LOOKING BEYOND THE HORIZON

2001

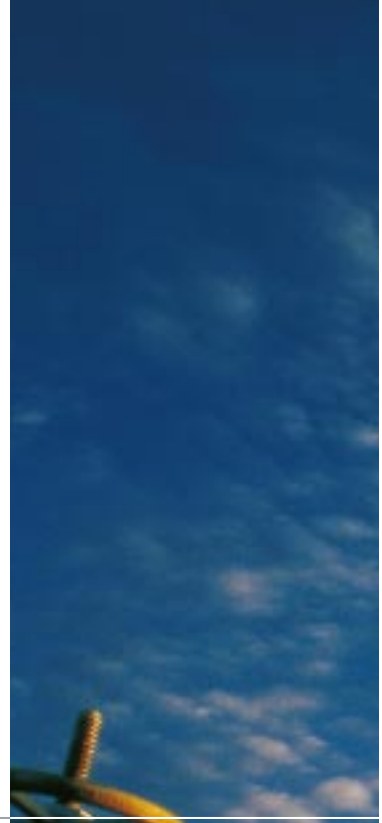
HUSKY ENERGY INC.

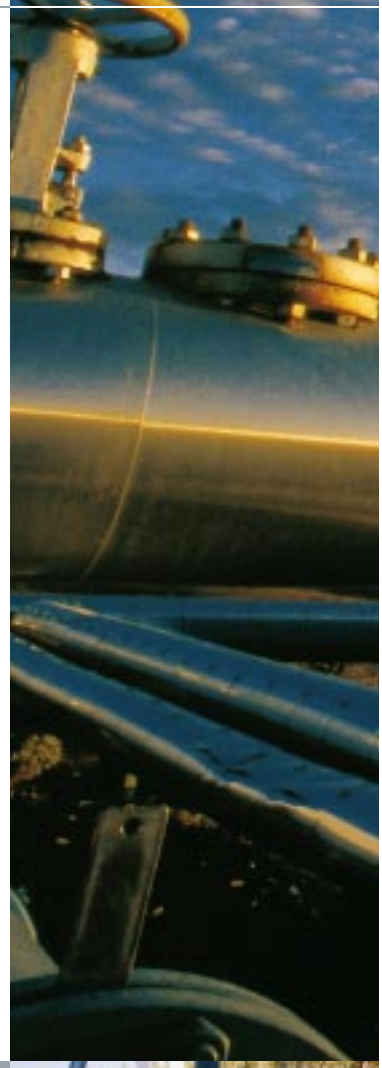
2001 ANNUAL REPORT

CORPORATE PROFILE

Husky Energy's roots began in 1938 and continue with assets and operations across Canada and internationally. Over the 64 years of Husky's history, the Company has diversified and grown, both internally and through acquisitions, culminating in record cash flow and earnings performance in 2001. Husky Energy participates in upstream, midstream and refined products business areas, with exploration, development, marketing, transportation, processing and retailing. Husky produces crude oil, natural gas, synthetic crude oil and a range of derivative products and reaches markets in North America and internationally.

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





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LOOKING BEYOND THE HORIZON

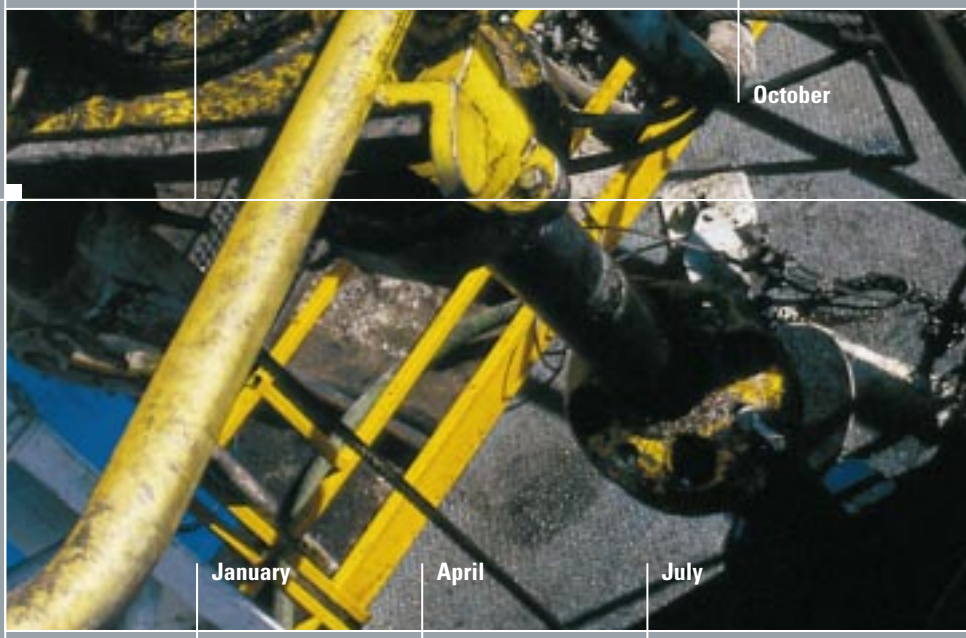
HUSKY'S DIVERSIFIED ASSETS AND OPERATIONS ARE STRATEGICALLY POSITIONED FOR NEAR-TERM AND LONGER-TERM GROWTH, TARGETING CONSISTENT VALUE ADDITIONS FOR SHAREHOLDERS.

2001

HUSKY'S 2001 CASH FLOW OF $1.9 BILLION REPRESENTS YEAR-OVER YEAR GROWTH OF 39%

LOOKING BEYOND THE HORIZON

HSE 2001



January

Development application for White Rose, Jeanne d'Arc Basin filed. Proposes floating production and offloading storage system.

April

Acquisition of Avid Oil & Gas and Titanium Oil & Gas Ltd. purchased for total, combined consideration of $110 million.

July

Exploration agreement signed for Wenchang, China. This augments development activity which is expected to add production in first half of 2002.

October

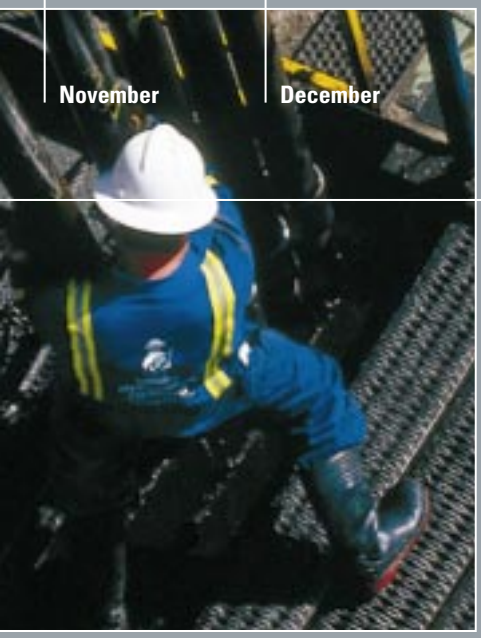
Husky signs historic agreement to promote education and employment for First Nation people from Frog Lake and Kehewin.

HUSKY AT A GLANCE

Husky invests in projects that add quality, long-term reserves and growth potential. Timely and strategic acquisitions supplement Husky's existing asset base.

Husky declared its fourth $0.09 per share dividend, or $0.36 per share for the year, to shareholders.

White Rose, in which Husky has a 72.5 percent working interest, receives government approval for a development program.



November **December**

UPSTREAM OPERATIONS

Exploration and development of crude oil, natural gas and related products take place, primarily, in Western Canada. East Coast offshore Canada and Wenchang, China will add production and reserves over the immediate and longer-term.

MIDSTREAM OPERATIONS

The Lloydminster Upgrader, a 1,900 kilometre heavy oil pipeline system, commodity marketing, natural gas storage and third-party processing are businesses that strengthen the Husky value chain.

REFINED PRODUCTS OPERATIONS

In the refined products segment continued investment in technology, upgrading of refineries and facilities, distinguishing brand identity and growth in non-fuel revenue, should result in solid performance.

2002 LOOKING BEYOND

The challenging environment continuing into 2002 will be met by an anticipated 10 percent production growth rate. Husky anticipates production to average in excess of 300,000 barrels of oil equivalent per day for 2002, with additions from core Western Canada project areas, East Coast offshore Canada and China.

FINANCIAL AND OPERATING HIGHLIGHTS

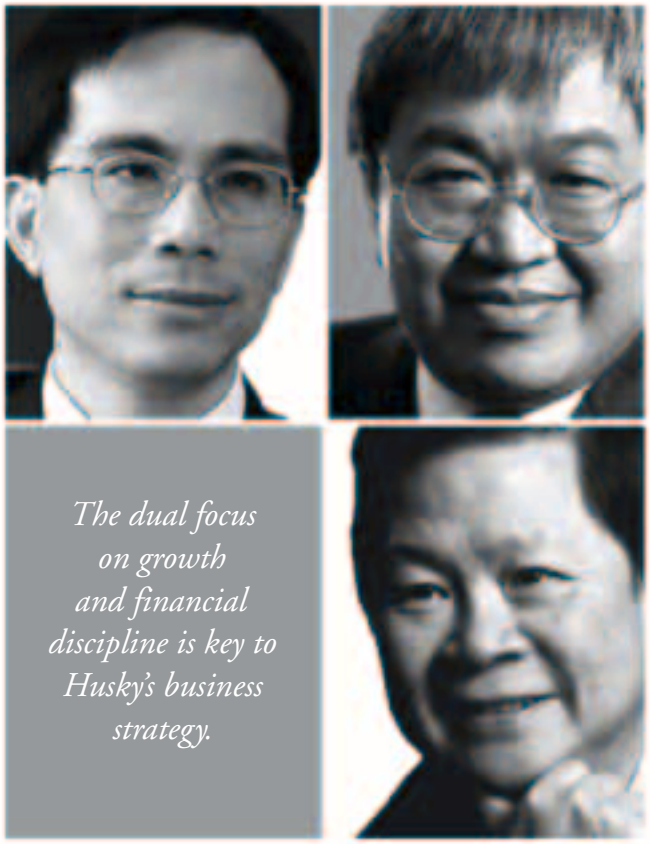
Financial Highlights				
Year ended December 31		**2001**	2000	1999
(millions of dollars except as noted)				
Sales and operating revenues, net of royalties		**6,627**	5,090	2,794
EBITDA		**2,042**	1,499	566
Cash flow from operations		**1,946**	1,399	517
Per share (dollars) - Basic		**4.60**	4.26	1.80
- Diluted		**4.57**	4.26	1.80
Net earnings		**701**	464	43
Per share (dollars) - Basic		**1.64**	1.39	0.10
- Diluted		**1.63**	1.39	0.10
Capital expenditures [1]		**1,473**	803	706
Return on average capital employed [2]	*(percent)*	**11.5**	12.8	5.1
Return on equity [3]	*(percent)*	**16.3**	20.1	8.3
Debt to capital employed [2]	*(percent)*	**32**	37	41
Debt to cash flow from operations [4]	*(times)*	**1.1**	1.7	2.7

[1] *Excludes corporate acquisitions.*
[2] *Capital employed is defined as the average of short and long-term debt and shareholders' equity (2000 is weighted).*
[3] *Equity for purposes of this calculation has been weighted for 2000 and includes amounts due to shareholders prior to August 25, 2000.*
[4] *2000 is based on the year-end Husky Energy balance sheet and income statement.*

Operating Highlights				
Year ended December 31		**2001**	2000	1999
Production, before royalties				
Light/medium crude oil and NGL	*(mbbls/day)*	**112.0**	63.6	26.5
Lloydminster heavy crude oil	*(mbbls/day)*	**65.4**	53.5	42.1
		177.4	117.1	68.6
Natural gas	*(mmcf/day)*	**573**	358	251
Barrels of oil equivalent (6:1)	*(mboe/day)*	**272.8**	176.8	110.4
Proved reserves, before royalties				
Light/medium crude oil and NGL	*(mmbbls)*	**430**	440	145
Lloydminster heavy crude oil	*(mmbbls)*	**169**	114	105
Natural gas	*(bcf)*	**1,966**	1,909	1,077
Barrels of oil equivalent (6:1)	*(mmboe)*	**927**	872	430
Synthetic crude oil sales	*(mbbls/day)*	**59.5**	60.6	61.9
Pipeline throughput	*(mbbls/day)*	**537**	528	394
Light refined products	*(millions of litres/day)*	**7.6**	7.4	7.6
Asphalt and residuals	*(mbbls/day)*	**21.4**	20.2	17.1
Refinery throughput	*(mbbls/day)*	**33.9**	32.6	28.1

CO-CHAIRMEN OF THE BOARD

Mr. Victor T. K. Li (left) is Managing Director and Deputy Chairman of Cheung Kong (Holdings) Limited and Deputy Chairman of Hutchison Whampoa Limited of Hong Kong. Mr. Canning K. N. Fok (right) is Group Managing Director and Deputy Chairman of Hutchison Whampoa Limited of Hong Kong.

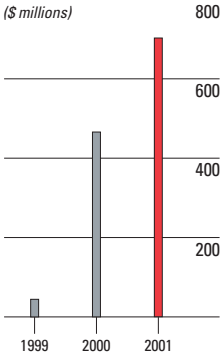


The dual focus on growth and financial discipline is key to Husky's business strategy.

PRESIDENT AND CEO

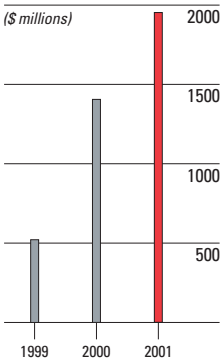
Mr. John C. S. Lau has led the Company since 1993, overseeing major acquisitions and the transition from a private to publicly traded corporation. Each year Mr. Lau and the management team establish and review a five-year growth plan for Husky.

Net Earnings



We are pleased to report to shareholders that Husky Energy achieved record financial results in 2001. Husky's net earnings in 2001 were $701 million, 51 percent higher than net earnings of $464 million in the previous year. Cash flow rose 39 percent to $1.9 billion compared with $1.4 billion in 2000. These results reflect the exceptional business environment of high commodity prices during the first half of the year, which resulted in Husky achieving earnings of $496 million and cash flow of $1.2 billion, and the impact of lower commodity prices, wider heavy/light oil differentials and higher operating costs in the second half of the year with earnings of $205 million and cash flow of $765 million.

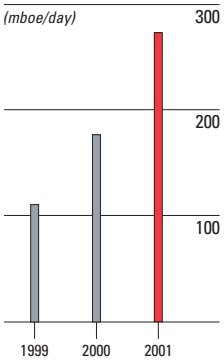
Cash Flow From Operations



Capital expenditures for the year totalled $1.5 billion compared with $803 million in 2000. At the end of 2001, Husky's long-term debt, including amounts due within one year, totalled $2.1 billion, compared with $2.3 billion at the end of 2000.

Husky has a diverse asset base with substantial growth potential. The Company's East Coast assets contribute immediate production with Terra Nova, in the medium-term with the development of White Rose, and in the longer-term with the development potential of Husky's other East Coast assets. Husky is one of the largest interest holders in the Jeanne d'Arc Basin. The Wenchang offshore project in China is expected to add production in 2002 with future growth potential from the Wenchang 39-05 exploration block. Terra Nova and Wenchang alone are expected to add an annual average of 18,000 barrels of oil per day to production in 2002. Peak production for these projects is expected to be approximately 35,000 barrels of oil per day.

Total Production



In Western Canada, increased natural gas production from exploration and development projects in the British Columbia and Alberta foothills, northeastern British Columbia and northwestern Alberta regions will continue to be part of Husky's growth strategy.

The Company's heavy oil assets in the Lloydminster area, including the Upgrader and pipeline system form an integrated suite of assets structured to take advantage of the oil commodity value chain. Substantial growth is expected in this area over the next five years. Over that same five-year time frame, it is expected that the high-quality oil sands leases will be converted to core producing areas for the Company. Husky has a substantial oil sands acreage position of 80,000 net acres in several key leases in northern Alberta. It is estimated that these oil sands leases have over eight billion barrels of oil bitumen in place, with estimated recoverable reserves of approximately two billion barrels.

In the midstream segment, the focus will be on the development of Husky's pipeline and infrastructure facilities, and in particular at the Upgrader in Lloydminster to support the Company's medium to long-term upstream heavy oil growth plans. Husky is in the planning stage of expanding the capacity of its Hussar gas storage facility to 75 billion cubic feet by mid-2003.

In the refined products segment, continued investment in technology, upgrading of refineries and facilities, distinguishing brand identity and growth in non-fuel revenue should result in continued growth. Expansion opportunities for this business are being assessed.

The year 2002 will be a challenging year with the current environment of lower commodity prices and an uncertain economic outlook. However, with our growth strategy in place and the management team focussed and committed to maintaining financial discipline while maximizing opportunities that deliver shareholder value, we have full confidence in the future of Husky Energy.

We would like to record our appreciation to the Board of Directors for their contributions during the year, and to the Company's management team and employees, whose dedication and hard work has contributed to the success of Husky Energy.

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

February 5, 2002

The year 2001 was one of solid growth, record earnings and cash flow for the Company. We have maintained our focus on financial discipline and strategic growth initiatives, notwithstanding the lower commodity prices and economic uncertainty in the latter half of 2001. We are confident that Husky's balanced portfolio of assets and focus on growth over the next five years will increase shareholder value.

In view of the world economic climate and volatile commodity prices, we would like to take this opportunity to address questions regarding Husky and its strategies which may be of interest to our shareholders.

Q. 2001 WAS A YEAR OF VOLATILITY AND UNCERTAINTY IN THE ENERGY SECTOR. GIVEN THE CURRENT ECONOMIC CONDITIONS, IS HUSKY GOING TO LIMIT ITS CAPITAL EXPENDITURE IN 2002?

We expect the capital expenditure program of $1.4 billion, which we have announced for 2002, to be funded from operational cash flow. Husky has the ability to reduce this capital program if commodity prices result in lower than expected operational cash flow.

Q. WHY WERE HUSKY'S OPERATING COSTS HIGHER IN 2001 THAN 2000?

Operating costs have trended upwards in 2001 as properties acquired in 2000 have a higher proportion of shallow gas and mature waterflood operations. In addition, higher fuel and power costs and start-up of 400 new heavy oil zones in 2001 put pressure on operating costs.

Our ongoing cost reduction programs which include uneconomic production shut-ins, rationalizations and optimization programs are expected to reduce overall unit operating costs to about $6.00 per barrel of oil equivalent.

"Our Upstream objectives includes an annual growth rate of approximately 10 percent over the next five years."

Q. HUSKY WAS THE THIRD MOST ACTIVE DRILLING OPERATOR IN WESTERN CANADA IN 2001. WHAT ARE THE COMPANY'S PLANS FOR 2002?

Husky continues as an active drilling operator in 2002. The Company plans to drill between 1,000 and 1,100 wells during the year of which approximately 500 are planned for the first quarter, 400 targeting natural gas in winter locations and 100 delineation wells at Kearl. Drilling plans for the remainder of the year consist of approximately 300 heavy oil and 200 oil and gas wells.

Q. HOW HAS THE ENERGY SECTOR'S CONSOLIDATION AFFECTED HUSKY, AND DO YOU SEE HUSKY AS A "BUYER" OR "SELLER" IN 2002?

One of Husky's objectives is the creation of shareholder value. In 2001, Husky was both a buyer and a seller of assets where value could be realized. Husky's growth strategy is based on the development of its existing diverse asset base. Husky has an ongoing review of strategic alternatives to enhance shareholder value which include merger, acquisition or sale.

Q. WHAT IS HUSKY'S OIL SANDS PROGRAM IN 2002?

At Kearl in the Athabasca region delineation drilling is underway and front-end engineering and design work will begin in 2002. Husky budgeted to drill up to 100 delineation wells in the Kearl region in 2002. As part of its oil sands development strategy, Husky completed an asset swap transaction at Kearl whereby Husky increased its working interest in the in-situ project from approximately 51 percent to 80 percent and became the operator.

Q. WHY DOES THE DEVELOPMENT OF OIL SANDS ASSETS MAKE ECONOMIC SENSE UNDER THE CURRENT COMMODITY PRICE ENVIRONMENT?

Husky expects that the development of its oil sands assets in Western Canada over the next decade will form an important part of its growth strategy. We believe that technology will be developed to a point that will permit recovery and processing to be economical. Commodity prices are volatile and cyclical and long-term price assumptions must be used in project evaluation.

"We have plans in place which focus on new initiatives to grow and improve the profitability of the Company."

Q. WHAT IS THE STATUS OF THE WENCHANG PROJECT, AND WHAT IS HUSKY'S LONG-TERM STRATEGY FOR OFFSHORE CHINA DEVELOPMENT?

The Wenchang development project is expected to commence production in the second quarter of 2002. Cash flow from this project will fund the exploration costs for block 39-05, which is adjacent to the existing development project. Husky's interests in the South China Sea will form part of Husky's long-term growth strategy.

Q. DO YOU ANTICIPATE DIFFICULTY MOVING FORWARD WITH MAJOR PROJECTS LIKE THOSE OFF THE EAST COAST OF CANADA?

The development of our offshore East Coast assets also forms part of our long-term growth strategy. While the investment in these projects is substantial, the economics for the projects include assumptions on long-term prices. As each of these long-term projects come on stream, the cash flow generated provides funding for the rest of the projects to be undertaken.

Q. HUSKY HAS TALKED ABOUT AN UPGRADER EXPANSION FOR SEVERAL YEARS NOW. WHAT IS THE STATUS OF EXPANSION PLANS FOR THE UPGRADER?

Engineering evaluations of different processing technologies, including optimum feedstock and product qualities and yields are complete. This work has determined the expansion configuration and requirements of the facility. Our 2002 capital budget includes an amount for the front-end engineering and design (FEED) work. A decision to proceed with the expansion will be made following completion of the FEED in late 2002, or early 2003.

Preliminary engineering suggests the cost for a 150,000 barrels per day expansion of the Upgrader is approximately $1.3 billion to $1.5 billion in 2001 dollars, depending on the technologies utilized, the yield configuration and the infrastructure required in conjunction with the facility.

"With a strong, balanced portfolio of assets,
Husky is entering into an era of large-scale developments."

Q. WHAT IS HUSKY'S VIEW OF ITS REFINED PRODUCTS BUSINESS, AND DO YOU SEE THAT SEGMENT EXPANDING?

Husky has 580 petroleum retail outlets comprised of car/truck stops, bulk plants and retail outlets with convenience stores. We continue to upgrade our services to maintain customer loyalty. We also have a program to improve light oil product sales through outlet upgrades and ethanol enhanced product marketing. Opportunity for a major expansion into new geographic regions is continually being assessed and evaluated.

Q. WHAT ARE YOUR PRODUCTION TARGETS FOR 2002 AND BEYOND?

Our current five-year plan has production growing 10 percent per year. Production in 2002 is expected to average 300,000 barrels of oil equivalent per day, based on our announced capital expenditure program for 2002. Production has commenced at Terra Nova, and production at Wenchang is expected to commence mid-year. Forecast production growth from British Columbia and northwest Alberta exploration and development areas is expected to add to our production in 2002.

Q. WHAT IS HUSKY'S GREATEST CHALLENGE AT PRESENT?

The year 2002 will be a challenging year. Husky is entering into an era of large-scale project developments while continuing to optimize current operations. The major challenge for the Company will be in the successful implementation of those projects, while maintaining a focus on current operations and financial discipline.

With the strong support from our Board of Directors and the dedication from the Management Team, Husky is well positioned to handle this challenge.

"Husky's Board and management have a common commitment to growth with an unyielding focus on financial discipline."

MIDSTREAM

Husky's midstream activities of gathering, transporting, upgrading, storing and marketing, diversify Husky's revenue stream, optimize infrastructure and enhance market position. Approximately 485,000 barrels per day of oil and 1.6 billion cubic feet per day of natural gas are currently being marketed by Husky.

