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

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER

04020322

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

P.G. 3/1/04

For the month of March 2004

Commission File Number: 1-04307

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)

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-_______.

Doc #:NY6:699442.1

On March 18, 2004, Husky Energy Inc. filed, and mailed to its stockholders, its annual report for the fiscal year ended December 31, 2003. The annual report is attached hereto as Exhibit A.

SIGNATURES

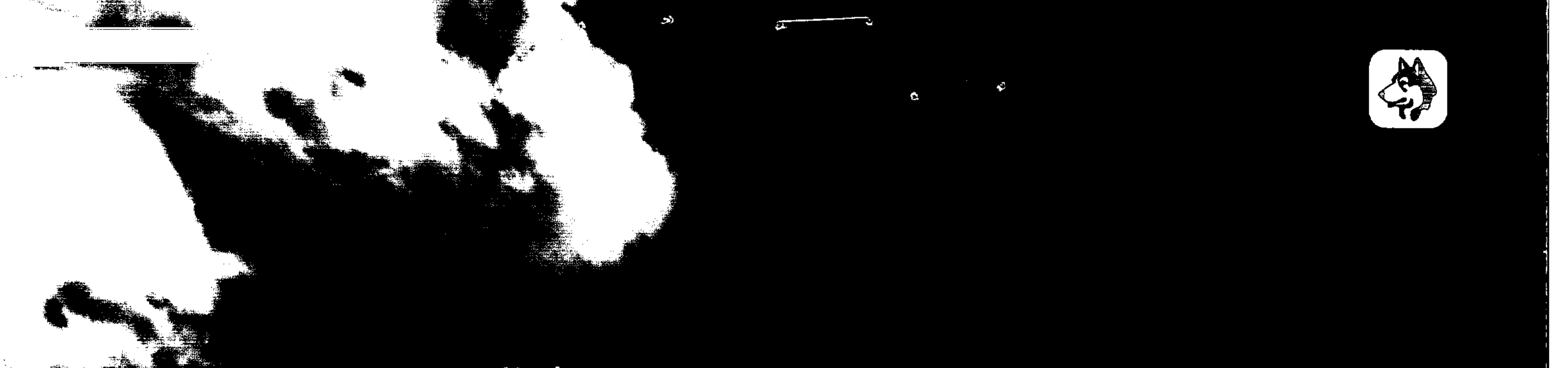
Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HUSKY ENERGY INC.

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

Date: March 18, 2004

EXHIBIT A



Husky Energy Inc. Annual Report 2003

Expanding the Horizon

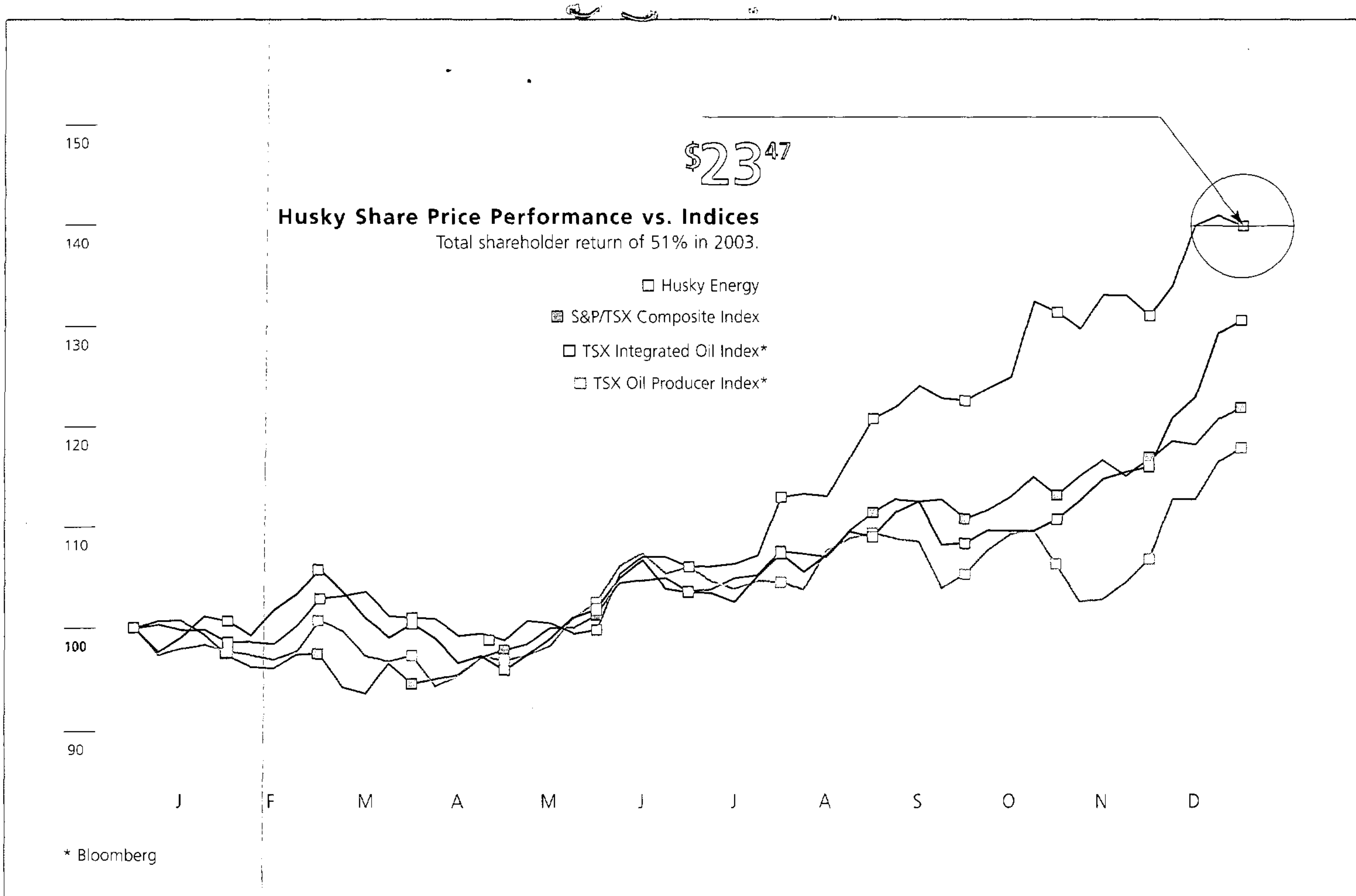


TABLE OF CONTENTS

Husky at a Glance

2 Financial & Operating Highlights

3 Report to Our Shareholders

6 Questions & Answers

10 Report on Operations

26 Health, Safety & Environment

28 Husky and the Community

30 Corporate Governance

32 Management's Discussion and Analysis

68 Management's Report

68 Auditors' Report to the Shareholders

69 Consolidated Financial Statements

72 Notes to the Consolidated Financial Statements

100 Supplemental Financial and Operating Information

114 Corporate Information

118 Investor Information

Inside Back Cover

Glossary of Terms and Abbreviations

Mission To maximize returns to our shareholders in a socially responsible manner.

Vision To create superior shareholder value through financial discipline and a quality asset base.

Profile Husky Energy is a Canadian-based integrated energy and energy-related company. Our operations consist of three business segments: upstream, midstream and refined products.

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

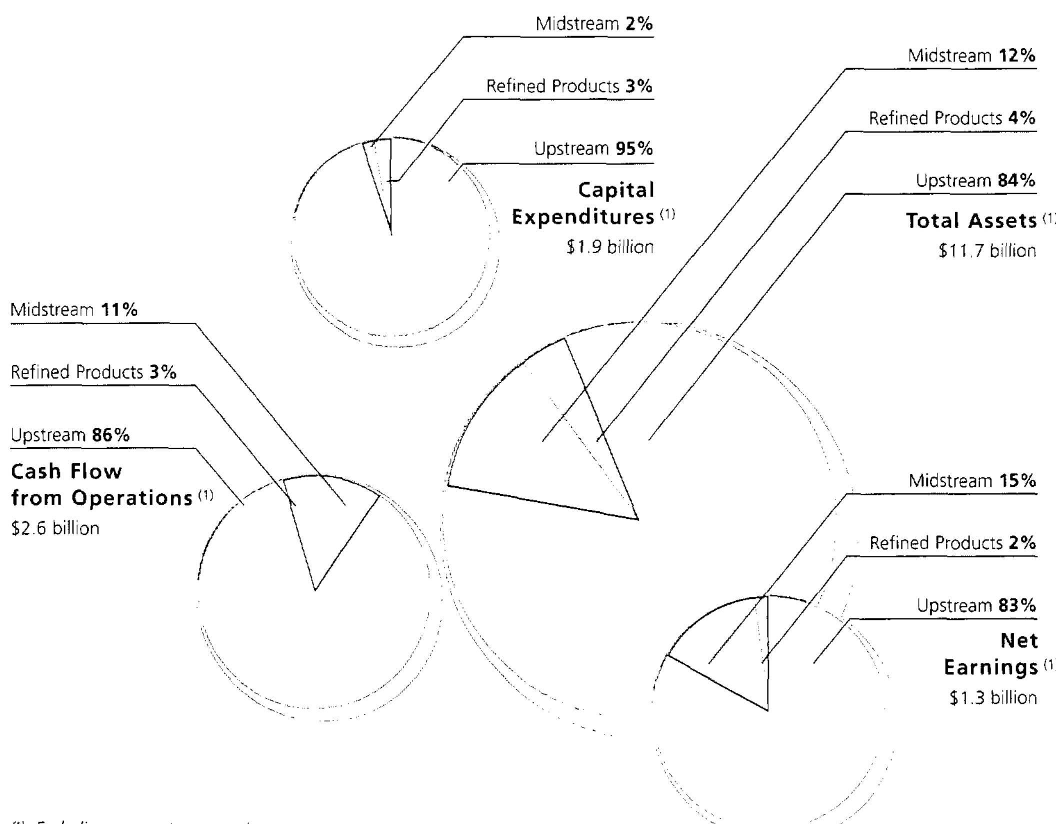
Midstream includes the upgrading of heavy crude oil into premium quality synthetic crude oil, pipeline transportation, gas storage, cogeneration, and commodities marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.

Refined products includes the refining, marketing and distribution of gasoline, diesel, asphalt, ethanol, and ancillary services in Canada and the United States. Refined products also manages a network of over 550 retail outlets from Ontario to British Columbia and the Yukon.

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

Annual Report to the Shareholders

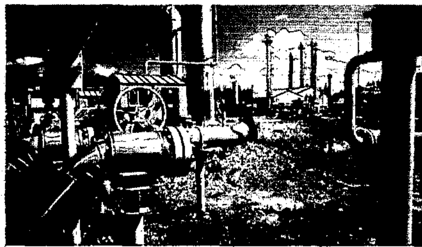
2003 Performance

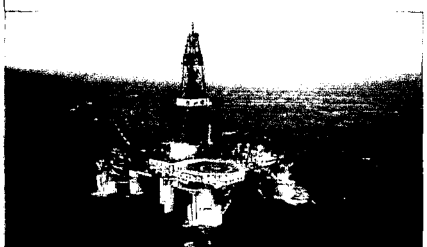


(1) *Excluding corporate segment.*

2003 Plans	2003 Achievements	2004 Plans
• Drill and tie-in 300 shallow gas wells in northwestern Alberta and drill 100 gas wells and expand facilities at Shackleton	• 111 percent of production replaced, average daily production of 273,000 boe/day. Marathon acquisition added 39.8 mmboe of proved reserves	• Maintain 2003 drilling program and achieve production replacement ratio greater than 100 percent
• Increase thermal and heavy oil production from Bolney/Celtic operations	• Increased Bolney/Celtic by 5,000 bbls/day, total heavy oil reached 107,800 bbls/day in the fourth quarter	• Continue expanded heavy oil program by drilling 400 to 500 wells
• Drill 60 exploratory wells	• Drilled over 60 net exploratory wells	• Continue natural gas exploration program and expand oil exploration into the NWT
• Submit commercial application for Tucker	• Commercial application submitted, front-end engineering and design work completed	• Obtain regulatory approval for Tucker project and initiate development
• Continue delineation of Sunrise and commence environmental impact assessment	• Drilled 212 core wells and initiated the environmental impact assessment	• Initiate regulatory approval process for the proposed Sunrise in-situ project
• Continue development drilling in Terra Nova and increase production	• Husky's share of production averaged 16,800 bbls/day with a netback of $32.99/bbl	• Increase production to 17,500 bbls/day
• Continue construction of White Rose production facilities and commence development drilling	• FPSO on schedule and development drilling initiated. Two successful delineation wells drilled	• Install topsides and continue development drilling
• Evaluate exploration leads on the Grand Banks for future drilling	• Identified drillable prospect in South Whale Basin	• Drill one exploration well in South Whale Basin
• Drill two exploration wells in the Wenchang 39/05 block	• Drilled two unsuccessful exploration wells	• Optimize Wenchang production with new development wells
• Proceed with exploration assessment of prospects and leads on new blocks	• Acquired a new exploration block in the East China Sea	• Drill at least two exploratory wells offshore China
	• New Madura gas sales contract under discussion	• Continue negotiations to complete new gas sales contract
• Increase upgrader capacity to 82,000 bbls/day by end of 2004	• Upgrader average annual synthetic crude oil sales record of 63.6 mbbls/day	• Continue with debottlenecking projects and improve operating efficiencies
• Focus on pipeline optimization in the short-term and expansion for the long-term	• Swapped 25 percent in Cactus Lake Pipeline for 100 percent in Edam Pipeline	• Exploit strategic position of assets in the heavy oil/bitumen corridor
• Expand marketing activities in the bitumen/heavy oil corridor	• Commodity marketing volumes exceeded 850,000 boe/day	• Expand marketing volumes to over 900,000 boe/day
• Increase throughput per outlet	• Increased throughput per outlet by 8.1 percent	• Increase throughput volumes per outlet
• Evaluate whether to upgrade refinery to meet new environmental regulations	• New average annual throughput record of 10.3 mbbls/day	• Finalize decision on meeting new environmental regulations
• Expand asphalt business by entering into new markets	• Set a new average annual throughput record of 25.7 mbbls/day	• Encourage adoption of higher asphalt specifications to increase sales
• Provide "E85" (ethanol-blended) fuel to fleet operations across Western Canada	• Established five refuelling sites for E85 ethanol blended fuel	• Initiate construction of a 130-million litre per year ethanol plant adjacent to upgrader

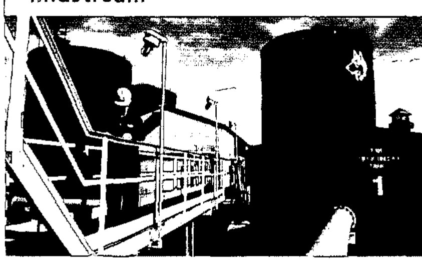
Upstream





Business Description	Strategic Focus
WESTERN CANADA	
• Development and production of crude oil and natural gas	• Increase oil and gas production through exploitation and exploration
• Development of heavy oil holdings	• Optimize and expand Lloydminster heavy oil operations
• Exploration for natural gas	• Focus on natural gas exploration in the deeper portion of the Basin
• Appraisal and development of our Cold Lake and Athabasca oil sands holdings in northern Alberta	• Develop bitumen resources commencing with Tucker and Sunrise (formerly Kearl)
CANADIAN EAST COAST	
• 12.51 percent interest in Terra Nova oil field	• Participate in continuing development of light oil production from Terra Nova
• 72.5 percent interest in and operator of White Rose oil field	• Achieve first production by late 2005/early 2006
• 2.1 million exploration acres and holder of 12 Significant Discovery Areas	• Explore satellite opportunities and development of area gas reserves
INTERNATIONAL	
• 40 percent interest in Wenchang 13-1 and 13-2 producing oil fields in the South China Sea	• Pursue development opportunities near Wenchang
• 100 percent interest in five exploration blocks in the South and East China Seas	• Increase resource base through exploration drilling
• 31.4 percent working interest in the Madura Block offshore Indonesia	• Increase production from international business to over 10 percent of total

Midstream



Business Description	Strategic Focus
• Upgrading of heavy oil into premium synthetic crude oil	• Increase upgrader capacity to meet future heavy oil and bitumen production volumes
• A 2,050-kilometre crude oil pipeline system	• Increase and optimize crude oil pipeline capacity
• Marketing of crude oil, natural gas and natural gas liquids, sulphur and coke	• Profitably grow the commodity marketing business

Refined Products

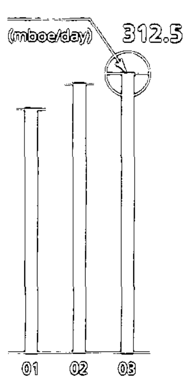
Business Description	Strategic Focus
• A retail network of over 550 outlets	• Enhance outlets with automation, upgrades, ancillary sales and alliances
• A 10,000-barrel per day light oil refinery at Prince George, BC	• Optimize product supply agreements
• A 25,000-barrel per day asphalt refinery at Lloydminster, Alberta	• Grow asphalt sales through higher margin premium quality products
• A 10-million litre per year ethanol plant in Minnedosa, Manitoba	• Expand the use of ethanol in gasoline and diesel fuels

Year ended December 31 (millions of dollars except where indicated)		2003	2002	2001
Financial Highlights				
Sales and operating revenues, net of royalties		**7,658**	6,384	6,596
Cash flow from operations		**2,459**	2,096	1,946
Per share *(dollars)* – Basic		**5.79**	4.94	4.60
– Diluted		**5.76**	4.92	4.57
Net earnings		**1,321**	804	654
Per share *(dollars)* – Basic		**3.23**	1.88	1.49
– Diluted		**3.22**	1.88	1.48
Capital expenditures [1]		**1,905**	1,692	1,473
Return on average capital employed	*(percent)*	**18.0**	12.2	10.9
Return on equity	*(percent)*	**24.0**	16.7	15.4
Debt to capital employed	*(percent)*	**23.1**	31.8	32.8
Debt to cash flow from operations	*(times)*	**0.7**	1.1	1.1

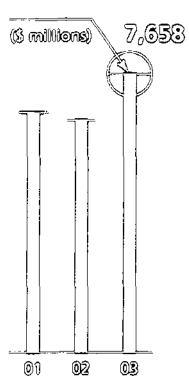
Operating Highlights				
Daily production, before royalties				
Light crude oil & NGL	*(mbbls/day)*	**71.6**	65.4	46.4
Medium crude oil	*(mbbls/day)*	**39.2**	44.8	47.2
Heavy crude oil	*(mbbls/day)*	**99.9**	95.1	83.8
Total crude oil & NGL	*(mbbls/day)*	**210.7**	205.3	177.4
Natural gas	*(mmcf/day)*	**610.6**	569.2	572.6
Barrels of oil equivalent	*(mboe/day)*	**312.5**	300.2	272.8
Proved reserves, before royalties				
Light crude oil & NGL	*(mmbbls)*	**223**	235	240
Medium crude oil	*(mmbbls)*	**94**	107	127
Heavy crude oil	*(mmbbls)*	**227**	227	232
Natural gas	*(bcf)*	**2,059**	2,095	1,966
Barrels of oil equivalent	*(mmboe)*	**887**	918	927
Synthetic crude oil sales	*(mbbls/day)*	**63.6**	59.3	59.5
Pipeline throughput	*(mbbls/day)*	**484**	457	537
Light oil products sales	*(million litres/day)*	**8.2**	7.7	7.6
Asphalt products sales	*(mbbls/day)*	**22.0**	20.8	21.4
Refinery throughput	*(mbbls/day)*	**36.0**	32.1	33.9

[1] *Excludes corporate acquisitions.*

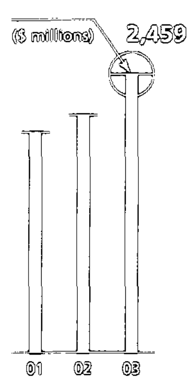
Daily Production, before Royalties



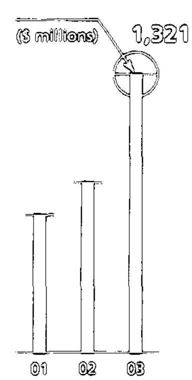
Revenue



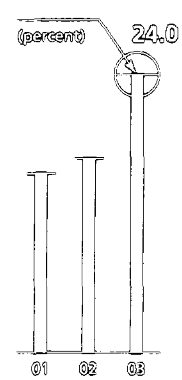
Cash Flow from Operations



Net Earnings

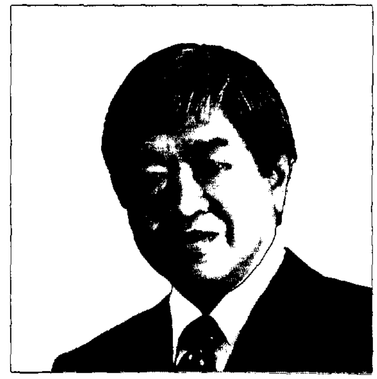


Return on Equity



Husky Energy delivers superior returns by building on our existing asset base. Our upstream strategy is focused on exploiting our portfolio of core assets and major development projects. These provide growth visibility in the near-, medium- and long-term horizon.

Our substantial midstream and refined products assets add value to the production chain and minimize the earning volatility arising from the commodity price cycle. At the same time we continue to evaluate alternatives to enhance shareholder value.



Mr. Victor T. K. Li (top left)
Co-Chairman

Mr. Canning K. N. Fok (top right)
Co-Chairman

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

Husky Energy Report to Our Shareholders

Expanding the Horizon

We are pleased to report that 2003 has been another excellent year for Husky Energy. Several factors contributed to our impressive 2003 financial results including strong commodity prices and increased oil and gas production.

The year was notable for the continued strength of oil and gas prices partly offset by the decline in the value of the U.S. dollar. Together with continued low interest rates this created a very favourable economic environment. We were able to capitalize on this through the acquisition of Marathon Canada and the payment of a special dividend to shareholders on October 1. Notwithstanding these transactions, net debt fell to $1.8 billion at year-end compared with $2.1 billion at the end of 2002.

Net earnings in 2003 were $1.32 billion or $3.22 per share (diluted), a 64 percent increase over 2002. Cash flow from operations was $2.5 billion, a 17 percent increase over 2002. Annual production was 312,500 barrels of oil equivalent (boe) per day, an increase of four percent from the previous year. Return on equity of 24 percent was up from 16.7 percent in 2002.

2003 was an extremely active year for Husky. We made excellent progress on several fronts and established the foundation for future growth.

- In February, Husky submitted a project application to provincial regulators for development of Tucker, a 30,000-barrel per day, steam-assisted gravity drainage (SAGD) in-situ bitumen project, near Cold Lake, Alberta. We are anticipating project approval in the first half of 2004.

- On October 1, Husky completed the acquisition of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. ("Marathon Canada") for $831 million. In a separate transaction, Husky sold certain of the Marathon Canada oil and gas properties to a third party for $431 million. The acquisition added 19,500 boe to Husky's daily production and was recognized by Oil and Gas Investor magazine as the M&A Deal of the Year.
- In November, Husky signed a petroleum contract with the China National Offshore Oil Corporation for the 04/35 exploration block in the East China Sea. This block is located in a gas-prone area near the Pinghu gas field, which is serviced by a pipeline to Shanghai.
- We initiated the engineering and design work for our Sunrise in-situ oil sands project in northern Alberta. This project has the potential to produce up to 200,000 barrels per day. We expect to issue a public disclosure document in the first quarter of 2004, which will be followed by a project application to provincial authorities later in the year.
- Our White Rose project achieved several major milestones during 2003:
  - The hull of the Floating Production Storage and Offloading (FPSO) vessel was launched in South Korea. It is expected to arrive in Marystown, Newfoundland and Labrador in April 2004.
  - We completed the three required glory holes: nine-metre excavations in the ocean floor used to shield wells and sub-sea production equipment from icebergs.
  - We began development drilling. A total of nine wells will be drilled over the next two years leading to first oil production in late 2005 or early 2006.
- The development of the Shackleton gas field in Saskatchewan progressed. By the end of the year we had 225 wells producing a total of 50 million cubic feet of gas per day.
- Husky averaged 610.6 million cubic feet per day of gas production in 2003, up seven percent from 2002.
- Husky achieved a heavy crude oil production record by averaging 107,800 barrels per day in the fourth quarter.
- We established a new upgrader average annual synthetic crude oil sales record of 63,600 barrels per day.
- Refined products set a new sales record for gasoline and diesel fuels of over three billion litres. Throughput per retail outlet increased by eight percent over 2002.

An unexpected development in the external environment in 2003 was the decline in value of the U.S. dollar compared with other major currencies including the Canadian dollar. During the year, the Canadian dollar strengthened from U.S. $0.633 to U.S. $0.774, an appreciation of 22 percent. Although Husky benefited from net foreign exchange gains on translation of U.S. denominated debt of $242 million before tax, the longer-term impact on the Company's cash flow and earnings will be less favourable as long as oil and gas prices continue to be largely denominated in U.S. dollars. The Company will continue to seek ways of managing volatility in exchange rates and commodity prices.

Your Board continues to monitor the evolution of corporate governance practices. In 2003, on the recommendation of the Corporate Governance Committee, and with the support of management, the Company's governance practices have been further strengthened. The committee will continue to scrutinize the Company's corporate governance practices and its compliance with Canadian and U.S. requirements.

Husky strives to be a leader in value creation and we are committed to maintaining our decade-long record of continuous growth. The Marathon acquisition showed that Husky is able to structure innovative transactions to maximize value.

In 2004, Husky has a planned capital expenditure program of $2.1 billion and expects continued growth in oil and gas production to between 320,000 and 350,000 barrels per day. Further ways to add shareholder value are being actively considered, including the financial restructuring of certain midstream and refined products assets.

Our industry faces volatile commodity prices and increasingly complex regulatory rules. Labour costs and Canada's Kyoto Accord commitments add a degree of uncertainty to oil sands and major heavy oil projects. Despite these challenges, Husky will continue to operate with financial discipline, superior asset management and innovative business transactions.

2003 was a record year for Husky. This success was due to the dedication, skill and enthusiasm of our management and employees, and the support of our shareholders. On behalf of the Board of Directors, we would like to express our appreciation for their contributions. We look forward to 2004, and another successful year for the Company.

Victor T. K. Li   Canning K. N. Fok   John C. S. Lau

Co-Chairmen   *President & Chief Executive Officer*

Husky had another excellent year in 2003. We reported record cash flow and earnings, and achieved several significant milestones. Total return to shareholders, including stock price appreciation and special and ordinary dividends, exceeded 50 percent. The challenge going forward will be to build on this record of performance in the face of potential volatility in commodity prices and exchange rates. John C. S. Lau discusses Husky's strategies, major achievements and challenges.

Answers from John C. S. Lau, President & CEO

Questions & Answers

How do you explain the significant gains in your stock price in 2003?

We were pleased with the increase in our stock price in 2003. We saw a return of 43 percent based on the December 31, 2002 closing price of $16.47 and December 31, 2003 closing price of $23.47. Including the dividends paid in 2003, the total return to shareholders increased to 51 percent.

We feel that investors are becoming familiar with Husky and our strategy for value creation. We have worked hard to establish a track record of financial discipline and earnings growth, and have been rewarded with increased interest in our stock which is being reflected in the higher stock price.

Did you achieve your production guidance for 2003? What is your guidance for 2004?

Actual 2003 production was in the middle of the guidance range announced in December 2002, including the Marathon Canada acquisition which added volumes in the fourth quarter. The 2004 guidance reflects stable volumes from existing producing assets. Beyond 2004 a significant boost will occur when White Rose comes on stream followed by oil sands and other longer-term projects. The Company's medium-term goal is to achieve a production level of 500,000 barrels of oil equivalent per day.

Daily production, before royalties		*2003 Guidance*	*2003 Actual*	*2004 Guidance*
Light crude oil & NGL	*(mbbls/day)*	120-130	71.6	67-76
Medium crude oil	*(mbbls/day)*		39.2	35-40
Heavy crude oil	*(mbbls/day)*	85-90	99.9	105-115
Natural gas	*(mmcf/day)*	580-620	610.6	670-710
Barrels of oil equivalent (6:1)	*(mboe/day)*	305-325	312.5	320-350

> "HUSKY'S OUTSTANDING PERFORMANCE IS DUE TO OUR EMPHASIS ON A STRONG BALANCE SHEET AND FINANCIAL DISCIPLINE WHICH IN TURN CREATE OPPORTUNITIES TO BUILD SHAREHOLDER VALUE."

How does the acquisition of Marathon Canada fit into Husky's strategy?

Acquisitions are part of Husky's strategy to grow production and create shareholder value. The Marathon Canada acquisition was recognized for its innovative transaction structure and value creation to Husky through immediate production and reserve additions in our key growth areas.

Proved oil and gas reserves declined in 2003. Can you grow production without new reserves?

At the end of 2003, Husky's total proved oil and gas reserves amounted to 887 million barrels of oil equivalent giving a proved reserve life of almost eight years.

In Western Canada, Husky replaced 111 percent of production in 2003 mainly through heavy oil additions and the acquisition of Marathon Canada.

In International, a revision of 30 million barrels of oil equivalent reflected the uncertain status of achieving an extension to the production sharing contract in our Madura Block in Indonesia. The operator plans to pursue an extension to the production sharing contract once a new gas sales agreement has been finalized.

Our share of White Rose contains 165 million barrels of probable oil reserves, which we would expect to be converted to proved as the project is developed. Husky's share in the White Rose area also contains additional possible reserves of 145 million barrels of oil together with 1.7 trillion cubic feet of possible gas reserves which could eventually be exploited using new technologies such as compressed natural gas. Tucker adds a further 79 million barrels of probable reserves and 273 million barrels of possible reserves. Sunrise contributes 2.25 billion barrels of possible reserves over the longer term.

In addition, we expect to add new reserves through international exploration and corporate acquisitions.

Husky declared a special dividend of $1.00 per share in 2003. What is the Company's policy with respect to future dividends?

Husky enjoyed record earnings in 2003 and our cash position increased significantly as a result of high commodity prices. The Board of Directors was pleased to provide a special cash dividend, allowing shareholders to benefit directly from the Company's superior financial performance. In addition, the regular quarterly cash dividend was increased by 11 percent from nine cents to 10 cents per common share.

Notwithstanding the special dividend, net debt at the end of 2003 was only $1.8 billion compared with $2.1 billion at the beginning of the year. Husky's strong balance sheet underpins our ability to complete existing major projects and fund continuing growth programs.

The Board of Directors will continue to review the Company's dividend policy with a view to maximizing the total return to shareholders.

What is your planned capital expenditure program for 2004?

The planned 2004 program and a comparison with 2003 is shown below:

($ millions)	*2003 Guidance*	*2003 Actual*	*2004 Guidance*
Upstream			
Western Canada	$ 1,040	$ 1,198	$ 1,150
East Coast	560	557	585
International	55	26	65
	1,655	1,781	1,800
Midstream	100	43	100
Refined Products	60	58	150
Corporate	25	23	30
	$ 1,840	$ 1,905	$ 2,080

Upstream activity in Western Canada will focus on gas exploration in the foothills, northeastern British Columbia and northwestern Alberta, and oil exploration in the central Mackenzie area of the Northwest Territories. One exploration well is planned offshore the East Coast, and at least two exploration wells offshore China. Midstream capital reflects debottlenecking projects at the Lloydminster upgrader. Refined products guidance includes a new ethanol plant at Lloydminster.

Can you provide an update on your oil and gas hedging plans for 2004?

The Company has implemented a corporate hedging program for 2004 to manage volatility of crude oil and natural gas prices. For 2004, 85,000 barrels of oil per day has been hedged at an average WTI price of U.S. $27.46 per barrel. For February and March 2004, the Company has hedged 70 million cubic feet of natural gas per day at an average NYMEX gas price of U.S. $6.69 per million British Thermal Units. For April 2004, the Company has hedged 20 million cubic feet of natural gas per day at an average NYMEX gas price of U.S. $6.38 per million British Thermal Units.

What is Husky's strategy for oil sands development?

Our strategy is to undertake a staged development of our high quality oil sands leases. Initially we plan to establish bitumen production of 30,000 barrels per day at Tucker. First production is expected three years from project sanction. We then have the potential to increase our oil sands production to 200,000 barrels of oil per day through a staged development of Sunrise.

TUCKER IN-SITU The timing of regulatory approval and the subsequent impact on major equipment availability have resulted in the Tucker first oil target date moving to 2007 from the originally planned start-up of 2006.

SUNRISE (KEARL) IN-SITU At Sunrise, we are drilling 140 stratigraphic wells during the winter of 2003-04. Geological data from the stratigraphic program will be incorporated into the geological model. This model will form the basis for the producing well layout and the facility configuration. A significant amount of the design work done at Tucker can be used at Sunrise.

What are your exploration plans offshore the East Coast of Canada?

Husky is one of the largest holders of exploration acreage off the East Coast. In 2004, we plan to drill a well at the Lewis Hill prospect in the South Whale Basin.

Can you provide an update on your South China Sea exploration activity?

Three-dimensional seismic has been completed on Block 23/15 and exploration drilling is expected to commence in the first half of 2004. A deep water prospect has been identified on Block 40/30, which Husky intends to drill in early 2004. The drilling of additional exploration wells in 2004 is contingent upon further technical evaluations.

Why is Husky building an ethanol plant?

The Saskatchewan government has recently mandated ethanol blending in gasoline. Building this plant in Lloydminster allows Husky to comply with this mandate, take advantage of synergies with our Lloydminster upgrader and continue our commitment to provide high quality, environmentally friendly transportation fuels.

The 130-million litre per year facility is expected to be operational by the end of 2005. The plant will cost $90-$95 million to build.

Is Husky currently looking at mergers, acquisitions or other ways of enhancing shareholder value?

The Company's growth strategy is based on exploiting our existing portfolio of core assets and development projects. In addition, we are continuing to evaluate alternatives to enhance shareholder value. These include mergers, acquisitions, asset sales and financial restructurings. Financial restructuring of certain midstream and refined products assets may provide a higher return to shareholders on the value of these businesses.

WESTERN CANADA

A major part of Husky's production, development, and exploration is in the Western Canada Sedimentary Basin. Growth plans include the drilling of deeper gas prospects and the development of our heavy oil and oil sands properties.

CANADA'S EAST COAST

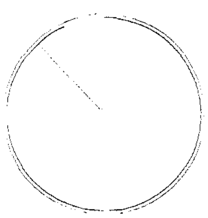
Canada's East Coast will play a key role in achieving our medium-term production targets. We hold significant exploration acreage on the Grand Banks, a 12.51 percent share in the producing Terra Nova oil field and 72.5 percent of the White Rose oil field, currently under development.

