived interest and dividends in those years would be recorded as interest on subordinated shareholders' loans and dividends on Class C shares and as capital contributions.

(i) Under U.S. GAAP, transportation costs are included in cost of sales rather than netted against sales and operating revenues. Transportation costs for 2002 were $256 million (2001 - $272 million; 2000 - $159 million).

(j) The Company amortizes the portion of the unrecognized gains or losses that exceed 10 percent of the greater of the projected benefit obligation or the market-related value of pension plan assets. The market-related value of the pension plan assets is either the fair value or a calculated value that recognizes changes in fair value over not more than five years. Under U.S. GAAP, an additional minimum liability is recognized if the unfunded accumulated benefit obligation exceeds the unfunded pension cost already recognized. If an additional minimum liability is recognized, an amount equal to the unrecognized prior service cost is recognized as an intangible asset and any excess is reported in other comprehensive income.

Additional U.S. GAAP Disclosures

FAS 133

Effective January 1, 2001, the Company adopted the provisions of FAS 133, which require that all derivatives be recognized as assets and liabilities on the balance sheet and measured at fair value. Gains or losses, including unrealized amounts, on derivatives that have not been designated as hedges, or were not effective as hedges, are included in earnings as they arise.

For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with equal or lesser amounts of changes in the fair value of the hedged item. During 2002, no amount of the gains or losses on these derivatives was excluded from the assessment of hedge effectiveness in these hedging relationships.

For derivatives designated as cash flow hedges, changes in the fair value of the derivatives are recognized in other comprehensive income until the hedged items are recognized in earnings. Any portion of the change in the fair value of the derivatives that is not effective in hedging the changes in future cash flows is included in earnings. The amount related to the hedge of commodity price risk was included in other comprehensive income at December 31, 2002. During 2002, no amounts were excluded from the assessment of effectiveness of the cash flow hedges.

Stock Option Plan

FAS 123, "Accounting for Stock-based Compensation", establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by FAS 123, Husky has elected to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board Opinion 25. Since all options were granted with exercise prices equal to the market price when the options were granted, no compensation expense has been charged to income at the time of the option grants. Had compensation cost for Husky's stock options been determined based on the fair market value at the grant dates of the awards, and amortized on a straight-line basis, consistent with methodology prescribed by FAS 123, Husky's net earnings and net earnings per share for the years ended December 31, 2002, 2001 and 2000 would have been the pro forma amounts indicated below:

	2002		2001		2000	
	As Reported	Pro Forma	As Reported	Pro. Forma	As Reported	Pro Forma
Net earnings	**$ 811**	**$ 798**	$ 297	$ 284	$ 447	$ 443
Net earnings per share - Basic	**$ 1.94**	**$ 1.91**	$ 0.71	$ 0.68	$ 1.39	$ 1.38
- Diluted	**$ 1.93**	**$ 1.90**	$ 0.71	$ 0.68	$ 1.39	$ 1.38

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 the same as note 11.

Depletion, Depreciation and Amortization

Upstream depletion, depreciation and amortization, per gross equivalent barrel is calculated by converting natural gas volumes to a barrel of oil equivalent ("boe") using the ratio of 6 mcf of natural gas to 1 barrel of crude oil (sulphur volumes have been excluded from the calculation). Depletion, depreciation and amortization per boe for the years ended December 31 were as follows:

	2002	2001	2000
Depletion, depreciation and amortization per boe [1]	**$ 6.96**	$ 6.88	$ 5.88

[1] Excludes the 2001 ceiling test write down.

Impairment or Disposal of Long-term Assets

In August 2001, the FASB issued FAS 144 "Accounting for the Impairment or Disposal of Long-term Assets", which addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. FAS 144 supersedes but retains the basic principles of FASB Statement No. 121 for the impairment of assets to be held and used. A two-step process is used to determine the impairment of the Company's long-term assets, other than assets covered by the full cost accounting policy, with the first step determining when impairment is recognized and the second step measuring the amount of the impairment. An impairment loss is recognized when the carrying amount of a long-lived asset exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is measured as the amount by which the long-lived asset's carrying value exceeds its fair value. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent.

A long-lived asset that meets the conditions as held for sale is measured at the lower of its carrying amount or fair value less costs to sell. Such assets are not amortized while they are classified as held for sale. The results of operations of a component of an entity that has been disposed of, or is classified as held for sale, is reported in discontinued operations if:

(a) The operations and cash flows of the component have been or will be eliminated as a result of the disposal transaction, and;

(b) The entity will not have a significant continuing involvement in the operations of the component after the disposal transaction.

A component of an entity comprises operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the enterprise. A component may be a reportable segment or an operating segment, a reporting unit, a subsidiary or an asset group.

This standard was adopted prospectively on January 1, 2002. It did not result in any differences between Canadian and U.S. GAAP in 2002.

Accounting for Guarantees

In November 2002, the FASB issued Financial Interpretation 45 "Accounting for Guarantees" ("FIN 45") that will require the recognition of a liability for the fair value of certain guarantees that require payments contingent on specified types of future events. The measurement standards of FIN 45 are applicable to guarantees entered into after January 1, 2003. For guarantees that existed as at December 31, 2002, FIN 45 requires additional disclosures which have been included in these financial statements to the extent applicable to the Company.

Accounting for Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation 46 "Accounting for Variable Interest Entities" ("FIN 46") that will require the consolidation of certain entities that are controlled through financial interests that indicate control (referred to as "variable interests"). Variable interests are the rights or obligations that convey economic gains or losses from changes in the values of the entity's assets or liabilities. The holder of the majority of an entity's variable interests will be required to consolidate the variable interest entity. The Company does not believe FIN 46 will result in the consolidation of any additional entities that existed at December 31, 2002.

Future Removal and Site Restoration

In June 2001, the FASB issued Statement No. 143 "Accounting for Asset Retirement Obligations" ("FAS 143"), which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and use of the asset. FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset. The liability is accreted at the end of each period through charges to operating expenses. The Company is required and plans to adopt the provisions of FAS 143 for the quarter ending March 31, 2003. The change will result in an increase to net property, plant and equipment of $56 million, an increase in future removal and site restoration liability of $58 million, a decrease to the future tax liability of $1 million and a decrease to retained earnings of $1 million.

