Annual report and accounts 2002

STATOIL

2002

Good net income of NOK 16.8 billion, on a par with Statoil's best-ever result of NOK 17.2 billion in 2001.

Improved profitability with return on capital employed of 14.9 per cent. Matches the best industry players.

Production record with 1 074 000 barrels of oil equivalent per day. The goal for 2004 is 1 120 000 barrels. Growth in 2002 was 6.7 per cent.

Reserve replacement ratio improved from 0.68 in 2001 to 0.78. The target for 2004 is for new reserves to exceed production.

Lower emissions of carbon dioxide, despite record-high output.

New operatorships on the NCS by taking over responsibility for the Snorre, Visund, Tordis and Vigdis fields from Norsk Hydro.

Strong international growth with production of 86 000 barrels of oil equivalent per day. Growth in 2002 was 28 per cent.

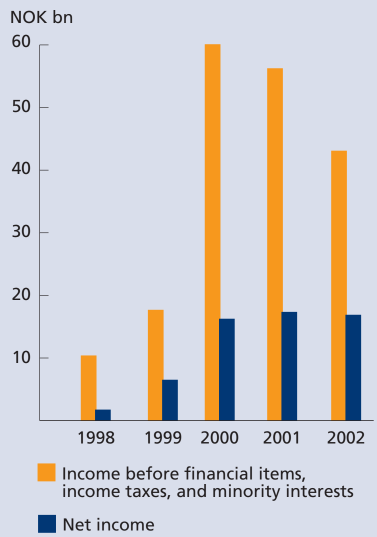
Gained new operatorships – in the South Pars field off Iran and in Plataforma Deltana off Venezuela.

New gas sales to the UK. Contract signed with British Gas Trading for supplies of five billion cubic metres annually for ten years.

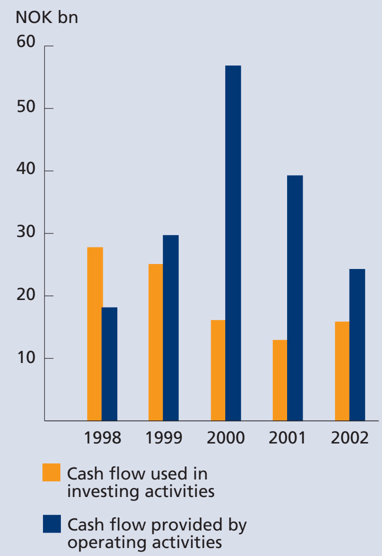
Strengthened market position in Poland, Estonia, Latvia and Lithuania through the acquisition of 140 petrol stations.

2002 statistics

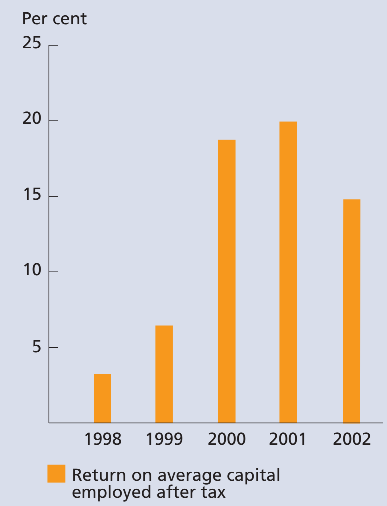
INCOME



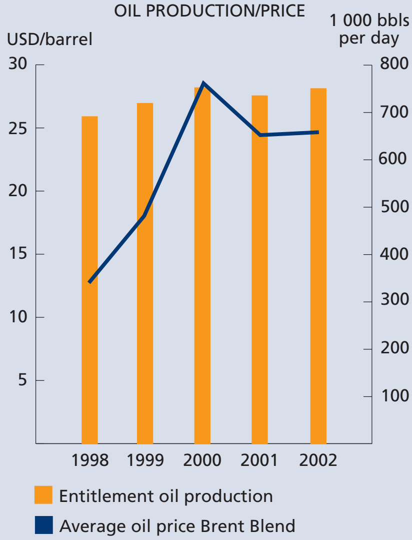
CASH FLOW



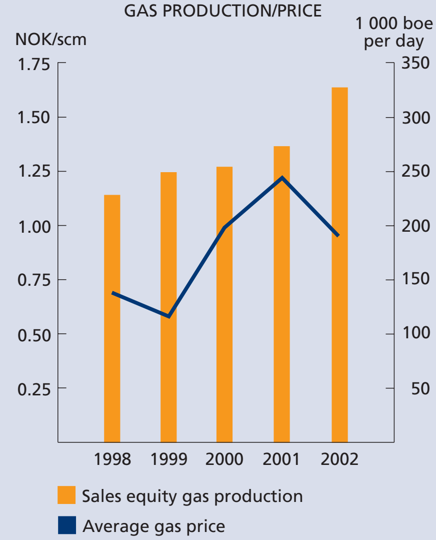
RETURN



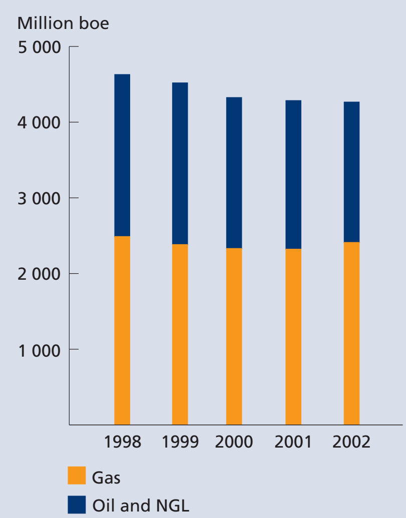
OIL PRODUCTION/PRICE



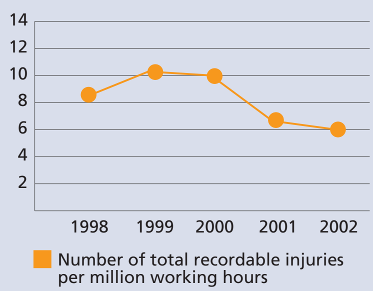
GAS PRODUCTION/PRICE



OIL/GAS RESERVES

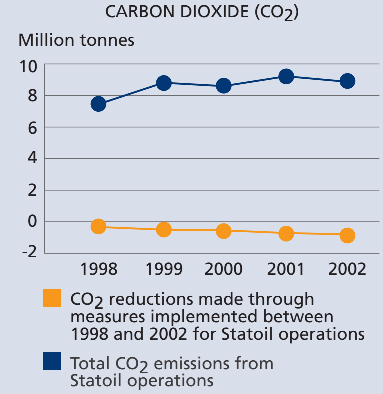


TOTAL RECORDABLE INJURY FREQUENCY



SERIOUS INCIDENT FREQUENCY

CARBON DIOXIDE (CO_2)



USGAAP - Financial highlights

KEY FIGURES IN NOK MILLION	*2002*	*2001*	*2000*	*1999*	*1998*
Financial information					
Total revenues	**243,814**	236,961	230,425	150,132	114,648
Income before financial items, income taxes and minority interests	**43,102**	56,154	59,991	17,578	10,287
Net income	**16,846**	17,245	16,153	6,409	1,640
Cash flow provided by operating activities	**24,023**	39,173	56,752	29,610	18,050
Cash flow used in investing activities	**16,756**	12,838	16,014	24,988	27,676
Interest-bearing debt	**37,128**	41,795	36,982	50,497	44,261
Net interest-bearing debt	**23,592**	34,077	23,379	42,856	37,538
Net debt to capital employed	**28.7%**	39.0%	25.0%	42.6%	44.1%
Return on average capital employed after tax	**14.9%**	19.9%	18.7%	6.4%	3.2%
Operational information					
Combined oil and gas production (thousand boe/day)	**1,074**	1,007	1,005	967	918
Proven oil and gas reserves (million boe)	**4,267**	4,277	4,317	4,511	4,621
Production cost (USD/barrel)	**3.05**	2.92	3.08	3.38	3.14
Finding and development cost (USD/barrel) (3-year average)	**6.17**	9.11	8.21	8.74	-
Reserve replacement ratio (3-year average)	**0.78**	0.68	0.86	1.03	-
Share information					
Net income per share	**7.78**	8.31	8.18	3.24	0.83
Net income per share adjusted for special items(1)	**7.72**	7.32	8.18	4.54	-
Share price at Oslo Stock Exchange 31 December	**58.50**	61.50	-	-	-
Weighted average number of ordinary shares outstanding	**2,165,422,239**	2,076,180,942	1,975,885,600	1,975,885,600	1,975,885,600

(1) Special items covers certain gains on sale of assets, write-downs and provisions. See "Operating and financial review and prospects". Income adjusted for special items is not calculated for 1998.

Definitions

NET INTEREST-BEARING DEBT =
Gross interest-bearing debt less cash and cash equivalents

NET DEBT TO CAPITAL EMPLOYED =
The relationship between net interest-bearing debt and capital employed

AVERAGE CAPITAL EMPLOYED =
Average of the capital employed at the beginning and end of the accounting period. Capital employed is net interest-bearing debt plus share capital and minority interests

RETURN ON AVERAGE CAPITAL EMPLOYED AFTER TAX =
Net income plus minority interests and net financial expenses after tax as a percentage of capital employed

PRODUCTION COSTS =
Operating expenses associated with production of oil and natural gas divided by total production (lifting) of oil and natural gas

FINDING AND DEVELOPMENT COSTS =
Calculated from new proven reserves, excluding acquisitions and disposals of reserves

RESERVE REPLACEMENT RATIO =
Additions to proven reserves, including acquisitions and disposals, divided by volumes produced

BARREL OF OIL EQUIVALENT (BOE) =
Oil and gas volumes expressed as a common unit of measurement. One boe is equal to one barrel of crude, or 159 standard cubic metres of gas

CARBON DIOXIDE (CO_2) =
Carbon dioxide emissions from Statoil operations embrace all sources such as turbines, boilers, engines, flares, drilling of exploration and production wells and well testing/workovers. Reductions in emissions are accumulated for the period 1998-2002

TOTAL RECORDABLE INJURY FREQUENCY =
The number of total recordable injuries per million working hours. Employees of Statoil and its contractors are included

SERIOUS INCIDENT FREQUENCY =
The number of incidents of a very serious nature per million working hours. An incident is an event or chain of events which has caused or could have caused injury, illness and/or damage to/loss of property, environmental damage or harm to a third party

KVITEBJØRN ON COURSE.
The topsides for the Kvitebjørn platform rolled out of the fabrication shop at ABB Offshore in Haugesund in December 2002. Weighing 10 800 tonnes, it was moved on 48 transporters with a total of 1 664 wheels. Kvitebjørn is due to start producing gas and condensate in 2004.
PAGE 25

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TECHNOLOGY PRIZE FROM THE WORLD PETROLEUM CONGRESS.
Statoil won this award for its underground storage of carbon dioxide in the Sleipner area.
PAGE 44

HIGHER DIVIDEND.
Statoil's board proposes a dividend of NOK 2.90 per share for 2002, as against NOK 2.85 for 2001.
PAGE 19

STATOIL VETTED 845 TANKERS AND REJECTED 12.
Ship's inspector Tore Tollefsen is one of the team which checks that vessels used by the group meet its high standards.
PAGE 46

STATOIL IS NOW OPERATOR FOR 20 FIELDS ON THE NCS.
Embraces 18 staffed platforms and production ships, four unstaffed units and 17 remotely-operated subsea installations.
PAGE 23

POPULAR TRAINEESHIPS.
Diana Startchenko from Murmansk is one of 24 trainees selected from 2 000 applicants.
PAGE 38

INVESTING HEAVILY ON THE NCS.
Statoil is involved in 14 new Norwegian offshore projects with a total investment framework of NOK 100 billion.
PAGE 25

The picture on the front cover was taken on the Sleipner East field by photographer Guri Dahl. She has captured Jarle Skjæveland in a happy mood, celebrating that his apprenticeship period is over. He became a qualified automation technician the day before this picture was taken.

Building for the future

2002 was a good year for Statoil with progress made in most areas.

Oil and gas production held a record-high level, with an increase of seven per cent from 2001. The demand for natural gas was greater than ever before. Ongoing improvement efforts in all of the group's business areas made a positive contribution to the strong results.

Efficiency is better and production regularity is higher than ever before. This is a result of Statoil's ability to exploit its competence and knowledge to enhance value creation through a process of continuous improvement.

> "The annual results for 2002 show that we are delivering"

Ambitious goals were set for 2004 when the company was floated in June 2001. These targets were considered by many to be too ambitious, but I feel certain that we will deliver the production growth and profitability that we promised. The annual results for 2002 show that we are delivering along the way.

The Norwegian continental shelf (NCS) is the backbone of our business and it will continue to be so for many years to come. We have succeeded in getting more out of our big fields – Statfjord and Gullfaks – than anyone thought possible just a few years ago. Our goal now is to extend the fields' lifetime by systematically developing technology, forms of organisation and modes of working.

We are in the midst of a hectic development phase. Statoil is operator for 12 development and modification projects on the NCS. Snøhvit is the biggest project. Its investment budget has been increased but the project remains profitable. Snøhvit breaches technological boundaries and it is a pioneering project on the environmental side.

We are investing in the future on the NCS.

Gas is becoming an ever more important source of energy. Demand is rising. Statoil sells nearly 70 per cent of all gas from the NCS. That gives us market strength and opportunities to enhance value creation. We gained a foothold in the British market last year. Our proximity to the UK gives us a clear competitive edge. Our ambition is to build a market position there which is similar to those of our main markets in continental Europe. That will require greater transport capacity from the NCS.

> "Gas is becoming an ever more important source of energy"

We will exploit our advantages, competence and experience in the continuing development of our gas position.

2002 was a year of breakthrough internationally. Output rose considerably. New projects were sanctioned in Azerbaijan and Angola and we gained our first operatorship in Iran. Although the project in Iran is not a large one, it represents an important step in the development of our international business.

> "2002 was a year of breakthrough internationally"

Earnings from the NCS allow us the time we need to build up profitable international upstream operations. In 10 years our international activities could account for 40 per cent of our total production.

We have invested in our refineries at Mongstad and Kalundborg, upgrading them to be able to supply tomorrow's products –more environmentally-friendly petrol and diesel. We have strengthened our market position in the new and interesting markets of the Baltic states and Poland.

We have a strong brand name.

We are building a future based on our competence, our ethics, and our environmental and social responsibility.

Olav Fjell
President and CEO

Diana Startchenko from Murmansk was one of 24 trainees to join Statoil in 2002. Although employed by International Exploration & Production, she is currently working on economic analysis for Natural Gas with the help of mentor Lars Bjerkelund (above). Statoil's two-year trainee programme, designed for university or college graduates, attracted 2 000 applicants in 2002.

Directors' report 2002

Introduction

The Statoil group's net income in 2002 came to NOK 16.8 billion, which is NOK 0.4 billion lower than in 2001. Income before financial items, tax and minority interests totalled NOK 43.1 billion in 2001 as against NOK 56.2 billion the year before. The return on capital employed was 14.9 per cent, as against 19.9 per cent in 2001.

The good results can primarily be attributed to high levels of oil and gas production and unrealised currency gains on the group's debt. Output rose by 6.7 per cent compared with 2001, despite extensive maintenance work and production limitations on the Norwegian continental shelf (NCS). Average oil and gas production totalled 1 074 000 barrels of oil equivalent (boe) per day, compared with 1 007 000 boe in 2001.

The board is particularly satisfied with developments in oil and gas production. Enhanced regularity and cost-effectiveness on the NCS have made considerable contributions to the good annual results. Developments over the past year have strengthened the group both financially and operationally.

The slightly weaker financial result compared with 2001 is mainly due to lower prices measured in Norwegian kroner. Measured in US dollars, the average oil price was two per cent higher than the year before, but measured in NOK it was nine per cent lower. The average gas price was 22 per cent lower than in 2001, and refining and petrochemical margins were considerably weaker than the year before.

Statoil's 2002 result includes a one-off gain of NOK 1.0 billion before tax, and NOK 0.7 billion after tax, on the sale of the upstream business in Denmark. The value of the LL 652 oil field in Venezuela was written down by NOK 0.8 billion before tax, or NOK 0.6 billion after tax. The 2001 result included one-off gains totalling NOK 2.3 billion before tax and NOK 2.1 billion after tax.

Remaining proven oil and gas reserves amounted to almost 4.3 billion boe at the end of 2002. In 2002, the reserve replacement rate was 98 per cent, a clear improvement compared with 89 per cent in 2001. Over the last three years the average reserve replacement rate has been 78 per cent.

Statoil's finding and development costs were USD 5.3 per boe last year compared with USD 4.6 per boe in 2001. Over the last three years, finding and development costs averaged USD 6.2 per boe. Production costs per boe rose from USD 2.9 in 2001 to USD 3.1 in 2002, due to a weakening of the USD against the NOK. Measured in NOK, production costs have decreased from NOK 26.4 per boe to NOK 24.2 per boe.

Good results for health, safety and the environment are very important and receive high priority in the group. Unfortunately, there were six fatal accidents in connection with the group's operations last year. However the frequency of recordable injuries and lost-time injuries has declined. The board will continue to monitor closely the group's efforts to improve HSE results.

In connection with the flotation in 2001, the group has established clear objectives for profitability and production growth up to 2004. In order to achieve the defined target for return on capital employed, an extensive improvement programme has been initiated. The objective is to realise cost reductions and improved earnings amounting to NOK 3.5 billion per year in 2004. At the end of 2002, annual improvements of NOK 1.6 billion have been achieved. Progress is running according to schedule in all of the business areas. In the board's view, the group is on track to delivering in accordance with its objectives.

The board proposes that the annual general meeting allocates a dividend of NOK 2.90 per share for 2002, as against NOK 2.85 for 2001.

Developments in Statoil's principal markets

At the start of 2003 the world economy was marked by a fear of war in Iraq. Economic indicators show that growth in the industrialised nations is low and there is a certain risk of a continued weak development in the global economy. The Norwegian economy is influenced in particular by the weak global growth, high pay costs, high interest rates and a strong Norwegian krone.

2002 was a year of big fluctuations in the oil market. The year started with production restrictions made by the Opec countries to prevent oil price reductions. The Norwegian authorities decided that oil production on the NCS should also be limited. In the second half of the year the restrictions in Norway were lifted. Unrest concerning Iraq influenced the oil market in the second half of 2002 and the strike in Venezuela had a big effect towards the end of the year. A major part of Venezuela's oil exports came to a halt and the oil price rose to over USD 30 per barrel. The Opec countries adjusted their oil production several times during the year in order to balance the market. On an annual basis, Statoil's average realised price for Brent Blend was USD 24.7 per barrel, compared with USD 24.1 in 2001. However, measured in NOK, the oil price fell by nine per cent. Uncertainty concerning the situation in the Middle East will also affect oil prices in 2003, with a risk of big fluctuations.

Demand for gas in western Europe continues to rise. The UK market is particularly promising for sales of Norwegian gas, since the demand there is rising while domestic production is declining. The market for gas in continental Europe is expanding and new marketplaces are developing. Statoil's average gas price last year was NOK 0.95 per standard cubic metre, compared with NOK 1.22 in 2001.

Refining margins in Europe fell heavily in 2002 compared with 2001. The average refining margin (fluid catalytic cracker margin) was USD 2.2 per barrel, as against USD 3.6 per barrel the year before. The average contract price for methanol was 22 per cent lower than the year before, measured in EUR.

Statoil's petrochemicals sector was also affected by developments in the global economy. Margins fell by 19 per cent in 2002. The decline was particularly strong towards the end of the year, with margins 39 per cent lower in the fourth quarter compared with the same period of 2001.

The competitive position of Norwegian industry has weakened by nearly 30 per cent since 1995. Differentials in pay compared with our most important trading partners have risen by 13 percentage points in local currency, while the exchange rate has been strengthened by almost 15 percentage points. A strong Norwegian krone entails higher costs measured in foreign currency and lower income in NOK. This is a clear competitive disadvantage for Statoil's operations on the NCS and for its manufacturing and marketing business.

Last year Statoil awarded contracts totalling NOK 30 billion to Norwegian companies. For the past 10 years, Norwegian suppliers have provided two-thirds of Statoil's total contracts. This also applies to 2002. However, for contracts involving a large number of working hours, the competitiveness of Norwegian firms is weakened and several contracts have therefore been won by companies outside Norway.

Exploration & Production Norway

Income before financial items, tax and minority interests totalled NOK 31.5 billion in 2002 as against NOK 40.7 billion in 2001. This decline primarily reflects lower oil and gas prices measured in NOK.

Statoil's oil and gas output from the NCS has shown a good trend. Production averaged 989 000 boe per day in 2002, an increase of roughly 48 000 boe per day compared with 2001. Gas output has risen due to increased demand, while oil production was slightly lower than in 2001. Regularity and cost-effectiveness on the NCS has improved further. The Sigyn field came on stream three months earlier than planned.

Finds were made in 14 of 20 wells drilled last year. The majority of these discoveries are relatively small, but promising, since they lie near existing infrastructure.

On 1 January 2003, Statoil took

Leif Terje Løddesøl
Chair

over Norsk Hydro's operatorships in the Tampen area and about 550 Hydro employees transferred to Statoil. The board expresses satisfaction at the good and efficient cooperation between the two companies in connection with the operatorship changes.

The board takes a particular interest in the development of the Snøhvit project in the Barents Sea, where the investment budget has been increased by NOK 5.8 billion to NOK 45.3 billion. The main reason for this increase is that the plant's capacity was increased by 30 per cent at an early stage, while the consequences of such an expansion in a large gas liquefaction facility were underestimated. In addition, costs rose due to the discussions with the Efta Surveillance Authority (ESA). Statoil has a 22.29 per cent interest in Snøhvit. The board will put high priority on the further follow-up of the project, which is the first development of a gas liquefaction plant in Europe. The board would point out that the Snøhvit project remains profitable. Statoil has conducted a detailed review of the development project. This has improved certainty about costs and project execution, and the company now has a good basis for implementing the development in accordance with updated plans.

The development of large projects such as Kvitebjørn, Mikkel, Kristin and Kollsnes NGL are running to budget and on schedule.

International Exploration & Production

Income before financial items, tax and minority interests totalled NOK 1.1 billion in 2002, as against NOK 1.3 billion the year before. This decline primarily reflects a reduction in special items, an increase in costs associated with business development and lower oil prices measured in NOK. This is partly offset by a production increase of 28 per cent.

International oil and gas output totalled 86 000 boe as against 67 000 boe in 2001. The Girassol field in Angola and the Sincor field in Venezuela have contributed substantially to production growth. Output will continue to rise as new fields come on stream.

Statoil passed an important milestone in 2002 when the group became operator for the offshore part of phases six, seven and eight on the large South Pars gas field in Iran. In Venezuela, Statoil has become operator for block 4 in Plataforma Deltana, off the country's eastern coast.

The group has access to several quality fields internationally. New field developments in Angola and Azerbaijan were sanctioned last year. A decision has also been taken to build an export line for oil from Azerbaijan to the Mediterranean.

Several new finds have been made off Angola and gas reserves have been proven off Nigeria.