Husky Energy's diverse asset base

Expanding the Horizon

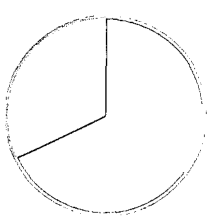
2003 OIL & GAS PRODUCTION
312,500 boe/day

Geographical Mix

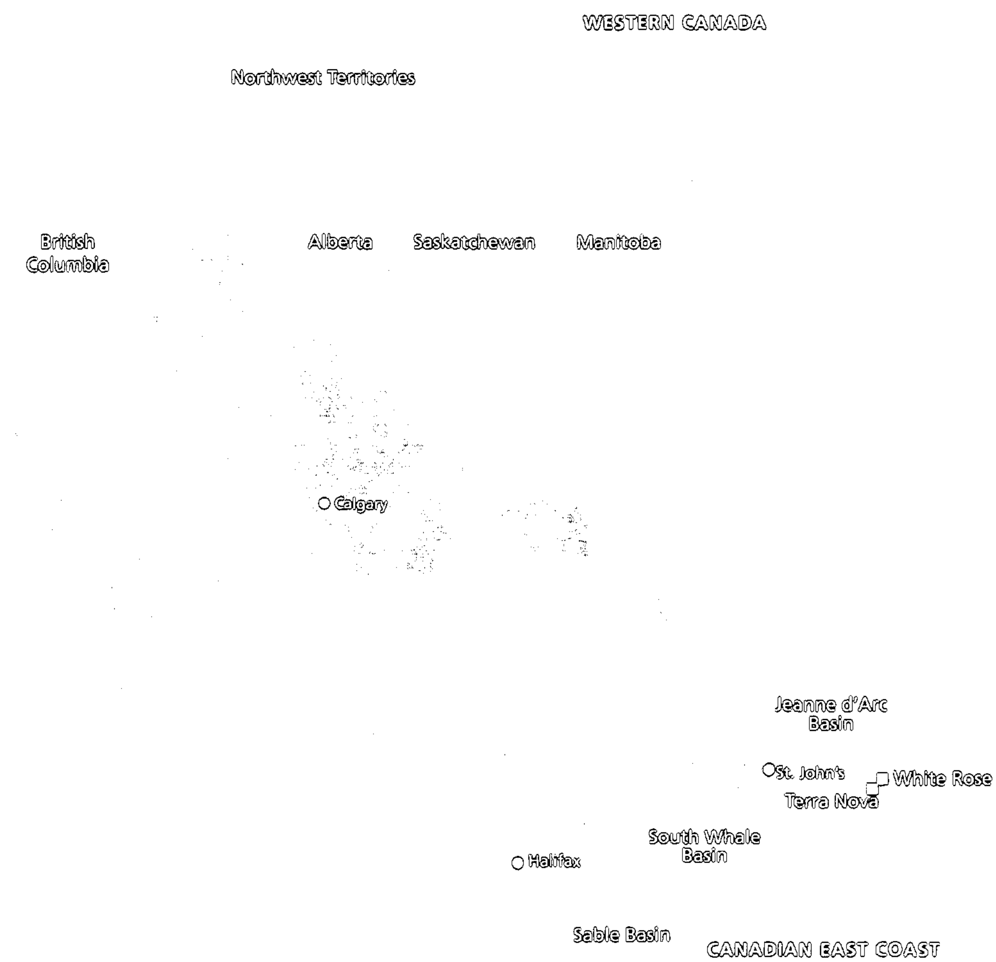


- Western Canada **88%**
- East Coast **5%**
- International **7%**

Product Mix



- Light Crude Oil **23%**
- Medium Crude Oil **12%**
- Heavy Crude Oil **32%**
- Natural Gas **33%**



INTERNATIONAL

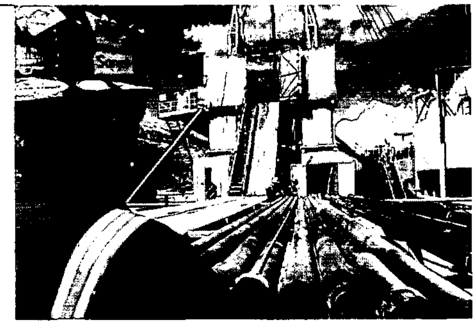
Our holdings in the Wenchang oil field in the South China Sea, exploration blocks offshore China, and a development opportunity in Indonesia's Madura Straits provide a strong base for expanding our international operations.

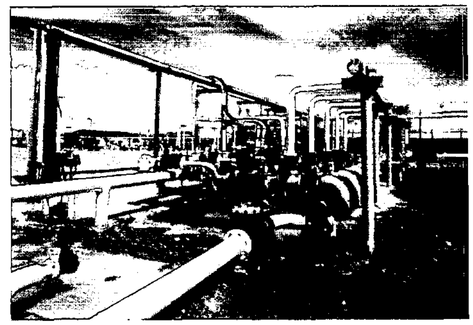
MIDSTREAM

Husky's midstream operations are critical to our strategy of exploiting synergies among our business segments and reducing the volatility of our cash flow streams. They include the heavy oil upgrader at Lloydminster, pipeline systems, commodity marketing, cogeneration, crude oil and natural gas storage and processing.

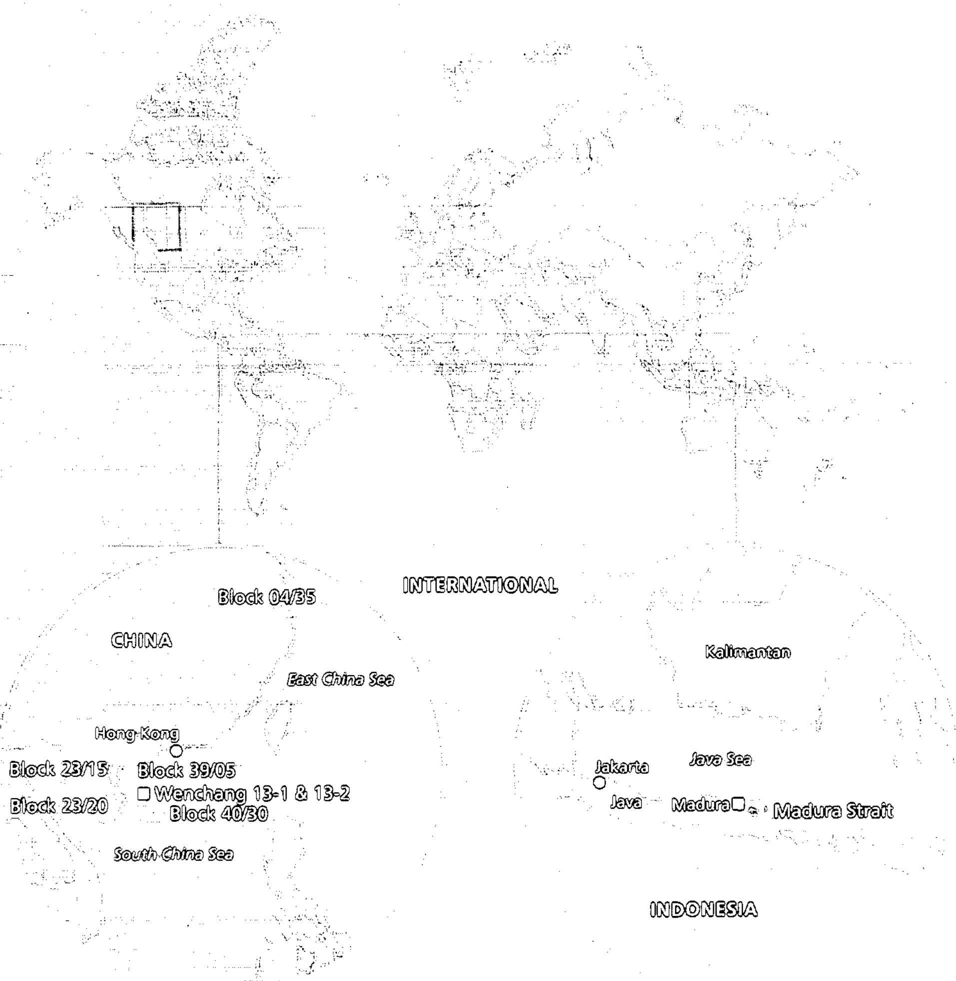
REFINED PRODUCTS

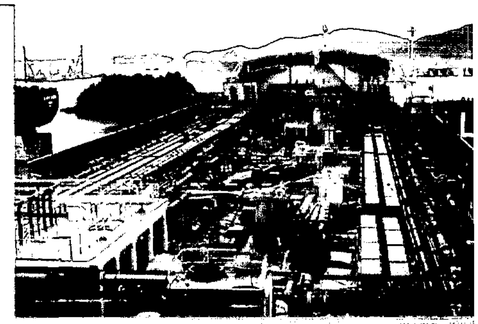
Refined products focuses on the refining, marketing and distribution of gasoline, diesel, asphalt, ethanol and ancillary services. Many of these products are marketed through our retail network under the Husky and Mohawk brands.

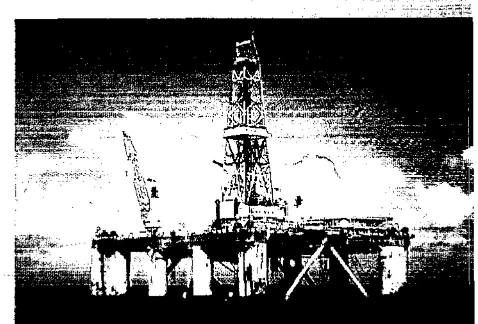


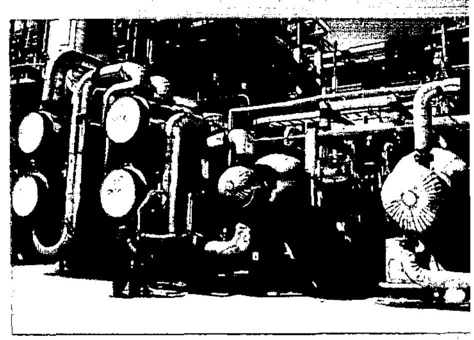


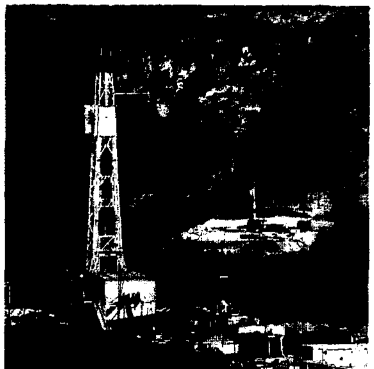
Husky is one of Canada's largest energy companies. During the past decade we have emphasized financial discipline while building substantial growth opportunities in Alberta's heavy oil/bitumen corridor, offshore Canada's East Coast and China.











In 2003, Husky increased gas production through the Marathon Canada acquisition and drilling activities at Shackleton.

MARATHON CANADA ACQUISITION SUMMARY

Acquisition price – $831 million

Proceeds from asset sales – $431 million

Net acquisition price – $400 million

SHACKLETON PROJECT SUMMARY

Working interest – 100 percent

First production – October 2002

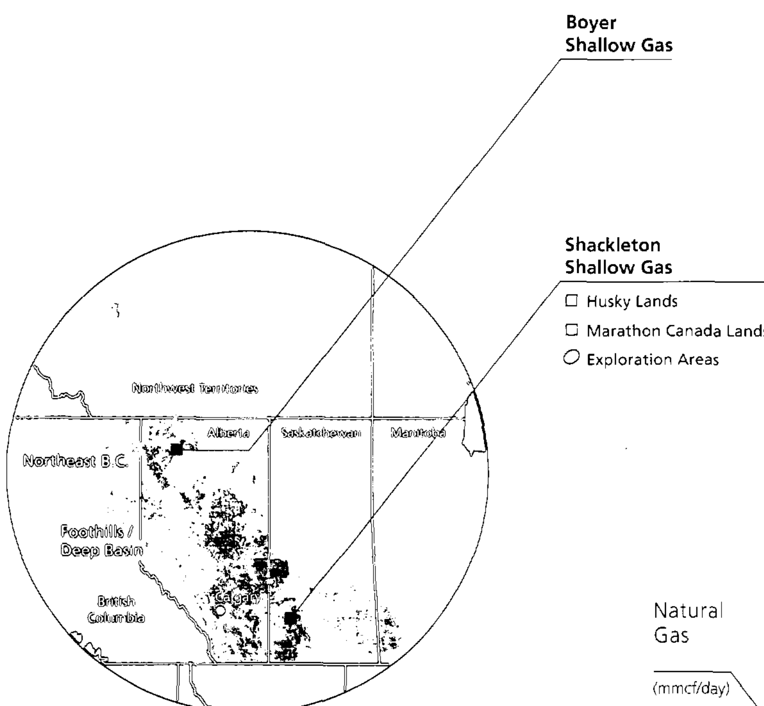
Proved reserves – 110 bcf

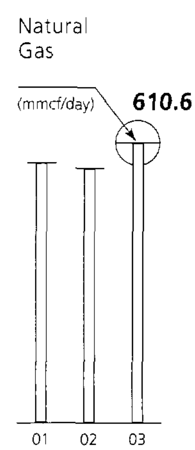
Probable reserves – 41 bcf

Peak production – 55 mmcf/day

OUTLOOK

We continue to focus our exploration in areas of long-life reserves and regions that have higher potential. Our development efforts will be directed towards shallow gas in northwestern Alberta and southern Saskatchewan.





Photos:

Marathon Canada drilling location in the foothills (left)

Drilling of shallow gas wells at Shackleton (top & right)

Husky is focused on the remaining natural gas potential of the Western Canada Sedimentary Basin. Our objective is to grow our Western Canadian production with a target in 2004 of 670 to 710 million cubic feet per day. This strategy requires the drilling of a portfolio of low-risk shallow gas prospects in the northwestern Alberta plains, and in southern Alberta and Saskatchewan that build on synergies with our existing infrastructure. The drilling of higher-risk deep gas prospects in the British Columbia and Alberta foothills complements this strategy.

Increasing oil and gas production in Western Canada

Focusing on natural gas

"Our Western Canada shallow gas strategy focuses on multi-zone step-out drilling and recompletions of tighter gas zones, which is expected to offset natural declines."

Bob Coward, Vice President of Western Canada Production

MARATHON CANADA ACQUISITION

On October 1, 2003, Husky acquired Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd., in one of the largest Canadian oil and gas transactions of 2003. We acquired proved reserves of 39.8 million barrels of oil equivalent, of which over 75 percent was natural gas, along with 660,000 net acres of undeveloped land in Alberta, British Columbia and the Northwest Territories.

SHACKLETON

Successful execution of our natural gas strategy has been demonstrated with our discoveries in the Shackleton and Lacadena areas, northwest of Swift Current, Saskatchewan. Commercial development was initiated in late 2002, and by the end of 2003, we had 225 wells producing 50 million cubic feet per day.

During the year, we expanded our existing facilities and completed a new compression plant at Spring Creek. Our 2004 plans include drilling 100 new wells, construction of a new plant at White Bear, and installing two additional compressors to support production of 55 million cubic feet per day.

EXPLORATION

During 2004, we plan to drill 61 exploratory wells in the foothills, Deep Basin and northeastern British Columbia regions targeting a variety of play types. We plan to drill gas wells in south central Alberta where there is synergy with our existing operations. Drilling activities are also planned for the former Marathon Canada properties in west central and northern Alberta, and northeastern British Columbia.

Photo (left to right): Bob Coward, Rob Penrose and Rod Mallmes

Husky's heavy oil growth strategy is focused in the Lloydminster area where we hold a significant acreage position and operations are integrated with our refining and upgrading assets. As operator, we control 98 percent of our production. Combined with our upgrader and pipeline system, our asset portfolio creates synergy between production, transportation, upgrading and refining. Our strategy is to increase production through the drilling of primary heavy oil wells, and the development of new thermal recovery projects.

In recognition of our low finding and development costs for heavy oil, Ziff Energy Group, an independent energy consulting firm, presented us with an award for the three-year period ending 2002.

Exploit strategic heavy oil position

Continued growth

"Husky's expertise and dominant land position in the Lloydminster area allows us to increase our heavy oil production."

Bob Coward, Vice President of Western Canada Production

LLOYDMINSTER

As part of our strategy in the Lloydminster area we increased the number of primary heavy oil wells drilled. This strategy has continued to be successful with 363 net oil wells drilled in 2003 with a success rate of 95 percent.

BOLNEY AND CELTIC

In 2003, Husky completed stage two of our three-stage plan for developing the Bolney/Celtic project. In this stage we improved the heat efficiency of the steam generation and battery processing unit. The new facilities were commissioned in October.

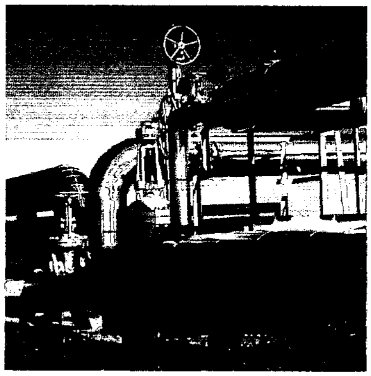
By the end of the year the combined Bolney/Celtic development was producing over 10,000 barrels of oil per day.

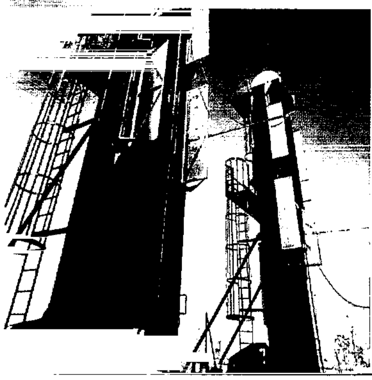
SINGLE-WELL MONITORING AND INTELLIGENT WELL ADVISORY SYSTEM

Husky has accelerated its use of single-well monitoring technology to track and analyze key production indicators at well sites. The sites are monitored 24 hours a day from a central location where operators can review performance and intervene on well problems. By the end of 2003, we had installed single-well monitoring technology on 1,400 wells.

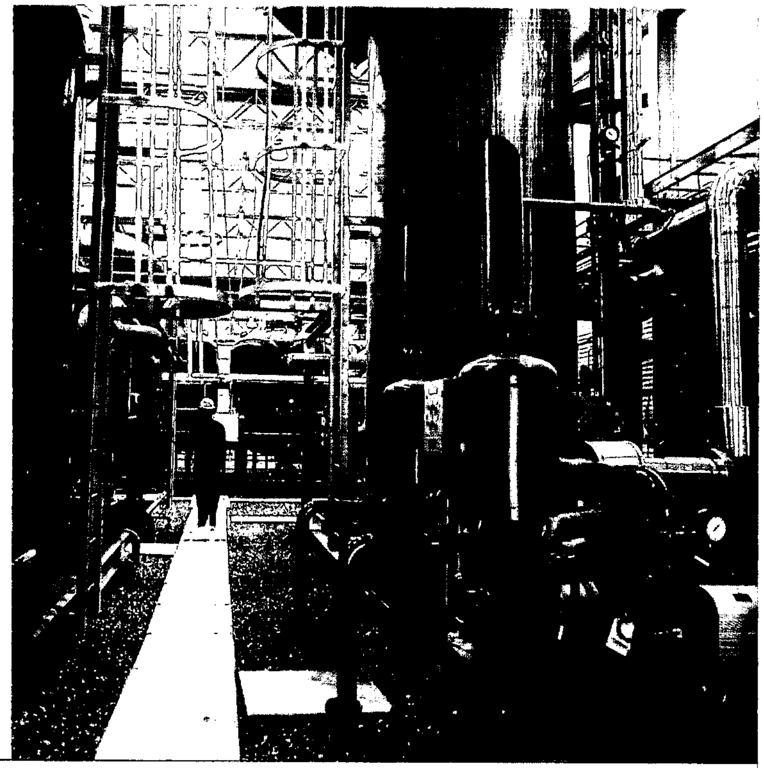
During the fourth quarter of 2003, we took the next step in well monitoring technology by piloting the Intelligent Well Advisory System (IWAS). IWAS analyzes well data and can predict well failures in advance of the failure occurring. If successful, IWAS will be deployed in our inventory of operating wells to improve production performance and reduce operating costs.

Photo (left to right): Bob Coward and David Long





Our heavy oil growth strategy has proven to be very successful. In the fourth quarter of 2003, our heavy oil production averaged 107,800 barrels per day.



TOTAL HEAVY OIL ASSETS

Average working interest – 98 percent

2003 production – 99,900 bbls/day

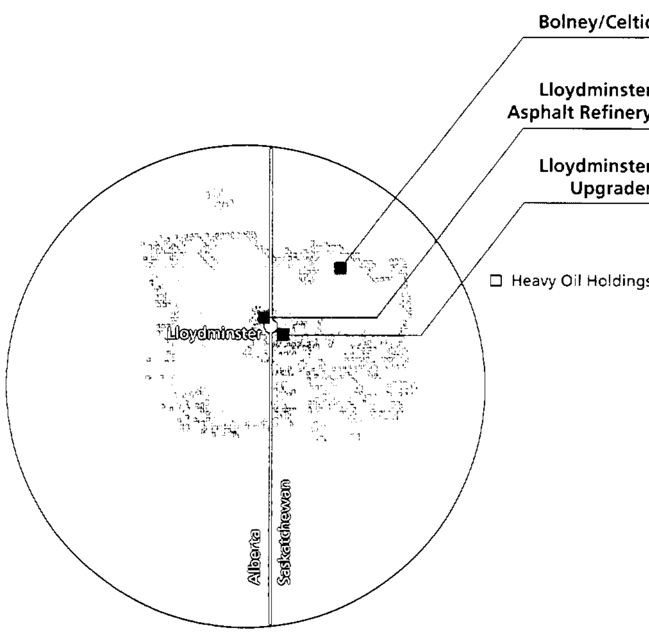
Proved reserves – 227 million bbls

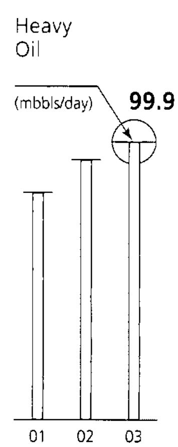
Probable reserves – 92 million bbls

Landholdings – 1.6 million acres

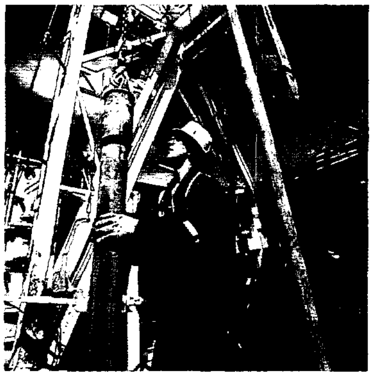
OUTLOOK

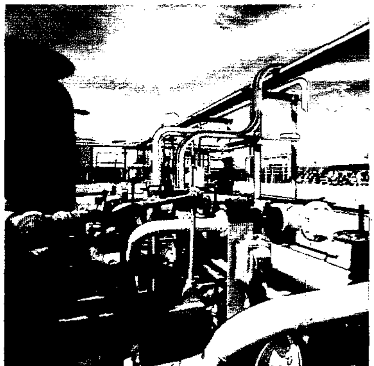
We will continue to exploit our heavy oil lands by drilling 400 to 500 primary heavy oil wells each year and seek new opportunities to implement thermal recovery technology.



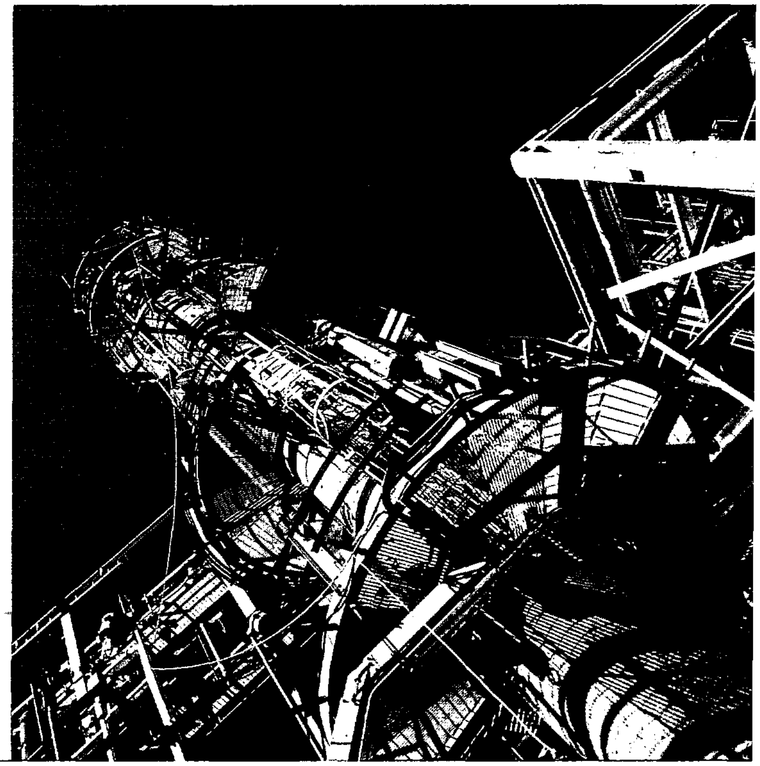


Photos:
Thermal pump jacks at Celtic (left)
Thermal steam and gathering lines (top)
Water treatment plant at Bolney/Celtic (right)





Our substantial holdings in the heavy oil/bitumen corridor ensure that Husky is well-positioned for long-term growth.



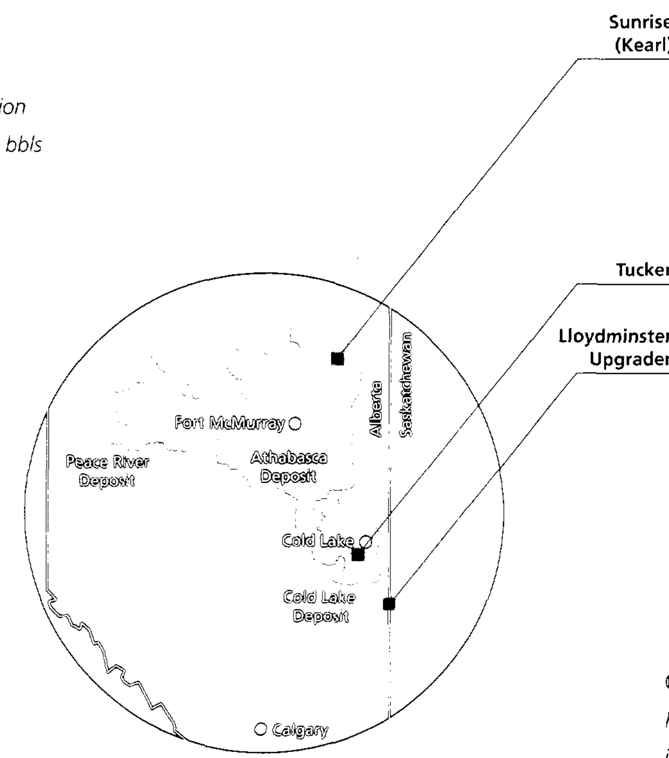
PROJECT SUMMARY

Tucker

- *Working interest – 100 percent*
- *First production – 3 years after project sanction*
- *Probable and possible reserves – 352 million bbls*
- *Peak production – 30,000 bbls/day*
- *Landholdings – 10,080 acres*

Sunrise

- *Working interest – 100 percent*
- *Possible reserves – 2.25 billion bbls*
- *Peak production – up to four 50,000 bbls/day stages*
- *Landholdings – 57,600 acres*



OUTLOOK

Husky's oil sands strategy is to establish commercial in-situ bitumen production of 30,000 barrels per day from Tucker within three years of project approval, and to grow production in 50,000-barrel per day stages from our Sunrise development.

Photos:

Lloydminster facilities where bitumen from Tucker could be processed (left & right)

Drilling of delineation wells (top)

Western Canada's oil sands are one of Husky's targeted long-term growth areas. We believe that bitumen and synthetic crude production will increase substantially during the next decade. Husky has significant leases in the Athabasca, Cold Lake and Peace River areas of Alberta. Our properties total in excess of 425,000 acres and are estimated to contain total resources of over 23 billion barrels of bitumen.

To take advantage of our existing pipeline and upgrading infrastructure in the Cold Lake and Lloydminster areas Tucker is our first planned oil sands project. Sunrise will follow with a staged development approach. These two projects have the potential to produce up to 200,000 barrels of bitumen per day.

Oil sands resources provide long-term growth potential

Positioned for development

"Husky plans to remain a major, long-term player in the Western Canadian petroleum business by pursuing commercial oil sands development projects."

Tom Graham,
Vice President,
Oil Sands

TUCKER

In February of 2003, we submitted a commercial application to provincial regulators requesting approval to construct a 30,000-barrel per day thermal in-situ project. Subject to confirmation that a hearing is not required, approval is anticipated during the first half of 2004. The project will use technology similar to steam assisted gravity drainage (SAGD).

During the year, we completed the front-end engineering and design work for the project and initiated detailed engineering for the thermal facilities.

SUNRISE (KEARL)

Husky's major oil sands project at Sunrise, formerly named Kearl, is located in the Athabasca region of northern Alberta.

During 2003, core data from 212 stratigraphic test wells was incorporated into a detailed geological model. Results are encouraging and a review is in progress to determine if there are sufficient resources in place to justify a larger capacity thermal project.

Feasibility studies are under way regarding project size, timing, utilities and transportation options as well as environmental issues. The preliminary gathering of the baseline data for the Environmental Impact Assessment (EIA) was completed in September. Husky expects to submit the commercial project application by mid-2004.

OTHER OIL SANDS LEASES

Husky's remaining oil sands properties, containing 15 billion barrels of bitumen resources, continue to be evaluated for development. The reservoir characteristics and available infrastructure make these properties more technically challenging.

Photo (left to right):
Brian Hunka and
Tom Graham

Husky has been actively involved offshore Canada's East Coast for more than 20 years and is well positioned for development and exploration activities. Canada's East Coast is key to achieving our medium-term growth target. We are the operator of the White Rose development in the Jeanne d'Arc Basin, and hold a significant acreage position on the Grand Banks.

Our plan is to increase oil production from Terra Nova and to complete the White Rose development, with first oil expected by late 2005 or early 2006. Evaluation of exploration opportunities continues, particularly in the South Whale Basin and we expect to drill several exploration wells in the next few years.

Husky is a major player offshore Canada's East Coast

White Rose on schedule

"The progress made in the construction of the FPSO for White Rose was outstanding and the workmanship displayed by the labour force has been first-rate. We expect delivery of a top quality vessel."

Walt DeBoni,
Vice President,
Canadian Frontier and International Business

Photo (left to right): Will Roach, Walt DeBoni, and Margaret Allan

WHITE ROSE

Development of the White Rose project is on schedule. Construction of the Floating Production, Storage and Offloading vessel (FPSO) and sub-sea facilities are currently under way. The turret and related equipment for the FPSO have been integrated into the hull. The FPSO has set sail from Korea for Marystown, Newfoundland and Labrador, where the topside modules are being constructed. The completed vessel is expected to sail for the White Rose field in the second half of 2005. Development drilling of the field began in September 2003. Husky is the operator of the project and has a 72.5 percent working interest in White Rose.

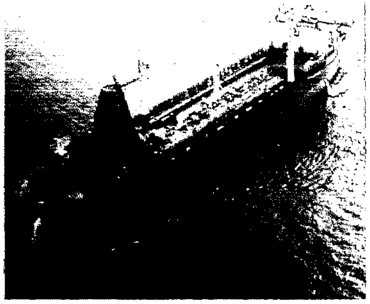
TERRA NOVA

Terra Nova, in which Husky holds a 12.51 percent interest, had a successful year in 2003. During the year, regulatory authorities increased the maximum allowable production rate to 180,000 barrels of oil per day. Husky's share of production averaged 16,800 barrels of oil per day.

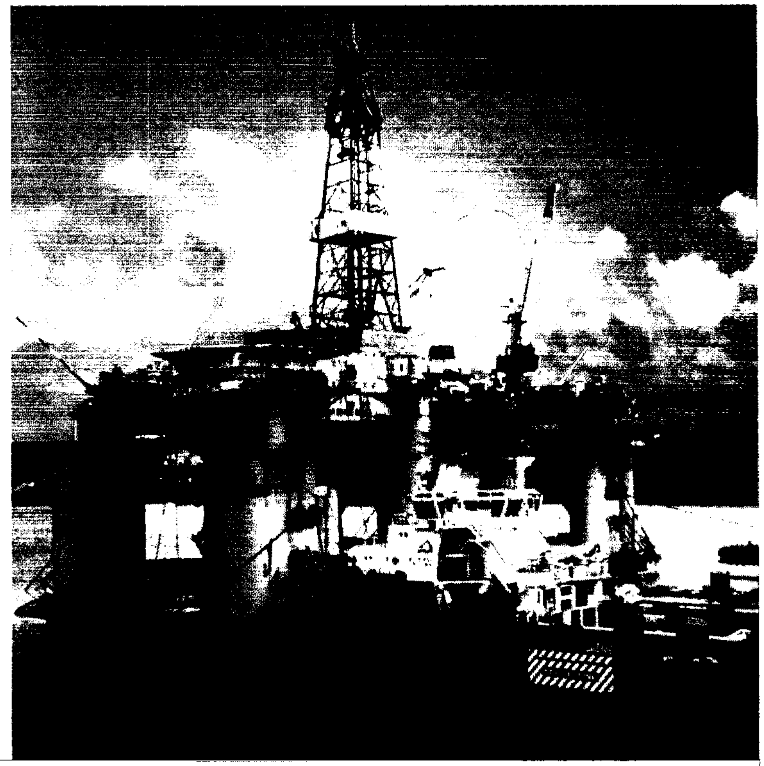
EXPLORATION

Husky believes the Grand Banks holds further potential. We have identified several exploration prospects close to the White Rose field. These include oil prospects that can be tied back to the White Rose FPSO to extend production life, and gas prospects that enhance the possibility of future Grand Banks gas development.

Exploration activity continues in other areas of the Grand Banks. Drilling of the Lewis Hill prospect in the South Whale Basin is planned for 2004.



The Glomar Grand Banks began development drilling at the White Rose field in September. The FPSO is expected to arrive in Marystown in Spring 2004.