CONTENTS

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION

Oil and Gas Producing Activities (unaudited)

The following disclosures have been prepared in accordance with FASB Statement No. 69 "Disclosures about Oil and Gas Producing Activities" ("FAS 69"):

Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and the Company's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Company's share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2002 no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

Results of Operations for Producing Activities

The following table sets forth revenue and direct cost information relating to the Company's oil and gas producing activities for the years ended December 31:

RESULTS OF OPERATIONS

($ millions)	Canada (1)			International (1)			Total (1)		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenue									
Sales	$ 1,738	$ 1,771	$ 1,158	$ 190	$ 4	$ 4	$ 1,928	$ 1,775	$ 1,162
Transfers	737	390	387	-	-	-	737	390	387
	2,475	2,161	1,545	190	4	4	2,665	2,165	1,549
Deduct									
Production costs	676	617	345	10	-	1	686	617	346
Depletion, depreciation and amortization	813	721	398	38	7	9	851	728	407
Income taxes	387	334	326	64	(1)	(3)	451	333	323
	1,876	1,672	1,069	112	6	7	1,988	1,678	1,076
Results of operations from producing activities	$ 599	$ 489	$ 476	$ 78	$ (2)	$ (3)	$ 677	$ 487	$ 473
Depletion, depreciation and amortization rates per gross equivalent barrel	$ 7.74	$ 7.24	$ 6.15	$ 8.33	$ 80.61	$ 90.39	$ 7.76	$ 7.31	$ 6.28

(1) *The costs in this schedule exclude corporate overhead, interest expense and other operating costs which are not directly related to producing activities.*

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Capitalized costs incurred in oil and gas producing activities for the years ended December 31 were as follows:

COSTS INCURRED

($ millions)		2002	2001	2000
Property acquisition costs (1) (2) (3)				
Proved	- Canada	$ 20	$ 366	$ 3,200
Unproved	- Canada	88	55	355
		108	421	3,555
Exploration costs	- Canada	257	262	159
	- Other	9	5	3
		266	267	162
Development costs	- Canada	1,127	774	412
	- China	66	99	85
		1,193	873	497
		$ 1,567	$ 1,561	$ 4,214

(1) *Property acquisition costs related to corporate acquisitions for proved properties in 2002 were nil; 2001 included $244 million.*

(2) *Property acquisition costs in 2000 included $3,181 million for proved properties and $333 million for unproved properties related to the acquisition of Renaissance.*

(3) *Property acquisition costs in 2000 excluded $135 million for proved properties and $19 million for unproved properties related to property exchanges.*

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (continued)

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Exploration costs include the costs of geological and geophysical activity, retaining undeveloped properties and drilling and equipping exploration wells.

Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and gas.

Exploration and development costs include administrative costs and depreciation of support equipment directly associated with these activities.

The following table sets forth a summary of oil and gas property costs not being amortized at December 31:

WITHHELD COSTS

($ millions)		Total	2002	2001	2000	Prior to 2000
Property acquisition	- Canada	$ 414	$ 37	$ 17	$ 251	$ 109
	- International	14	-	-	-	14
		428	37	17	251	123
Exploration	- Canada	271	79	57	48	87
	- International	6	6	-	-	-
		277	85	57	48	87
Development	- Canada	487	392	83	12	-
	- International	17	1	-	-	16
		504	393	83	12	16
Capitalized interest	- Canada	146	26	51	43	26
		$ 1,355	$ 541	$ 208	$ 354	$ 252

Capitalized Costs Relating to Oil and Gas Producing Activities

The capitalized costs and related accumulated depletion, depreciation and amortization, including impairments, relating to the Company's oil and gas exploration, development and producing activities at December 31 consisted of:

CAPITALIZED COSTS

($ millions)		2002	2001[1]	2000[1]
Unproved oil and gas properties	- Canada	$ 1,318	$ 1,052	$ 951
	- International	37	235	137
		1,355	1,287	1,088
Proved oil and gas properties	- Canada	10,207	9,301	8,072
	- International	432	159	153
		10,639	9,460	8,225
		11,994	10,747	9,313
Less accumulated depletion, depreciation and amortization	- Canada	3,894	3,272	2,622
	- International	185	147	139
		4,079	3,419	2,761
		$ 7,915	$ 7,328	$ 6,552
Net capitalized costs	- Canada	$ 7,631	$ 7,081	$ 6,401
	- International	284	247	151
		$ 7,915	$ 7,328	$ 6,552

[1] Capital related to 17 mmbbls of proved reserves at Terra Nova transferred to proved oil and gas properties. Terra Nova is a major development project off the East Coast of Canada.

Oil and Gas Reserve Information

In Canada, the Company's proved crude oil, natural gas liquids, natural gas and sulphur reserves are located in the provinces of Alberta, Saskatchewan and British Columbia, and offshore the East Coast. The Company's international proved reserves are located in Indonesia, China and Libya. The Company's proved developed and undeveloped reserves after deductions of royalties are summarized below:

RESERVES

	Canada			International		Total		
	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Sulphur *(mmlt)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Sulphur *(mmlt)*
Net proved developed and undeveloped reserves, after royalties [1] [2] [3] [4]								
End of year 1999	212.1	771.7	5.0	5.9	110.5	218.0	882.2	5.0
Revisions	12.9	(59.1)	-	(0.1)	(0.4)	12.8	(59.5)	-
Purchases	215.6	789.0	-	-	-	215.6	789.0	-
Discoveries and extensions	41.5	35.4	-	29.4	-	70.9	35.4	-
Production	(36.6)	(102.4)	(0.3)	(0.1)	-	(36.7)	(102.4)	(0.3)
End of year 2000	445.5	1,434.6	4.7	35.1	110.1	480.6	1,544.7	4.7
Revisions	37.0	74.0	0.1	0.7	5.1	37.7	79.1	0.1
Purchases	33.6	20.4	-	-	-	33.6	20.4	-
Sales	(1.6)	(18.4)	-	-	-	(1.6)	(18.4)	-
Discoveries and extensions	44.8	200.1	0.1	1.1	-	45.9	200.1	0.1
Production	(56.3)	(152.1)	(0.2)	(0.1)	-	(56.4)	(152.1)	(0.2)
End of year 2001	503.0	1,558.6	4.7	36.8	115.2	539.8	1,673.8	4.7
Revisions	-	14.7	0.3	(0.8)	(14.3)	(0.8)	0.4	0.3
Purchases	4.2	5.4	-	-	-	4.2	5.4	-
Sales	(14.5)	(16.6)	-	-	-	(14.5)	(16.6)	-
Discoveries and extensions	37.2	205.4	-	1.1	-	38.3	205.4	-
Production	(61.8)	(155.7)	(0.4)	(4.3)	-	(66.1)	(155.7)	(0.4)
End of year 2002	**468.1**	**1,611.8**	**4.6**	**32.8**	**100.9**	**500.9**	**1,712.7**	**4.6**
Net proved developed reserves, after royalties [1] [2] [3] [4]								
End of year 1999	161.8	669.3	4.8	0.6	-	162.4	669.3	4.8
End of year 2000	345.2	1,275.5	4.5	0.5	-	345.7	1,275.5	4.5
End of year 2001	378.1	1,342.2	4.6	0.6	-	378.7	1,342.2	4.6
End of year 2002	**360.9**	**1,272.8**	**3.7**	**28.2**	-	**389.1**	**1,272.8**	**3.7**

(1) Net reserves are the Company's lessor royalty, overriding royalty and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.

(2) Reserves are the estimated quantities of crude oil, natural gas and related substances anticipated from geological and engineering data to be recoverable from known accumulations, from a given date forward, by known technology, under existing operating conditions and prices in effect at year-end.

(3) Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

(4) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information has been developed utilizing procedures prescribed by FAS 69 and based on crude oil and natural gas reserve and production volumes estimated by the engineering staff of the Company. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's reserves.

The future cash flows presented below are based on sales prices, cost rates, and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2002 was based on the NYMEX year-end natural gas spot price of U.S. $4.60/mmbtu (2001 - U.S. $2.75/mmbtu; 2000 - U.S. $10.53/mmbtu) and on crude oil prices computed with reference to the year-end West Texas Intermediate price of U.S. $31.21/bbl (2001 - U.S. $19.96/bbl; 2000 - U.S. $26.72/bbl).