Statoil has acquired El Paso Merchant Energy's liquefied natural gas (LNG) contracts and rights to the import terminal for LNG at Cove Point in the USA. A new organisation is being established with responsibility for marketing gas to the US market. The board considers this to be an important step for Statoil in its role as a player in the international LNG market. Access to the gas markets on the US east coast represents an attractive opportunity for the group. Gas imports by the USA are expected to rise in coming years.

The board puts great emphasis on the further development of Statoil's international upstream activities, following the three main lines of strategy:

- creating close ties with national oil companies that want to draw on Statoil's experience for their own development
- exploiting the group's gas expertise along the entire value chain
- increasing international exploration.

This strategy builds upon the competence, technology and market know-how which the group has acquired through 30 years of operation, with its basis in Norwegian oil and gas resources.

Intensifying international activ-

Stein Bredal

Stein Bredal

Marit Bakke

Marit Bakke

Bjørn Erik Egeland

Bjørn Erik Egeland.

ities involves new challenges, particularly with regard to the political risk in the countries where the group does business.

Natural Gas

Income before financial items, tax and minority interests totalled NOK 8.9 billion in 2002, as against NOK 9.6 billion the year before. Statoil's gas sales increased by 34 per cent, from 14.7 billion cubic metres to 19.6 billion cubic metres. The effects of higher gas sales are largely offset by a 22 per cent reduction in the gas price measured in NOK. Statoil's reduced share in Statpipe has weakened the result by NOK 0.9 billion.

In the board's view, it is highly significant that Statoil has strengthened its position in the UK gas market through agreements with BP in 2001 and Centrica in 2002. The contract with the latter is the largest single deal, measured in annual volumes, since the Troll agreements in 1986. The acquisition of the development rights for an underground gas storage facility on the east coast of England will also serve to strengthen Statoil's competitiveness in a market with an increasing demand for imported gas.

A new model for company-based gas sales was introduced on 1 October. Statoil now markets and sells its own gas as well as the Norwegian state's gas. This accounts for nearly 70 per cent of total gas production on the NCS. Statoil has long-term agreements with more than 20 buyers of Norwegian gas.

The board is satisfied with the amicable settlement reached between Statoil and the European Commission concerning gas sales from the NCS. As of 1 January 2003, ownership of the Norwegian gas transport systems has been coordinated in the Gassled partnership. This will enhance overall efficiency.

Manufacturing & Marketing

Income before financial items, tax and minority interests totalled NOK 1.6 billion in 2002, as against NOK 4.5 billion the year before.

Sales of crude oil, refined products and NGL in the international market provided a very good financial result, on a par with the year before. The refining business had a result which is NOK 1.8 billion lower than the year before, due to developments in refining margins and exchange rates. The result for retailing was NOK 0.1 billion higher than the year before. Retailing was strengthened through its acquisitions in Poland and the Baltic states. Methanol had a slightly weaker result than in the record year of 2001. As a result of weaker prices the result declined by NOK 0.2 billion.

The result for the Borealis petrochemicals group improved by NOK 0.2 billion, despite lower prices, largely due to the ongoing improvement programme.

For 2002 as a whole, the result for the Navion shipping company is NOK 1.2 billion lower than in 2001. This is mainly due to lower rates for conventional shipping, lower utilisation of the shuttle tanker fleet and exchange rate trends. On 15 December 2002, Statoil signed an agreement to sell Navion to Teekay Shipping Corporation for about USD 800 million, with effect from 1 January 2003. The transaction is due to be finalised in the first half of 2003.

Health, safety and the environment

Statoil has stepped up efforts in recent years to prevent harm to people and the environment. The results for recordable injuries, lost-time injuries and serious incidents show a positive trend. But the six fatal accidents in 2002 represent a step backwards. These accidents, which occurred in Statoil itself and with contractors working for Statoil, have been investigated and measures have been adopted to help avoid similar accidents in the future. An agreement has also been signed with DuPont Safety Resources for assistance in strengthening safety efforts further. The objective is to improve management and control, behav-

Kaci Kullmann Five

Finn A Hvistendahl

Grace Skaugen

iour and attitudes throughout the organisation. The board will closely follow developments in safety work, both at Statoil and at the group's contractors. A safe workplace, free of injuries, is the goal.

Calculated per million working hours, the total recordable injury frequency improved from 6.7 in 2001 to 6.0 in 2002. The number of lost-time injuries per million working hours fell from 3.1 in 2001 to 2.8.

There is also an improvement in the number of serious incidents per million working hours. The serious incident frequency has declined from 4.1 in 2001 to 3.8.

Sickness absence is unchanged compared with 2001, and still low, at 3.4 per cent. Statoil has signed an agreement with the Norwegian National Insurance to pursue a more inclusive workplace. Companies taking part in this scheme commit themselves to following up employees on sick leave and adapting the workplace for older employees and personnel with a reduced capacity for work. Statoil has already worked actively for several years to promote presence instead of absence, which is in line with the intentions of this agreement.

Statoil works continuously to reduce emissions of greenhouse gases. Total carbon dioxide emissions from Statoil-operated facilities have declined in 2002 compared with 2001. This is principally due to good production regularity on the NCS. For its work on removal and storage of carbon dioxide in the North Sea's Sleipner area, Statoil was awarded the technology development prize at the World Petroleum Congress in Rio de Janeiro.

Emission trading will play an important part in climate policy in the years to come. The European Union is to launch a new emission trading system. The board believes that the Norwegian oil and gas business should have the same opportunities to take part as the petroleum industry within the EU member states.

Over the past few years, Statoil has invested more than NOK 1 billion in delivering cleaner fuel and heating oil. Its refineries will meet EU quality requirements for petrol and diesel from 2003, although the EU requirements will not apply until 2005.

In 2002 the spotlight was once again on international oil transport by ship following the accident off north-west Spain. This has been a key focus area in Statoil's safety efforts for many years. All ships which carry oil for Statoil have to go through a thorough vetting procedure. The tankers have to satisfy safety standards which are stricter than both national and international requirements. Statoil's standards were tightened in 2001 with regard to the age of ships and the requirement that all ships transporting heavy crude must have a double bottom or hull. There were no substantial spills of oil or chemicals in connection with tankers in 2002.

Sustainable development

For Statoil, sustainable development is associated with the consequences of the group's activities for people, the environment and society. Statoil will pursue its business in a profitable, safe and ethical manner. It will also show consideration to the environment and accept social responsibility.

The group's first sustainability report was published in 2002 and Statoil was included in the Dow Jones sustainability index. During the climate summit in Johannesburg in August, Statoil received an award for its work with sustainable development.

Actively adapting the business to social conditions and surroundings reduces risk, strengthens the group's reputation and thus improves profitability. By contributing to sustainable development Statoil can strengthen its position in the labour market, the capital market and the markets for its products.

A good working environment is an important part of the group's work on sustainable development. Statoil carries out annual surveys

Eli Sætersmoen

Knut Åm

of the working environment. The board is pleased to note improvements in employees' job satisfaction and motivation, cooperation and efficiency and confidence in the management. The employees also report that work with health, safety and the environment gets high priority.

There is a strong focus on diversity and equal opportunities. As of 2003 all business areas will report quarterly on progress in their work to create a better gender balance among their managers. All business areas share the goal of having at least 20 per cent women managers by 2005.

Financial developments for the group

Total revenues for Statoil in 2002 came to NOK 243.8 billion, an increase of just over NOK 6.9 billion from the year before.

Income before financial items, tax and minority interests totalled NOK 43.1 billion in 2002 as against NOK 56.2 billion in 2001. Net income came to NOK 16.8 billion, compared with NOK 17.2 billion in 2001.

Return on capital employed was 14.9 per cent, compared with 19.9 per cent in 2001. Earnings per share came to NOK 7.78 in 2002, as against NOK 8.31 the year before. Adjusted for special items, return on capital employed was 14.8 per cent as against 17.6 per cent in 2001.

Normalised return on capital employed came to 10.8 per cent, compared with 9.4 per cent in 2001. Normalised return on capital employed is based on an oil price of USD 16 per barrel, a gas price of NOK 0.70 per cubic metre, a refining margin of USD 3 per barrel, petrochemical margins of EUR 150 per tonne and a USD/NOK exchange rate of NOK 8.20.

Cash flow provided by operating activities was NOK 24.2 billion in 2002, compared with NOK 39.2 billion in 2001. This is due principally to a strengthened NOK, reduced downstream margins and an increase in taxes paid. Cash flows used in investing activities amounted to NOK 16.9 billion as against NOK 12.8 billion in 2001.

The group's gross interest-bearing debt at 31 December 2002 was NOK 37.1 billion, a decline of NOK 4.7 billion from a year earlier. The group's debt-equity ratio, defined as net interest-bearing debt in relation to capital employed, was 29 per cent at 31 December. The reduction is mainly due to lower interest-bearing debt as a result of the weaker USD/NOK exchange rate.

The group had NOK 12 billion in bank deposits and other liquid assets at 31 December 2002. Overall interest-bearing debt is denominated in US dollars.

At 31 December, Statoil managed a portfolio of about NOK 18 billion in bonds, certificates and shares. Fund management by the group relates to assets in Statoil Forsikring (insurance), the group's liquidity reserves and Statoil's pension funds. The pension funds are not consolidated in the accounts.

The group's financial reporting is in accordance with the US generally accepted accounting principles (USGAAP) as well as the Norwegian generally accepted accounting principles (NGAAP). Note 25 in the NGAAP accounts explains the differences between the two sets of accounts.

As required by section 3-3 of the Norwegian Accounting Act, the board confirms that the going concern assumption has been fulfilled. The accounts for 2002 have been prepared on that basis.

Net income for the Statoil ASA parent company according to NGAAP was NOK 16.4 billion.

The board proposes that the annual general meeting allocates a dividend of NOK 2.90 per share. The amount of the dividend comprises 37 per cent of the USGAAP result adjusted for profit on disposals and write-downs. The size of the dividend complies with the group's dividend policy.

The board proposes the following allocation of net income in the parent company, Statoil ASA (in NOK million):

Dividend	6 282
Retained earnings	11 050
Reserve for valuation variances	(955)
Total allocated	16 377

The company's distributable equity amounts to NOK 33 200 million.

Statoil's governing bodies

At Statoil's annual general meeting in May 2002, a new corporate assembly was elected. After the election the corporate assembly comprised the following representatives: Anne Kathrine Slungård, (chair), Wenche Meldahl, (deputy chair), Kjell Bjørndalen, Kirsti Høegh Bjørneset, Erlend Grimstad, Gunnar Mathisen, Anita Roarsen and Asbjørn Rolstadås. The employees elected Arvid Færaas, Hans M Saltveit, Einar Arne Iversen and Åse Karin Staupe as members.

In June, the corporate assembly elected a new board of directors for Statoil: Leif Terje Løddesøl (chair), Maurey Devine, Grace Skaugen, Eli Sætersmoen, Finn A Hvistendal and Knut Åm. The employees elected Marit Bakke, Stein Bredal and Bjørn Erik Egeland. Maurey Devine withdrew from the board in the summer of 2002, and Kaci Kullmann Five was elected as a new director.

The members of the board all have broad experience of Norwegian and international business and society, as well as knowledge of the industry. None of the directors have any business relations with Statoil. Statoil's corporate executive committee is not represented on the board. The directors are elected for two years at a time. The board's responsibilities are based on the requirements laid down in legislation and the company's articles of association.

Statoil puts great emphasis on good corporate governance. On the owner side this is exercised through the company's administration, board of directors, corporate assembly and annual general meeting.

As a listed company in New York, Statoil must comply with the Sarbanes-Oxley Act which was passed in the USA in 2002. In the main, the division of responsibilities between the administration and the board in the Sarbanes-Oxley Act accords with the Act relating to Public Limited Companies in Norway. The management systems required by the new Act in the USA are in effect already established practice in Statoil.

Further developments for the group

At the start of 2003, Statoil's financial and operational position is strong. The group's cost structure has been improved. The board will give priority to achieving the goals for 2004 which were communicated in connection with the flotation in 2001:

- 12 per cent return on capital employed with normalised prices, margins and exchange rates
- increase in oil and gas output to 1 120 000 boe per day in 2004.

The board has sanctioned projects which will help the group to reach its objectives for production growth in 2004. Access to new projects will enable a production growth of roughly four per cent per year, also beyond 2004.

The board's overriding objective is to maximise the value of the group's oil and gas resources. On the NCS, Statoil is operator for nearly 60 per cent of overall production. The group is responsible for major, demanding development projects such as the Kristin field in the Norwegian Sea, and the Snøhvit field in the Barents Sea. These are projects which will contribute to the group's long-term growth. The board will keep a very close eye on these projects. The restructuring of the Tampen area in the North Sea, with a view to increased value creation, is one of Statoil's most highly prioritised assignments. A decision on the further development of the Tampen area will be taken in 2004.

The board found last year's international upstream activities encouraging. The operatorship gained in Iran was particularly important. Increased internationalisation of the upstream business is crucial to the group's ability to expand in the longer term. Substantial finds are under development in Angola and the Caspian Sea. The group is also working to develop new business opportunities in its existing core areas and in Russia, Brazil, Mexico, northern Africa and the Middle East.

Access to new exploration acreage on the NCS and internationally is seen by the board to be crucial to the group's long-term development. Exploration efforts will be intensified.

Last year, Statoil further strengthened its position as a leading player in the European gas market. The contracts signed with British buyers show Statoil to be competitive in the UK market. The board sees big opportunities for continued development in this market and will prioritise efforts to establish new transport solutions to the UK.

In the Manufacturing & Marketing business area Statoil will exploit the opportunities for integration with the upstream business to increase value creation. This applies to Mongstad as well as Tjeldbergodden. Statoil's strong brand will be used to strengthen the group's leading position in the Scandinavian markets and in markets outside Scandinavia. Acquiring Shell's petrol stations in the three Baltic states in 2002 has improved Statoil's market position. A strong focus will be maintained on enhancing the efficiency of all parts of the downstream business.

The board is committed to developing further Statoil's organisation and expertise, so that the group will be able to meet the challenges on the NCS and in the increasing international activities.

The board's fundamental objective is to secure for the shareholders the best possible value creation and return on their investment in the group. A strong focus will therefore be put on efforts to increase efficiency and to maintain strict capital discipline.

Statoil's profitability and growth targets are based on assumptions for organic growth. The group's existing portfolio makes it possible to realise the goals for 2004 and form the basis for continued growth after 2004. The board will continuously assess the group's development through measures of a non-organic character. Statoil's financial position makes it possible to implement such measures if they are in line with the group's main strategic direction and contribute to long-term value creation for the shareholders.

Stavanger, 17 February 2003
The board of directors
of Statoil ASA

Group profile

- Statoil is an integrated oil and gas company with a strong focus on exploration and production. Represented in 25 countries with 17 115 employees. Head office is in Stavanger.

Statoil has three production ships in operation on the NCS and one in the South China Sea. Pictured here is Åsgard A, one of the world's largest vessels of its kind.

- The group's objective is to run its business with zero harm to people or the environment and zero accidents or losses.
- Statoil supports sustainable development which meets the needs of the present without compromising the opportunities for future generations.
- The leading operator on the Norwegian continental shelf and one of the world's largest offshore oil operators.
- Participant in a number of international oil and gas finds and in rising production from fields in Azerbaijan, Angola and Venezuela.
- The largest supplier of natural gas in Norway – including sales on behalf of the Norwegian state – to a growing European market.
- One of the world's largest net sellers of crude, including sales on behalf of the Norwegian state. Extensive sales of oil products and natural gas liquids.
- Has 1 883 service stations in nine countries.
- Considerable industrial operations:
  - operates two oil refineries
  - production operator for the world's largest offshore pipeline system
  - production operator for Europe's largest gas treatment plant, other land facilities and gas receiving stations in continental Europe
  - operator for Europe's largest methanol plant
  - 50 per cent interest in the Borealis petrochemicals group.
- Technology work with emphasis on focused research and close collaboration with supplier companies. Statoil is a leading company in:
  - using seismics to improve oil recovery
  - subsea solutions
  - floating production under harsh weather conditions
  - design, operation and maintenance of large pipelines
  - storage of carbon dioxide (CO_2) in the sub-surface.

Targets

When Statoil was floated on the stock exchange in 2001, the company presented goals for its operations and return on equity.

- Twelve per cent return on capital employed in 2004 with a normalised oil price of USD 16 per barrel.
- Output of 1 120 000 barrels of oil equivalent in 2004.
- Output of 1 260 000 barrels of oil equivalent in 2007, with 260 000 barrels expected from international operations.
- Improvement programme which will contribute NOK 3.5 billion to income before financial items in 2004.
- Finding and development costs will be below USD 6 per barrel for the period 2002-2004.
- Production costs will be lower than USD 2.80 per barrel.
- Access to new reserves will exceed those in production.
- Debt will be no higher than 40-45 per cent in relation to capital employed.

www.statoil.com/statoils_world

Strategies

The business

- Create greater value for Statoil's shareholders.
- Develop further the group's strong position as leading player on the NCS.
- Build a strong position as oil and gas producer internationally.
- Strengthen and develop the group's position as producer and marketer of natural gas in Europe and in new markets.
- Maintain the position as a leading global oil seller and strengthen the group's core positions in manufacturing and marketing.

Technology and the environment

- Develop further the group's expertise in reservoir management, subsea production and floating production.
- Develop technological solutions along the gas chain.
- Continue to develop and adopt technology for capturing, utilising and storing carbon dioxide.
- Develop and apply energy-efficient technology which reduces greenhouse gas emissions.
- Build a stronger culture within health, safety and the environment (HSE).

The organisation and the community

- Develop further Statoil's organisation based on uniform leadership and common values as formulated in the *We in Statoil* values document. Important focus areas are recruitment, appointing and developing managers, restructuring and effective expertise development.
- Realise ambitions for growth through proactive and wholesome business operations based on sustainability, ethics and social responsibility.

Organisation

At the end of 2002, Statoil had 17 115 employees. This is an increase of 429 compared with a year earlier. A total of 5 901 of Statoil's employees work outside Norway.

Statoil ranks as one of the world's largest offshore oil and gas operators. At 31 December 2002, 3 021 of its employees worked on fixed and floating installations off Norway.

Exploration & Production Norway
The business area is responsible for Statoil's operations on the Norwegian continental shelf (NCS). Statoil accounted for 58 per cent of total Norwegian oil and gas output in 2002. The company is operator for 20 oil and gas fields, comprising 18 platforms and production ships with crew, four unstaffed installations and 17 remotely controlled subsea facilities. Employees: 5 774, of whom 3 021 work offshore.

International Exploration & Production
INT is responsible for Statoil's overall exploration activities outside the core areas of the NCS, and for the development and production of oil and gas internationally. In 2002 the business area delivered eight per cent of Statoil's equity production of oil and gas. Statoil has important positions in the Caspian region, western Africa, Venezuela and western Europe. Employees: 598, of whom 243 work outside Norway.

Natural Gas
Statoil is a leading player in Europe with customers in 11 countries. In addition to Statoil's equity gas, the business area markets the Norwegian state's gas. It is also responsible for two-thirds of Norway's gas exports. Statoil has large interests in, and operational responsibility for, Norwegian gas export trunkline systems and treatment plants and terminals on land. Employees: 937, of whom 132 work outside Norway.

Manufacturing & Marketing
The business area is responsible for refining and selling Statoil's and the Norwegian state's crude oil. Statoil is one of the world's largest sellers of crude with an average volume of 2.2 million barrels per day. It also sells rich gas, refined oil products and natural gas in the Nordic countries. It has 1 883 service stations in nine countries, operates two refineries, has interests in a third and operates Europe's largest methanol plant. It has a 50 per cent share in the Borealis petrochemicals group.

Employees: 7 130, of whom 5 526 work outside Norway.

Technology
Technology is responsible for developing and maintaining Statoil's expertise in key technology areas. It assists in providing cost-effective technical solutions and is responsible for commercialisation of technology and industrial rights. Its responsibilities cover research and development, exploration and reservoir technology, drilling and well services, environmental and safety technology, concept development and project management. Employees: 949.

Corporate services and corporate centre
Corporate services covers finance, accounting, legal services, human resources and office support as well as education, information technology, health, safety and the environment and communication. Employees: 1 465. The corporate centre comprises advisory staff functions for the corporate executive committee. Employees: 262.

Corporate executive committee

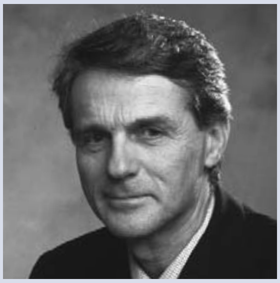
Olav Fjell (51),
President and CEO

Henrik Carlsen (56),
Executive vice president,
Exploration & Production Norway

Richard John Hubbard (52),
Executive vice president,
International Exploration
& Production

Peter Mellbye (53),
Executive vice president,
Natural Gas

Erling Øverland (50),
Executive vice president,
Manufacturing & Marketing



Terje Overvik (51),
Executive vice president,
Technology

Inge K Hansen (56)
Chief financial officer
and executive vice president,
Corporate Centre and Services

Elisabeth Berge (48),
Executive vice president,
Corporate Communication

Staff functions and corporate services

Health, safety and the environment: Stig Bergseth, senior vice president

Corporate control, planning and accounting: Eldar Sætre, senior vice president

Group finance: Jon A Jacobsen, senior vice president

Human resources: Kjølv E Egeland, senior vice president

Legal affairs: Jacob S Middelthon, senior vice president

Information and communication technology: Ole A Jørgensen, senior vice president

Corporate services: Randi Grung Olsen, senior vice president

Corporate audit: Svein Andersen, senior vice president

Public affairs: Wenche Skorge, vice president

Investor relations: Mari Thjømøe, vice president

Promotion and media: Hans Aasmund Frisak, vice president

Country analysis and social responsibility: Geir Westgaard, vice president

Operative David Finda is one of 160 crew on the Girassol production ship, which ranks as the world's largest. Operated by TotalFinaElf, the Girassol field lies in 1 350 metres of water off Angola and came on stream in December 2001. It now produces almost 200 000 barrels of oil per day, with Statoil's share totalling about 25 000 daily barrels.

Corporate governance

Statoil's fundamental objective is to create value for its owners through profitable operations and commercial development. It is a major requirement that the group's resources are used effectively to achieve greater profitability, economic strength and financial flexibility.

Statoil works to maintain a leading position among oil and gas companies when it comes to combining good financial results with a responsibility for the environment and the community.

Statoil puts great emphasis on exercising good corporate governance and treating its shareholders equally. This requires clear management principles and business targets as well as good follow-up and control. The group's governing bodies comprise the board of directors, the corporate assembly and the annual general meeting. While working to safeguard the owners' interests, the board is also accountable to the employees, authorities, partners, suppliers, customers and lenders, in addition to the general public and non-governmental organisations (NGOs). The governing principles established will ensure good management and control of the business. In 2002, Statoil's governing system for overall management and control was certified to the international ISO 9001 standard.

Annual general meeting

The annual general meeting (AGM) is the company's highest body. It is held once a year, before the end of June. The AGM elects members of the corporate assembly for a period of two years. The corporate assembly has eight shareholder-elected and four employee-elected members. It monitors the board's work, approves the group's accounts and deals with cases of major significance. The corporate assembly appoints two members to the election committee and elects representatives to the board.