WHITE ROSE PROJECT SUMMARY

Working interest – 72.5 percent

Husky's share:

Probable reserves – 165 million bbls

Peak production – 66,700 bbls/day

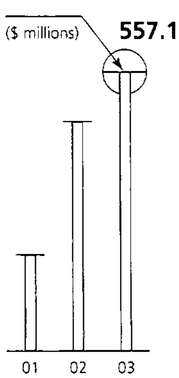
Number of wells – 19-21

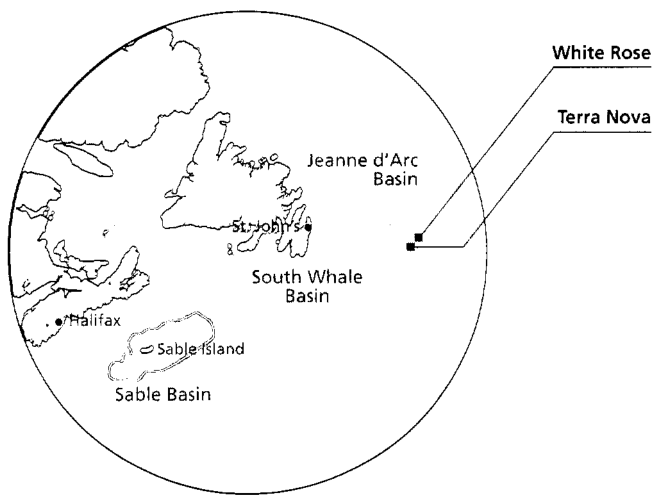
Field life – 10-15 years

First oil – late 2005 or early 2006

Budgeted development cost – gross $2.35 billion

East Coast Capital Expenditures





OUTLOOK

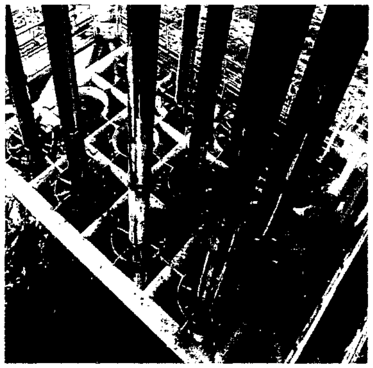
Husky's share of production from Terra Nova in 2004 is anticipated to average 17,500 barrels per day.

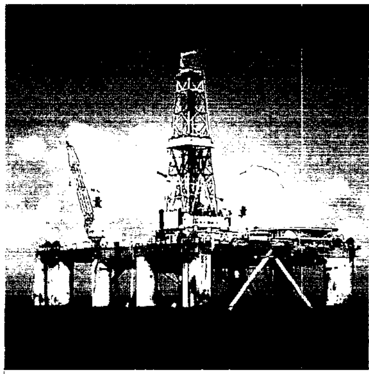
Our plans for White Rose include:

- *Installation of topsides on the FPSO hull*
- *Shuttle tankers delivered in second quarter of 2005*
- *FPSO sails for White Rose in the second half of 2005*
- *First oil production in late 2005 or early 2006*

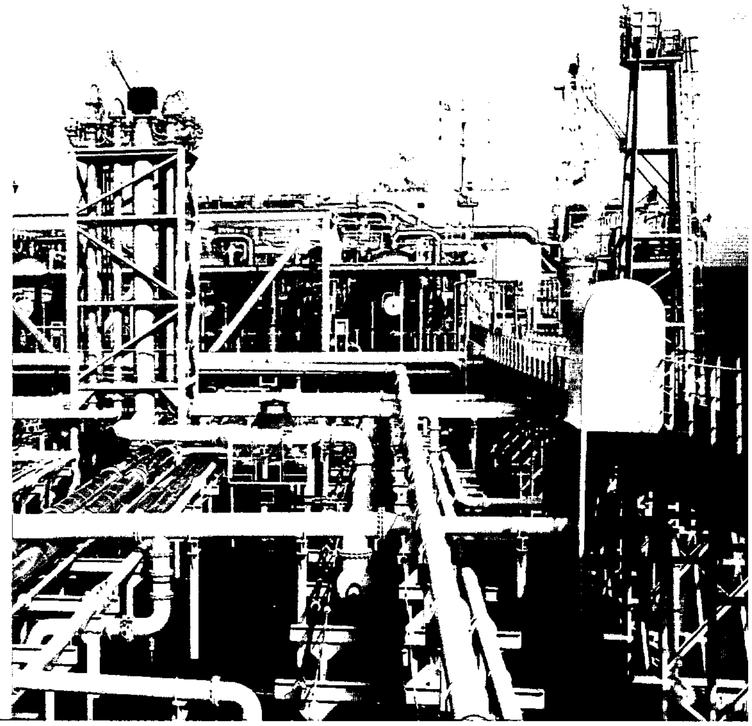
Continued evaluation of the South Whale and Jeanne d'Arc Basins in anticipation of exploration drilling in 2004.

Photos:
Installing 18-foot propellers on the FPSO (left)
SeaRose FPSO during sea trials in Korea (top)
Glomar Grand Banks being upgraded for development drilling (right)





Wenchang has provided us with an international base in a region with great exploration potential and proximity to major oil and gas markets.



WENCHANG PROJECT SUMMARY

Working interest – 40 percent

Husky's share:

Proved and probable reserves – 27 million bbls

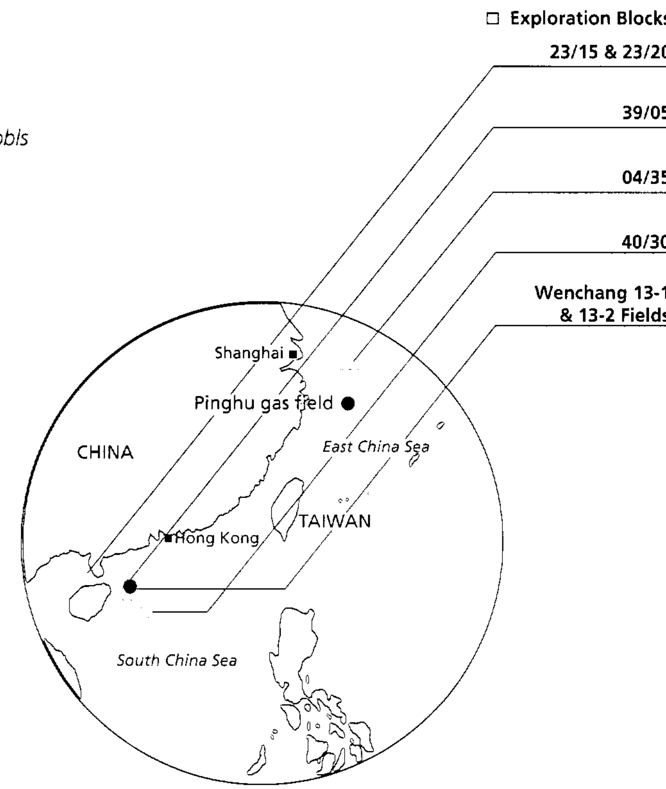
Peak production – 24,000 bbls/day

Number of wells – 21

Field life – 10-12 years

First oil – July 2002

FPSO storage capacity – 850,000 bbls



OUTLOOK

Husky's share of production from Wenchang is expected to average 18,000 to 20,000 barrels per day in 2004.

Our exploration drilling plans for 2004 include:

- *A prospect in the deep water 40/30 block in the Pearl River Mouth Basin*
- *A well on Block 23/15 in the Beibu Gulf*
- *Additional exploration wells in late 2004*

Photos:
Exploration drilling in the South China Sea (left)
Production wells on the Wenchang platform (top)
Topsides of the Wenchang FPSO (right)

Husky continues to build on its production base at Wenchang, in the South China Sea. Wenchang was the first step in our international growth strategy. In 2003, we acquired additional exploration blocks in the South China Sea and in the East China Sea. Our East China Sea block is an excellent opportunity to gain access into a region with good exploration potential, and proximity to major gas markets in Shanghai.

With our 31.4 percent working interest in the Madura block, offshore Indonesia, we are now well positioned to participate in growth opportunities in southeast Asia.

International footprint established in Asia

Offshore growth opportunities

"Oil and gas demand in China has been expanding at a phenomenal rate. Successful exploration in this region will allow us to capitalize on this growth."

Dave Taylor, Vice President, Exploration

Photo (left to right): Dave Taylor, Janice Knoechel and David Johnson

WENCHANG

The success of our Wenchang joint venture is an example of our international growth strategy. Husky has a 40 percent working interest, in partnership with the China National Offshore Oil Corporation (CNOOC), in the Wenchang 13-1 and 13-2 offshore oil fields, 400 kilometres southwest of Hong Kong.

In 2003, the Wenchang oil fields exceeded our expectations with average Husky production of 22,400 barrels of oil per day. We plan to drill up to three development wells in 2004 to optimize production and to improve oil recovery.

Operating costs for this area continue to be the lowest in the Company. Operating at peak production, costs are currently less than U.S. $1.50 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

South China Sea Husky holds a 100 percent interest in four exploration blocks in the South China Sea, totalling 15,274 square kilometres or 3.8 million acres. CNOOC has the right to participate in any development with up to a 51 percent interest. During the year, we drilled two exploratory wells and made significant progress on our exploration plans for this area.

In September, we completed a three-dimensional seismic program over Block 23/15 in the Beibu Gulf. The data is being processed and interpreted with drilling expected to commence during the first half of 2004. In Block 40/30, we identified a large structure that we plan to drill in 2004.

East China Sea As part of our expansion in China, we signed a petroleum contract with CNOOC for the 04/35 exploration block in the East China Sea, located 350 kilometres east of Shanghai, covering an area of 4,835 square kilometres or 1.2 million acres. A single exploration well to 2,500 metres depth is required during the first three years of the contract.

Husky's midstream operations include an extensive portfolio of assets located across Western Canada and linked to key North American transportation systems. They include our heavy oil upgrader, pipeline systems, commodity marketing, electricity generation, crude oil and natural gas storage, and processing. Our midstream operations help minimize the price volatility associated with commodity prices and heavy and light oil price differentials, and add value to our production chain.

Strategically located in the heavy oil/bitumen corridor

Midstream assets

"Husky relies on its midstream business to be the window on the industry, to minimize Husky's cash flow volatility and build synergies with its asset base."

Don Ingram,
Senior Vice President,
Midstream and
Refined Products

LLOYDMINSTER UPGRADER

At the centre of Husky's upgrading and refining operations is the Lloydminster heavy oil upgrader. It processes heavy oil feedstock into premium quality synthetic crude and diluent. The synthetic crude is sold to refiners in Eastern Canada and the United States, and the diluent is returned to the field for heavy oil blending. Approximately 85 percent of the upgrader and asphalt refinery feedstock comes from our own production.

In 2003, improved throughput efficiency led to a new synthetic crude oil sales record of 63,600 barrels per day. During the year, we continued with our debottlenecking projects that are expected to increase throughput capacity by six percent to 82,000 barrels of heavy oil and diluent per day.

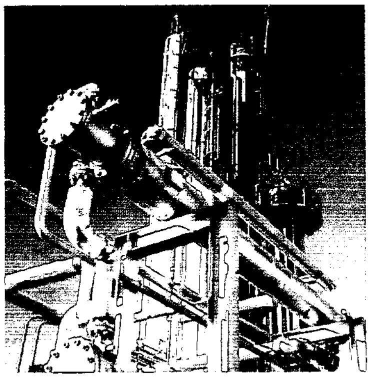
PIPELINES

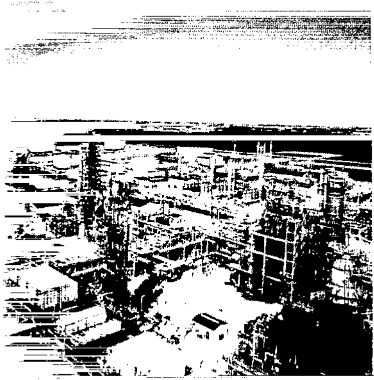
Husky owns and operates a 2,050-kilometre pipeline transmission system. The system transports heavy oil production from the Lloydminster and Cold Lake areas to Husky's terminal, upgrading and refining facilities in Lloydminster. Heavy and synthetic crude oil is then transported from Lloydminster to Husky's terminal at Hardisty, Alberta, where it is delivered into the Enbridge and Express pipeline systems.

COMMODITY MARKETING

Commodity Marketing provides the commercial link between Husky's upstream, midstream and downstream activities. Its focus is to capture for Husky a larger portion of the value chain between the production and consumption of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.

Photo (left to right):
Roy Warnock, Don Mulrain,
Terrance Kutryk and
Don Ingram





Our midstream assets capture related business opportunities, providing Husky with a competitive advantage.

FACILITIES

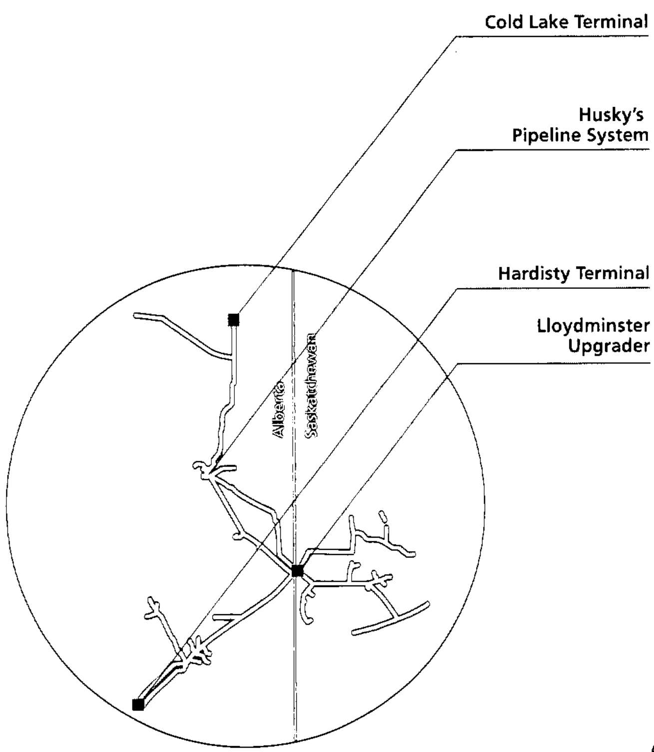
Upgrader capacity – 77,000 bbls/day

Pipeline system – 2,050 km

Natural gas storage – 20 bcf

Cogeneration

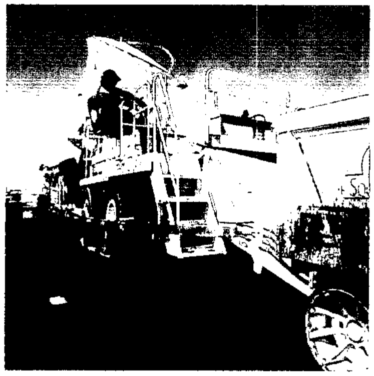
- *50 percent interest in 215 MW facility at Lloydminster*
- *50 percent interest in 90 MW facility at Rainbow Lake*

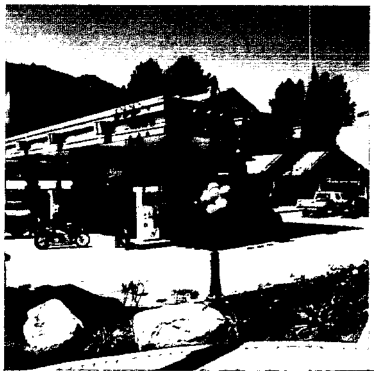


Photos:
Aerial view of the Lloydminster upgrader (left)
Gas storage facility at Hussar, Alberta (top)
Cogeneration facility at the upgrader site (right)

OUTLOOK

In 2004, Husky is planning a number of projects directed at increasing the upgrader's throughput capacity. In the longer term, there are opportunities to increase capacity of all facilities.





In 2003, we supplied 8,500 tonnes of asphalt used in paving Calgary's Deerfoot Trail extension, one of the largest paving projects in recent Alberta history.

RETAIL OUTLETS – 2003

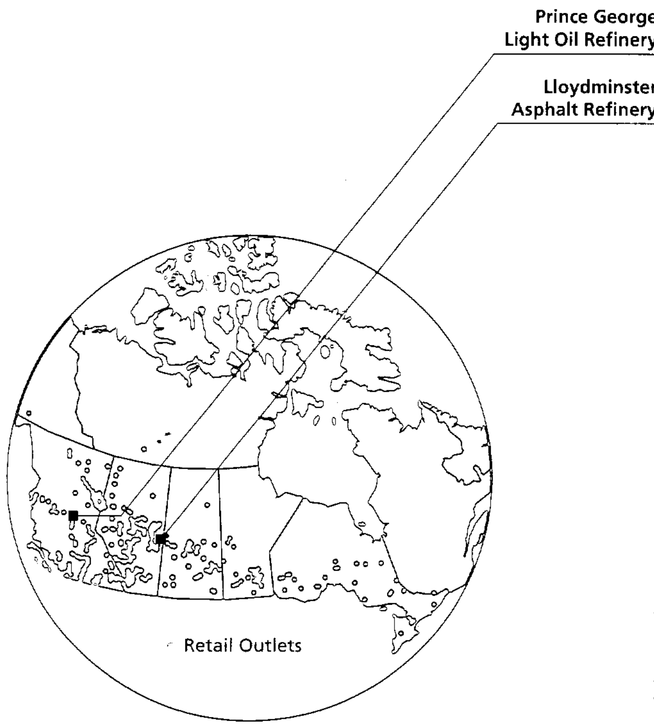
Service stations – 484
Travel centres – 44
Bulk distributors – 24
Total outlets – 552
Cardlocks [1] *– 72*
Convenience stores [1] *– 507*
Husky House restaurants [1] *– 41*

[1] *Included in outlet total.*

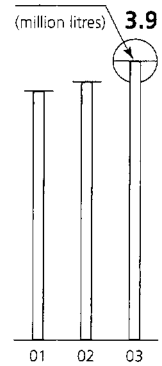
OUTLOOK

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

Husky plans to construct a world-class ethanol plant at Lloydminster, to produce ethanol for blending into gasoline. The 130-million litre per year facility is expected to be operational by the end of 2005.



Refined Products Throughput per Outlet



Photos:
New retail outlet at Whistler, British Columbia (left)
Road paving, using Husky's premium-quality asphalt (top)
Calgary's newest Husky Market on Macleod Trail (right)

Husky's refined products assets play an important role in delivering our production to market; capturing synergies with other segments of the business. A refinery in Prince George, British Columbia processes light oil. Heavy crude oil is processed at our asphalt refinery in Lloydminster, Alberta, and ethanol for fuel and industrial uses is produced at our plant in Minnedosa, Manitoba. Our refined products are marketed through over 550 retail outlets, travel centres, and bulk distribution centres from Vancouver Island to Ontario.

Building on the well-established Husky and Mohawk brand names

Refined products

"The year 2003 saw new records set for light oil and asphalt sales volumes, and increased unit volume throughput. These results show that our marketing strategies are positioning Husky for continued growth."

Don Ingram, Senior Vice President, Midstream and Refined Products

Photo (left to right): Don Ingram, Chuck Juergens and Vince Chin

RETAIL NETWORK

Our retail outlets provide customers with fast, easy service at the pump and standardized products. In 2002, we initiated a strategy to upgrade our retail outlets to a combination retail gas and convenience store format designed to increase sales per customer visit. Ten upgraded or new Husky Markets were opened during 2003.

Our strategy continues to meet expectations. Gross sales margins have increased in the new stores. Average throughput per retail outlet in 2003 was almost four million litres per year or an eight percent improvement over 2002. Light oil products sales set a new record of over three billion litres, a seven percent increase over 2002.

PRINCE GEORGE LIGHT OIL REFINERY

The light oil refinery at Prince George has a design throughput capacity of 10,000 barrels per day. The refinery produces all grades of unleaded gasoline, seasonal diesel fuels, mixed propane and butane, and heavy fuel oil.

ASPHALT REFINING AND MARKETING

Our Lloydminster refinery processes heavy crude into asphalt products used in road construction and maintenance, manufactured building products, locomotive blendstock, and specialty oil field products. The refinery has a total throughput capacity of 25,000 barrels per day of heavy crude oil. It also produces a distillate stream used by the upgrader, and a condensate stream used to blend with heavy oil production.

During 2003, we set an annual sales record of over 750,000 cubic metres of asphalt. We also had increases in total refinery sales volume (asphalt, tops and residual), and a 36 percent increase in the sale of modified asphalts (polymer and oxidized paving grades). To facilitate this growth we completed construction of the Winnipeg Emulsion Asphalt Complex, a combined emulsion plant and asphalt terminal.

Responsibility for protecting the health and safety of our employees and the public rests with each of our employees, from the senior executive level to the front line worker. Our health, safety and environmental management systems are constantly updated in response to Husky's growth, new technology and a changing regulatory environment. In 2003, Husky established a Corporate Environmental Committee composed of senior executives to take a broader and longer-term perspective of environmental issues. As a part of our proactive approach to addressing environmental concerns, Husky works with stakeholders to discuss mitigation strategies. We also work closely with oil and gas regulatory agencies on changing guidelines and compliance issues.

Growth in a socially responsible manner

Our corporate commitment

"Key to the success of Husky's Corporate Environmental Committee is the role played by our HS&E managers whose strength is their professionalism and commitment."

Wendell Carroll, Vice President, Corporate Administration

Photo (back left to right): Mike Satre, Sher Follett, Ken Jackson, Lois Garrett and Wendell Carroll

HEALTH AND SAFETY PERFORMANCE

Husky's 2003 accident frequency rate was 0.36 lost-time accidents (LTA) per 200,000 person-hours. Offsetting the increase in LTA frequency rate was a notable decline of 40 percent in average lost-time days per accident. The Company's performance compared to industry was recognized by rebates on our Workers' Compensation Board premiums.

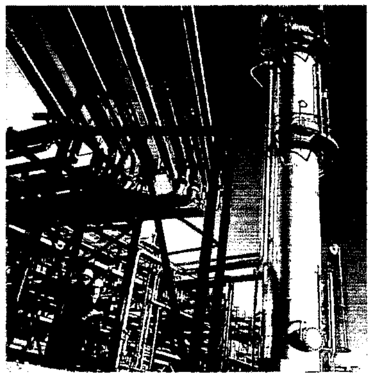
During the year, our major facilities reached safety milestones without a lost-time accident: the Prince George refinery reached over 400,000 person-hours, Rainbow Lake district achieved over one million person-hours, and the Lloydminster upgrader achieved approximately 3.5 million person-hours. The East Coast offshore drilling operations achieved one year without an employee lost-time accident.

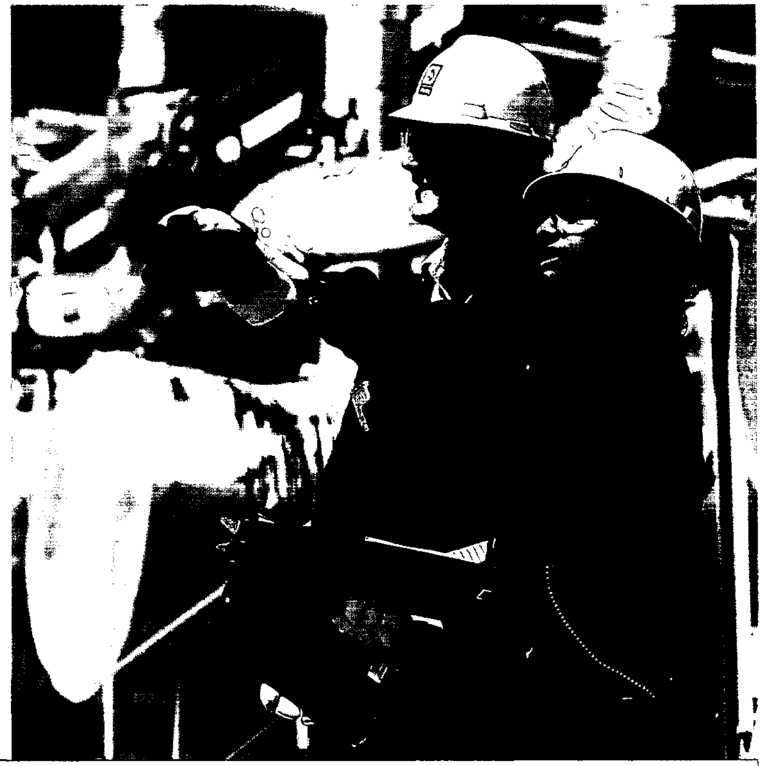
ENVIRONMENTAL STEWARDSHIP

Emission Reductions Husky is an active participant in several initiatives to improve air quality. We have significantly reduced sulphur dioxide emissions at our Rainbow Lake sour gas processing facility since commencing acid gas injection. In 2003, we installed a titanium-promoted catalyst at our Ram River sour gas processing facility. Combined emissions at the two facilities have been reduced by 30 percent since 2000.

Husky supports efforts to reduce greenhouse gas emissions and has taken numerous steps to reduce operational emissions. This has resulted in a reduction of 3.3 million tonnes of carbon dioxide equivalents (CO_2E) over business-as-usual projections. Husky has an aggressive program to reduce flaring and venting of hydrocarbons in its operations. In 2003, we were successful in reducing flaring and venting volumes by an additional 10 percent.

Endangered Species Reintroduction Research Husky is the title sponsor of the Calgary Zoo's Endangered Species Reintroduction Research Program. Husky's support will help the Program become the leader in reintroduction research in Canada and restore four endangered species to Western Canada.





We have been recognized for our health, safety and environmental initiatives in the communities where we do business.

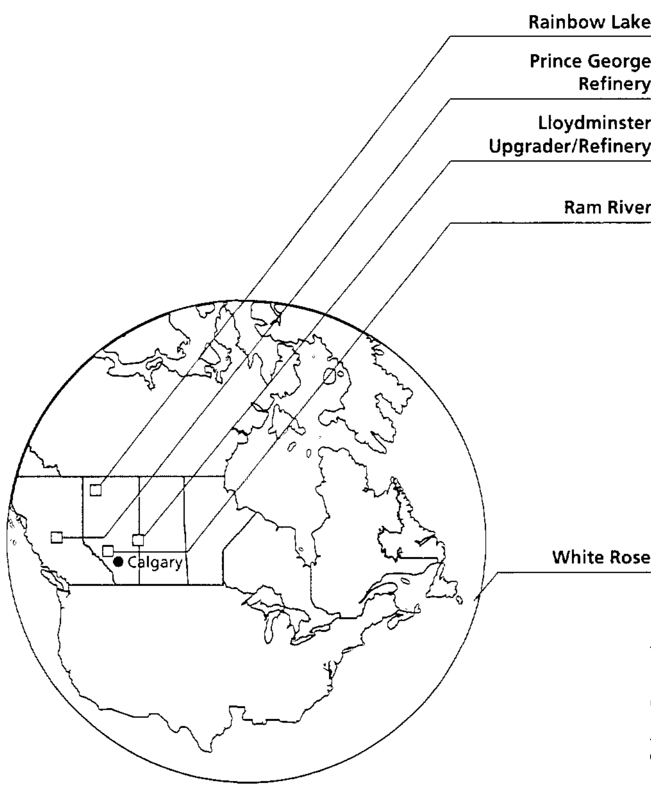
2003 AWARDS

During 2003, Husky received a number of awards for its Health, Safety and Environmental performance including:

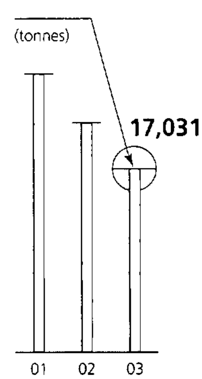
- *Canadian Association of Petroleum Producers' Stewardship award*
- *Canadian National Railway Safe Handling award*
- *Voluntary Challenge Registry Gold Level Reporter award*
- *Canadian Pacific Railway Chemical Shipper Safety award*

OUTLOOK

The new federal and provincial health, safety and environment (HS&E) regulatory initiatives will continue to pose challenges for Husky. We intend to meet these challenges and continue to improve our corporate HS&E performance.



Total Husky Sulphur Dioxide (SO_2) Emissions



Photos:

Preserving our environment by leaving a small footprint of our activities (left)

Reduction of sulphur dioxide emissions at the Rainbow Lake facility (top)

Health and safety of our employees and the public begins at the front line (right)

Husky donated over $2.4 million to non-profit organizations across Canada in 2003. More than 50 percent of the contributions were provided to educational endeavours.

HUSKY AND OUR COMMUNITIES

During 2003, we were honoured to be recognized for our ongoing support of the following:

University of Calgary – 25 years

Western Canada High School, Calgary, Alberta – 11 years

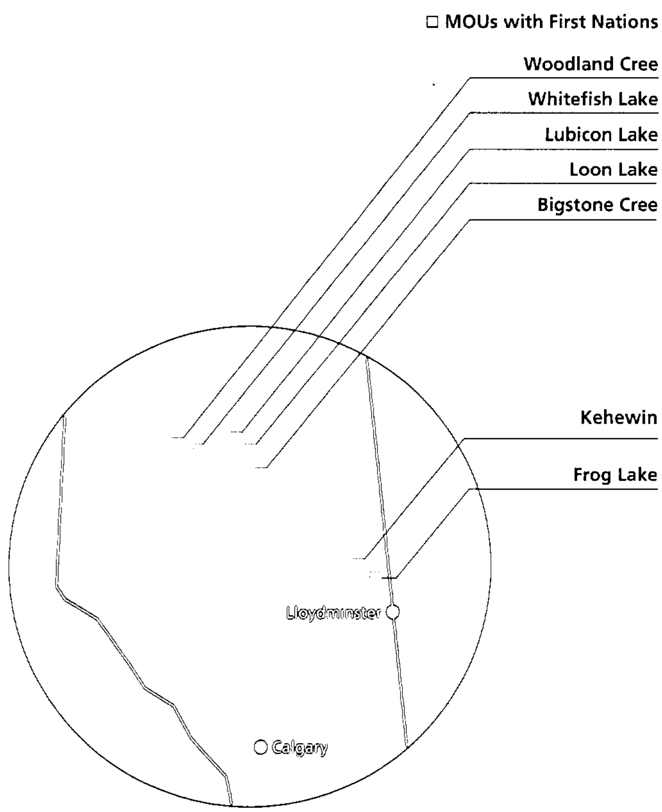
Lakeland College, Lloydminster, Alberta – 10 years

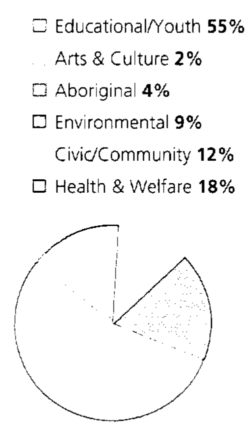
Indian Events Committee, Calgary Stampede – 10 years

Calgary Handi-Bus Association – 10 years

OUTLOOK

Husky will continue its support for community giving and look for those programs which provide far-reaching benefits that maximize the value of the contributions made.





2003 Charitable Donations

Photos:

Title sponsor of Calgary Zoo's Endangered Species Reintroduction Research Program (left)

John C. S. Lau was bestowed the honorary First Nations name of Chief Wolf Dog at Indian Village at the Calgary Stampede (top)

Western Canada High School's performance of A Midsummer Night's Dream, *a salute to Husky for its ongoing support (right)*

We are a member of the communities, in which we live and do business, and as such have a responsibility to them. Husky seeks to promote mutually-shared responsibilities by encouraging our employees to conduct our business in accordance with the values of equality, understanding, trust and respect.

We also believe that organizations have a role in improving their communities. In fulfilling this responsibility we have focused on three areas: aboriginal affairs, the advancement of education, and community donations.

Investment in the communities where we operate

Husky and the community

"Participation in the community should not be viewed as an obligation but as a responsibility to be enjoyed and encouraged."

John C. S. Lau, President & CEO, Husky Energy Inc.

ABORIGINAL AFFAIRS

To ensure that members of First Nations can benefit from education, training, employment, and business opportunities, we have signed memorandums of understanding (MOUs) with seven First Nations in Alberta. These MOUs set out general principles for resolving concerns arising from Husky's operations in these communities.

Husky has developed several other initiatives to assist the 16 aboriginal communities where we have activities. We provide bursaries to students to complete their high school and work towards certification or undergraduate degrees. Husky awarded $37,500 in aboriginal scholarships in 2003. We participate in Lakeland College's Aboriginal Petroleum Employment Training Program, at Lloydminster, Alberta, through donations and the hiring of graduates, and support an aboriginal youth pride initiative at Jack James Senior High School, in Calgary.

EDUCATION

In 2003, we established a $2 million endowment at Memorial University in St. John's, Newfoundland and Labrador for the creation of the Husky Energy Chair in Oil and Gas Research. The chair is the first of its kind for the University. We also made a $50,000 contribution to the Western Canada High School Alumni Legacy Fund, in Calgary, for scholarships to graduates.

In October, we entered into a partnership at Lakeland College that allows faculty and students to be on-site and gain hands-on experience during the site reclamation and remediation of our Kodiak Refinery site, in Lloydminster.

COMMUNITY DONATIONS

Photo (back left to right): Wendell Carroll, Jade Cooper, Susan Anderson, Sandra Anderson, John C. S. Lau and Joan Anderson

We encourage our employees to help improve those communities where we work and live. Under our Annual Charitable Donations Program, selected charitable donations from our employees are matched by contributions from Husky. During 2003, our employees and Husky donated over $500,000 to 43 charities.

Our Board of Directors is principally responsible for the Company's corporate governance practices. The Board of Directors has delegated some of its responsibilities in monitoring and enhancing 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 2003, with the encouragement of the Board, the Company made good progress in strengthening its governance practices and responded effectively to changes in the marketplace.

Husky Energy Inc. Board of Directors

Corporate governance

The Management Information Circular issued in connection with the April 22, 2004 annual meeting describes the Company's corporate governance practices and a comparison with the Toronto Stock Exchange Guidelines.

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

- approve, monitor and provide guidance on the strategic planning process. The President & CEO and senior management team have direct responsibility for the ongoing strategic planning process and the establishment of long-term goals for the Company, which are reviewed and approved not less than annually, by the Board of Directors;
- identify the principal risks of the Company's business and take reasonable steps to ensure the implementation of appropriate systems to manage and monitor these risks;
- delegate to the President & CEO the authority to manage and supervise the business of the Company, including the making of all decisions regarding the Company's operations that are not specifically reserved to the Board of Directors under the terms of that delegation of authority. The Board also determines what, if any, executive limitations may be required in the exercise of the authority delegated to management, and in this regard approves operational policies within which management will operate;
- approve the Company's annual business and financial plans;
- oversee the integrity of the Company's internal control and management information systems; and
- oversee effective communication with shareholders.