REFINED PRODUCTS

Husky has an extensive refined products business as a leading Western Canada producer and marketer of fuel and asphalt. Competitive and cyclical, Husky's refined products business benefits from Husky's long history, customer recognition, upgraded services and new products.

WESTERN CANADA UPSTREAM

Husky's upstream operations include the exploration for, and production of light, medium and heavy crude oil, natural gas and natural gas liquids. Organized into geographic and geologic areas, reinvestment in each business unit is driven by objectives of effective capital investment and profitability. Growth in production over the next ten years is planned to come from northwestern Alberta plains shallow gas, British Columbia and Alberta foothills deep gas, Lloydminster heavy oil area and Cold Lake and Athabasca oil sand deposits.

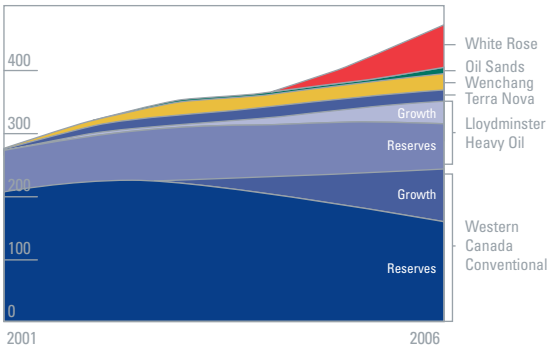
INTRODUCTION TO OPERATIONS

Behind the well-known "Husky" brand is a broad base of energy sector assets that has a diversified and growing revenue stream.

OPERATIONS OVERVIEW

Husky's quality assets, projects and undeveloped lands in many prime exploration and development areas of Canada and internationally provide it with growth opportunities. Land holdings of 7.5 million net undeveloped acres throughout the Western Canadian Sedimentary Basin provide Husky with a high-quality portfolio of prospects and cash-flow-generating projects that support immediate and longer-term growth strategies and form the base production. Augmenting this Western Canada base is the production potential to be realized over the next five years from White Rose and Terra Nova, offshore Canada's East Coast and Wenchang, offshore China. Husky's continued investment in oil sands and heavy oil, both growth areas in Western Canada, will also add production potential over the longer term. Growing production is expected to contribute to increased earnings and cash flow as well as add to Husky's underlying asset value.

Production Targets *(mboe/day)*



OFFSHORE UPSTREAM

Immediate production contributions and long-term potential are being realized from projects offshore Canada's East Coast and from the Wenchang project in China.

Husky is active in the upstream, midstream and refined products energy sectors in Canada, and in the upstream sector internationally, and has built a suite of assets for the creation of shareholder value.

WESTERN CANADA UPSTREAM

Each of Husky's core areas has dedicated, multi-disciplined, technical teams charged with the mandate to meet growth targets while adhering to cost objectives.

WESTERN CANADA CORE AREAS

Husky's core areas in Western Canada are: British Columbia and Foothills [1], Northwest Alberta Plains [2], East Central [3], Lloydminster Heavy Oil and Gas [4] and Southern Alberta and Saskatchewan [5]

WESTERN CANADA UPSTREAM

Husky is strategically positioned to participate in the efficient recovery and processing of heavy oil, oil sands and bitumen.

WESTERN CANADA UPSTREAM

Western Canada upstream activity in 2001 featured participation in 1,129 wells with an average working interest of 91 percent and an overall success rate of approximately 91 percent, making Husky the third most active drilling operator in Western Canada. While activity through 2001 was impacted by lower commodity prices in the second half of the year, Husky's drilling program was successful in identifying several new pool discoveries. Finding and development costs for 2001 averaged $8.07 per barrel of oil equivalent. Augmenting development of Husky's existing land base were corporate acquisitions totalling $125 million, which increased land holdings in key areas including East Central and Lloydminster. Husky intends to accelerate strategic acquisitions and the sale of non-core assets. This upgrading of assets with a focus on core operating areas will consolidate growth prospects and allow for greater control over operating costs. Growth in production over the next ten years is planned to come from northwestern Alberta plains shallow gas, British Columbia and Alberta foothills deep gas, primary/thermal heavy oil production development in the Lloydminster area, and from holdings in the Cold Lake and Athabasca oil sand deposits, as well as from offshore oil projects. These major, long-term projects are expected to make a substantial contribution to reserves and production over the next decade.

British Columbia and Foothills

Deep, liquids-rich natural gas reserves in the British Columbia and Alberta foothills region have become a focus area for Western Canada upstream activity. In 2001, Husky participated in the drilling of a total of 50 gross (39 net) development wells – which resulted in 23.5 net crude oil wells and 12.5 net natural gas wells.

Development activity focussed on the Rocky Mountain House, Edson and Grande Prairie regions of Alberta and added 30 million cubic feet per day of natural gas production and 1,500 barrels per day of liquids production.

A pipeline gathering system expansion was undertaken in the Ram River corridor in 2001 with the southern gathering system expanding 86 kilometres to the Burnt Timber area and completion and start-up of the 25-kilometre Chungo gathering system northwest of Ram River. These two infrastructure expansions increased raw gas inlet volumes at the Ram River plant by 70 million cubic feet per day, increasing the total plant inlet volume to 575 million cubic feet per day, or 92 percent of design capacity. Husky's net production from these tie-ins was 27 million cubic feet per day.

Southern Alberta and Saskatchewan

In the southern regions of Alberta and Saskatchewan, oil and gas production is expected to be maintained at 43,500 barrels of oil per day and 40 million cubic feet of gas per day. Maintaining these rates of production will require a careful reinvestment program which focuses on selected exploratory opportunities in new areas, on infill and stepout drilling and on waterflood recovery from existing reservoirs.

Husky will continue to expand its shallow natural gas plays. A new Milk River gas pool was discovered in 2001, adding to natural gas reserves. A facility at the discovery is scheduled to come onstream by July of 2002. In addition, a gas exploratory program to evaluate Husky's extensive land base in this area will be undertaken in 2002.

Continual technical advances and the accumulation of expertise in core areas are combining to maximize the value of Husky's high working interest project areas.

NORTHWEST ALBERTA PLAINS

In 2002 an additional 270 wells are planned with a target of adding 55 million cubic feet per day of natural gas production.

LLOYDMINSTER HEAVY OIL AND GAS

The Lloydminster area represents an integrated operation of extensive infrastructure and heavy oil production that maximizes the commodity value chain.

WESTERN CANADA UPSTREAM

Upstream operations are driven by innovation and increased efficiency. Applying technology effectively has resulted in improvements in recovery rates.

Northwest Alberta Plains

Natural gas reserves and production growth is the primary focus in this region. An extensive well-drilling program is in place. In 2001 a total of 170 wells, averaging a 95 percent working interest, were drilled. The 75 million cubic feet per day expansion of the Rainbow Lake plant was completed in 2001 to accelerate oil recovery from tertiary miscible floods and to handle the expected increase in gas production from the expanded exploration and development programs being undertaken in 2002.

Innovation in field operations is one of Husky's targets. At Rainbow Lake Husky made substantial progress with a leading-edge technology applied during the gas plant expansion. With a new treatment for the acid content in the natural gas stream, Husky was able to reduce operating costs and lower emissions. Known as an "acid gas re-injection facility," the application uses acid gas as miscible solvent to improve oil recovery.

East Central

Husky's presence in this area has been significantly augmented over the past two years through acquisitions. Production from the area in 2001 averaged 57,000 barrels of oil equivalent per day comprising 45 percent sweet dry natural gas and 55 percent medium gravity crude oil. With a well developed infrastructure and high working interests, optimization is the strategy for this area. Development plans are focussed on step-out drilling to extend existing pools, infill drilling to improve reserves recovery, drilling for by-passed pay targets and secondary recovery programs such as waterfloods.

Lloydminster Heavy Oil and Gas

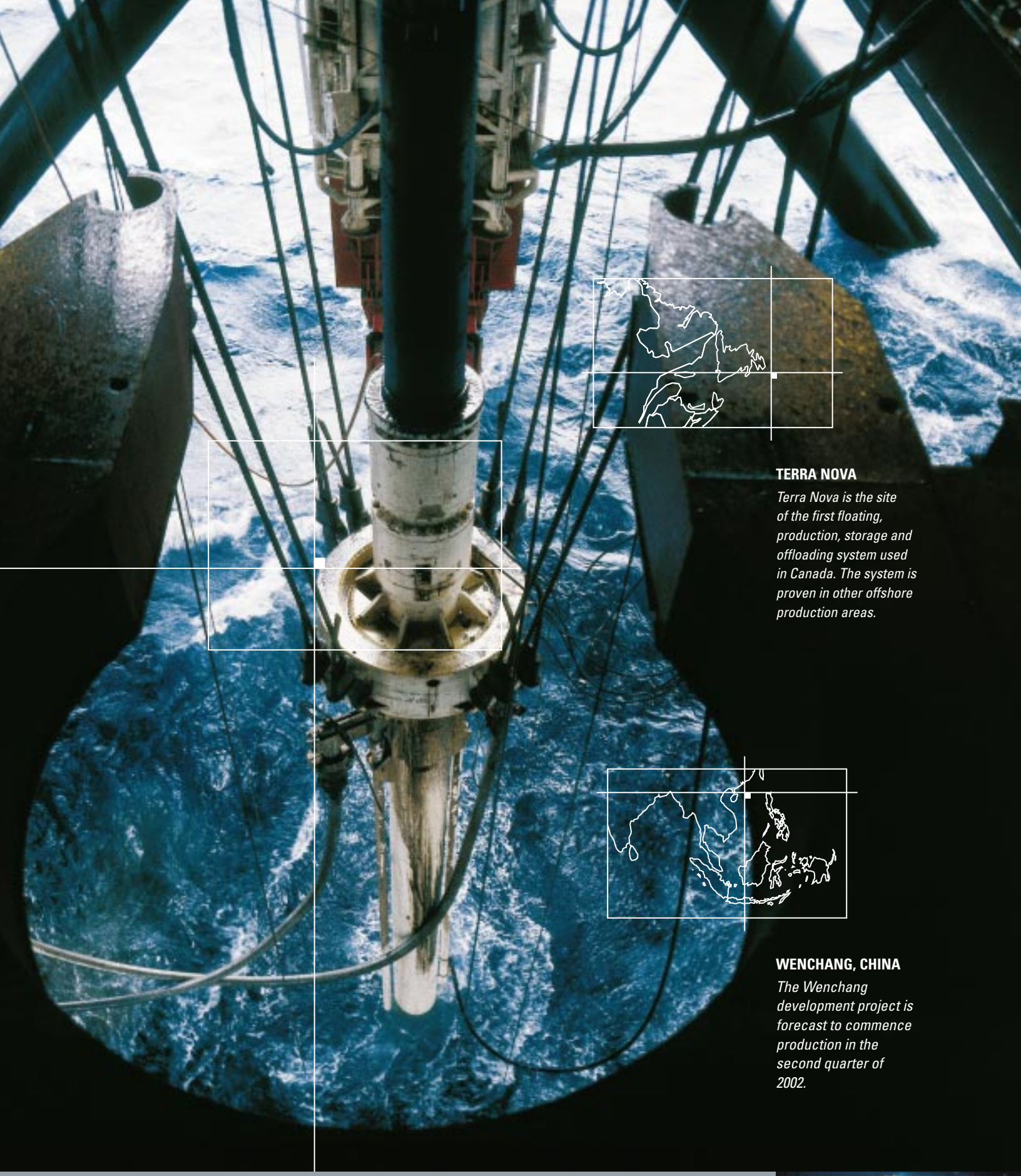
Husky has a long history in the Lloydminster heavy oil area, with average annual production in 2001 of 65,000 barrels of heavy oil per day. This production is supported by Husky's Upgrader facility and an extensive pipeline infrastructure. Husky has over the years implemented technological applications to improve reserve recovery and lower operating costs.

A thermal heavy oil project at Pikes Peak, Saskatchewan produced approximately 9,000 barrels of oil per day in 2001. A second thermal project was commenced in the Bolney-Celtic area. The project is designed for production of 17,000 barrels of oil per day and is expected to start production with 5,400 barrels of oil per day in 2002.

Oil Sands

In northeast Alberta, where substantial oil sands deposits are located, Husky has a significant presence with assets at Kearl and Cold Lake. This position was augmented in early 2002 with an asset swap that increased Husky's interests in the Kearl in-situ thermal recovery project from approximately 51 to 80 percent and gave Husky the role of operator. In exchange, Husky reduced its working interest from approximately 51 percent to 25 percent in the mining project area. The swap will allow for more focus on the development of each of the projects and maximize efficiencies. Up to 100 wells are planned at the Kearl in-situ project in 2002 to gather the information required for reservoir simulation models and development plans.

Western Canada Upstream operations are extensive with high working interests and concentrated project areas, well supported with infrastructure.



TERRA NOVA

Terra Nova is the site of the first floating, production, storage and offloading system used in Canada. The system is proven in other offshore production areas.

WENCHANG, CHINA

The Wenchang development project is forecast to commence production in the second quarter of 2002.

OFFSHORE OPERATIONS

Tapping into rich reserves of light crude oil and natural gas is part of Husky's growth strategy.

OFFSHORE EXPLORATION AND DEVELOPMENT

With over 20 years of experience in Canada's offshore East Coast basins, Husky is well positioned to capitalize on the area's rich reserves. East Coast offshore, in particular the Jeanne d'Arc Basin on the Grand Banks of Newfoundland, is a main area of focus for Husky. In the Jeanne d'Arc Basin, Husky is the largest license holder with 1.8 million net acres in seven exploration licenses, 12 significant discovery areas plus one production license.

Husky invested $191 million, including capitalized interest, in 2001 developing the Terra Nova and White Rose projects. In 2002, offshore exploration and development expenditures are expected to total $210 million.

Husky has leveraged its offshore East Coast Canada experience into an international offshore project with its participation in an offshore development project in China. The attraction of the offshore program is the size of potential oil and gas pools.

While the offshore projects are expected to have a meaningful impact on growth over the long-term, the investment in those projects is expected to form a relatively small part of the Company's overall capital investment program.

Terra Nova

The Terra Nova development project which commenced production in January 2002, is the first Grand Banks field to be developed with a floating, production, storage and offloading system. Husky expects its share of production (12.51 percent working interest) from Terra Nova to average 10,000 barrels of oil per day in 2002 and approximately 16,000 barrels of oil per day at peak production. The first well in the Far East block of the field was successfully drilled in 2001, and further delineation wells in the Far East block are planned over the next three years.

White Rose

Husky is the operator and has a 72.5 percent working interest in the White Rose development field. A critical milestone was reached in December 2001 when the project received government sanction from the Canada-Newfoundland Offshore Petroleum Board. The next steps will involve internal and partner sanction with a decision expected by the end of the first half of 2002.

International Offshore - China

The Wenchang development project is forecast to commence production in the second quarter of 2002. Husky's share of production (40 percent working interest) from Wenchang is expected to be 8,000 barrels of oil per day in 2002 and 20,000 barrels of oil per day at peak production. Husky is the operator of a large exploration block surrounding the development project at Wenchang. Preliminary evaluation of the existing seismic data shows several prospects on the block. With the combination of exploration potential and the expected production in 2002, this area forms part of Husky's long-term growth strategy.

Husky has taken a lead role in offshore exploration and development and has developed solid expertise for managing these large-scale projects. With Husky's depth of experience, the Company was able to identify and acquire a significant interest in an offshore China project at Wenchang.

THE UPGRADER

The Husky Lloydminster Upgrader processes heavy oil feedstock into high-quality synthetic crude oil, which can be refined into premium quality transportation fuels.

ENERGY DIVERSIFICATION

A 215-megawatt cogeneration plant on site provides 100 percent of the Upgrader's steam requirements and the excess power supplies about 10 percent of Saskatchewan's power supply.

LLOYDMINSTER UPGRADER

Not only is the Upgrader rated as a top performer in efficiency, but it has an excellent safety record with no lost time accidents since 1996.

MIDSTREAM

Husky's midstream activity began with a major strategic investment to realize the value from its heavy oil assets in the Lloydminster area. This strategic investment was the Lloydminster Upgrader which began operating as a 54,000 barrel a day facility in 1992.

The Upgrader processes heavy oil from the Lloydminster and Cold Lake areas of Alberta and Saskatchewan into synthetic crude oil. The synthetic crude oil is a premium quality product. The diluent resulting from the Upgrader process is recycled and sold to move the heavy oil production in the Lloydminster area. Synthetic crude oil is shipped to refiners located in the United States and Canada.

The Upgrader's throughput averaged 71,700 barrels per day in 2001 of which 59,500 barrels per day was synthetic crude oil sales. The result was record EBITDA of $249 million. The success of the Upgrader facility has undertaken an assessment of a possible major expansion that would take the facility from approximately 70,000 to upwards of 150,000 barrels of oil per day. Husky is proceeding with the front-end engineering and design in 2002 and a decision on this major growth program will be made following the completion of this work.

A new initiative is the Hussar, Alberta natural gas storage facility which completed its first full year of operation in 2001 and exceeded financial performance targets by 200 percent. The facility has functioned far beyond designed capacity through 2001, contributing to its exceptional performance.

Midstream activity realizes profits from handling, processing and marketing Husky's production as well as product on behalf of other producers. Husky established new corporate records in earnings and cash flow contribution from this segment during 2001 by marketing natural gas, crude oil, natural gas liquids and sulphur.

Another advantage of midstream activity is its low capital requirement. Capital spending in 2001 was $105 million and will increase to $130 million in 2002. Of the $130 million, $56 million is designated for the Husky Lloydminster Upgrader for expansion front end engineering and design and de-bottlenecking projects.

Optimizing midstream potential is aided by the extensive heavy oil pipeline and processing infrastructure owned and operated by Husky primarily in the bitumen corridor. Commodity marketing activities help capture a larger share of the "value added" in the midstream business. This business is a profit centre on its own and offers a significant strategic advantage to the upstream and retail product operations because of the market information gained when handling 485,000 barrels per day of oil and 1.6 billion cubic feet per day of natural gas. Recognized as a growth area for the Company, Husky targets to be managing 700,000 barrels of oil per day and 2 billion cubic feet per day of natural gas by 2005. In order to manage the growth, new management information systems were put in place in 2001 which will greatly improve the ability to grow with minimal increase in personnel.

The Hussar, Alberta natural gas storage facility was developed in-house, using engineering, geology, accounting, marketing and business development staff to convert a depleted gas pool into a 17 bcf gas storage facility.

RETAIL NETWORK

Husky has 580 independently operated Husky and Mohawk branded service stations and truck stops that span from Vancouver Island to eastern Ontario.

REFINED PRODUCTS

Husky's asphalt division sold 21.4 thousand barrels per day in 2001, setting a new corporate performance record, driven by North American demand.

REFINED PRODUCTS

Much of Husky's refined product activity is tightly linked to its upstream and midstream operations, providing a strategic benefit as well as a diversified revenue base. Husky's upstream operations are the source of feedstock while transportation infrastructure and marketing link refined products to customers.

Husky operates a retail network which includes service stations, truck stops and bulk distribution facilities located from Vancouver Island on the west coast to the eastern border of Ontario.

The retail marketing network contributes a solid base of fuel and non-fuel sales, highlighted by non-fuel sales contributing cash flow of $26 million in 2001. A particular strength of Husky's retail presence is its highly regarded car/truck stops which offer a full range of quality facilities and services. Customer loyalty and asphalt marketing contributed to record EBITDA of $155 million in 2001, an increase of 101 percent over 2000 results.

Husky will continue to develop and strengthen its market presence, under both Husky and Mohawk brands, in 2002. In addition, Husky will continue to pursue strategic alliances with third parties to sell various consumer products at Husky and Mohawk branded petroleum outlets. Other plans for 2002 include adding "Pay at the Pump" technology to improve service and flexibility for customers. Husky will consider acquisitions and joint venture opportunities to further enhance its existing distribution system.

Husky sells refined petroleum products directly to various commercial markets, including independent dealers, national rail companies and major industrial and commercial customers in Western Canada and Northwestern United States.

In 2001 Husky also signed a lubricant distribution contract with Chevron which will provide Husky with one of the top rated product lines for commercial, industrial and passenger vehicle markets.

In the refined products business Husky became the first company in Canada to road test an environmentally friendly diesel fuel. In cooperation with the City of Winnipeg, 10 city transit buses will run for six months on a new fuel, a blend of ethanol and diesel designed to reduce particulates by up to 50 percent.

The Lloydminster asphalt refinery had another record year. This operation realized record throughput in 2001 which was supported by the lowest unit operating costs in its history. Adding to this success, the facility was recognized with safe handling and shipping awards in 2001. Husky made a commitment to technology in the asphalt business when it established the Chair in Bituminous Materials and laboratory facilities at the University of Calgary. The commitment has led to asphalt sales all over North America.

Husky's Prince George, British Columbia refinery average throughput for 2001 was 10.2 thousand barrels per day. Consistent with all of Husky's operations in 2001, the facility showed improvement with a flare volume reduction of 83 percent and a fuel consumption reduction of 4.6 percent. Husky is pursuing acquisitions and joint venture opportunities to further enhance its existing refining capacity.

Husky's asphalt division accounted for 92 percent of the increase in Refined Product's operating profit in 2001. Husky signed a lubricant distribution contract with Chevron which will provide a top rated product line to Husky customers.

COMMUNITY SUPPORT

Annual Charitable Campaigns are organized and supported by employees and held in Calgary and Lloydminster. Proceeds are donated to community organizations and charities, with Husky maintaining a matching program.

ENVIRONMENT

Husky has continuing partnerships with organizations such as Ducks Unlimited, Trout Unlimited and other groups concerned with environmental issues.

COMMUNITY

Husky now has co-operative agreements with five First Nations: Frog Lake First Nation, Kehewin Cree Nation, Woodland Cree Nation, the Lubicon Cree Nation and the Loon Lake First Nation.

HUSKY AND THE COMMUNITY

Husky's commitment to supporting organizations dedicated to helping communities and the residents who live in them is ongoing. In 2001, Husky supported organizations involved in education, culture, health, welfare, civic activities and recreation.

Husky believes in the long-term benefits of education and research – not only for the community as a whole, but as a legacy to future generations. Husky annually provides scholarships to young adults committed to pursuing post-secondary education, particularly in the areas of geology, geophysics, engineering or environmental studies. In addition, formal partnerships with a number of high schools are supported through financial contributions, employee involvement and student work experience programs within the Company.

Husky is a long-term supporter of the University of Calgary through funding and employee involvement in several designated Chairs. Husky supports the Petroleum Chair in Petroleum Engineering, the Chair laboratory in the Calgary Centre for Innovative Technology, and the Bituminous Materials Chair. In 2001, Husky was honoured by the University of Calgary with the 2001 Dean's Award for Corporate Leadership from the Faculty of Engineering.

Husky's Aboriginal Affairs program promotes employment, education and business opportunities for First Nation people. Demonstrating its commitment to First Nation people, in 2001 Husky and the Frog Lake First Nation and Kehewin Cree Nation signed a Memorandum of Understanding whereby a workforce base will be set up to promote education and employment for First Nation People from the two Nations. Husky now has cooperative agreements with five First Nations.

HEALTH, SAFETY AND ENVIRONMENT

Health and Safety

In 2001 Husky commissioned a review of its Health and Safety Management systems and qualified for the Certificate of Recognition under the Alberta government's "Partnerships in Health and Safety" program. In 2001 the Lloydminster Upgrader established a new safety record of 2.7 million person/hours without a lost time accident.