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (continued)

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company's crude oil and natural gas reserves at December 31, for the years presented.

STANDARDIZED MEASURE

($ millions)	Canada [1]			International [1]			Total [1]		
	2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Future cash inflows	**$ 25,830**	$ 14,102	$ 23,701	**$ 2,719**	$ 1,600	$ 1,787	**$ 28,549**	$ 15,702	$ 25,488
Future costs									
Future production and development costs	**7,239**	7,541	5,996	**502**	523	609	**7,741**	8,064	6,605
Future income taxes	**7,278**	2,540	7,384	**860**	310	402	**8,138**	2,850	7,786
Future net cash flows	**11,313**	4,021	10,321	**1,357**	767	776	**12,670**	4,788	11,097
Deduct 10% annual discount factor	**4,966**	1,667	4,859	**518**	329	404	**5,484**	1,996	5,263
Standardized measure of discounted future net cash flows	**$ 6,347**	$ 2,354	$ 5,462	**$ 839**	$ 438	$ 372	**$ 7,186**	$ 2,792	$ 5,834

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for the years presented.

CHANGES IN STANDARDIZED MEASURE

($ millions)	Canada [1]			International [1]			Total [1]		
	2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Present value at January 1	**$ 2,354**	$ 5,462	$ 1,612	**$ 438**	$ 372	$ 72	**$ 2,792**	$ 5,834	$ 1,684
Sales and transfers, net of production costs	**(1,802)**	(1,556)	(1,204)	**(179)**	(2)	(3)	**(1,981)**	(1,558)	(1,207)
Net change in sales and transfer prices, net of development and production costs	**7,752**	(5,843)	2,159	**732**	(48)	18	**8,484**	(5,891)	2,177
Extensions, discoveries and improved recovery, net of related costs	**676**	356	460	**40**	17	410	**716**	373	870
Revisions of quantity estimates	**(30)**	237	46	**(28)**	10	(2)	**(58)**	247	44
Accretion of discount	**390**	949	279	**59**	55	13	**449**	1,004	292
Sale of reserves in place	**(189)**	(6)	(3)	**-**	-	-	**(189)**	(6)	(3)
Purchase of reserves in place	**45**	174	5,681	**-**	-	-	**45**	174	5,681
Changes in timing of future net cash flows and other	**(191)**	95	(717)	**80**	10	3	**(111)**	105	(714)
Net change in income taxes	**(2,658)**	2,486	(2,851)	**(303)**	24	(139)	**(2,961)**	2,510	(2,990)
Present value at December 31	**$ 6,347**	$ 2,354	$ 5,462	**$ 839**	$ 438	$ 372	**$ 7,186**	$ 2,792	$ 5,834

[1] *The schedules above are calculated using year-end prices, costs, statutory income tax rates and existing proved oil and gas reserves. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.*

Reserve Information

RESERVE RECONCILIATION

	Canada				International		Total	
	Light/Med. Crude Oil & NGL *(mmbbls)*	Lloydminster Heavy Crude Oil *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*
	Western Canada			East Coast				
Proved reserves, before royalties [1]								
Proved reserves at December 31, 1999	138.3	105.0	933.9	-	7.0	142.9	250.3	1,076.8
Revisions	3.6	6.6	(17.2)	-	-	-	10.2	(17.2)
Purchases (includes Renaissance)	258.5	0.3	933.4	-	-	-	258.8	933.4
Discoveries, extensions and improved recovery	12.7	21.4	47.0	11.3	32.2	-	77.6	47.0
Production	(23.2)	(19.6)	(131.0)	-	(0.1)	-	(42.9)	(131.0)
Proved reserves at December 31, 2000	389.9	113.7	1,766.1	11.3	39.1	142.9	554.0	1,909.0
Revisions	0.8	24.9	22.5	1.2	0.2	-	27.1	22.5
Purchases	11.9	23.7	23.7	-	-	-	35.6	23.7
Sales	(1.8)	-	(21.1)	-	-	-	(1.8)	(21.1)
Discoveries, extensions and improved recovery	13.3	30.0	240.7	4.8	1.2	-	49.3	240.7
Production	(41.5)	(23.2)	(209.0)	-	(0.1)	-	(64.8)	(209.0)
Proved reserves at December 31, 2001	372.6	169.1	1,822.9	17.3	40.4	142.9	599.4	1,965.8
Revisions	(6.5)	18.4	(37.2)	-	-	-	11.9	(37.2)
Purchases	0.5	4.4	6.2	-	-	-	4.9	6.2
Sales	(16.4)	-	(19.0)	-	-	-	(16.4)	(19.0)
Discoveries, extensions and improved recovery	6.9	17.8	386.5	18.5	1.2	-	44.4	386.5
Production	(36.7)	(29.0)	(207.8)	(4.8)	(4.5)	-	(75.0)	(207.8)
Proved reserves at December 31, 2002	**320.4**	**180.7**	**1,951.6**	**31.0**	**37.1**	**142.9**	**569.2**	**2,094.5**
Proved developed reserves, before royalties [2]								
December 31, 1999	132.2	56.4	817.6	-	0.6	-	189.2	817.6
December 31, 2000	337.8	64.8	1,579.9	-	0.5	-	403.1	1,579.9
December 31, 2001	322.5	95.8	1,576.5	6.2	0.6	-	425.1	1,576.5
December 31, 2002	**284.5**	**116.3**	**1,546.5**	**7.4**	**30.7**	-	**438.9**	**1,546.5**
Probable reserves, before royalties [3]								
December 31, 1999	64.6	78.0	235.9	256.3	0.9	18.9	399.8	254.8
December 31, 2000	135.2	78.1	434.1	202.3	5.3	18.9	420.9	453.0
December 31, 2001	131.8	81.2	405.6	213.3	4.2	18.9	430.5	424.5
December 31, 2002	**161.0**	**85.5**	**383.9**	**201.6**	**4.1**	**18.9**	**452.2**	**402.8**

(1) Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

(2) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

(3) Probable reserves are considered to be those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which may reasonably be deemed proven at the present time, or those reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions which contain proved reserves. The risk associated with those reserves generally ranges from 40 to 80 percent.