The board

The board takes decisions on Statoil's plans and budgets and handles cases of major strategic or economic significance for the business. The board is responsible for the accounts and presents a proposal for allocation of net income to the AGM. The board appoints the chief executive and establishes formal powers of attorney between the board and the chief executive.

Each quarter, the chief executive presents to the board the accounts, progress report in relation to Statoil's plans and budgets, including investments, cash flows, financial position, project progress and risk issues. Once a year, the chief executive informs the board about internal control in the group.

The directors are independent of, and have no business relationships with, Statoil. The corporate executive committee is not represented on the board. The corporate assembly elects six members of the board, which in addition comprises three directors elected among the employees. Directors are elected for two years at a time and the board's chair receives an annual remuneration currently stipulated to be NOK 300 000. Annual remuneration for the directors is NOK 165 000.

Chief executive and corporate executive committee

The chief executive's corporate executive committee comprises the chief executive and seven executive vice presidents, each with responsibility for their own business area or corporate staff function.

In 2002, the chief executive received a salary and other remuneration of NOK 3 770 000. The board has devised an incentive scheme for the chief executive, with a bonus which has a ceiling of 30 per cent of basic salary. The size of the bonus paid depends on the goals achieved by the group, in relation to the commercial targets determined jointly by the board and the chief executive.

Performance pay

Statoil's 360 top managers are included in a reward system of individual performance contracts which allow for a bonus of up to 20 per cent of basic salary. The purpose of this is to strengthen Statoil's long-term competitive position through increased focus on the requirements and expectations to results demanded of

Statoil's managers. The performance contracts contain the most important corporate goals, with special emphasis on sub-targets which the individual managers are responsible for delivering. Importance is attached to ensuring consistency and connections between the targets throughout the organisation. On the basis of the performance contract agreed between the chief executive and the board, the chief executive establishes contracts with the executive vice presidents of the business areas. Further down the organisation, contracts are formed so that the targets for the members of a management team evolve from and underpin the manager's targets.

Statoil has established a bonus system which applies to all employees of the parent company. This involves an annual bonus of up to five per cent, depending on whether the company reaches its financial targets.

Information and equal treatment

Statoil puts emphasis on keeping the stock market well informed about developments in the group's results and future prospects. At any given time the stock market must have correct and equal information about Statoil, to provide the basis for a correct valuation of the group. Statoil distributes all information relevant to the share price to the Oslo Stock Exchange, the New York Stock Exchange and the Securities and Exchange Commission. Such information is distributed without delay and simultaneously to the capital market and the media. Trading of the Statoil share increased on average in 2002. The investors perceive this as positive and it leads to a more effective valuation and pricing of the company.

The group's investor relations function reports to the corporate executive committee and handles the group's dialogue with the capital market. Investor relations is also responsible for distributing and registering information to comply with the guidelines applicable where Statoil's securities are listed. News and relevant company information is published on Statoil's internet sites. A separate investor relations site provides new and historic financial information, as well as presentations made by the group's top management.

Values and attitudes

Statoil works purposefully to develop a strong, uniform corporate culture with a clear value basis. Honesty, integrity and compliancy underpin the group's operations. Statoil's value basis is expressed in the group's governing documents, with the most fundamental guidelines summarised in *We in Statoil.* That document describes the direction and level of ambition for Statoil's development and states the principles and values which underpin management, the development of corporate culture and work processes. *Ethics in Statoil* specifies requirements and provides guidelines for the business activities.

Social responsibility

Statoil's main objective is to create value for its owners. The result is best when good financial results are combined with responsibility to the environment and society. Statoil is increasingly being asked to account for and demonstrate how it makes a positive contribution to society and what it creates locally. Much attention was devoted to this topic in the group's first sustainability report, published in 2002. It will be discussed in greater detail in the next report which is scheduled for publication in June 2003.

Health, safety and the environment

A high standard within health, safety and the environment is a prerequisite for creating good financial results over time. Statoil's efforts denote a desire to contribute to sustainable development. That means that impact assessments for health, safety and the environment are integrated in business strategy, risk management and project management.

Risk management and internal control

Statoil operates mainly in the global crude oil market and markets for refined products and natural gas, as well as the financial markets. The company is thus exposed to changes in feedstock and product prices, exchange rates and interest rate fluctuations. These variables all affect earnings, operating costs, investments and financing. Statoil has an extensive system for risk management which identifies, quantifies and handles different risk categories.

The company has established a committee with responsibility for risk management throughout the group. This committee is headed by the chief financial officer.

Statoil's internal audit function is the group's independent controlling body which monitors the business to ensure that it is subject to adequate management and control. It reports directly to the chief executive or, when appropriate, directly to the board.

The company's external auditor is appointed by the AGM and the auditor carries out no other assignments for the company which could lead to conflicts of integrity.

Shares and shareholder matters

www.statoil.com/ir

Statoil's fundamental objective is, through profitability, growth and continuing development, to create value for its shareholders, employees and society. It aims to give shareholders a competitive return on their share capital, so that owning shares in Statoil becomes an attractive option. Returns will be realised by the sum of rising share price and dividends. Statoil's objective is to pay out 45-50 per cent of its result to the shareholders, measured as an average over several years, and taking account of the industry's business cycles. A dividend of NOK 2.85 per share was paid out for 2001. The proposed dividend for 2002 is NOK 2.90. This gives shareholders a dividend yield of 5.3 per cent, given a share price of NOK 55 per share.

62 000 shareholders

Statoil is quoted by the ticker symbol STL on the Oslo Stock Exchange (OSE). On the New York Stock Exchange (NYSE), American depository receipts (ADRs) are traded under the ticker symbol STO. There is one class of shares. These may be freely traded and have equal voting rights. Statoil has about 62 000 shareholders and about 60 per cent of its employees own shares. The Norwegian state owns 81.7 per cent of the share capital and the other shareholders are spread throughout the world. The international shareholders' portion has increased from roughly 76 per cent at the end of 2001 to 81 per cent in 2002. In 2002, a total of 1 558 026 bonus shares were distributed to small private shareholders who had retained their shares for one year following the flotation of 18 June 2001.

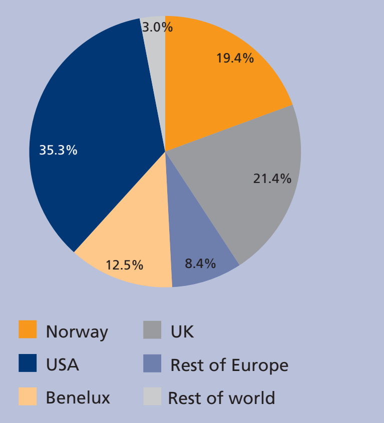
Good liquidity

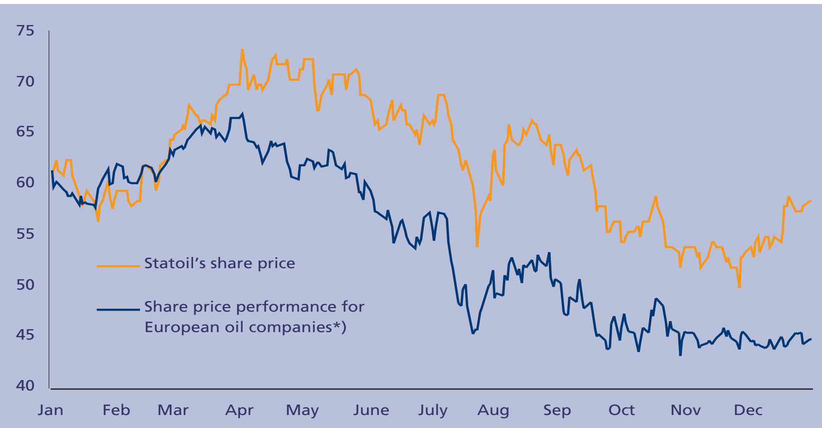
Statoil is the largest company on the OSE measured in market value. In 2002, 730 million Statoil shares, with a total value of NOK 45.4 billion, were traded on the OSE. The average daily turnover was 2.9 million shares, or NOK 182 million. Trading of ADRs on the NYSE in 2002 came to USD 106 million. The share price fell by 4.9 per cent, from NOK 61.50 at 1 January to NOK 58.50 at 31 December. The OSE's all-share index fell by 31.4 per cent. Total shareholder return, including dividend and measured in NOK, was marginally negative at minus 0.2 per cent in 2002. Measured in USD, in relation to the Stoxx energy index, the Statoil share price shows a return of 28 per cent, while the energy index showed a return of minus three per cent.

Main shareholders		
1	81.72%	THE NORWEGIAN STATE
2	2.68%	STATE STREET BANK & TRUST CO.*
3	1.65%	JPMORGAN CHASE BANK*
4	0.77%	BOSTON SAFE DEP & TRUST (USA NOM)*
5	0.69%	FIDELITY FUNDS-EUROP. GROWTH/SICAV
6	0.68%	JPMORGAN CHASE BANK
7	0.50%	BANK OF NEW YORK*
8	0.38%	THE NORTHERN TRUST CO.*
9	0.37%	FOLKETRYGDFONDET
10	0.37%	THE NORTHERN TRUST CO.*
11	0.36%	CLEARSTREAM BANKING S.A.*
12	0.30%	EUROCLEAR BANK S.A./N.V. ('BA')*
13	0.26%	THE NORTHERN TRUST CO.*
14	0.25%	VITAL FORSIKRING ASA
15	0.25%	DEUTSCHE BANK AG (GCS) LONDON
16	0.24%	DEUTSCHE BANK TRUST CO AMERICAS*
17	0.18%	GJENSIDIGE NOR SPAREFORSIKRING
18	0.17%	BSDT - ABN AMRO GLOBAL CUSTODY N.V*
19	0.17%	INVESTORS BANK + TRUST (WEST) TREA*
20	0.16%	DEUTSCHE BANK AG*

* Client accounts or similar

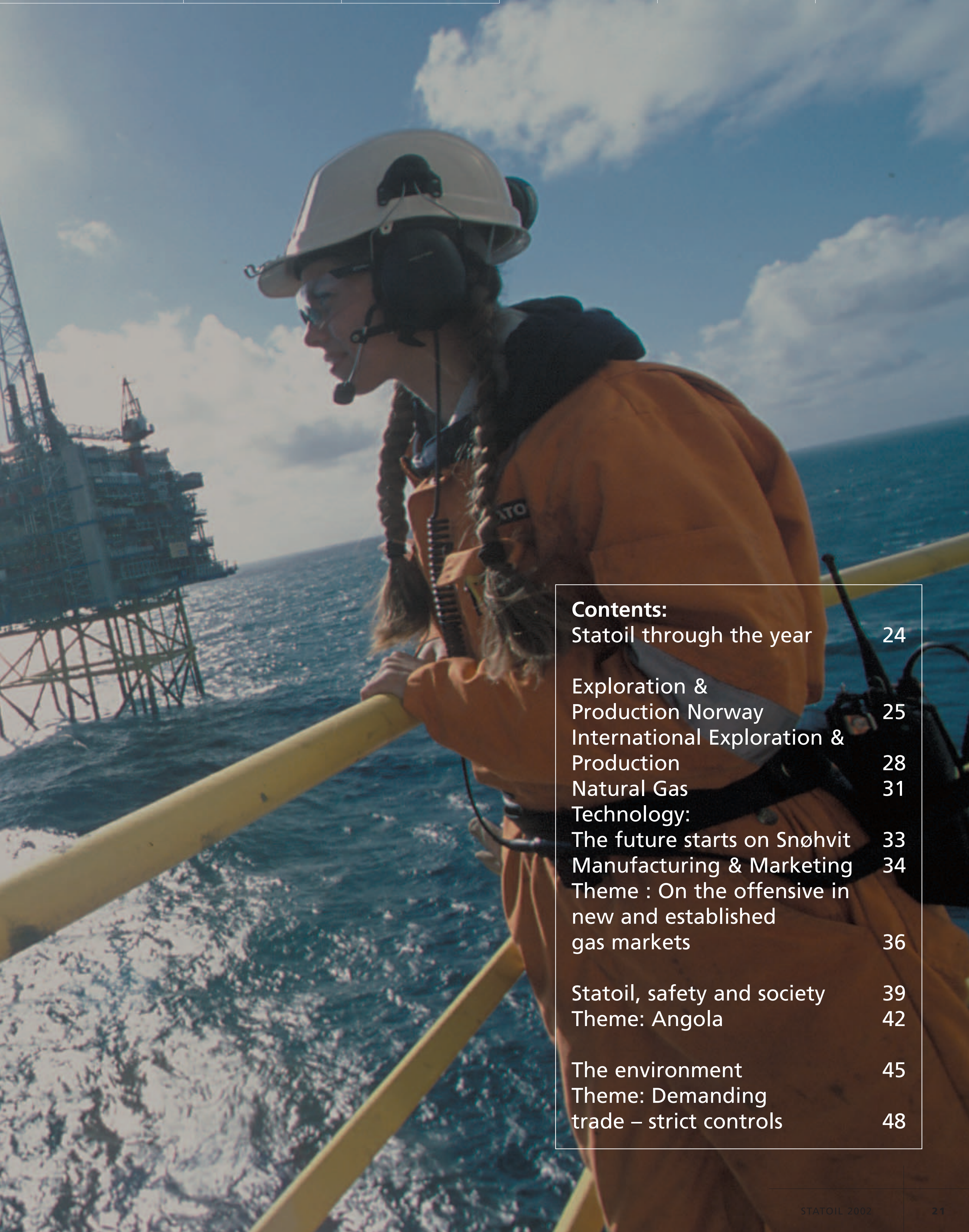
SHAREHOLDERS BY GEOGRAPHICAL AREA
Excluding the Norwegian state's interest of 81.7%





*) Stoxx Energy Index , rebased for Statoil's share price, measured in NOK.

Platform life offers more than gales and surging waves. The Sleipner fields can bask at times in summer sunshine and glittering sea. Process technician Cecilie Oksum Ralle has taken a break from work to devote some time to quiet reflection. Output from the Sleipner area increased sharply in 2002, making a significant contribution to a production growth of more than four per cent on the NCS.



Contents:

Statoil through the year

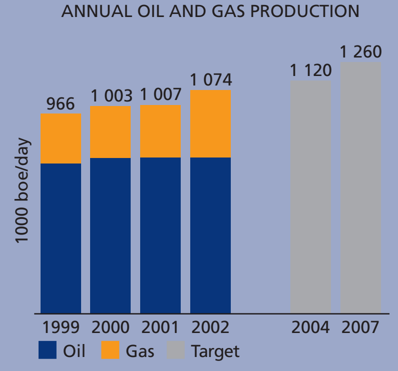
The breadth of Statoil's activities in 2002 is presented in the three main chapters, *Business operations, Statoil, safety and society* and *The environment.* These chapters reflect Statoil's wish to contribute to sustainable development by combining sound business operations with a practical responsibility for the environment and society.

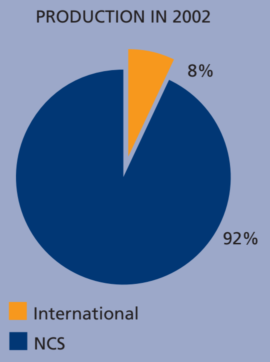
Statoil has taken over the Visund operatorship, and the Norsk Hydro logo on the platform derrick must be replaced.

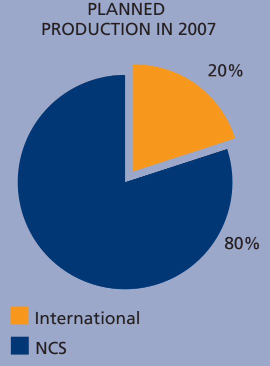
Statoil's operations in 2002 are characterised by a high rate of production, good regularity, cost savings and a substantially increased level of activity. Net income for the year is NOK 16.8 billion. This is NOK 0.4 billion less than the 2001 result, which was the best ever for Statoil. All of the group's business areas have made a contribution to the good result.

The slightly weaker financial result for 2002 is due to the fact that the average oil price, measured in NOK, was nine per cent lower than the year before, even though it was two per cent higher measured in USD. The gas price was 22 per cent lower in 2002 than in 2001, while gas volumes sold increased by no less than 34 per cent. Gas activities were firmly on the agenda in 2002: construction of the Snøhvit gas liquefaction plant started, a new gas contract was signed in the UK and a foothold was gained in the US gas market.

Along with increased demand, requirements to cleaner production are being tightened. Statoil is taking this challenge seriously. A number of measures which will contribute to improving the external environment have been implemented in existing operations and incorporated in the planning of new projects.







Exploration & Production Norway

Statoil is the leading producer on the Norwegian continental shelf (NCS). The fields operated by the group account for 58 per cent of Norway's total oil and gas production. Statoil is operator for 20 oil and gas fields, which comprise 18 platforms and production ships with crew, four unstaffed installations and 17 remotely-operated subsea facilities. Operations in the Exploration & Production Norway business area are organised in four core areas: Troll/Sleipner, Tampen, Halten/Nordland and the Tromsø Patch.

Key figures (NOK million)	2002	2001
Total revenues	56,290	65,655
Income before financial items	31,463	40,697
Gross investments	11,023	10,759

Statoil's output on the NCS set a new record in 2002, averaging 989 000 boe per day. This is an increase of 5.2 per cent from 2001. The positive development in production is due to high regularity at the facilities and high sales of natural gas to Statoil's customers in Europe.

At the beginning of 2003 Statoil took over operatorship for the Snorre, Visund, Tordis and Vigdis fields from Norsk Hydro. The handover brought Statoil 550 new employees. About 250 of these work on the Snorre A and B and Visund platforms. Vigdis and Tordis are subsea installations.

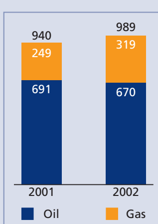
Statoil becomes sole operator

The handover means that Statoil is now the sole operator in the Tampen area. Tampen comprises the main Statfjord, Gullfaks, Snorre and Visund fields, which have a total of nine staffed platforms, and several subsea developments tied back to the main fields. The transfer of operatorship from Hydro to Statoil was agreed in connection with Hydro's acquisition of Saga Petroleum in 1999.

Tampen is an important core area for Statoil, but it is also of major significance for national oil and gas production. The area produces about one million boe per day, corresponding to a quarter of total Norwegian output. The production picture is however complex. Some fields are under development, while output on others is declining. Statoil has initiated extensive efforts to find solutions which will result in the longest possible production on Tampen. A separate project, Tampen 2020, has been launched with the aim of boosting value creation and

www.statoil.com/fields_ncs

Stena Don proved more oil and gas with an appraisal well in the Tyrihans South field in the Norwegian Sea. A total of 20 exploration wells were completed on the NCS in 2002, including 13 operated by Statoil. Five were drilled as extensions to producing wells. Fourteen discoveries were made, with an overall volume found in the order of 130 million barrels of oil equivalent.



Oil and gas production	2002	2001
Oil (thousand boe per day)	670	691
Natural gas (thousand boe per day)	319	249
Total production (thousand boe per day)	989	940

Operating developments	2002	2001
Reserve replacement ratio (1)	0.6	0.8
Finding and development costs (USD/boe) (2)	5.9	9.4
Production cost (USD/boe) (3)	3.0	2.8

(1) Additions to proven reserves including acquisitions and disposals, divided by volumes produced. 3-year average.
(2) Total exploration activities, investments in field installations. 3-year average.
(3) Production costs for fields and transport systems.

extending the producing life of the area. The challenges on Tampen concern unitisation and efficiency improvements, environmental challenges linked to high water production and, not least, profitability for fields in a late production phase. Statfjord is a good illustration of these challenges.

Statfjord late phase

At its peak the Statfjord field produced 850 000 barrels of crude per day, which represents four times the Norwegian consumption.

Statoil's oil and gas production – Norwegian continental shelf		
(1 000 barrels of oil equivalent/day)		
Field	2002	Statoil's share
Statfjord	98.1	44.34%
Statfjord East	9.8	25.05%
Statfjord North	9.5	21.88%
Gullfaks	159.1	61.00%
Troll Gas	100.9	20.81%
Heidrun	24.2	12.43%
Norne	48.7	25.00%
Sleipner West	119.3	49.50%
Sleipner East	34.8	49.60%
Åsgard	84.8	25.00%
Veslefrikk	5.5	18.00%
Sygna	7.7	24.73%
Gungne	16.3	52.60%
Glitne	21.9	58.90%
Huldra	12.4	19.66%
Total Statoil operated	753.2	
Partner operated	235.7	
Underlifting	-3.2	
Total production	985.6	

Output is now down to 125 000 barrels per day. The continued operation of Statfjord is now being studied in a separate project known as Statfjord late phase. Its aim is to extend the lifetime of Statfjord by recovering the huge reserves of gas still present in the field, as well as some oil which is difficult to access. The solution for Statfjord late phase is due to be presented later in 2003, with a decision expected in early 2004.

Big opportunities

The opportunities in the Tampen area are still great. Forty per cent of oil and 15 per cent of gas reserves has so far been produced. As operator for Statfjord and Gullfaks, Statoil has achieved considerable results through increased oil recovery. Output represents 1.5 billion barrels of crude more than originally predicted, at a sales value of almost NOK 250 billion. Oil production from Statfjord has passed a recovery rate of 60 per cent, and efforts are now being made to push this factor to over 68 per cent.

Kristin contracts

In connection with the development of the Kristin gas field on the Halten Bank, which is now under development, several large contracts were awarded in 2002. The contract to build the steel hull, worth NOK 475 billion, went to Samsung Heavy Industries Co in South Korea. Aker Stord was awarded the contract to build the deck, process facilities and utilities, at a value of NOK 5 billion. A letter of intent was also concluded with Kværner Oilfield Products to build subsea production equipment for the field. This agreement is worth NOK 1 billion.

Kvitebjørn on schedule

Located near the Tampen area, the Kvitebjørn gas and condensate field will come on stream in 2004. In the course of the year contracts were placed for the installation of pipelines and the hook-up and testing of the platform systems.

The lower part of the platform jacket was installed on the field in September. The water depth is some 190 metres, and the steel jacket has been constructed in two parts which will be hooked up on the field in March 2003. The topsides, weighing 10 000 tonnes, rolled out of the fabrication shop at the ABB Offshore Systems yard in Haugesund just before Christmas.

Snøhvit contracts

The development of the Snøhvit project was approved in March 2002. Snøhvit will be the first export facility for liquefied natural gas (LNG) in Norway, and

Shuttle tanker *Polytraveller* lifted the first cargo from Statfjord on 9 December 1979, and thereby secured a lasting place in Statoil's history. On 3 December 2002, it delivered its last shipment to the crude oil terminal at Mongstad. After 23 years of service, primarily with crude cargoes from Statfjord and Gullfaks, the ship had reached retirement age.

Europe. Several large contracts were placed in 2002. Germany's Linde industrial group was awarded a contract worth NOK 1.6 billion for engineering, purchasing and construction management for the gas liquefaction plant. Belgium's Tractebel Industry Engineering will supply product tanks and vessel loading systems, at a value of NOK 2.3 billion. The contract for blasting and levelling work at the site of the land plant on Melkøya outside Hammerfest was awarded to the AFS-Pihl Group. Dragados Offshore in Spain will build and install the processing facilities. The value of this contract is NOK 1.5 billion.