Environment

Husky continues to employ operational procedures and to develop retail products designed to enhance environmental protection. In Husky's upstream operations the flaring of natural gas associated with oil and gas production is being reduced through power generation units which use gas that would otherwise be flared to generate electricity. The electricity generated is used on-site or tied into the local power grid.

In 2001 Husky was recognized by Canada's Climate Change Registry for the fourth time, this time as a Gold Champion Reporter. Husky continues to work with the public, industry and government on key wilderness and land use issues by directly participating in important research on caribou, grizzly bear and wolves.

Safety achievement awards in 2001 included a Saskatchewan Workers' Compensation Merit Rebate, an Alberta Petro Chemical Safety Council (Northern) Award, a Burlington Northern & Santa Fe Railway Company 2000 Stewardship Award and a Canadian Pacific Railway Inaugural Chemical Shipper Safety Award.

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2001

HUSKY ENERGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

LOOKING INSIDE HUSKY

HUSKY NET EARNINGS IN 2001 WERE $701 MILLION

51% HIGHER THAN THE PREVIOUS YEAR

This discussion and analysis should be read in conjunction with the Consolidated Financial Statements and Auditors' Report included in this Annual Report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles in Canada. The effect of significant differences between Canadian and United States accounting principles is disclosed in note 17 to the Consolidated Financial Statements.

Unless otherwise indicated, all production is before royalties (gross) and prices include the effect of hedging (realized). A barrel of oil equivalent (boe) or an mcf equivalent (mcfe) is based on a rate of six mcf of natural gas to one barrel of crude oil.

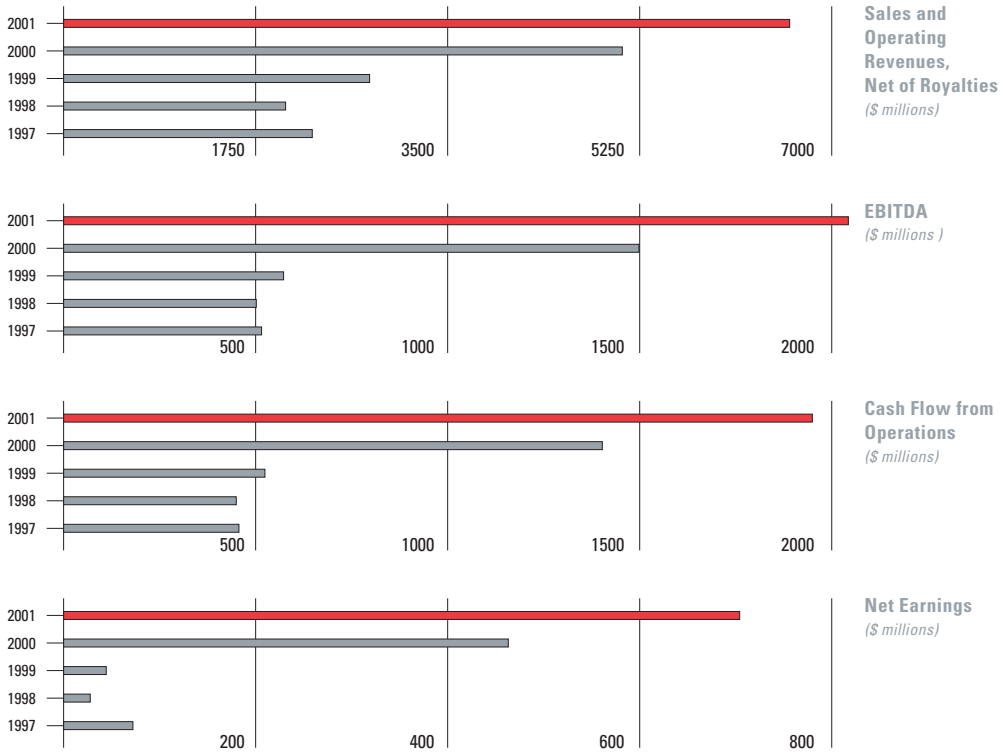
Forward Looking Statements

Certain of the statements included in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report including statements which may contain words such as "could", "expect", "believe," "will" and similar expressions and statements relating to matters that are not historical facts are forward-looking and are based upon Husky's current belief as to the outcome and timing of such future events. There are numerous risks and uncertainties that can affect the outcome and timing of events, including many factors beyond the control of Husky. These factors include, but are not limited to, the matters described under the heading "Business Environment". Should one or more of these risks or uncertainties occur, or should any of the underlying assumptions prove incorrect, Husky's actual results and plans for 2002 and beyond could differ materially from those expressed in the forward-looking statements.

Overview

Husky's operating activities are divided into three 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 in certain international areas. The midstream segment includes heavy crude oil upgrading operations, commodity marketing and infrastructure operations, which includes pipeline, processing, storage and cogeneration. The refined products segment includes the refining of crude oil and marketing of refined petroleum products.

Year ended December 31 ($ millions, except per share amounts and production)		**2001**	% Change	2000	% Change	1999
Sales and operating revenues, net of royalties		**$ 6,627**	30	$ 5,090	82	$ 2,794
EBITDA		**2,042**	36	1,499	165	566
Cash flow from operations		**1,946**	39	1,399	171	517
Per share - Basic		**4.60**	8	4.26	137	1.80
- Diluted		**4.57**	7	4.26	137	1.80
Net earnings		**701**	51	464	979	43
Per share - Basic		**1.64**	18	1.39	1,290	0.10
- Diluted		**1.63**	17	1.39	1,290	0.10
Production						
Light/medium crude oil & NGL	*(mbbls/day)*	**112.0**	76	63.6	140	26.5
Lloydminster heavy crude oil	*(mbbls/day)*	**65.4**	22	53.5	27	42.1
Natural gas	*(mmcf/day)*	**572.6**	60	358.0	43	250.5
Barrels of oil equivalent (6:1)	*(mboe/day)*	**272.8**	54	176.8	60	110.4



Consolidated Results

Net earnings were $701 million, or $1.63 per share (diluted) in 2001 compared with $464 million, or $1.39 per share in 2000 (1999 - $43 million, or $0.10 per share). Cash flow from operations was $1,946 million or $4.57 per share (diluted) in 2001 compared with $1,399 million or $4.26 per share in 2000 (1999 - $517 million or $1.80 per share).

Upstream

Operating profit from the upstream segment increased $24 million to $820 million in 2001 compared with $796 million in 2000. Production of crude oil and NGL increased by 51 percent in 2001 to 177.4 mbbls/day from 117.1 mbbls/day in 2000. Production of natural gas increased by 60 percent in 2001 to 572.6 mmcf/day from 358.0 mmcf/day in 2000. The increased production resulted primarily from a full year of operations following the acquisition of Renaissance Energy Ltd. ("Renaissance") on August 25, 2000. The effect of the higher oil and gas production during 2001 was substantially offset by lower crude oil prices, higher unit operating costs and higher unit depletion, depreciation and amortization ("DD&A") expense.

Operating profit from the upstream segment increased $621 million to $796 million in 2000 compared with $175 million in 1999. The higher operating profit in 2000 compared to 1999 reflected the inclusion of the Renaissance properties for approximately four months of 2000 and higher oil and gas prices, the effects of which were partially offset by higher unit operating costs and DD&A.

Midstream

Operating profit from the midstream segment increased $159 million to $404 million in 2001 compared to $245 million in 2000. The higher operating profit was due to higher upgrading differentials and commodity marketing volumes and margins in 2001.

Operating profit from the midstream segment increased $119 million to $245 million in 2000 compared to $126 million in 1999. The higher operating profit in 2000 was primarily due to higher upgrading differentials, higher pipeline volume and new infrastructure business.

Refined Products

Operating profit from the refined products segment increased $75 million to $124 million in 2001 compared to $49 million in 2000. The higher operating profit was primarily due to higher asphalt sales and margins in 2001.

Operating profit from the refined products segment was $49 million in both 2000 and 1999. Lower light oil refined product margins in 2000 were offset by improved margins and higher sales volume for asphalt products.

Business Environment

Average Benchmark Prices

		2001	2000	1999
West Texas Intermediate	*(U.S. $/bbl)*	**$ 25.97**	$ 30.20	$ 19.24
NYMEX natural gas	*(U.S. $/mmbtu)*	**4.38**	3.91	2.27
AECO natural gas	*($/GJ)*	**5.97**	4.76	2.81

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

Commodity Prices

Oil and natural gas prices have been, and are expected to be, volatile and subject to fluctuations based on a number of factors beyond Husky's control. The prices received for the crude oil and NGL sold by Husky are related to the price of crude oil in world markets. The market price of heavy crude oil trades at a discount or differential to light crude oil.

World oil prices fell during 2001 after rising throughout most of 2000. The price for West Texas Intermediate ("WTI") crude oil, an industry benchmark, averaged U.S. $25.97/bbl, U.S. $30.20/bbl and U.S. $19.24/bbl in 2001, 2000 and 1999, respectively. In 2001 average monthly WTI prices fluctuated between U.S. $32.18/bbl in January to U.S. $17.48/bbl in November. WTI ended the year at U.S. $19.78/bbl. Husky's realized price for light/medium crude oil and NGL in 2001 averaged $27.19/bbl and for Lloydminster heavy crude oil $15.85/bbl.

The demand for natural gas is affected by factors beyond Husky's control, such as weather patterns in North America, pipeline delivery capacity, the availability of alternative sources of energy supply and general industry activity levels. There have been and continue to be periodic imbalances between supply and demand for natural gas.

Natural gas prices realized by Husky are based either on fixed price contracts, on spot prices or on prices on the New York Mercantile Exchange ("NYMEX") or on other United States regional market prices. The U.S. natural gas benchmark, NYMEX price averaged U.S. $4.38/mmbtu during 2001, 12 percent higher than the U.S. $3.91/mmbtu in 2000 and 93 percent higher than the U.S. $2.27/mmbtu in 1999. In 2001 average monthly NYMEX prices fluctuated between U.S. $9.79/mmbtu in January to U.S. $1.89/mmbtu in October. The NYMEX natural gas price ended the year at U.S. $2.57/mmbtu. Husky's realized natural gas prices in 2001 averaged $5.47/mcf.

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

The profitability of Husky's upgrading operations is dependent upon the revenues from the synthetic crude oil produced exceeding the costs of the blended heavy oil feedstock and 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. As Husky has significant heavy crude oil production, any negative effect of such a cost increase of feedstock or synthetic crude price on the upgrading operations would be offset by a positive effect on revenues in the upstream segment.

The differential between the price of synthetic crude oil at Lloydminster and blended heavy crude oil feedstock averaged $17.91/bbl in 2001, $13.77/bbl in 2000 and $6.49/bbl in 1999. The widening of the differential over the three-year period reflected increased supply of heavy crude oil and strong demand for light crude oil.

Foreign Exchange

Husky's results of operations are affected by the exchange rate between the Canadian and U.S. dollars. A majority of Husky's revenues are received in U.S. dollars or by reference to U.S. dollar denominated prices, while the majority of Husky's expenditures are in Canadian dollars. Accordingly, a change in the value of the Canadian dollar relative to the U.S. dollar has the effect of increasing or decreasing revenues. In addition, a change in 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 the related interest expense. See note 16 to the Consolidated Financial Statements for further disclosure on the Company's use of derivative financial instruments to manage foreign currency risk.

At December 31, 2001 the Company had hedged the exchange rate on U.S. $24 million per month with currency collars for varying periods up to 2003.

Interest Rates

Husky is exposed to interest rate fluctuations on its floating rate debt and also to derivative financial instruments with sensitivity to interest rates. The Company maintains a portion of its total debt in floating rate facilities. The Company will occasionally fix its floating rate debt or, alternatively, create a variable rate for its fixed rate debt using derivative financial instruments. See note 16 to the Consolidated Financial Statements for further disclosure on the Company's use of derivative financial instruments to manage interest rate risk.

At December 31, 2001 $185 million of the Company's long-term debt and $100 million of the Company's short-term debt had variable interest rates. At December 31, 2001, the Company had U.S. $35 million of fixed interest rate debt swapped to floating rates at an average of LIBOR - 0.13 percent until 2003.

Environment 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 and is required to obtain operating licenses and adhere to certain standards and controls regarding activities relating to oil and gas exploration, development and production as well as refining, transportation, marketing and storage of petroleum, natural gas and refined petroleum products. Changes to regulations could have an adverse effect on Husky's results of operations and financial condition.

International Operations

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

Risk Management

Husky uses derivative financial instruments when considered appropriate to hedge exposure to changes in the price of crude oil and natural gas and fluctuations in interest rates and foreign currency exchange rates. Husky does not engage in transactions involving derivative financial instruments for trading or other speculative purposes. See note 16 to the Consolidated Financial Statements for further disclosure on the Company's use of derivative financial instruments.

Results of Operations *Upstream*

Upstream Earnings Summary			
Year ended December 31 ($ millions)	**2001**	2000	1999
Gross revenue	**$ 2,667**	$ 2,055	$ 765
Royalties	**471**	327	94
Hedging	**–**	155	69
Net revenue	**2,196**	1,573	602
Costs and expenses	**648**	370	204
EBITDA	**1,548**	1,203	398
DD&A	**728**	407	223
Operating profit (EBIT)	**$ 820**	$ 796	$ 175

Net Revenue Variance Analysis					
($ millions)	Light/ medium crude oil & NGL	Lloyd-minster heavy crude oil	Natural gas	Other	Total
Year ended December 31, 1999					
Net revenue	$ 188	$ 223	$ 174	17	$ 602
Price changes	255	144	362	3	764
Volume changes	344	80	96		520
Royalties	(116)	(24)	(93)		(233)
Hedging	(29)	(54)	(3)		(86)
Processing				6	6
Year ended December 31, 2000					
Net revenue	$ 642	$ 369	$ 536	26	$ 1,573
Price changes	(348)	(253)	59	(8)	(550)
Volume changes	632	114	404		1,150
Royalties	(49)	27	(122)		(144)
Hedging	49	102	4		155
Processing			12		12
Year ended December 31, 2001					
Net revenue	**$ 926**	**$ 359**	**$ 881**	**$ 30**	**$ 2,196**

Gross Daily Production				
Year ended December 31		**2001**	2000	1999
Light/medium crude oil & NGL	*(mbbls/day)*	**112.0**	63.6	26.5
Lloydminster heavy crude oil	*(mbbls/day)*	**65.4**	53.5	42.1
Natural gas	*(mmcf/day)*	**573**	358	251
Barrels of oil equivalent	*(mboe/day)*	**272.8**	176.8	110.4

Average Realized Prices		2001	2000	1999
Light/medium crude oil & NGL	*($/bbl)*	**$ 27.19**	$ 35.88	$ 24.47
Hedging		**–**	2.46	2.95
Light/medium & NGL price realized		**$ 27.19**	$ 33.42	$ 21.52
Lloydminster heavy crude oil	*($/bbl)*	**$ 15.85**	$ 26.45	$ 19.08
Hedging		**–**	5.19	3.08
Lloydminster heavy crude price realized		**$ 15.85**	$ 21.26	$ 16.00
Natural gas price	*($/mcf)*	**$ 5.47**	$ 5.18	$ 2.43
Hedging		**–**	0.02	0.02
Natural gas price realized		**$ 5.47**	$ 5.16	$ 2.41

2001 compared with 2000

Husky's operating profit from the upstream segment increased $24 million (3 percent) to $820 million in 2001 from $796 million in 2000.

Husky's total revenues from upstream operations (before hedging) increased $612 million (30 percent) to $2,667 million in 2001 from $2,055 million in 2000.

The increase in upstream revenues for 2001 was primarily due to higher production of crude oil and natural gas added by the acquisition of Renaissance and heavy oil exploitation programs in the Lloydminster heavy oil area. The positive revenue effect of higher production was partially offset by lower crude oil and NGL prices. Light/medium crude oil and NGL realized prices averaged 19 percent lower in 2001 compared with 2000 and Lloydminster heavy crude realized oil prices averaged 25 percent lower in 2001 compared with 2000. Natural gas realized prices averaged six percent higher in 2001 compared with 2000. The lower light/medium crude oil and NGL prices were in part due to softer markets and also to the production of a heavier average grade of crude oil. The inclusion of the Renaissance properties increased the proportion of Husky's crude oil production of medium gravity crude, which trades at a discount to light sweet crudes.

Husky's total upstream operating costs increased $278 million (75 percent) to $648 million in 2001 from $370 million in 2000, primarily due to higher production in 2001. Operating costs per unit of production increased 13 percent in 2001 compared to 2000 as a result of increased production of heavier gravity crude oil, the operation of mature properties under waterflood and a higher proportion of low pressure shallow natural gas.

The upstream segment's DD&A increased $321 million (79 percent) to $728 million in 2001 from $407 million in 2000. Total DD&A per boe was $7.31 in 2001 compared to $6.28 in 2000. The increase in DD&A rate was primarily due to a full year of operations for the Renaissance properties.

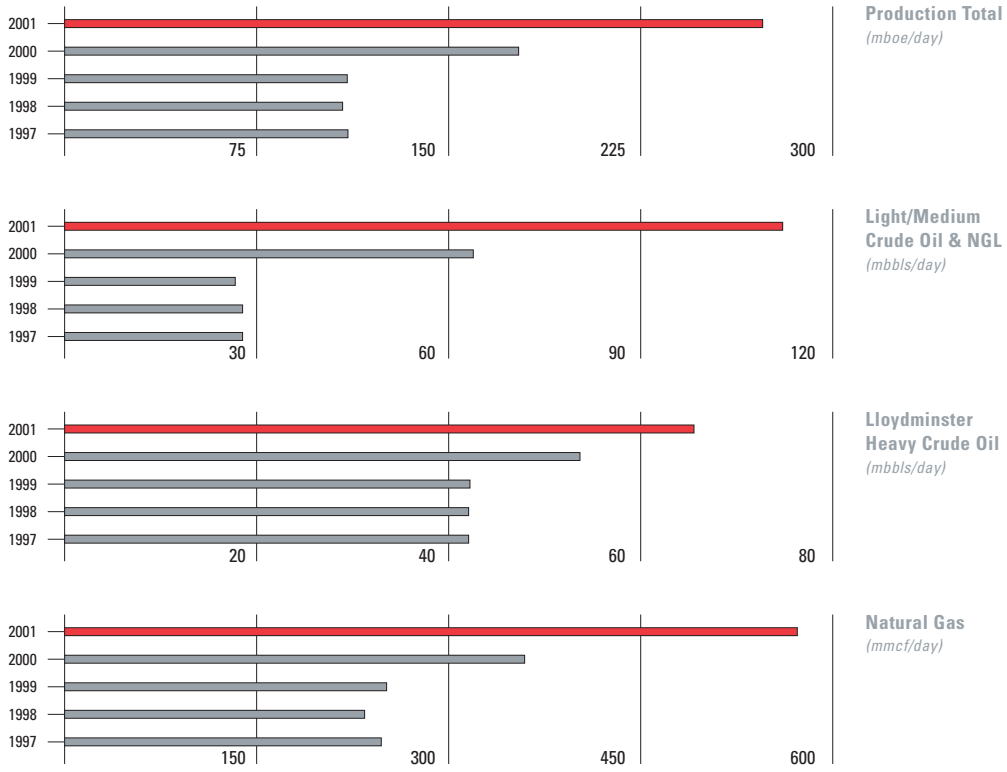
2000 compared with 1999

Husky's operating profit from the upstream segment increased $621 million (355 percent) to $796 million in 2000 from $175 million in 1999.

Husky's total revenues from upstream operations (before hedging) increased $1,290 million (169 percent) to $2,055 million in 2000 from $765 million in 1999.

The increase in upstream revenues for 2000 was due to higher production of crude oil and natural gas. The Renaissance properties added $658 million or 51 percent of the increase in revenues. The remainder of the increase in upstream revenue was due to higher crude oil production from the former Husky properties. Heavy oil production increased to 54 mbbls/day in 2000 from 42 mbbls/day in 1999. The addition of producing properties at Valhalla and Wapiti in 2000 added an additional 9 mboe/day or $112 million in gross revenue.

Husky's total upstream operating costs increased $165 million (80 percent) to $370 million in 2000 from $205 million in 1999 due to higher production in 2000. Operating costs per unit of production increased 13 percent in 2000 compared to 1999 as a result of increased production of heavier gravity crude oil, the operation of mature properties under waterflood and a higher proportion of low pressure shallow natural gas.



Upstream DD&A increased $184 million (83 percent) to $407 million in 2000 from $223 million in 1999. Total DD&A per boe was $6.28 in 2000 compared to $5.56 in 1999. The increase in the DD&A rate was due to the inclusion of the Renaissance properties, which have a higher depletion rate than the former Husky properties.

Light/Medium Crude Oil Netbacks [1]			
Year ended December 31 (per boe)	**2001**	2000	1999
Sales revenue	**$ 27.42**	$ 35.71	$ 24.95
Royalties	**4.56**	5.93	2.80
Hedging	**–**	2.46	2.95
Operating costs	**7.78**	6.71	5.49
Netback	**$ 15.08**	$ 20.61	$ 13.71

Lloydminster Heavy Crude Oil Netbacks [1]			
Year ended December 31 (per boe)	**2001**	2000	1999
Sales revenue	**$ 16.00**	$ 26.45	$ 19.05
Royalties	**0.85**	2.40	1.51
Hedging	**–**	5.19	3.08
Operating costs	**8.02**	6.75	6.71
Netback	**$ 7.13**	$ 12.11	$ 7.75

Natural Gas Netbacks [2]			
Year ended December 31 (per mcfe)	**2001**	2000	1999
Sales revenue	**$ 5.39**	$ 5.28	$ 2.54
Royalties	**1.26**	1.08	0.48
Hedging	**–**	0.02	0.02
Operating costs	**0.62**	0.59	0.50
Netback	**$ 3.51**	$ 3.59	$ 1.54

Total Upstream Netbacks			
Year ended December 31 (per boe)	**2001**	2000	1999
Sales revenue	**$ 26.42**	$ 31.41	$ 18.56
Royalties	**4.73**	5.05	2.33
Hedging	**–**	2.40	1.72
Operating costs	**6.39**	5.64	4.98
Netback	**$ 15.30**	$ 18.32	$ 9.53

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

Upstream Capital Investments and Reserve Additions

Upstream capital expenditures increased $617 million to $1,317 million in 2001 from $700 million in 2000. In Western Canada, upstream capital expenditures increased $603 million to $1,022 million in 2001 from $419 million in 2000. The increase in capital spending in Western Canada primarily reflects a full year of operations following the acquisition of the Renaissance properties. These properties are located mostly in the undisturbed portion of the Western Canada Sedimentary Basin below the interior plains of Alberta and Saskatchewan and are generally mature oil fields under secondary pressure maintenance schemes and shallow natural gas properties. Capital expenditures in the Lloydminster heavy oil areas of Alberta and Saskatchewan increased $191 million to $324 million in 2001 from $133 million in 2000. Husky drilled 490 wells in the Lloydminster area in 2001 (320 wells in 2000) resulting in 415 oil well completions and 39 natural gas well completions. In 2001, a 3,000 bbl/day heavy oil thermal project at Bolney, Saskatchewan was acquired for $70 million.

Exploration spending in Western Canada increased $118 million to $236 million in 2001 from $118 million in 2000 (approximately 23 percent of total upstream capital spending in Western Canada in 2001, down from 28 percent in 2000). In 2001 exploration remained focussed along the foothills and deep basin areas of western Alberta and in northeastern British Columbia.

In 2001, Husky invested $125 million in corporate acquisitions, which included the acquisition of the remaining 62 percent interest in Avid Oil & Gas Ltd.

Offshore the east coast of Canada, Husky's 2001 capital spending in the Jeanne d'Arc Basin totalled $191 million. Capital spending on the Terra Nova oil field development amounted to $117 million (including capitalized interest of $34 million) and pre-development spending on the White Rose oil field amounted to $70 million (including $17 million of capitalized interest).