Quarterly Financial and Operating Information

SEGMENTED OPERATIONAL INFORMATION

		2002				2001			
		Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream									
Daily production, before royalties									
Light/medium crude oil & NGL *(mbbls/day)*		137.8	131.4	116.6	117.5	111.3	112.7	108.6	115.5
Lloydminster heavy crude oil *(mbbls/day)*		83.9	80.0	76.9	76.9	75.0	69.1	60.3	56.9
		221.7	211.4	193.5	194.4	186.3	181.8	168.9	172.4
Natural gas *(mmcf/day)*		577.4	561.6	571.8	566.0	568.7	567.1	570.8	584.0
Total production *(mboe/day)*		317.9	305.1	288.9	288.7	281.1	276.3	264.0	269.7
Average realized sales prices									
Light/medium crude oil & NGL *($/bbl)*		$ 36.64	$ 36.72	$ 32.42	$ 26.17	$ 19.44	$ 31.74	$ 28.86	$ 28.72
Lloydminster heavy crude oil *($/bbl)*		$ 25.47	$ 30.94	$ 27.02	$ 20.68	$ 10.44	$ 23.65	$ 15.52	$ 13.81
Natural gas *($/mcf)*		$ 4.76	$ 3.42	$ 3.98	$ 3.10	$ 3.01	$ 3.25	$ 6.57	$ 9.05
Operating costs *($/boe)*		$ 6.66	$ 6.19	$ 6.19	$ 5.88	$ 6.54	$ 6.24	$ 6.19	$ 5.31
Operating netbacks [1]									
Light/medium crude oil & NGL *($/boe)*		$ 24.29	$ 23.74	$ 20.40	$ 15.19	$ 7.43	$ 18.03	$ 17.01	$ 18.09
Lloydminster heavy crude oil *($/boe)*		$ 13.22	$ 20.63	$ 17.81	$ 12.46	$ 3.29	$ 14.04	$ 6.08	$ 4.87
Natural gas *($/mcfge)*		$ 3.18	$ 2.19	$ 2.39	$ 2.03	$ 1.74	$ 1.99	$ 4.28	$ 6.05
Total *($/boe)*		$ 19.71	$ 19.67	$ 17.67	$ 13.47	$ 7.34	$ 14.88	$ 17.62	$ 21.97
Net wells drilled [2]									
Exploration	Oil	3	6	6	5	8	8	15	45
	Gas	14	16	18	83	6	11	5	68
	Dry	2	2	1	9	4	2	3	25
		19	24	25	97	18	21	23	138
Development	Oil	107	190	112	44	116	195	129	102
	Gas	160	67	10	216	53	57	17	94
	Dry	17	14	6	18	11	23	7	22
		284	271	128	278	180	275	153	218
		303	295	153	375	198	296	176	356
Success ratio *(percent)*		94	95	95	93	92	92	95	87
Midstream									
Synthetic crude oil sales *(mbbls/day)*		67.5	47.3	51.3	71.2	49.7	66.5	65.6	56.2
Upgrading differential *($/bbl)*		$ 13.06	$ 9.92	$ 10.43	$ 9.85	$ 16.85	$ 13.18	$ 19.56	$ 21.61
Pipeline throughput *(mbbls/day)*		476	436	448	469	518	498	583	550
Refined Products									
Refined product sales volumes									
Light oil products *(million litres/day)*		7.9	8.2	7.4	7.2	7.5	8.2	7.3	7.4
Asphalt products *(mbbls/day)*		14.2	30.6	20.5	17.7	19.9	29.9	20.6	15.0
Refinery throughput									
Lloydminster refinery *(mbbls/day)*		17.8	25.2	19.9	25.2	25.8	26.1	20.5	22.2
Prince George refinery *(mbbls/day)*		10.9	11.0	7.7	10.9	10.2	8.8	10.7	10.9
Refinery utilization *(percent)*		82	103	79	103	103	100	89	95

[1] *Operating netbacks are Husky's average realized prices less royalties, hedging (gains)/losses and operating costs on a per unit basis.*

[2] *Western Canada.*

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION

SEGMENTED FINANCIAL INFORMATION

($ millions)	Upstream				Midstream							
					Upgrading				Infrastructure and Marketing			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
2002												
Sales and operating revenues, net of royalties	$ 781	$ 738	$ 635	$ 511	$ 301	$ 192	$ 195	$ 221	$ 1,367	$ 953	$ 958	$ 952
Costs and expenses												
Operating, cost of sales, selling and general	206	189	171	163	265	183	182	181	1,321	905	916	896
Depletion, depreciation and amortization	231	218	202	200	5	4	4	5	6	5	5	4
Interest - net	-	-	-	-	-	-	-	-	-	-	-	-
Foreign exchange	-	-	-	-	-	-	-	-	-	-	-	-
	437	407	373	363	270	187	186	186	1,327	910	921	900
Earnings (loss) before income taxes	344	331	262	148	31	5	9	35	40	43	37	52
Current income taxes	26	8	1	20	-	1	-	-	(19)	13	4	8
Future income taxes	108	117	83	34	11	2	2	10	31	5	10	13
Net earnings (loss)	$ 210	$ 206	$ 178	$ 94	$ 20	$ 2	$ 7	$ 25	$ 28	$ 25	$ 23	$ 31
Capital employed [2]	$ 6,040	$ 6,027	$ 6,001	$ 5,919	$ 319	$ 343	$ 324	$ 306	$ 431	$ 428	$ 194	$ 268
Total assets	$ 8,220	$ 8,105	$ 7,860	$ 7,723	$ 658	$ 665	$ 657	$ 640	$ 850	$ 871	$ 736	$ 845
2001												
Sales and operating revenues, net of royalties	$ 367	$ 549	$ 578	$ 671	$ 147	$ 255	$ 259	$ 225	$ 1,153	$ 796	$ 839	$ 1,592
Costs and expenses												
Operating, cost of sales, selling and general	182	171	160	135	81	215	176	166	1,111	758	785	1,539
Depletion, depreciation and amortization	193	185	176	174	4	5	5	3	4	5	4	4
Interest - net	-	-	-	-	-	-	-	-	-	-	-	-
Foreign exchange	-	-	-	-	-	-	-	-	-	-	-	-
	375	356	336	309	85	220	181	169	1,115	763	789	1,543
Earnings (loss) before income taxes	(8)	193	242	362	62	35	78	56	38	33	50	49
Current income taxes	3	5	5	4	1	-	-	-	-	1	-	-
Future income taxes	3	79	60	148	21	13	18	20	16	14	20	21
Net earnings (loss)	$ (14)	$ 109	$ 177	$ 210	$ 40	$ 22	$ 60	$ 36	$ 22	$ 18	$ 30	$ 28
Capital employed [2]	$ 5,715	$ 5,685	$ 5,633	$ 5,444	$ 320	$ 303	$ 313	$ 337	$ 395	$ 373	$ 275	$ 254
Total assets	$ 7,407	$ 7,298	$ 7,104	$ 7,051	$ 644	$ 610	$ 610	$ 620	$ 862	$ 853	$ 835	$ 822

[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.*

SEGMENTED FINANCIAL INFORMATION (CONTINUED)