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 of Directors. The members of each committee are non-management directors.

Audit Committee

M. J. G. Glynn (Chair), R. D. Fullerton, T. C. Y. Hui and W. E. Shaw.

The Audit Committee is responsible for review and approval of the quarterly financial statements, management's discussion and analysis, all press releases containing financial disclosure, and the Company's oil and gas reserves reporting. The committee recommends to the Board the appointment and remuneration of the external auditors. The external auditors report directly to the committee. All non-audit work performed by the external auditors is to be approved by the committee. The committee also has oversight responsibility for the internal control systems that management has established.

Compensation Committee

C. K. N. Fok (Chair), 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 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.

Corporate Governance Committee

H. Kluge (Chair), E. L. Kwok and W. E. Shaw.

This committee 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-Chairs, 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 procedures are in place so that the Board can function independently of management.

Health, Safety and Environment Committee

H. Kluge (Chair), 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 and achievement of specific environmental objectives and targets, and to monitor compliance with the Company's environmental policies.

Husky Energy Inc. 2003

Management's Discussion and Analysis

34 Overview

34 Summary of Results

34 Business Environment

38 Sensitivity Analysis

38 Husky's Business Plan

40 Results of Operations

40 Upstream

44 Midstream

46 Refined Products

46 Corporate

48 Capital Resources

48 Operating Activities

48 Financing Activities

48 Investing Activities

48 Capital Expenditures

50 Oil and Gas Reserves

55 Liquidity

55 Sources of Capital

57 Contractual Obligations and Commercial Commitments

57 Off Balance Sheet Arrangements

58 Transactions with Related Parties and Major Customers

58 Financial and Derivative Instruments

60 Application of Critical Accounting Estimates

62 New Accounting Standards

64 Results of Operations for 2002 Compared with 2001

65 Forward-looking Statements

66 Evaluation of Disclosure Controls and Procedures

February 2, 2004

MANAGEMENT'S DISCUSSION AND ANALYSIS

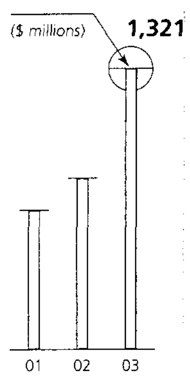
Management's Discussion and Analysis is the Company's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Company's financial position and prospects. It should be read in conjunction with the Consolidated Financial Statements and notes thereto and the Supplemental Information on Oil and Gas Exploration and Production Activities. 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 20 of the Consolidated Financial Statements. The following discussion and analysis refers primarily to 2003 as compared with 2002, unless otherwise indicated. Refer to the section "Results of Operations for 2002 Compared with 2001" for an abridged discussion. All dollar amounts are in millions of Canadian dollars, unless otherwise indicated. The calculations of barrels of oil equivalent ("boe") and thousand 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. Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties, and prices are those realized by the Company, which include the effect of hedging gains and losses.

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 as an indicator of the Company's financial performance. The Company'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 consolidated cash flow from operations are considered to be a corporate responsibility.

Certain of the statements set forth under "Management's Discussion and Analysis" 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 the Company'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 the Company. These factors include, but are not limited to, the matters described under the heading "Business Environment". Should one or more of these events occur, or should any of the underlying assumptions prove incorrect, the Company's actual results and plans for 2004 and beyond could differ materially from those expressed in the forward-looking statements. The Company does not undertake to update, revise or correct any of the forward-looking information. Such forward-looking statements should be read in conjunction with the Company's disclosures under the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995". Refer to the section "Forward-looking Statements".

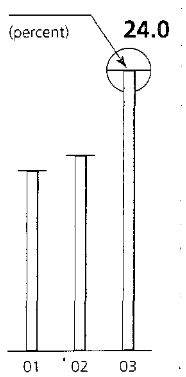
Overview

Net Earnings



Net earnings grew 64 percent, setting a new record

Return on Equity



Return on equity grew to 24 percent in 2003, well ahead of the Company's target of 15 percent

SUMMARY OF RESULTS

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 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 marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.
- The refined products segment includes the refining of crude oil and the marketing of refined petroleum products including asphalt products.

Segmented Financial Summary

Year ended December 31		**2003**	% Change	2002	% Change	2001
($ millions, except where indicated)						
Sales and operating revenues,						
net of royalties		**$ 7,658**	20	$ 6,384	(3)	$ 6,596
Cash flow from operations		**2,459**	17	2,096	8	1,946
Segmented earnings						
Upstream		**$ 1,048**	52	$ 688	43	$ 482
Midstream		**185**	15	161	(37)	256
Refined Products		**28**	(13)	32	(49)	63
Corporate and eliminations		**60**	178	(77)	48	(147)
Net earnings		**$ 1,321**	64	$ 804	23	$ 654
Per share – Basic		**$ 3.23**	72	$ 1.88	26	$ 1.49
– Diluted		**3.22**	71	1.88	27	1.48
Dividends declared per share		**1.38**	283	0.36	–	0.36
Return on equity	*(percent)*	**24.0**		16.7		15.4
Return on average						
capital employed	*(percent)*	**18.0**		12.2		10.9

BUSINESS ENVIRONMENT

Husky's financial results are significantly influenced by its business environment. Risks include, but are not limited to:

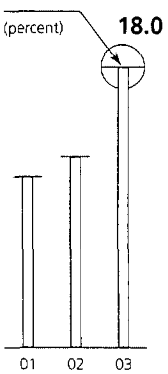
- Crude oil and natural gas prices
- Cost to find, develop, produce and deliver crude oil and natural gas
- Demand for and ability to deliver natural gas
- The exchange rate between the Canadian and U.S. dollars
- Refined products margins
- Demand for Husky's pipeline capacity
- Demand for refined petroleum products
- Government regulations
- Cost of capital

Average Benchmark Prices and U.S. Exchange Rate

		2003	2002	2001
West Texas Intermediate ("WTI") [1]	*(U.S. $/bbl)*	**$ 31.04**	$ 26.08	$ 25.97
Canadian par light crude 0.3% sulphur	*($/bbl)*	**$ 43.56**	$ 40.28	$ 39.39
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**$ 5.39**	$ 3.25	$ 4.38
NIT natural gas	*($/GJ)*	**$ 6.35**	$ 3.86	$ 5.97
WTI/Lloyd blend differential	*(U.S. $/bbl)*	**$ 8.55**	$ 6.47	$ 10.74
U.S./Canadian dollar exchange rate	*(U.S. $)*	**$ 0.716**	$ 0.637	$ 0.646

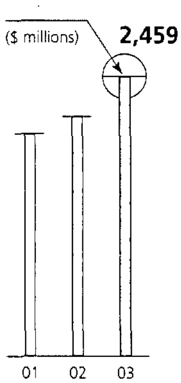
(1) Prices quoted are near-month contract prices for settlement during the next month.

Return on Average Capital Employed



Return increased to 18 percent in 2003 compared with the Company's target of at least 10 percent

Cash Flow from Operations



Higher commodity prices boosted cash flow from operations by 17 percent in 2003

Commodity Price Risk

Husky's earnings depend largely on the profitability of its upstream business, which is significantly affected by fluctuations in oil and gas prices. Commodity prices have been, and are expected to continue to be, volatile due to a number of factors beyond Husky's control. Refer to the section "Financial and Derivative Instruments" for a discussion of the Company's use of hedging contracts.

Crude Oil

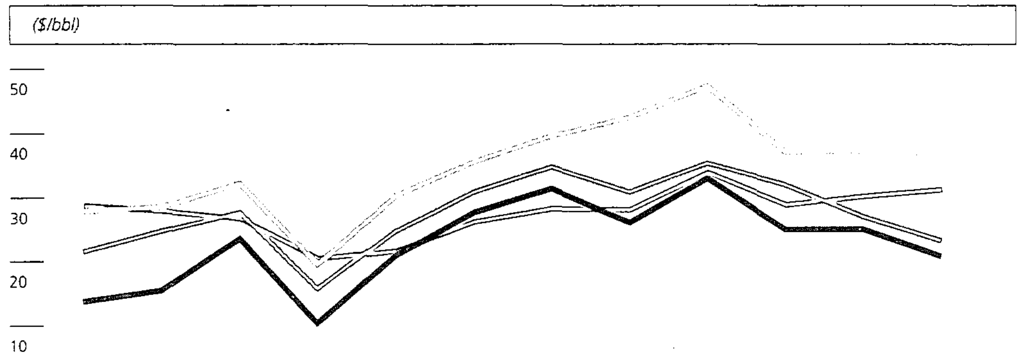
The prices received for the crude oil and NGL sold by Husky are related to the price of crude oil in world markets. Prices for heavy crude oil and other lesser quality crudes trade at a discount or differential to light crude oil. These prices are further affected by the use of hedging contracts, which provide for payments or receipts depending on whether the underlying commodity price is higher or lower than an agreed upon strike price.

Benchmark crude oil prices averaged higher in 2003 compared with 2002. The price for West Texas Intermediate ("WTI") crude oil averaged U.S. $32.70/bbl in January 2003 and fluctuated between monthly averages of U.S. $35.73/bbl and U.S. $28.07/bbl during the remainder of the year.

During 2003 buoyant world crude oil prices resulted from production quotas set by the Organization of Petroleum Exporting Countries ("OPEC"), Nigerian and Venezuelan production restrictions and the war in Iraq. Iraqi production averaged approximately 350,000 bbls/day from April through July 2003. In August Iraqi production recovered considerably and averaged 1,400,000 bbls/day from August through October 2003 or approximately 70 percent of normal pre-war levels. OPEC has maintained a greater degree of production discipline over the past three years with the intention of maintaining prices within a U.S. $22/bbl – U.S. $28/bbl price range. Toward the end of 2003, OPEC announced cuts to its production quotas that were intended to keep prices within the price band. Numerous factors could affect world crude oil prices in the remainder of 2004. Early January 2004 commercial crude oil inventories were significantly lower than the five-year average. Low crude oil inventories restrict the refiners' ability to increase distillate production, should protracted cold weather increase heating demand.

During 2003 heavy crude oil differentials averaged U.S. $8.55/bbl for WTI/Lloyd blend compared with U.S. $6.47/bbl during 2002. The wider differential tends to reduce Husky's overall financial results as the Company's crude oil production is weighted toward heavier gravity crudes. In periods of wider differentials, Husky's heavy oil upgrader offsets in part the impact of lower heavy crude prices.

WTI and Husky Realized Crude Oil Prices



	Q1-01	Q2-01	Q3-01	Q4-01	Q1-02	Q2-02	Q3-02	Q4-02	Q1-03	Q2-03	Q3-03	Q4-03
West Texas Intermediate *(U.S. $)* □	$28.72	$27.96	$26.76	$20.43	$21.64	$26.25	$28.27	$28.15	$33.86	$28.91	$30.20	$31.18
Husky realized light crude oil price *(C $)*	$27.87	$28.62	$32.24	$19.51	$30.35	$35.56	$39.64	$42.58	$47.44	$37.17	$37.35	$36.78
Husky realized medium crude oil price *(C $)* □	$21.55	$24.81	$27.78	$15.84	$24.84	$30.90	$34.76	$30.92	$35.39	$32.05	$27.12	$23.27
Husky realized heavy crude oil price *(C $)* ■	$13.81	$15.52	$23.65	$10.44	$20.95	$27.75	$31.41	$26.20	$33.02	$25.13	$25.13	$20.84

Natural Gas

The price of natural gas in North America is affected by regional supply and demand factors, particularly those affecting the United States such as weather conditions, pipeline delivery capacity, 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 such as OPEC.

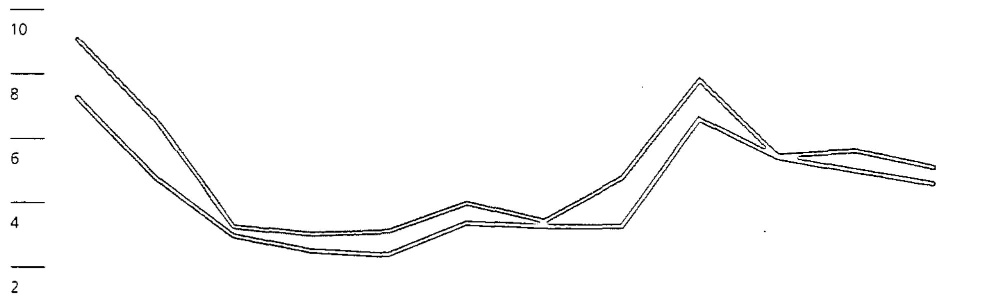
Throughout the last five months of 2003 natural gas prices on the New York Mercantile Exchange ("NYMEX") drifted lower, averaging just over U.S. $5/mmbtu. With the arrival of colder weather at the end of November, prices on the NYMEX began to increase and the near-month price on December 31, 2003 for February 2004 delivery was U.S. $6.19/mmbtu. At the beginning of January 2004 natural gas storage in the U.S. was just above the five-year average.

The selling price for Husky's natural gas is based either on fixed price contracts, spot prices, NYMEX or other regional market prices. The prices received are further affected by the Company's hedging contracts, which provide for payments or receipts depending on whether the underlying commodity price is higher or lower than an agreed upon strike price. Refer to "Financial and Derivative Instruments" for a discussion of the Company's use of hedging contracts.

Upgrading Differential

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 from heavy oil production.

NYMEX Natural Gas and Husky Realized Natural Gas Prices



	Q1-01	Q2-01	Q3-01	Q4-01	Q1-02	Q2-02	Q3-02	Q4-02	Q1-03	Q2-03	Q3-03	Q4-03
NYMEX natural gas *(U.S. $/mmbtu)*	$7.27	$4.78	$2.98	$2.50	$2.38	$3.37	$3.26	$3.25	$6.60	$5.39	$4.97	$4.58
Husky realized natural gas price *(C $/mcf)*	$9.05	$6.57	$3.25	$3.01	$3.10	$3.98	$3.42	$4.76	$7.80	$5.43	$5.58	$5.08

Refined Products Margins

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

Integration

Husky's production of light, medium and heavy crude oil and natural gas 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 commodity price volatility. Although predominantly an oil and gas producer, Husky's integrated organization is such that the upstream business segment's output provides input to the midstream and refined products segments.

Foreign Exchange Risk

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 oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities and correspondingly an increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. The majority of Husky's expenditures 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, 2003, 74 percent or $1.5 billion of Husky's long-term debt and capital securities was denominated in U.S. dollars. The Cdn./U.S. exchange rate at the end of 2003 was $1.29. The percentage of Husky's long-term debt exposed to the Cdn./U.S. exchange rate decreases to 54 percent when the cross currency swaps are included. Refer to "Financial and Derivative Instruments".

Interest Rates

The Company maintains a portion of its debt in floating rate facilities which are exposed to interest rate fluctuations. The Company will occasionally fix its floating rate debt or create a variable rate for its fixed rate debt using derivative financial instruments. Refer to "Financial and Derivative Instruments".

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, exchange controls, currency fluctuations, royalty and tax increases, import and export regulations and other foreign laws or policies affecting foreign trade or investment.

SENSITIVITY ANALYSIS

The following table is indicative of the relative effect on net earnings and cash flow of changes in certain key variables. The analysis is based on business conditions and production volumes during 2003. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis

Item	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
		($ millions)	*($/share)* [4]	*($ millions)*	*($/share)* [4]
WTI benchmark crude oil price					
Excluding hedges	U.S. $1.00/bbl	93	0.22	63	0.15
Including hedges	U.S. $1.00/bbl	54	0.13	34	0.08
NYMEX benchmark natural gas price [1]					
Excluding hedges	U.S. $0.20/mmbtu	34	0.08	21	0.05
Including hedges	U.S. $0.20/mmbtu	18	0.04	10	0.02
Light/heavy crude oil differential [2]	Cdn. $1.00/bbl	(25)	(0.06)	(16)	(0.04)
Light oil margins	Cdn. $0.005/litre	15	0.04	9	0.02
Asphalt margins	Cdn. $1.00/bbl	8	0.02	5	0.01
Exchange rate *(U.S. $ per Cdn. $)* [3]					
Including hedges	U.S. $0.01	(50)	(0.12)	(34)	(0.08)

(1) Includes decrease in earnings related to natural gas consumption.
(2) Includes impact of upstream and upgrading operations only.
(3) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $8 million in net earnings based on December 31, 2003 U.S. dollar denominated debt levels.
(4) Based on December 31, 2003 common shares outstanding of 422 million.

HUSKY'S BUSINESS PLAN

Husky will continue to execute its long-term business plan, which is expected to increase reserves and production in the upstream business segment through selective acquisitions and effective exploration and development programs. Husky will also continue to enhance growth and returns through expansion, upgrading and optimization of the midstream and refined products businesses.

The light and medium gravity crude oil potential of the Western Canada Sedimentary Basin, although considerable, is generally believed to be composed of smaller accumulations. Husky plans to optimize production from its properties in the Western Canada Sedimentary Basin through programs to improve recovery and through acquisitions and dispositions. Husky benefits from having a significant position in several key producing areas in Western Canada. Husky is the operator of the majority of its operations and has extensive infrastructure, which affords opportunities for cost control and economies of scale.

Husky plans to more than offset production declines from light and medium crude oil properties in the Western Canada Sedimentary Basin by further exploitation of heavy oil in the Lloydminster area of Alberta and Saskatchewan, development of oil sands properties in Alberta, production from the White Rose offshore project and production from projects offshore China. In addition, 2004 plans include an oil exploration program in an area new to Husky in the central Mackenzie region of the Northwest Territories.

The natural gas potential of the Western Canada Sedimentary Basin is considered to be favourable both for shallow gas on the undisturbed plains and larger deep accumulations in the Deep Basin and foothills overthrust areas. Husky's natural gas production is expected to increase as a result of exploration concentrated in these areas west of the fifth meridian in Alberta and British Columbia and natural gas development activity throughout the Basin, as well as through selective acquisitions and asset rationalization.

In 2004 Husky intends to invest $2.1 billion in capital programs. Capital totalling $1.15 billion is planned to be spent on upstream programs located throughout the Western Canada Sedimentary Basin, $585 million on programs offshore the East Coast of Canada and $65 million on international programs primarily offshore China. Capital programs in the midstream segment will total $100 million primarily for further debottlenecking of the Lloydminster Upgrader and $150 million in the refined products segment primarily for further upgrading of the marketing outlet system and construction of an ethanol production facility. Husky plans to invest $30 million in corporate areas in 2004.

Husky's 2004 business plan assumes that:

- WTI will average U.S. $26.50/bbl and the WTI/Lloyd blend differential will average U.S. $6.96/bbl
- NYMEX natural gas price will average U.S. $5.25/mcf
- the Canadian dollar will average U.S. $0.73
- U.S. $ LIBOR will average 2.50 percent
- Husky's total production will average 320 to 350 mboe/day. Production in 2004 comprises 67 to 76 mbbls/day of light crude oil and NGL, 35 to 40 mbbls/day of medium crude oil, 105 to 115 mbbls/day of heavy crude oil and 670 to 710 mmcf/day of natural gas

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 speculative purposes.

During 2003 Husky entered into contractual arrangements whereby between approximately 25 percent and 27 percent of 2004 planned annual production has been hedged. Crude oil production totalling 31 mmbbls has been hedged at an average price of U.S. $27.46/bbl throughout 2004 and 4.8 bcf of natural gas production has been hedged at an average price of U.S. $6.65/mmbtu from February to April 2004. This will protect cash flow and earnings in 2004 and facilitate the execution of 2004 capital programs. In addition, Husky has hedged a portion of its power purchases. From January to December 2004, 329,400 MWh have been hedged at an average price of $46.72/MWh.

UPSTREAM

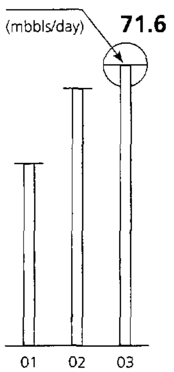
2003 Compared with 2002

Husky's earnings from the upstream segment increased by $360 million (52 percent) to $1,048 million in 2003 from $688 million in 2002.

Upstream Earnings Summary

Year ended December 31 ($ millions)	**2003**	2002	2001
Gross revenues	**$ 3,796**	$ 3,120	$ 2,667
Royalties	**584**	460	502
Hedging (gain)/loss	**26**	(5)	–
Net revenues	**3,186**	2,665	2,165
Operating and administrative expenses	**855**	729	648
DD&A	**958**	851	728
Income taxes	**325**	397	307
Earnings	**$ 1,048**	$ 688	$ 482

Daily Production, before Royalties – Light Crude Oil & NGL



Light crude oil & NGL production grew nine percent in 2003 due to Wenchang and Terra Nova

Husky's total revenues from upstream operations were $3,796 million in 2003 compared with $3,120 million in 2002 primarily due to:

- higher price realization for crude oil and natural gas
- higher sales volumes of light and heavy crude oil and natural gas

the effect of which was partially offset by:

- lower sales volume of medium crude oil
- higher unit operating costs

Higher production volumes of heavy crude oil were primarily due to:

- the ongoing Lloydminster heavy oil development programs and progress at the Bolney/Celtic steam assisted gravity drainage thermal project

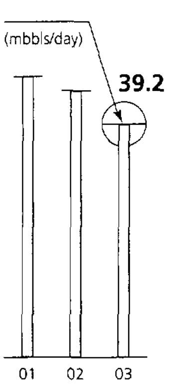
Operating costs per unit of production increased 11 percent in 2003 compared with 2002 primarily as a result of:

- higher energy costs
- higher operating and maintenance costs for light/medium crude oil properties under secondary and tertiary recovery schemes in Western Canada
- higher operating and maintenance costs for the extensive facilities associated with shallow gas production in Western Canada

partially offset by:

- lower unit operating costs at Terra Nova and Wenchang

Daily Production, before Royalties – Medium Crude Oil



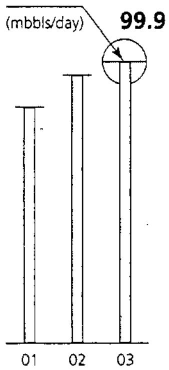
Lower medium crude oil production in 2003 reflected natural declines and non-core property sales

Depletion, depreciation and amortization ("DD&A") increased to $8.40/boe in 2003 from $7.76/boe in 2002 and primarily resulted from:

- higher maintenance capital requirements for properties under secondary and tertiary recovery and shallow natural gas operations
- offshore operations that require substantial infrastructure capital
- acquired oil and gas properties which, in accordance with the purchase method of accounting, are recorded at fair value

Income taxes with respect to the upstream business segment decreased in 2003 to $325 million from $397 million in 2002 despite higher pre-tax earnings. Income taxes in 2003 were partially offset by a number of non-recurring benefits. On June 13, 2003, Bill C-48 received first reading in the House of Commons and thus was considered to be substantively enacted. This amendment to the Income Tax Act reduces the income tax rate on resource income by seven percent, provides for the deduction from income of crown royalties and eliminates the resource allowance deduction. The amendment will be phased in over a five-year period. The total benefit recorded with respect to Bill C-48 was $141 million. In addition, a non-recurring upstream benefit totalling $18 million was recorded pursuant to Bill 41, the Alberta Corporate Tax Amendment Act, 2003. Both benefits reduced future income taxes related to upstream operations.

Daily Production, before Royalties – Heavy Crude Oil



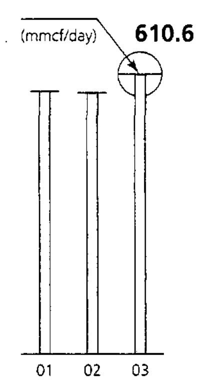
Heavy crude oil production grew five percent in 2003, setting a new record

During 2002, a non-recurring benefit of $23 million was recorded with respect to Alberta and British Columbia income tax rate reductions.

Net Revenue Variance Analysis

($ millions)	Crude Oil & NGL	Natural Gas	Other	Total
Year ended December 31, 2001				
Net revenues	$ 1,262	$ 873	$ 30	$ 2,165
Price changes	573	(342)	8	239
Volume changes	218	(7)	–	211
Royalties	(71)	113	–	42
Hedging	5	–	–	5
Processing	–	–	3	3
Year ended December 31, 2002				
Net revenues	1,987	637	41	2,665
Price changes	85	450	–	535
Volume changes	59	58	–	117
Royalties	16	(140)	–	(124)
Hedging	(50)	19	–	(31)
Processing	–	–	24	24
Year ended December 31, 2003				
Net revenues	**$ 2,097**	**$ 1,024**	**$ 65**	**$ 3,186**

Daily Production, before Royalties – Natural Gas

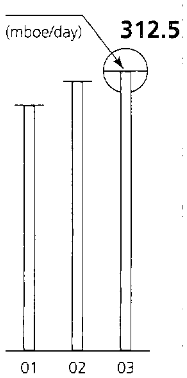


Natural gas production increased seven percent in 2003, reflecting the Marathon Canada acquisition

Daily Production, before Royalties

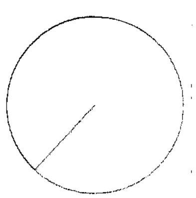
Year ended December 31		**2003**	2002	2001
Light crude oil & NGL	*(mbbls/day)*	**71.6**	65.4	46.4
Medium crude oil	*(mbbls/day)*	**39.2**	44.8	47.2
Heavy crude oil	*(mbbls/day)*	**99.9**	95.1	83.8
Natural gas	*(mmcf/day)*	**610.6**	569.2	572.6
Barrels of oil equivalent (6:1)	*(mboe/day)*	**312.5**	300.2	272.8

Daily Production, before Royalties – Total



Total daily production grew four percent in 2003

2003 Upstream Revenue Mix



Percent of upstream sales revenues, after royalties

Average Realized Prices

Year ended December 31		**2003**	2002	2001
Light crude oil & NGL	*($/bbl)*	**$ 39.53**	$ 36.17	$ 33.15
Hedging (gain)/loss		**0.80**	(0.09)	–
Light crude oil & NGL price realized		**$ 38.73**	$ 36.26	$ 33.15
Medium crude oil	*($/bbl)*	**$ 31.42**	$ 30.16	$ 23.69
Hedging (gain)/loss		**1.85**	(0.19)	–
Medium crude oil price realized		**$ 29.57**	$ 30.35	$ 23.69
Heavy crude oil price realized	*($/bbl)*	**$ 25.87**	$ 26.60	$ 17.02
Natural gas price	*($/mcf)*	**$ 5.86**	$ 3.83	$ 5.47
Hedging (gain)/loss		**(0.08)**	–	–
Natural gas price realized		**$ 5.94**	$ 3.83	$ 5.47

Upstream Revenue Mix

Year ended December 31	**2003**	2002	2001
Percentage of upstream sales revenues, after royalties			
Light crude oil & NGL	**28%**	24%	14%
Medium crude oil	**11%**	25%	28%
Heavy crude oil	**27%**	25%	16%
Natural gas	**34%**	26%	42%
Total	**100%**	100%	100%

Effective Royalty Rates

Year ended December 31	**2003**	2002	2001
Percentage of upstream sales revenues			
Light crude oil & NGL	**12%**	13%	21%
Medium crude oil	**18%**	17%	18%
Heavy crude oil	**11%**	11%	9%
Natural gas	**21%**	18%	23%
Total	**16%**	15%	19%

Operating Netbacks

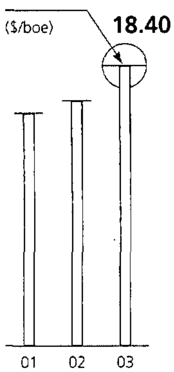
Western Canada

Light Crude Oil Netbacks [(1)]

Year ended December 31 (per boe)	**2003**	2002	2001
Sales revenues	**$ 39.91**	$ 33.66	$ 34.25
Royalties	**7.28**	4.55	5.76
Hedging (gain)/loss	**0.56**	(0.17)	–
Operating costs	**9.27**	10.46	8.15
Netback	**$ 22.80**	$ 18.82	$ 20.34

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

Total Western Canada Upstream Netbacks



Higher netbacks in 2003 reflected strong light crude oil and natural gas prices

Medium Crude Oil Netbacks (1)

Year ended December 31 (per boe)	**2003**	2002	2001
Sales revenues	**$ 31.57**	$ 29.92	$ 23.86
Royalties	**5.28**	5.59	4.39
Hedging (gain)/loss	**1.79**	(0.19)	–
Operating costs	**9.53**	7.19	7.18
Netback	**$ 14.97**	$ 17.33	$ 12.29

Heavy Crude Oil Netbacks (1)

Year ended December 31 (per boe)	**2003**	2002	2001
Sales revenues	**$ 25.98**	$ 26.48	$ 17.20
Royalties	**2.76**	3.45	1.93
Operating costs	**9.09**	7.18	7.40
Netback	**$ 14.13**	$ 15.85	$ 7.87

Natural Gas Netbacks (2)

Year ended December 31 (per mcfge)	**2003**	2002	2001
Sales revenues	**$ 5.79**	$ 3.97	$ 5.39
Royalties	**1.29**	0.81	1.30
Hedging (gain)/loss	**(0.08)**	–	–
Operating costs	**0.79**	0.70	0.58
Netback	**$ 3.79**	$ 2.46	$ 3.51

Total Western Canada Upstream Netbacks (1)

Year ended December 31 (per boe)	**2003**	2002	2001
Sales revenues	**$ 31.58**	$ 27.04	$ 26.42
Royalties	**5.48**	4.46	5.04
Hedging (gain)/loss	**0.14**	(0.05)	–
Operating costs	**7.56**	6.54	6.08
Netback	**$ 18.40**	$ 16.09	$ 15.30

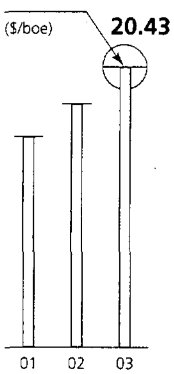
Terra Nova Crude Oil Netbacks

Year ended December 31 (per boe)	**2003**	2002	2001
Sales revenues	**$ 38.91**	$ 35.47	$ –
Royalties	**0.81**	0.36	–
Hedging (gain)/loss	**1.95**	–	–
Operating costs	**3.16**	3.62	–
Netback	**$ 32.99**	$ 31.49	$ –

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

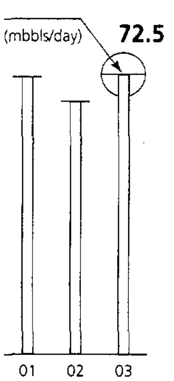
(2) Includes associated co-products converted to mcfge.

Total Upstream Netbacks



Husky's highest netbacks came from offshore oil production

Upgrader Throughput



Upgrader throughput set a new record in 2003

Wenchang Crude Oil Netbacks

Year ended December 31 (per boe)	2003	2002	2001
Sales revenues	**$ 41.45**	$ 44.36	$ –
Royalties	**3.80**	2.65	–
Operating costs	**1.94**	2.15	–
Netback	**$ 35.71**	$ 39.56	$ –

Total Upstream Netbacks (1)

Year ended December 31 (per boe)	2003	2002	2001
Sales revenues	**$ 32.69**	$ 28.12	$ 26.42
Royalties	**5.11**	4.20	5.04
Hedging (gain)/loss	**0.23**	(0.05)	–
Operating costs	**6.92**	6.24	6.08
Netback	**$ 20.43**	$ 17.73	$ 15.30

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

MIDSTREAM

2003 Compared with 2002

Total midstream earnings increased by $24 million (15 percent) to $185 million in 2003 from $161 million in 2002.

Upgrading Earnings Summary

Year ended December 31 ($ millions, except where indicated)		2003	2002	2001
Gross margin		**$ 313**	$ 246	$ 428
Operating costs		**205**	154	192
Other expenses (recoveries)		**(4)**	(6)	(12)
DD&A		**20**	18	17
Income taxes		**21**	26	73
Earnings		**$ 71**	$ 54	$ 158
Upgrader throughput (1)	*(mbbls/day)*	**72.5**	65.4	71.7
Synthetic crude oil sales	*(mbbls/day)*	**63.6**	59.3	59.5
Upgrading differential	*($/bbl)*	**$ 12.88**	$ 10.81	$ 17.91
Unit margin	*($/bbl)*	**$ 13.51**	$ 11.05	$ 19.79
Unit operating cost (2)	*($/bbl)*	**$ 7.77**	$ 6.48	$ 7.35

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

Upgrading earnings increased by 31 percent in 2003 primarily due to:

- wider upgrading differential, which averaged $12.88/bbl in 2003 versus $10.81/bbl in 2002
- higher throughput and sales volume

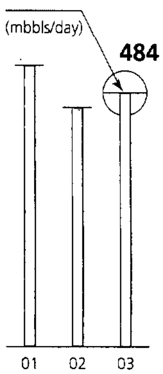
partially offset by:

- higher unit operating costs, which were primarily energy related

Upgrading Earnings Variance Analysis

($ millions)	
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
Volume	18
Differential	49
Operating costs – energy related	(49)
Operating costs – non-energy related	(2)
Other	(2)
DD&A	(2)
Income taxes	5
Year ended December 31, 2003	**$ 71**

Pipeline Throughput



Pipeline throughput increased six percent in 2003

Infrastructure and Marketing Earnings Summary

Year ended December 31 ($ millions, except where indicated)	**2003**	2002	2001
Gross margin			
Pipeline	**$ 66**	$ 55	$ 86
Other infrastructure and marketing	**141**	147	111
	207	202	197
Other expenses	**8**	10	10
DD&A	**21**	20	17
Income taxes	**64**	65	72
Earnings	**$ 114**	$ 107	$ 98
Aggregate pipeline throughput *(mbbls/day)*	**484**	457	537

Infrastructure and marketing earnings increased by seven percent in 2003 primarily due to:

- higher heavy crude oil pipeline throughput
- higher cogeneration income

partially offset by:

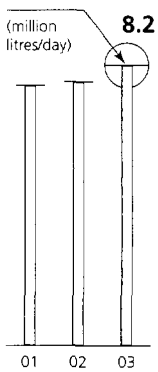
- lower crude oil and natural gas commodity marketing margins

REFINED PRODUCTS

2003 Compared with 2002

Total refined products earnings decreased by $4 million (13 percent) to $28 million in 2003 from $32 million in 2002. Light oil refined products earnings decreased primarily due to lower fuel margins. Earnings from asphalt products operations increased reflecting strong margins and sales volumes.