Internationally Husky's capital expenditures totalled $104 million, $102 million of which was spent on exploration and development offshore southern China.

Upstream capital expenditures amounted to $700 million in 2000. Upstream capital expenditures in Western Canada totalled $419 million and included $114 million for development in the Lloydminster heavy oil area and $187 million in conventional oil and gas areas primarily in Alberta. Exploration spending in 2000 totalled $118 million in Western Canada approximately one third of which was spent in the Alberta foothills and northeastern British Columbia. In 2000, $194 million was spent on offshore east coast Canada exploration and development projects, which included the Terra Nova development project and the White Rose delineation project. In 2000, $87 million was spent in international areas, $85 million of which was spent on the Wenchang oil field development project offshore southern China.

Upstream capital expenditures amounted to $570 million in 1999. During 1999, $309 million of capital spending was for exploration and development activities off the east coast of Canada. Included in the East Coast spending was $31 million to acquire additional interests in the White Rose project and other properties in the Jeanne d'Arc Basin. Upstream capital expenditures in

Western Canada totalled $238 million including $81 million for development in the Lloydminster heavy oil area and $76 million for exploration. Exploration spending was approximately 32 percent of upstream capital expenditures in Western Canada. Exploration spending in Western Canada in 1999 was concentrated in the Alberta and northeast British Columbia foothills. In 1999, $23 million was spent in international areas.

Upstream Capital Expenditures*				
Year ended December 31 ($ millions)		**2001**	2000	1999
Exploration	Western Canada	**$ 236**	$ 118	$ 76
	East Coast Canada	**81**	63	153
	International	**5**	–	–
		322	181	229
Development	Western Canada	**786**	301	162
	East Coast Canada	**110**	131	156
	International	**99**	87	23
		995	519	341
		$ 1,317	$ 700	$ 570

**Excludes corporate acquisitions.*

Planned 2002 Capital Expenditures

Husky's current plan is to spend approximately $1.2 billion in the upstream segment during 2002 including approximately $975 million in Western Canada and $210 million for the Canadian offshore east coast and international areas. In Western Canada Husky will focus on the British Columbia and Alberta foothills deep gas, northwest Alberta plains shallow gas, Lloydminster heavy oil and the oil sands region of Athabasca. Husky's expenditures off Canada's east coast will be primarily devoted to the White Rose oil field development project and internationally on the Wenchang exploration program.

2002 Production Forecast

Husky anticipates 2002 production will increase by 10 percent to average in excess of 300 mboe/day. Light crude oil and NGL production is anticipated to average between 125 and 135 mbbls/day. Heavy oil production is estimated to average 75 mbbls/day. Natural gas production is estimated to average between 600 to 650 mmcf/day.

Reserve Additions

In 2001 Husky's addition to total proved reserves of crude oil and NGL was 110 mmbbls, of which 39 percent was from discoveries and extensions, 30 percent from revisions of previous estimates and 31 percent from acquisitions, net of divestitures. Total additions of proved reserves of crude oil and NGL replaced 169 percent of 2001 crude oil and NGL production. During 2001 Husky's addition to total proved reserves of natural gas was 266 bcf, 90 percent from discoveries and extensions, nine percent from revisions of previous estimates and the remainder from net acquisitions. Total additions of proved reserves of natural gas in 2001 replaced 127 percent of 2001 natural gas production.

The internally generated oil and gas reserves of the Company were audited by McDaniel and Associates Consultants Ltd. as of December 31, 2001. In the opinion of McDaniel and Associates Consultants Ltd. the overall proved crude oil and natural gas reserves estimates appear to be reasonable and have been presented in accordance with generally accepted petroleum engineering and evaluation principles. McDaniel and Associates Consultants Ltd. further opined that had they performed a standard detailed audit of the Husky properties the resultant estimates would be within 10 percent of the reserves as reported by Husky.

Summary of Reserves

Light/Medium Crude Oil and NGL						
	2001		2000		1999	
Year ended December 31 (mmbbls)	Gross	Net	Gross	Net	Gross	Net
Proved developed	**329**	**287**	338	283	133	112
Proved undeveloped	**101**	**89**	102	88	12	11
Total proved	**430**	**376**	440	371	145	123

Lloydminster Heavy Crude Oil Reserves						
	2001		2000		1999	
Year ended December 31 (mmbbls)	Gross	Net	Gross	Net	Gross	Net
Proved developed	**96**	**92**	65	63	56	51
Proved undeveloped	**73**	**72**	49	47	49	45
Total proved	**169**	**164**	114	110	105	96

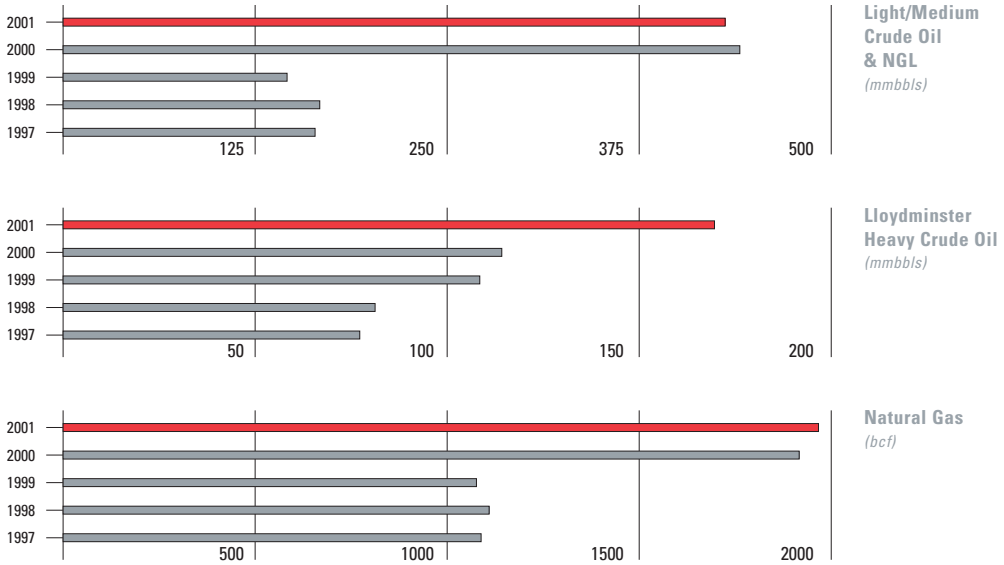
Natural Gas Reserves						
	2001		2000		1999	
Year ended December 31 (bcf)	Gross	Net	Gross	Net	Gross	Net
Proved developed	**1,577**	**1,342**	1,580	1,276	818	669
Proved undeveloped	**389**	**332**	329	269	259	213
Total proved	**1,966**	**1,674**	1,909	1,545	1,077	882

Barrels of Oil Equivalent						
	2001		2000		1999	
Year ended December 31 (mmboe)	Gross	Net	Gross	Net	Gross	Net
Proved developed	**688**	**603**	666	559	326	274
Proved undeveloped	**239**	**216**	206	180	104	92
Total proved	**927**	**819**	872	739	430	366

Reserve [1] Life Index			
Year ended December 31 (years)	**2001**	2000 [2]	1999
Light/medium crude oil and NGL	**10.5**	10.2	15.0
Lloydminster heavy crude oil	**7.0**	5.4	6.8
Natural gas	**9.4**	9.0	11.8
Barrels of oil equivalent	**9.3**	8.7	10.7

[1] *Includes total proved reserves.*
[2] *Based on annualized Q-4 production for 2000.*

Gross Proved Reserves



Finding and Development Costs

Total*				
Year ended December 31	**1999-2001**	**2001**	2000	1999
Total capitalized costs *($ millions)*	**$ 2,331**	**$ 1,172**	$ 638	$ 521
Proved reserve additions and revisions *(mmboe)*	**252**	**121**	93	38
Average cost per boe	**$ 9.26**	**$ 9.69**	$ 6.88	$ 13.72

**Excludes net acquisitions.*

Western Canada*				
Year ended December 31	**1999-2001**	**2001**	2000	1999
Total capitalized costs *($ millions)*	**$ 1,538**	**$ 920**	$ 400	$ 218
Proved reserve additions and revisions *(mmboe)*	**222**	**114**	49	59
Average cost per boe	**$ 6.92**	**$ 8.07**	$ 8.13	$ 3.68

**Excludes oil sands and net acquisitions.*

Production Replacement

Total				
Year ended December 31	**1999-2001**	**2001**	2000	1999
Production *(mmboe)*	**205**	**100**	65	40
Proved reserve additions and revisions *(mmboe)*	**252**	**121**	93	38
Production replacement ratio (excluding net acquisitions) *(percent)*	**123**	**121**	143	94
Proved reserve additions including net acquisitions *(mmboe)**	**311**	**155**	117	39
Production replacement ratio (including net acquisitions) *(percent)**	**152**	**155**	181	97

**2000 excludes Renaissance acquisition.*

Western Canada*				
Year ended December 31	**1999-2001**	**2001**	2000	1999
Production *(mmboe)*	**205**	**100**	65	40
Proved reserve additions and revisions *(mmboe)*	**222**	**114**	49	59
Production replacement ratio (excluding net acquisitions) *(percent)*	**109**	**114**	76	147
Proved reserve additions including net acquisitions *(mmboe)***	**282**	**148**	74	60
Production replacement ratio (including net acquisitions) *(percent)***	**138**	**148**	114	149

**Excludes oil sands.*
***2000 excludes Renaissance acquisition.*

Recyle Ratio

Total				
Year ended December 31	**1999-2001**	**2001**	2000	1999
EBITDA netback *($/boe)*	**$ 15.38**	**$ 15.54**	$ 18.60	$ 9.84
Proved finding and development cost *($/boe)**	**$ 9.26**	**$ 9.69**	$ 6.88	$ 13.72
Recycle ratio**	**1.66**	**1.60**	2.70	0.72

**Excludes net acquisitions.*
***The recycle ratio is a measure of the efficiency of Husky's capital program relative to product netbacks.*

Western Canada				
Year ended December 31	**1999-2001**	**2001**	2000	1999
EBITDA netback *($/boe)*	**$ 15.35**	**$ 15.54**	$ 18.55	$ 9.74
Proved finding and development cost *($/boe)**	**$ 6.92**	**$ 8.07**	$ 8.13	$ 3.68
Recycle ratio**	**2.22**	**1.93**	2.28	2.65

** Excludes oil sands and net acquisitions.*
***The recycle ratio is a measure of the efficiency of Husky's capital program relative to product netbacks.*

Western Canada Drilling							
		2001		2000		1999	
Year ended December 31 (wells)		Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	**78**	**76**	16	13	9	9
	Gas	**102**	**90**	30	20	13	5
	Dry	**36**	**34**	9	9	9	9
		216	**200**	55	42	31	23
Development	Oil	**594**	**542**	411	363	203	190
	Gas	**251**	**221**	92	70	42	23
	Dry	**68**	**63**	30	28	23	22
		913	**826**	533	461	268	235
Total		**1,129**	**1,026**	588	503	299	258

Undeveloped Land Holdings				
	2001		2000	
Year ended December 31 (thousands of acres)	Gross	Net	Gross	Net
Alberta	**5,980**	5,373	6,139	5,616
Saskatchewan	**2,066**	1,921	2,760	2,639
British Columbia	**188**	141	239	173
Manitoba	**76**	75	162	162
Western Canada	**8,310**	7,510	9,300	8,590
Northwest Territories and Arctic	**1,538**	409	1,534	409
Eastern Canada	**1,878**	1,471	1,838	1,489
Total Canada	**11,726**	9,390	12,672	10,488
International	**1,425**	697	707	221
Total	**13,151**	10,087	13,379	10,709

Results of Operations *Midstream*

Upgrading Operations				
Year ended December 31 ($ millions)		**2001**	2000	1999
Gross margin		**$ 428**	$ 321	$ 172
Operating costs		**192**	158	114
Other expenses (recoveries)		**(13)**	(2)	(7)
EBITDA		**249**	165	65
DD&A		**17**	16	16
Operating profit (EBIT)		**$ 232**	$ 149	$ 49
Upgrader throughput [1]	*(mbbls/day)*	**71.7**	70.0	71.8
Synthetic crude oil sales	*(mbbls/day)*	**59.5**	60.6	61.9
Upgrading differential	*($/bbl)*	**17.91**	13.77	6.49
Unit operating costs [2]	*($/bbl)*	**7.35**	6.17	4.35

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

Upgrading EBITDA Variance Analysis	
EBITDA year ended December 31, 1999	$ 65
Volume	(3)
Differential	160
Operating costs - energy	(80)
Operating costs - non-energy	27
Other	(4)
EBITDA year ended December 31, 2000	$ 165
Volume	(7)
Differential	116
Operating costs - energy	(29)
Operating costs - non-energy	(6)
Other	10
EBITDA year ended December 31, 2001	**$ 249**

Infrastructure and Marketing			
Year ended December 31 ($ millions)	**2001**	2000	1999
Gross margin			
Pipeline	**$ 86**	$ 87	$ 54
Other infrastructure and marketing	**111**	30	41
	197	117	95
Other expenses	**8**	6	5
EBITDA	**189**	111	90
DD&A	**17**	15	13
Operating profit (EBIT)	**$ 172**	$ 96	$ 77
Aggregate pipeline throughput *(mbbls/day)*	**537**	528	394

2001 compared with 2000

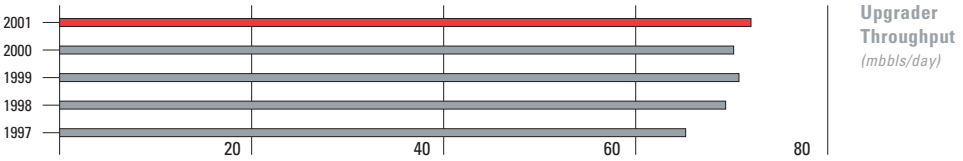
Total midstream operating profit increased $159 million (65 percent) to $404 million in 2001 from $245 million in 2000. Upgrading operations accounted for 52 percent of the increase in midstream operating profit and was due to the higher upgrading differential. The upgrading differential is the difference between the price received for synthetic crude oil and the cost of blended heavy crude oil feedstock. The differential averaged $17.91/bbl in 2001 compared with $13.77/bbl in 2000. The effect of the higher upgrading differential was partially offset by higher energy related operating costs. Upgrading operating costs averaged $7.35/bbl in 2001 compared with $6.17/bbl in 2000.

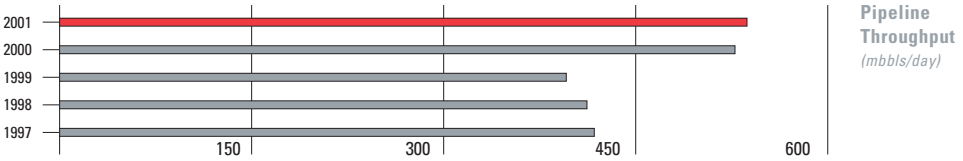
Infrastructure and marketing operations accounted for 48 percent of the increase in midstream operating profit and was primarily due to higher sales volume and margins for brokered natural gas, improved margins for blended heavy crude oil and a non-recurring loss on a contract termination incurred in 2000.

2000 compared with 1999

Total midstream operating profit increased $119 million (94 percent) to $245 million in 2000 from $126 million in 1999. Upgrading operations accounted for 84 percent of the increase in midstream operating profit. The upgrading differential averaged $13.77/bbl in 2000 compared with $6.49/bbl in 1999. The effect of the higher upgrading differential was partially offset by higher operating costs and lower throughput. The decrease in throughput in 2000 was due to a plant turnaround in May 2000. Upgrading operations operating costs averaged $6.17/bbl in 2000 compared with $4.35/bbl in 1999 as a result of higher natural gas and thermal energy costs.

Infrastructure and marketing operations accounted for 16 percent of the increase in midstream operating profit in 2000 over that for 1999 and was primarily due to higher heavy crude oil throughput and increased pipeline and processing revenue. The addition of cogeneration and natural gas storage operations in 2000 also contributed to higher operating profit from the infrastructure operations. A $19 million non-recurring loss on a contract termination in 2000 in the commodity marketing business was partially offset by higher brokered natural gas volume.





Midstream Capital Expenditures

Midstream capital expenditures amounted to $105 million in 2001 and were primarily for the upgrader, pipeline systems and cogeneration facilities.

Midstream Capital Expenditures			
Year ended December 31 ($ millions)	**2001**	2000	1999
Upgrader	**$ 47**	$ 12	$ 15
Infrastructure and marketing	**58**	47	79
	$ 105	$ 59	$ 94

Planned capital expenditures in 2002 amount to $130 million of which $56 million is for front-end engineering and design for an expansion of the Husky Lloydminster Upgrader and debottlenecking to improve throughput.

Results of Operations
Refined Products

Light Oil Products				
Year ended December 31 ($ millions, except where indicated)		**2001**	2000	1999
Gross margin - fuel sales		**$ 69**	$ 55	$ 68
- ancillary sales		**27**	26	27
		96	81	95
Operating expenses		**30**	27	25
Other expenses		**16**	13	15
EBITDA		**50**	41	55
DD&A		**25**	22	20
Operating profit (EBIT)		**$ 25**	$ 19	$ 35
Number of fuel outlets		**580**	579	597
Fuel sales volume	*(million litres/day)*	**7.6**	7.4	7.6
Refinery throughput	*(mbbls/day)*	**10.2**	9.2	10.2

Asphalt Products				
Year ended December 31 ($ millions, except where indicated)		**2001**	2000	1999
Gross margin		**$ 106**	$ 38	$ 22
Other expenses		**1**	2	2
EBITDA		**105**	36	20
DD&A		**6**	6	6
Operating profit (EBIT)		**$ 99**	$ 30	$ 14
Sales volume	*(mbbls/day)*	**21.4**	20.2	17.1
Refinery throughput	*(mbbls/day)*	**23.7**	23.4	17.9

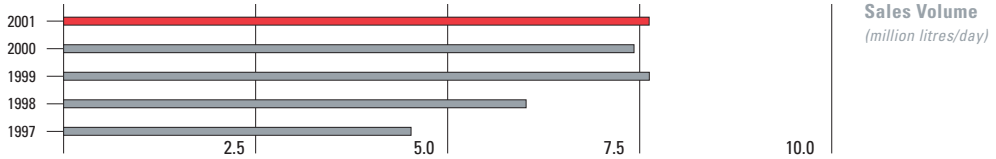
2001 compared with 2000

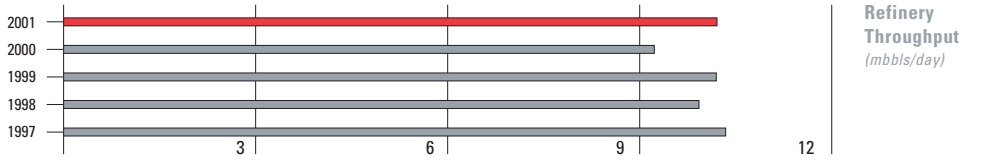
Total refined products operating profit increased $75 million (153 percent) to $124 million in 2001 from $49 million in 2000. Asphalt product operations accounted for 92 percent of the increase in operating profit and was due to the lower cost feedstock and increased sales volume throughout most of the year. Improved operating profit from light oil refined products operations in 2001 was primarily due to higher margins.

2000 compared with 1999

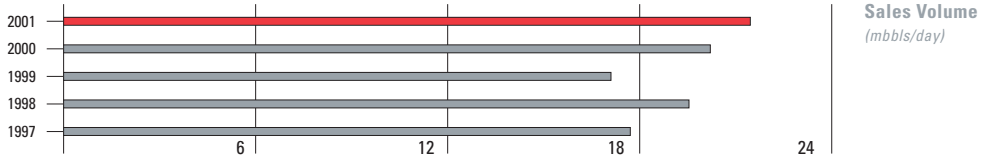
Total refined products operating profit was at the same level in 2000 as in 1999, $49 million. Asphalt product operations operating profit increased 114 percent in 2000 due to improved margins and higher sales volumes. Light oil refined product operating profit decreased 46 percent primarily due to higher feedstock costs that could not be passed through to the customer.

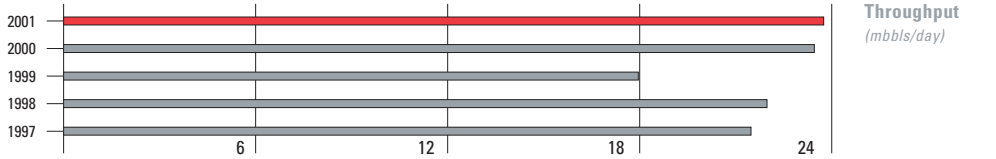
Light Oil Products





Asphalt Products





Refined Products Capital Expenditures

Refined products capital expenditures amounted to $29 million in 2001, a level similar to 2000 (1999 - $34 million). In 2001, capital expenditures of $22 million were incurred for marketing outlet improvements, ($19 million in 2000), the remainder in both periods was for refinery maintenance.

Planned capital expenditures in 2002 are currently expected to be $82 million and are intended primarily for asset optimization ($40 million), refinery maintenance ($20 million), refinery upgrades ($14 million) and $8 million for various other capital programs.

Results of Operations
Corporate

Interest

2001 compared with 2000

Net interest in 2001 of $101 million was the same as in 2000. Total interest paid, net of interest income, amounted to $152 million in 2001 compared to $144 million in 2000. Interest capitalized in 2001 amounted to $51 million compared to $43 million in 2000. Capitalized interest was primarily in respect of the Terra Nova and White Rose projects. Interest paid in 2000 included $9 million in respect of the partial redemption of the Husky Terra Nova 8.45 percent senior secured bonds. Husky's average interest rate in 2001 was approximately 6.9 percent compared to 7.5 percent in 2000.

2000 compared with 1999

Net interest in 2000 increased $39 million to $101 million from $62 million in 1999. Total interest paid, net of interest income, amounted to $144 million in 2000 compared to $94 million in 1999. Interest capitalized in 2000 amounted to $43 million compared to $32 million in 1999. Capitalized interest was primarily in respect of Terra Nova and White Rose projects. Interest paid in 2000 included $9 million in respect of the partial redemption of the Husky Terra Nova 8.45 percent senior secured bonds. Husky's average interest rate in 2000 was approximately 7.5 percent compared to 7.7 percent in 1999.

Foreign Exchange

Husky recorded $34 million in foreign exchange losses in 2001 compared with $5 million in 2000 primarily due to the weaker Canadian dollar. Foreign exchange losses in 1999 amounted to $25 million.

Income Taxes

Income tax expense in 2001 amounted to $433 million, an increase of $62 million over the $371 million in 2000. The increase in income tax expense reflects higher pre-tax earnings partially offset by an Alberta corporate tax rate reduction which was effective in 2001. Income tax expense increased $320 million to $371 million in 2000 from $51 million in 1999 primarily due to higher pre-tax earnings in 2000.

Corporate Capital Expenditures

Corporate capital expenditures amounted to $22 million in 2001, $15 million in 2000 and $8 million in 1999 and were primarily for computer hardware and software and office furniture and equipment.