($ millions)	Refined Products				Corporate and Eliminations [1]				Total			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
2002												
Sales and operating revenues,												
net of royalties	$ 326	$ 431	$ 322	$ 231	$ (1,078)	$ (645)	$ (451)	$ (556)	$ 1,697	$ 1,669	$ 1,659	$ 1,359
Costs and expenses												
Operating, cost of sales,												
selling and general	318	395	292	217	(1,081)	(642)	(436)	(537)	1,029	1,030	1,125	920
Depletion, depreciation												
and amortization	9	9	8	8	5	3	4	4	256	239	223	221
Interest - net	-	-	-	-	25	28	24	27	25	28	24	27
Foreign exchange	-	-	-	-	(5)	75	(65)	8	(5)	75	(65)	8
	327	404	300	225	(1,056)	(536)	(473)	(498)	1,305	1,372	1,307	1,176
Earnings (loss) before												
income taxes	(1)	27	22	6	(22)	(109)	22	(58)	392	297	352	183
Current income taxes	(1)	4	1	-	-	-	-	-	6	26	6	28
Future income taxes	1	7	8	2	(7)	(33)	(20)	(30)	144	98	83	29
Net earnings (loss)	$ (1)	$ 16	$ 13	$ 4	$ (15)	$ (76)	$ 42	$ (28)	$ 242	$ 173	$ 263	$ 126
Capital employed [2]	$ 338	$ 360	$ 383	$ 375	$ 384	$ 176	$ 233	$ (2)	$ 7,512	$ 7,334	$ 7,135	$ 6,866
Total assets	$ 534	$ 554	$ 523	$ 516	$ 313	$ 153	$ 189	$ 6	$10,575	$10,348	$ 9,965	$ 9,730
2001												
Sales and operating revenues,												
net of royalties	$ 274	$ 429	$ 345	$ 301	$ (326)	$ (559)	$ (290)	$ (1,009)	$ 1,615	$ 1,470	$ 1,731	$ 1,780
Costs and expenses												
Operating, cost of sales,												
selling and general	254	371	296	285	(330)	(552)	(283)	(1,000)	1,298	963	1,134	1,125
Depletion, depreciation												
and amortization	9	7	7	8	4	3	4	3	214	205	196	192
Interest - net	-	-	-	-	23	24	26	28	23	24	26	28
Foreign exchange	-	-	-	-	15	56	(50)	73	15	56	(50)	73
	263	378	303	293	(288)	(469)	(303)	(896)	1,550	1,248	1,306	1,418
Earnings (loss) before												
income taxes	11	51	42	8	(38)	(90)	13	(113)	65	222	425	362
Current income taxes	1	-	-	-	-	(1)	-	1	5	5	5	5
Future income taxes	7	21	16	4	(32)	(28)	7	(28)	15	99	121	165
Net earnings (loss)	$ 3	$ 30	$ 26	$ 4	$ (6)	$ (61)	$ 6	$ (86)	$ 45	$ 118	$ 299	$ 192
Capital employed [2]	$ 329	$ 304	$ 342	$ 364	$ (81)	$ (78)	$ (103)	$ (96)	$ 6,678	$ 6,587	$ 6,460	$ 6,303
Total assets	$ 428	$ 491	$ 499	$ 498	$ 29	$ 10	$ (4)	$ -	$ 9,370	$ 9,262	$ 9,044	$ 8,991

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION

SEGMENTED FINANCIAL INFORMATION

($ millions)		2002				2001			
		Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Capital expenditures									
Upstream	- Western Canada	$ 326	$ 207	$ 156	$ 345	$ 264	$ 323	$ 186	$ 249
	- East Coast Canada	97	169	154	38	54	43	54	40
	- International	8	25	22	20	35	21	18	30
		431	401	332	403	353	387	258	319
Midstream	- Upgrader	11	9	12	9	37	5	3	2
	- Infrastructure and marketing	5	2	3	7	22	6	5	25
		16	11	15	16	59	11	8	27
Refined products		22	9	9	4	12	7	5	5
Corporate		10	5	5	3	11	9	2	-
		$ 479	$ 426	$ 361	$ 426	$ 435	$ 414	$ 273	$ 351

Five-Year Financial and Operating Information

SEGMENTED FINANCIAL INFORMATION

($ millions)	Upstream					Midstream									
						Upgrading					Infrastructure and Marketing				
	2002	2001	2000	1999	1998	2002	2001	2000	1999	1998	2002	2001	2000	1999	1998
Year ended December 31															
Sales and operating revenues, net of royalties	$ 2,665	$ 2,165	$ 1,549	$ 595	$ 440	$ 909	$ 886	$ 1,006	$ 641	$ 412	$ 4,230	$ 4,380	$ 2,309	$ 1,284	$ 999
Costs and expenses															
Operating, cost of sales, selling and general	729	648	375	214	200	811	638	848	581	346	4,038	4,193	2,193	1,190	909
Depletion, depreciation and amortization	851	728	407	223	214	18	17	16	16	14	20	17	15	13	12
Interest - net	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Foreign exchange	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1,580	1,376	782	437	414	829	655	864	597	360	4,058	4,210	2,208	1,203	921
Earnings (loss) before income taxes	1,085	789	767	158	26	80	231	142	44	52	172	170	101	81	78
Current income taxes	55	17	10	3	3	1	1	1	1	1	6	1	-	-	-
Future income taxes	342	290	305	50	20	25	72	53	21	22	59	71	45	36	35
Net earnings (loss)	$ 688	$ 482	$ 452	$ 105	$ 3	$ 54	$ 158	$ 88	$ 22	$ 29	$ 107	$ 98	$ 56	$ 45	$ 43
Capital employed - as at December 31 [2]	$ 6,040	$ 5,715	$ 5,398	$ 2,077	$ 1,653	$ 319	$ 320	$ 352	$ 392	$ 418	$ 431	$ 395	$ 312	$ 353	$ 319
Total assets - as at December 31	$ 8,220	$ 7,407	$ 6,735	$ 2,839	$ 2,375	$ 658	$ 644	$ 613	$ 606	$ 605	$ 850	$ 862	$ 1,000	$ 652	$ 441

[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.*

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

SEGMENTED FINANCIAL INFORMATION

($ millions)		2002	2001	2000	1999	1998
Capital expenditures						
Upstream	- Western Canada	**$ 1,034**	$ 1,022	$ 419	$ 238	$ 233
	- East Coast Canada	**458**	191	194	309	191
	- International	**75**	104	87	23	15
		1,567	1,317	700	570	439
Midstream	- Upgrader	**41**	47	12	15	283
	- Infrastructure and marketing	**17**	58	47	79	68
		58	105	59	94	351
Refined products		**44**	29	29	34	27
Corporate		**23**	22	15	8	12
		$ 1,692	$ 1,473	$ 803	$ 706	$ 829

SEGMENTED FINANCIAL INFORMATION (CONTINUED)

($ millions)	Refined Products					Corporate and Eliminations [1]					Total				
	2002	2001	2000	1999	1998	2002	2001	2000	1999	1998	2002	2001	2000	1999	1998
Year ended December 31															
Sales and operating revenues, net of royalties	**$ 1,310**	$ 1,349	$ 1,347	$ 904	$ 664	**$ (2,730)**	$ (2,184)	$ (1,145)	$ (637)	$ (492)	**$ 6,384**	$ 6,596	$ 5,066	$ 2,787	$ 2,023
Costs and expenses															
Operating, cost of sales, selling and general	**1,222**	1,206	1,288	842	591	**(2,696)**	(2,165)	(1,060)	(514)	(437)	**4,104**	4,520	3,644	2,313	1,609
Depletion, depreciation and amortization	**34**	31	28	26	20	**16**	14	15	15	13	**939**	807	481	293	273
Interest - net	**-**	-	-	-	-	**104**	101	101	62	70	**104**	101	101	62	70
Foreign exchange	**-**	-	-	-	-	**13**	94	39	(55)	63	**13**	94	39	(55)	63
	1,256	1,237	1,316	868	611	**(2,563)**	(1,956)	(905)	(492)	(291)	**5,160**	5,522	4,265	2,613	2,015
Earnings (loss) before income taxes	**54**	112	31	36	53	**(167)**	(228)	(240)	(145)	(201)	**1,224**	1,074	801	174	8
Current income taxes	**4**	1	1	1	1	**-**	-	-	-	-	**66**	20	12	5	5
Future income taxes	**18**	48	14	16	23	**(90)**	(81)	(66)	(50)	(92)	**354**	400	351	73	8
Net earnings (loss)	**$ 32**	$ 63	$ 16	$ 19	$ 29	**$ (77)**	$ (147)	$ (174)	$ (95)	$ (109)	**$ 804**	$ 654	$ 438	$ 96	$ (5)
Capital employed - as at December 31 [2]	**$ 338**	$ 329	$ 351	$ 366	$ 381	**$ 384**	$ (81)	$ (50)	$ 158	$ 134	**$ 7,512**	$ 6,678	$ 6,363	$ 3,346	$ 2,905
Total assets - as at December 31	**$ 534**	$ 428	$ 487	$ 476	$ 421	**$ 313**	$ 29	$ (6)	$ 203	$ 233	**$10,575**	$ 9,370	$ 8,829	$ 4,776	$ 4,075