Light Oil Products Sales Volume



Light oil products sales set a new record in 2003

Refined Products Earnings Summary

Year ended December 31 ($ millions, except where indicated)		2003	2002	2001
Gross margin				
Fuel sales		**$ 71**	$ 81	$ 69
Ancillary sales		**28**	26	27
Asphalt sales		**51**	45	106
		150	152	202
Operating and other expenses		**70**	64	59
DD&A		**34**	34	31
Income taxes		**18**	22	49
Earnings		**$ 28**	$ 32	$ 63
Number of fuel outlets		**552**	571	580
Refined products sales volume				
Light oil products	*(million litres/day)*	**8.2**	7.7	7.6
Light oil products per outlet	*(thousand litres/day)*	**10.8**	10.0	9.5
Asphalt products	*(mbbls/day)*	**22.0**	20.8	21.4
Refinery throughput				
Prince George refinery	*(mbbls/day)*	**10.3**	10.1	10.2
Lloydminster refinery	*(mbbls/day)*	**25.7**	22.0	23.7

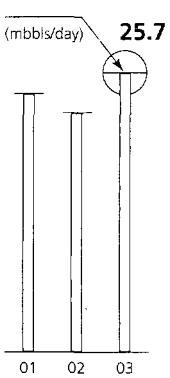
CORPORATE

2003 Compared with 2002

Interest

Interest – net, which is total debt charges net of interest income and capitalized interest, was $73 million in 2003 compared with $104 million in 2002. Interest capitalized in 2003 was $52 million compared with $26 million in 2002 reflecting the higher aggregate capital invested in the White Rose development project in 2003. Interest income was $6 million in 2003 compared with $1 million in 2002. Total interest on short- and long-term debt in 2003 was $131 million, the same as in 2002. During 2003 interest on lower debt levels was offset by the effect of higher after swap interest rates. The impact of the interest rate risk management activities was a reduction to interest expense of $17 million in 2003. Husky's effective interest rate for 2003 after the effect of interest rate swaps was 6.32 percent compared with 5.48 percent during 2002.

Lloydminster Refinery Throughput



Lloydminster refinery throughput set a new record in 2003

Foreign Exchange

Foreign exchange gains of $215 million in 2003 comprised $315 million of gains on U.S. dollar denominated long-term debt partially offset by $73 million of cross currency swap losses and $27 million of foreign exchange losses on other monetary items.

Consolidated Income Taxes

Consolidated income taxes increased in 2003 to $474 million from $420 million in 2002 as a result of higher pre-tax earnings. Income taxes in 2003 were partially offset by a number of non-recurring benefits. On June 13, 2003, Bill C-48 received first reading in the House of Commons and thus was considered to be substantively enacted. This amendment to the Income Tax Act reduces the income tax rate on resource income by seven percent, provides for the deduction from income of crown royalties and eliminates the resource allowance deduction. The amendment will be phased in over a five-year period. The total benefit recorded was $141 million. In addition, a non-recurring benefit totalling $20 million was recorded pursuant to Bill 41, the Alberta Corporate Tax Amendment Act, 2003. Both benefits reduced future income taxes. During 2002, a non-recurring benefit of $31 million was recorded with respect to federal, Alberta and British Columbia income tax rate reductions.

In 2003 current income taxes totalled $147 million and comprised $73 million with respect to the Wenchang oil field operation, $22 million of capital taxes and $52 million of Canadian income tax.

The following table shows the effect of non-recurring benefits for the periods noted:

($ millions)	**2003**	2002
Income taxes as reported	**$ 474**	$ 420
Canadian federal and provincial tax changes	**161**	31
Pro forma income taxes	**$ 635**	$ 451

At December 31, 2003 and 2002, Husky's Canadian tax pools consisted of the following:

($ millions)	**2003**	2002
Canadian exploration expense	**$ 42**	$ 440
Canadian development expense	**1,103**	967
Canadian oil and gas property expense	**814**	1,066
Foreign exploration and development expense	**142**	172
Undepreciated capital costs	**2,909**	2,305
Other	**22**	56
	$ 5,032	$ 5,006

Capital Resources

OPERATING ACTIVITIES

In 2003 cash generated by operating activities was $2,572 million, an increase of $680 million from the $1,892 million recorded in 2002. The higher cash from operating activities in 2003 was primarily due to higher commodity prices and a change in non-cash working capital.

FINANCING ACTIVITIES

In 2003 cash used in financing activities amounted to $800 million. The cash used was composed of the repayment of long-term debt of $971 million, payment of the return on capital securities of $29 million, dividends of $580 million, including a $1.00 per share special dividend and settlement of a cross currency swap of $32 million. Cash provided by financing activities in 2003 comprised $598 million issuance of long-term debt and $71 million utilization of operating lines, $51 million of proceeds from the exercise of stock options, proceeds from interest rate swaps totalling $44 million and a change of $48 million in non-cash working capital.

Husky's long-term debt balances were also reduced by $315 million during 2003 as a result of the narrowing of the exchange rate between Canadian and U.S. currencies.

INVESTING ACTIVITIES

Cash used in investing activities amounted to $2,075 million in 2003, an increase of $486 million from the $1,589 million in 2002. Cash invested in 2003 was composed of capital expenditures of $1,905 million, acquisition of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. ("Marathon Canada") for $809 million partially offset by $511 million of proceeds from asset sales, primarily certain Marathon Canada properties. Change in non-cash working capital and other adjustments amounted to $128 million provided by investing activities.

Capital Expenditures

The following table shows Husky's capital expenditures for the years ended December 31:

Year ended December 31 ($ millions)	**2003** [1]	2002	2001
Upstream			
Exploration			
Western Canada	**$ 326**	$ 304	$ 236
East Coast Canada	**24**	41	81
International	**26**	9	5
	376	354	322
Development			
Western Canada	**872**	730	786
East Coast Canada	**533**	417	110
International	**–**	66	99
	1,405	1,213	995
	1,781	1,567	1,317
Midstream			
Upgrader	**25**	41	47
Infrastructure and marketing	**18**	17	58
	43	58	105
Refined Products	**58**	44	29
Corporate	**23**	23	22
	$ 1,905	$ 1,692	$ 1,473

(1) 2003 does not include the acquisition of Marathon Canada.

Upstream Capital Expenditures

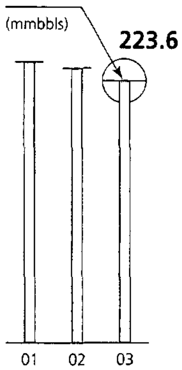
Western Canada During 2003 capital expenditures for exploration and development in Western Canada totalled $1,198 million compared with $1,034 million during 2002.

Total development spending in Western Canada during 2003 amounted to $872 million compared with $730 million during 2002. In 2003 development capital was directed to the following areas:

- Alberta northwest plains area, $183 million for shallow natural gas drilling, completions and installation of facilities in the Boyer/Cherpeta districts.
- Lloydminster heavy oil area, $303 million for continued exploitation and optimization including work on the Bolney/Celtic thermal project, with a year-end exit rate of 10 mbbls/day. Lloydminster capital expenditures during 2002 and 2001 were $273 million and $324 million, respectively.
- East central and southern Alberta and southern Saskatchewan, $259 million primarily for in-fill drilling, facilities optimization, acquisitions and development of the Shackleton/Lacadena natural gas project in southwestern Saskatchewan. By the end of 2003, 240 net wells had been drilled and completed in the Shackleton area. Capital expenditures in the east central and southern Alberta and southern Saskatchewan areas totalled $180 million and $193 million during 2002 and 2001, respectively.
- British Columbia and Alberta foothills area, $122 million for facilities optimization and in-fill drilling at major Alberta foothills natural gas properties. Capital expenditures in the British Columbia and Alberta foothills area totalled $105 million and $115 million during 2002 and 2001, respectively.

Exploration expenditures on Husky's prospects in the Western Canada Sedimentary Basin in 2003 amounted to $326 million compared with $304 million in 2002. The primary exploration targets were natural gas prospects in the Alberta foothills as well as step-out drilling throughout Husky's properties in the Basin. In addition, pre-development spending during 2003 on the oil sands projects at Sunrise and Tucker, Alberta included in exploration capital expenditures amounted to $41 million. Capital expenditures on the oil sands projects totalled $20 million and $8 million during 2002 and 2001, respectively.

Proved Reserves – Light Crude Oil & NGL

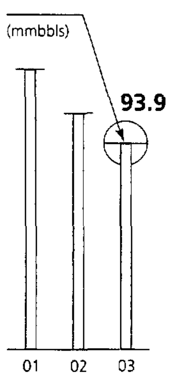


Light crude oil & NGL proved reserves declined by five percent in 2003

Western Canada Drilling

Year ended December 31 (wells)		2003		2002		2001	
		Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	**12**	**11**	21	20	78	76
	Gas	**147**	**124**	139	131	102	90
	Dry	**22**	**21**	15	14	36	34
		181	**156**	175	165	216	200
Development	Oil	**520**	**490**	497	453	594	542
	Gas	**540**	**518**	485	453	251	221
	Dry	**60**	**57**	58	55	68	63
		1,120	**1,065**	1,040	961	913	826
Total		**1,301**	**1,221**	1,215	1,126	1,129	1,026

Proved Reserves – Medium Crude Oil



Medium crude oil proved reserves fell by 13 percent in 2003

East Coast Canada Capital expenditures at Husky's White Rose oil field development offshore Newfoundland and Labrador amounted to $505 million in 2003 compared with $395 million in 2002. Capital expenditures with respect to the Terra Nova oil field amounted to $28 million in 2003 compared with $22 million in 2002.

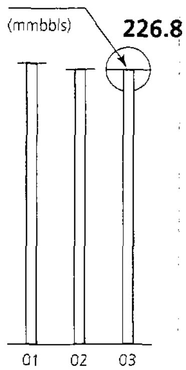
Capital expenditures for the 2003 East Coast exploration program amounted to $24 million.

International Exploration spending in the South China Sea amounted to $26 million in 2003 compared with $9 million in 2002. Spending in 2003 was primarily related to drilling two exploration wells and preparation for an exploration program that involved shooting an extensive seismic program in blocks 23-15, 39-05 and 40-30 followed by interpretation of the data. Drilling is expected to commence in the fourth quarter of 2004.

Midstream Capital Expenditures

Midstream capital expenditures in 2003 of $43 million were primarily for upgrader, pipeline and cogeneration plant upgrades and upgrader debottlenecking front-end engineering.

Proved Reserves – Heavy Crude Oil



Heavy crude oil proved reserves were unchanged in 2003

Refined Products Capital Expenditures

Refined products capital expenditures in 2003 of $58 million were primarily for marketing outlet improvements and refinery maintenance.

Corporate Capital Expenditures

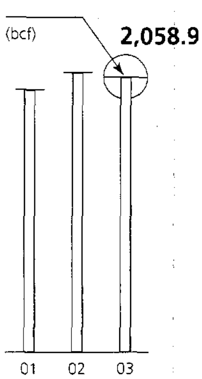
Corporate capital expenditures amounted to $23 million in 2003 and 2002 and were primarily for computer hardware and software and office furniture and equipment.

Oil and Gas Reserves

One of the fundamental measures of value creation is the efficient addition of oil and gas reserves. During the three years ended December 31, 2003, Husky replaced an average of 105 percent of production on a boe basis, inclusive of acquisitions and divestitures.

During 2003, additions to proved natural gas reserves amounted to 485 bcf. Field extensions and improved recovery at Craigend, Alberta and Muskwa and Bivouac, British Columbia totalled 187 bcf, discoveries in the Alberta foothills area amounted to 114 bcf and acquisitions added 184 bcf, primarily from the acquisition of Marathon Canada, which accounted for 180 bcf. Natural gas revisions reduced reserves by 275 bcf due to a reclassification of proved natural gas reserves for Madura, Indonesia, water incursion at Ricinus in the Alberta foothills area and higher shallow gas declines at Caribou and Evergreen, Alberta. Non-core divestitures amounted to 23 bcf.

Proved Reserves – Natural Gas



Proved natural gas reserves declined by two percent in 2003

During 2003, 57 mmbbls were added to proved crude oil and NGL reserves. Additions to proved reserves from discoveries and extensions totalled 36 mmbbls primarily in the Lloydminster heavy oil area. Revisions of 9 mmbbls reflect positive technical revisions of 14 mmbbls supported by improved performance primarily in the Lloydminster area partially offset by revisions of 5 mmbbls primarily due to a reclassification of NGL reserves at Madura, Indonesia. Acquisitions of proved reserves added 12 mmbbls, 9 mmbbls of which was acquired with Marathon Canada. Non-core property divestitures were 5 mmbbls in 2003.

At December 31, 2003, 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 $5.8 billion compared with $7.2 billion at the end of 2002.

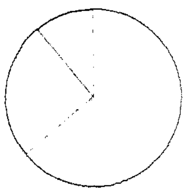
McDaniel & Associates Consultants Ltd., *an independent firm of oil and gas reserves evaluation engineers,* was engaged to conduct an audit of Husky's crude oil, natural gas and natural gas products reserves. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices in the United States and as set out in the Canadian Oil and Gas Evaluation Handbook.

Summary of Reserves

Light Crude Oil & NGL Reserves

Year ended December 31 (mmbbls)	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Proved developed	**200**	**177**	193	171	175	153
Proved undeveloped	**23**	**18**	42	32	65	58
Total proved	**223**	**195**	235	203	240	211

Total Proved Reserves at December 31, 2003



- Light Crude Oil & NGL **25%**
- Medium Crude Oil **11%**
- Heavy Crude Oil **25%**
- Natural Gas **39%**

Total proved reserves fell by three percent in 2003

Medium Crude Oil Reserves

Year ended December 31 (mmbbls)	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Proved developed	**86**	**73**	94	79	109	95
Proved undeveloped	**8**	**7**	13	12	18	16
Total proved	**94**	**80**	107	91	127	111

Heavy Crude Oil Reserves

Year ended December 31 (mmbbls)	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Proved developed	**156**	**144**	152	139	141	131
Proved undeveloped	**71**	**66**	75	68	91	87
Total proved	**227**	**210**	227	207	232	218

Natural Gas Reserves

Year ended December 31 (bcf)	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Proved developed	**1,712**	**1,423**	1,547	1,273	1,577	1,342
Proved undeveloped	**347**	**294**	548	440	389	332
Total proved	**2,059**	**1,717**	2,095	1,713	1,966	1,674

Barrels of Oil Equivalent

Year ended December 31 (mmboe)	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Proved developed	**727**	**632**	697	601	688	603
Proved undeveloped	**160**	**140**	221	185	239	216
Total proved	**887**	**772**	918	786	927	819

Reserve Life Index [(1)]

Year ended December 31 (years)	2003	2002	2001
Light crude oil & NGL	**8.6**	9.8	14.1
Medium crude oil	**6.6**	6.5	7.4
Heavy crude oil	**6.2**	6.5	7.6
Natural gas	**9.2**	10.1	9.4
Barrels of oil equivalent	**7.8**	8.4	9.3

(1) *Includes total proved reserves.*

Reserve Reconciliation [(1)]

	Canada					International		Total	
	Western Canada				East Coast				
	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural Gas	Light Crude Oil	Light Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas
	(mmbbls)	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(bcf)*
Proved reserves, before royalties [(2)]									
Proved reserves at December 31, 2000	181.2	135.7	186.7	1,766.1	11.3	39.1	142.9	554.0	1,909.0
Revisions	6.5	0.3	18.9	22.5	1.2	0.2	–	27.1	22.5
Purchases	2.4	9.5	23.7	23.7	–	–	–	35.6	23.7
Sales	–	(1.8)	–	(21.1)	–	–	–	(1.8)	(21.1)
Discoveries, extensions and improved recovery	9.0	1.0	33.3	240.7	4.8	1.2	–	49.3	240.7
Production	(16.9)	(17.2)	(30.6)	(209.0)	–	(0.1)	–	(64.8)	(209.0)
Proved reserves at December 31, 2001	182.2	127.5	232.0	1,822.9	17.3	40.4	142.9	599.4	1,965.8
Revisions	(4.8)	9.7	7.0	(37.2)	–	–	–	11.9	(37.2)
Purchases	0.2	–	4.7	6.2	–	–	–	4.9	6.2
Sales	(1.8)	(14.2)	(0.4)	(19.0)	–	–	–	(16.4)	(19.0)
Discoveries, extensions and improved recovery	5.3	0.9	18.5	386.5	18.5	1.2	–	44.4	386.5
Production	(14.6)	(16.4)	(34.7)	(207.8)	(4.8)	(4.5)	–	(75.0)	(207.8)
Proved reserves at December 31, 2002	166.5	107.5	227.1	1,951.6	31.0	37.1	142.9	569.2	2,094.5
Revisions	5.0	1.3	6.4	(131.6)	0.8	(4.5)	(142.9)	9.0	(274.5)
Purchases	9.3	–	2.8	183.9	–	–	–	12.1	183.9
Sales	(0.9)	(2.5)	(1.4)	(23.1)	–	–	–	(4.8)	(23.1)
Discoveries, extensions and improved recovery	5.4	1.9	28.4	301.0	–	–	–	35.7	301.0
Production	(11.8)	(14.3)	(36.5)	(222.9)	(6.1)	(8.2)	–	(76.9)	(222.9)
Proved reserves at December 31, 2003	**173.5**	**93.9**	**226.8**	**2,058.9**	**25.7**	**24.4**	**–**	**544.3**	**2,058.9**
Proved developed reserves, before royalties [(3)]									
December 31, 2000	167.5	117.6	117.5	1,579.9	–	0.5	–	403.1	1,579.9
December 31, 2001	168.6	108.7	141.0	1,576.5	6.2	0.6	–	425.1	1,576.5
December 31, 2002	154.8	93.6	152.4	1,546.5	7.4	30.7	–	438.9	1,546.5
December 31, 2003	**158.5**	**85.8**	**156.2**	**1,712.4**	**17.2**	**24.4**	**–**	**442.1**	**1,712.4**
Probable reserves, before royalties [(4)] [(5)]									
December 31, 2000	72.4	35.2	105.7	434.1	202.3	5.3	18.9	420.9	453.0
December 31, 2001	72.0	36.0	105.0	405.6	213.3	4.2	18.9	430.5	424.5
December 31, 2002	70.3	24.1	152.0	383.9	201.6	4.2	18.9	452.2	402.8
December 31, 2003	**61.0**	**13.8**	**171.3**	**381.3**	**182.2**	**7.0**	**66.5**	**435.3**	**447.8**

(1) Husky applied for and was granted an exemption from National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" to provide oil and gas reserves disclosures in accordance with the U.S. Securities and Exchange Commission guidelines and the U.S. Financial Accounting Standards Board disclosure standards. The information disclosed may differ from information prepared in accordance with National Instrument 51-101. Husky's internally generated oil and gas reserves data was audited by an independent firm of consulting engineers.

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

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

(4) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves (Canadian Oil and Gas Evaluation Handbook). The Securities and Exchange Commission in the United States does not generally permit disclosure of probable reserves to be included in filed documents due to the higher level of uncertainty associated with probable reserves.

(5) Heavy crude oil probable reserves include bitumen located in the oil sands designated regions of Alberta.

Finding and Development Costs

Western Canada [1]

Year ended December 31		2001-2003	2003	2002	2001
Total capitalized costs	*($ millions)*	**$3,019.1**	**$1,132.7**	$ 994.2	$ 892.2
Proved reserve additions and revisions	*(mmboe)*	**284.3**	**76.6**	94.8	112.9
Average cost per boe		**$ 10.62**	**$ 14.79**	$ 10.49	$ 7.90

(1) Excludes oil sands and acquisitions/divestitures.

Production Replacement

Total

Year ended December 31		2001-2003	2003	2002	2001
Production	*(mmboe)*	**323.3**	**114.1**	109.6	99.6
Proved reserve additions and revisions	*(mmboe)*	**284.0**	**49.1**	114.5	120.4
Production replacement ratio (excluding acquisitions/divestitures)	*(percent)*	**88**	**43**	104	121
Proved reserve additions and revisions (including acquisitions/divestitures)	*(mmboe)*	**338.6**	**83.2**	100.9	154.5
Production replacement ratio (including acquisitions/divestitures)	*(percent)*	**105**	**73**	92	155

Western Canada [1]

Year ended December 31		2001-2003	2003	2002	2001
Production	*(mmboe)*	**299.4**	**99.7**	100.2	99.5
Proved reserve additions and revisions	*(mmboe)*	**284.3**	**76.6**	94.8	112.9
Production replacement ratio (excluding acquisitions/divestitures)	*(percent)*	**95**	**77**	95	113
Proved reserve additions and revisions (including acquisitions/divestitures)	*(mmboe)*	**338.9**	**110.7**	81.2	147.0
Production replacement ratio (including acquisitions/divestitures)	*(percent)*	**113**	**111**	81	148

(1) 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 operating netback by the proved finding and development cost on a boe basis.

Western Canada [1]

Year ended December 31		**2001-2003**	**2003**	2002	2001
Operating netback	*($/boe)*	**$ 16.60**	**$ 18.40**	$ 16.09	$ 15.30
Proved finding and development cost	*($/boe)*	**$ 10.62**	**$ 14.79**	$ 10.49	$ 7.90
Recycle ratio		**1.56**	**1.24**	1.53	1.94

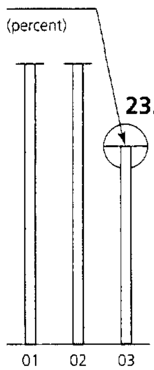
[1] *Excludes oil sands.*

Undeveloped Land Holdings

Year ended December 31 (thousands of acres)	**2003**		2002	
	Gross	Net	Gross	Net
Western Canada				
Alberta	**5,508**	**4,852**	5,416	4,907
Saskatchewan	**2,057**	**1,911**	2,098	1,986
British Columbia	**713**	**491**	314	273
Manitoba	**9**	**8**	13	13
	8,287	**7,262**	7,841	7,179
Northwest Territories and Arctic	**527**	**184**	463	175
Eastern Canada	**2,414**	**2,104**	2,414	2,104
Total Canada	**11,228**	**9,550**	10,718	9,458
International	**4,464**	**2,066**	4,464	2,066
Total	**15,692**	**11,616**	15,182	11,524

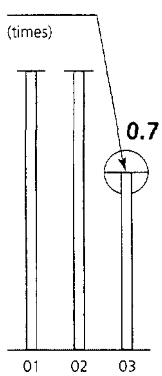
Liquidity

Debt to Capital Employed



Debt to capital employed ratio fell to 23 percent in 2003

Debt to Cash Flow from Operations



Debt to cash flow from operations ratio strengthened in 2003 despite the Marathon Canada acquisition and payment of a special dividend

SOURCES OF CAPITAL

As at December 31, 2003 Husky's outstanding long-term debt totalled $1,698 million, including amounts due within one year, compared with $2,385 million at December 31, 2002.

At December 31, 2003 Husky had no funds drawn under its $830 million revolving syndicated credit facility. Interest rates under 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. The syndicated credit facility requires Husky to maintain a debt to cash flow ratio of less than three times and a consolidated net worth of at least $3.6 billion.

At December 31, 2003 Husky had no funds drawn under its $100 million credit facility. The terms of this facility are substantially the same as the syndicated credit facility.

At December 31, 2003 the Company had drawn $71 million and utilized in support of letters of credit $18 million of its $195 million in short-term borrowing 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. In addition, Husky utilized $88 million under dedicated letter of credit facilities.

The Company has an agreement to sell up to $250 million of net trade receivables on a revolving basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates, to be paid on an ongoing basis. As at December 31, 2003, $250 million of net trade receivables had been sold under this agreement. The arrangement matures on January 31, 2009.

The Company believes that, based on its current forecast for commodity prices for 2004, its 2004 capital program of $2.1 billion and non-cancellable cash contractual obligations and commitments will be funded by operating activities and, to the extent required, available credit facilities. In the event of significantly lower cash flow, the Company would be able to defer certain of its capital spending programs without penalty.

The Company declared dividends that aggregated $1.38 per share ($580 million) in 2003 including a special dividend of $1.00 per share. The Board of Directors of Husky has established a dividend policy that pays quarterly dividends of $0.10 ($0.40 annually) per common share. 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.

Cash and cash equivalents at December 31, 2003 totalled $3 million compared with $306 million at the beginning of the year.

Financial Ratios

Year ended December 31		**2003**	2002	2001
Cash flow – operating activities	*($ millions)*	**$ 2,572**	$ 1,892	$ 1,930
– financing activities	*($ millions)*	**$ (800)**	$ 3	$ (423)
– investing activities	*($ millions)*	**$ (2,075)**	$ (1,589)	$ (1,507)
Debt to capital employed	*(percent)*	**23.1**	31.8	32.8
Debt to cash flow from operations	*(times)*	**0.7**	1.1	1.1
Corporate reinvestment ratio [1]		**0.9**	0.8	0.8

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

Credit Ratings

Husky receives debt ratings from three rating agencies. In determining Husky's debt rating the agencies evaluate several factors including, but not limited to, the industry Husky operates in, volatility of the industry, the geographical and business diversity and quality of the Company's asset base, near- and long-term production growth opportunities, capital allocation and cost structure issues, capital structure and character of oil and gas reserves. There are debt rating features in Husky's debt covenants that cause a change in interest rates in certain debt facilities and may cause the issuance of letters of credit pursuant to the terms of certain commercial contracts. In addition the Company's debt ratings could affect the ability of the Company to secure new or additional credit facilities if the rating falls below investment grade.

At December 31, 2003 Husky had the following credit ratings:

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

Capital Requirements

Husky plans to invest capital in the following segments in 2004:

Year ended December 31 ($ millions)	**2004 Estimate**
Upstream	
Western Canada	$ 1,150
East Coast Canada	585
International	65
	1,800
Midstream	100
Refined Products	150
Corporate	30
	$ 2,080

In order to retain undeveloped acreage Husky is required to drill wells within a certain time frame otherwise the acreage is relinquished. In order to maintain its undeveloped acreage at current retention rates over the period 2004 to 2007, Husky estimates drilling expenditures of approximately $75 million in 2004, $65 million in 2005 and $45 million during both 2006 and 2007.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

In the normal course of business Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

Contractual Obligations

Payments due by period ($ millions)	Total	2004-2006	2007-2008	Thereafter
Long-term debt	$ 1,698	$ 545	$ 146	$ 1,007
Capital securities	291	–	–	291
Operating leases	514	194	145	175
Firm transportation agreements	1,788	679	369	740
Unconditional purchase obligations	915	776	124	15
Exploration lease agreements	497	167	97	233
Engineering and construction commitments	597	597	–	–
	$ 6,300	$ 2,958	$ 881	$ 2,461

Investment Canada Undertakings

In respect of the acquisition of Marathon Canada, Husky confirmed certain undertakings to the Minister Responsible for the Investment Canada Act. The undertakings included capital expenditures on the purchased and retained Marathon Canada lands amounting to $65 million, spending on community activities amounting to $1.35 million and environmental expenditures of $40 million, all to occur in 2004.

Asset Retirement Obligations

The above table does not include asset retirement obligations. The Company currently includes such obligations in the amortizing base of its oil and gas properties. Effective January 1, 2004 with the adoption of the Canadian Institute of Chartered Accountants ("CICA") section 3110, "Asset Retirement Obligations", the Company will record a separate liability for the fair value of its asset retirement obligations. See note 20 to the Consolidated Financial Statements.

Post-retirement Benefit Obligations

The above table does not include post-retirement obligations. Husky has a defined contribution pension plan and a post-retirement health and dental care plan for its employees. In addition Husky has a defined benefit pension plan for approximately 230 employees. In 1991 admittance to the defined benefit pension plan ended after the majority of members transferred to the newly created defined contribution pension plan.

Other Obligations

Husky is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

OFF BALANCE SHEET ARRANGEMENTS

Husky does not currently utilize any off balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions or for any other purpose.

Transactions with Related Parties and Major Customers

Husky, in the ordinary course of business, entered into a lease for an eight-year term effective September 1, 2000 with Western Canadian Place Ltd. The terms of the lease provide for the lease of office space, management services and operating costs at commercial rates. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. During 2003 Husky paid approximately $17 million for office space in Western Canadian Place.

Husky did not have any customers that constituted more than five percent of total sales and operating revenues during 2003.

Financial and Derivative Instruments

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Refer to the section "Business Environment". Husky, from time to time, uses derivative instruments to manage its exposure to these risks.

COMMODITY PRICE RISK MANAGEMENT

Husky uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

The Company implemented a corporate hedging program for 2004 to manage the volatility of natural gas and crude oil prices.

Natural Gas

The 2003 natural gas hedging program was in effect from April 2003 to December 2003. During that period Husky received net payments totalling $24 million on these contracts.

At December 31, 2003 Husky had natural gas swap agreements in place to hedge 2004 production. The contracts were as follows:

Natural Gas Hedges

	Notional Volumes	Term	Price	Unrecognized Gain/(Loss)
	(mmcf/day)			*($ millions)*
NYMEX fixed price	70	February 2004	U.S. $6.69/mmbtu	$ 1
	70	March 2004	U.S. $6.69/mmbtu	2
	20	April 2004	U.S. $6.38/mmbtu	1
				$ 4

Crude Oil

Crude oil hedges on 27.6 mmbbls were in effect from January to December 2003. During that period Husky recorded net payments totalling $36 million on these contracts.

Husky had a put option contract in effect from July to December 2003 on 3.7 mmbbls of crude oil with a strike price of U.S. $27/bbl. The contract was a full-term settlement contract. Husky paid $8 million for the contract which was charged to earnings over the contract period.

At December 31, 2003 Husky had crude oil swap agreements in place to hedge 2004 production. The contracts were as follows:

Crude Oil Hedges

	Notional Volumes	Term	Price	Unrecognized Gain/(Loss)
	(mbbls/day)			*($ millions)*
NYMEX fixed price	85	Jan. to Dec. 2004	U.S. $27.46/bbl	$ (109)

Power Consumption

At December 31, 2003, Husky had hedged power consumption as follows:

Power Consumption Hedges

	Notional Volumes	Term	Price	Unrecognized Gain/(Loss)
	(MW)			*($ millions)*
Fixed price purchase	20.0	Jan. to Dec. 2004	$46.25/MWh	$ 1
	17.5	Jan. to Dec. 2004	$47.25/MWh	1
				$ 2

FOREIGN CURRENCY RISK MANAGEMENT

At December 31, 2003, the Company had the following cross currency debt swaps in place:

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

At December 31, 2003 the cost of a U.S. dollar in Canadian currency was $1.2924.

In 2003 the cross currency swaps resulted in an offset to foreign exchange gains on translation of U.S. dollar denominated debt amounting to $73 million.

INTEREST RATE RISK MANAGEMENT

In 2003 the interest rate risk management activities resulted in a decrease to interest expense of $17 million.

The cross currency swaps resulted in an addition to interest expense of $13 million in 2003.

Husky has an interest rate swap on $200 million of long-term debt effective February 8, 2002 whereby 6.95 percent was swapped for CDOR + 175 bps until July 14, 2009. During 2003 this swap resulted in an offset to interest expense amounting to $4 million.

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

Husky had three interest rate swaps that were unwound in 2003. During 2003, the impact of these three swaps before they were unwound was an offset to interest expense of $6 million. The amortization of the swap terminations resulted in an additional $8 million offset to interest expense.

Application of Critical Accounting Estimates

Husky's financial statements have been prepared in accordance with generally accepted accounting principles. The significant accounting policies used by Husky are disclosed in note 3 to the Consolidated Financial Statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discusses such accounting policies and 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. Husky's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

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

PROVED OIL AND GAS RESERVES

Proved oil and gas reserves, as defined by the U.S. Securities and Exchange Commission Regulation S-X Rule 4-10, 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, i.e., prices and costs as of the date the estimate is made.

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 oil and gas reserve 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 and estimated future development costs less estimated salvage values 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 would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would 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.

IMPAIRMENT OF LONG-LIVED ASSETS

The Company is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

FAIR VALUE OF DERIVATIVE INSTRUMENTS

Periodically Husky utilizes financial derivatives to manage market risk. The purpose of the hedge is to provide an element of stability to Husky's cash flow in a volatile environment. Husky discloses the estimated fair value of open hedging contracts as at the end of a reporting period. Effective January 1, 2004 Husky will adopt CICA Accounting Guideline 13, "Hedging Relationships" ("AcG-13"). AcG-13 has essentially the same criteria to be satisfied before the application of hedge accounting is permitted as the corresponding requirements of the Financial Accounting Standards Board ("FASB") Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). Refer to the description of FAS 133 in note 20 to the Consolidated Financial Statements.

The estimation of the fair value of certain hedging derivatives requires considerable judgement. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility data and, which when compared with Husky's open hedging contracts, produce cash inflow or outflow variances over the contract period. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through quotes from financial institutions.

Accounting rules for transactions involving derivative instruments are complex and subject to a range of interpretation. The FASB has established the Derivative Implementation Group task force, which, on an ongoing basis, considers issues arising from interpretation of these accounting rules. The potential exists that the task force may promulgate interpretations that differ from those of the Company. In this event the Company's policy would be modified.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004 the Company will change its accounting policy with respect to accounting for asset retirement obligations. CICA section 3110, essentially the same as FASB's Statement No. 143, "Accounting for Asset Retirement Obligations" ("FAS 143"), requires the fair value of asset retirement obligations to be recorded when they are incurred rather than merely accumulated or accrued over the useful life of the respective asset.

The Company, under the current policy, is required to provide for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated 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, the actual income tax liability may differ significantly from that estimated and recorded by management.

BUSINESS COMBINATIONS

Over recent years Husky has grown considerably through combining with other businesses. Husky acquired Marathon Canada in 2003. This transaction was accounted for using what is now the only accounting method available, the purchase method. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and gas properties primarily relies on placing a value on the oil and gas reserves. The valuation of oil and gas reserves entails the process described above under the caption "Proved Oil and Gas Reserves" but in contrast incorporates the use of economic forecasts that estimate future changes in prices and costs. In addition this methodology is used to value unproved oil and gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of proved reserves.

GOODWILL

The process of accounting for the purchase of a company, described above, results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise the determination of goodwill is also imprecise. In accordance with the recent issuance of FASB Statement No. 142 and CICA section 3062, "Goodwill and Other Intangible Assets", goodwill is no longer amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires Husky to determine the fair value of its assets and liabilities. Such a process involves considerable judgement.

New Accounting Standards

ASSET RETIREMENT OBLIGATIONS

In June 2001 the FASB issued FAS 143, "Accounting for Asset Retirement Obligations". FAS 143 was effective January 1, 2003 for U.S. reporting purposes. The Canadian version of FAS 143, CICA section 3110, which is essentially the same, is effective January 1, 2004. These new methods for accounting for asset retirement obligations require 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 CICA section 3110, the Company will adjust its existing future removal and site restoration liability retroactively with restatement.