Sensitivity Analysis

The following table shows the effect on net earnings of changes in certain key variables. The analysis is based on business conditions and production volumes during 2001. Each separate item in the sensitivity analysis assumes the others are constant. While these sensitivities are applicable for the period and magnitude of increases 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 Earnings	
		($ millions)	*($/share)* [5]	*($ millions)*	*($/share)* [5]
WTI benchmark crude oil price	U.S. $1.00/bbl	88	0.21	56	0.13
NYMEX benchmark natural gas price [1]	U.S. $0.20/mmbtu	37	0.09	20	0.05
Light/Heavy crude oil differential [2]	Cdn. $1.00/bbl	(26)	(0.06)	(16)	(0.04)
Light oil margins	Cdn. $0.005/litre	14	0.03	8	0.02
Asphalt margins	Cdn. $1.00/bbl	8	0.02	4	0.01
Exchange rate (U.S. $ per Cdn. $) [3]	U.S. $0.01	(39)	(0.09)	(24)	(0.06)
Interest rate [4]	1%	(4)	(0.01)	(2)	(0.01)

[1] *Includes decrease in earnings related to natural gas consumption.*
[2] *Includes impact of upstream and upgrading operations only.*
[3] *Assumes no foreign exchange gains or losses. In 2002 a new accounting standard eliminates the deferral of foreign exchange gains and losses on long-term monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $12 million in net earnings based on December 31, 2001 U.S. debt levels.*
[4] *Interest rate sensitivity based on annual weighted average obligations.*
[5] *Based on December 31, 2001 common shares outstanding of 416.9 million.*

Liquidity and Capital Resources

Financial Ratios

Year ended December 31	**2001**	2000	1999
Cash flow from operations *($ millions)*	**1,946**	1,399	517
Debt to capital employed *(percent)*	**32.4**	37.1	41.0
Debt to cash flow from operations	**1.1**	1.7	2.7
Corporate reinvestment ratio [1]	**0.8**	0.6	1.3

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

In 2001 cash generated by operating activities was $1,930 million, an increase of $721 million (60 percent) from the $1,209 million recorded in 2000 (1999 - $487 million). Cash used for investing activities amounted to $1,507 million in 2001 compared with $651 million in 2000 (1999 - $789 million).

In 2001 investing activities comprised $1,507 million for capital expenditures and acquisition costs partially offset by asset sales of $67 million and other adjustments of $24 million, which consisted primarily of change in non-cash working capital. In 2000 investing activities comprised $841 million of capital expenditures and acquisition costs partially offset by asset sales of $2 million, reduction of other assets of $80 million and change in non-cash working capital of $108 million. The reduction of other assets was related to the release and subsequent use for general corporate purposes of funds which had been maintained in connection with the Husky Terra Nova Finance Ltd. 8.45 percent senior secured bonds. In 1999 investing activities comprised $706 million of capital expenditures, $94 million increase in other assets and $4 million increase in non-cash working capital partially offset by $15 million of asset sales. The increase in other assets consisted primarily of $85 million of term deposits that were related to the Husky Terra Nova Finance Ltd. 8.45 percent senior secured bonds.

In 2001 financing activities utilized a net $423 million, comprised mainly of net debt repayments of $290 million, dividends of $150 million, return on Capital Securities of $30 million and reduction of site restoration provision of $4 million partially offset by change in non-cash working capital of $42 million and proceeds from stock options exercised of $9 million.

Financing Activities

At December 31, 2001 Husky's outstanding long-term debt, including amounts due within one year, totalled $2,092 million compared with $2,344 million at December 31, 2000.

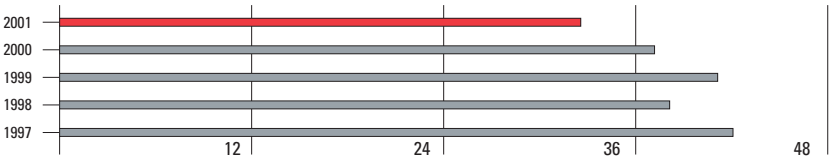
At December 31, 2001 $185 million (U.S. $116 million) had been drawn under the Company's $1 billion revolving syndicated credit facility. Interest rates on this facility vary and are based on Canadian prime, Bankers' Acceptance, U.S. Libor or U.S. base rate, depending on the borrowing option, credit rating assigned to the Company's senior unsecured debt and whether the facility is revolving or non-revolving. As at December 31, 2001 the Company had unutilized committed long-term lines of credit totalling $815 million.

At December 31, 2001 the Company had drawn or otherwise utilized in support of letters of credit $102 million of the $195 million short term credit facilities. The interest rates applicable to these facilities vary and are based on Canadian prime, Bankers' Acceptance, money market rates or U.S. dollar equivalents.

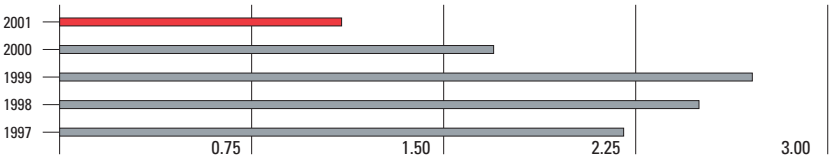
The Company has an agreement to sell up to $220 million of trade receivables on a continual basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates, to be paid on an ongoing basis. The average effective rate in 2001 was approximately 4.7 percent (2000 - 6.0 percent). The Company has potential exposure to an immaterial amount of credit loss under this agreement. As at December 31, 2001 $220 million of trade receivables had been sold.

The Company believes that, based on its current forecast for commodity prices for 2002, its capital program of $1.4 billion will be funded by operating activities and, to the extent required, available lines of credit.

The Company declared dividends aggregating $0.36 per share ($150 million) in 2001. This was the first year the Company paid dividends on common shares since 1987.



Debt to Capital Employed
(percent)



Debt to Cash Flow from Operations
(times)

At December 31, 2001 Husky had the following credit ratings:

	Rated	Debt Rated
Standard and Poor's Rating Service	BBB	Senior Unsecured Debt
	BB+	Capital Securities
	BBB	8.45% Senior Secured Bonds
Moody's Investor Service	Baa2	Senior Unsecured Debt
	Ba1	Capital Securities
	Baa2	8.45% Senior Secured Bonds
Dominion Bond Rating Service	BBB (high)	Senior Unsecured Long-Term Notes
	BBB	Capital Securities

2001

HUSKY ENERGY INC.
CONSOLIDATED FINANCIALS STATEMENTS & NOTES

HUSKY'S 2001 CAPITAL EXPENDITURES TOTALLED

$1.5 billion

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 since 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 consistent basis with that in the financial statements.

Husky Energy 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 and financial reporting matters. The Committee reviews the consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

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

John C. S. Lau
President & Chief Executive Officer
Calgary, Alberta

Neil McGee
Vice President &
Chief Financial Officer

February 5, 2002

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Husky Energy Inc., as at December 31, 2001, 2000 and 1999 and the consolidated statements of earnings, retained earnings (deficit), and cash flows for each of the years in the three year period ended December 31, 2001. 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.

With respect to the consolidated financial statements for each of the years in the two year period ended December 31, 2001 and 2000 we conducted our audit in accordance with Canadian generally accepted auditing standards and United States generally accepted auditing standards. With respect to the consolidated financial statements for year ended December 31, 1999 we conducted our audit in accordance with Canadian generally accepted auditing standards. 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, 2001, 2000 and 1999 and the results of its operations and cash flows for each of the years in the three year period ended December 31, 2001 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Calgary, Canada
Chartered Accountants (KPMG LLP)

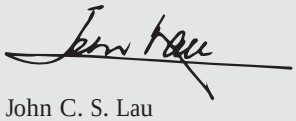
February 5, 2002

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of dollars)	**2001**	2000	1999
Assets			
Current assets			
Accounts receivable	**$ 376**	$ 715	$ 315
Inventories *(note 4)*	**226**	186	134
Prepaid expenses	**24**	27	14
	626	928	463
Property, plant and equipment, net *(notes 1, 5)* (full cost accounting)	**8,715**	7,841	4,189
Other assets *(note 9)*	**162**	133	163
	$ 9,503	$ 8,902	$ 4,815
Liabilities and Shareholders' Equity			
Current liabilities			
Bank operating loans *(note 8)*	**$ 100**	$ 34	$ 31
Accounts payable and accrued liabilities	**821**	1,076	518
Long-term debt due within one year *(note 9)*	**144**	33	2
	1,065	1,143	551
Long-term debt *(note 9)*	**1,948**	2,311	1,349
Site restoration provision *(note 5)*	**212**	178	95
Future income taxes *(note 10)*	**1,695**	1,231	825
Due to shareholders *(note 11)*	**–**	–	1,743
Shareholders' equity			
Capital securities and accrued return *(note 13)*	**350**	347	347
Class B shares *(note 11)*	**–**	–	200
Common shares *(note 12)*	**3,397**	3,388	–
Retained earnings (deficit)	**836**	304	(295)
	4,583	4,039	252
Commitments and contingencies *(note 15)*			
	$ 9,503	$ 8,902	$ 4,815

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

William Shurniak
Director

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31 (millions of dollars, except per share amounts)	**2001**	2000	1999
Sales and operating revenues, net of royalties	**$ 6,627**	$ 5,090	$ 2,794
Costs and expenses			
Cost of sales and operating expenses	**4,456**	3,516	2,151
Selling and administration expenses	**88**	67	48
Depletion, depreciation and amortization *(notes 1, 5)*	**807**	481	293
Interest - net *(note 9)*	**101**	101	62
Ownership charges	**–**	82	117
Foreign exchange	**34**	5	25
Other - net	**7**	3	4
	5,493	4,255	2,700
Earnings before income taxes	**1,134**	835	94
Income taxes *(note 10)*			
Current	**20**	12	5
Future	**413**	359	46
	433	371	51
Net earnings	**$ 701**	$ 464	$ 43
Earnings per share *(note 12)*			
Basic	**$ 1.64**	$ 1.39	$ 0.10
Diluted	**$ 1.63**	$ 1.39	$ 0.10

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (DEFICIT)

Year ended December 31 (millions of dollars)	**2001**	2000	1999
Beginning of year	**$ 304**	$ (295)	$ (322)
Net earnings	**701**	464	43
Dividends on common shares	**(150)**	–	–
Return on capital securities *(note 13)*	**(33)**	(30)	(29)
Related future income taxes *(note 10)*	**14**	13	13
Reduction of stated capital *(note 11)*	**–**	160	–
Employee future benefits *(note 14)*	**–**	(8)	–
End of year	**$ 836**	$ 304	$ (295)

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, except per share amounts)	**2001**	2000	1999
Operating activities			
Net earnings	**$ 701**	$ 464	$ 43
Items not affecting cash			
Depletion, depreciation and amortization	**807**	481	293
Future income taxes	**413**	359	46
Foreign exchange - non cash	**22**	10	16
Ownership charges	**–**	82	117
Other	**3**	3	2
Cash flow from operations	**1,946**	1,399	517
Change in non-cash working capital *(note 7)*	**(16)**	(190)	(30)
	1,930	1,209	487
Financing activities			
Bank operating loans financing - net	**66**	3	3
Long-term debt issue	**–**	535	375
Long-term debt repayment	**(356)**	(800)	(57)
Redemption of preferred shares	**–**	(364)	–
Return on capital securities payment	**(30)**	(30)	(31)
Deferred credits	**(4)**	(4)	(6)
Proceeds from exercise of stock options	**9**	–	–
Dividends on common shares	**(150)**	–	–
Change in non-cash working capital *(note 7)*	**42**	102	18
	(423)	(558)	302
Available for investing	**$ 1,507**	$ 651	$ 789
Investing activities			
Capital expenditures	**$ (1,473)**	$ (803)	$ (706)
Corporate acquisitions	**(125)**	(38)	–
Asset sales	**67**	2	15
Other assets	**6**	80	(94)
Change in non-cash working capital *(note 7)*	**18**	108	(4)
	$ (1,507)	$ (651)	$ (789)
Cash equivalents *(note 3)*			
Cash flow from operations per share *(note 12)*			
Basic	**$ 4.60**	$ 4.26	$ 1.80
Diluted	**$ 4.57**	$ 4.26	$ 1.80

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 of Canadian dollars.

Note 1

Segmented Financial Information

	Upstream			Midstream					
				Upgrading			Infrastructure and Marketing		
	2001	2000	1999	**2001**	2000	1999	**2001**	2000	1999
Year ended December 31									
Sales and operating revenues, net of royalties	**$ 2,196**	$ 1,573	$ 602	**$ 886**	$ 1,006	$ 641	**$ 4,380**	$ 2,309	$ 1,284
Costs and expenses [3]	**648**	370	204	**637**	841	576	**4,191**	2,198	1,194
EBITDA	**1,548**	1,203	398	**249**	165	65	**189**	111	90
Depletion, depreciation and amortization	**728**	407	223	**17**	16	16	**17**	15	13
Interest - net	**–**	–	–	**–**	–	–	**–**	–	–
Ownership charges	**–**	–	–	**–**	–	–	**–**	–	–
	728	407	223	**17**	16	16	**17**	15	13
Earnings before income taxes	**820**	796	175	**232**	149	49	**172**	96	77
Income taxes									
Current	**–**	–	–	**–**	–	–	**–**	–	–
Future	**–**	–	–	**–**	–	–	**–**	–	–
Net earnings	**$ 820**	$ 796	$ 175	**$ 232**	$ 149	$ 49	**$ 172**	$ 96	$ 77
Cash flow from operations	**$ 1,548**	$ 1,203	$ 398	**$ 249**	$ 165	$ 65	**$ 189**	$ 111	$ 90
Capital expenditures - Year ended December 31	**$ 1,317**	$ 700	$ 570	**$ 47**	$ 12	$ 15	**$ 58**	$ 47	$ 79
Property, plant and equipment - As at December 31									
Cost									
Canada	**$ 10,353**	$ 9,023	$ 4,916	**$ 958**	$ 912	$ 900	**$ 575**	$ 510	$ 472
International	**394**	290	203	**–**	–	–	**–**	–	–
	$ 10,747	$ 9,313	$ 5,119	**$ 958**	$ 912	$ 900	**$ 575**	$ 510	$ 472
Accumulated depletion, depreciation and amortization									
Canada	**$ 3,272**	$ 2,622	$ 2,270	**$ 354**	$ 337	$ 320	**$ 165**	$ 148	$ 134
International	**147**	139	130	**–**	–	–	**–**	–	–
	$ 3,419	$ 2,761	$ 2,400	**$ 354**	$ 337	$ 320	**$ 165**	$ 148	$ 134
Net									
Canada	**$ 7,081**	$ 6,401	$ 2,646	**$ 604**	$ 575	$ 580	**$ 410**	$ 362	$ 338
International	**247**	151	73	**–**	–	–	**–**	–	–
	$ 7,328	$ 6,552	$ 2,719	**$ 604**	$ 575	$ 580	**$ 410**	$ 362	$ 338
Identifiable assets - As at December 31 [2]									
Canada	**$ 7,081**	$ 6,401	$ 2,646	**$ 604**	$ 575	$ 580	**$ 410**	$ 362	$ 338
International	**247**	151	73	**–**	–	–	**–**	–	–
	$ 7,328	$ 6,552	$ 2,719	**$ 604**	$ 575	$ 580	**$ 410**	$ 362	$ 338

	Refined Products			Corporate and Eliminations [1]			Total		
	2001	2000	1999	**2001**	2000	1999	**2001**	2000	1999
Year ended December 31									
Sales and operating revenues, net of royalties	**$ 1,349**	$ 1,347	$ 904	**$ (2,184)**	$ (1,145)	$ (637)	**$ 6,627**	$ 5,090	$ 2,794
Costs and expenses [3]	**1,194**	1,270	829	**(2,085)**	(1,088)	(575)	**4,585**	3,591	2,228
EBITDA	**155**	77	75	**(99)**	(57)	(62)	**2,042**	1,499	566
Depletion, depreciation and amortization	**31**	28	26	**14**	15	15	**807**	481	293
Interest - net	**–**	–	–	**101**	101	62	**101**	101	62
Ownership charges	**–**	–	–	**–**	82	117	**–**	82	117
	31	28	26	**115**	198	194	**908**	664	472
Earnings before income taxes	**124**	49	49	**(214)**	(255)	(256)	**1,134**	835	94
Income taxes									
Current	**–**	–	–	**20**	12	5	**20**	12	5
Future	**–**	–	–	**413**	359	46	**413**	359	46
Net earnings	**$ 124**	$ 49	$ 49	**$ (647)**	$ (626)	$ (307)	**$ 701**	$ 464	$ 43
Cash flow from operations	**$ 155**	$ 77	$ 75	**$ (195)**	$ (157)	$ (111)	**$ 1,946**	$ 1,399	$ 517
Capital expenditures - Year ended December 31	**$ 29**	$ 29	$ 34	**$ 22**	$ 15	$ 8	**$ 1,473**	$ 803	$ 706
Property, plant and equipment - As at December 31									
Cost									
Canada	**$ 655**	$ 628	$ 603	**$ 143**	$ 108	$ 322	**$ 12,684**	$11,181	$ 7,213
International	**–**	–	–	**–**	–	–	**394**	290	203
	$ 655	$ 628	$ 603	**$ 143**	$ 108	$ 322	**$ 13,078**	$11,471	$ 7,416
Accumulated depletion, depreciation and amortization									
Canada	**$ 330**	$ 302	$ 275	**$ 95**	$ 82	$ 98	**$ 4,216**	$ 3,491	$ 3,097
International	**–**	–	–	**–**	–	–	**147**	139	130
	$ 330	$ 302	$ 275	**$ 95**	$ 82	$ 98	**$ 4,363**	$ 3,630	$ 3,227
Net									
Canada	**$ 325**	$ 326	$ 328	**$ 48**	$ 26	$ 224	**$ 8,468**	$ 7,690	$ 4,116
International	**–**	–	–	**–**	–	–	**247**	151	73
	$ 325	$ 326	$ 328	**$ 48**	$ 26	$ 224	**$ 8,715**	$ 7,841	$ 4,189
Identifiable assets - As at December 31 [2]									
Canada	**$ 325**	$ 326	$ 328	**$ 835**	$ 1,085	$ 845	**$ 9,255**	$ 8,749	$ 4,737
International	**–**	–	–	**1**	2	5	**248**	153	78
	$ 325	$ 326	$ 328	**$ 836**	$ 1,087	$ 850	**$ 9,503**	$ 8,902	$ 4,815

[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] *Identifiable assets by segment are the total assets specifically attributable to those operations as at December 31 of each year. Corporate includes accounts receivable, inventories, prepaid expenses, other assets and corporate assets.*

[3] *Costs and expenses include cost of sales and operating expenses, selling and administration expenses, foreign exchange and other – net.*

Note 2 Nature of Operations and Organization

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

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

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

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

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

Note 3 Significant Accounting Policies

These financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which, in the case of the Company, differ in certain respects from those in the United States. These differences are described in note 17, Reconciliation to Accounting Principles Generally Accepted in the United States.

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

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

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

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

a) Cash Equivalents

Cash equivalents consists of cash in the bank, less outstanding cheques, and deposits with a maturity of less than three months. For each of the years ended December 31, 2001, 2000 and 1999 there was no change from the beginning balance for cash equivalents of nil.

b) Inventory Valuation

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

c) Property, Plant and Equipment

i) Oil and Gas

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

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

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

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

ii) Other Plant and Equipment

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

iii) Future Removal and Site Restoration Costs

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

d) Financial Instruments

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

In November 2001, the Accounting Standards Board ("AcSB") of the Canadian Institute of Chartered Accountants ("CICA") issued an Accounting Guideline "Hedging Relationships" that establishes standards for the documentation and effectiveness of hedging activities that are substantially similar to the corresponding requirements in Financial Accounting Standards Board ("FASB") Statement No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). The new recommendations will be effective January 1, 2003. Note 17 discloses the impact of FAS 133 on the financial statements for 2001.

e) Revenue Recognition

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

f) Foreign Currency Translation

Foreign denominated long-term monetary assets and liabilities of Canadian operations are translated at the current rate of exchange. Unrealized translation gains or losses are deferred and amortized over the remaining lives of the long-term monetary items.

Capital securities are adjusted to the current rate of exchange through a deferral and amortization to retained earnings over their expected lives.

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

In November 2001, the AcSB of the CICA revised recommendations on Foreign Currency Translation. The new recommendations will be effective January 1, 2002 and will eliminate the deferral and amortization of foreign exchange gains and losses on long-term monetary items. The change will result in a reduction of retained earnings at January 1, 1999 of $79 million, earnings after tax of $47 million, $27 million, and ($54) million for the years ended December 31, 2001, 2000 and 1999, respectively, a reduction to other assets of $133 million and a reduction to the future tax liability of $34 million as at December 31, 2001.

g) Stock-Based Compensation Plans

In accordance with the Company's stock option plan, common share options are granted to directors, officers and certain other employees. The Company does not recognize compensation expense on the issuance of common share options under this plan because the exercise price of the share options is equal to the market value of the common shares when they are granted.

In November 2001, the AcSB of the CICA issued recommendations on Stock-Based Compensation and other Stock-Based Payments. The new standards will be effective January 1, 2002 and will require additional disclosures for options granted to directors, officers and employees and that a compensation cost be recorded for the fair value of any options granted to non-employees. The recommendations are substantially similar to those in FASB Statement No. 123 "Accounting for Stock-Based Compensation" ("FAS 123"). Management believes that there will be no significant impact on our financial statements as a result of this standard. Note 17 presents the disclosures required by FAS 123 in the financial statements.

h) Earnings Per Share

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

Note 4 Inventories

	2001	2000	1999
Crude oil and refined petroleum products	**$ 140**	$ 132	$ 117
Natural gas	**69**	41	2
Materials, supplies and other	**17**	13	15
	$ 226	$ 186	$ 134

Note 5 Property, Plant and Equipment

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

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

	2001	2000	1999
Canada	**$ 1,226**	$ 1,073	$ 646
International	**235**	137	58
	$ 1,461	$ 1,210	$ 704

The Company has estimated future removal and site restoration costs of $653 million at December 31, 2001 (2000 - $619 million, 1999 - $237 million). During 2001 actual removal and site restoration expenditures amounted to $18 million (2000 - $10 million, 1999 - $6 million).

Note 6 Plan of Arrangement

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

As at December 31, 2001 there is no amount remaining in accounts payable and accrued liabilities for severance and other direct acquisition costs.

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

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

The following table represents the unaudited pro forma results of the Company as though the acquisition had occurred on January 1, 1999:

	2000	1999
Sales and operating revenues, net of royalties	$ 5,930	$ 3,693
Net earnings	$ 766	$ 207
Earnings per share - Basic and Diluted	$ 1.80	$ 0.46

Note 7 Cash Flows

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

	2001	2000	1999
Decrease (increase) in non-cash working capital			
Accounts receivable	**$ 361**	$ (254)	$ (156)
Inventories	**(40)**	(38)	(53)
Prepaid expenses	**3**	2	2
Accounts payable and accrued liabilities	**(280)**	310	191
Change in non-cash working capital	**44**	20	(16)
Relating to:			
Financing activities	**42**	102	18
Investing activities	**18**	108	(4)
Operating activities	**$ (16)**	$ (190)	$ (30)

b) Other cash flow information:

	2001	2000	1999
Cash taxes paid	**$ 13**	$ 9	$ 1
Cash interest paid	**$ 145**	$ 138	$ 80

Note 8 Bank Operating Loans

At December 31, 2001 the Company had short-term borrowing lines of credit with banks totalling $195 million (2000 - $234 million, 1999 - $125 million), of which $102 million (2000 - $84 million, 1999 - $42 million) had been used for bank operating loans and letters of credit. Interest payable is based on Bankers' Acceptance, money market, or prime rates. During 2001, the weighted average interest rate on short-term borrowings was approximately 4.6 percent.