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION

UPSTREAM OPERATING INFORMATION

	2002	2001	2000	1999	1998
Daily production, before royalties					
Light/medium crude oil & NGL *(mbbls/day)*	**125.9**	112.0	63.6	26.5	27.6
Lloydminster heavy crude oil *(mbbls/day)*	**79.4**	65.4	53.5	42.1	42.0
	205.3	177.4	117.1	68.6	69.6
Natural gas *(mmcf/day)*	**569.2**	572.6	358.0	250.5	232.6
Total production *(mboe/day)*	**300.2**	272.8	176.8	110.4	108.4
Average realized sales prices					
Light/medium crude oil & NGL *($/bbl)*	**$ 33.28**	$ 27.19	$ 33.42	$ 21.52	$ 16.07
Lloydminster heavy crude oil *($/bbl)*	**$ 26.09**	$ 15.85	$ 21.26	$ 16.00	$ 8.26
Natural gas *($/mcf)*	**$ 3.83**	$ 5.47	$ 5.16	$ 2.41	$ 2.17
Operating costs *($/boe)*	**$ 6.24**	$ 6.08	$ 5.27	$ 4.80	$ 4.53
Operating netbacks [1]					
Light/medium crude oil & NGL *($/boe)*	**$ 21.20**	$ 15.08	$ 20.61	$ 13.71	$ 9.78
Lloydminster heavy crude oil *($/boe)*	**$ 16.02**	$ 7.13	$ 12.11	$ 7.75	$ 1.61
Natural gas *($/mcfge)*	**$ 2.44**	$ 3.51	$ 3.59	$ 1.54	$ 1.46

[1] Operating netbacks are Husky's average realized prices less royalties, hedging (gains)/losses and operating costs on a per unit basis.

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

UPSTREAM OPERATING INFORMATION (CONTINUED)

		2002		2001		2000		1999		1998	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled [1]											
Exploration	Oil	**21**	**20**	78	76	16	13	9	9	16	11
	Gas	**139**	**131**	102	90	30	20	13	5	9	7
	Dry	**15**	**14**	36	34	9	9	9	9	8	6
		175	**165**	216	200	55	42	31	23	33	24
Development	Oil	**497**	**453**	594	542	411	363	203	190	75	55
	Gas	**485**	**453**	251	221	92	70	42	23	22	7
	Dry	**58**	**55**	68	63	30	28	23	22	6	4
		1,040	**961**	913	826	533	461	268	235	103	66
		1,215	**1,126**	1,129	1,026	588	503	299	258	136	90
Success ratio *(percent)*		**94**	**94**	91	91	93	93	89	88	90	89

[1] *Western Canada.*

UNDEVELOPED LAND HOLDINGS

(thousands of acres - net)	2002	2001	2000	1999	1998
Western Canada					
Alberta	**4,907**	5,373	5,616	692	877
Saskatchewan	**1,986**	1,921	2,639	586	662
British Columbia	**273**	141	173	66	133
Manitoba	**13**	75	162	-	-
	7,179	7,510	8,590	1,344	1,672
Northwest Territories and Arctic	**175**	409	409	417	474
Eastern Canada	**2,104**	1,471	1,489	258	243
Total Canada	**9,458**	9,390	10,488	2,019	2,389
International	**2,066**	697	221	389	392
Total	**11,524**	10,087	10,709	2,408	2,781

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION

Selected Eleven-Year Financial and Operating Summary

($ millions, except where indicated)	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Sales and operating revenues, net of royalties	**$ 6,384**	$ 6,596	$ 5,066	$ 2,787	$ 2,023	$ 2,282	$ 2,104	$ 1,783	$ 1,373	$ 1,138	$ 977
Net earnings (loss)	**$ 804**	$ 654	$ 438	$ 96	$ (5)	$ 55	$ 49	$ 20	$ (40)	$ (249)	$ (395)
Net earnings per share											
Basic	**$ 1.88**	$ 1.49	$ 1.28	$ 0.34	$ (0.04)	$ 0.20	$ 0.18	$ 0.08	$ (0.15)	$ (0.92)	$ (1.46)
Diluted	**$ 1.88**	$ 1.48	$ 1.28	$ 0.34	$ (0.04)	$ 0.20	$ 0.18	$ 0.08	$ (0.15)	$ (0.92)	$ (1.46)
Cash flow from operations	**$ 2,096**	$ 1,946	$ 1,399	$ 517	$ 449	$ 453	$ 378	$ 303	$ 242	$ 171	$ 183
Cash flow from operations per share											
Basic	**$ 4.94**	$ 4.60	$ 4.26	$ 1.80	$ 1.61	$ 1.68	$ 1.40	$ 1.12	$ 0.90	$ 0.63	$ 0.68
Diluted	**$ 4.92**	$ 4.57	$ 4.26	$ 1.80	$ 1.61	$ 1.68	$ 1.40	$ 1.12	$ 0.90	$ 0.63	$ 0.68
Capital expenditures [1]	**$ 1,692**	$ 1,473	$ 803	$ 706	$ 829	$ 601	$ 218	$ 155	$ 257	$ 315	$ 312
Total debt	**$ 2,385**	$ 2,192	$ 2,378	$ 1,382	$ 1,131	$ 1,014	$ 853	$ 1,474	$ 1,667	$ 1,570	$ 1,570
Debt to capital employed *(percent)*	**32**	33	37	41	39	43	42	63	69	67	62
Debt to cash flow from operations *(times)*	**1.1**	1.1	1.7	2.7	2.5	2.2	2.3	4.9	6.9	9.2	8.6
Reinvestment ratio [3] *(percent)*	**76**	78	57	134	199	132	46	44	62	117	118
Return on average capital employed [2] *(percent)*	**12.2**	10.9	12.4	6.9	4.2	7.2	6.7	5.5	1.2	(8.5)	(12.8)
Return on equity [4] *(percent)*	**16.7**	15.4	19.4	11.4	6.7	12.1	11.7	14.1	(3.0)	(28.3)	(31.0)
Upstream											
Daily production, before royalties											
Light/medium crude oil & NGL *(mbbls/day)*	**125.9**	112.0	63.6	26.5	27.6	27.6	28.3	27.7	29.4	29.9	28.9
Lloydminster heavy crude oil *(mbbls/day)*	**79.4**	65.4	53.5	42.1	42.0	41.9	34.5	30.0	26.6	21.9	18.4
	205.3	177.4	117.1	68.6	69.6	69.5	62.8	57.7	56.0	51.8	47.3
Natural gas *(mmcf/day)*	**569**	573	358	251	233	246	268	286	248	246	252
Total production *(mboe/day)*	**300.2**	272.8	176.8	110.4	108.4	110.6	107.5	105.4	97.4	92.8	89.3
Total proved reserves, before royalties *(mmboe)*	**918**	927	872	430	431	421	432	416	401	408	472
Midstream											
Synthetic crude oil sales *(mbbls/day)*	**59.3**	59.5	60.6	61.9	54.8	27.5	26.8	26.6	18.8	11.3	0.6
Upgrading differential *($/bbl)*	**$ 10.81**	$ 17.91	$ 13.77	$ 6.49	$ 7.85	$ 8.54	$ 5.94	$ 4.34	$ 4.18	$ 5.50	$ 5.22
Pipeline throughput *(mbbls/day)*	**457**	537	528	394	412	417	359	296	238	217	169
Refined products											
Light oil sales *(million litres/day)*	**7.7**	7.6	7.4	7.6	6.0	4.5	4.2	3.9	3.2	2.9	2.5
Asphalt product sales *(mbbls/day)*	**20.8**	21.4	20.2	17.1	19.5	17.7	15.1	13.5	13.1	10.8	9.9
Refinery throughput											
Lloydminster refinery *(mbbls/day)*	**22.0**	23.7	23.4	17.9	21.9	21.5	18.4	15.6	16.4	13.2	10.9
Prince George refinery *(mbbls/day)*	**10.1**	10.2	9.2	10.2	9.9	10.3	10.0	9.9	9.7	9.7	8.7
Refinery utilization *(percent)*	**92**	97	93	80	91	91	81	73	75	65	56