The Company has estimated that the cumulative effect will be an increase of the future removal and site restoration liability of $129 million, an increase of related net property, plant and equipment of $164 million, an increase to the future income tax liability of $13 million and an increase in retained earnings of $22 million.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

In June 1998 the FASB issued FAS 133, "Accounting for Derivative Instruments and Hedging Activities". This was followed in June 2000 when the FASB promulgated FAS 138, which amended FAS 133 and FAS 149, a further modification that was effective for contracts entered into or modified after June 30, 2003. In Canada the Accounting Standards Board ("AcSB") intends to bring Canadian accounting standards into line with those in the U.S. by a two-stage approach. The first stage is an amendment to AcG-13, "Hedging Relationships", which is effective January 1, 2004 and establishes criteria to be satisfied before hedge accounting may be applied. The second stage comprises three exposure drafts that were issued on March 31, 2003. The culmination of stage two is expected to complete the harmonization of the Canadian accounting for derivatives, for all intents and purposes, with U.S. GAAP.

These accounting standards require that every derivative instrument, including certain derivative instruments embedded in other contracts, be recorded on the balance sheet as either an asset or liability measured at fair value. These standards further establish that changes in the fair value be recognized currently in earnings unless the arrangement can meet the "effective hedge" criteria.

STOCK-BASED COMPENSATION PLANS

In October 1995 the FASB issued Statement No. 123, "Accounting for Stock-based Compensation Plans" ("FAS 123"), which established a fair value method of accounting for stock-based compensation and required companies that continued to account for stock-based compensation in accordance with the "intrinsic method" to provide a pro forma disclosure that reflects the difference between the two methods. In January 2003 the FASB issued FAS 148, an amendment to FAS 123, which provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. The FASB plans to issue another exposure draft in the first quarter of 2004 and issue the final statement in the second quarter of 2004. Effective January 1, 2004, CICA section 3870, "Stock-based Compensation and Other Stock-based Payments", will require all public companies to expense all stock-based compensation. This standard provides for the retroactive adoption of fair value accounting effective January 1, 2004. After January 1, 2004 the fair value of stock-based compensation will be recognized as an expense in the financial statements.

OIL AND GAS FULL COST ACCOUNTING

In July 2003 the AcSB issued Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" ("AcG-16"), replacing AcG-5. AcG-16 provides for methodology consistent with CICA section 3063, "Impairment of Long-lived Assets", CICA section 3475, "Disposal of Long-lived Assets and Discontinued Operations" and FASB Statement No. 144, "Accounting for the Impairment and Disposal of Long-lived Assets".

The new standards prescribe the recognition of impairment only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and measure the impairment amount as the difference between the carrying amount and the fair value. In addition, discontinued operations disclosure will be required upon the disposition of a component or cost centre of the entity rather than an entire business segment.

Quarterly Financial Summary

($ millions, except where indicated)	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4	2002 Q3	2002 Q2	2002 Q1
Sales and operating revenues, net of royalties	**$ 1,800**	**$ 1,871**	**$ 1,769**	**$ 2,218**	$ 1,697	$ 1,669	$ 1,659	$ 1,359
Net earnings	**$ 245**	**$ 243**	**$ 427**	**$ 406**	$ 242	$ 173	$ 263	$ 126
Earnings per share								
– Basic	**$ 0.62**	**$ 0.55**	**$ 1.06**	**$ 1.01**	$ 0.57	$ 0.38	$ 0.64	$ 0.29
– Diluted	**$ 0.62**	**$ 0.54**	**$ 1.05**	**$ 1.00**	$ 0.57	$ 0.38	$ 0.64	$ 0.29
Cash flow from operations	**$ 568**	**$ 604**	**$ 540**	**$ 747**	$ 635	$ 590	$ 498	$ 373
Share price								
– High	**$ 23.95**	**$ 20.95**	**$ 18.14**	**$ 17.49**	$ 17.20	$ 17.00	$ 17.98	$ 17.80
– Low	**$ 20.40**	**$ 17.35**	**$ 16.15**	**$ 16.03**	$ 15.43	$ 14.00	$ 15.85	$ 14.20
– Close (end of period)	**$ 23.47**	**$ 20.50**	**$ 17.50**	**$ 16.93**	$ 16.47	$ 16.70	$ 16.66	$ 17.10
Shares traded *(thousands)*	**22,171**	**35,453**	**24,858**	**18,371**	20,478	30,620	31,159	34,383
Dividends declared per share	**$ 0.10**	**$ 1.10**	**$ 0.09**	**$ 0.09**	$ 0.09	$ 0.09	$ 0.09	$ 0.09
Number of weighted average common shares outstanding *(thousands)*								
– Basic	**421,702**	**419,729**	**418,539**	**418,163**	417,748	417,497	417,393	416,939
– Diluted	**423,830**	**422,010**	**420,331**	**419,985**	419,567	419,136	419,558	418,951

Results of Operations for 2002 Compared with 2001

The 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 evident in the infrastructure and marketing segment with respect to natural gas marketing revenues.

Net earnings in 2002 were $804 million compared with $654 million in 2001. The increase of $150 million was attributable to the following:

Upstream – increase of $206 million

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

partially offset by:

- lower prices for natural gas
- higher operating costs and DD&A
- higher income taxes

Midstream – decrease of $95 million

- narrower upgrading differential
- lower pipeline throughput

partially offset by:

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

Refined Products – decrease of $31 million

- ☐ lower asphalt product margins

partially offset by:

- ☐ improved gasoline and distillate margins
- ☐ lower income taxes

Corporate – increase of $70 million

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

partially offset by:

- ☐ higher intersegment profit eliminations

Forward-looking Statements

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

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

The reader is cautioned not to place undue reliance on Husky's forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, that contribute to the possibility that the predicted outcomes will not occur. The risks, uncertainties and other factors, many of which are beyond Husky's control, that could influence actual results include, but are not limited to:

- ☐ fluctuations in commodity prices
- ☐ changes in general economic, market and business conditions
- ☐ fluctuations in supply and demand for Husky's products
- ☐ fluctuations in the cost of borrowing
- ☐ Husky's use of derivative financial instruments to hedge exposure to changes in commodity prices and fluctuations in interest rates and foreign currency exchange rates
- ☐ political and economic developments, expropriations, royalty and tax increases, retroactive tax claims and changes to import and export regulations and other foreign laws and policies in the countries in which Husky operates
- ☐ Husky's ability to receive timely regulatory approvals
- ☐ the integrity and reliability of Husky's capital assets
- ☐ the cumulative impact of other resource development projects

- the accuracy of Husky's oil and gas reserve estimates, estimated production levels and Husky's success at exploration and development drilling and related activities
- the maintenance of satisfactory relationships with unions, employee associations and joint venturers
- competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy
- the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures
- actions by governmental authorities, including changes in environmental and other regulations
- the ability and willingness of parties with whom Husky has material relationships to fulfil their obligations
- the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Husky or other parties whose operations or assets directly or indirectly affect Husky

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

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 Securities 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.

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.

Husky Energy Inc. 2003

Consolidated Financial Statements and Notes

68 Management's Report

68 Auditors' Report to the Shareholders

69 Consolidated Balance Sheets

70 Consolidated Statements of Earnings

70 Consolidated Statements of Retained Earnings

71 Consolidated Statements of Cash Flows

72 Notes to the Consolidated Financial Statements

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 LLP, the independent auditors, in accordance with generally accepted auditing standards on behalf of the shareholders. KPMG LLP 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 2, 2004

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Husky Energy Inc., as at December 31, 2003, 2002 and 2001 and the consolidated statements of earnings, retained earnings, and cash flows for each of the years in the three-year period ended December 31, 2003. 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, 2003, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Alberta, Canada

February 2, 2004

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of dollars)	2003	2002	2001
Assets			
Current assets			
Cash and cash equivalents	**$ 3**	$ 306	$ –
Accounts receivable *(note 4)*	**618**	572	376
Inventories *(note 5)*	**211**	243	226
Prepaid expenses	**33**	23	24
	865	1,144	626
Property, plant and equipment, net *(notes 1, 6)*			
(full cost accounting)	**10,685**	9,347	8,715
Goodwill *(note 7)*	**120**	–	–
Other assets *(note 11)*	**112**	84	29
	$ 11,782	$ 10,575	$ 9,370
Liabilities and Shareholders' Equity			
Current liabilities			
Bank operating loans *(note 9)*	**$ 71**	$ –	$ 100
Accounts payable and accrued liabilities *(note 10)*	**1,126**	794	805
Long-term debt due within one year *(note 11)*	**259**	421	144
	1,456	1,215	1,049
Long-term debt *(note 11)*	**1,439**	1,964	1,948
Other long-term liabilities *(note 12)*	**390**	266	228
Future income taxes *(note 13)*	**2,608**	2,003	1,659
Commitments and contingencies *(note 14)*			
Shareholders' equity			
Capital securities and accrued return *(note 15)*	**298**	364	367
Common shares *(note 16)*	**3,457**	3,406	3,397
Retained earnings	**2,134**	1,357	722
	5,889	5,127	4,486
	$ 11,782	$ 10,575	$ 9,370

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

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)	2003	2002	2001
Sales and operating revenues, net of royalties	**$ 7,658**	$ 6,384	$ 6,596
Costs and expenses			
Cost of sales and operating expenses	**4,825**	4,009	4,425
Selling and administration expenses	**119**	94	88
Depletion, depreciation and amortization *(notes 1, 6)*	**1,058**	939	807
Interest – net *(note 11)*	**73**	104	101
Foreign exchange *(note 11)*	**(215)**	13	94
Other – net	**3**	1	7
	5,863	5,160	5,522
Earnings before income taxes	**1,795**	1,224	1,074
Income taxes *(note 13)*			
Current	**147**	66	20
Future	**327**	354	400
	474	420	420
Net earnings	**$ 1,321**	$ 804	$ 654
Earnings per share *(note 16)*			
Basic	**$ 3.23**	$ 1.88	$ 1.49
Diluted	**$ 3.22**	$ 1.88	$ 1.48

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (millions of dollars)	2003	2002	2001
Beginning of year	**$ 1,357**	$ 722	$ 253
Net earnings	**1,321**	804	654
Dividends on common shares *(note 16)*	**(580)**	(151)	(150)
Return on capital securities *(note 15)*	**38**	(29)	(53)
Related future income taxes *(note 13)*	**(2)**	11	18
End of year	**$ 2,134**	$ 1,357	$ 722

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2003**	2002	2001
Operating activities			
Net earnings	**$ 1,321**	$ 804	$ 654
Items not affecting cash			
Depletion, depreciation and amortization	**1,058**	939	807
Future income taxes	**327**	354	400
Foreign exchange *(note 11)*	**(242)**	–	82
Other	**(5)**	(1)	3
Cash flow from operations	**2,459**	2,096	1,946
Change in non-cash working capital *(note 8)*	**113**	(204)	(16)
Cash flow – operating activities	**2,572**	1,892	1,930
Financing activities			
Bank operating loans financing – net	**71**	(100)	66
Long-term debt issue	**598**	972	–
Long-term debt repayment	**(971)**	(678)	(356)
Settlement of cross currency swap	**(32)**	–	–
Return on capital securities payment	**(29)**	(31)	(30)
Debt issue costs	**–**	(9)	–
Deferred credits	–	–	(4)
Proceeds from exercise of stock options	**51**	9	9
Proceeds from interest swaps monetization	**44**	–	–
Dividends on common shares	**(580)**	(151)	(150)
Change in non-cash working capital *(note 8)*	**48**	(9)	42
Cash flow – financing activities	**(800)**	3	(423)
Available for investing	**1,772**	1,895	1,507
Investing activities			
Capital expenditures	**(1,905)**	(1,692)	(1,473)
Corporate acquisitions	**(809)**	(3)	(125)
Asset sales	**511**	93	67
Other	**5**	(20)	6
Change in non-cash working capital *(note 8)*	**123**	33	18
Cash flow – investing activities	**(2,075)**	(1,589)	(1,507)
Increase (decrease) in cash and cash equivalents	**(303)**	306	–
Cash and cash equivalents at beginning of year	**306**	–	–
Cash and cash equivalents at end of year	**$ 3**	$ 306	$ –

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

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

Note 1 Segmented Financial Information

	Upstream			Midstream		
				Upgrading		
	2003	2002	2001	**2003**	2002	2001
Year ended December 31						
Sales and operating revenues, net of royalties	**$ 3,186**	$ 2,665	$ 2,165	**$ 1,013**	$ 909	$ 886
Costs and expenses						
Operating, cost of sales, selling and general	**855**	729	648	**901**	811	638
Depletion, depreciation and amortization	**958**	851	728	**20**	18	17
Interest – net	**–**	–	–	**–**	–	–
Foreign exchange	**–**	–	–	**–**	–	–
	1,813	1,580	1,376	**921**	829	655
Earnings (loss) before income taxes	**1,373**	1,085	789	**92**	80	231
Current income taxes	**95**	55	17	**1**	1	1
Future income taxes	**230**	342	290	**20**	25	72
Net earnings (loss)	**$ 1,048**	$ 688	$ 482	**$ 71**	$ 54	$ 158
Capital employed – As at December 31	**$ 6,652**	$ 6,040	$ 5,715	**$ 456**	$ 319	$ 320
Property, plant and equipment – As at December 31						
Cost						
Canada	**$ 13,601**	$ 11,525	$ 10,353	**$ 1,022**	$ 998	$ 958
International	**496**	469	394	**–**	–	–
	$ 14,097	$ 11,994	$ 10,747	**$ 1,022**	$ 998	$ 958
Accumulated depletion, depreciation and amortization						
Canada	**$ 4,633**	$ 3,894	$ 3,272	**$ 391**	$ 372	$ 354
International	**250**	185	147	**–**	–	–
	$ 4,883	$ 4,079	$ 3,419	**$ 391**	$ 372	$ 354
Net						
Canada	**$ 8,968**	$ 7,631	$ 7,081	**$ 631**	$ 626	$ 604
International	**246**	284	247	**–**	–	–
	$ 9,214	$ 7,915	$ 7,328	**$ 631**	$ 626	$ 604
Capital expenditures – Year ended December 31 (2)	**$ 1,781**	$ 1,567	$ 1,317	**$ 25**	$ 41	$ 47
Total assets – As at December 31 (3)						
Canada	**$ 9,547**	$ 7,883	$ 7,160	**$ 649**	$ 658	$ 644
International	**259**	337	247	**–**	–	–
	$ 9,806	$ 8,220	$ 7,407	**$ 649**	$ 658	$ 644

(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) *Includes site restoration expenditures. See note 12, Other Long-term Liabilities.*

(3) *2003 includes goodwill on Marathon Canada Limited acquisition related to Upstream.*

Midstream			Refined Products			Corporate and Eliminations [1]			Total		
Infrastructure and Marketing											
2003	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
$ 4,946	$ 4,230	$ 4,380	**$ 1,502**	$ 1,310	$ 1,349	**$ (2,989)**	$ (2,730)	$ (2,184)	**$ 7,658**	$ 6,384	$ 6,596
4,747	4,038	4,193	**1,422**	1,222	1,206	**(2,978)**	(2,696)	(2,165)	**4,947**	4,104	4,520
21	20	17	**34**	34	31	**25**	16	14	**1,058**	939	807
–	–	–	**–**	–	–	**73**	104	101	**73**	104	101
–	–	–	**–**	–	–	**(215)**	13	94	**(215)**	13	94
4,768	4,058	4,210	**1,456**	1,256	1,237	**(3,095)**	(2,563)	(1,956)	**5,863**	5,160	5,522
178	172	170	**46**	54	112	**106**	(167)	(228)	**1,795**	1,224	1,074
27	6	1	**9**	4	1	**15**	–	–	**147**	66	20
37	59	71	**9**	18	48	**31**	(90)	(81)	**327**	354	400
$ 114	$ 107	$ 98	**$ 28**	$ 32	$ 63	**$ 60**	$ (77)	$ (147)	**$ 1,321**	$ 804	$ 654
$ 350	$ 431	$ 395	**$ 320**	$ 338	$ 329	**$ (120)**	$ 384	$ (81)	**$ 7,658**	$ 7,512	$ 6,678
$ 615	$ 591	$ 575	**$ 757**	$ 702	$ 655	**$ 188**	$ 165	$ 143	**$ 16,183**	$ 13,981	$ 12,684
–	–	–	**–**	–	–	**–**	–	–	**496**	469	394
$ 615	$ 591	$ 575	**$ 757**	$ 702	$ 655	**$ 188**	$ 165	$ 143	**$ 16,679**	$ 14,450	$ 13,078
$ 203	$ 184	$ 165	**$ 391**	$ 360	$ 330	**$ 126**	$ 108	$ 95	**$ 5,744**	$ 4,918	$ 4,216
–	–	–	**–**	–	–	**–**	–	–	**250**	185	147
$ 203	$ 184	$ 165	**$ 391**	$ 360	$ 330	**$ 126**	$ 108	$ 95	**$ 5,994**	$ 5,103	$ 4,363
$ 412	$ 407	$ 410	**$ 366**	$ 342	$ 325	**$ 62**	$ 57	$ 48	**$ 10,439**	$ 9,063	$ 8,468
–	–	–	**–**	–	–	**–**	–	–	**246**	284	247
$ 412	$ 407	$ 410	**$ 366**	$ 342	$ 325	**$ 62**	$ 57	$ 48	**$ 10,685**	$ 9,347	$ 8,715
$ 18	$ 17	$ 58	**$ 58**	$ 44	$ 29	**$ 23**	$ 23	$ 22	**$ 1,905**	$ 1,692	$ 1,473
$ 701	$ 850	$ 862	**$ 525**	$ 534	$ 428	**$ 101**	$ 313	$ 29	**$ 11,523**	$ 10,238	$ 9,123
–	–	–	**–**	–	–	**–**	–	–	**259**	337	247
$ 701	$ 850	$ 862	**$ 525**	$ 534	$ 428	**$ 101**	$ 313	$ 29	**$ 11,782**	$ 10,575	$ 9,370

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, Canada.

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 other 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

a) Principles of Consolidation and the Preparation of Financial Statements

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 20, Reconciliation to Accounting Principles Generally Accepted in the United States.

The preparation of financial statements in conformity with Canadian 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.

Substantially all of the Company's upstream activities are conducted jointly with third parties and accordingly the accounts reflect the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flow from these activities.

b) Cash and Cash Equivalents

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

c) 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.

d) 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 activity, 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 gross 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. Gains or losses on the disposition of oil and gas properties are not recognized unless the gain or loss changes the depletion rate by 20 percent or more.

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 the related future income tax liability and site restoration liability, 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, administration expenses, financing costs and income taxes. Any amounts in excess of these limits are charged to earnings.

In September 2003, the Accounting Standards Board ("AcSB") of the Canadian Institute of Chartered Accountants ("CICA") issued Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" ("AcG-16"), which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil and Gas Industry" ("AcG-5"). AcG-16 will be effective January 1, 2004. AcG-16 modifies the ceiling test in AcG-5 to be consistent with CICA section 3063, "Impairment of Long-lived Assets", which requires the impairment test to be performed by comparing the carrying amount of a cost centre to its fair value. For full cost oil and gas companies an impairment loss is to be recognized when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not considered recoverable if the carrying amount exceeds the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. Fair value is estimated using the expected present value approach which incorporates risks and uncertainties in the expected future cash flows which are discounted using a risk free rate. AcG-16 is consistent with CICA section 3475, "Disposal of Long-lived Assets and Discontinued Operations". For full cost oil and gas companies, discontinued operations presentation is only used when a cost centre has been disposed of.

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 which range from five to 20 years. 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, 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.

In March 2003, the AcSB issued CICA section 3110, "Asset Retirement Obligations", that addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs. The new recommendations will be effective January 1, 2004 and are substantially similar to the U.S. Financial Accounting Standards Board ("FASB") Statement No. 143, "Accounting for Asset Retirement Obligations" ("FAS 143"). Note 20 presents the recognition, measurement and disclosure required by FAS 143 in the financial statements.

e) Impairment or Disposal of Long-lived Assets

In December 2002, the AcSB issued CICA section 3063, "Impairment of Long-lived Assets", and section 3475, "Disposal of Long-lived Assets and Discontinued Operations", that address the accounting and reporting for the impairment and disposal of long-lived assets and are substantially similar to FASB Statement No. 144, "Accounting for the Impairment and Disposal of Long-lived Assets". Section 3063 will be effective January 1, 2004. Section 3475 was in effect for 2003. An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value. Testing for recoverability uses the undiscounted cash flows expected from the asset's use and disposition. 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, are reported in discontinued operations if: i) the operations and cash flows of the component have been or will be eliminated as a result of the disposal transaction; and, ii) 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.

f) Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net assets acquired. Goodwill is subject to impairment tests on an annual basis unless three conditions are met: i) the assets and liabilities that make up the reporting unit have not changed significantly since the most recent fair value determination; ii) the most recent fair value determination resulted in an amount that exceeded the carrying amount of the reporting unit by a substantial margin; and, iii) based on an analysis of events that have occurred and circumstances that have changed since the most recent fair value determination, the likelihood that a current fair value determination would be less than the current carrying amount of the reporting unit is remote. The two-step impairment test begins with comparing the fair value of the reporting unit with its carrying amount. If any potential impairment is indicated, then it is quantified by comparing the carrying value of goodwill to its fair value, based on the fair value of the assets and liabilities of the reporting unit. Impairment losses would be recognized in current period earnings. Refer to note 7, Acquisition of Marathon Canada.

g) Derivative Financial Instruments

Derivative financial instruments are utilized by the Company to manage market risk against the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

When applicable, the Company formally documents all relationships between hedged items and hedging items, the risk management objectives and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also formally assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Company may enter into commodity price contracts to hedge anticipated sales of oil and natural gas production to manage its exposure to price fluctuations. The Company's production is expected to be sufficient to deliver all required volumes. Gains and losses from these contracts are recognized in upstream oil and gas revenues as the related sales occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers in order to retain market prices while meeting customer or supplier pricing requirements. The Company's production is expected to be sufficient to deliver all required volumes. Gains and losses from these contracts are recognized in midstream revenues or cost of sales as the related sales or purchases occur.

The Company may enter into interest rate swap agreements to manage its fixed and floating interest rate mix on long-term debt. These swaps are designated as hedges of the underlying debt. These agreements require the periodic exchange of payments without the exchange of the notional principal amount upon which the payments are based and are recorded as an adjustment to the interest expense on the hedged debt instrument. The related amount payable or receivable from the counterparties is recorded as an adjustment to accrued interest.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The forward premium or discount on the forward foreign exchange option contract is amortized as an adjustment to interest expense over the term of the contract.

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

Realized and unrealized gains or losses associated with derivative financial instruments which have been terminated or cease to be effective prior to maturity are deferred under current or non-current assets or liabilities on the balance sheet and recognized into income in the period in which the underlying hedged transaction is recognized. In the event that a designated hedged item is sold, extinguishes or matures prior to the termination of the related derivative financial instrument, any realized or unrealized gain or loss is recognized into earnings.

In December 2001, the AcSB issued Accounting Guideline 13, "Hedging Relationships", that establishes standards for the documentation and effectiveness of hedging activities that are substantially similar to the corresponding documentation requirements in FASB Statement No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). The new recommendations will be effective January 1, 2004. Note 20 discloses the impact of FAS 133 on the financial statements for 2003.

h) Employee Future Benefits

The Company provides a defined contribution pension plan and a post-retirement health and dental care plan to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. The cost of the pension benefits earned by employees in the defined contribution pension plan is paid and expensed when incurred. The cost of the benefits earned by employees in the post-retirement health and dental care plan and defined benefit pension plan is charged to earnings as services are rendered using the projected benefit method prorated on service. The cost of the post-retirement health and dental care plan and defined benefit pension plan reflects a number of assumptions that affect the expected future benefit payments. These assumptions include, but are not limited to, attrition, mortality, the rate of return on pension plan assets and salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The plan assets are valued at fair value for the purposes of calculating the expected return on plan assets.

Adjustments arising out of plan amendments, changes in assumptions and experience gains and losses are normally amortized over the expected remaining average service life of the employee group.

i) 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.

j) Foreign Currency Translation

Results of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars at the monthly average exchange rates for revenue and expenses, except for depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Monetary assets and liabilities are translated at current exchange rates and non-monetary assets and liabilities 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.

k) Stock-based Compensation

In accordance with the Company's stock option plan, common share options may be 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 options is equal to the market value of the common shares when the options are granted. In accordance with CICA section 3870, "Stock-based Compensation and Other Stock-based Payments", note 16 discloses the impact on the financial statements for options granted after January 1, 2002. The recommendations are substantially similar to those in FASB Statement No. 123, "Accounting for Stock-based Compensation" ("FAS 123"). Note 20 presents the disclosures required by FAS 123 in the financial statements.

In September 2003, the AcSB amended the recommendations on stock-based compensation. The new recommendations will be effective January 1, 2004 and will require that all stock-based compensation be measured and recognized based on the fair value of the instruments and will result in an expense that is recognized in the financial statements. The Company intends to adopt the changes retroactively in 2004 without restatement of prior periods. Retained earnings for 2004 will be decreased by $44 million with an increase to contributed surplus of $21 million and an increase to share capital of $23 million.

l) 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.

m) Reclassification

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

Note 4 Accounts Receivable

	2003	2002	2001
Trade receivables	**$ 568**	$ 530	$ 379
Investment tax credit	**48**	45	–
Allowance for doubtful accounts	**(12)**	(11)	(8)
Other	**14**	8	5
	$ 618	$ 572	$ 376

Sale of Accounts Receivable

In November 2003, the Company established a securitization program to sell, on a revolving basis, up to $250 million of accounts receivable to a third party. As at December 31, 2003, $250 million in outstanding accounts receivable had been sold under the program. The agreement includes a program fee based on Canadian commercial paper rates.

In 2002 and 2001, the Company had an agreement to sell up to $200 million of net trade receivables on a continual basis. The agreement called for purchase discounts which were based on Canadian commercial paper rates. The average effective rate for 2002 and 2001 was approximately 2.8 percent and 4.7 percent, respectively.

Note 5 Inventories

	2003	2002	2001
Crude oil and refined petroleum products	**$ 121**	$ 166	$ 140
Natural gas	**69**	50	69
Materials, supplies and other	**21**	27	17
	$ 211	$ 243	$ 226

Note 6 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:

	2003	2002	2001
Canada	**$ 1,814**	$ 1,318	$ 1,226
International	**54**	37	235
	$ 1,868	$ 1,355	$ 1,461

Note 7 Acquisition of Marathon Canada

Effective October 1, 2003 the Company acquired all of the issued and outstanding shares of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. ("Marathon Canada") for cash consideration of U.S. $611 million (Cdn. $831 million). The results of Marathon Canada are included in the consolidated financial statements of the Company from the date of acquisition.

The allocation of the aggregate purchase price based on the estimated fair values of Marathon Canada's net assets acquired at October 1, 2003 was as follows:

	Allocation
Net assets acquired	
Working capital [(1)]	$ 5
Property, plant and equipment	1,008
Goodwill [(2)]	120
Site restoration	(38)
Future income taxes	(264)
	$ 831

(1) *Working capital acquired includes cash of $22 million.*

(2) *Allocated to the Company's upstream segment and not deductible for income tax purposes. Refer to note 1, Segmented Financial Information.*

In conjunction with the above acquisition of Marathon Canada, the Company sold certain of the Marathon Canada oil and gas properties to a third party for cash consideration of U.S. $320 million (Cdn. $431 million).

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

a) Change in non-cash working capital was as follows:

	2003	2002	2001
Decrease (increase) in non-cash working capital			
Accounts receivable	**$ (7)**	$ (153)	$ 361
Inventories	**31**	(17)	(40)
Prepaid expenses	**(10)**	1	3
Accounts payable and accrued liabilities	**270**	(11)	(280)
Change in non-cash working capital	**284**	(180)	44
Relating to:			
Financing activities	**48**	(9)	42
Investing activities	**123**	33	18
Operating activities	**$ 113**	$ (204)	$ (16)

b) Other cash flow information:

		2003		2002		2001
Cash taxes paid	**$**	**69**	$	20	$	13
Cash interest paid	**$**	**134**	$	139	$	145

Note 9 Bank Operating Loans

At December 31, 2003 the Company had short-term borrowing lines of credit with banks totalling $195 million (2002 and 2001 – $195 million). As at December 31, 2003, $71 million (2002 – nil; 2001 – $100 million) had been used for bank operating loans and $18 million (2002 – $12 million; 2001 – $2 million) had been used for letters of credit. Interest payable is based on Bankers' Acceptance, money market, or prime rates. During 2003, the weighted average interest rate on short-term borrowings was approximately 3.7 percent (2002 – 2.9 percent; 2001 – 4.6 percent).

Note 10 Accounts Payable and Accrued Liabilities

		2003		2002		2001
Trade payables	**$**	**58**	$	87	$	58
Accrued liabilities		**794**		562		547
Dividend payable		**42**		38		38
Current income taxes		**117**		51		7
Other		**115**		56		155
	$	**1,126**	$	794	$	805

Note 11 Long-term Debt

		Cdn. $ Amount			U.S. $ Amount		
	Maturity	2003	2002	2001	2003	2002	2001
Long-term debt							
Revolving syndicated credit facility		**$ –**	$ –	$ 185	**$ –**	$ –	$ 116
6.25% notes	2012	**517**	632	–	**400**	400	–
6.875% notes		**–**	237	239	**–**	150	150
7.125% notes	2006	**194**	237	239	**150**	150	150
7.55% debentures	2016	**258**	316	318	**200**	200	200
8.45% senior secured bonds	2004-12	**188**	256	276	**145**	162	173
Private placement notes	2004-5	**41**	107	135	**32**	68	85
Medium-term notes	2004-9	**500**	600	700	**–**	–	–
Total long-term debt		**1,698**	2,385	2,092	**$ 927**	$ 1,130	$ 874
Amount due within one year		**(259)**	(421)	(144)			
		$ 1,439	$ 1,964	$ 1,948			

Interest – net for the years ended December 31 was as follows:

	2003	2002	2001
Long-term debt	$ **129**	$ 128	$ 148
Short-term debt	**2**	3	5
	131	131	153
Amount capitalized	**(52)**	(26)	(51)
	79	105	102
Interest income	**(6)**	(1)	(1)
	$ **73**	$ 104	$ 101

Foreign exchange for the years ended December 31 was as follows:

	2003	2002	2001
(Gain) loss on translation of U.S. dollar denominated long-term debt	$ **(315)**	$ –	$ 82
Cross currency swaps	**73**	–	–
Other losses	**27**	13	12
	$ **(215)**	$ 13	$ 94

As at December 31, 2003, other assets included $19 million (2002 – $23 million; 2001 – $17 million) of deferred debt issue costs.

The revolving syndicated credit facility allows the Company to borrow up to $830 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 three-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 Company's $100 million credit facility has substantially the same terms as the syndicated credit facility.

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 7.125 percent notes and the 7.55 percent debentures represent unsecured securities issued under a trust indenture dated October 31, 1996. These securities mature in 2006 and 2016, respectively. The 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 Terra Nova oil field and associated facilities. The repayment of the securities is contracted to be made solely from revenue from the Terra Nova oil field. There is also a charge created by the partnership on its interest in the assets of the Terra Nova 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 were issued under two separate note agreements dated January 31, 2001 and have a weighted average interest rate of 6.86 percent. 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 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 D	200	6.30%	June 2004
Series E	200	6.95%	July 2009
	$ 500		

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: 2004 – $259 million; 2005 – $60 million; 2006 – $226 million; 2007 – $126 million; and, 2008 – $20 million.

Note 12 Other Long-term Liabilities

	2003	2002	2001
Site restoration	**$ 303**	$ 248	$ 211
Cross currency swaps	**41**	–	–
Interest rate swaps	**26**	–	–
Employee future benefits	**20**	17	16
Other	**–**	1	1
	$ 390	$ 266	$ 228

The Company has estimated future removal and site restoration costs of $851 million at December 31, 2003 (2002 – $703 million; 2001 – $653 million). During 2003 actual removal and site restoration expenditures amounted to $35 million (2002 – $17 million; 2001 – $18 million) and were included in capital expenditures.

Note 13 Income Taxes

The combined provision for income taxes in the Consolidated Statements of Earnings and Retained Earnings 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:

	2003	2002	2001
Earnings before income taxes			
Canadian	**$ 1,572**	$ 1,070	$ 1,067
Foreign jurisdictions	**223**	154	7
	1,795	1,224	1,074
Statutory income tax rate *(percent)*	**40.2**	41.6	43.7
Expected income tax	**722**	509	469
Effect on income tax of:			
Change in statutory tax rate	**(161)**	(31)	(52)
Return on capital securities	**2**	(11)	(18)
Royalties, lease rentals and mineral taxes payable to the crown	**175**	159	184
Resource allowance on Canadian production income	**(183)**	(212)	(219)
Non-deductible capital taxes	**22**	18	20
Gains and losses on foreign exchange	**(45)**	–	20
Rate benefit on timing of partnership earnings	**(23)**	–	–
Foreign jurisdictions	**(16)**	(13)	–
Other – net	**(17)**	(10)	(2)
	$ 476	$ 409	$ 402
Charged (credited) to:			
Income tax expense	**$ 474**	$ 420	$ 420
Retained earnings	**2**	(11)	(18)
	$ 476	$ 409	$ 402

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

	2003	2002	2001
Future tax liabilities			
Property, plant and equipment	**$ 2,261**	$ 2,014	$ 1,882
Foreign exchange gains taxable on realization	**32**	–	–
Timing of partnership items	**504**	185	–
Other temporary differences	**2**	30	7
	2,799	2,229	1,889
Future tax assets			
Loss carryforwards	**2**	7	28
Foreign exchange losses deductible on realization	**–**	28	26
Site restoration and other deferred credits	**112**	105	93
Provincial royalty rebates	**52**	48	46
Other temporary differences	**25**	38	37
	191	226	230
	$ 2,608	$ 2,003	$ 1,659

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 requires payments to them when the average differential between heavy crude oil feedstock and synthetic crude oil exceeds $6.50 per barrel. The calculation is based on a two-year rolling average of the differential. During 2003, the Company capitalized $10 million (2002 – $23 million; 2001 – $32 million) of payments under this arrangement.