Note 9 Long-term Debt

		Maturity	2001	2000	1999
Long-term debt					
Revolving syndicated credit facility			**$ –**	$ –	$ 100
	- U.S. $116	2006	**185**	174	
Non-revolving syndicated credit facility				300	
6.875% notes	*- U.S. $150*	2003	**239**	225	216
7.125% notes	*- U.S. $150*	2006	**239**	225	217
7.550% debentures	*- U.S. $200*	2016	**318**	300	289
10.6% notes	*- U.S. $116*	2089			168
8.45% senior secured bonds	*- 1999 U.S. $250; 2000 U.S. $179; 2001 U.S. $173*	2002-12	**276**	268	361
Private placement notes	*- 2000 U.S. $101; 2001 U.S. $85*	2003-5	**135**	152	
Medium-term notes		2002-9	**700**	700	
Total long-term debt			**2,092**	2,344	1,351
Amount due within one year			**(144)**	(33)	(2)
			$ 1,948	$ 2,311	$ 1,349

As at December 31, 2001, other assets include deferred foreign exchange losses of $133 million (2000 - $73 million, 1999 - $39 million) on the translation of the U.S. dollar based long-term debt and $17 million (2000 - $20 million, 1999 - $25 million) of deferred debt issue costs.

The revolving syndicated credit facility allows the Company to borrow up to $1 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a one year committed revolving credit facility, extendible annually. In the event that the lenders do not consent to such extension, the revolving credit facility will convert to a four year non-revolving amortizing term loan. Interest rates vary based on Canadian prime, Bankers' Acceptance, U.S. Libor or U.S. base rate, depending on the borrowing option selected, credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt and whether the Company borrows under the revolving or non-revolving condition.

The 6.875 percent notes, the 7.125 percent notes and the 7.550 percent debentures represent unsecured securities issued under a trust indenture dated October 31, 1996. Such securities mature in 2003, 2006 and 2016, respectively. The 6.875 percent and 7.125 percent notes are not redeemable prior to maturity. The 7.550 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 10.6 percent obligation outstanding at December 31, 1999 represented unsecured notes due July 20, 2089. These notes were refinanced in July 2000 under the Company's syndicated credit facility.

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 have been 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. Principal and 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 12.5 percent of the oil field and associated facilities. The repayment of the securities is contracted to be made solely from revenue from the oil field. There is also a charge created by the partnership on its interest in the assets of the oil field and associated facilities in favour of the security holders. In addition, certain financial obligations require letters of credit or cash equivalents as collateral.

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

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

Issue	Amount	Interest Rate	Maturity Date
Series A	$ 100	5.90%	February 2002
Series B	100	6.85%	February 2007
Series C	100	5.75%	February 2003
Series D	200	6.30%	June 2004
Series E	200	6.95%	July 2009
	$ 700		

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 2002 - $144 million; 2003 - $424 million; 2004 - $272 million; 2005 - $134 million; and 2006 - $404 million. The maturities of the amounts outstanding under the syndicated credit facility are presented based on the Company's ability to refinance those amounts with the undrawn portion of the facility.

Interest - net for the years ended December 31 consists of:

	2001	2000	1999
Long-term debt	**$ 148**	$ 144	$ 97
Short-term debt	**5**	4	3
	153	148	100
Amount capitalized	**(51)**	(43)	(32)
Amount charged to expense	**102**	105	68
Interest income	**(1)**	(4)	(6)
	$ 101	$ 101	$ 62

Note 10 Income Taxes

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

	2001	2000	1999
Earnings before taxes	**$ 1,134**	$ 835	$ 94
Statutory income tax rate	**43.7%**	44.7%	44.7%
Expected income tax	**496**	373	42
Effect on income tax of:			
Change in statutory tax rate	**(52)**		
Ownership charges		15	20
Return on capital securities	**(14)**	(13)	(13)
Royalties, lease rentals and mineral taxes payable to the crown	**184**	141	40
Resource allowance on Canadian production income	**(219)**	(175)	(57)
Non-deductible capital taxes	**20**	12	5
Other - net	**4**	5	1
	$ 419	$ 358	$ 38
Charged (credited) to:			
Income tax expense	**$ 433**	$ 371	$ 51
Retained earnings	**(14)**	(13)	(13)
	$ 419	$ 358	$ 38

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

	2001	2000	1999
Future tax liabilities			
Property, plant and equipment	**$ 1,882**	$ 1,467	$ 976
Other temporary differences	**7**	2	2
	1,889	1,469	978
Future tax assets			
Loss carryforwards	**28**	103	40
Foreign exchange losses (gains) deductible on realization	**(10)**	(12)	17
Site restoration and other deferred credits	**93**	81	47
Provincial royalty rebates	**46**	45	45
Other temporary differences	**37**	21	4
	194	238	153
Future income taxes	**$ 1,695**	$ 1,231	$ 825

Note 11 Shareholders' Investment Prior to Restructuring

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

	Class A Preferred	Subordinated Shareholders' Loans	Class C Preferred	Total Due to Shareholders	Class B Preferred	Husky Energy Common
Balance January 1, 1999	$ 359	$ 807	$ 460	$ 1,626	$ 200	$ –
Subordinated shareholders' loan interest [1]			67	67		
Class C share dividends			44	44		
Interest capitalized to principal		6		6		
Balance December 31, 1999	359	813	571	1,743	200	–
Subordinated shareholders' loan interest [1]			44	44		
Class C share dividends			34	34		
Interest capitalized to principal		4		4		
Redeemed for assets	(209)			(209)	(10)	
Exchanged for Husky Energy common shares	(150)			(150)	(190)	340
Conversion of subordinated shareholders' loans		(817)	817	–		
Reduction of stated capital			(160)	(160)		
Cancelled on amalgamation			(1,306)	(1,306)		1,306
Paid in capital						8
Balance December 31, 2000	$ –	$ –	$ –	$ –	$ –	$ 1,654

[1] *Reflects the capitalization of interest on the subordinated shareholders' loans to Class C preferred shares.*

Note 12 Share Capital

The Company's authorized share capital is as follows:

Common shares – an unlimited number of no par value.

Preferred shares – an unlimited number of no par value.

Changes to issued share capital are as follows:

Common Shares

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

Preferred Shares

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

Stock Options

The following options to purchase common shares have been awarded to directors, officers and certain other employees. At December 31, 2001, 30.0 million common shares were reserved for issuance under the Company stock option plan. The exercise price of the option is equal to the average market price of the Company's common shares during the five trading days prior to the date of the award. Under the stock option plan the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year.

	Number of Shares *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Options Exercisable *(thousands)*
January 1, 2000	–	$ –	–	–
Granted	8,995	$ 13.61	5	
Assumed on Renaissance acquisition	1,372	$ 15.77	2	
Cancelled	(606)	$ 13.61	5	
December 31, 2000	9,761	$ 13.91	4	1,372
Granted	664	$ 15.60	4	
Exercised	(656)	$ 13.99	3	
Cancelled	(1,167)	$ 15.81	2	
December 31, 2001	**8,602**	**$ 13.78**	**4**	**2,853**

In 2000, the Company granted 1.4 million Renaissance replacement options to purchase common shares of Husky in exchange for certain share purchase options to purchase common shares of Renaissance previously held by employees of Renaissance. The former shareholders of Husky Oil Limited were also granted warrants to acquire, for no additional consideration, 1.86 common shares of the Company for each common share issued on the exercise of a Renaissance replacement option. The warrants are exercisable only if and when the Renaissance replacement options are exercised and provide for the issue of a maximum of 2.5 million common shares. As at December 31, 2001, there were 1.2 million common shares remaining which could potentially be issued as a result of the exercise of these warrants. Note 17 includes U.S. GAAP stock option disclosures.

Per Share Amounts

The calculation of basic net earnings and cash flow from operations per common share is based on the weighted average number of common shares outstanding of 416.1 million, 321.2 million and 270.3 million for the years ended December 31, 2001, 2000 and 1999, respectively, and net earnings and cash flow from operations after deducting return on capital securities, net of applicable income taxes.

Diluted net earnings and cash flow from operations per common share were calculated using 418.6 million, 321.2 million and 270.3 million shares for the years ended December 31, 2001, 2000 and 1999, respectively, which included the dilutive impact of options and warrants outstanding under the employee stock option plan calculated using the "treasury stock method".

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

During 2001 the Company declared dividends of $0.36 per common share.

Note 13 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, have been classified as equity. The return amounts, net of income taxes, are classified as distributions of equity.

The amount disclosed as capital securities in shareholders' equity at December 31 consists of the following:

	2001	2000	1999
Capital securities - *U.S. $225,000*	**$ 358**	$ 338	$ 325
Unamortized foreign exchange	**(16)**	3	16
Unamortized costs of issue	**(4)**	(5)	(5)
Accrued return	**12**	11	11
	$ 350	$ 347	$ 347

Note 14 Pension Plans and Other Post-Retirement Benefits

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

The accrued benefit liability at December 31, 2001 was comprised of $4 million for pension obligations and $16 million for future medical and dental coverage.

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

	2001	2000	1999
Discount rate	**7.3%**	7.3%	8.0%
Long term rate of increase in compensation levels	**5.0%**	5.0%	5.0%
Long term rate of return on plan assets	**8.0%**	8.0%	8.0%

The status of the benefit plans and accrued benefit liability at December 31 are as follows:

	2001	2000	1999
Plan assets at fair market value, principally marketable debt and equity securities and cash equivalents	**$ 85**	$ 90	$ 83
Projected benefit obligation	**(111)**	(106)	(79)
Excess assets (excess obligation)	**(26)**	(16)	4
Unrecognized gains (losses)	**6**	(2)	(7)
Accrued benefit liability	**$ (20)**	$ (18)	$ (3)

Note 15 Commitments and Contingencies

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

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

The Company 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 favor, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

Note 16 Financial Instruments and Risk Management

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

Carrying Values and Estimated Fair Values of Financial Instruments

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

Assets (Liabilities)	2001		2000	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	**$ (2,092)**	**$ (2,143)**	$ (2,344)	$ (2,348)
Foreign exchange contracts	**–**	**(29)**	–	(5)
Interest rate swaps	**–**	**4**	–	5
Natural gas contracts	**–**	**15**	–	5
Crude oil contracts	**–**	**–**	–	–
Fixed physical sales contracts	**–**	**114**	–	–
Fixed physical purchase contracts	**–**	**(88)**	–	–

Upstream Commodity Price Risk

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

At December 31, 2001 the Company had hedged 7.5 mmcf of natural gas per day at NYMEX for the years 2002-2005 at an average price of U.S. $1.92 per mcf.

During 2001 the impact was insignificant (2000 - loss of $150 million, 1999 - loss of $69 million) from upstream hedges.

Commodity Marketing Activities

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

In addition, the Company has a portfolio of fixed price offsetting physical forward purchase and sale natural gas contracts. The objective of these contracts is to "lock in" a positive spread between the physical purchase and sales contract prices. At December 31, 2001 the Company had entered into offsetting fixed price physical arrangements to concurrently sell and purchase natural gas for 49 mmcf per day for 2002 through October of 2003 to receive an average fixed margin of $0.18 per mcf. In addition, the Company had entered into fixed price physical forward sales with respect to natural gas inventory held in storage for 51 mmcf per day through October 2002 to receive an average fixed margin of $0.74 per mcf.

At December 31, 2001 the Company had also entered into a number of arrangements, consistent with the strategies described above, the impact of which is insignificant to the Company's operations.

Foreign Currency Rate Risk

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

At December 31, 2001 the Company had hedged the exchange rate on U.S. dollars through currency collars for U.S. $24 million per month at an average floor exchange rate of 1.49 and an average ceiling exchange rate of 1.54 for varying periods up to 2003. The counterparties to the collars have options to extend the arrangements for varying periods into 2003 and 2004.

During 2001 the Company realized a loss of $4 million (2000 - loss of $5 million, 1999 - loss of $8 million) from foreign currency risk management activities.

Interest Rate Risk

The majority of the Company's long-term debt has fixed interest rates and various maturities. The Company periodically uses interest rate swaps to manage its financing costs. At December 31, 2001 the Company had swapped U.S. $35 million of fixed interest rate bearing debt to a floating rate exposure at an average of LIBOR - 0.13 percent to the year 2003.

During 2001 the Company realized a gain of $2 million (2000 - gain of $1 million, 1999 - gain of $2 million) from interest rate 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 nonperformance by counterparties to its financial instruments. The Company primarily deals with major financial institutions and investment grade rated entities to mitigate these risks.

Sale of Accounts Receivable

The Company has an agreement to sell trade receivables up to $220 million on a continual basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates to be paid on an ongoing basis. The average effective rate for 2001 was approximately 4.7 percent (2000 - 6.0 percent, 1999 - 5.3 percent). The Company has potential exposure to an immaterial amount of credit loss under this agreement.

Note 17 Reconciliation to Accounting Principles Generally Accepted in the United States

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada, which differ in some respects to 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	2001	2000	1999
Net earnings	**$ 701**	$ 464	$ 43
Adjustments			
Full cost accounting [a]	**(544)**	26	22
Related income taxes	**235**	(12)	(10)
Foreign currency translation [b]	**(80)**	(51)	103
Related income taxes	**18**	17	(35)
Post retirement benefits [c]		(4)	(1)
Related income taxes		2	
Return on capital securities [d]	**(33)**	(30)	(29)
Related income taxes	**14**	13	13
Gain on energy trading contracts [e]	**20**		
Related income taxes	**(8)**		
Derivatives and hedging [e]	**(20)**		
Related income taxes	**8**		
Accounting for income taxes [f]	**(6)**	6	13
Net earnings under U.S. GAAP	**$ 305**	$ 431	$ 119
Earnings before taxes	**$ 477**	$ 776	$ 189
Net earnings per share under U.S. GAAP - Basic	**$ 0.73**	$ 1.34	$ 0.44
- Diluted	**$ 0.73**	$ 1.30	$ 0.44

Condensed Consolidated Balance Sheets	2001		2000		1999	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets [e]	**$ 626**	**$ 756**	$ 928	$ 928	$ 463	$ 463
Property, plant and equipment, net [a]	**8,715**	**7,950**	7,841	7,620	4,189	3,942
Other assets [b]	**162**	**33**	133	76	163	133
	$ 9,503	**$ 8,739**	$ 8,902	$ 8,624	$ 4,815	$ 4,538
Current liabilities [c] [e]	**$ 1,065**	**$ 1,203**	$ 1,143	$ 1,165	$ 551	$ 562
Long-term debt [d]	**1,948**	**2,306**	2,311	2,649	1,349	1,674
Site restoration provision	**212**	**212**	178	178	95	103
Future income taxes [a] [b] [c] [e] [f]	**1,695**	**1,373**	1,231	1,154	825	757
Due to shareholders					1,743	1,743
Capital securities and accrued return [d]	**350**		347		347	
Share capital and contributed surplus [g] [h]	**3,397**	**3,631**	3,388	3,622	200	274
Accumulated other comprehensive income [e]		**3**				
Retained earnings (deficit)	**836**	**11**	304	(144)	(295)	(575)
	$ 9,503	**$ 8,739**	$ 8,902	$ 8,624	$ 4,815	$ 4,538

Condensed Consolidated Statements of Retained Earnings (Deficit) and Comprehensive Income						
	2001		2000		1999	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Retained earnings (deficit), beginning of year	**$ 304**	**$ (144)**	$ (295)	$ (575)	$ (322)	$ (693)
Net earnings for the period	**701**	**305**	464	431	43	119
Dividends on common shares & other	**(150)**	**(150)**	152			(1)
Capital securities, net of tax [d]	**(19)**		(17)		(16)	
Retained earnings (deficit), end of year	**$ 836**	**$ 11**	$ 304	$ (144)	$ (295)	$ (575)
Other comprehensive income - cumulative effect of change in accounting - net of tax [e]	**$ –**	**$ (10)**	$ –	$ –	$ –	$ –
Cash flow hedges - net of tax [e]		**13**				
Accumulated other comprehensive income [e]	**$ –**	**$ 3**	$ –	$ –	$ –	$ –

Condensed Consolidated Statements of Earnings						
	2001		2000		1999	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Sales and operating revenues [e] [i]	**$ 6,627**	**$ 6,889**	$ 5,090	$ 5,249	$ 2,794	$ 2,886
Costs and expenses [b] [d] [i]	**4,585**	**4,937**	3,591	3,805	2,228	2,218
Depletion, depreciation and amortization [a]	**807**	**1,352**	481	455	293	271
Interest, net [d]	**101**	**134**	101	131	62	91
Ownership charges			82	82	117	117
Income taxes [a] [b] [c] [d] [e] [f]	**433**	**167**	371	345	51	70
Net earnings, before cumulative effect of change in accounting	**701**	**299**	464	431	43	119
Change in accounting - net of tax		**6**				
Net earnings	**$ 701**	**$ 305**	$ 464	$ 431	$ 43	$ 119

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

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

(b) The Company has deferred unrealized gains and losses on translation of foreign denominated long-term monetary items which are amortized over the remaining lives of the items. Under U.S. GAAP, gains or losses on translation of foreign denominated long-term monetary items, including those on capital securities, are credited or charged to earnings immediately.

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

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

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

At December 31, 2001, the Company recorded additional assets and liabilities for U.S. GAAP purposes of $22.4 million and $37.5 million respectively for the fair values of derivative financial instruments. During 2001, a charge of $17.7 million, net of tax, was included in income for U.S. GAAP purposes for unrealized losses on foreign currency derivatives and natural gas basis swaps that did not qualify for hedge accounting under FAS 133. The Company also recorded a net gain of $0.6 million, net of tax, in revenue for U.S. GAAP purposes with respect to derivatives designated as hedges of change in the fair value of certain fixed price commodity contracts and offsetting changes in the fair value of those contracts. In addition, the amount included in other comprehensive income was adjusted by a $13.5 million loss, net of tax for changes in the fair values of the derivatives designated as hedges of cash flows relating to commodity price risk and the transfer to income of amounts applicable to cash flows occurring in 2001.

Under U.S. GAAP, contracts resulting from energy trading activities are required to be recorded at fair value. These contracts may include derivatives and contracts that would not meet the definition of derivatives. Under Canadian GAAP, the impact of these contracts is recorded as they settle on a monthly basis. Under U.S. GAAP, at December 31, 2001, the Company has recorded additional assets of $114.1 million, liabilities of $88.4 million and a reduction to inventory of $5.9 million and included the resulting unrealized gains in earnings.

(f) The Company adopted the liability method of accounting for income taxes in 1999. The Canadian GAAP liability method requires the measurement of future income tax liabilities and assets using income tax rates that reflect enacted income tax rate reductions provided it is more likely than not that the Company will be eligible for such rate reductions in the period of reversal. U.S. GAAP allows recording of such rate reductions only when claimed.

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

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

(i) Under U.S. GAAP, transportation costs are included in cost of sales rather than netted off of sales revenues. Transportation costs for 2001 were $272 million (2000 - $159 million, 1999 - $92 million).

Additional U.S. GAAP Disclosures

FAS 133

Effective January 1, 2001, the Company adopted the provisions of FAS 133, which requires 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 income 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 2001, no amount of the gains or losses on these derivatives were 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 each period. All amounts included in other comprehensive income at December 31, 2001 relate to the hedge of commodity price risk. During 2001, 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 the 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 ("APB 25"). Since all options were granted with exercise prices equal to the market price when the options were granted, no compensation expense has been charged to income at the time of the option grants. Had compensation cost for the 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 income and net income per share for years ended December 31, 2001 and 2000 would have been the pro forma amounts indicated below:

	2001		2000	
	As Reported	Pro Forma	As Reported	Pro Forma
Net earnings	**$ 305**	**$ 294**	$ 431	$ 427
Net earnings per common share - Basic	**$ 0.73**	**$ 0.71**	$ 1.34	$ 1.33
- Diluted	**$ 0.73**	**$ 0.71**	$ 1.30	$ 1.28

The weighted average fair market value of options granted in 2001 was $5.70 (2000 - $5.03) per option. The fair value of each option granted was estimated on the date of grant using the Modified Black-Scholes option-pricing model with the following assumptions: risk-free interest rate of 3.5 percent (2000 - 5.5 percent), volatility of 45 percent (2000 - 30 percent), expected life of five years (2000 - five years) and expected dividend of $0.36 per common share.

Depletion, depreciation and amortization

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

	2001	2000	1999
Depletion, depreciation and amortization per boe [1]	**$ 6.88**	$ 5.88	$ 5.02

[1] *Excluding the 2001 ceiling test write down.*

Future Removal and Site Restoration

In June 2001, the FASB issued Statement No. 143 "Accounting for Asset Retirement Obligations" ("FAS 143"), which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and use of the asset. Statement No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset. The liability is accreted at the end of each period through charges to operating expenses. The Company is required and plans to adopt the provisions of FAS 143 for the quarter ending March 31, 2003. The Company has not yet estimated the impact of adopting this standard.

Impairment or Disposal of Long-term Assets

In August 2001, the FASB issued Statement No. 144 "Accounting for the Impairment or Disposal of Long-term Assets" ("FAS 144"), which addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. FAS 144 supercedes but retains the basic principles of Statement No. 121 for the impairment of assets to be held and used. Assets to be disposed of through abandonment or an exchange for similar productive assets will be classified as held for use until they cease to be used. FAS 144 establishes criteria that must be met in order to classify an asset or group as held for sale. Assets classified as held for sale will be measured at the lower of their carrying amount or fair value less cost to sell, and depreciation will cease when the asset or group is classified as held for sale. FAS 144 broadens the definition of disposals to be presented as discontinued operations to include components of an entity that comprise operating and cash flows that clearly can be distinguished, operationally and financial reporting purposes from the rest of the entity. The Company will be required to adopt the provisions of FAS 144 on a prospective basis for the period beginning January 1, 2002 which will not result in the restatement of income for 2001 or prior periods. The Company can not yet estimate the impact of adopting this standard for 2002.