[1] *Excludes corporate acquisitions.*
[2] *Capital employed for purposes of this calculation has been weighted for 2000.*
[3] *Reinvestment ratio is based on net capital expenditures including corporate acquisitions (other than Renaissance Energy Ltd.).*
[4] *Equity for purposes of this calculation has been weighted for 2000 and includes amounts due to shareholders prior to August 25, 2000.*

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

CORPORATE INFORMATION

Officers/Executives Husky Energy Inc.

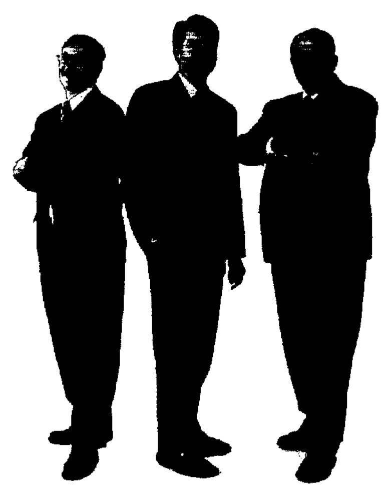
Donald R. Ingram
Senior Vice President, Midstream & Refined Products

James D. Girgulis
Vice President, Legal & Corporate Secretary

Neil D. McGee
Vice President & Chief Financial Officer

John C.S. Lau
President & CEO

David R. Taylor
Vice President, Exploration



Robert S. Coward
Vice President, Western Canada Production

Walter DeBoni
Vice President, Canada Frontier & International Business

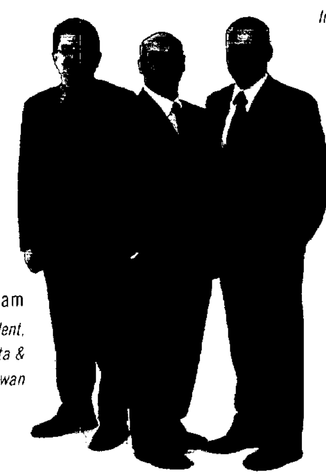
Officers/Executives Husky Oil Operations Limited

K. Wendell Carroll
Vice President, Corporate Administration

J. Michael D'Aguiar
Treasurer

L. Geoffrey Barlow
Controller

Richard M. Alexander
Vice President, Investor Relations & Communications



J. Thomas Graham
Vice President, East Central Alberta & Southern Saskatchewan

Larry R. Bell
Vice President, Exploration & Production Services

Roy C. Warnock
Vice President, Upgrading & Refining

BOARD OF DIRECTORS

Victor T.K. Li
Co-Chairman

Victor T.K. Li, a resident of Hong Kong, has been a co-chairman of the board and a director of Husky Energy Inc. since 2000. Mr. Li is managing director and deputy chairman of Cheung Kong (Holdings) Limited. He is deputy chairman and executive director of Hutchison Whampoa Limited, chairman of Cheung Kong Infrastructure Holdings Limited, and of CK Life Sciences Int'l., (Holdings) Inc. Mr. Li is an executive director of Hongkong Electric Holdings Limited and a director of The Hongkong and Shanghai Banking Corporation Limited.

Canning K.N. Fok
Co-Chairman

Canning K.N. Fok [(2)], a resident of Hong Kong, has been a co-chairman of the board and a director of Husky Energy Inc. since 2000. Mr. Fok is group managing director and executive director of Hutchison Whampoa Limited. He is chairman of Hutchison Telecommunications (Australia) Limited, Hutchison Harbour Ring Limited and Partner Communications Company Ltd. Mr. Fok is the deputy chairman of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited and a director of Cheung Kong (Holdings) Limited and Hutchison Whampoa Finance (CI) Limited.

Martin J.G. Glynn

Martin J.G. Glynn [(1)], a resident of Vancouver, has been a director of Husky Energy Inc. since 2000. Mr. Glynn is the president, chief executive officer and a director of HSBC Bank Canada. He is a director and chief operating officer of HSBC North America Inc., a director of HSBC Bank USA, and chairman and a director of HSBC Canadian Direct Insurance Incorporated. Mr. Glynn is a director of Wells Fargo HSBC Trade Bank N.A. in the United States.

Ronald G. Greene

Ronald G. Greene [(2)], a resident of Calgary, has been a director of Husky Energy Inc. since 2000. He is president and chief executive officer of Tortuga Investment Corp., chairman of Denbury Resources Inc. and a director of WestJet Airlines Ltd. Mr. Greene was the founder and chairman of Renaissance Energy Ltd. until its merger with Husky Energy Inc. in 2000. [(5)]

Terence C.Y. Hui

Terence C.Y. Hui [(1)], a resident of Vancouver, has been a director of Husky Energy Inc. since 2000. Mr. Hui is the president & chief executive officer of Concord Pacific Group Inc. He is the president of Adex Securities Inc. and chairman of Maximizer Software Inc.

Brent D. Kinney

Brent D. Kinney [(3)], a resident of Dubai, United Arab Emirates, has been a director of Husky Energy Inc. since 2000. Mr. Kinney is an independent businessman and a director of Dragon Oil plc in the United Arab Emirates.

Holger Kluge

Holger Kluge [(2) (3) (4)], a resident of Toronto, has been a director of Husky Energy Inc. since 2000. Mr. Kluge is a director of Hongkong Electric Holdings Limited, Hutchison Telecommunications (Australia) Limited, TOM.COM LIMITED and Assante Corp.