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

At December 31, 2003, the Company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

	2004	2005	2006	2007	2008	After 2008	Total
Operating leases	$ 50	$ 68	$ 76	$ 75	$ 70	$ 175	$ 514
Firm transportation agreements	236	219	224	199	170	740	1,788
Unconditional purchase obligations	332	234	210	118	6	15	915
Exploration lease agreements	47	47	73	51	46	233	497
Engineering and construction commitments	391	206	–	–	–	–	597
	$ 1,056	$ 774	$ 583	$ 443	$ 292	$ 1,163	$ 4,311

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 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 amount, net of income taxes, is classified as a distribution of equity. Return on capital securities comprises the return and foreign exchange on the capital securities.

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

	2003	2002	2001
Capital securities – U.S. $225	**$ 291**	$ 355	$ 358
Unamortized costs of issue	**(3)**	(3)	(3)
Accrued return	**10**	12	12
	$ 298	$ 364	$ 367

In November 2003 the AcSB revised recommendations in CICA section 3860, "Financial Instruments – Disclosure and Presentation", on the classification of obligations that must or could be settled with an entity's own equity instruments. The new recommendations will be effective January 1, 2005 and will result in the Company's capital securities being classified as liabilities instead of equity. The accrued return on the capital securities and the issue costs would be classified outside of shareholders' equity. The return on the capital securities would be a charge to earnings. The revision will be applied retroactively in 2005.

Note 16 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, none outstanding.

Changes to issued share capital were as follows:

Common Shares

	Number of Shares	Amount
January 1, 2001	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
Options and warrants exercised	4,302,141	51
December 31, 2003	**422,175,742**	**$ 3,457**

Stock Options

At December 31, 2003, 25.7 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. A downward adjustment of $0.82 to the exercise price of all outstanding stock options effective September 3, 2003 was made pursuant to the terms of the stock option plan under which the options were issued as a result of the special $1.00 per share dividend that was declared on July 23, 2003. 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.

The following options to purchase common shares have been awarded to directors, officers and certain other employees:

	Number of Shares *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Options Exercisable *(thousands)*
January 1, 2001	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
Granted	591	$ 19.17	5	
Exercised	(3,789)	$ 13.45	2	
Forfeited	(125)	$ 14.71	2	
December 31, 2003	**4,597**	**$ 13.88**	**2**	**3,564**

At December 31, 2003, the options outstanding had exercise prices ranging from $10.34 to $22.01.

Warrants

In 2000, the Company granted 1.4 million Renaissance Energy Ltd. ("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. During 2003, 276,500 warrants were exercised (2002 – 208,500; 2001 – 226,000). As at December 31, 2003, there were 295,820 common shares remaining which could potentially be issued as a result of the exercise of these warrants. The Renaissance replacement options had a weighted average contractual life of 0.6 years.

Stock-based Compensation

The fair values of all common share options granted are estimated on the date of grant using the 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:

	2003	2002	2001
Weighted average fair market value per option	**$ 4.00**	$ 5.19	$ 5.70
Risk-free interest rate *(percent)*	**3.9**	3.6	3.5
Volatility *(percent)*	**23**	43	45
Expected life *(years)*	**5**	5	5
Expected annual dividend per share	**$ 0.36**	$ 0.36	$ 0.36

The fair values of all common share options granted prior to September 3, 2003 were revalued at the modification date using the Black-Scholes option-pricing model. The weighted average fair market value of outstanding stock options as at September 3, 2003 and the assumptions used in their determination are as noted below:

Weighted average fair market value per option	$ 7.14
Risk-free interest rate *(percent)*	2.8
Volatility *(percent)*	20
Expected life *(years)*	2.3
Expected annual divided per share	$ 0.40

The Company follows the intrinsic value method of accounting for stock-based compensation for its stock option plan, under which compensation cost is not recognized. If the Company applied the fair value method, additional compensation cost of $3.9 million for all options granted would be recognized over the vesting period due to the modification of all options outstanding. For the year ended December 31, 2003, additional compensation cost of $3.6 million would be recognized.

If the Company applied the fair value method at the grant dates for options granted after January 1, 2002 and also to all options granted, the Company's net earnings and earnings per share would have been as follows:

	2003	2002	2001
Compensation cost – options granted after January 1, 2002 [1]	**$ 5**	$ –	$ –
Compensation cost – all options granted [1]	**$ 14**	$ 13	$ 13
Net earnings available to common shareholders			
As reported	**$ 1,357**	$ 787	$ 620
Options granted after January 1, 2002	**$ 1,352**	$ 787	$ 620
All options granted	**$ 1,343**	$ 774	$ 607
Weighted average number of common shares outstanding *(millions)*			
Basic	**419.5**	417.4	416.1
Diluted	**421.5**	419.3	418.6
Basic earnings per share			
As reported	**$ 3.23**	$ 1.88	$ 1.49
Options granted after January 1, 2002	**$ 3.22**	$ 1.88	$ 1.49
All options granted	**$ 3.20**	$ 1.86	$ 1.46
Diluted earnings per share			
As reported	**$ 3.22**	$ 1.88	$ 1.48
Options granted after January 1, 2002	**$ 3.21**	$ 1.88	$ 1.48
All options granted	**$ 3.18**	$ 1.85	$ 1.45

[1] *Includes options modified.*

Effective January 1, 2004 the Company is required to measure stock-based compensation and recognize an expense in the financial statements. The Company will be adopting the change in 2004 on a retroactive basis without restatement of prior periods for all options granted. Retained earnings will be decreased by $44 million, which includes a cost of $4 million for the year ended December 31, 2000.

Earnings Per Share Amounts

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

Diluted earnings per common share includes the dilutive impact of options and warrants outstanding under the Company 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 per common share, as the Company has neither the obligation nor intention to settle amounts due through the issuance of shares.

During 2003 the Company declared dividends of $1.38 per common share (2002 and 2001 – $0.36 per common share), including a special dividend of $1.00 per common share.

Note 17 Employee Future 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 health and dental coverage to its retirees which is accrued over the expected average remaining service life of the employees.

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

	2003	2002	2001
Discount rate *(percent)*	**6.0**	6.3	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 average health care cost trend used was eight percent, which is reduced by 0.50 percent until 2009. The average dental care cost trend used was four percent, which remains constant.

Defined Benefit Pension Plan

The status of the defined benefit pension plan at December 31 was as follows:

BENEFIT OBLIGATION	2003	2002	2001
Benefit obligation, beginning of year	**$ 108**	$ 95	$ 93
Current service cost	**2**	2	1
Interest cost	**7**	7	6
Benefits paid	**(6)**	(6)	(5)
Actuarial losses	**7**	10	–
Benefit obligation, end of year	**$ 118**	$ 108	$ 95

FAIR VALUE OF PLAN ASSETS	2003	2002	2001
Fair value of plan assets, beginning of year	**$ 77**	$ 85	$ 90
Contributions	**8**	2	2
Benefits paid	**(6)**	(6)	(5)
Return on plan assets	**6**	7	6
Gain (loss) on plan assets	**2**	(11)	(8)
Foreign exchange losses	**(2)**	–	–
Fair value of plan assets, end of year	**$ 85**	$ 77	$ 85

FUNDED STATUS OF PLAN		2003		2002		2001
Fair value of plan assets	$	**85**	$	77	$	85
Benefit obligation		**(118)**		(108)		(95)
Excess assets (obligation)		**(33)**		(31)		(10)
Unrecognized past service costs		**1**		1		–
Unrecognized losses		**32**		27		6
Accrued benefit liability	$	**–**	$	(3)	$	(4)

The composition of the defined benefit pension plan's assets at year-end 2003 was U.S. common equities 15 percent, Canadian common equities 27 percent, Canadian mutual funds 12 percent, Canadian government bonds 33 percent and Canadian corporate bonds 13 percent.

During 2003 Husky contributed $8 million to the defined benefit pension plan's assets, $6 million of which was in respect of additional contributions as a result of the plan's deficiency. Husky currently plans to contribute a similar amount in 2004.

Post-retirement Health and Dental Care Plan

The status of the post-retirement health and dental care plan at December 31 was as follows:

BENEFIT OBLIGATION		2003		2002		2001
Benefit obligation, beginning of year	$	**21**	$	16	$	14
Current service cost		**2**		1		1
Interest cost		**1**		1		1
Benefits paid		**(1)**		–		–
Actuarial losses		**–**		3		–
Benefit obligation, end of year	$	**23**	$	21	$	16

FUNDED STATUS OF PLAN		2003		2002		2001
Benefit obligation	$	**(23)**	$	(21)	$	(16)
Unrecognized losses		**3**		4		–
Accrued benefit liability	$	**(20)**	$	(17)	$	(16)

The assumed health care cost trend can have a significant effect on the amounts reported for Husky's post-retirement health and dental care plan. A one percent increase and decrease in the assumed trend rate would have the following effect:

		1% Increase		1% Decrease
Effect on total service and interest cost components	$	1	$	–
Effect on post-retirement benefit obligation	$	4	$	(3)

Pension Expense and Post-retirement Health and Dental Care Expense

The expenses for the years ended December 31 were as follows:

PENSION EXPENSE	2003	2002	2001
Defined benefit pension plan			
Employer current service cost	**$ 2**	$ 2	$ 1
Interest cost	**7**	7	6
Expected return on plan assets	**(6)**	(7)	(6)
Amortization of net actuarial losses	**2**	–	–
	5	2	1
Defined contribution pension plan	**11**	10	8
Total expense	**$ 16**	$ 12	$ 9

POST-RETIREMENT HEALTH AND DENTAL CARE EXPENSE	2003	2002	2001
Employer current service cost	**$ 2**	$ 1	$ 1
Interest cost	**1**	1	1
Total expense	**$ 3**	$ 2	$ 2

Note 18 Related Party Transactions

Husky, in the ordinary course of business, entered into a lease for an eight-year term effective September 1, 2000 with Western Canadian Place Ltd. The terms of the lease provide for the lease of office space, management services and operating costs at commercial rates. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. During 2003 Husky paid approximately $17 million for office space in Western Canadian Place.

Husky did not have any customers that constituted more than five percent of total sales and operating revenues during 2003.

Note 19 Financial Instruments and Risk Management

Carrying Values and Estimated Fair Values of Financial Assets and Liabilities

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 these instruments.

The estimated fair value of the long-term debt at December 31 was as follows:

	2003		2002		2001	
	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	**$ 1,698**	**$ 1,869**	$ 2,385	$ 2,579	$ 2,092	$ 2,143

The fair value of the long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates.

Unrecognized Gains (Losses) on Derivative Instruments

	2003	2002	2001
Commodity price risk management			
Natural gas	**$ (8)**	$ (4)	$ 15
Crude oil	**(109)**	6	–
Power consumption	**2**	–	–
Interest rate risk management			
Interest rate swaps	**31**	86	4
Foreign currency risk management			
Foreign exchange contracts	**(19)**	(7)	(29)
Foreign exchange forwards	**15**	(5)	–

Commodity Price Risk Management

Natural Gas

At December 31, 2003 the Company had hedged 70 mmcf of natural gas per day at NYMEX for February and March 2004 at an average price of U.S. $6.69 per mmbtu and 20 mmcf of natural gas per day at NYMEX for April 2004 at an average price of U.S. $6.38 per mmbtu. During 2003 the impact of the 2003 hedge program was a gain of $24 million.

At December 31, 2003 the Company had also hedged 7.5 mmcf of natural gas per day at NYMEX for the years 2004 and 2005 at an average price of U.S. $1.92 per mcf. During 2003 the impact was a loss of $8 million (2002 and 2001 – insignificant).

Crude Oil

At December 31, 2003 the Company had hedged crude oil averaging 85,000 bbls per day from January to December 2004 at an average fixed WTI price of U.S. $27.46 per bbl. The impact of the hedge program for 2003 was a loss of $36 million (2002 – gain of $5 million).

Power Consumption

In 2003 the Company hedged power consumption of 329,400 MWh from January to December 2004 at an average fixed price of $46.72 per MWh.

Natural Gas Contracts

The Company has a portfolio of fixed and basis 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 sale contract prices. At December 31, 2003 the Company had the following offsetting physical purchase and sale contracts:

	Volumes *(mmcf)*	Unrecognized Gain (Loss)
Physical purchase contracts	16,971	$ –
Physical sale contracts	(16,971)	$ 2

Interest Rate Risk Management

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, 2003 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)*
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps
7.55% debentures	U.S. $200	November 15, 2011	U.S. LIBOR + 194 bps

During 2003 the Company realized a gain of $17 million (2002 – gain of $29 million; 2001 – gain of $2 million) from interest rate risk management activities.

In 2003, the Company unwound three interest rate swaps. Proceeds of $44 million have been deferred and are being amortized to income over the remaining term of the debt.

Foreign Currency Risk Management

The Company manages its exposure to foreign exchange rate fluctuations by balancing the U.S. dollar denominated cash flows from operations with U.S. dollar denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency.

At December 31, 2003 the Company had the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate *(percent)*
7.125% notes	U.S. $150	$218	November 15, 2006	8.74
6.25% notes	U.S. $150	$212	June 15, 2012	7.41

The Company hedged U.S. dollar revenues for various amounts and maturities through 2005 through the use of foreign exchange forwards. The total amount hedged using long-dated forwards at December 31, 2003 was U.S. $52 million at an average forward rate of $1.5625. The total amount hedged using short-dated forwards at December 31, 2003 was U.S. $70 million at an average forward rate of $1.3166.

During 2003 the Company realized a loss of $56 million (2002 – loss of $11 million; 2001 – loss of $4 million) from foreign currency risk management activities.

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.

Note 20 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 from those in the United States. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements were insignificant except as described below:

CONSOLIDATED STATEMENTS OF EARNINGS

	2003	2002	2001
Net earnings	**$ 1,321**	$ 804	$ 654
Adjustments:			
Full cost accounting [(a)]	**80**	88	(544)
Related income taxes	**(30)**	(37)	235
Foreign currency translation on capital securities [(b)]	**67**	3	(20)
Related income taxes	**(12)**	(1)	5
Return on capital securities [(b)]	**(29)**	(32)	(33)
Related income taxes	**11**	11	14
Derivatives and hedging [(c)]	**(1)**	22	(30)
Related income taxes	**1**	(9)	12
Gain (loss) on energy trading contracts [(c)]	**(15)**	(2)	20
Related income taxes	**6**	1	(8)
Asset retirement obligations [(d)]	**15**	–	–
Related income taxes	**(2)**	–	–
Stock-based compensation [(e)]	**(46)**	–	–
Accounting for income taxes [(f)]	**–**	(37)	(14)
Earnings before cumulative effect of change in accounting principle under U.S. GAAP	**1,366**	811	291
Cumulative effect of change in accounting principle, net of tax [(c) (d)]	**9**	–	6
Net earnings under U.S. GAAP	**$ 1,375**	$ 811	$ 297
Weighted average number of common shares outstanding under U.S. GAAP *(millions)*			
Basic	**419.5**	417.4	416.1
Diluted	**421.5**	419.3	418.6
Earnings per share before cumulative effect of change in accounting principle under U.S. GAAP			
Basic	**$ 3.26**	$ 1.94	$ 0.70
Diluted	**$ 3.24**	$ 1.93	$ 0.70
Earnings per share under U.S. GAAP			
Basic	**$ 3.28**	$ 1.94	$ 0.71
Diluted	**$ 3.26**	$ 1.93	$ 0.71

CONDENSED CONSOLIDATED BALANCE SHEETS

	2003		2002		2001	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets (c)	**$ 865**	**$ 924**	$ 1,144	$ 1,292	$ 626	$ 756
Property, plant and equipment, net (a) (d)	**10,685**	**10,251**	9,347	8,670	8,715	7,950
Other assets (c) (j)	**232**	**236**	84	89	29	33
	$ 11,782	**$ 11,411**	$ 10,575	$ 10,051	$ 9,370	$ 8,739
Current liabilities (b) (c) (j)	**$ 1,456**	**$ 1,635**	$ 1,215	$ 1,301	$ 1,049	$ 1,187
Long-term debt (b) (c)	**1,439**	**1,761**	1,964	2,406	1,948	2,306
Other long-term liabilities (d)	**390**	**519**	266	266	228	228
Future income taxes (a) (b) (c) (d) (f) (j)	**2,608**	**2,372**	2,003	1,772	1,659	1,361
Capital securities and accrued return (b)	**298**	**–**	364	–	367	–
Share capital and contributed surplus (g) (h)	**3,457**	**3,737**	3,406	3,640	3,397	3,631
Retained earnings	**2,134**	**1,478**	1,357	683	722	23
Accumulated other comprehensive income						
Cash flow hedges, net of tax (c)	**–**	**(76)**	–	(7)	–	3
Minimum pension liability, net of tax (j)	**–**	**(15)**	–	(10)	–	–
	$ 11,782	**$ 11,411**	$ 10,575	$ 10,051	$ 9,370	$ 8,739

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

	2003		2002		2001	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Retained earnings (deficit), beginning of year	**$ 1,357**	**$ 683**	$ 722	$ 23	$ 253	$ (124)
Net earnings	**1,321**	**1,375**	804	811	654	297
Dividends on common shares	**(580)**	**(580)**	(151)	(151)	(150)	(150)
Capital securities, net of tax and foreign exchange (b)	**36**	**–**	(18)	–	(35)	–
Retained earnings, end of year	**$ 2,134**	**$ 1,478**	$ 1,357	$ 683	$ 722	$ 23
Accumulated other comprehensive income, beginning of year	**$ –**	**$ (17)**	$ –	$ 3	$ –	$ –
Cumulative effect of change in accounting, net of tax (c)	**–**	**–**	–	–	–	(10)
Cash flow hedges, net of tax (c)	**–**	**(69)**	–	(10)	–	13
Minimum pension liability, net of tax (j)	**–**	**(5)**	–	(10)	–	–
Accumulated other comprehensive income, end of year	**$ –**	**$ (91)**	$ –	$ (17)	$ –	$ 3

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

	2003		2002		2001	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Sales and operating revenues [(c) (i)]	**$ 7,658**	**$ 6,943**	$ 6,384	$ 5,778	$ 6,596	$ 5,606
Costs and expenses [(b) (c) (e) (i)]	**4,732**	**4,012**	4,117	3,488	4,614	3,654
Accretion expense [(d)]	**–**	**22**	–	–	–	–
Depletion, depreciation and amortization [(a) (d)]	**1,058**	**941**	939	851	807	1,351
Interest – net [(b)]	**73**	**102**	104	136	101	134
Earnings before income taxes	**1,795**	**1,866**	1,224	1,303	1,074	467
Income taxes [(a) (b) (c) (d) (f)]	**474**	**500**	420	492	420	176
Earnings before cumulative effect of change in accounting principle	**1,321**	**1,366**	804	811	654	291
Cumulative effect of change in accounting principle, net of tax [(c) (d)]	**–**	**9**	–	–	–	6
Net earnings	**1,321**	**1,375**	804	811	654	297
Other comprehensive income [(c) (j)]	**–**	**74**	–	20	–	(3)
Comprehensive income	**$ 1,321**	**$ 1,449**	$ 804	$ 831	$ 654	$ 294

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	2003	2002	2001
Cash flow – operating activities – Canadian GAAP	**$ 2,572**	$ 1,892	$ 1,930
Adjustments			
Return on capital securities payment	**(29)**	(31)	(30)
Settlement of asset retirement liabilities	**(34)**	–	–
Cash flow – operating activities – U.S. GAAP	**2,509**	1,861	1,900
Cash flow – financing activities – Canadian GAAP	**(800)**	3	(423)
Adjustments			
Return on capital securities payment	**29**	31	30
Cash flow – financing activities – U.S. GAAP	**(771)**	34	(393)
Cash flow – investing activities – Canadian GAAP	**(2,075)**	(1,589)	(1,507)
Adjustments			
Settlement of asset retirement liabilities	**34**	–	–
Cash flow – investing activities – U.S. GAAP	**(2,041)**	(1,589)	(1,507)
Change in cash and cash equivalents	**$ (303)**	$ 306	$ –

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 and major development projects 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) The Company records the capital securities as a component of equity and the return and foreign exchange gains or losses 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 and foreign exchange gains or losses would be charged to earnings. See note 15, Capital Securities.

(c) 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 million and $10 million, respectively, and recorded a resulting cumulative effect of change in accounting principle to increase earnings by $6 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 $4 million and $23 million, respectively, and a resulting reduction of other comprehensive income within shareholders' equity of $10 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 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 cumulative effect of change in accounting principle increased earnings per share under U.S. GAAP by $0.01 (basic and diluted).

At December 31, 2003 the Company recorded additional assets and liabilities for U.S. GAAP purposes of $52 million (2002 – $111 million; 2001 – $22 million) and $172 million (2002 – $122 million; 2001 – $38 million), respectively, for the fair values of derivative financial instruments. During 2003, a gain of $1 million, net of tax (2002 – gain of $11 million; 2001 – insignificant), 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 loss of $2 million, net of tax (2002 and 2001 – gain of $1 million), 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 $69 million loss, net of tax (2002 – gain of $10 million; 2001 – loss of $13 million), 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 2003.

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 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, at December 31, 2003 the Company recorded additional assets and liabilities of $7 million (2002 – $37 million; 2001 – $114 million) and $5 million (2002 – $19 million; 2001 – $88 million), respectively, and included the resulting unrealized loss, net of tax, in earnings for the year of $9 million (2002 – loss of $1 million; 2001 – gain of $11 million).

Under U.S. GAAP, gains and losses on energy trading contracts have been netted against sales and operating revenues.

(d) In 2003, the Company adopted FAS 143, "Accounting for Asset Retirement Obligations", which requires the fair value of a liability for an asset retirement obligation to be recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related tangible long-lived asset. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the asset. The liability is accreted at the end of each period through charges to accretion expense. The change was effective January 1, 2003, and the related cumulative effect of change in accounting principle to net earnings to December 31, 2002 was an increase of $9 million ($20 million before income taxes) or $0.02 per share (diluted). At January 1, 2003, the change resulted in an increase to net property, plant and equipment of $58 million, an increase in the asset retirement obligations which are included in other long-term liabilities of $38 million, an increase to the future income tax liability of $11 million and an increase to retained earnings of $9 million. The application of FAS 143 did not have a material impact on the Company's depreciation, depletion and amortization rate. There was no impact on the Company's cash flow as a result of adopting FAS 143.

The following table provides changes to asset retirement obligations for the year ended December 31, 2003:.

Asset retirement obligations, January 1, 2003	$	286
Liabilities incurred during year		17
Acquisition of Marathon Canada		38
Divestitures		(5)
Revision of previous estimate		108
Liabilities settled during year		(34)
Accretion expense		22
Asset retirement obligations, December 31, 2003	**$**	**432**

The following table shows the effect on the Company's net earnings and earnings per share as if FAS 143 had been in effect in prior years. There was a $10 million increase to net earnings for each of the years ended December 31, 2002 and 2001.

As at and for the years ended December 31		2002		2001
As reported				
Net earnings under U.S. GAAP	$	811	$	297
Earnings per share under U.S. GAAP				
Basic	$	1.94	$	0.71
Diluted	$	1.93	$	0.71
Pro forma				
Net earnings under U.S. GAAP	$	821	$	307
Earnings per share under U.S. GAAP				
Basic	$	1.97	$	0.74
Diluted	$	1.96	$	0.73
Asset retirement obligations				
Beginning of year	$	269	$	255
End of year	$	286	$	269

(e) On September 3, 2003 the Company modified the exercise price of all outstanding options. Under U.S. GAAP these options must be accounted for using variable accounting where the in-the-money portion of the vested stock options outstanding is required to be adjusted through the statement of earnings as compensation expense over the remaining vesting period. The amount of stock-based compensation expense charged to earnings for the year ended December 31, 2003 was $46 million. The compensation expense will be revalued at each reporting date based on the share price and the number of vested stock options outstanding.

(f) The liability method under Canadian GAAP 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 in 2000, the deficit of Husky Oil Limited of $160 million 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 2003 were $232 million (2002 – $256 million; 2001 – $272 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. At December 31, 2003 the additional minimum liability was increased by $6 million (2002 – $19 million) with a decrease to other comprehensive income of $5 million (2002 – decrease of $10 million), net of tax.

Additional U.S. GAAP Disclosures

Acquisition of Marathon Canada

As described in note 7, Acquisition of Marathon Canada, the Company purchased all of the outstanding shares of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. This transaction increased the reserve base and created cost efficiencies, increasing shareholder value.

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 2003, 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, 2003. During 2003, 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, no compensation expense has been charged to income at the time of the option grants. On September 3, 2003 the Company modified the exercise price of all outstanding options, resulting in the use of variable accounting for these modified stock options. The compensation expense recorded under variable accounting has been removed from the pro forma amounts indicated below. 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 earnings per share for the years ended December 31, 2003, 2002 and 2001 would have been the pro forma amounts indicated below:

	2003		2002		2001	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
Net earnings	**$ 1,375**	**$ 1,407**	$ 811	$ 798	$ 297	$ 284
Earnings per share						
Basic	**$ 3.28**	**$ 3.35**	$ 1.94	$ 1.91	$ 0.71	$ 0.68
Diluted	**$ 3.26**	**$ 3.34**	$ 1.93	$ 1.90	$ 0.71	$ 0.68

The fair values of all common share options granted are estimated on the date of grant using the 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 described in note 16.

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 as calculated under U.S. GAAP for the years ended December 31 were as follows:

	2003	2002	2001
Depletion, depreciation and amortization per boe (1)	**$ 7.57**	$ 6.96	$ 6.88

(1) *Excludes the 2001 ceiling test write down.*

Accounting for Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation 46 "Accounting for Variable Interest Entities" ("FIN 46") that requires the consolidation of Variable Interest Entities ("VIEs"). VIEs are entities that have insufficient equity or their equity investors lack one or more of the specified elements that a controlling entity would have. The VIEs are controlled through financial interests that indicate control (referred to as "variable interests"). Variable interests are the rights or obligations that expose the holder of the variable interest to expected losses or expected residual gains of the entity. The holder of the majority of an entity's variable interests is considered the primary beneficiary of the VIE and is required to consolidate the VIE. In December 2003 the FASB issued FIN 46R which superceded FIN 46 and restricts the scope of the definition of entities that would be considered VIEs that require consolidation. The Company does not believe FIN 46R results in the consolidation of any additional entities that existed at December 31, 2003.

Husky Energy Inc. 2003

Supplemental Financial and Operating Information

101 Supplemental Information on Oil and Gas Exploration and Production Activities

107 Quarterly Financial and Operating Information

110 Five-year Financial and Operating Information

113 Selected Ten-year Financial and Operating Summary

Supplemental Information on Oil and Gas Exploration and Production 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, 2003 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

	Canada [1]			International [1]			Total [1]		
($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Revenue									
Sales	**$ 2,090**	$ 1,738	$ 1,771	**$ 310**	$ 190	$ 4	**$ 2,400**	$ 1,928	$ 1,775
Transfers	**786**	737	390	**–**	–	–	**786**	737	390
	2,876	2,475	2,161	**310**	190	4	**3,186**	2,665	2,165
Operating expenses									
Production costs	**794**	676	617	**17**	10	–	**811**	686	617
Depletion, depreciation and amortization	**892**	813	721	**66**	38	7	**958**	851	728
Income taxes	**527**	387	334	**102**	64	(1)	**629**	451	333
	2,213	1,876	1,672	**185**	112	6	**2,398**	1,988	1,678
Results of operations from producing activities	**$ 663**	$ 599	$ 489	**$ 125**	$ 78	$ (2)	**$ 788**	$ 677	$ 487
Amortization rates per gross equivalent barrel	**$ 8.43**	$ 7.74	$ 7.24	**$ 8.00**	$ 8.33	$ 80.61	**$ 8.40**	$ 7.76	$ 7.31

[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)		2003	2002	2001
Property acquisition costs [1]				
Proved	– Canada	**$ 541**	$ 20	$ 366
Unproved	– Canada	**106**	88	55
		647	108	421
Exploration costs	– Canada	**298**	257	262
	– Other	**26**	9	5
		324	266	267
Development costs	– Canada	**1,381**	1,127	774
	– China	**–**	66	99
		1,381	1,193	873
		$ 2,352	$ 1,567	$ 1,561

[1] *Property acquisition costs related to corporate acquisitions for proved properties in 2003 were $517 million (2002 – nil; 2001 – $244 million).*

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, 2003, by the year in which the costs were incurred:

WITHHELD COSTS

($ millions)		Total	2003	2002	2001	Prior to 2001
Property acquisition	– Canada	**$ 406**	$ 56	$ 37	$ 17	$ 296
	– International	**14**	–	–	–	14
		420	56	37	17	310
Exploration	– Canada	**324**	131	40	57	96
	– International	22	16	6	–	–
		346	147	46	57	96
Development	– Canada	**886**	477	392	17	–
	– International	**18**	1	–	–	17
		904	478	392	17	17
Capitalized interest	– Canada	**198**	52	26	51	69
		$ 1,868	$ 733	$ 501	$ 142	$ 492

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)		2003	2002	2001 [1]
Unproved oil and gas properties	– Canada	**$ 1,814**	$ 1,318	$ 1,052
	– International	**54**	37	235
		1,868	1,355	1,287
Proved oil and gas properties	– Canada	**11,787**	10,207	9,301
	– International	**442**	432	159
		12,229	10,639	9,460
		14,097	11,994	10,747
Less accumulated depletion, depreciation and amortization	– Canada	**4,633**	3,894	3,272
	– International	**250**	185	147
		4,883	4,079	3,419
		$ 9,214	$ 7,915	$ 7,328
Net capitalized costs	– Canada	**$ 8,968**	$ 7,631	$ 7,081
	– International	**246**	284	247
		$ 9,214	$ 7,915	$ 7,328

[1] *Capital related to 17 mmbbls of proved reserves at Terra Nova transferred to proved oil and gas properties. Terra Nova was a major development project off the East Coast of Canada in 2001.*

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 China and Libya. The Company's proved developed and undeveloped reserves after deductions of royalties are summarized below:

RESERVES [1]

	Canada			International		Total		
	Crude Oil & NGL	Natural Gas	Sulphur	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Sulphur
	(mmbbls)	*(bcf)*	*(mmlt)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(bcf)*	*(mmlt)*
Net proved developed and undeveloped reserves, after royalties [2] [3] [4] [5]								
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
Revisions	18.4	(88.9)	0.1	(2.8)	(100.9)	15.6	(189.8)	0.1
Purchases	9.2	146.2	–	–	–	9.2	146.2	–
Sales	(4.2)	(15.9)	(0.1)	–	–	(4.2)	(15.9)	(0.1)
Discoveries and extensions	32.6	245.6	0.1	–	–	32.6	245.6	0.1
Production	(61.1)	(182.2)	(0.5)	(7.5)	–	(68.6)	(182.2)	(0.5)
End of year 2003	**463.0**	**1,716.6**	**4.2**	**22.5**	**–**	**485.5**	**1,716.6**	**4.2**
Net proved developed reserves, after royalties [2] [3] [4] [5]								
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
End of year 2003	**372.0**	**1,422.9**	**3.8**	**22.5**	**–**	**394.5**	**1,422.9**	**3.8**

[1] *Husky applied for and was granted an exemption from National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" to provide oil and gas reserves disclosures in accordance with the U.S. Securities and Exchange Commission guidelines and the U.S. Financial Accounting Standards Board disclosure standards. The information disclosed may differ from information prepared in accordance with National Instrument 51-101. Husky's internally generated oil and gas reserves data was audited by an independent firm of consulting engineers.*

[2] *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.*

[3] *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.*

[4] *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.*

[5] *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 reserves 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, 2003 was based on the NYMEX year-end natural gas spot price of U.S. $5.96/mmbtu (2002 – U.S. $4.60/mmbtu; 2001 – U.S. $2.75/mmbtu) and on crude oil prices computed with reference to the year-end West Texas Intermediate price of U.S. $32.51/bbl (2002 – U.S. $31.21/bbl; 2001 – U.S. $19.96/bbl). The price of West Texas Intermediate in Canadian dollars was lower at December 31, 2003 than at December 31, 2002 as a result of the Cdn./U.S. dollar exchange rate, which was $1.29 at December 31, 2003 compared with $1.58 at December 31, 2002.

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

	Canada [1]			International [1]			Total [1]		
($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Future cash inflows	**$24,003**	$25,830	$14,102	**$ 928**	$ 2,719	$ 1,600	**$24,931**	$28,549	$15,702
Future costs									
Future production and development costs	**8,645**	7,239	7,541	**146**	502	523	**8,791**	7,741	8,064
Future income taxes	**5,696**	7,278	2,540	**247**	860	310	**5,943**	8,138	2,850
Future net cash flows	**9,662**	11,313	4,021	**535**	1,357	767	**10,197**	12,670	4,788
Deduct 10% annual discount factor	**4,242**	4,966	1,667	**117**	518	329	**4,359**	5,484	1,996
Standardized measure of discounted future net cash flows	**$ 5,420**	$ 6,347	$ 2,354	**$ 418**	$ 839	$ 438	**$ 5,838**	$ 7,186	$ 2,792

[1] The schedule above is 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.

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

	Canada [1]			International [1]			Total [1]		
($ millions)	**2003**	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Present value at January 1	**$ 6,347**	$ 2,354	$ 5,462	**$ 839**	$ 438	$ 372	**$ 7,186**	$ 2,792	$ 5,834
Sales and transfers, net of production costs	**(2,097)**	(1,802)	(1,556)	**(293)**	(179)	(2)	**(2,390)**	(1,981)	(1,558)
Net change in sales and transfer prices, net of development and production costs	**(1,379)**	7,752	(5,843)	**(376)**	732	(48)	**(1,755)**	8,484	(5,891)
Extensions, discoveries and improved recovery, net of related costs	**541**	676	356	**–**	40	17	**541**	716	373
Revisions of quantity estimates	**76**	(30)	237	**(97)**	(28)	10	**(21)**	(58)	247
Accretion of discount	**1,055**	390	949	**130**	59	55	**1,185**	449	1,004
Sale of reserves in place	**(47)**	(189)	(6)	**–**	–	–	**(47)**	(189)	(6)
Purchase of reserves in place	**304**	45	174	**–**	–	–	**304**	45	174
Changes in timing of future net cash flows and other	**(237)**	(191)	95	**(49)**	80	10	**(286)**	(111)	105
Net change in income taxes	**857**	(2,658)	2,486	**264**	(303)	24	**1,121**	(2,961)	2,510
Present value at December 31	**$ 5,420**	$ 6,347	$ 2,354	**$ 418**	$ 839	$ 438	**$ 5,838**	$ 7,186	$ 2,792

(1) The schedule above is 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.