Increased costs

There has been a NOK 5.8 billion increase in the investment budget for the Snøhvit project, from NOK 39.5 to 45.3 billion. This was mainly due to a 30 per cent increase in the capacity of the gas liquefaction plant. The consequences of such an expansion, which led to a considerable rise in weight, were underestimated. In addition, the start of construction work in the spring of 2002 was delayed for three months because the environmental organisation Bellona complained to the Efta Surveillance Authority (ESA) about the project's tax position. Bellona thought that the tax regime for the project contravened the EEA's rules on state support. The case was clarified between the Norwegian authorities and ESA, but the delay contributed to a rise in costs for the project.

Environmental opposition

When work at the plant started up, demonstrations against the development were held in Hammerfest, stopping work for two weeks. Opposition to increasing national carbon dioxide emissions, and to opening the Barents Sea up for further exploration activity and development, were the reasons behind this campaign. On the Snøhvit field all the carbon dioxide from the reservoirs will be reinjected, but there will be emissions to the air from the cooling process at the gas liquefaction plant. This will amount to 900 000 tonnes annually.

A good environmental project

In other respects, Snøhvit is a good environmental project. None of its installations will interfere with fishing as the subsea facilities can be overtrawled. The field will be produced in closed systems with no emissions. A biological treatment plant on land will deal with harmful emissions.

www.statoil.com/snohvit

Statoil is involved in 14 development projects on the NCS, with a total investment budget of NOK 100 billion. The development period will last until 2006. The most important projects can be found below.

Projects under development

Field	Statoil's share	Statoil's investment*	Production start	Plateau production Statoil's share **	Liftetime (years)
Snøhvit	22.29%	10.1	2006	27 000	30
Kristin	46.60%	7.9	2005	110 000	12
Mikkel	41.62%	0.9	2003	22 000	17
Kvitebjørn	50.00%	5.0	2004	105 000	17
Sigyn	50.00%	1.0	2002	23 000	9
Fram Vest	20.00%	0.9	2003	12 000	18

*Estimated in NOK bn **Boe/day

Blasting and levelling the site for the gas liquefaction plant at Melkøya in northern Norway is well under way. The workforce had reached 250 people in early 2003, and will rise to 1 200 when activity peaks in 2004-05.

Sleipner satellite Sigyn came on stream in December 2002, three months ahead of schedule. This field contains both gas and light oils, which are processed on Sleipner A.

International Exploration & Production

The International Exploration & Production (INT) business area is responsible for all of Statoil's exploration activities outside the Norwegian continental shelf, as well as development and production of oil and gas internationally. INT is also responsible for the group's sales of natural gas outside Europe. Statoil has substantial positions in the Caspian region, western Africa, western Europe and Venezuela.

Key figures (NOK million)	2002	2001
Total revenues	6,769	7,693
Income before financial items	1,086	1,291
Gross investments	5,995	5,027

2002 was a new successful year for Statoil's exploration and production activities outside the Norwegian continental shelf (NCS). The increase in production was greater than anticipated and the group made a breakthrough in Iran when it was awarded an operatorship in South Pars, the world's largest gas field. In February 2003, the group was also awarded an operatorship off Venezuela. The decisions to develop fields in Angola and Azerbaijan will make a major contribution to future production growth.

Girassol – quickly to plateau

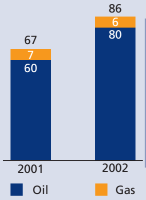
Average international oil and gas production totalled 86 000 boe per day. This is an increase of 28 per cent from 2001, and 5 000 barrels more than was planned at the beginning of 2002.

The Girassol field, off the coast of Angola, contributes strongly to the growth in production. The field came on stream in December 2001 and reached plateau output of 200 000 barrels of crude per day five months before target, in February 2002. Statoil has a 13 per cent interest in the field.

Girassol in Venezuela and Sincor in Venezuela are the main contributors to Statoil's production outside the NCS.

Production in Sincor is based on producing large volumes of heavy crude and upgrading it to a synthetic sulphur-free crude. Sincor started normal production in March 2002, when the upgrading facility was ready. Statoil has a number of employees with key positions in the project. Production ran smoothly, until it was shut down for 10 weeks between December 2002 and February 2003, due to political unrest and strikes in Venezuela's oil industry.

While Sincor may be characterised as a success, production from the LL 652 oil field in Lake Maracaibo has been disappointing. Output is low and expectations of recovering more oil from the 35-year-old field, with new wells and production equipment, have not been met. Statoil wrote down the field's value by NOK 2 billion in 2001, and is now writing it down by a further NOK 0.8 billion.



Oil and gas production	2002	2001
Oil (thousand boe per day)	80	60
Natural gas (thousand boe per day)	6	7
Total production (thousand boe per day)	86	67

Operating developments	2002	2001
Reserve replacement ratio (1)	2.8	2.5
Finding and development costs (USD/boe) (2)	6.9	8.6
Production cost (USD/boe) (3)	3.3	5.2

(1) Additions to proven reserves including acquisitions and disposals, divided by volumes produced. 3-year average.
(2) Total exploration activities, investments in field installations. 3-year average.
(3) Production costs for fields and transport systems.

Developments in Angola

In 2002, three new developments in Angola were approved and these will provide increased production in three-four years' time. The Kizomba B, Xikomba and Jasmim fields will together give Statoil 45 000 barrels per day. Along with output from Girassol and Kizomba A, which was sanctioned in 2001, this will bring Statoil's total production from Angola up to roughly 80 000 barrels per day from 2006. With Dalia, which is planned for sanction in 2003, output will exceed 100 000 barrels.

Pipeline from Baku

In Azerbaijan, Statoil and its partners in the Azeri-Chirag-Gunashli (ACG) oil field have sanctioned the second development phase of this large field. When phase II is completed, Statoil's share of production from the field will reach almost 60 000 barrels per day.

Plans were also approved to build a pipeline to carry ACG oil from Baku in Azerbaijan, through Georgia, to the port of Ceyhan on the Turkish Mediterranean coast. This is a gigantic pipeline project in which Statoil will invest about NOK 2 billion. Construction will start in the spring of 2003 and the line will be ready in 2005.

Operatorship in Iran

An important goal in Statoil's internationalisation was reached in October when the group entered into an agreement with the Iranian company Petropars, to become operator for phases six, seven and eight in the development of the gigantic gas and condensate field, South Pars. Statoil will build three production platforms and three pipelines from the field to a treatment plant on land. The group will invest NOK 2.2 billion in South Pars, and investments and return will be covered by sales revenues from liquefied petroleum gases and condensate. The development is due to be completed in 2004.

Statoil is also assessing other opportunities for participation in the development of Iran's oil and gas reserves.

Statoil in the South China Sea

For more than five years, Statoil has been operator for oil production on the Lufeng field in the South China Sea. Production regularity has been nearly 99 per cent. At the end of 2002 the *Munin* production ship had produced just over 30 million barrels of oil with a sales value of USD 532 million. The field is now producing 7 000 barrels per day.

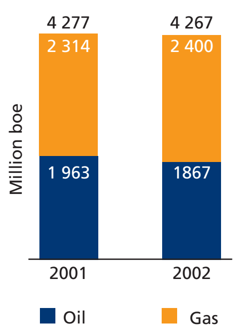
Lufeng was brought on stream on 27 December 1997. It is a small field and the initial plan was to produce for three years. This time frame has been extended twice, first until 2002 and then until 2004. Statoil has a 75 per cent interest in Lufeng, while the China National Offshore Oil Company holds 25 per cent. In addition to responsibility for day-to-day operation, Statoil is responsible for training Chinese personnel.

Statoil's oil and gas production – International		
(1 000 barrels of oil equivalent/day)		
Field	2002	Statoil's share
Girassol	23.2	13.33%
Azeri-Chirag-Gunashli	9.5	8.56%
Sincor	14.1	15.00%
LL 652	2.0	27.00%
Siri (sold in 2002)	6.6	40.00%
Lufeng	4.6	75.00%
Alba	11.3	17.00%
Dunlin	4.5	28.76%
Merlin	0.3	2.35%
Schiehallion	5.9	5.88%
Total oil	81.8	
Jupiter (gas)	5.6	30.00%
Total	87.4	

An 8.7 per cent stake is held by Statoil in a new oil pipeline from the Caspian to Ceyhan on the Mediterranean coast of Turkey. Due to extend 1 760 kilometres, this line will make it possible to boost production from Azerbaijan's Azeri-Chirag-Gunashli field.

Girassol off Angola is the biggest contributor to Statoil's non-Norwegian production.

PROVEN RESERVES



Exploration operator in Venezuela

Statoil has been awarded operatorship in an exploration block in the Plataforma Deltana area off Venezuela. Covering an area of 1 435 square kilometres, the acreage lies in 200-800 metres of water. The licences in Plataforma Deltana are the first offshore awards made by Venezuela.

Statoil has also gained interests in two new exploration licences off Brazil and is now involved in a total of four licences there.

Systematic efforts are being made in a number of countries to gain access to exploration acreage and operatorships. In 2002, Statoil participated in a number of interesting finds, the majority of them proven in Angola.

Gas to Turkey and the USA

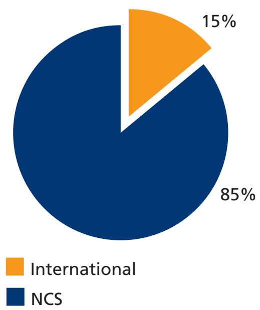
During 2002 the first stage in the development of Azerbaijan's gigantic Shah Deniz gas and condensate field in the Caspian reached a decision. Development of the field and the gas export line was sanctioned by the licensees on 27 February 2003. Statoil and technical operator BP are the main participants in Shah Deniz with a 25.5 per cent interest each. Investments in the field, a pipeline to land, land-based facilities and a 650-kilometre line – the South Caucasus Pipeline – for export through Georgia to the Turkish border, will amount to USD 3.2 billion. A sales contract has been signed for the supply of 6.6 billion scm of gas annually to the Turkish market. Sales to Georgia and Azerbaijan come in addition, along with sales of condensate. Production is set to start in 2006. Statoil will be commercial operator, with responsibility for gas sales, contract administration and business development for the Shah Deniz gas and condensate field in the Caspian. The deal also covers the transport system. In 2002 Statoil signed a deal with the US company El Paso to take over the purchase contract for liquefied natural gas (LNG) from the Snøhvit field. Statoil has also secured the rights to one third of the capacity at the LNG terminal at Cove Point, Maryland, USA. This means that Statoil will begin selling gas in the US market in 2003.

Corrib delayed

Development of the Corrib gas field north-west of Ireland has been delayed. Due to start in late 2003/early 2004, production has been postponed for about a year due to extensive consultation and approval processes. Shell is operator and Statoil's 36.5 per cent interest will give a production share of 3.25 million scm of gas per day.

Statoil's exploration and production operations on the Danish continental shelf have been sold to Danish state oil company, Dong.

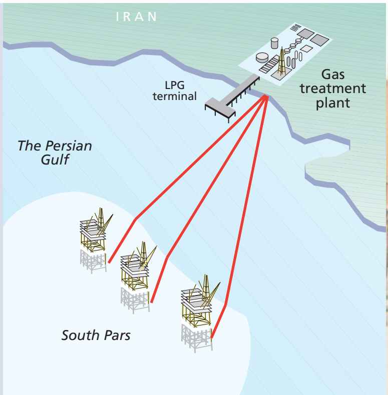
RESERVES



Projects under development

Field	Statoil's share	Statoil's investment*	Production start	Plateau production Statoil's share **	Lifetime (years)
Azeri-Chirag-Gunashli phase 1	8.56%	2.3	2005	28 000	15
Azeri-Chirag-Gunashli phase 2	8.56%	3.5	2006	30 000	15
Xikomba	13.33%	0.4	2003/4	9 000	7
Kizomba A	13.33%	3.9	2004	30 000	20
Kizomba B	13.33%	3.7	2005	30 000	20
Jasmim	13.33%	0.5	2003/4	6 000	6
Corrib	36.50%	2.3	2005	20 000	15
South Pars 6, 7 and 8	Max 40%	2.3	2005	20 000	4***

*Estimated in NOK bn **Boe/day ***Pay-back period



Statoil achieved a breakthrough in Iran with the award of the offshore operatorship for phases six-eight of the South Pars gas development. The group will build three production platforms and lay three pipelines to a land plant, with production due to start in late 2004.

Natural Gas

The Natural Gas business area is responsible for transporting, processing and marketing gas from the NCS to Europe. In addition to its own gas, Statoil markets the Norwegian state's directly-owned gas, and thereby accounts for two-thirds of total Norwegian gas exports.

Key figures (NOK million)	2002	2001
Total revenues	24,536	23,468
Income before financial items	8,918	9,629
Gross investments	465	671

Statoil has had strong growth in sales of natural gas from the NCS, with 19.6 billion cubic metres (scm) of equity gas sold in 2002. The equivalent figure in 2001 was 14.7 billion scm, representing an increase of 34 per cent.

In addition, the group sold 23.5 billion scm on behalf of the state's direct financial interest (SDFI). The corresponding figure for 2001 was 18.9 billion scm.

Expanding gas market

In the course of the last 10 years gas consumption in Europe has risen by as much as 40 per cent. During the same period Statoil has strengthened its position as a major player in the European gas market. The group now covers more than seven per cent of Europe's gas consumption through its sales of equity and SDFI gas. European gas consumption was 485 billion scm in 2001 and 490 billion scm in 2002. The International Energy Agency (IEA) expects an annual growth in gas consumption of three per cent in the period 2000-2010.

The UK, which has previously been self-sufficient in natural gas, now ranks as an exciting market. UK imports are set to increase and Statoil has good opportunities to build a strong position. Statoil's market position is described more closely on pages 34 and 35.

New contract in the UK

In June 2002 Statoil signed an agreement with British Gas Trading for the supply of five billion scm of natural gas per year, over a period of 10 years. British Gas Trading is a subsidiary of Centrica, which is the UK's largest supplier to the household market. Deliveries will start in 2005.

Statoil entered into an agreement with BP in 2001 for a total supply of 24 billion cubic metres of gas to the UK market over 15 years.

With a total volume of 74 billion cubic metres for these two contracts, Statoil asserts its position as the largest exporter of gas to the UK.

Acquiring gas storage

In 2002 Statoil acquired the development rights for an underground gas storage facility to be built at Aldbrough, near Hull, on the east coast of England. The new facility will act as a buffer against possible terminal interruptions, and will provide security of supply for

A 30 per cent stake is held by Statoil in the Dublin Bay Power Plant in Ireland. This facility will be able to meet 10 per cent of total Irish electricity requirements.

Statoil has a 32 per cent average interest in three large LNG carriers which will ship Snøhvit gas to markets in southern Europe and the USA. Under construction in Japan, these vessels are due for delivery between November 2005 and April 2006.

Statoil's gas deliveries to the UK market. It will also function as a business tool in marketing operations. Consisting of three underground salt caverns, the facility will be ready in 2007.

Gas hub in Germany

In a joint venture with Ruhrgas and BEB, Statoil has established the North Western European Hub Company. The company will provide hub services for gas transactions in the Emden area, a geographically central region for gas throughput from the NCS to the German and Dutch pipeline network. By exploiting the physical facilities in this area, the group is able to offer its customers trading opportunities associated with short-term gas supplies in northwest Europe.

www.statoil.com/pipelines

Poland uncertain

In September 2001 a sizeable deal was agreed for the sale of natural gas to the Polish Oil and Gas Company. Starting in 2008, the Polish company was to receive 73.5 billion cubic metres of gas over a period of 16 years. However, the contract has not been ratified since some conditions have not been met. There is growing uncertainty as to whether these terms will be resolved before the final deadline of 1 October 2005.

EU withdrew statement of objections

In July 2002, the European Commission decided to withdraw a statement of objections issued against Statoil and other companies operating on the NCS. The statement concerned the marketing of Norwegian gas through the Gas Negotiating Committee (GFU). It was withdrawn after Statoil and the European Union reached an amicable settlement. Statoil has committed itself to offering for sale a total of 13 billion cubic metres of gas to new customers between 1 June 2001 and 30 September 2005.

The definition of a new customer is all companies within the EU which were not among Statoil's long-term customers prior to 2001. The agreement is retrospective to 1 June 2001. A portion of the gross volume has already been sold.

Statoil has undertaken this without any admission that the company's marketing and GFU gas marketing activities constituted an infringement of the competition rules of the EU.

Office in Paris

The gas market's structure is undergoing change as a result of the implementation of the EU gas directive. There is a strong increase in the number of potential new customers, while the sales contracts are becoming shorter and the volumes smaller. Statoil has therefore opened an office in Paris to create new business opportunities and to follow up the markets in France, Italy and Spain where Statoil is involved. These countries could also become important markets for the group's future equity production of gas outside the NCS.

New company for gas pipelines and terminals

As of 1 January 2003, the ownership interests in the Norwegian gas transport systems and terminals have been merged into a new partnership, Gassled. Various interests in a total of 15 licences have been unitised. The new organisational model, with state-run Gassco as operator, opens opportunities for more efficient operations and development of the Norwegian gas transport system. Statoil is technical service provider for the majority of the lines and terminals in Gassled. The group has an interest of 21 per cent in Gassled, while its interests in the receiving stations in Zeebrugge and Dunkerque, which are part of Gassled, are about 10 per cent and 13 per cent respectively.

A gas tanker berthed at the Kårstø processing complex. Statoil has interests in and is technical service provider for large parts of Norway's gas export infrastructure. This comprises the world's largest submarine pipeline system and gas treatment plants in Norway, continental Europe and Scotland.

The future starts on Snøhvit

[Technology]

Research into multiphase flow technology has been pursued by Statoil for more than 20 years, and the group is among the world leaders in this area. The ability to transport unprocessed mixtures of oil, water and gas in the same pipeline has made it possible to develop the Snøhvit gas field in the Barents Sea. This is because operator Statoil can eliminate a staffed offshore installation, with its associated operating costs. As a result, Snøhvit also opens wide perspectives for the future.

Major savings

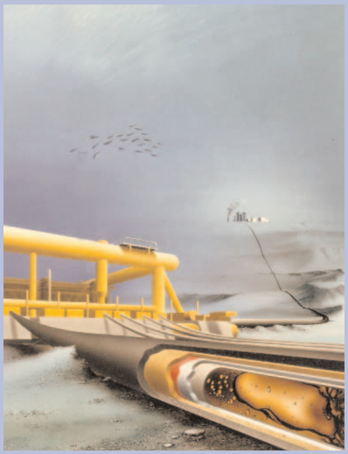
The subsea solution on Snøhvit is based on piping the unprocessed wellstream, comprising gas, condensate, water and carbon dioxide, over the 175 kilometres to land. This means that Statoil has taken a big step forward with multiphase flow technology, since the longest distance over which unprocessed gas and liquids are currently piped is about 100 kilometres. Statoil already operates multiphase flow transport on the Åsgard field in the Norwegian Sea and between Troll A and the gas terminal at Kollsnes near Bergen. Applying this technology on Troll A made it possible to take the big gas processing plant originally intended for the platform and place it on land. The result was a big reduction in platform size, offshore staffing and development costs.

Extensive research

Statoil's research centre in Trondheim has devoted considerable efforts to understanding how multiphase flows behave under different conditions, and how the most predictable and stable behaviour can be achieved in the pipeline. The group has made great strides in technical knowledge of such transport, and vice president Ingve R Theodorsen at the centre sees great possibilities.

Northern promise

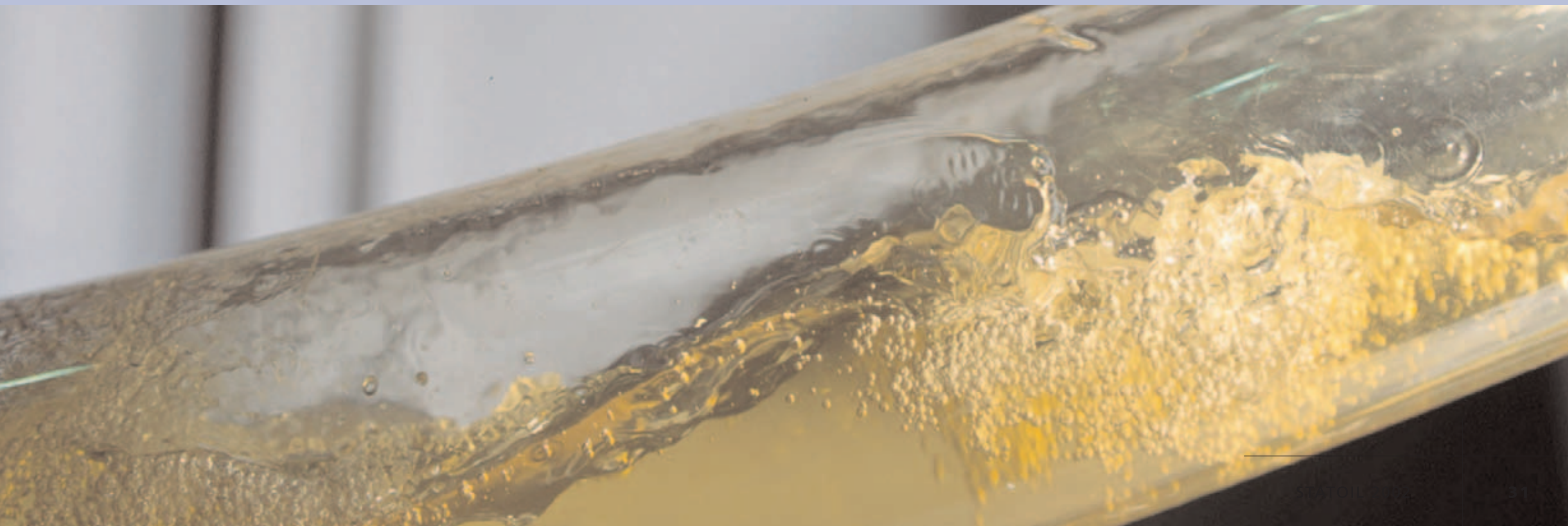
"Expertise in multiphase flow technology is a very valuable commodity, which we can utilise in our internationalisation efforts," he says. "It can be applied to further



With the Snøhvit development, multiphase flow has been extended to almost twice the existing distance for such transport.

projects in the far north. I see nothing to prevent a subsea development with associated multiphase flow transport on Russia's big Shtokman gas field in the Barents Sea."

Nor would Mr Theodorsen rule out the possibility that environmental demands will require the oil industry to find alternatives to conventional development solutions. In that event, Statoil's expertise with multiphase flow and subsea production solutions would put it in a strong position.



The challenge in piping unprocessed oil, gas and water through the same line is that the various components (phases) behave differently. Substantial research efforts have been devoted to predicting what happens in the pipeline.

Manufacturing & Marketing

The Manufacturing & Marketing business area embraced seven business clusters in 2002: *oil trading and supply*, responsible for the sale of crude oil, NGL and refined products, *refining*, which processes crude oils at Mongstad and Kalundborg, *Nordic energy*, selling traditional oil products and natural gas in the Nordic region, *retailing*, responsible for the service station network, *methanol*, operating methanol production at Tjeldbergodden, the *Navion* shipping company and *Borealis*, the European petrochemicals group owned 50 per cent by Statoil.