Poh Chan Koh

Poh Chan Koh, a resident of Hong Kong, has been a director of Husky Energy Inc. since 2000. Miss Koh is the finance director of Harbour Plaza Hotel Management (International) Ltd.

Eva L. Kwok	Eva L. Kwok [2][4], a resident of Vancouver, has been a director of Husky Energy Inc. since 2000. Mrs. Kwok is a director, chairman and chief executive officer of Amara International Investment Corp. She is a director of Air Canada, Bank of Montreal Group of Companies, Telesystem International Wireless Inc. and CK Life Sciences Int'l., (Holdings) Inc.
Stanley T.L. Kwok	Stanley T.L. Kwok [3], a resident of Vancouver, has been a director of Husky Energy Inc. since 2000. Mr. Kwok is the president of Stanley Kwok Consultants. Mr. Kwok is a director of Amara International Investment Corp., Cheung Kong (Holdings) Limited and CTC Bank of Canada.
John C.S. Lau *President & CEO*	John C.S. Lau, a resident of Calgary, has been a director of Husky Energy Inc. since 2000. Mr. Lau is the president & chief executive officer of Husky Energy Inc.
Wilmot L. Matthews	Wilmot L. Matthews [1][4], a resident of Toronto, has been a director of Husky Energy Inc. since 2000. Mr. Matthews has been involved in all aspects of investment banking by serving in various positions with Nesbitt Burns Inc. and its predecessor companies, most recently as vice chairman and director. Mr. Matthews is currently president of Marjad Inc., chairman and chief executive officer of Helptrain Inc. and a director of WestJet Airlines Ltd. [5]
Wayne E. Shaw	Wayne E. Shaw [1], a resident of Toronto, has been a director of Husky Energy Inc. since 2000. Mr. Shaw is a Barrister and Solicitor at Stikeman Elliott LLP.
William Shurniak *Deputy Chairman*	William Shurniak, a resident of Australia, has been deputy chairman and a director of Husky Energy Inc. since 2000. Mr. Shurniak is a director and chairman of ETSA Utilities, Powercor Australia Limited and CitiPower Pty Ltd. He is a director of Envestra Limited and Downer Edi Ltd. Mr. Shurniak is also a director of Hutchison Whampoa Limited.
Frank J. Sixt	Frank J. Sixt [2], a resident of Hong Kong, has been a director of Husky Energy Inc. since 2000. Mr. Sixt is group finance director and executive director of Hutchison Whampoa Limited. He is the chairman of TOM.COM LIMITED. Mr. Sixt is an executive director of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited, and a director of Cheung Kong (Holdings) Limited, Hutchison Whampoa Finance (CI) Limited, Hutchison Telecommunications (Australia) Limited and Partner Communications Company Ltd.

(1) *Audit Committee*

(2) *Compensation Committee*

(3) *Health, Safety & Environment Committee*

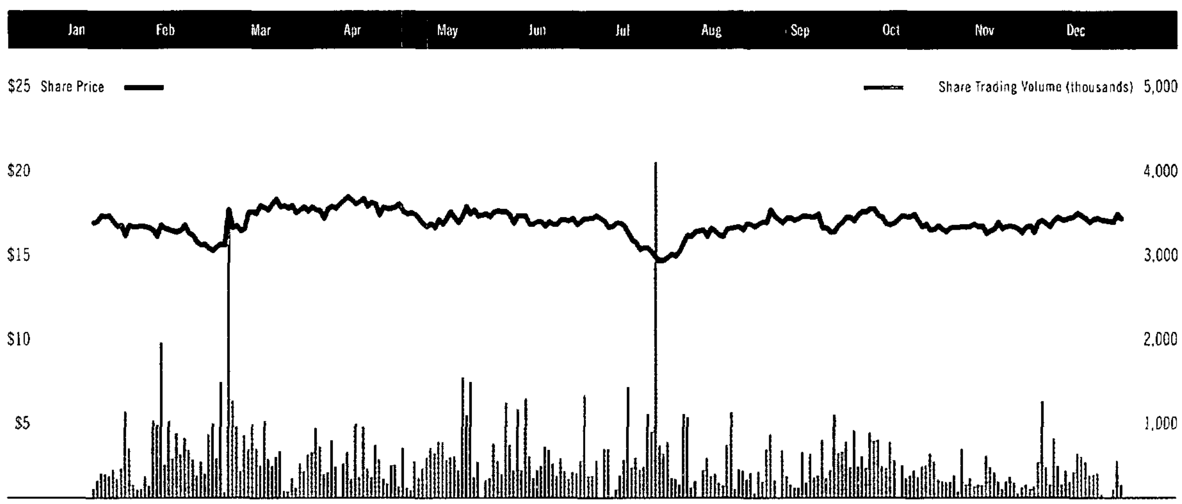
(4) *Corporate Governance Committee*

(5) *Will not be standing for re-election at the annual meeting on April 30, 2003.*

COMMON SHARE INFORMATION

Year ended December 31		2002	2001	2000
Share price	High	$ 17.98	$ 20.95	$ 15.95
	Low	$ 14.00	$ 13.10	$ 11.50
	Close at December 31	$ 16.47	$ 16.47	$ 14.90
Average daily trading volumes *(thousands)*		463	625	979
Number of common shares outstanding, December 31 *(thousands)*		417,874	416,878	415,803
Number of weighted average common shares outstanding *(thousands)*				
	Basic	417,425	416,100	415,803
	Diluted	419,334	418,640	416,753

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.



Terms and Abbreviations

bbls	barrels
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
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, retained earnings and amounts due to shareholders prior to August 25, 2000
Total Debt	Long-term debt including current portion and bank operating loans

Natural gas converted on the basis that six mcf of natural gas 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.

INVESTOR INFORMATION

Stock Exchange Listing
The Toronto Stock Exchange: HSE

Outstanding Shares
The number of common shares outstanding (in thousands) at December 31, 2002 was 417,874.

Transfer Agent and Registrar
Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company, Inc. Share certificates may be transferred at Computershare's principal offices in Calgary, Toronto, Montreal and Vancouver, and at Computershare's principal office in Denver, Colorado in the United States.

Queries regarding share certificates, dividends and estate transfers should be directed to Computershare Trust Company at 1-888-267-6555 (toll free in North America).

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Terra Nova website: www.terranovaproject.com
Wenchang website: www.huskywenchang.com
White Rose website: www.huskywhiterose.com

Auditors
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1200, 205 - 5 Avenue S.W.
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Dividends
Husky's Board of Directors has approved a dividend policy that pays quarterly dividends. Since August 2000, the Corporation has paid quarterly dividends of $0.09 ($0.36 annually) per common share. This policy will be reviewed by the Board from time to time.

Annual Meeting
The annual meeting of shareholders will be held at 10:30 a.m. on April 30, 2003 in the Crystal Ballroom at the Fairmont Palliser Hotel, 133 - 9 Avenue S.W., Calgary, Alberta.

Additional Publications
The following publications are made available on our website or from our Investor Relations department:

- Annual Information Form, filed with the Canadian securities regulators
- Form 40-F, filed with the U.S. Securities and Exchange Commission
- Quarterly Reports

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