Quarterly Financial and Operating Information

SEGMENTED OPERATIONAL INFORMATION

	2003				2002			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream								
Daily production, before royalties								
Light crude oil & NGL *(mbbls/day)*	**72.0**	**65.2**	**74.9**	**74.3**	78.8	71.9	56.1	54.8
Medium crude oil *(mbbls/day)*	**37.9**	**38.2**	**39.4**	**41.4**	43.5	44.4	44.6	46.7
Heavy crude oil *(mbbls/day)*	**107.8**	**99.2**	**94.7**	**97.8**	99.4	95.2	92.8	92.9
	217.7	**202.6**	**209.0**	**213.5**	221.7	211.5	193.5	194.4
Natural gas *(mmcf/day)*	**655.7**	**585.7**	**609.4**	**591.2**	577.4	561.6	571.8	566.0
Total production *(mboe/day)*	**327.0**	**300.2**	**310.6**	**312.1**	317.9	305.1	288.9	288.7
Average realized sales prices								
Light crude oil & NGL *($/bbl)*	**$ 35.82**	**$ 33.01**	**$ 36.30**	**$ 46.14**	$ 41.08	$ 38.54	$ 33.96	$ 28.45
Medium crude oil *($/bbl)*	**$ 23.27**	**$ 27.12**	**$ 32.05**	**$ 35.39**	$ 30.92	$ 34.76	$ 30.90	$ 24.84
Heavy crude oil *($/bbl)*	**$ 20.84**	**$ 25.13**	**$ 25.13**	**$ 33.02**	$ 26.20	$ 31.41	$ 27.75	$ 20.95
Natural gas *($/mcf)*	**$ 5.08**	**$ 5.58**	**$ 5.43**	**$ 7.80**	$ 4.76	$ 3.42	$ 3.98	$ 3.10
Operating costs *($/boe)*	**$ 6.87**	**$ 6.71**	**$ 6.80**	**$ 7.39**	$ 6.66	$ 6.19	$ 6.19	$ 5.88
Operating netbacks [1]								
Light crude oil *($/boe)*	**$ 25.14**	**$ 28.85**	**$ 28.89**	**$ 34.71**	$ 30.83	$ 27.74	$ 23.25	$ 17.68
Medium crude oil *($/boe)*	**$ 9.52**	**$ 13.15**	**$ 17.34**	**$ 19.51**	$ 16.68	$ 20.39	$ 18.18	$ 14.20
Heavy crude oil *($/boe)*	**$ 10.45**	**$ 14.00**	**$ 13.51**	**$ 19.03**	$ 13.52	$ 19.90	$ 17.82	$ 12.16
Natural gas *($/mcfge)*	**$ 3.34**	**$ 3.59**	**$ 3.21**	**$ 5.19**	$ 3.18	$ 2.19	$ 2.39	$ 2.03
Total *($/boe)*	**$ 16.60**	**$ 19.44**	**$ 19.49**	**$ 26.54**	$ 19.71	$ 19.67	$ 17.67	$ 13.47
Net wells drilled [2]								
Exploration Oil	**3**	**4**	**1**	**3**	3	6	6	5
Gas	**32**	**11**	**11**	**70**	14	16	18	83
Dry	**1**	**–**	**3**	**17**	2	2	1	9
	36	**15**	**15**	**90**	19	24	25	97
Development Oil	**116**	**202**	**65**	**107**	107	190	112	44
Gas	**137**	**107**	**64**	**210**	160	67	10	216
Dry	**5**	**14**	**6**	**32**	17	14	6	18
	258	**323**	**135**	**349**	284	271	128	278
	294	**338**	**150**	**439**	303	295	153	375
Success ratio *(percent)*	**98**	**96**	**94**	**89**	94	95	95	93
Midstream								
Synthetic crude oil sales *(mbbls/day)*	**62.2**	**66.0**	**66.5**	**59.4**	67.5	47.3	51.3	71.2
Upgrading differential *($/bbl)*	**$ 13.40**	**$ 11.91**	**$ 12.65**	**$ 14.11**	$ 13.06	$ 9.92	$ 10.43	$ 9.85
Pipeline throughput *(mbbls/day)*	**502**	**477**	**480**	**478**	476	436	448	469
Refined Products								
Refined products sales volumes								
Light oil products *(million litres/day)*	**8.2**	**8.5**	**7.8**	**8.3**	7.9	8.2	7.4	7.2
Asphalt products *(mbbls/day)*	**19.7**	**30.5**	**20.7**	**17.1**	14.2	30.6	20.5	17.7
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	**26.1**	**26.6**	**25.4**	**24.8**	17.8	25.2	19.9	25.2
Prince George refinery *(mbbls/day)*	**11.5**	**8.2**	**11.0**	**10.6**	10.9	11.0	7.7	10.9
Refinery utilization *(percent)*	**107**	**99**	**104**	**101**	82	103	79	103

(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.*

SEGMENTED FINANCIAL INFORMATION

($ millions)	Upstream Q4	Upstream Q3	Upstream Q2	Upstream Q1	Midstream Upgrading Q4	Midstream Upgrading Q3	Midstream Upgrading Q2	Midstream Upgrading Q1
2003								
Sales and operating revenues, net of royalties	$ 722	$ 740	$ 760	$ 964	$ 229	$ 252	$ 256	$ 276
Costs and expenses								
Operating, cost of sales, selling and general	221	199	212	223	196	225	228	252
Depletion, depreciation and amortization	267	229	233	229	5	5	5	5
Interest – net	–	–	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–	–	–
	488	428	445	452	201	230	233	257
Earnings (loss) before income taxes	234	312	315	512	28	22	23	19
Current income taxes	5	13	39	38	1	–	–	–
Future income taxes	55	91	(83)	167	9	7	(3)	7
Net earnings (loss)	$ 174	$ 208	$ 359	$ 307	$ 18	$ 15	$ 26	$ 12
Capital employed	$ 6,652	$ 6,187	$ 6,111	$ 6,192	$ 456	$ 462	$ 468	$ 308
Total assets (2)	$ 9,806	$ 8,834	$ 8,541	$ 8,649	$ 649	$ 654	$ 655	$ 662
2002								
Sales and operating revenues, net of royalties	$ 781	$ 738	$ 635	$ 511	$ 301	$ 192	$ 195	$ 221
Costs and expenses								
Operating, cost of sales, selling and general	206	189	171	163	265	183	182	181
Depletion, depreciation and amortization	231	218	202	200	5	4	4	5
Interest – net	–	–	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–	–	–
	437	407	373	363	270	187	186	186
Earnings (loss) before income taxes	344	331	262	148	31	5	9	35
Current income taxes	26	8	1	20	–	1	–	–
Future income taxes	108	117	83	34	11	2	2	10
Net earnings (loss)	$ 210	$ 206	$ 178	$ 94	$ 20	$ 2	$ 7	$ 25
Capital employed	$ 6,040	$ 6,027	$ 6,001	$ 5,919	$ 319	$ 343	$ 324	$ 306
Total assets	$ 8,220	$ 8,105	$ 7,860	$ 7,723	$ 658	$ 665	$ 657	$ 640

(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) *Includes goodwill on Marathon Canada Limited acquisition related to Upstream.*

Midstream				Refined Products				Corporate and Eliminations [1]				Total			
Infrastructure and Marketing															
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
$ 1,139	$ 1,170	$ 1,205	$ 1,432	$ 335	$ 431	$ 352	$ 384	$ (625)	$ (722)	$ (804)	$ (838)	$ 1,800	$ 1,871	$ 1,769	$ 2,218
1,089	1,125	1,166	1,367	318	390	340	374	(625)	(729)	(794)	(830)	1,199	1,210	1,152	1,386
6	5	5	5	8	8	9	9	7	7	6	5	293	254	258	253
–	–	–	–	–	–	–	–	16	16	20	21	16	16	20	21
–	–	–	–	–	–	–	–	(43)	–	(72)	(100)	(43)	–	(72)	(100)
1,095	1,130	1,171	1,372	326	398	349	383	(645)	(706)	(840)	(904)	1,465	1,480	1,358	1,560
44	40	34	60	9	33	3	1	20	(16)	36	66	335	391	411	658
22	4	(4)	5	(13)	14	3	5	7	4	4	–	22	35	42	48
(6)	10	15	18	17	(2)	(2)	(4)	(7)	7	15	16	68	113	(58)	204
$ 28	$ 26	$ 23	$ 37	$ 5	$ 21	$ 2	$ –	$ 20	$ (27)	$ 17	$ 50	$ 245	$ 243	$ 427	$ 406
$ 350	$ 446	$ 442	$ 395	$ 320	$ 403	$ 425	$ 351	$ (120)	$ 141	$ 424	$ 361	$ 7,658	$ 7,639	$ 7,870	$ 7,607
$ 701	$ 792	$ 945	$ 847	$ 525	$ 585	$ 607	$ 610	$ 101	$ 851	$ 584	$ 406	$ 11,782	$ 11,716	$ 11,332	$ 11,174
$ 1,367	$ 953	$ 958	$ 952	$ 326	$ 431	$ 322	$ 231	$ (1,078)	$ (645)	$ (451)	$ (556)	$ 1,697	$ 1,669	$ 1,659	$ 1,359
1,321	905	916	896	318	395	292	217	(1,081)	(642)	(436)	(537)	1,029	1,030	1,125	920
6	5	5	4	9	9	8	8	5	3	4	4	256	239	223	221
–	–	–	–	–	–	–	–	25	28	24	27	25	28	24	27
–	–	–	–	–	–	–	–	(5)	75	(65)	8	(5)	75	(65)	8
1,327	910	921	900	327	404	300	225	(1,056)	(536)	(473)	(498)	1,305	1,372	1,307	1,176
40	43	37	52	(1)	27	22	6	(22)	(109)	22	(58)	392	297	352	183
(19)	13	4	8	(1)	4	1	–	–	–	–	–	6	26	6	28
31	5	10	13	1	7	8	2	(7)	(33)	(20)	(30)	144	98	83	29
$ 28	$ 25	$ 23	$ 31	$ (1)	$ 16	$ 13	$ 4	$ (15)	$ (76)	$ 42	$ (28)	$ 242	$ 173	$ 263	$ 126
$ 431	$ 428	$ 194	$ 268	$ 338	$ 360	$ 383	$ 375	$ 384	$ 176	$ 233	$ (2)	$ 7,512	$ 7,334	$ 7,135	$ 6,866
$ 850	$ 871	$ 736	$ 845	$ 534	$ 554	$ 523	$ 516	$ 313	$ 153	$ 189	$ 6	$ 10,575	$ 10,348	$ 9,965	$ 9,730

SEGMENTED FINANCIAL INFORMATION

($ millions)		2003				2002			
		Q4 [1]	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Capital expenditures									
Upstream	– Western Canada	**$ 371**	**$ 272**	**$ 185**	**$ 370**	$ 326	$ 207	$ 156	$ 345
	– East Coast Canada	**194**	**169**	**90**	**104**	97	169	154	38
	– International	**5**	**9**	**2**	**10**	8	25	22	20
		570	**450**	**277**	**484**	431	401	332	403
Midstream	– Upgrader	**10**	**5**	**6**	**4**	11	9	12	9
	– Infrastructure and marketing	**8**	**5**	**3**	**2**	5	2	3	7
		18	**10**	**9**	**6**	16	11	15	16
Refined Products		**30**	**11**	**9**	**8**	22	9	9	4
Corporate		**9**	**5**	**7**	**2**	10	5	5	3
		$ 627	**$ 476**	**$ 302**	**$ 500**	$ 479	$ 426	$ 361	$ 426

[1] Does not include the acquisition of Marathon Canada Limited.

Five-year Financial and Operating Information

SEGMENTED FINANCIAL INFORMATION

	Upstream					Midstream									
						Upgrading					Infrastructure and Marketing				
($ millions)	2003	2002	2001	2000	1999	2003	2002	2001	2000	1999	2003	2002	2001	2000	1999
Year ended December 31															
Sales and operating revenues, net of royalties	**$ 3,186**	$ 2,665	$ 2,165	$ 1,549	$ 595	**$ 1,013**	$ 909	$ 886	$ 1,006	$ 641	**$ 4,946**	$ 4,230	$ 4,380	$ 2,309	$ 1,284
Costs and expenses															
Operating, cost of sales, selling and general	**855**	729	648	375	214	**901**	811	638	848	581	**4,747**	4,038	4,193	2,193	1,190
Depletion, depreciation and amortization	**958**	851	728	407	223	**20**	18	17	16	16	**21**	20	17	15	13
Interest – net	**–**	–	–	–	–	**–**	–	–	–	–	**–**	–	–	–	–
Foreign exchange	**–**	–	–	–	–	**–**	–	–	–	–	**–**	–	–	–	–
	1,813	1,580	1,376	782	437	**921**	829	655	864	597	**4,768**	4,058	4,210	2,208	1,203
Earnings (loss) before income taxes	**1,373**	1,085	789	767	158	**92**	80	231	142	44	**178**	172	170	101	81
Current income taxes	**95**	55	17	10	3	**1**	1	1	1	1	**27**	6	1	–	–
Future income taxes	**230**	342	290	305	50	**20**	25	72	53	21	**37**	59	71	45	36
Net earnings (loss)	**$ 1,048**	$ 688	$ 482	$ 452	$ 105	**$ 71**	$ 54	$ 158	$ 88	$ 22	**$ 114**	$ 107	$ 98	$ 56	$ 45
Capital employed – As at December 31	**$ 6,652**	$ 6,040	$ 5,715	$ 5,398	$ 2,077	**$ 456**	$ 319	$ 320	$ 352	$ 392	**$ 350**	$ 431	$ 395	$ 312	$ 353
Total assets – As at December 31 [2]	**$ 9,806**	$ 8,220	$ 7,407	$ 6,735	$ 2,839	**$ 649**	$ 658	$ 644	$ 613	$ 606	**$ 701**	$ 850	$ 862	$ 1,000	$ 652

[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] 2003 includes goodwill on Marathon Canada Limited acquisition related to Upstream.

SEGMENTED FINANCIAL INFORMATION

($ millions)		2003 [1]	2002	2001	2000	1999
Capital expenditures						
Upstream	– Western Canada	**$ 1,198**	$ 1,034	$ 1,022	$ 419	$ 238
	– East Coast Canada	**557**	458	191	194	309
	– International	**26**	75	104	87	23
		1,781	1,567	1,317	700	570
Midstream	– Upgrader	**25**	41	47	12	15
	– Infrastructure and marketing	**18**	17	58	47	79
		43	58	105	59	94
Refined Products		**58**	44	29	29	34
Corporate		**23**	23	22	15	8
		$ 1,905	$ 1,692	$ 1,473	$ 803	$ 706

[1] *Does not include the acquisition of Marathon Canada Limited.*

SEGMENTED FINANCIAL INFORMATION (CONTINUED)

	Refined Products					Corporate and Eliminations [1]					Total				
($ millions)	2003	2002	2001	2000	1999	2003	2002	2001	2000	1999	2003	2002	2001	2000	1999
Year ended December 31															
Sales and operating revenues, net of royalties	**$ 1,502**	$ 1,310	$ 1,349	$ 1,347	$ 904	**$(2,989)**	$ (2,730)	$ (2,184)	$ (1,145)	$ (637)	**$ 7,658**	$ 6,384	$ 6,596	$ 5,066	$ 2,787
Costs and expenses															
Operating, cost of sales, selling and general	**1,422**	1,222	1,206	1,288	842	**(2,978)**	(2,696)	(2,165)	(1,060)	(514)	**4,947**	4,104	4,520	3,644	2,313
Depletion, depreciation and amortization	**34**	34	31	28	26	**25**	16	14	15	15	**1,058**	939	807	481	293
Interest – net	**–**	–	–	–	–	**73**	104	101	101	62	**73**	104	101	101	62
Foreign exchange	**–**	–	–	–	–	**(215)**	13	94	39	(55)	**(215)**	13	94	39	(55)
	1,456	1,256	1,237	1,316	868	**(3,095)**	(2,563)	(1,956)	(905)	(492)	**5,863**	5,160	5,522	4,265	2,613
Earnings (loss) before income taxes	**46**	54	112	31	36	**106**	(167)	(228)	(240)	(145)	**1,795**	1,224	1,074	801	174
Current income taxes	**9**	4	1	1	1	**15**	–	–	–	–	**147**	66	20	12	5
Future income taxes	**9**	18	48	14	16	**31**	(90)	(81)	(66)	(50)	**327**	354	400	351	73
Net earnings (loss)	**$ 28**	$ 32	$ 63	$ 16	$ 19	**$ 60**	$ (77)	$ (147)	$ (174)	$ (95)	**$ 1,321**	$ 804	$ 654	$ 438	$ 96
Capital employed – As at December 31	**$ 320**	$ 338	$ 329	$ 351	$ 366	**$ (120)**	$ 384	$ (81)	$ (50)	$ 158	**$ 7,658**	$ 7,512	$ 6,678	$ 6,363	$ 3,346
Total assets – As at December 31	**$ 525**	$ 534	$ 428	$ 487	$ 476	**$ 101**	$ 313	$ 29	$ (6)	$ 203	**$11,782**	$10,575	$ 9,370	$ 8,829	$ 4,776

UPSTREAM OPERATING INFORMATION

	2003	2002	2001	2000	1999
Daily production, before royalties					
Light crude oil & NGL *(mbbls/day)*	**71.6**	65.4	46.4	42.8	22.3
Medium crude oil *(mbbls/day)*	**39.2**	44.8	47.2	20.8	4.2
Heavy crude oil *(mbbls/day)*	**99.9**	95.1	83.8	53.5	42.1
	210.7	205.3	177.4	117.1	68.6
Natural gas *(mmcf/day)*	**610.6**	569.2	572.6	358.0	250.5
Total production *(mboe/day)*	**312.5**	300.2	272.8	176.8	110.4
Average realized sales prices					
Light crude oil & NGL *($/bbl)*	**$ 38.73**	$ 36.26	$ 33.15	$ 36.49	$ 22.03
Medium crude oil *($/bbl)*	**$ 29.57**	$ 30.35	$ 23.69	$ 27.10	$ 18.78
Heavy crude oil *($/bbl)*	**$ 25.87**	$ 26.60	$ 17.02	$ 21.26	$ 16.00
Natural gas *($/mcf)*	**$ 5.94**	$ 3.83	$ 5.47	$ 5.16	$ 2.41
Operating costs *($/boe)*	**$ 6.92**	$ 6.24	$ 6.08	$ 5.27	$ 4.80
Operating netbacks [1]					
Light crude oil *($/boe)*	**$ 29.49**	$ 25.74	$ 20.37	$ 20.78	$ 12.15
Medium crude oil *($/boe)*	**$ 14.97**	$ 17.33	$ 12.29	$ 17.53	$ 11.49
Heavy crude oil *($/boe)*	**$ 14.13**	$ 15.85	$ 7.87	$ 12.10	$ 7.91
Natural gas *($/mcfge)*	**$ 3.79**	$ 2.46	$ 3.51	$ 3.59	$ 1.54

[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

		2003		2002		2001		2000		1999	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled [1]											
Exploration	Oil	**12**	**11**	21	20	78	76	16	13	9	9
	Gas	**147**	**124**	139	131	102	90	30	20	13	5
	Dry	**22**	**21**	15	14	36	34	9	9	9	9
		181	**156**	175	165	216	200	55	42	31	23
Development	Oil	**520**	**490**	497	453	594	542	411	363	203	190
	Gas	**540**	**518**	485	453	251	221	92	70	42	23
	Dry	**60**	**57**	58	55	68	63	30	28	23	22
		1,120	**1,065**	1,040	961	913	826	533	461	268	235
		1,301	**1,221**	1,215	1,126	1,129	1,026	588	503	299	258
Success ratio *(percent)*		**94**	**94**	94	94	91	91	93	93	89	88

[1] Western Canada.

UNDEVELOPED LAND HOLDINGS

(thousands of acres – net)	2003	2002	2001	2000	1999
Western Canada					
Alberta	**4,852**	4,907	5,373	5,616	692
Saskatchewan	**1,911**	1,986	1,921	2,639	586
British Columbia	**491**	273	141	173	66
Manitoba	**8**	13	75	162	–
	7,262	7,179	7,510	8,590	1,344
Northwest Territories and Arctic	**184**	175	409	409	417
Eastern Canada	**2,104**	2,104	1,471	1,489	258
Total Canada	**9,550**	9,458	9,390	10,488	2,019
International	**2,066**	2,066	697	221	389
Total	**11,616**	11,524	10,087	10,709	2,408

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Sales and operating revenues,										
net of royalties	**$ 7,658**	$ 6,384	$ 6,596	$ 5,066	$ 2,787	$ 2,023	$ 2,282	$ 2,104	$ 1,783	$ 1,373
Net earnings (loss)	**$ 1,321**	$ 804	$ 654	$ 438	$ 96	$ (5)	$ 55	$ 49	$ 20	$ (40)
Earnings per share										
Basic	**$ 3.23**	$ 1.88	$ 1.49	$ 1.28	$ 0.34	$ (0.04)	$ 0.20	$ 0.18	$ 0.08	$ (0.15)
Diluted	**$ 3.22**	$ 1.88	$ 1.48	$ 1.28	$ 0.34	$ (0.04)	$ 0.20	$ 0.18	$ 0.08	$ (0.15)
Cash flow from operations	**$ 2,459**	$ 2,096	$ 1,946	$ 1,399	$ 517	$ 449	$ 453	$ 378	$ 303	$ 242
Cash flow from operations per share										
Basic	**$ 5.79**	$ 4.94	$ 4.60	$ 4.26	$ 1.80	$ 1.61	$ 1.68	$ 1.40	$ 1.12	$ 0.90
Diluted	**$ 5.76**	$ 4.92	$ 4.57	$ 4.26	$ 1.80	$ 1.61	$ 1.68	$ 1.40	$ 1.12	$ 0.90
Capital expenditures [1]	**$ 1,905**	$ 1,692	$ 1,473	$ 803	$ 706	$ 829	$ 601	$ 218	$ 155	$ 257
Total debt	**$ 1,769**	$ 2,385	$ 2,192	$ 2,378	$ 1,382	$ 1,131	$ 1,014	$ 853	$ 1,474	$ 1,667
Debt to capital employed *(percent)*	**23**	32	33	37	41	39	43	42	63	69
Debt to cash flow from operations *(times)*	**0.7**	1.1	1.1	1.7	2.7	2.5	2.2	2.3	4.9	6.9
Reinvestment ratio [2] *(percent)*	**90**	76	78	57	134	199	132	46	44	62
Return on average capital										
employed [3] *(percent)*	**18.0**	12.2	10.9	12.4	6.9	4.2	7.2	6.7	5.5	1.2
Return on equity [4] *(percent)*	**24.0**	16.7	15.4	19.4	11.4	6.7	12.1	11.7	14.1	(3.0)
Upstream										
Daily production, before royalties										
Light crude oil & NGL *(mbbls/day)*	**71.6**	65.4	46.4	42.8	22.3	23.7	23.6	24.2	23.6	25.1
Medium crude oil *(mbbls/day)*	**39.2**	44.8	47.2	20.8	4.2	3.9	4.0	4.1	4.1	4.3
Heavy crude oil *(mbbls/day)*	**99.9**	95.1	83.8	53.5	42.1	42.0	41.9	34.5	30.0	26.6
	210.7	205.3	177.4	117.1	68.6	69.6	69.5	62.8	57.7	56.0
Natural gas *(mmcf/day)*	**611**	569	573	358	251	233	246	268	286	248
Total production *(mboe/day)*	**312.5**	300.2	272.8	176.8	110.4	108.4	110.6	107.5	105.4	97.4
Total proved reserves, before royalties *(mmboe)*	**887**	918	927	872	430	431	421	432	416	401
Midstream										
Synthetic crude oil sales *(mbbls/day)*	**63.6**	59.3	59.5	60.6	61.9	54.8	27.5	26.8	26.6	18.8
Upgrading differential *($/bbl)*	**$ 12.88**	$ 10.81	$ 17.91	$ 13.77	$ 6.49	$ 7.85	$ 8.54	$ 5.94	$ 4.34	$ 4.18
Pipeline throughput *(mbbls/day)*	**484**	457	537	528	394	412	417	359	296	238
Refined Products										
Light oil products sales *(million litres/day)*	**8.2**	7.7	7.6	7.4	7.6	6.0	4.5	4.2	3.9	3.2
Asphalt products sales *(mbbls/day)*	**22.0**	20.8	21.4	20.2	17.1	19.5	17.7	15.1	13.5	13.1
Refinery throughput										
Prince George refinery *(mbbls/day)*	**10.3**	10.1	10.2	9.2	10.2	9.9	10.3	10.0	9.9	9.7
Lloydminster refinery *(mbbls/day)*	**25.7**	22.0	23.7	23.4	17.9	21.9	21.5	18.4	15.6	16.4
Refinery utilization *(percent)*	**103**	92	97	93	80	91	91	81	73	75

(1) Excludes corporate acquisitions.

(2) Reinvestment ratio is based on net capital expenditures including corporate acquisitions (other than Renaissance Energy Ltd.).

(3) Capital employed for purposes of this calculation has been weighted for 2000.

(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.

Board of Directors

Co-Chairman

Victor T. K. Li, a resident of Hong Kong, has been 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.

Co-Chairman

Canning K. N. Fok [2], a resident of Hong Kong, has been 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 Harbour Ring Limited, Hutchison Telecommunications (Australia) Limited, Partner Communications Company Ltd. and Vanda Systems & Communications Holdings Limited. 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.

Deputy Chairman

William Shurniak, a resident of Australia, has been 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 Hutchison Whampoa Limited, Envestra Limited and CrossCity Motorways Pty Ltd.

Director

R. Donald Fullerton [1], a resident of Toronto, has been a director of Husky Energy Inc. since 2003. Throughout his career he has sat on a wide variety of national and multinational boards and has served on the boards of many educational, medical and cultural institutions. He currently serves on the boards of George Weston Ltd., Asia Satellite Communications Ltd. and Partner Communications Ltd.

Director

Martin J. G. Glynn [1], a resident of New York, has been a director of Husky Energy Inc. since 2000. Mr. Glynn is the president, chief executive officer and a director of HSBC Bank USA. He is a director of HSBC Bank Canada, HSBC North America Inc. and of Wells Fargo HSBC Trade Bank N.A.

Director

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

Director

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, and Aurado Energy Inc.

(1) Audit Committee
(2) Compensation Committee
(3) Health, Safety & Environment Committee
(4) Corporate Governance Committee

Director

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, Loring Ward International Limited and TOM.COM LIMITED.

Director

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.

Director

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 the Bank of Montreal Group of Companies and CK Life Sciences Int'l., (Holdings) Inc.

Director

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. He is a director of Amara International Investment Corp., Cheung Kong (Holdings) Limited and CTC Bank of Canada.

President & CEO, Director

John C.S. Lau, a resident of Calgary, has been a director of Husky Energy Inc. since 2000. Prior to joining Husky in 1992, Mr. Lau served in a number of senior executive roles within the Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies.

Director

Wayne E. Shaw(1)(4), a resident of Toronto, has been a director of Husky Energy Inc. since 2000. Mr. Shaw is a senior partner at Stikeman Elliott LLP, Barristers & Solicitors.

Director

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, 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.

The Management Information Circular and the Annual Information Form contain additional information regarding the Directors.

(1) Audit Committee
(2) Compensation Committee
(3) Health, Safety & Environment Committee
(4) Corporate Governance Committee

Officers/Executives

Husky Energy Inc.

President & CEO

John C. S. Lau, president and chief executive officer is responsible for Husky's corporate direction, strategic planning and corporate policies, and is also a member of the Company's Board of Directors. Before joining Husky he served in a number of senior executive roles within the Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies. Mr. Lau is a fellow member of the Institute of Chartered Accountants, the Australian Society of Accountants, the Hong Kong Society of Accountants, the Taxation Institute of Hong Kong, and the Institute of Chartered Secretaries of Administrators of the United Kingdom.

Vice President, Legal & Corporate Secretary

James D. Girgulis was appointed vice president, legal and corporate secretary of Husky Energy in 2000. He was previously general counsel and corporate secretary of Husky Oil Limited. Prior to joining Husky he held positions with Alberta and Southern Gas Co. and Alberta Natural Gas Company. Mr. Girgulis was called to the Alberta Bar in 1982.

Senior Vice President, Midstream & Refined Products

Donald R. Ingram, senior vice president, midstream & refined products has been an officer of Husky since 1994. He joined the Company in 1982 and has over 30 years in the midstream and downstream business. Mr. Ingram is a Certified Management Accountant (CMA) and is a fellow of the Society of Management Accountants of Canada (FCMA).

Vice President & Chief Financial Officer

Neil D. McGee was appointed vice president and chief financial officer of Husky Energy in 2000, after joining Husky in 1998 as vice president and chief financial officer. Prior to joining Husky, he served as senior manager of corporate finance and corporate secretary at Hutchison Whampoa.

Husky Oil Operations Limited

Vice President & Controller

L. Geoffrey Barlow was appointed controller in 2000 and promoted to vice president and controller in 2003. He was previously controller and a member of the management team at Renaissance Energy. Mr. Barlow is a Chartered Accountant (CA) and is a member of the Institute of Chartered Accountants of Alberta and the Financial Executive Institute of Canada.

Vice President, Exploration & Production Services

Larry R. Bell was appointed vice president, exploration and production services in 2002, and is responsible for surface land, mineral land, drilling and completions, facilities engineering and technical services, reservoir engineering and reserves. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and director and chairman of Western Canada Spill Services Ltd.

Vice President, Corporate Administration

Wendell Carroll, vice president, corporate administration, joined Husky in 2000 and brings with him 30 years' experience as a senior manager with TransCanada PipeLines, Fracmaster and Bow Valley Industries. He is accountable for human resources, health, safety and environment, risk management, diversity, materials and services management, and facilities and records management and real estate.

Vice President, Western Canada Production

Robert S. Coward became a corporate officer in 1993 and has served with Husky since 1977. He was appointed vice president, Western Canada production in 2000 and is responsible for optimizing the value of Husky's assets by increasing both reserves and production, and by controlling costs. Mr. Coward is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Treasurer

J. Michael D'Aguiar joined Husky as treasurer in 2002, and is responsible for the treasury department and associated financial functions. He has extensive financial experience in the international upstream oil industry. Prior to joining Husky he was chief financial officer of Ranger Oil.

Vice President, Canadian Frontier & International Business

Walter DeBoni was appointed vice president, Canadian Frontier and International Business in 2002, and is responsible for Husky's East Coast and international operations. Before joining Husky he served as president & CEO of Bow Valley Energy, chairman of ARC Energy Trust and President & COO of Morrison Petroleums. Mr. DeBoni is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum Engineers.

Vice President, Oil Sands

J. Thomas Graham joined Husky in 1979 and since then has increasingly held senior levels of responsibility. He was appointed vice president in 1998 and assumed responsibility for the oil sands business unit in 2003. Mr. Graham is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and the Association of Professional Engineers of Saskatchewan.

Vice President, Exploration

David R. Taylor is vice president, exploration with responsibility for capitalizing on Husky's quality assets. Mr. Taylor was previously vice president of exploration for Renaissance Energy, and held senior technical and executive positions at Renaissance, Chauvco Resources, Imperial Oil and Exxon. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, the Canadian Society of Petroleum Geologists and the American Association of Petroleum Geologists.

Vice President, Upgrading & Refining

Roy C. Warnock has more than 25 years' experience in oil refining and upgrading, and joined Husky in 1983. He served as the manager of Husky's Prince George refinery and the Lloydminster upgrader, before his appointment as vice president, upgrading and refining. Mr. Warnock is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and Association of Professional Engineers and Geoscientists of Saskatchewan.

Common Share Information

Year ended December 31		2003	2002	2001
Share price	High	**$ 23.95**	$ 17.98	$ 20.95
	Low	**$ 16.03**	$ 14.00	$ 13.10
	Close at December 31	**$ 23.47**	$ 16.47	$ 16.47
Average daily trading volumes *(thousands)*		**400**	463	625
Number of common shares outstanding, December 31 *(thousands)*		**422,176**	417,874	416,878
Number of weighted average common shares outstanding *(thousands)*				
	Basic	**419,543**	417,425	416,100
	Diluted	**421,549**	419,334	418,640

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.

Stock Exchange Listing
Toronto Stock Exchange: HSE

Outstanding Shares
The number of common shares outstanding (in thousands) at December 31, 2003 was 422,176.

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 1-800-564-6253 (toll free in North America) or by email at service@computershare.com.

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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 Fifth Avenue S.W.
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Dividends
Husky's Board of Directors has approved a dividend policy that pays quarterly dividends. From August 2000 to April 2003, the Corporation paid quarterly dividends of $0.09 ($0.36 annually) per common share. This policy was reviewed by the Board in July 2003 and the quarterly dividend was increased to $0.10 ($0.40 annually) per common share. This policy will continue to be reviewed by the Board from time to time. Additionally, the Board of Directors approved a special cash dividend of $1.00 per common share, which was paid on October 1, 2003.

Annual Meeting
The annual meeting of shareholders will be held at 10:30 a.m. on April 22, 2004 in the Crystal Ballroom at the Fairmont Palliser Hotel, 133 Ninth 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 Canadian securities regulators
- Form 40-F, filed with the U.S. Securities and Exchange Commission
- Quarterly Reports
- Management Information Circular

Glossary of Terms and Abbreviations

bbls	barrels
bcf	billion cubic feet
boe	*barrels of oil equivalent*
bps	basis points
CDOR	Certificate of Deposit Offered Rate
GJ	gigajoule
hectare	1 hectare is equal to 2.47 acres
km	kilometre
LIBOR	London Interbank Offered Rate
mbbls	thousand barrels
mbbls/day	thousand barrels per day
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per day
mcf	thousand cubic feet
mcfge	thousand cubic feet of gas equivalent
mmbbls	million barrels
mmboe	million barrels of oil equivalent
mmbtu	million British Thermal Units
mmcf	*million cubic feet*
mmcf/day	million cubic feet per day
mmlt	million long tons
MW	megawatt
MWh	megawatt hour
NGL	natural gas liquids
NIT	NOVA Inventory Transfer [1]
NYMEX	New York Mercantile Exchange
tcf	trillion cubic feet
WTI	West Texas Intermediate

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

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
Reserves	The remaining company share of reserves before deduction of estimated royalties
Net Debt	Total debt net of cash and cash equivalents
Total Debt	Long-term debt including current portion and bank operating loans

Natural gas converted on the basis that six mcf 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.

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