Key figures (NOK million)	2002	2001
Total revenues	211,152	203,387
Income before financial items	1,637	4,480
Gross investments	1,771	811

www.statoil.com/marketing

Oil trading and supply

The international crude oil market was largely characterised by rising prices during 2002, with Brent Blend reference crude reaching a high of USD 31.9 per barrel and a low of USD 18. Developments were affected by weak growth in the world economy. Production restrictions were instituted on the NCS during the first half-year. Brent Blend was expanded to include two new crude qualities – Forties and Oseberg. This is expected to provide a more predictable and representative pricing of crudes from the North Sea area, which is very important for Statoil. The group sold an average of 2.4 million daily barrels of oil during 2002, with its own production accounting for 31 per cent, sales of crude bought from the Norwegian state 45 per cent and third-party crude 24 per cent. Statoil's most important oil customers are its own refining operations and major oil companies in Scandinavia, Europe, the USA and Asia.

Oil trading yielded a good financial result for Statoil in 2002.

Refining

Apart from a brief period in late autumn, refining margins were low in 2002 and the result for the year is unsatisfactory. A new desulphurisation plant for gas oils began operating at Kalundborg in July, and a similar facility for petrol is due to come on stream at Mongstad during the first quarter of 2003. Both plants have been completed as planned and within budget. A new oil spill response centre at Mongstad ensures that the port is now better equipped to prevent and clean up oil spills. Jetty capacity for crude exports from Mongstad is to be expanded. This will make it possible to load more tankers which can carry crude to the USA and Asia. Supplies from Mongstad and Kalundborg are delivered to their own distribution network and to customers in Scandinavia, Europe and the USA.

Statoil is due to deliver its first energy solution incorporating seawater-based heat pumps and propane to a large housing project in Stavanger.

Agreements have been concluded by Statoil to acquire 79 service stations in Poland and 61 in Estonia, Latvia and Lithuania. This will bring its total network in these countries to about 200 forecourts in Poland and 150 in the Baltic states. The transactions are due to be completed in the first quarter of 2003.

Nordic energy

Nordic energy improved its results once again in 2002. This partly reflects some increase in volumes sold, but above all a sharp reduction in costs. The Meganor subsidiary, which pursued electricity sales to the household market in Norway, has been sold. Electricity sales to large corporate customers are being maintained by Statoil as an important supplement to its oil product sales.

Statoil is the first company in Norway to offer a new heating oil which contains 90 per cent less sulphur than conventional products. The group has acquired 24 diesel oil facilities from Fortum in Sweden, which helps to reinforce its network of service stations for heavy vehicles.

Retailing

Statoil strengthened its position in the petrol market during 2002. An agreement was concluded on acquiring the Preem Petroleum service station network in Poland. Agreement was reached with Shell to acquire its forecourt network in the Baltic states of Estonia, Latvia and Lithuania. Eleven new stations were built in Poland and the Baltic states during 2002.

The number of automated stations operated under the 1-2-3 brand was expanded from 21 at 1 January to 59 by 31 December. Of these, 49 are in Scandinavia and 10 in the Baltic states. Statoil Detaljhandel Skandinavia AS, owned 50-50 with the ICA/Ahold retailing chain, is continuing to develop its service concept. Providing a wider range of groceries in forecourt shops, it was in place at 161 stations by 31 December – an increase of 61 over the year.

At 31 December, Statoil had a total of 1 883 staffed and automated stations in nine countries.

A service station opened near Oslo in late 2002 incorporates a further development of Statoil's design concept. This will be applied when building new forecourts and in the modernisation of the whole station network.

Navion sold

Navion was sold in December to Norsk Teekay AS, a wholly-owned subsidiary of Teekay Shipping Corporation, for a net price of about USD 800 million. The financial date of the transaction was 1 January, and the sale is expected to be closed during the first six months of 2003. Navion's holdings in the *West Navion* drill ship and the *Navion Odin* multipurpose shuttle tanker were transferred to Statoil before the sale.

West Navion is owned 50-50 with Smedvig, while *Navion Odin* is wholly owned by Statoil.

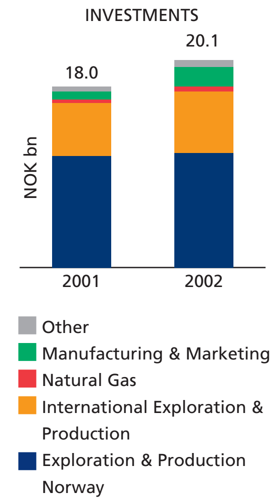
Methanol

Methanol operations at Tjeldbergodden were again characterised by high regularity and HSE results remained very good. Prices were weak at the start of the year, but recovered somewhat during the second half. From the autumn of 2002, Statoil has extended the market for its methanol to include customers in the USA and Canada. It already has a strong market position in Europe.

Borealis

The involvement in petrochemicals through Statoil's 50 per cent holding in Borealis was characterised by rising prices in the first half-year and a sharp downturn during the second. Although the business yielded a better result than the year before, it is still not satisfactory, despite positive effects of the current improvement programme.

The Borouge company owned by Borealis and the Abu Dhabi National Oil Company officially inaugurated its new petrochemical complex at Ruwais in the United Arab Emirates in October. It began operating on 1 February 2002, and was completed on time and under budget. With one plant for ethylene and two for polyethylene, the complex is based on the Borstar technology developed by Borealis. This makes it possible to produce thinner and stronger plastic products.



Statoil's Kalundborg refinery in Denmark could deliver virtually sulphur-free diesel oil from July 2002. That provides a marked reduction in emissions, which meets the EU requirements expected to be introduced in 2005. A corresponding investment at Mongstad will allow the group to deliver virtually sulphur-free petrol in 2003.

In 2002, Statoil delivered LPG for the first time to Japan – one of the world's most important markets for this product. Norway ranks as the world's third largest LPG exporter.

[Theme] On the offensive in new and established gas markets

Statoil has traditionally produced, transported and marketed Norwegian gas to a limited group of buyers in continental Europe. The number of continental customers has now vastly increased, and the UK is becoming an important market. Statoil sells gas to the USA, builds gas liquefaction plants, invests in LNG carriers and aims to sell gas from Azerbaijan to Turkey.

European oil consumption has increased by seven per cent over the past decade, while gas consumption has risen by no less than 40 per cent –from 340 billion cubic metres in 1991 to 470 billion in 2001.

Statoil has devoted these 10 years to building itself up into one of the biggest players in the European gas market. It currently meets just over seven per cent of Europe's needs with its own equity gas and supplies from the state's direct financial interest on the NCS.

"I think the sharp growth will continue," says Peter Mellbye, executive vice president for Statoil's Natural Gas business area. He believes that the group is well placed to increase its share of an expanding market.

Can deliver more

"Our gas reserves are close to the market," Mr Mellbye notes. "We've built up an infrastructure of gas treatment plants and transport systems, which means we can expand our capacity at modest cost to provide additional volumes. That applies not only for pipeline transport, but also for gas to be liquefied in the Snøhvit plant under construction at Melkøya outside Hammerfest in northern Norway.

"If we find more gas to supplement the reserves in Snøhvit, it will make good economic sense to build a second processing facility to handle the extra volumes."

He adds that this makes it a big challenge for Statoil to find more gas on the NCS.

The UK has become an important market for the group. Growth in British gas consumption has been even stronger than in continental Europe, rising by no less than 70 per cent over the past decade to 95 billion cubic metres in 2001. That corresponds to 20 per cent of overall European demand.

Commitment to the UK

Statoil is making a big commitment to the UK market, which must increase gas imports sharply in coming years as domestic supplies decline. Within two years, the group will be marketing 8.6 billion cubic metres of gas annually in Britain.

Mr Mellbye believes it would be realistic to have even higher ambitions: "We could reach an annual volume of 20 billion cubic metres in the UK market."

Statoil's historic role has been production on the NCS, pipeline transport and sale to a handful of major European customers under long-term contracts. A politically-

The UK has become an important gas market for Statoil, which concluded sales contracts with British buyers in both 2001 and 2002. The graph shows the market share for Norwegian gas in the countries to which Statoil exports gas.

directed liberalisation of the European Union's gas market will change customer patterns. While Statoil had four European gas buyers in 1980, it now has about 30. While large customers have had to reduce their purchases, new opportunities are opening up. Companies supplied by Statoil for a long time remain its biggest customers after the liberalisation. According to Mr Mellbye, the main challenge is to protect the value of existing contracts while pursuing new market opportunities.

LNG to the USA

Statoil will also be operational in the US gas market from June 2003, after acquiring capacity in one of the country's four LNG import terminals. This Cove Point facility is not far from Washington DC. Access to its import capacity will allow Statoil to sell gas to the American market.

During the first few years, gas supplies will be acquired through purchase or swap agreements. But Statoil will start selling its gas to the USA in 2006, when Snøhvit comes on stream. The group will ship LNG across the Atlantic. It has a 32 per cent interest in three large LNG carriers under construction to transport Snøhvit gas.

"Becoming operational in the LNG market with our own gas will be an important milestone for us," says Mr Mellbye. "We're a big gas player with substantial expertise throughout the value chain, from production to end users. So it's also important for us to develop as a player in a sharply expanding LNG market."

Seeking sales to Turkey

On the basis of a substantial gas discovery off Azerbaijan, Statoil is working to establish a market for natural gas in Turkey. The group has a 25.5 per cent interest in the Shah Deniz gas field in the Azeri sector of the Caspian Sea, which depends for its development on finding a Turkish market. A contract has been signed by Statoil with national gas company Botas in Turkey, covering annual sales of six billion cubic metres from 2006. The Turkish gas market has expanded sharply over the past decade. Annual consumption has more than tripled, reaching 15.5 billion cubic metres in 2001. The country produces no gas of its own, and imports supplies by pipeline from Russia and as LNG from Algeria and Nigeria.

"I'm confident that we'll achieve the breakthrough we need in Turkey, and I'm convinced that pipeline gas from Azerbaijan is the most competitive supply alternative," says Mr Mellbye.

"Statoil is in a good position to secure new interests in a gas market which will continue to grow," says executive vice president Peter Mellbye.

Culture is energy. Statoil has cooperation agreements with music festivals, young musicians and the Stavanger Symphony Orchestra. Backed by the group as its principal sponsor since 1990, the orchestra is represented here by brass players Øyvind Grong (left), Leif Værum Larsen, Ebbe Sivertsen and Gaute Vikdal.

www.statoil.com/sponsor

Statoil, safety and society

Statoil published its first special report on sustainable development in 2002. In the group's view, sustainability is about the impact of its operations on people, the environment and society. As chief executive Olav Fjell has put it: "Statoil will operate profitably, safely, in an ethically acceptable way, and showing concern for the environment and social responsibility. We are committed to delivering good results against three bottom lines – the financial, the environmental and the social."

This chapter deals with the third bottom line – the effects of the group's operations on the community.

Culture and values

Statoil works purposefully to develop a strong and unified corporate culture rooted in clear values. This finds expression in the group's governing documents. The fundamental guidelines are enshrined in *We in Statoil*, which summarises the group's values and business principles, and describes how it wants to conduct its business.

Expertise

Great emphasis is placed by Statoil on developing its employees and managers. Several management development programmes are being pursued. A new programme for senior executives was established in 2002. Statoil has growth ambitions and is committed to a rapid build-up of its international oil and gas production. That means increased recruitment of personnel outside Norway. It also involves challenges related to pursuing operations in countries with varying degrees of transparency, responsibility, freedom of assembly and speech, and form of government.

To meet these challenges, an international strategy was drawn up in 2002 for personnel and organisational development. It aims to create understanding and support for Statoil's culture and values, and deals otherwise with measures related to training, selection of managers and mobility of personnel across the group.

Equal opportunities

Statoil's policy is to provide equality of opportunity for all, regardless of gender, age and cultural background. The group believes that diversity in its organisation has a value in itself, and that different viewpoints help to ensure better decisions. Equal opportunities and diversity are regarded as a competitive advantage.

The group's ambition is for women to occupy at least 20 per cent of senior managerial positions at all levels. At 31 December 2002, this proportion was 15 per cent. The proportion of women managers in the under-45 age group is 27 per cent.

Popular trainee programme

Special measures have been

www.statoil.com/future

Statoil reached the 30th anniversary of its formal incorporation on 18 September 2002. Former chief executives Arve Johnsen and Harald Norvik took part in the celebration together with Olav Fjell. Mr Johnsen holds the cigar box which housed Statoil's first petty cash and a few stamps. His secretary, Marit Falch, took this container with her to work and used it during the initial weeks when she and Mr Johnsen were the company's only employees.

adopted by Statoil to strengthen its recruitment of young personnel. A two-year group trainee programme has been established, directed at young people with higher education qualifications. Two thousand applications were received for 24 trainee posts in 2002. Participants in the programme gain work experience from different business areas in Statoil as a basis for their future career development with the group.

Statoil has one of the largest intakes of apprentices among Norwegian companies, and welcomed 119 of these on two-year contracts in 2002.

Attractive employer

Statoil has registered increased interest in the group among students. In 2002, it was rated as the most attractive employer among final-year engineering and economics students in Norway.

Job applications to Statoil are also on the rise. More than 11 000 were processed in 2002.

Health and the working environment

The results of Statoil's 2002 working environment survey show progress in most areas from 2001. Job satisfaction, trust in the management and confidence that Statoil will succeed in fulfilling its ambitions have strengthened. The survey was carried out electronically for the first time.

Sickness absence in Statoil is at a low and stable level of 3.4 per cent. The group's objectives are zero work-related injuries and illness, as well as modes of working which promote creativity, efficiency, good health and well-being.

Statoil offers training programmes for employees with chronic musculoskeletal disorders. One of the Norwegian government's measures for reducing sickness absence involves collaborating with industry on an inclusive workplace. This commits the company to working actively to reduce sickness absence and to making arrangements to allow personnel whose capacity for work has been reduced to remain in employment.

Statoil's goal is zero injuries, accidents or losses, and to conduct its business in a way which avoids hazardous incidents. Despite a favourable trend, with a continued decline in the number of personal injuries, the group and its suppliers suffered six fatal accidents in 2002. That compares with two the year before. Each of these accidents is discussed in more detail under HSE accounting.

Against this background, US company DuPont Safety Resources has been commissioned to undertake a detailed review of Statoil's safety culture. This will focus on routines for management and control, as well as behaviour and attitudes at all levels of the organisation.

Fewer injuries

The total recordable injury frequency (the number of recordable injuries per million working hours) declined from 6.7 in 2001 to six. Statoil records and analyses all incidents which cause or could have caused injury or loss. The most serious incidents are investigated. This is done to learn lessons and to transfer these both in-house and externally.

Safety conditions at Statoil's facilities on land and offshore were surveyed in 2001 and 2002.

"Open safety dialogues" are used systematically to reduce risky behaviour in work operations. These dialogues take place between manager and subordinate at the work site. Risk elements of the job and possible measures to prevent injury are discussed. Almost 2 000 managers received training in this tool during 2002.

Robberies and road tanker accidents account for a large proportion of serious incidents in the Manufacturing & Marketing busi-

www.statoil.com/job

Charles Tjessem (31), a cook at Statoil and product manager for its canteens, won the unofficial world championship for master chefs in Lyons during January 2003. The group's apprentice cooks have also done well in competition, winning the Nordic championship for trainees three years in a row.

Statoil's IT step training programme, first launched in 1997, was extended in 2002. Per Haaland, currently on a posting to Iran, is one of many employees who accepted the offer of upgraded computer hardware and a new training package.

Prize for maritime safety

The chief executive's health, safety and environmental prize is awarded annually to highlight and reward work which has yielded good HSE results. Sixty-five candidates were nominated in 2002, and the winner was the maritime operations sector in Statoil and the relevant shipping companies for their efforts to make supply, emergency response and anchorhandling activities safer.

Very good results have been achieved, demonstrating that a high HSE performance can also yield efficient operation. In addition to establishing very good attitudes, the work has developed standards which are now industry norms. The number of collisions between vessels and installations fell from 12 in 2000 to one per year in 2001 and 2002, while the number of injuries almost halved from 2001 to 2002. No serious injuries were incurred in connection with anchorhandling during 2002, while Statoil suffered fatal accidents relating to this type of work in both 2000 and 2001.

ness area. Systematic efforts to prevent robberies and encourage defensive driving are an important priority for the distribution chain.

Social commitment

In common with other oil companies which operate in challenging countries, Statoil is increasingly being asked to demonstrate how it makes a positive contribution and what it creates locally. Much attention was devoted to this topic in the group's first sustainability report, and it will be discussed in greater detail in the next report. This is scheduled for publication in 2003.

Statoil's most important contribution is measured as value creation. That represents the impact of its investment on jobs, procurement of goods and services, transfer of technology and expertise, infrastructure development and tax revenues.
Through its social investment, the group also seeks to contribute to local capacity building in education, health and human rights. It does this primarily by channelling funds through humanitarian organisations pursuing local development work.

Support for work on human rights

Three Nigerian human rights organisations received project support from Statoil in 2002. One of these ventures aims to expand judicial capacity in the country to help reduce the amount of time people spend remanded in custody. The second involves familiarising Islamic Sharia judges – who base their judgements on the Koran – with the UN declaration on human rights. A total of 120 judges from six states in northern Nigeria are to receive training in human rights. The third project seeks to combat criminal behaviour among young people.

Statoil established its own strategy on HIV/Aids in 2002 in order to support the fight against this disease in areas in which the group operates. The aim is to prevent suffering and loss for both those infected and the group. This is pursued through information and courses which equip people to look after themselves, their families and their workplace.

Since 1986 Statoil has carried out annual working environment and organisation surveys. The results are used in the group's improvement work. Support for the survey has been good, and the response rate in 2002 was 84 per cent. The average score for the question "All in all, how well do you enjoy your job?" was 4.6. This was measured on a scale from 1 to 6, where 1 is "not very much" and 6 is "very much".

[Theme] Secure school for traumatised children

The acacia tree spreads its shady branches over the 25 children sitting on stones and tree stumps at the Candjanguite refugee camp in south-eastern Angola.

They are not distracted either by the birds twittering in the canopy or by the livestock grazing in the hot surrounding fields.

The children stare intently at a board which teacher José Gala has hung on the tree trunk. He is giving a maths lesson, and asks the class initially to tell him the date.

Mr Gala is one of 43 teachers in the camp who have been trained to use the teacher's emergency package (TEP) developed by Unicef. This system has also been dubbed "school-in-a-box", since each educator gets all their necessary aids in a metre-long blue metal box.

The Norwegian Refugee Council has been providing TEP education since 1996, and has a staff of 14 teachers who visit the camps and train others to apply the method.

In 2002, the council devoted funds received from Statoil to finance courses and the establishment of TEP schools in Matala local authority, which embraces Candjanguite.

Mr Gala's blue box contains enough materials for two teachers to hold two classes under a tree, in a tent or in an abandoned building. These include a cloth poster with the alphabet, another with numbers, a large clock, slates for the pupils, chalk, pencils, small wooden blocks for language and number games and other teaching materials.

Almost 40 years of war mean that a whole generation of Angolans has missed out on schooling. The one-year TEP model provides basic reading, writing and arithmetic skills for children from 12 to 17. They are then qualified to attend regular schools.

The class under the tree breaks into song. Children do that often here, because they sing about what they are involved with.

Mr Gala speaks Portuguese, the official language of Angola which all schoolchildren must learn. But many in the class only know their native tongue, and have problems following the lessons to begin with.

The teachers also find it challenging to deal with children traumatised by war.

"We know for certain that both sides in the conflict recruited children," says Berit Norbakke, the Norwegian who heads the refugee council's TEP project. "They were captured and forced to work behind the lines."

She estimates that about 70 per cent of the children in each class are traumatised. They have seen adults shot and killed, their mothers, fathers and siblings killed or abused by soldiers, or people injured by landmines.

"We must show them we care," says Alexandre Moises, head of TEP education in the camp. "Lessons must include a lot of play, song and drama."

Splitting a class with the maximum of 25 pupils into smaller groups or pairs is important, because it makes the youngsters feel more secure.

"That makes heavy demands on the teachers," explains Ms Norbakke. "When the children learn through play, they don't experience the education as exceptionally demanding."

More than 50 per cent of Angolans are younger than 18, and the country has the world's second-highest child mortality rate after Sierra Leone.

The nation is rich in resources, particularly petroleum and diamonds, but it nevertheless ranks as one of the world's poorest states.

Gracianne Sekula and her friends are having a maths lesson in the fields around the Candjanguite refugee camp.

"Corruption and lack of transparency contribute to the unequal distribution of resources," Ms Norbakke observes. "But education can't be corrupted. You can't steal what people have in their heads."

The refugee council has been running camps for internally displaced people since 1994, and distributes food, emergency items and clothing. It educates people about preventive health care and HIV/Aids, and fights for refugee rights.

A major seed corn project was pursued by the council during 2002 in Huila province, which embraces Matala. Seed for 100 000 people arrived before the rainy season, thereby averting a famine.

Peace was restored to Angola in April 2002. The war-weary population have a hesitant hope that fighting will not flare up again.

"We've seen an increase in the number of people returning to their homes over the past couple of months," reports Ms Norbakke. "That's a sign of confidence in the peace."

At peak, the region around Candjanguite had 80 000 displaced people in 20 different camps. Refugees driven by hunger continued to arrive after the fighting stopped, right up to November 2002.

The number of displaced people in the region has now fallen to 30 000 in six-seven camps. If peace persists and the camps continue to empty, the refugee council's work will be over in one-two years.

In 2002, Statoil contributed to the Norwegian Refugee Council's work in Angola. The council provided training for 43 teachers to provide basic education for around 1 000 children who are mostly internal refugees.
Statoil also supports projects run by the Norwegian People's Relief Association on education, regional development and land-mine clearance.
And the group is supporting a home for street boys, a centre for HIV/Aids and water drilling in Cabinda province.

Ariake has arrived at Saint John on the Canadian east coast with crude oil from Mongstad, and terminal workers Darrel Muise (left) and Ken Nauffts have got everything ready to start discharging 267 000 tonnes of crude. Statoil exported 30 million tonnes of crude to the USA and Canada in 2002, adding up to 150 tanker consignments. All vessels shipping oil for Statoil are inspected once a year, and 80 per cent of crude oil carriers which sail for the group have a double bottom or hull.

The environment

"Statoil's vision is to build a world-class international oil and gas company. This requires that we are among the absolute front runners in protecting the environment. No other avenue is open. If these environmental responsibilities are not taken seriously, we will lose legitimacy, competitiveness and the licence to operate." This is how chief executive Olav Fjell has formulated Statoil's ambitions and commitments on the environment. The group's goal is therefore to conduct its business without harm to people or the environment.

Frame conditions

Emissions to the air are largely regulated by international agreements. The Kyoto protocol on reducing greenhouse gas emissions and the Gothenburg protocol, which commits signatories to cut emissions of nitrogen and sulphur oxides as well as volatile organic compounds (VOC), are particularly important for Statoil's business. Discharges of oil and chemicals in the north-eastern Atlantic are regulated by the Oslo-Paris (Ospar) convention. This requires that the oil content in produced water released to the sea must not exceed 30 milligrams per litre by 2006, when the total annual volume of such discharges must be 15 per cent lower than in 2000.