Note 18 Supplemental Information - Oil and Gas Producing Activities (unaudited)

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

Oil and Gas Reserves

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

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

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

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

Subsequent to December 31, 2001 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:

	Canada [1]			International [1]			Total [1]		
	2001	2000	1999	**2001**	2000	1999	**2001**	2000	1999
Revenue									
Sales	**$ 1,802**	$ 1,182	$ 349	**$ 4**	$ 4	$ 4	**$ 1,806**	$ 1,186	$ 353
Transfers	**390**	387	249				**390**	387	249
	2,192	1,569	598	**4**	4	4	**2,196**	1,573	602
Deduct									
Production costs	**648**	369	202		1	2	**648**	370	204
Depletion, depreciation and amortization	**721**	398	212	**7**	9	11	**728**	407	223
Income taxes	**334**	326	65	**(1)**	(3)	(4)	**333**	323	61
	1,703	1,093	479	**6**	7	9	**1,709**	1,100	488
Results of operations from producing activities	**$ 489**	$ 476	$ 119	**$ (2)**	$ (3)	$ (5)	**$ 487**	$ 473	$ 114
Depletion, depreciation and amortization rates per gross equivalent barrel	**$ 7.24**	$ 6.15	$ 5.29	**$ 80.61**	$ 90.39	$ 86.14	**$ 7.31**	$ 6.28	$ 5.56

[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 are as follows:

		2001	2000	1999
Property acquisition costs [1] [2] [3]				
Proved	- Canada	**$ 366**	$ 3,200	$ 18
Unproved	- Canada	**55**	355	43
		421	3,555	61
Exploration Costs	- Canada	**262**	159	186
	- Libya			5
	- Other	**5**	3	1
		267	162	192
Development Costs	- Canada	**774**	412	300
	- China	**99**	85	17
		873	497	317
		$ 1,561	$ 4,214	$ 570

[1] *Property acquisition costs in 2001 include $244 million for proved properties related to corporate acquisitions.*

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

[3] *Property acquisition costs in 2000 exclude $135 million for proved properties and $19 million for unproved properties related to property exchanges.*

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

		Total	2001	2000	1999	Prior to 1999
Property acquisition	- Canada	$ 436	**$ 17**	$ 304	$ 41	$ 74
	- International	14				14
		450	**17**	304	41	88
Exploration	- Canada	294	**80**	48	80	86
Development	- Canada	376	**83**	103	112	78
	- International	221	**102**	85	17	17
		597	**185**	188	129	95
Capitalized interest	- Canada	120	**51**	43	21	5
		$ 1,461	**$ 333**	$ 583	$ 271	$ 274

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 consist of:

		2001	2000	1999
Unproved oil and gas properties	- Canada [1]	**$ 1,052**	$ 951	$ 646
	- International	**235**	137	58
		1,287	1,088	704
Proved oil and gas properties	- Canada [1]	**9,301**	8,072	4,270
	- International	**159**	153	146
		9,460	8,225	4,416
		10,747	9,313	5,120
Less accumulated depletion, depreciation and amortization	- Canada	**3,271**	2,622	2,271
	- International	**147**	139	130
		3,418	2,761	2,401
		$ 7,329	$ 6,552	$ 2,719
Net capitalized costs	- Canada	**$ 7,082**	$ 6,401	$ 2,646
	- International	**247**	151	73
		$ 7,329	$ 6,552	$ 2,719

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

Oil and Gas Reserve Information

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

	Canada			International		Total		
	Crude Oil and Natural Gas Liquids	Natural Gas	Sulphur	Crude Oil and Natural Gas Liquids	Natural Gas	Crude Oil and Natural Gas Liquids	Natural Gas	Sulphur
	(mmbbls)	*(bcf)*	*(mmlt)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(bcf)*	*(mmlt)*
Net proved developed and undeveloped reserves, after royalties [1] [2] [3] [4]								
End of year 1998	**220.1**	**798.2**	**4.8**	**7.1**	**139.3**	**227.2**	**937.5**	**4.8**
Revision of previous estimates	1.0	23.0	0.6	(1.1)	(28.8)	(0.1)	(5.8)	0.6
Purchase of reserves in place	1.1					1.1		
Sale of reserves in place		(3.1)					(3.1)	
Discoveries and extensions	12.0	23.9				12.0	23.9	
Production	(22.1)	(70.3)	(0.4)	(0.1)		(22.2)	(70.3)	(0.4)
End of year 1999	**212.1**	**771.7**	**5.0**	**5.9**	**110.5**	**218.0**	**882.2**	**5.0**
Revision of previous estimates	12.9	(59.1)		(0.1)	(0.4)	12.8	(59.5)	
Purchase of reserves in place	215.6	789.0				215.6	789.0	
Discoveries and extensions	41.5	35.4		29.4		70.9	35.4	
Production	(36.6)	(102.4)	(0.3)	(0.1)		(36.7)	(102.4)	(0.3)
End of year 2000	**445.5**	**1,434.6**	**4.7**	**35.1**	**110.1**	**480.6**	**1,544.7**	**4.7**
Revision of previous estimates	37.0	74.0	0.1	0.7	5.1	37.7	79.1	0.1
Purchase of reserves in place	33.6	20.4				33.6	20.4	
Sale of reserves in place	(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**
Net proved developed reserves, after royalties [1] [2] [3] [4]								
End of year 1998	175.8	672.5	4.5	0.8		176.6	672.5	4.5
End of year 1999	161.8	669.3	4.8	0.6		162.4	669.3	4.8
End of year 2000	345.2	1,275.5	4.5	0.5		345.7	1,275.5	4.5
End of year 2001	**378.1**	**1,342.2**	**4.6**	**0.6**		**378.7**	**1,342.2**	**4.6**

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

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

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

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

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

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

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

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

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2001 was based on the Company's average natural gas price of $2.87/mcf and on crude oil prices computed with reference to an average West Texas Intermediate price of U.S. $19.78/bbl. The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2000 was based on the Company's average natural gas price of $8.65/mcf and on crude prices computed with reference to an average West Texas Intermediate price of U.S. $28.40/bbl. The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 1999 was based on the Company's average natural gas price of $2.22/mcf and on crude oil prices computed with reference to an average West Texas Intermediate price of U.S. $26.09/bbl.

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

	Canada			International			Total		
	2001	2000	1999	**2001**	2000	1999	**2001**	2000	1999
Future cash inflows	**$ 14,102**	$ 23,701	$ 7,638	**$ 1,600**	$ 1,787	$ 754	**$ 15,702**	$ 25,488	$ 8,392
Future costs									
Future production and development costs	**7,541**	5,996	2,513	**523**	609	287	**8,064**	6,605	2,800
Future income taxes	**2,540**	7,384	2,120	**310**	402	183	**2,850**	7,786	2,303
Future net cash flows	**4,021**	10,321	3,005	**767**	776	284	**4,788**	11,097	3,289
Deduct: 10% annual discount factor	**1,667**	4,859	1,393	**329**	404	212	**1,996**	5,263	1,605
Standardized measure of discounted future net cash flows [1]	**$ 2,354**	$ 5,462	$ 1,612	**$ 438**	$ 372	$ 72	**$ 2,792**	$ 5,834	$ 1,684

Changes in Standardized Measure of Discounted Future 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.

	Canada			International			Total		
	2001	2000	1999	**2001**	2000	1999	**2001**	2000	1999
Future discounted net cash flows at beginning of year	**$ 5,462**	$ 1,612	$ 740	**$ 372**	$ 72	$ 21	**$ 5,834**	$ 1,684	$ 761
Sales and transfer, net of production costs	**(1,556)**	(1,204)	(397)	**(2)**	(3)	(2)	**(1,558)**	(1,207)	(399)
Net change in sales and transfer prices, net of development and production costs	**(5,843)**	2,159	1,710	**(48)**	18	43	**(5,891)**	2,177	1,753
Extensions, discoveries and improved recovery, net of related costs	**356**	460	151	**17**	410		**373**	870	151
Revisions of quantity estimates	**237**	46	22	**10**	(2)	(12)	**247**	44	10
Accretion of discount	**949**	279	125	**55**	13	2	**1,004**	292	127
Sale of reserves in place	**(6)**	(3)	(3)				**(6)**	(3)	(3)
Purchase of reserves in place	**174**	5,681	20				**174**	5,681	20
Changes in timing of future net cash flows and other	**95**	(717)	(88)	**10**	3	57	**105**	(714)	(31)
Net change in income taxes	**2,486**	(2,851)	(668)	**24**	(139)	(37)	**2,510**	(2,990)	(705)
End of year [1]	**$ 2,354**	$ 5,462	$ 1,612	**$ 438**	$ 372	$ 72	**$ 2,792**	$ 5,834	$ 1,684

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

Reserve Information

Reserve Reconciliation

	Canada				International			
	Western Canada			East Coast			Total	
	Light/Med. Crude Oil & NGL	Lloydminster Heavy Crude Oil	Natural Gas	Light Crude Oil	Light Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas
Proved Reserves, before royalties [1]	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(bcf)*
Proved reserves at Dec 31, 1997	144	77	939	12	8	143	241	1,082
Revision of previous estimate	1	13	64		(1)		13	64
Purchase of reserves in place		1	26				1	26
Sales of reserves in place	(1)		(14)				(1)	(14)
Discoveries and extensions	4	5	31	9			18	31
Production	(10)	(15)	(85)				(25)	(85)
Proved reserves at December 31, 1998	138	81	961	21	7	143	247	1,104
Revision of previous estimate	6	27	40	(21)			12	40
Purchase of reserves in place	2						2	–
Sales of reserves in place			(4)					(4)
Discoveries and extensions	2	12	28				14	28
Production	(10)	(15)	(91)				(25)	(91)
Proved reserves at December 31, 1999	138	105	934	–	7	143	250	1,077
Revision of previous estimate	7	8	(17)				15	(17)
Purchase of reserves in place (incl. Renaissance)	258	1	933				259	933
Sales of reserves in place								
Discoveries and extensions	10	20	47	11	32		73	47
Production	(23)	(20)	(131)				(43)	(131)
Proved reserves at December 31, 2000	390	114	1,766	11	39	143	554	1,909
Revision of previous estimate	2	28	24	2	1		33	24
Purchase of reserves in place	12	24	24				36	24
Sales of reserves in place	(2)		(22)				(2)	(22)
Discoveries and extensions	12	27	240	4			43	240
Production	(41)	(24)	(209)				(65)	(209)
Proved reserves at December 31, 2001	**373**	**169**	**1,823**	**17**	**40**	**143**	**599**	**1,966**
Proved developed reserves, before royalties [2]								
December 31, 1997	134	60	775	–	–	–	194	775
December 31, 1998	133	62	816	–	–	–	195	816
December 31, 1999	133	56	818	–	–	–	189	818
December 31, 2000	338	65	1,580	–	–	–	403	1,580
December 31, 2001	**322**	**96**	**1,577**	**6**	**1**	–	**425**	**1,577**
Probable reserves, before royalties [3]								
December 31, 1997	57	47	344	53	1	19	158	363
December 31, 1998	61	68	298	44	1	19	174	317
December 31, 1999	65	78	236	256	1	19	400	255
December 31, 2000	136	78	434	202	5	19	421	453
December 31, 2001	**132**	**81**	**406**	**213**	**5**	**19**	**431**	**425**

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

[2] *Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered through known accumulations where a significant expenditure is required.*

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

Quarterly Financial and Operating Summary

Highlights	2001				2000			
($ millions, except where indicated)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Sales and operating revenues, net of royalties	**$ 1,623**	**$ 1,478**	**$ 1,738**	**$ 1,788**	$ 1,769	$ 1,352	$ 1,018	$ 951
EBITDA	**$ 307**	**$ 500**	**$ 589**	**$ 646**	$ 636	$ 414	$ 231	$ 218
Net earnings	**$ 49**	**$ 156**	**$ 254**	**$ 242**	$ 232	$ 138	$ 55	$ 39
Net earnings per share								
- Basic	**$ 0.11**	**$ 0.36**	**$ 0.60**	**$ 0.57**	$ 0.54	$ 0.41	$ 0.19	$ 0.13
- Diluted	**$ 0.11**	**$ 0.36**	**$ 0.60**	**$ 0.57**	$ 0.54	$ 0.41	$ 0.19	$ 0.13
Cash flow from operations	**$ 287**	**$ 478**	**$ 561**	**$ 620**	$ 601	$ 388	$ 219	$ 191
Cash flow from operations per share								
- Basic	**$ 0.67**	**$ 1.13**	**$ 1.33**	**$ 1.47**	$ 1.42	$ 1.16	$ 0.78	$ 0.68
- Diluted	**$ 0.66**	**$ 1.12**	**$ 1.32**	**$ 1.46**	$ 1.42	$ 1.16	$ 0.78	$ 0.68
Share price								
- High	**$ 20.25**	**$ 20.95**	**$ 17.30**	**$ 15.80**	$ 15.10	$ 15.95	N/A	N/A
- Low	**$ 15.06**	**$ 14.65**	**$ 13.10**	**$ 13.20**	$ 11.50	$ 12.50	N/A	N/A
- Close (end of period)	**$ 16.47**	**$ 17.85**	**$ 16.22**	**$ 13.25**	$ 14.90	$ 13.95	N/A	N/A
Shares traded *(thousands)*	**59,251**	**46,993**	**25,333**	**25,280**	32,848	51,368	N/A	N/A
Number of weighted average common shares outstanding *(thousands)*								
- Basic	**416,545**	**416,025**	**415,878**	**415,805**	415,803	327,219	N/A	N/A
- Diluted	**419,367**	**419,153**	**418,337**	**417,555**	415,883	327,340	N/A	N/A

Segmented Financial Information	2001				2000			
($ millions)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Sales and operating revenues, net of royalties								
Upstream	**$ 375**	**$ 557**	**$ 585**	**$ 679**	$ 656	$ 438	$ 249	$ 230
Midstream								
Upgrader	**147**	**255**	**259**	**225**	296	287	186	237
Infrastructure and marketing	**1,153**	**796**	**839**	**1,592**	767	548	535	459
	1,300	**1,051**	**1,098**	**1,817**	1,063	835	721	696
Refined products	**274**	**429**	**345**	**301**	364	399	317	267
Intersegment eliminations [1]	**(326)**	**(559)**	**(290)**	**(1,009)**	(314)	(320)	(269)	(242)
	$ 1,623	**$ 1,478**	**$ 1,738**	**$ 1,788**	$ 1,769	$ 1,352	$ 1,018	$ 951
EBITDA								
Upstream	**$ 197**	**$ 386**	**$ 423**	**$ 542**	$ 502	$ 341	$ 187	$ 173
Midstream								
Upgrader	**66**	**41**	**83**	**59**	94	30	14	27
Infrastructure and marketing	**43**	**38**	**54**	**54**	34	27	21	29
Refined products	**26**	**60**	**51**	**18**	25	24	19	9
Corporate and eliminations [1] [2]	**(25)**	**(25)**	**(22)**	**(27)**	(19)	(8)	(10)	(20)
	$ 307	**$ 500**	**$ 589**	**$ 646**	$ 636	$ 414	$ 231	$ 218
Net earnings								
Upstream	**$ 4**	**$ 201**	**$ 247**	**$ 368**	$ 325	$ 239	$ 124	$ 108
Midstream								
Upgrader	**62**	**36**	**78**	**56**	90	25	11	23
Infrastructure and marketing	**39**	**33**	**50**	**50**	30	23	18	25
	101	**69**	**128**	**106**	120	48	29	48
Refined products	**17**	**53**	**44**	**10**	18	16	13	2
Operating profit [3]	**122**	**323**	**419**	**484**	463	303	166	158
Corporate and eliminations [1] [4]	**(73)**	**(167)**	**(165)**	**(242)**	(231)	(165)	(111)	(119)
	$ 49	**$ 156**	**$ 254**	**$ 242**	$ 232	$ 138	$ 55	$ 39
Cash flow from operations								
Upstream	**$ 197**	**$ 386**	**$ 423**	**$ 542**	$ 502	$ 341	$ 187	$ 173
Midstream								
Upgrader	**66**	**41**	**82**	**60**	94	30	14	27
Infrastructure and marketing	**43**	**38**	**54**	**54**	34	27	21	29
	109	**79**	**136**	**114**	128	57	35	56
Refined products	**26**	**60**	**52**	**17**	25	24	19	9
Corporate and eliminations [1] [5]	**(45)**	**(47)**	**(50)**	**(53)**	(54)	(34)	(22)	(47)
	$ 287	**$ 478**	**$ 561**	**$ 620**	$ 601	$ 388	$ 219	$ 191

[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] *Corporate includes corporate administrative costs, other income and expenses and foreign exchange.*

[3] *Operating profit is total revenue less operating expenses. Operating expenses exclude general corporate expense, foreign exchange, interest expense and income taxes.*

[4] *Corporate includes corporate administrative costs, depreciation of corporate assets, other income and expenses, interest, foreign exchange, income taxes and ownership charges.*

[5] *Corporate includes corporate administrative costs, other income and expenses, interest, foreign exchange – cash and current income taxes.*

Segmented Financial Information (continued)	2001				2000			
($ millions)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Capital expenditures [6]								
Upstream - Western Canada	**$ 264**	**$ 323**	**$ 186**	**$ 249**	$ 204	$ 84	$ 69	$ 62
- East Coast	**54**	**43**	**54**	**40**	42	51	57	44
- International	**35**	**21**	**18**	**30**	87	–	–	–
	353	**387**	**258**	**319**	333	135	126	106
Midstream - Upgrader	**37**	**5**	**3**	**2**	4	3	3	2
- Infrastructure and marketing	**22**	**6**	**5**	**25**	15	7	6	19
	59	**11**	**8**	**27**	19	10	9	21
Refined products	**12**	**7**	**5**	**5**	11	6	8	4
Corporate	**11**	**9**	**2**	**–**	2	2	8	3
	$ 435	**$ 414**	**$ 273**	**$ 351**	$ 365	$ 153	$ 151	$ 134
Depletion, depreciation and amortization								
Upstream	**$ 193**	**$ 185**	**$ 176**	**$ 174**	$ 177	$ 102	$ 63	$ 65
Midstream - Upgrading	**4**	**5**	**5**	**3**	4	5	3	4
- Infrastructure and marketing	**4**	**5**	**4**	**4**	4	4	3	4
	8	**10**	**9**	**7**	8	9	6	8
Refined products	**9**	**7**	**7**	**8**	7	8	6	7
Corporate	**4**	**3**	**4**	**3**	3	3	5	4
	$ 214	**$ 205**	**$ 196**	**$ 192**	$ 195	$ 122	$ 80	$ 84

[6] *Excludes corporate acquisitions.*

Upstream Operating Information	2001				2000			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Production, before royalties								
Light/medium crude oil & NGL *(mbbls/day)*	**111.3**	**112.7**	**108.6**	**115.5**	117.9	66.5	34.7	34.6
Lloydminster heavy crude oil *(mbbls/day)*	**75.0**	**69.1**	**60.3**	**56.9**	57.0	54.9	52.0	50.0
	186.3	**181.8**	**168.9**	**172.4**	174.9	121.4	86.7	84.6
Natural gas *(mmcf/day)*	**568.7**	**567.1**	**570.8**	**584.0**	575.0	373.7	224.1	256.7
Total production *(mboe/day)*	**281.1**	**276.3**	**264.0**	**269.7**	270.7	183.7	124.1	127.4
Average realized sales prices								
Light/medium crude oil & NGL *($/bbl)*	**$ 19.44**	**$ 31.74**	**$ 28.86**	**$ 28.72**	$ 30.84	$ 38.74	$ 33.41	$ 32.55
Lloydminster heavy crude oil *($/bbl)*	**$ 10.44**	**$ 23.65**	**$ 15.52**	**$ 13.81**	$ 11.46	$ 26.98	$ 24.14	$ 23.20
Natural gas *($/mcf)*	**$ 3.01**	**$ 3.25**	**$ 6.57**	**$ 9.05**	$ 7.38	$ 4.57	$ 3.37	$ 2.58
Operating costs *($/boe)*	**$ 6.84**	**$ 6.54**	**$ 6.51**	**$ 5.62**	$ 6.16	$ 5.66	$ 5.25	$ 4.80
Netbacks [1]								
Light, medium crude oil & NGL *($/bbl)*	**$ 7.43**	**$ 18.03**	**$ 17.01**	**$ 18.09**	$ 18.11	$ 24.32	$ 22.55	$ 21.37
Lloydminster heavy crude oil *($/bbl)*	**$ 3.29**	**$ 14.04**	**$ 6.08**	**$ 4.87**	$ 2.39	$ 16.49	$ 15.48	$ 14.78
Natural gas *($/mcf)*	**$ 1.74**	**$ 1.99**	**$ 4.28**	**$ 6.05**	$ 5.30	$ 3.10	$ 2.17	$ 1.59
Total *($/boe)*	**$ 7.34**	**$ 14.88**	**$ 17.62**	**$ 21.97**	$ 19.82	$ 19.91	$ 16.44	$ 14.59
Net wells drilled [2]								
Exploration — Oil	**8**	**8**	**15**	**45**	6	5	–	2
Exploration — Gas	**6**	**11**	**5**	**68**	14	5	–	1
Exploration — Dry	**4**	**2**	**3**	**25**	7	2	–	–
	18	**21**	**23**	**138**	27	12	–	3
Development — Oil	**116**	**195**	**129**	**102**	131	94	55	83
Development — Gas	**53**	**57**	**17**	**94**	55	8	6	1
Development — Dry	**11**	**23**	**7**	**22**	9	4	6	9
	180	**275**	**153**	**218**	195	106	67	93
	198	**296**	**176**	**356**	222	118	67	96
Success ratio *(percent)*	**92**	**92**	**95**	**87**	93	95	91	91

[1] *Netbacks are Husky's average realized price less royalties and operating costs on a per unit basis.*
[2] *Western Canada.*

Midstream Operating Information	2001				2000			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Synthetic crude oil sales *(mbbls/day)*	**49.7**	**66.5**	**65.6**	**56.2**	65.6	66.1	49.8	60.9
Upgrading differential *($/bbl)*	**$ 16.85**	**$ 13.18**	**$ 19.56**	**$ 21.61**	$ 24.35	$ 11.00	$ 9.21	$ 8.67
Pipeline throughput *(mbbls/day)*	**518**	**498**	**583**	**550**	543	508	498	483

Refined Products Operating Information	2001				2000			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Refined product sales volumes								
Light oil products *(million litres/day)*	**7.5**	**8.2**	**7.3**	**7.4**	7.5	7.7	7.5	7.0
Asphalt products *(mbbls/day)*	**19.9**	**29.9**	**20.6**	**15.0**	20.2	27.0	18.4	15.1
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	**25.8**	**26.1**	**20.5**	**22.2**	24.8	25.7	22.2	20.8
Prince George refinery *(mbbls/day)*	**10.2**	**8.8**	**10.7**	**10.9**	10.8	7.9	7.6	10.6
Refinery utilization *(percent)*	**103**	**100**	**89**	**95**	102	96	85	90

Five Year Financial and Operating Summary

Highlights						
($ millions, except where indicated)		**2001**	2000	1999	1998	1997
Sales and operating revenues		**$ 6,627**	$ 5,090	$ 2,794	$ 2,029	$ 2,288
EBITDA		**$ 2,042**	$ 1,499	$ 566	$ 502	$ 513
Net earnings		**$ 701**	$ 464	$ 43	$ 25	$ 72
Net earnings per share	- Basic	**$ 1.64**	$ 1.39	$ 0.10	$ 0.07	$ 0.27
	- Diluted	**$ 1.63**	$ 1.39	$ 0.10	$ 0.07	$ 0.27
Cash flow from operations		**$ 1,946**	$ 1,399	$ 517	$ 449	$ 453
Cash flow from operations per share	- Basic	**$ 4.60**	$ 4.26	$ 1.80	$ 1.61	$ 1.68
	- Diluted	**$ 4.57**	$ 4.26	$ 1.80	$ 1.61	$ 1.68
Debt to capital employed [1] *(percent)*		**32**	37	41	38	42
Debt to cash flow from operations [2] *(times)*		**1.1**	1.7	2.7	2.5	2.2
Return on average capital employed [1] *(percent)*		**11.5**	12.8	5.1	5.2	7.9
Return on equity [3] *(percent)*		**16.3**	20.1	8.3	8.2	13.2
Share Price	- High	**$ 20.95**	15.95	–	–	–
	- Low	**$ 13.10**	11.50	–	–	–
	- Close (end of period)	**$ 16.47**	14.90	–	–	–
Shares traded *(thousands)*		**156,857**	84,216	–	–	–
Number of weighted average common shares outstanding *(thousands)*	- Basic	**416,100**	415,803	–	–	–
	- Diluted	**418,640**	440,569	–	–	–

[1] *Capital employed is defined as the average of short and long-term debt and shareholders' equity (2000 is weighted).*
[2] *2000 is based on year-end Husky Energy Inc. Balance Sheet and Income Statement.*
[3] *Equity for purposes of this calculation has been weighted for 2000 and includes due to shareholders prior to August 25, 2000.*

Condensed Consolidated Balance Sheets	As at December 31,				
($ millions)	**2001**	2000	1999	1998	1997
Assets					
Current assets	**$ 626**	$ 928	$ 463	$ 258	$ 377
Property, plant and equipment, net	**8,715**	7,841	4,189	3,780	3,097
Other assets	**162**	133	163	156	117
	$ 9,503	$ 8,902	$ 4,815	$ 4,194	$ 3,591
Liabilities and Shareholders' Equity					
Current liabilities	**$ 1,065**	$ 1,143	$ 551	$ 360	$ 392
Long-term debt	**1,948**	2,311	1,349	1,099	1,011
Site restoration provision	**212**	178	95	91	78
Due to shareholders	**–**	–	1,743	1,626	1,519
Future income taxes	**1,695**	1,231	825	792	731
Capital securities and accrued return	**350**	347	347	348	–
Class B shares	**–**	–	200	200	200
Common shares	**3,397**	3,388	–	–	–
Retained earnings (deficit)	**836**	304	(295)	(322)	(340)
	$ 9,503	$ 8,902	$ 4,815	$ 4,194	$ 3,591