Stricter standards from 2005

The Norwegian authorities have specified that harmful discharges to the sea must reach zero by 2005. This means ceasing or significantly reducing the release of certain environmental toxins, and a substantial reduction in the risk of harm from using and discharging chemicals.

The European Union's integrated pollution prevention and control (IPPC) directive calls for the use of the best available techniques to reduce emissions/discharges. From 2007, these requirements will also apply to existing installations. The convention on biological diversity signed at Rio de Janeiro in 1992 imposes a commitment to take account of biodiversity.

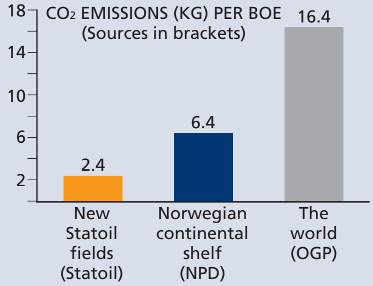
Emissions and environmental impact

Oil and gas production causes emissions and discharges to the natural environment. The level of these is influenced by the volume produced and by a field's reservoir conditions and age. Emissions relating to oil and gas processing depend on the type of feedstock involved and the products being produced. They are influenced by plant design, technology and operating regularity.

Emissions to the air include carbon dioxide, methane, VOC, and sulphur and nitrogen oxides. These contribute variously to the greenhouse effect, acid precipitation and the formation of ground-level ozone. Offshore operations account for the bulk of Statoil's carbon dioxide and nitrogen oxide emissions, while refining is responsible for most of the sulphur dioxide it releases.

Increased water production

Discharges to the sea embrace oil, organic compounds and chemicals, and derive largely from produced



Carbon dioxide emissions from new Statoil fields are among the lowest in the world.
(NPD: Norwegian Petroleum Directorate, OGP: International Association of Oil & Gas Producers)

New technology and more environment-friendly chemicals have been adopted on Heidrun in the Norwegian Sea to prevent deposition in the wells. These measures have been implemented in close cooperation with the supplies industry, and emissions of possibly environmentally-harmful chemicals per well workover were halved by comparison with 2001.

water and drilling. Possible harmful environmental effects relate particularly to compounds which are slow to degrade and are highly toxic or have a potential for bioaccumulation. Operations on the NCS are the biggest source of Statoil's discharges to the sea. The volume of produced water released has expanded sharply in recent years because certain fields are in a late phase. Statoil's offshore and land-based activities generate waste. Emphasis is given to recovering and recycling the latter, with hazardous waste being treated in line with prevailing regulations.

Reducing emissions

Continuous efforts are being made to reduce emissions to the air and discharges to the sea through research and the development of ever-better technology, effective emergency response and good management based on extensive risk assessments. The aim is continuous improvement through enhanced energy efficiency and other purposeful measures on existing and future installations.

Discharges to the sea attracted particular attention in 2002. Work was devoted to developing new technological solutions and to phasing out environmentally-hazardous chemicals, and Statoil is well on the way to meeting the government's requirement for zero harmful discharges from its oil and gas fields by 2005.

Chemicals released from Statoil's offshore operations have been reduced from 2001 to 2002. Of these, 89 per cent cause little or no environmental impact while 10 per cent have acceptable environmental properties. Only 0.6 per cent are questionable, and these are being phased out.

Environmental monitoring

The condition of the environment around Statoil's installations is monitored through regular programmes. Environmental monitoring covers both water quality and seabed sediments, and shows a satisfactory trend.

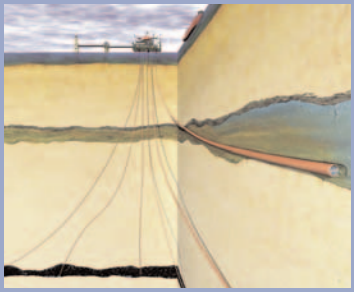
Where emissions to the air are concerned, continuous efforts are being made to reach the goal of trimming 1.5 million tonnes of carbon dioxide equivalent from the annual volume of greenhouse gases released on Statoil's installations by 2010, compared with the amount which would be emitted without special measures.

Statoil supports the Kyoto protocol and the adoption of emission trading to limit the release of greenhouse gases in a cost-effective manner. The group is making the necessary preparations to meet requirements for lower

www.statoil.com/co2

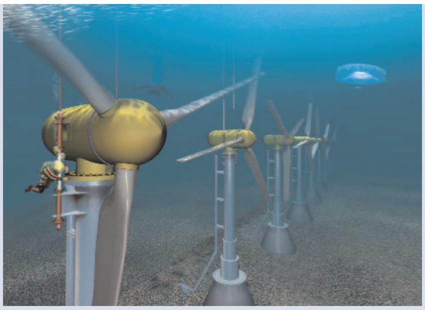
International prize for carbon dioxide storage

The technology development prize from the World Petroleum Congress went to Statoil in 2002 for its work on injecting and storing carbon dioxide in a sub-surface aquifer in the Sleipner area of the North Sea. This project was selected as the winner from among 78 candidates.



About a million tonnes of carbon dioxide are returned underground and stored in the Sleipner area every year. This technology will also be applied on Statoil's Snøhvit project in the Barents Sea, which comes on stream in 2006. Some 700 000 tonnes of the greenhouse gas will be stored there annually.

Ranked as the world's first industrial-scale carbon storage operation, the Sleipner area project has attracted great international attention. Statoil has helped to launch a new European network on dealing with carbon dioxide, with companies from all over Europe participating.



Through a 24 per cent holding in the Hammerfest Strøm company, Statoil is involved in constructing a new tidal power station at Kvalsundet in northern Norway.

Statoil heads a collaboration with 23 other companies on the NCS to reduce emissions of volatile organic compounds (VOC) from offshore loading. Eight VOC recovery plants will be operational on shuttle tankers by 31 March 2003. One of these is on *Juanita.*

greenhouse gas emissions. During 2002, it doubled its investment in the World Bank's carbon fund to USD 10 million.

Biological diversity

New oil and gas fields are often found in environmentally-sensitive areas, including both Arctic and tropical regions. These areas usually have poorly-developed infrastructures, and efforts are being made to identify technology and operating methods which protect the environment and ensure that local communities make positive progress.

Statoil is participating in the energy biodiversity initiative (EBI) together with three other oil companies and five environmental organisations. The EBI was awarded a prize at the 2002 world summit in Johannesburg for its work on protecting biological diversity.

Strict transport requirements

About 110 million tonnes of hydrocarbons were shipped by tanker from fields, terminals and refineries to customers world-wide in 2002. Road tankers belonging to or hired by Statoil covered about 35 million kilometres delivering products to service stations and customers. CO_2 emissions relating to these consignments are estimated at some 27 000 tonnes, or roughly 0.3 per cent of the total CO_2 released from Statoil operations.

Safety and environmental performance are important in selecting road tankers. Key measures include a high carrying capacity to reduce the number of consignments, modern engine technology with lower fumes, optimal route planning through good navigation systems, and using diesel oil with good environmental properties.

Cleaner products

Automotive fuels and heating oils are the principal products in Statoil's manufacturing and marketing segment. Its objective is that these commodities should rank among the best for technical user and environmental properties.

Burning oil products has a negative impact locally, regionally and globally. Emissions per unit of energy produced have been substantially reduced in recent years through cleaner products and improved engine and treatment technologies.

Alternative automotive fuels and new additives are under constant assessment and testing. Renewable fuel products such as rape methyl ester (RME), bioethanol and biogas are offered where customer demand exists. Statoil adds about five per cent bio-ethanol to roughly a fifth of all the petrol it sells in Sweden.

The group is the first oil company in Norway to offer a new heating oil with substantially reduced sulphur emissions. Launched in late 2002, this product contains almost 90 per cent less sulphur than conventional heating oil. Statoil's goal is to develop a profitable business which leads to sustainable energy production and increased use of clean energy bearers. A new energy sector is working on renewable energy, energy efficiency, carbon dioxide removal and use, and hydrogen as a future energy bearer.

Investments and costs

Statoil devoted NOK 800 million to research and development in 2002 with the aim of finding, producing and processing oil and gas more efficiently and cheaply, with less energy and with a decreasing impact on the environment.

A provision of NOK 8 056 million was made at 31 December under the unit of production method to meet the future cost of shutting down and removing oil and gas production facilities. NOK 706 million was charged against income.

Reusing offshore installations and equipment offers financial and environmental gains. In 2002, the trading and service sector earned NOK 51 million on sales of surplus materials.

Annual carbon tax paid for 2002 on emissions from Statoil-operated installations on the NCS totalled about NOK 1.4 billion.

Compressors are to be installed on Troll A to drive its gas ashore as natural reservoir pressure declines. Statoil has opted for units driven by hydropower. The gas-fuelled alternative would have emitted several hundred thousand tonnes of carbon dioxide annually.

Statoil produces and sells wood pellets in Norway, Denmark and Sweden. A total of 55 000 tonnes of this biomass were produced in 2002, up from 27 000 tonnes the year before.

[Theme] Demanding trade – strict controls

Randgrid **has just berthed at the Mongstad terminal near Bergen with a full cargo from the Heidrun field in the Norwegian Sea. A consignment totalling 117 000 tonnes of crude is safely in port, and ship's inspector Tore Tollefsen from Statoil has gone aboard. After shaking hands, master Karl-Otto Jonassen accompanies him on a routine check of the shuttle tanker.**

Cargoes shipped by *Randgrid* belong to its owner, ConocoPhillips. But the vessel is nevertheless inspected once a year by Statoil because it shuttles between Heidrun and Mongstad, which are both operated by the group. In that capacity, Statoil can refuse to accept tankers which fail to meet a number of requirements for their technical and operational condition. These are specified in detailed regulations which the shipowner has undertaken to observe.

Randgrid passes its inspection on this occasion. The vessel ranks as one of the finest crude oil carriers operating in Norwegian waters. Built in 1995, it features a double hull and dual propulsion systems, and maintains a high standard throughout.

But keeping tankers in good technical condition and operating them safely and acceptably is essential. Should an accident happen, the consequences for the maritime environment can often be catastrophic. Reminders of that are received time and again – most recently off Spain this winter.

Major user

Statoil is a major user of tanker services. Some 3 200 single voyages were undertaken for the group in 2002, carrying 110 million tonnes of crude oil, oil products and gases. Each of these journeys represented an environmental and safety risk. In addition came all the vessels lifting oil for other companies on fields and at Statoil's terminals.

A small department with seven-eight staff at the Stavanger head office is responsible for vetting and approving vessels in Statoil. This entity is headed by Leif Solem Farstad, a former master with Norway's Bergesen d.y tanker company. His staff includes naval architects, former chief engineers or masters. Their capacity is too limited to perform anything like the number of inspections required, so contacts have been forged with inspectors in a number of ports. This department is also Statoil's resource for setting vessel guidelines and quality standards.

Meeting standards

"We're charged with ensuring that the ships we charter, and the companies we take them from, meet the standards we specify," explains Capt Farstad.

He says that Statoil has few

Approval in several stages

No tanker can sail for Statoil until it has been through a multi-phase vetting procedure.

Questionnaire

As a first step, the vessel owner must complete an extensive questionnaire about the ship's condition. The answers determine whether the tanker should be chartered. Input from the questionnaire and other sources is stored in a database which contains detailed information on more than 3 000 tankers.

Age

The vessel must not be more than 20 years old. Exceptions can be made for gas carriers up to 30 years old and tankers in service for 25 years. Such ships must undergo an extra inspection which includes hull structural strength, engine condition and the loading/discharging equipment.

No general requirement

Statoil does not require a double hull or bottom generally but these feature on 80 per cent of crude oil carriers sailing for the group. The proportion of such vessels is rising.

Double hull/bottom

Ships over 5 000 deadweight tonnes carrying heavy fuel oil or similar products must have a double hull or bottom. The *Prestige*, which sank off Spain in November 2002, could not have been chartered by Statoil because of its age and single hull.

Inspection

Ships chartered for Statoil are inspected on the basis of an industry standard used by a number of oil companies. This lets one company charter a vessel which has been vetted by another.

problems with low-standard vessels, partly because companies operating such ships consciously refrain from offering them to the group. The requirements set for charters by Statoil and other major oil companies are well known in the shipping community. As a result, the worst cases find other employers. But some ships assessed do fail Statoil's vetting procedure. The group rejected 12 of the 845 ships it inspected in 2002.

Capt Farstad believes that the technical standard of the world tanker fleet is improving, but says the position for quality of crew and shipowner organisations is more complex.

Phased out

About 50 per cent of the world fleet still comprises single-hulled tankers, but rules from the International Maritime Organisation mean that the last such vessels will be phased out in 2015. The loss of the *Prestige* off Spain could speed up this process, says Capt Farstad.

Statoil has been involved in maritime oil transport since 1979, when it lifted its first consignment of crude from Statfjord in the North Sea. The volume of oil handled has grown and grown since then, and the group will also eventually be transporting substantial amounts of natural gas by sea. So far, only minor amounts of oil have been spilled from Statoil's tanker shipments. No serious pollution has occurred. Together with shipping companies, vessel crews and terminal staff, Capt Farstad and his team work every day to keep things that way.

Inspector Tore Tollefsen (left) and captain Karl-Otto Jonassen discuss the fire-fighting equipment on *Randgrid* while the tanker discharges crude oil at Mongstad.

Fishing vessels are dwarfed by the sheer-sided Lofoten mountains of northern Norway. Fishing and aquaculture ranks with oil and gas as the country's most important industries. Statoil is conscious of its responsibility for life in the sea, and its environmental efforts assume that the two industries will be able to develop side by side.

HSE accounting for 2002

Statoil's objective is to operate with zero harm to people or the environment, in accordance with the principles for sustainable development. The group supports the Kyoto protocol and the 16 principles of the International Chamber of Commerce for sustainable development. We apply the precautionary principle in the conduct of our business.

Statoil's management system for health, safety and the environment (HSE) forms an integrated part of the group's total management system, and is described in its governing documents.

A key element in the HSE management system is registration, reporting and assessment of relevant data. HSE performance indicators have been established to assist this work. The intention is to document quantitative developments over time and strengthen the decision-making basis for systematic and purposeful improvement efforts.

HSE data are gathered by the business units and reported to the corporate executive committee, which evaluates trends and decides whether improvement measures are required. The chief executive submits the HSE results and associated assessments to the board together with the group's quarterly reports. These results are posted to the group's intranet and its internet site.

Statoil's three group-wide performance indicators for safety are the total recordable injury frequency, the lost-time injury frequency and the serious incident frequency. These are reported quarterly at corporate level for Statoil employees and contractors, both collectively and separately. Sickness absence is reported annually for Statoil employees.

The group-wide indicators for the environment are reported annually at corporate level, with the exception of oil spills which are reported quarterly. Indicators for the external environment – oil spills, emissions of carbon dioxide and nitrogen oxides, energy consumption and the waste recovery factor – are reported for Statoil-operated activities. This includes the Gassled facilities at Kårstø, for which Gassco is operator, while Statoil is responsible for the technical operation.

All of the group's main activities are included in the HSE accounting. Data for Navion are included, with safety data and oil spills (number of hours, in accordance with shipping industry practice). Oil spills are the only data on the external environment included for the service stations.

Historical data include figures relating to acquired operations from the acquisition date. Correspondingly, figures relating to divested operations are included up to the divestment date.

Results

Statoil suffered six fatal accidents in 2002:

On 17 April a contractor employee died on board the *Byford Dolphin* rig after being hit by a falling object. The rig was working on the Sigyn field in the North Sea.

On 20 August a Statoil employee died following a fire at the Kalundborg refinery.

On 16 September a contractor employee was killed when a dumper truck overturned at Melkøya in Finnmark county.

On 11 October a Statoil driver was killed in a road tanker accident in Ireland.

On 21 November a contractor employee lost his life when he fell overboard in a working accident on the *Berge Danuta* LPG tanker in the Bay of Biscay.

On 26 November a contractor employee died after being hit by a vehicle at a service station in Nyborg in Denmark.

All of the accidents have been investigated, the causes recorded and improvement measures initiated.

Overall, the total recordable injury frequency, lost-time injury frequency and serious incident frequency all show an improvement in 2002 compared with 2001.

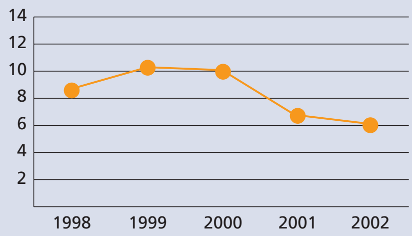
More than 79 million hours worked in 2002 (including contractors) form the basis for the HSE accounting. This is an increase of 10 million hours from 2001. The rise is partly due to development projects at the refineries and an increase in the number of service stations. Contractors handle a large proportion of the assignments for which Statoil is responsible as operator or principal company.

Use of resources, emissions and waste volumes for Statoil's largest land-based plants and operations on the NCS are shown in separate overviews. See also the information on health, safety and the environment in the directors' report and the review of Statoil's operations.

In addition to this corporate accounting, the business units prepare more specific statistics and analyses which are used in their improvement efforts.

Statoil's performance indicators for HSE

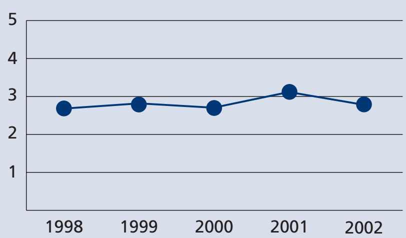
TOTAL RECORDABLE INJURY FREQUENCY



Definition: The number of fatalities, lost-time injuries, cases of alternative work necessitated by an injury and other recordable injuries, excluding first-aid injuries per million working hours.

Developments: The total recordable injury frequency (including both Statoil employees and contractors) declined from 6.7 in 2001 to 6.0 in 2002. There has been an improvement for Statoil employees, and for contractors in particular, in 2002 compared with 2001. For Statoil employees the frequency was 4.2 as against 4.4 in 2001. For contractors it was 7.6 compared with 8.8 in 2001.

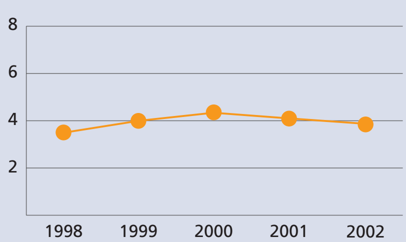
LOST-TIME INJURY FREQUENCY



Definition: The number of lost-time injuries and fatal accidents per million working hours.

Developments: The lost-time injury frequency (including both Statoil employees and contractors) was 2.8 in 2002 as against 3.1 in 2001. There has been an improvement for Statoil employees, and for contractors in particular, in 2002 compared with 2001. The frequency for Statoil employees was 2.4 as against 2.5 in 2001. For contractors it was 3.1 compared with 3.7 in 2001.

SERIOUS INCIDENT FREQUENCY

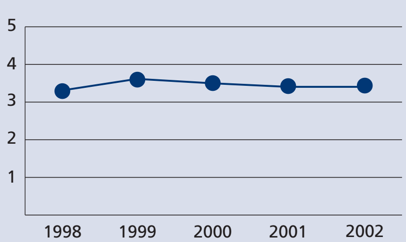


Definition: The number of incidents of a very serious nature per million working hours.(1)

Developments: The serious incident frequency (including both Statoil employees and contractors) was 3.8 in 2002 as against 4.1 in 2001, while the number of serious incidents has increased from 287 in 2001 to 297 in 2002.

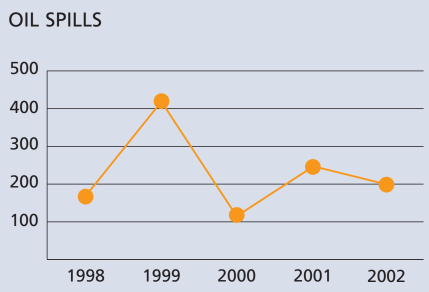
(1) An incident is an event or chain of events which has caused or could have caused injury, illness and/or damage to/loss of property, the environment or a third party. Risk matrices have been established where all undesirable incidents are categorised according to the degree of seriousness, and this forms the basis for follow-up in the form of notification, investigation, reporting, analysis, experience transfer and improvement.

SICKNESS ABSENCE



Definition: The total number of days of sickness absence as a percentage of possible working days (Statoil employees).

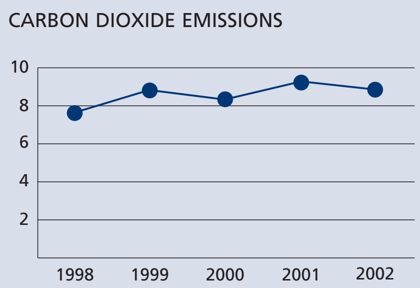
Developments: Sickness absence was 3.4 per cent in 2002, and this is the same as in 2001. Sickness absence has been consistently low over the entire five-year period. This result is well below the Norwegian average (7.1 per cent according to the NHO 2001 study).



Definition: Unintentional oil spills to the external environment from Statoil operations (in cubic metres). (2)

Developments: The number of unintentional oil spills in 2002 was 432 as against 414 in 2001. The volume of unintentional spills has been reduced from 246 cubic metres in 2001 to 200 in 2002. The figure shows the volume of oil spills in cubic metres.

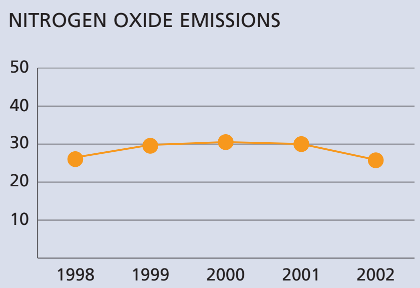
(2)All unintentional oil spills are included in the figures with the exception of those collected inside a facility (platform/plant) and which accordingly cause no harm to the surrounding environment. However, such spills are included for downstream operations.



Definition: Total emissions of carbon dioxide in million tonnes from Statoil operations.(3)

Developments: Carbon dioxide emissions totalled 8.9 million tonnes in 2002 as against 9.2 million in 2001. One important reason for this is good production regularity for operations on the NCS, where carbon dioxide emissions as a whole have been reduced even though the volume of produced hydrocarbons has increased.

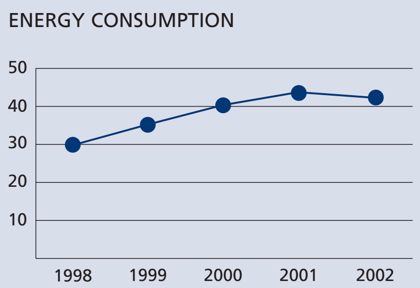
(3) Carbon dioxide emissions embrace all sources such as turbines, boilers, engines, flares, drilling of exploration and production wells, well testing/workovers and residual emissions from the carbon dioxide separation plant for natural gas on Sleipner T. The distribution of products (by Statoil road tanker, boat or railway) to customers (private, companies, petrol stations, airports) is included. Support services such as helicopter traffic, supply and standby ships and shuttle tankers are excluded.



Definition: Total emissions of nitrogen oxides in thousand tonnes from Statoil operations.(4)

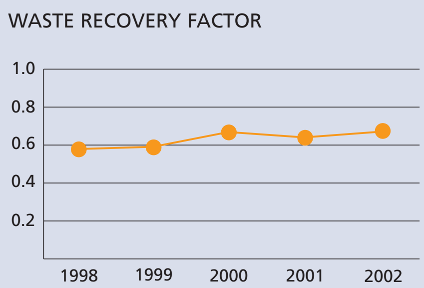
Developments: Emissions of nitrogen oxides totalled 26.4 thousand tonnes in 2002 as against 29.5 thousand tonnes in 2001. One important reason for this is improved production regularity for operations on the NCS.