Segmented Financial Information					
($ millions)	**2001**	2000	1999	1998	1997
Sales and operating revenues, net of royalties					
Upstream	**$ 2,196**	$ 1,573	$ 602	$ 446	$ 579
Midstream - Upgrader	**886**	1,006	641	412	279
- Infrastructure and marketing	**4,380**	2,309	1,284	999	1,437
	5,266	3,315	1,925	1,411	1,716
Refined products	**1,349**	1,347	904	664	613
Intersegment eliminations [1]	**(2,184)**	(1,145)	(637)	(492)	(620)
	$ 6,627	$ 5,090	$ 2,794	$ 2,029	$ 2,288
EBITDA					
Upstream	**$ 1,548**	$ 1,203	$ 398	$ 252	$ 380
Midstream - Upgrader	**249**	165	65	77	60
- Infrastructure and marketing	**189**	111	90	81	67
	438	276	155	158	127
Refined products	**155**	77	75	84	53
Corporate and eliminations [1] [2]	**(99)**	(57)	(62)	8	(47)
	$ 2,042	$ 1,499	$ 566	$ 502	$ 513
Upstream	**$ 820**	$ 796	$ 175	$ 38	$ 175
Midstream - Upgrader	**232**	149	49	63	48
- Infrastructure and marketing	**172**	96	77	69	61
	404	245	126	132	109
Refined products	**124**	49	49	64	40
Operating profit [3]	**1,348**	1,090	350	234	324
Corporate and eliminations [1] [4]	**(647)**	(626)	(307)	(209)	(252)
	$ 701	$ 464	$ 43	$ 25	$ 72
Cash flow from operations					
Upstream	**$ 1,548**	$ 1,203	$ 398	$ 252	$ 380
Midstream - Upgrader	**249**	165	65	77	60
- Infrastructure and marketing	**189**	111	90	81	67
	438	276	155	158	127
Refined products	**155**	77	75	84	53
Corporate and eliminations [1] [5]	**(195)**	(157)	(111)	(45)	(107)
	$ 1,946	$ 1,399	$ 517	$ 449	$ 453

[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] *Corporate includes corporate administrative costs, other income and expenses and foreign exchange.*

[3] *Operating profit is total revenue less operating expenses. Operating expenses exclude general corporate expense, foreign exchange, interest expense and income taxes.*

[4] *Corporate includes corporate administrative costs, depreciation of corporate assets, other income and expenses, interest, foreign exchange, income taxes and ownership charges.*

[5] *Corporate includes corporate administrative costs, other income and expenses, interest, foreign exchange – cash and current income taxes.*

Segmented Financial Information (continued)					
($ millions)	**2001**	2000	1999	1998	1997
Capital expenditures [6]					
Upstream - Western Canada	**$ 1,022**	$ 419	$ 238	$ 233	$ 234
- East Coast	**191**	194	309	191	29
- International	**104**	87	23	15	11
	1,317	700	570	439	274
Midstream - Upgrader	**47**	12	15	283	6
- Infrastructure and marketing	**58**	47	79	68	140
	105	59	94	351	146
Refined products	**29**	29	34	27	23
Corporate	**22**	15	8	12	158
	$ 1,473	$ 803	$ 706	$ 829	$ 601
Depletion, depreciation and amortization					
Upstream	**$ 728**	$ 407	$ 223	$ 214	$ 205
Midstream - Upgrading	**17**	16	16	14	12
- Infrastructure and marketing	**17**	15	13	12	6
	34	31	29	26	18
Refined products	**31**	28	26	20	13
Corporate	**14**	15	15	13	7
	$ 807	$ 481	$ 293	$ 273	$ 243
Identifiable assets					
Upstream	**$ 7,328**	$ 6,552	$ 2,719	$ 2,355	$ 2,157
Midstream - Upgrader	**604**	575	580	586	317
- Infrastructure and marketing	**410**	362	338	290	233
	1,014	937	918	876	550
Refined products	**325**	326	328	320	161
Corporate [7]	**836**	1,087	850	643	723
	$ 9,503	$ 8,902	$ 4,815	$ 4,194	$ 3,591

[6] *Excludes corporate acquisitions.*

[7] *Corporate includes accounts receivable, inventories, prepaid expenses, other assets and corporate assets.*

Upstream Operating Information	2001	2000	1999	1998	1997
Production, before royalties					
Light/medium crude oil & NGL *(mbbls/day)*	**112.0**	63.6	26.5	27.6	27.6
Lloydminster heavy crude oil *(mbbls/day)*	**65.4**	53.5	42.1	42.0	41.9
	177.4	117.1	68.6	69.6	69.5
Natural gas *(mmcf/day)*	**572.6**	358.0	250.5	232.6	246.0
Total production *(mboe/day)*	**272.8**	176.8	110.4	108.4	110.6
Average realized sales prices					
Light/medium crude oil & NGL *($/bbl)*	**$ 27.19**	$ 33.42	$ 21.52	$ 16.07	$ 23.55
Lloydminster heavy crude oil *($/bbl)*	**$ 15.85**	$ 21.26	$ 16.00	$ 8.26	$ 14.16
Natural gas *($/mcf)*	**$ 5.47**	$ 5.16	$ 2.41	$ 2.17	$ 2.21
Operating costs *($/boe)*	**$ 6.39**	$ 5.64	$ 4.98	$ 4.68	$ 4.73
Netbacks [1]					
Light/medium crude oil & NGL *($/bbl)*	**$ 15.08**	$ 20.61	$ 13.71	$ 9.78	$ 15.51
Lloydminster heavy crude oil *($/bbl)*	**$ 7.13**	$ 12.11	$ 7.75	$ 1.61	$ 6.24
Natural gas *($/mcf)*	**$ 3.51**	$ 3.59	$ 1.54	$ 1.46	$ 1.50

[1] *Netbacks are Husky's average realized prices less royalties and operating costs on a per unit basis.*

Upstream Operating Information (continued)		2001		2000		1999		1998		1997	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled [1]											
Exploration	Oil	**78**	**76**	16	13	9	9	16	11	35	34
	Gas	**102**	**90**	30	20	13	5	9	7	3	2
	Dry	**36**	**34**	9	9	9	9	8	6	14	13
		216	**200**	55	42	31	23	33	24	52	49
Development	Oil	**594**	**542**	411	363	203	190	75	55	174	159
	Gas	**251**	**221**	92	70	42	23	22	7	9	3
	Dry	**68**	**63**	30	28	23	22	6	4	13	11
		913	**826**	533	461	268	235	103	66	196	173
		1,129	**1,026**	588	503	299	258	136	90	248	222
Success ratio *(percent)*		**91**	**91**	93	93	89	88	90	89	89	89

[1] *Western Canada.*

Undeveloped Land Holdings					
(thousands of acres - net)	**2001**	2000	1999	1998	1997
Canada					
Alberta	**5,373**	5,616	692	877	864
Saskatchewan	**1,921**	2,638	586	662	614
British Columbia	**141**	173	66	133	112
Manitoba	**75**	163			
Western Canada	**7,510**	8,590	1,344	1,672	1,590
NWT	**409**	409	417	474	473
East Coast	**1,471**	1,489	258	243	125
Total Canada	**9,390**	10,488	2,019	2,389	2,188
International	**697**	221	389	392	392
	10,087	10,709	2,408	2,781	2,580

Midstream Operating Information	**2001**	2000	1999	1998	1997
Synthetic crude oil sales *(mbbls/day)*	**59.5**	60.6	61.9	54.8	27.5
Upgrading differential *($/bbl)*	**$ 17.91**	$ 13.77	$ 6.49	$ 7.85	$ 8.54
Pipeline throughput *(mbbls/day)*	**537**	528	394	412	417

Refined Products Operating Information	**2001**	2000	1999	1998	1997
Refined product sales volume					
Light oil products *(million litres/day)*	**7.6**	7.4	7.6	6.0	4.5
Asphalt products *(mbbls/day)*	**21.4**	20.2	17.1	19.5	17.7
Refinery throughput					
Lloydminster refinery *(mbbls/day)*	**23.7**	23.4	17.9	21.9	21.5
Prince George refinery *(mbbls/day)*	**10.2**	9.2	10.2	9.9	10.3
Refinery utilization *(percent)*	**97**	93	80	91	91

Selected Ten Year Financial and Operating Summary

($ millions, except where indicated)	**2001**	2000	1999	1998	1997	1996	1995	1994	1993	1992
Sales and operating revenues, net of royalties	**$ 6,627**	$ 5,090	$ 2,794	$ 2,029	$ 2,288	$ 2,111	$ 1,783	$ 1,373	$ 1,138	$ 977
Net earnings	**$ 701**	$ 464	$ 43	$ 25	$ 72	$ 35	$ (22)	$ (6)	$ (238)	$ (351)
Cash flow from operations	**$ 1,946**	$ 1,399	$ 517	$ 449	$ 453	$ 378	$ 303	$ 242	$ 171	$ 183
Capital expenditures [1]	**$ 1,473**	$ 803	$ 706	$ 829	$ 601	$ 218	$ 155	$ 257	$ 315	$ 312
Total debt [2]	**$ 2,192**	$ 2,378	$ 1,382	$ 1,131	$ 1,014	$ 853	$ 1,474	$ 1,667	$ 1,570	$ 1,570
Debt to capital employed [3] *(percent)*	**32**	37	41	38	42	41	62	67	66	61
Debt to cash flow from operations [4] *(times)*	**1.1**	1.7	2.7	2.5	2.2	2.3	4.9	6.9	9.2	8.6
Reinvestment ratio [5] *(percent)*	**78**	57	134	199	132	46	44	62	117	118
Return on average capital employed [3] *(percent)*	**11.5**	12.8	5.1	5.2	7.9	6.1	3.6	2.5	(7.9)	(11.0)
Return on equity [6] *(percent)*	**16.3**	20.1	8.3	8.2	13.2	9.9	8.0	1.5	(25.5)	(26.8)
Upstream										
Production										
Light/medium crude oil & NGL *(mbbls/day)*	**112.0**	63.6	26.5	27.6	27.6	28.3	27.7	29.4	29.9	28.9
Lloydminster heavy crude oil *(mbbls/day)*	**65.4**	53.5	42.1	42.0	41.9	34.5	30.0	26.6	21.9	18.4
	177.4	117.1	68.6	69.6	69.5	62.8	57.7	56.0	51.8	47.3
Natural gas *(mmcf/day)*	**573**	358	251	233	246	268	286	248	246	252
Total production *(mboe/day)*	**272.8**	176.8	110.4	108.4	110.6	107.5	105.4	97.4	92.8	89.3
Total proved reserves, before royalties *(mmboe)*	**927**	872	430	431	421	432	416	401	408	472
Midstream										
Synthetic crude oil sales *(mbbls/day)*	**59.5**	60.6	61.9	54.8	27.5	26.8	26.6	18.8	11.3	0.6
Upgrading differential *($/bbl)*	**$ 17.91**	$ 13.77	$ 6.49	$ 7.85	$ 8.54	$ 5.94	$ 4.34	$ 4.18	$ 5.50	$ 5.22
Pipeline throughput *(mbbls/day)*	**537**	528	394	412	417	359	296	238	217	169
Refined products										
Light oil sales *(mbbls/day)*	**7.6**	7.4	7.6	6.0	4.5	4.2	3.9	3.2	2.9	2.5
Asphalt sales *(mbbls/day)*	**21.4**	20.2	17.1	19.5	17.7	15.1	13.5	13.1	10.8	9.9

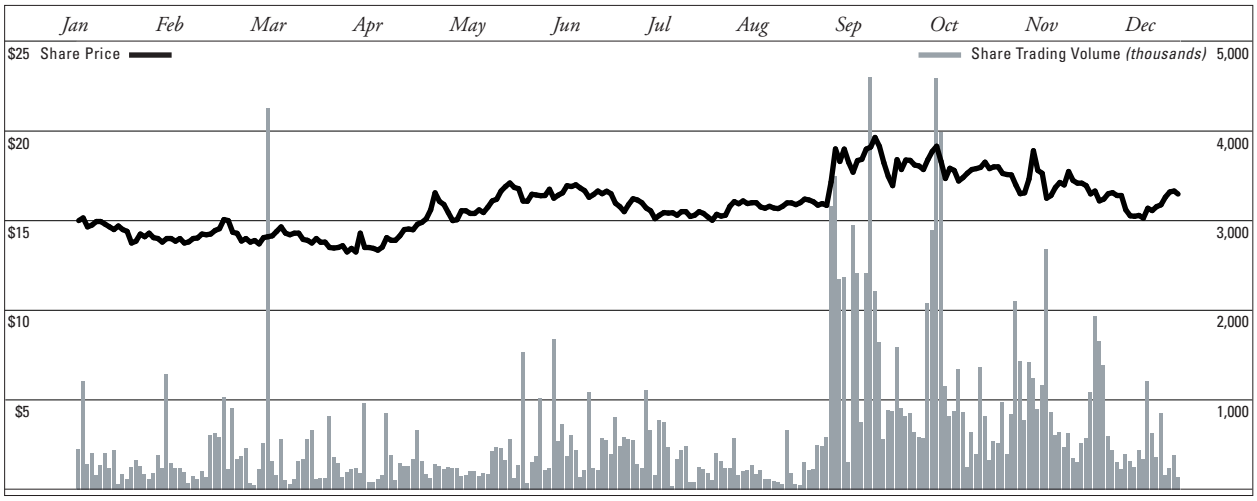
[1] *Excludes investment in other assets and corporate acquisitions.*
[2] *Year 1992 to 1995 total debt excludes asset in financial swap.*
[3] *Capital employed is defined as the average of short and long-term debt and shareholders' equity (2000 is weighted).*
[4] *2000 is based on year-end balance sheet and Husky Energy Inc income statement.*
[5] *Reinvestment ratio is based on capital expenditures including corporate acquisitions (other than Renaissance Energy Ltd.).*
[6] *Equity for purposes of this calculation has been weighted for 2000 and includes amounts due to shareholders prior to August 25, 2000.*

COMMON SHARE INFORMATION

Year ended December 31		**2001**	2000
Share Price	High	**$ 20.95**	$ 15.95
	Low	**$ 13.10**	$ 11.50
	Close at December 31	**$ 16.47**	$ 14.90
Average daily trading volumes *(thousands)*		**625**	979
Number of common shares outstanding, December 31 *(thousands)*		**416,878**	415,803

(1) *Trading in Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. HSE is included in the S&P Global 1200, TSE 300 Composite, S&P/TSE 60, TSE 100 and Toronto 35 indices, and is represented in the integrated oil subgroup in the TSE 300 Composite.*

2001 Share Trading



Terms and Abbreviations

bbls	barrels
mbbls	thousand barrels
mbbls/day	thousand barrels per day
mmbbls	million barrels
mcf	thousand cubic feet
mmcf	million cubic feet
mmcf/day	million cubic feet per day
bcf	billion cubic feet
tcf	trillion cubic feet
boe	barrels of oil equivalent
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per day
mmboe	million barrels of oil equivalent
mcfe	thousand cubic feet of gas equivalent
GJ	gigajoule
mmbtu	million British Thermal Units
mmlt	million long tons
hectare	1 hectare is equal to 2.47 acres

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
EBIT	Earnings from operations before interest and income taxes (operating profit)
EBITDA	Earnings from operations before interest, income taxes and depletion, depreciation and amortization
Equity	Amounts due to shareholders, capital securities and accrued return, shares and retained earnings
Free Cash Flow	Cash flow from operations less capitalized administration and capitalized interest
Total Debt	Long-term debt including current portion and short-term debt

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.

Officers/Executives Husky Energy Inc.

John C. S. Lau
President & CEO

Mr. John C. S. Lau was appointed Chief Executive Officer of Husky in 1993. Mr. Lau is also a member of Husky Energy's Board of Directors. Prior to joining Husky, Mr. Lau served in a number of senior executive roles within the Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies. Mr. Lau holds a Bachelor of Economics degree (BEc) and a Bachelor of Commerce degree (BComm), and is a Fellow member of the Institute of Chartered Accountants in Australia.

James D. Girgulis
Vice President, Legal & Corporate Secretary

Mr. Girgulis has held increasingly senior positions with Husky since joining the Company in 1994 and was appointed Vice President, Legal in 2000. His responsibilities include that of Corporate Secretary of the Corporation. Mr. Girgulis has a Bachelor of Laws degree (LLB).

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

Mr. Ingram is a 30 year veteran of the midstream and downstream business in North America. He joined Husky in 1982 and has been an Officer since 1994. Mr. Ingram is a Certified Management Accountant (CMA) and is a Fellow of the Society of Management Accountants of Canada (FCMA).

Neil D. McGee
Vice President & Chief Financial Officer

Mr. McGee joined Husky in January 1998 as Vice President and Chief Financial Officer. Prior to joining Husky, he was Senior Manager of Corporate Finance and Corporate Secretary at Hutchison Whampoa Limited in Hong Kong. Mr. McGee holds a Bachelor of Arts degree (BA) and a Bachelor of Laws degree (LLB) from the Australian National University.

Officers/Executives Husky Oil Operations Limited

Richard M. Alexander
Vice President, Investor Relations & Communications

Mr. Alexander joined Husky in 2000 as Treasurer. Mr. Alexander has held a number of senior financial positions in the oil and gas industry over the past 20 years. He is a Chartered Financial Analyst charterholder (CFA), a member of the Society of Financial Analysts and a Certified Management Accountant (CMA).

L. Geoffrey Barlow
Controller

Mr. Barlow has been with Husky since 2000. He brings 20 years of oil and gas industry experience to the executive team. 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.

K. Wendell Carroll
Vice President, Corporate Administration

Mr. Carroll joined Husky in 2000, and has almost 30 years corporate administrative experience, including various leadership roles with major corporations. He holds a Bachelor of Arts (BA) degree and has a strong record of developing the internal systems necessary to achieve business objectives in companies experiencing rapid growth.

Robert S. Coward
Vice President, Western Canada Production

Mr. Coward has been an Officer with Husky since 1995, and has been with the Company since 1977. He is responsible for the operations, development and stepout exploitation for gas, light oil and heavy oil in the Western Canadian basin. Mr. Coward holds a Bachelor of Science (BSc) in Chemical Engineering and is a member of APEGGA*.

J. Michael D'Aguiar
Treasurer

Mr. D'Aguiar joined Husky in 2002. He has 25 years experience in the international oil and gas industry, including positions in financial management with several major oil companies. Mr. D'Aguiar is a Chartered Accountant (CA) and a member of the Institute of Chartered Accountants of England and Wales.

Officers/Executives Husky Oil Operations Limited

J. Thomas Graham
Vice President,
Southern Alberta &
Saskatchewan Operations

Mr. Graham joined Husky in 1979 as a heavy oil operations engineer and has held increasingly senior levels of responsibility since then, including development of Indonesia's first Enhanced Oil Recovery project. He assumed the responsibility of Vice President Heavy Oil and Gas in 1998. Mr. Graham holds a Bachelor of Science (BSc) in Mechanical Engineering and is a member of APEGGA* and the Association of Professional Engineers of Saskatchewan.

Terence L. Sharkey
Vice President,
Drilling & Completions

Mr. Sharkey joined Husky in 2000 as Vice President, Drilling and Completions, continuing the same position he held at Renaissance Energy since 1996. Mr. Sharkey has a wide range of experience, both domestic and international. He is a Certified Engineering Technician (CET) and is a member of the Alberta Society of Engineering Technologists and the Canadian Association of Drilling Engineers.

David R. Taylor
Vice President,
Exploration

Mr. Taylor joined Husky in 2000 as Vice President, Exploration, continuing the role he filled at Renaissance Energy since 1999. Prior to joining Renaissance, Mr. Taylor held executive and senior level positions with several major oil companies. He holds a Master of Science (MSc) (Geology) and is a member of APEGGA*, the Canadian Society of Petroleum Geologists and the American Association of Petroleum Geologists.

Roy C. Warnock
Vice President,
Upgrading & Refining

Mr. Warnock has more than 25 years experience in the refining and upgrading business. He joined Husky in 1983, and has held the position of manager of Husky's Prince George Refinery as well as the Lloydminster Upgrader. Mr. Warnock holds a Bachelor of Science (BSc) in Chemical Engineering and is a member of APEGGA* and the Association of Professional Engineers and Geoscientists of Saskatchewan.

**APEGGA - Association of Professional Engineers, Geologists and Geophysicists of Alberta*

Board of Directors

Co-Chairmen

Victor T. K. Li
Managing Director, and
Deputy Chairman Cheung
Kong (Holdings) Limited &
Deputy Chairman, Hutchison
Whampoa Limited
Hong Kong

Canning K. N. Fok [1]
Group Managing Director
Hutchison Whampoa Limited
Hong Kong

Deputy Chairman

William Shurniak [2]
Chairman
ETSA Utilities and Powercor
Australia Limited
Australia

Directors

Martin J. G. Glynn [2]
President, Chief Executive
Officer & Director,
HSBC Bank of Canada
Vancouver

Ronald G. Greene [1]
President & Chief
Executive Officer,
Tortuga Investment Corp.
Calgary

Terence C. Y. Hui
President & Chief
Executive Officer,
Concord Pacific Group Inc.
Vancouver

Brent D. Kinney [3]
Independent Businessman
Dubai, United Arab Emirates

Holger Kluge [1] [3] [4]
Retired President,
Canadian Imperial Bank of
Commerce, Personal and
Commercial Bank
Toronto

Poh Chan Koh
Finance Director,
Harbour Plaza Hotel
Management
(International) Ltd.
Hong Kong

Eva L. Kwok [1] [4]
Chairman &
Chief Executive Officer,
Amara International
Investment Corp.
Vancouver

Stanley T. L. Kwok [3]
President, Stanley Kwok
Consultants & Director,
Amara International
Investment Corp.
Vancouver

John C. S. Lau
President & Chief
Executive Officer,
Husky Energy Inc.
Calgary

Wilmot L. Matthews [2] [4]
Independent Businessman
Toronto

Wayne E. Shaw [2]
Barrister and Solicitor
Stikeman Elliott
Toronto

Frank J. Sixt [1]
Executive Director & Group
Finance Director,
Hutchison Whampoa Limited
Hong Kong

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Corporate Secretary

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Senior Vice President,
Midstream & Refined
Products

Neil D. McGee
Vice President &
Chief Financial Officer

K. Wendell Carroll
Vice President,
Corporate Administration

Robert S. Coward
Vice President,
Western Canada Production

J. Michael D'Aguiar
Treasurer

J. Thomas Graham
Vice President, Southern
Alberta & Saskatchewan
Operations

Terence L. Sharkey
Vice President,
Drilling & Completions

David R. Taylor
Vice President, Exploration

Roy C. Warnock
Vice President, Upgrading
& Refining

Husky Oil Operations Limited

John C. S. Lau
Chairman of the Board,
President & Chief Executive
Officer

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Vice President, Legal &
Corporate Secretary

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

Neil D. McGee
Vice President &
Chief Financial Officer

Richard M. Alexander
Vice President, Investor
Relations & Communications

L. Geoffrey Barlow
Controller

[1] *Compensation Committee*
[2] *Audit Committee*
[3] *Health, Safety and Environment Committee*
[4] *Corporate Governance Committee*

CORPORATE PROFILE

Husky Energy's roots began in 1938 and continue with assets and operations across Canada and internationally. Over the 64 years of Husky's history, the Company has diversified and grown, both internally and through acquisitions, culminating in record cash flow and earnings performance in 2001. Husky Energy participates in upstream, midstream and refined products business areas, with exploration, development, marketing, transportation, processing and retailing. Husky produces crude oil, natural gas, synthetic crude oil and a range of derivative products and reaches markets in North America and internationally.

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

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