(4) Nitrogen oxide emissions embrace all sources such as turbines, boilers, engines, flares, drilling of exploration and production wells and well testing/workovers. Support services such as helicopter traffic, supply and standby ships, shuttle tankers and distribution of products are excluded.



Definition: Total energy consumption in terawatt-hours for Statoil operations. This includes net electricity purchases, energy from gas- and diesel-fired power generation and energy losses through flaring. Energy consumption based on the use of fossil fuels is calculated as fuel energy content.

Developments: Energy consumption has been reduced from 44.2 TWh in 2001 to 42.1 TWh in 2002. This reduction is mainly due to lower energy consumption in the Manufacturing & Marketing business area due to turnarounds at the Mongstad and Kalundborg refineries, and at the methanol plant at Tjeldbergodden.



Definition: The waste recovery factor comprises commercial waste from Statoil operations and represents the amount of waste for recovery in relation to the total quantity of waste.(5) Hazardous waste is not included.

Developments: The recovery factor for 2002 was 0.68 as against 0.65 in 2001. The Exploration & Production Norway and Natural Gas business areas, and the corporate services entity, whose responsibilities include managing Statoil's office buildings, have increased their recovery rate, while the Manufacturing & Marketing business area has seen a decline in its recovery rate compared with 2001.

(5) The quantity of waste for recovery is the total quantity of waste from the plant's operations which has been delivered for reuse, recycling or incineration with energy efficiency. Hazardous waste is defined by national legislation in each country.

Environmental data for 2002

NORWEGIAN CONTINENTAL SHELF[1]

ENERGY

Diesel[2]	709 GWh
Electricity	15.9 GWh
Fuel gas	21 200 GWh
Flare gas	3 020 GWh

RAW MATERIALS[3]

Oil/condensate	95.0 mill scm
Gas[4]	76.4 bn scm
Water	78.4 mill scm

UTILITIES

Chemicals process/prodn	43 200 tonnes
Chemicals drilling/well	106 800 tonnes

OTHER

Injection water as pressure support	131 mill scm

PRODUCTS

Oil/condensate	95.0 mill scm
Gas for sale	54.6 bn scm

EMISSIONS TO AIR

CO_2	5 350 000 tonnes
nmVOC[5]	160 000 tonnes
Methane[5]	21 800 tonnes
NO_x	22 000 tonnes
SO_2	152 tonnes

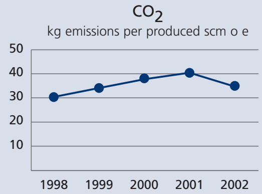
DISCHARGES TO WATER

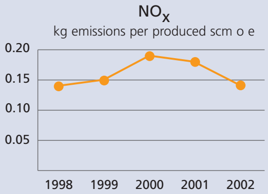
Produced water	74.7 mill scm
Oil in oily water	1 770 tonnes
Accidental oil spills	56.5 m^3
Chemicals:[6]	
Process/production	27 100 tonnes
Drilling/well	36 000 tonnes

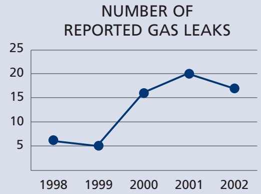
WASTE

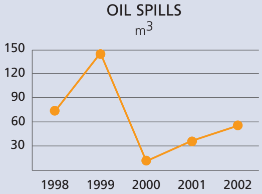
Waste for landfill	2 240 tonnes
Waste for recovery	5 800 tonnes
Recovery factor	0.72
Hazardous waste:	
Oily cuttings/mud	15 900 tonnes
Other	4 370 tonnes

1) NCS includes UK sector of Statfjord, but excludes the Troll gas treatment plant at Kollsnes
2) Represents 70 200 tonnes
3) Includes 24.1 mill scm o e supplies from third party (Snorre, Tordis, Vigdis and Visund)
4) Includes fuel gas (1.78 bn scm), flare gas (0.254 bn scm) and injected gas for pressure support, etc (19.7 bn scm)
5) Includes buoy loading
6) Includes 56 300 tonnes water and green chemicals









TROLL GAS TREATMENT PLANT, KOLLSNES

ENERGY

Electricity	803 GWh
Fuel gas	79.0 GWh
Flare gas	31.8 GWh

RAW MATERIALS

Rich gas Troll A	22.2 bn scm
Rich gas Troll B	1.78 bn scm
Rich gas Troll C	1.63 bn scm

UTILITIES

Monoethylene glycol	400 m^3
Caustics	187 m^3
Acid	176 m^3
Other chemicals	53 m^3

PRODUCTS

Gas	25.6 bn scm
Condensate	0.64 mill scm

EMISSIONS TO AIR[1]

CO_2	20 500 tonnes
NO_x	13.1 tonnes
CO	15.4 tonnes
nmVOC	241 tonnes
Methane	693 tonnes

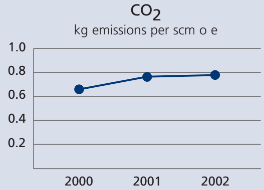
DISCHARGES TO WATER[1]

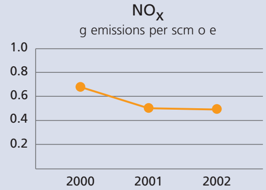
Treated water/effluent	116 000 m^3
Total organic carbon (TOC)	1.71 tonnes
Monoethylene glycol	2.33 tonnes
Methanol	0.23 tonnes
Hydrocarbons	0.07 tonnes
Ammonium	0.05 tonnes
Phenol	0.01 tonnes

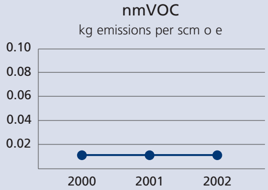
WASTE

Waste for landfill	153 tonnes
Waste for recovery	89 tonnes
Recovery factor	0.37
Hazardous waste:	
Sludge from treatment plant	274 tonnes
Other	132 tonnes

1) Regulatory requirements have been met for all parameters







MONGSTAD[1]

ENERGY

Electricity	372 GWh
Fuel gas and steam	5 380 GWh
Flare gas	564 GWh

RAW MATERIALS

Crude oil	7 391 000 tonnes
Other process raw materials	1 339 000 tonnes
Blending components	340 000 tonnes

UTILITIES

Acids	640 tonnes
Caustics	1 400 tonnes
Additives	1 050 tonnes
Process chemicals	2 610 tonnes

PRODUCTS 8 571 000 tonnes

Propane	Butane
Naphtha	Gas oil
Petrol	Petcoke/sulphur
Jet fuel	

EMISSIONS TO AIR[3)]

CO_2	1 472 000 tonnes
SO_2	896 tonnes
NO_x	1 606 tonnes
nmVOC refinery	9 400 tonnes
nmVOC terminal	10 000 tonnes
Methane	2 370 tonnes

DISCHARGES TO WATER[3)]

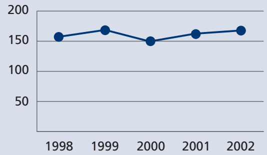
Oil in oily water	4.0 tonnes
Phenol	1.0 tonnes
Ammonium	46.9 tonnes

WASTE

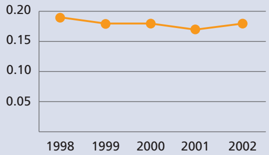
Waste for landfill	869 tonnes
Waste for recovery	737 tonnes
Recovery factor	0.46
Hazardous waste[4)]	7 540 tonnes

1) Includes data for the refinery, crude oil terminal and Vestprosess facilities
2) Processed volumes means crude oil and other process raw materials
3) Regulatory requirements have been met for all parameters except ammonium (concentrations per day) and noise
4) 80% goes to recovery

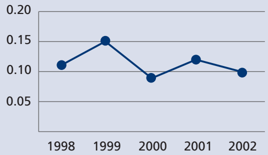
CO_2
kg emissions per tonne processed volumes[2)]



NO_x
kg emissions per tonne processed volumes[2)]



SO_2
kg emissions per tonne processed volumes[2)]



KALUNDBORG

ENERGY

Electricity	151 GWh
Steam	84 GWh
Fuel gas	2 180 GWh
Flare gas	117 GWh

RAW MATERIALS

Crude oil	4 376 000 tonnes
Other process raw materials	46 800 tonnes
Blending components	327 000 tonnes

UTILITIES

Acids	700 tonnes
Caustics	1 200 tonnes
Additives	25 tonnes
Process chemicals	268 tonnes
Ammonia, liquid	1 730 tonnes

PRODUCTS 4 561 000 tonnes

Propane	Butane
Naphtha	Gas oil
Petrol	Fuel oil
Jet fuel	ATS (fertiliser)

EMISSIONS TO AIR[2)]

CO_2	485 000 tonnes
SO_2	753 tonnes
NO_x	586 tonnes
nmVOC	2 400 tonnes
Methane	600 tonnes

DISCHARGES TO WATER[2)]

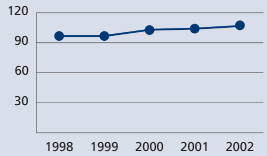
Oil in oily water	1.84 tonnes
Phenol	0.04 tonnes
Suspended matter	26.6 tonnes
Sulphide	0.07 tonnes
Nitrogen	15.9 tonnes

WASTE

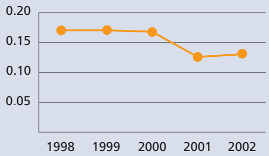
Waste for landfill	146 tonnes
Waste for recovery	626 tonnes
Recovery factor	0.81
Hazardous waste	574 tonnes

1) Processed volumes means crude oil and other process raw materials
2) Regulatory requirements have been met for all parameters except nitrogen (concentrations per day)

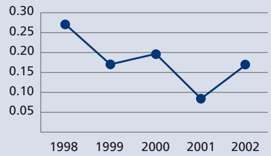
CO_2
kg emissions per tonne processed volumes[1)]



NO_x
kg emissions per tonne processed volumes[1)]



SO_2
kg emissions per tonne processed volumes[1)]



TJELDBERGODDEN

ENERGY	
Diesel	1 GWh
Electricity	66 GWh
Fuel gas	1 360 GWh
Flare gas	149 GWh

RAW MATERIALS	
Rich gas	430 000 tonnes
Condensate	0 tonnes

UTILITIES	
Caustics	232 tonnes
Acids	59 tonnes
Other chemicals	20 tonnes

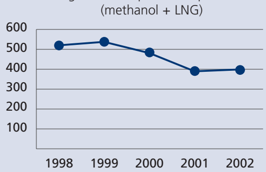
PRODUCTS	
Methanol	814 000 tonnes
Oxygen	17 300 tonnes
Nitrogen	34 000 tonnes
Argon	14 500 tonnes
LNG	9 900 tonnes

EMISSIONS TO AIR[2]	
CO_2	329 500 tonnes
nmVOC	180 tonnes
Methane	90 tonnes
NO_x	393 tonnes
SO_2	0.2 tonnes

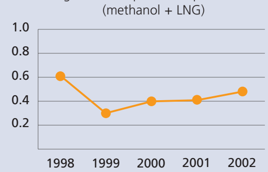
DISCHARGES TO WATER[2]	
Cooling water	143.6 mill m^3
Total organic carbon (TOC)	1.5 tonnes
Suspended matter	1 tonne
Nitrogen	1.8 tonnes

WASTE	
Waste for landfill[1]	93 tonnes
Waste for recovery	177 tonnes
Recovery factor	0.66
Hazardous waste:	
Sludge from treatment plant	272 tonnes
Other	38 tonnes

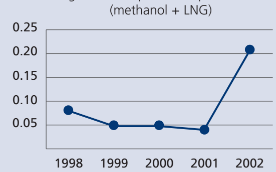
CO_2
kg emissions per tonne product
(methanol + LNG)



NO_x
kg emissions per tonne product[3]
(methanol + LNG)



nmVOC
kg emissions per tonne product [4]
(methanol + LNG)



1) Waste incinerated without energy efficiency
2) Regulatory requirements have been met for all parameters except TOC, suspended matter and pH (concentrations per day)
3) NO_x has been measured from the flare in 2002, and the new method has been used to calculate the data for 1999-2002
5) A new method of measuring methane and nmVOC has been used in 2002

KÅRSTØ GAS PROCESSING PLANT AND TRANSPORT SYSTEMS

ENERGY[1]	
Fuel gas	4 970 GWh
Electricity bought	213 GWh
Diesel	1 GWh
Flare gas	250 GWh

RAW MATERIALS[2]	
Rich gas	15.5 mill tonnes
Condensate	4.66 mill tonnes

UTILITIES	
Hydrochloric acid	206 tonnes
Sodium hydroxide	108 tonnes
Other chemicals	18 tonnes

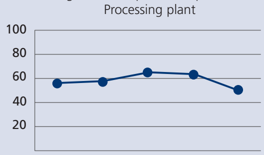
PRODUCTS[6]	
Lean gas	12.00 mill tonnes
Propane	2.40 mill tonnes
I-butane	0.52 mill tonnes
N-butane	0.92 mill tonnes
Naphtha	0.49 mill tonnes
Condensate	2.94 mill tonnes
Ethane	0.52 mill tonnes
Electricity sold	27 GWh

EMISSIONS TO AIR [3] [5]	
SO_2	2.02 tonnes
NO_x	820 tonnes
nmVOC	3 350 tonnes
Methane	1 750 tonnes
CO_2	1 153 000 tonnes

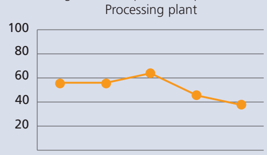
DISCHARGES TO WATER[5]	
Cooling water	325 mill m^3
Treated water	0.56 mill m^3
Oil in oily water	617 kg
Total organic carbon (TOC)	18.0 tonnes

WASTE[4]	
Waste for landfill	320 tonnes
Waste for recovery	998 tonnes
Recovery factor	0.76
Hazardous waste[7]	130 tonnes

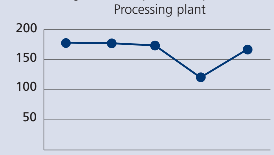
CO_2
kg emissions per tonne product
Processing plant



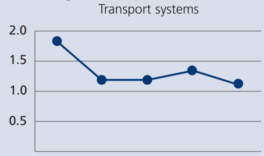
NO_x
g emissions per tonne product
Processing plant



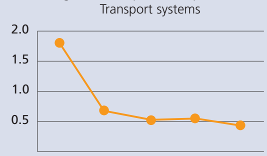
nmVOC
g emissions per tonne product
Processing plant



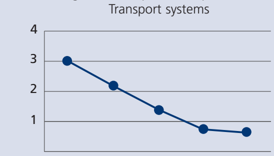
CO_2
kg emissions per tonne product
Transport systems



NO_x
g emissions per tonne product
Transport systems



nmVOC
g emissions per tonne product
Transport systems



1) Includes energy consumption for transport systems: 0.32 TWh fuel gas and 0.009 TWh electricity
2) Excludes gas transport by transport systems: 63.8 mill tonnes
3) Includes emissions from transport systems: 72 600 tonnes CO_2, 29 tonnes NO_x, 41 tonnes nmVOC and 372 tonnes methane
4) Includes waste from transport systems: 22 tonnes for landfill, 34 tonnes for recovery, 16 tonnes hazardous waste.
5) Regulatory requirements have been met for all parameters except nmVOC and methane (applies to the processing plant)
6) Products from the processing plant
7) In addition, 17 000 tonnes of oily water

Report from Ernst & Young AS

We have reviewed the annual health, safety and environment accounting for Statoil ASA in 2002, as presented in the annual report and accounts for 2002 on pages 49-54. The HSE accounting is the responsibility of the corporate executive committee.

The purpose of our work has been to express an opinion on the HSE accounting, based on the review we have carried out. Our review has covered the following activities:

- discussions with the corporate management for health, safety and the environment on the contents of the HSE accounting, including a review of the group's management system for health, safety and the environment.
- interviewing personnel with responsibilities within HSE and personnel who assist in collecting the figures in the HSE report. Focus areas have included the scope and quality assurance of data. In this context, we have visited 10 reporting entities.
- random checks to verify that figures from the various reporting entities have been correctly incorporated in the HSE accounts, and overall analyses of the figures compared with earlier reporting periods.
- random checks to verify that the HSE figures presented are based on consistent and recognised methods for measuring, analysing and quantifying data.
- assessment of whether the overall information is presented in an appropriate manner in the HSE accounting.

On this basis, we can confirm that for the HSE accounting on pages 49-54:

- Statoil has established a well-functioning management system for health, safety and the environment, and continuous improvement work is actively pursued.
- in our opinion, the HSE accounting deals with information on matters relating to health, safety and the environment which are important from a group perspective.
- this information appears to be appropriately presented in the HSE accounts.
- the reviewed data basis is based on consistent and recognised methods for measuring, analysing and quantifying data.
- the HSE performance indicators and environmental charts are in accordance with information submitted by the various reporting entities.

Our review was conducted in accordance with standard of auditing no 920 on agreed-upon procedures. As a consequence, our report is confined to the aspects specified above.

Stavanger, 14 March 2003
ERNST & YOUNG AS

Gustav Eriksen
Gustav Eriksen
State authorised public accountant

Jostein Johannessen
Jostein Johannessen
State authorised public accountant

Site preparation for the Snøhvit land facilities is in full swing on Melkøya island, with some 2.5 million cubic metres of spoil to be moved. That corresponds to 200 000 dumper-truck loads. This picture was taken on a December morning, when darkness prevails virtually around the clock. The southbound Coastal Express ship can been seen in the background making for nearby Hammerfest.

Operating and Financial Review and Prospects

You should read the following discussion of our financial condition and results of operations in connection with our audited financial statements and relevant notes.

Overview

In the year ended December 31, 2002, we had total revenues of NOK 243.8 billion and net income of NOK 16.8 billion. In the year ended December 31, 2002, we produced 274 million barrels of oil and 18.8 bcm (665 bcf) of natural gas, resulting in total production of 392 million boe. Our proved reserves as of December 31, 2002 consisted of approximately 1.9 billion barrels of crude oil and NGL and 382 bcm (13.5 tcf) of natural gas, resulting in a total of approximately 4.3 billion boe.

We divide our operations into the following four business segments:

- Exploration and Production Norway (E&P Norway), which includes our exploration, development and production operations relating to crude oil and natural gas on the NCS;
- International Exploration and Production (International E&P), which includes all of our exploration, development and production operations relating to crude oil and natural gas outside of Norway, and sales of natural gas outside of Europe;
- Natural Gas, which is responsible for the processing, transport and sales of natural gas to Europe from our upstream operations on the NCS; and
- Manufacturing and Marketing, which comprises downstream activities including sales and trading of crude oil, NGL and refined products, refining, retail and industrial marketing, methanol production and sales, petrochemical operations through our 50% interest in Borealis and shipping operations.

Improvement Program. Statoil specified in 2002 the improvement efforts designed to reach a target of 12% normalized return on average capital employed in 2004. This target is based on an average realized oil price of USD 16 per barrel, natural gas price of NOK 0.70 per scm, refining margin of USD 3.0 per barrel, Borealis margin of EUR 150 per tonne and a NOK/ USD exchange rate of 8.20. All prices are measured in real 2000 terms. The target is to improve income before financial items, income taxes and minority interest by NOK 3.5 billion in 2004, compared to 2001. At the end of 2002 an improvement of NOK 1.6 billion has been achieved and the program is progressing according to schedule in all business segments.

Portfolio changes. An overall review of our strategy and asset portfolio has been carried out over the last few years. This resulted in the restructuring of our asset portfolio both on the NCS and internationally, and included provisions and writedowns against some of our upstream and downstream assets. See —Combined Results of Operations—Years ended December 31, 2002, 2001 and 2000—Income before financial items, income taxes and minority interest.

On the NCS we restructured our portfolio as follows:
In 2002, we have sold our interests in the Varg field and a 14.9% interest in the Mikkel Unit (reducing our interest to 41.62%). Related to these agreements we realized a non-taxable gain of approximately NOK 0.2 billion. We have also in 2002 aligned interests in the Oseberg licenses with the SDFI, resulting in a Statoil share of 15.3% in each of the three licenses.

In June 2001, we realized a non-taxable gain of approximately NOK 1.4 billion related to the sale of our interests in our non-core assets in the Grane, Jotun and Njord fields and a 12% interest in the Snøhvit field in Norway (reducing our interest to 22.29%). In 2000, these assets accounted for revenues of NOK 1.5 billion and contributed NOK 364 million to our depreciation charge. At December 31, 2000 these interests represented 54 mmboe of proved reserves.

We restructured our International E&P portfolio as follows:
With an effective date of July 1, 2002 we sold our E&P operations in Denmark (the Siri and Lulita fields) to the Danish company DONG Efterforskning og Produktion with a realized pre-tax profit of NOK 1.0 billion (NOK 0.7 billion after tax). In 2001 these assets accounted for revenues of NOK 1.0 billion and contributed NOK 0.5 billion to our depreciation charge. At December 31, 2001 these interests represented 3.0 mmboe of proved reserves.

In May 2001, we sold our 4.76% interest in the Kashagan oil field discovery off Kazakhstan in the Caspian Sea and realized a pre-tax profit of NOK 1.6 billion (NOK 1.2 billion after tax).

In December 2001, we sold our operations in Vietnam for a gain before taxes of NOK 1.3 billion (NOK 0.9 billion after tax).

In December 2001, we decided to write down the book value of our interests in the LL652 oil field in Venezuela due to a slower-than-expected reservoir repressurization resulting in a reduction of the projected volumes of oil recoverable during the remaining contract. Through the writedown we recognized a pre-tax loss of NOK 2.0 billion (NOK 1.4 billion after tax) in 2001. In December 2002, we decided to further write down the book value of our interests in the LL652 oil field to zero due to new geologic assessments as a result of less than anticipated effect of the water and gas injection. Through the last writedown we recognized a pre-tax loss of NOK 0.8 billion (NOK 0.6 billion after tax) in 2002.

In 2000, we divested our exploration interests in the Gulf of Mexico. We recorded a provision of NOK 500 million against this sale in 1999, the year in which we decided to divest these interests. In 2000 we also sold our marketing activities in Statoil Energy in the US.

In Natural Gas, we restructured our portfolio as follows:
In October 2001, we implemented a new strategy for our UK business with the effect that we sold our small customer portfolio to Shell Gas Direct, and we shifted from an end user sales focus towards sales to larger, industrial customers. As part of the SDFI transaction in 2001, our ownership in Statpipe was reduced from 58.25% to 25% from June 1, 2001.

In Manufacturing and Marketing, we restructured our portfolio as follows:
In December 2002, our 100% owned subsidiary Navion was sold to Norsk Teekay AS, which is a wholly-owned subsidiary of Teekay Shipping Corporation, for approximately USD 800 million, effective from January 1, 2003. The closing is expected to occur in the second quarter of 2003 pending satisfactory assignment of certain contractual arrangements. In 2002 Navion accounted for revenues of NOK 7.2 billion and depreciation of NOK 0.5 billion. Statoil continues to own 50% of the drillship *West Navion* and 100% of the multi-purpose vessel *Odin*, former *Navion Odin*.

In October 2001, we increased our ownership in Navion from 80% to 100%. In addition, we sold our interests in the production ships *Navion Munin* and *Berge Hugin* to Bluewater in the second half of 2001.

In May 2001, we sold our 15% interest in the Malaysian Refining Company, Malaysia to the two other shareholders in that refinery, Petronas and Conoco Asia.

Factors Affecting Our Results of Operations

Our results of operations substantially depend on:
- crude oil prices, which on average in US dollars increased significantly in 2000, but decreased in 2001 and increased slightly in 2002;
- natural gas contract prices, which on average strengthened considerably in 2000 and 2001, but decreased in 2002;
- trends in the exchange rate between the US dollar, in which the trading price of crude oil is generally stated and to which natural gas prices are frequently related, and NOK, in which our accounts are reported and a substantial portion of our costs are incurred; and
- our oil and gas production volumes, which in turn depend on available petroleum reserves, and our own as well as our partners' expertise in recovering oil and gas from those reserves.

Our results will also be affected by trends in the international oil industry, including:
- recent volatility in oil prices, possible or continued actions by the Norwegian Government, or possible or continued actions by members of the Organization of Petroleum Exporting Countries (OPEC) affecting price levels;
- increasing competition for exploration opportunities and operatorships; and
- the deregulation of the natural gas markets, which may cause substantial changes to the existing market structures and to the overall level and volatility of prices.

In addition, as of the date of filing of this Annual Report the effects that the Iraqi crisis may have on the price of oil, natural gas and petroleum products, as well as any effects on the NOK/ USD exchange rate, are highly uncertain.

The following table shows the yearly average crude oil trading prices, natural gas contract prices and NOK/ USD exchange rates for 2000, 2001 and 2002.

	2000	*2001*	*2002*
Crude oil (USD/bbl Brent blend)	28.5	24.4	25.0
Natural gas from the Norwegian Continental Shelf (NOK per scm)	0.99	1.22	0.95
NOK/ USD average daily exchange rate	8.81	8.99	7.97

The following table illustrates how certain changes in the crude oil price, natural gas contract prices, refining margins and the NOK/ USD exchange rate may impact our income before financial items, income taxes and minority interest and our net income assuming activity at levels achieved in 2002.

Sensitivities on 2002 results

(IN NOK BILLION)	*CHANGE IN EBIT(1)*	*CHANGE IN NET INCOME*
Oil price (+/- USD 1/bbl)	2.2	0.6
Natural gas price (+/- NOK 0.1/scm)	1.8	0.4
Refining margins (+/- USD 1/bbl)	0.8	0.5
US dollar exchange rate impact on revenues and costs (+/- NOK 0.50)	3.0	0.7
US dollar exchange rate impact on financial debt (+/- NOK 0.50)	-	1.3

(1) Income before financial items, income taxes and minority interest.

The sensitivities on our financial results shown in the table above would differ from those that would actually appear in our consolidated financial statements because our consolidated financial statements would also reflect the effect on proved reserves, trading margins in the Natural Gas and Manufacturing and Marketing business segments, our exploration expenditures, development and exploration success rate, inflation, potential tax system changes, as well as the effect of any hedging programs in place.

Our hedging activities are designed to assist our long-term strategic development and attainment of targets by protecting financial flexibility and cash flow, allowing the corporation to be able to undertake profitable projects/ acquisitions and avoiding forced divestments during periods of adverse market conditions. For the oil price, we have entered into a downside protection structure for some of our production, reducing price risk below USD 18 per barrel for 2002 and below USD 16 per barrel for 2003. Natural gas is primarily sold under price formulas that establish time lags for the change of the gas price. The refining margin was not hedged for 2002, but for 2003 a minor part has been hedged to reflect our view of the markets.

We manage our debt as an integrated part of our total risk management program. The currency mix of the debt has been optimized with regard to underlying cash flow exposure. Our cash-flow exposure is primarily US dollar driven; thus, our debt is in US dollars.

Fluctuating foreign exchange rates can have a significant impact on our operating results. Our revenues are mainly denominated in US dollars, while our operating expenses and income taxes payable accrue to a large extent in NOK. We seek to manage this currency mismatch by issuing or swapping long-term debt into US dollars and engaging in foreign currency hedging. We manage the risk arising from our interest rate exposures through the use of interest rate derivatives, primarily interest rate swaps, based on a benchmark for the interest reset profile of our total loan portfolio. See —Liquidity and Capital Resources—Risk Management. In general, an increase in the value of the US dollar against the NOK can be expected to increase our reported earnings. However, because our currently debt outstanding is in US dollars, the benefit to Statoil would be offset in the near term by an increase in the value of our debt, which would be recorded as a financial expense and, accordingly, would adversely affect our net income. See —Liquidity and Capital Resources—Risk Management.

We market and sell the Norwegian State's oil and gas together with our own production. Historically, when we took SDFI production of oil and gas into our own inventory, for example for use in our downstream operations (e.g., in our refining business or our downstream retail operations), we included the proceeds from the sale of such production in our revenues and the price we paid to the Norwegian State in our cost of goods sold. When we sold the SDFI oil and gas on to external customers directly, however, we did not take SDFI production into our own inventory, and we included only the net result of this trading activity in our revenues.

Anticipating our initial public offering, the Norwegian State, acting as sole shareholder, held an extraordinary general meeting on February 27, 2001 and approved a resolution stating that Statoil shall continue to market and sell the Norwegian State's oil and gas. The terms that apply to our marketing and sale of the SDFI oil and gas after the Norwegian State's restructuring of its oil and gas assets are set out in the owner's instruction which was adopted by our annual general meeting on May 25, 2001 and became effective on June 17, 2001. Pursuant to the owner's instruction, we agreed to purchase all of the SDFI oil and natural gas liquid, NGL, produced and, therefore, include the proceeds from the sale of the SDFI production as revenue and the price that we pay to the Norwegian State as cost of goods sold. The treatment of our sales of SDFI natural gas remains the same.

Historically, we paid to the Norwegian State the "norm price" for crude oil set by the Norwegian Petroleum Price Board, an independent panel of assessors, based on an average of spot market prices and contract prices for NCS oil during the recent month. The price we paid to the Norwegian State for NGL and natural gas was equal to the price actually obtained from the sale to third parties. After June 17, 2001, the price that we pay to the Norwegian State for natural gas, however, is either the market value, if we take the natural gas into our own inventory, or, if we sell the natural gas directly to external customers or to us, our payment to the Norwegian State is based on either achieved prices, a net back formula or market value. We now purchase all of the Norwegian State's oil and NGL. Pricing of the crude oil is based on market reflective prices. NGL prices are based on either achieved prices, market value or market reflective prices.

Total purchases of oil and NGL from the Norwegian State by Statoil amounted to NOK 72,298 million (374 mmboe), NOK 53,291 million (265 mmboe) and NOK 42,290 million (173 mmboe) in 2002, 2001 and 2000, respectively.

As with all producers on the NCS, we pay a royalty to the Norwegian State for NCS oil produced from fields approved for development prior to January 1, 1986. Oil fields in our portfolio that paid royalty in 2002 are Statfjord, Gullfaks and Oseberg, which together represented 30%, 27% and 24% of our total NCS petroleum production in 2000, 2001 and 2002 respectively. The royalty is generally paid in kind, and varies from 8% to 16% of the oil produced. We purchase from the Norwegian government at the "norm price" all royalty oil paid in kind by producers on the NCS. We include the costs of purchase and the proceeds from the sale of the royalty oil, which we resell or refine, in our cost of goods sold and sales revenue, respectively. No royalty is paid from fields approved for development on or after January 1, 1986. Royalty obligations from Statfjord were abolished January 1, 2003, and royalty obligations from Gullfaks and Oseberg will be abolished by 2006.

Historically, our revenues have largely been generated from the production of oil and natural gas from the NCS. Norway imposes a 78% marginal tax rate on income from offshore oil and gas activities. Our earnings volatility is moderated as a result of the significant amount of our Norwegian offshore income that is subject to a 78% tax rate in profitable periods and the significant tax assets generated by our Norwegian offshore operations in any loss-making periods. A significant part of the taxes we pay are paid to the Norwegian State. In June 2001, the Storting enacted certain changes in the taxation of petroleum operations.

Combined Results of Operations

The following table shows certain income statement data, expressed in each case as a percentage of total revenues.

	YEAR ENDED DECEMBER 31, 2000	2001	2002
CONSOLIDATED STATEMENTS OF INCOME			
Revenues:			
Sales	99.8%	97.8%	99.3%
Equity in net income (loss) of affiliates	0.2%	0.2%	0.2%
Other income	0.0 %	2.0%	0.5%
Total revenues	100.0 %	100%	100%
Expenses:			
Cost of goods sold	51.9%	53.4%	60.7%
Operating expenses	12.5%	12.5%	11.6%
Selling, general and administrative expenses	1.7%	1.5%	2.2%
Depreciation, depletion and amortization	6.8%	7.6%	6.9%
Exploration expenses	1.1%	1.2%	0.9%
Total expenses before financial items	74.0%	76.2%	82.3%
Income before financial items, income taxes and minority interest	26.0%	23.8%	17.7%

Years ended December 31, 2002, 2001 and 2000

Sales. Statoil markets and sells the Norwegian State's share of oil and gas production from the NCS. From June 2001, Statoil no longer acts as an agent to sell SDFI oil production to third parties. As such, all purchases and sales of SDFI oil production are recorded as cost of goods sold and sales, respectively, whereas before, the net result of any trading activity was included in sales.

All oil received by the Norwegian State as royalty in kind from fields on the NCS is purchased by Statoil. Statoil includes the costs of purchase and proceeds from the sale of this royalty oil in its Cost of goods sold and Sales respectively.

Our sales revenue totaled NOK 242.2 billion in 2002, compared to NOK 231.7 billion in 2001 and NOK 229.8 billion in 2000. The 5% increase in sales revenues from 2001 to 2002 was mainly due to a 22% increase in crude oil volumes bought from third parties and SDFI, primarily resulting from sales under the owner's instruction and a 32% increase in sales of equity natural gas. This was to a large extent offset by a 9% reduction in realized oil prices measured in NOK due to the weakening of US dollar measured against NOK, a 22% reduction of our realized price of natural gas and a 39% reduction in the refining margin (FCC-margin). The decrease in realized refining margins was negatively affected by an 11% weakening of the US dollar against the NOK. In addition, the contribution from Statpipe was reduced as a consequence of our interest being reduced from 58.25% to 25% as of June 1, 2001, as part of the SDFI transaction.

The NOK 10.5 billion increase in sales revenues in 2002 compared to 2001 was approximately NOK 30 billion due to increased SDFI and third party volumes and approximately NOK 5 billion due to an increase in the volumes sold of natural gas. Offsetting these increases, sales revenues decreased by approximately NOK 15 billion due to reduced oil prices measured in NOK, by approximately NOK 4 billion due to reduced natural gas prices, by NOK 7 billion due to a reduction in sales revenues from refining and other downstream activities, and approximately NOK 1 billion due to the reduced contribution from Statpipe.

Our average daily oil production (lifting) decreased from 754,900 barrels in 2001 to 748,200 barrels in 2002. The 1% decrease in average daily oil production from 2001 to 2002 was primarily due to lower production from declining fields including Gullfaks, Statfjord, Sleipner, Oseberg, Alba and Lufeng. Yme was decommissioned during 2001 and Njord and Jotun were sold in 2001. In addition, Varg and Siri were sold in 2002. The planned maintenance period in 2002 was longer and included more fields than in 2001. In addition, the Norwegian government on December 17, 2001 decided to reduce oil production on the NCS by 150,000 barrels per day, covering the period January 1 to June 30, 2002. Our share was approximately 18,500 barrels per day. This was partly offset by the start of production from the Girassol field in Angola, increased production from the Sincor field due to start up of the Sincor upgrading plant in the first quarter of 2002, higher production from Åsgard due to operating difficulties in 2001 and the fact that Glitne and Huldra both began producing in late 2001. In addition, as a result of an overlifting position on the NCS in 2001, as compared to an underlifting position for 2002, we lifted a lower volume of oil on the NCS than that represented by our total equity interest in

2002, while in 2001, we lifted a higher volume of oil than that represented by our total equity interest. See below for a description of the difference between produced volumes and lifted volumes.

Our gas volumes sold of own produced gas were 18.8 bcm (666 bcf) in 2002, compared to 14.9 bcm (527 bcf) in 2001 and 14.7 bcm (519 bcf) in 2000.

The NOK 1.9 billion increase in sales revenues from 2000 to 2001 was in part due to approximately NOK 35 billion in increased SDFI and third party volumes and approximately NOK 4 billion due to an increase in the price and volumes sold of natural gas. Partly offsetting these increases, sales revenues decreased by approximately NOK 20 billion due to reduced oil prices, by approximately NOK 7 billion due to a reduction in sales revenues from refining, and approximately NOK 4 billion due to the absence of revenues from the marketing arm of Statoil Energy Inc. following the sale in 2000, as well as a reduced contribution from Statpipe.

Our average daily oil production increased from 733,300 barrels in 2000 to 754,900 barrels in 2001. This was primarily a result of the production of extra heavy oil from the Sincor field in Venezuela, increased production from the early oil phase on the Azeri-Chirag-Gunashli field in Azerbaijan, the effect of the Gullfaks Satellites Phase II, Glitne, Snorre North and Troll C fields coming on stream in Norway and increases in production from the Åsgard, Norne, Sygna, Oseberg Satellites and Snorre South fields. There was, however, a lower than expected production increase at Åsgard due to a shutdown of production on the Åsgard B platform due to leakages in the welded joints on the subsea flow lines from the production wells to the platform. In addition, as a result of an underlifting position on the NCS in 2000, as compared to an overlifting position for 2001, we lifted a higher volume of oil on the NCS than represented by our total equity interest in 2001, while in 2000 we lifted a lower volume of oil than represented by our total equity interest. The increase in average daily oil production was partially offset by a decline in the output from the Lufeng field in China and the Siri field in Denmark and a decline in the output from the mature fields Statfjord and Gullfaks on the NCS as well as reduced production from the Heidrun and Sleipner fields and the decommissioning of the Yme field.

We record revenues from sales of production based on lifted volumes. The term "production" as used in this section means lifted volumes. The term "production" used in other sections, means produced volumes, which include lifted volumes adjusted for under- and overlifting. Overlifting and underlifting positions are a result of Statoil lifting either a higher or a lower volume of oil than that represented by our total equity interest in that field.

Equity in net income (loss) of affiliates. Equity in net income (loss) of affiliates principally includes our 50% equity interest in Borealis, our 50% equity interest in Statoil Detaljhandel Skandinavia, our 50% equity interest in the P/R West Navion DA, our former 15% interest in the Melaka refinery which was sold in 2001, and miscellaneous other affiliates. Our share of equity in net income of affiliates was NOK 366 million in 2002, NOK 439 million in 2001 and NOK 523 million in 2000. The reduction from 2001 to 2002 was primarily due to decreased income from investments in P/R West Navion DA as well as decreased income from miscellaneous other affiliates. This decrease was partly offset by increased income of Borealis mainly due to an increase in sold volumes by 4% and contribution from an ongoing improvement program. The Borealis margins, however, were reduced by EUR 25 per tonne, approximately 19% from 2001 to 2002. The decrease from 2000 to 2001 was primarily due to reduced income of Borealis as a result of reduced petrochemical margins.

Other income. Other income was NOK 1.3 billion in 2002, NOK 4.8 billion in 2001 and NOK 0.1 billion in 2000. The NOK 1.3 billion income in 2002 is primarily related to the gain on the sale of the E&P operations off Denmark, including the Siri and Lulita fields. The NOK 4.8 billion income in 2001 primarily comprises the gain realized on the sale of non-core assets in the Grane, Njord and Jotun fields and a 12% interest in the Snøhvit field, the sale of our 4.76% interest in the Kashagan oil field discovery in the Caspian Sea and the sale of our operations in Vietnam.

Cost of goods sold. Historically, our cost of goods sold included the cost of oil and gas production that we purchased for resale or refining, including SDFI oil and gas purchased for our own inventory, including royalty oil. Beginning on June 17, 2001, our cost of goods sold includes the cost of the SDFI oil and NGL production that we purchase pursuant to the owner's instruction, regardless of whether it is for resale to external customers directly or for our own inventory. See —Factors Affecting Our Results of Operations above for more information.

Cost of goods sold increased to NOK 147.9 billion in 2002 from NOK 126.2 billion in 2001 and NOK 119.5 billion in 2000. The 17% increase in 2002 is mainly due to increased purchase of SDFI volumes and third party volumes. This was partly offset by a reduction in crude oil prices measured in NOK.

The 6% increase from 2000 to 2001 was primarily due to increased purchase of SDFI volumes pursuant to the owner's instruction and third party volumes. This was partly offset by a reduction in crude oil prices and the sale in 2000 of the marketing arm of our subsidiary, Statoil Energy Inc.

Operating expenses. Our operating expenses include production costs in fields and transport systems related to our share of oil and gas production. Operating expenses decreased to NOK 28.3 billion in 2002 compared to NOK 29.4 billion in 2001 and NOK 28.9 billion in 2000. The 4% decrease from 2001 to 2002 is mainly related to reduced platform costs and lower future site removal costs due to updated removal estimates. This is partly offset by increased insurance costs and variable costs due to the higher production volume in 2002 compared with 2001.

The 2% increase from 2000 to 2001 reflects a NOK 0.5 billion and NOK 0.2 billion increase in the operating expenses of our Manufacturing and Marketing and Natural Gas business segments, respectively. The increases are primarily due to increased volumes of oil and gas transported. We also recognized an increase in operating expenses due to new fields coming on stream, and an increase in preparation for operational activities for new fields. These increases were partly offset by reduced provisions as a result of updated cost estimates for future removal of field installations on the NCS, and reduced operating costs within our International E&P segment mainly due to lower production of oil and gas.

Selling, general and administrative expenses. Our selling, general and administrative expenses include costs relating to the selling and marketing of our products, including business development costs, payroll and employee benefits. Our selling, general and administrative expenses increased to NOK 5.5 billion in 2002 compared to NOK 4.3 billion in 2001 and NOK 3.9 billion in 2000.

The increase from 2001 to 2002 was primarily due to increased business development in International E&P and increases in the rig provisions within E&P Norway, most of which affected changes in selling, general and administrative expenses from 2001 to 2002. This is partly offset by a reduction in selling, general and administrative expenses in our Manufacturing and Marketing business segment. The increase from 2000 to 2001 was mainly due to the Manufacturing and Marketing business area, which had an increase of approximately NOK 0.4 billion, partly offset by our sale of the marketing arm of our subsidiary, Statoil Energy Inc. in 2000.

Over the period 1998-2002 we provided approximately NOK 1.7 billion for the anticipated reduction in market value of company exposed fixed-price mobile drilling rig contracts. At December 31, 2002, the remaining provision for these losses was approximately NOK 1.0 billion based on our assumptions regarding our own utilization of the rigs and the rate and duration at which we could sublet these rigs in the Norwegian market to third parties and the development of the NOK/ USD exchange rate. These assumptions reflect management judgment and are rechallenged based on the most current information each time financial statements are prepared. Since the end of the year 2002, the state of the Norwegian drilling rig market has changed for the worse, and there cannot be any guarantee that conditions will not continue to be poor for the foreseeable future. We will continue to monitor the situation and will review in accordance with our procedures the provisions during the preparation of financial results with respect to our first quarter. If market conditions continue to be poor, and other important factors do not change to offset for the negative effects of poor market conditions, we may as a result of our accounting practices be required to take additional provisions at such time.

Depreciation, depletion and amortization expenses. Our depreciation, depletion and amortization expenses include depreciation of production installations and transport systems, depletion of fields in production, amortization of intangible assets and depreciation of capitalized exploration costs as well as writedown of impaired long-lived assets. Depreciation, depletion and amortization expenses were NOK 16.8 billion in 2002, NOK 18.1 billion in 2001 and NOK 15.7 billion in 2000.

The 2002 figure includes a writedown of NOK 0.8 billion on the LL652 oil field in Venezuela. The NOK 2.0 billion writedown on the same field in 2001 accounts for most of the reduction from 2001 to 2002. This is however, partly offset by higher depreciation from new fields coming on stream.

The increase of 15% from 2000 to 2001 was due principally to the writedown of NOK 2.0 billion on the LL652 oil field in Venezuela and increased depreciation due to higher production.

Exploration expenses. Our exploration expenditure is capitalized to the extent our exploration efforts are deemed successful and is otherwise expensed as incurred. Our exploration expenses consist of the expensed portion of our current-period exploration expenditures and write-offs of exploration expenditures capitalized in prior periods. Exploration expenses were NOK 2.2 billion in 2002, NOK 2.9 billion in 2001 and NOK 2.5 billion in 2000. The reduction of 24% from 2001 to 2002 was mainly due to a lower level of exploration activity within E&P Norway, partly offset by higher exploration activity within International E&P. In addition there was a decrease in exploration expenditure capitalized in previous years but written off in 2002 compared to 2001. A total of 20 exploration and appraisal wells were completed in 2002, of which 15 resulted in discoveries. Including sidetracks from exploration wells and exploration extensions derived from production wells, a total of 28 wells were completed in 2002, 21 of which resulted in discoveries.

The increase of 17% from 2000 to 2001 was mainly due to a NOK 0.5 billion increase in exploration expenditure capitalized in previous years but written off in 2001 and a lower success rate in 2001 which resulted in a higher level of costs being expensed. This was partly offset by a NOK 0.7 billion decrease in exploration expenditures, primarily as a result of a lower level of exploration activity within our International E&P business segment that was partly offset by an increase in the exploration activity on the NCS. A total of 27 exploration and appraisal wells were completed in 2001, of which 15 resulted in discoveries.

Income before financial items, income taxes and minority interest. Income before financial items, income taxes and minority interest totaled NOK 43.1 billion in 2002, NOK 56.2 billion in 2001 and NOK 60.0 billion in 2000. The 23% decline from 2001 to 2002 is mainly related to lower oil and natural gas prices measured in NOK and lower margins in the downstream segment. Oil prices in 2002 measured in USD increased by 2% compared to 2001. However, measured in NOK, the oil price decreased by 9% and the natural gas price decreased by 22%, compared with 2001. Refining, petrochemical and shipping margins were also lower in 2002 compared to 2001, due to weaker markets. The income for the downstream area has also been negatively affected by the stronger NOK measured against the US dollar.

Income before financial items, income taxes and minority interest for 2002 included special items of NOK 1.0 billion before tax related to a gain from the sale of the upstream activity in Denmark, partly offset by a write down of LL652 in Venezuela in 2002 of NOK 0.8 billion before tax. 2001 included special items (gains) of NOK 2.3 billion before tax.

The 6% decline from 2000 to 2001 is mainly due to a 13% decrease in oil prices in NOK, a 29% reduction in refining margins and a NOK 2 billion writedown of LL652 in Venezuela in 2001. These effects have partly been offset by a 23% increase in gas prices, a 3% increase in produced volumes of oil and NOK 4.3 billion in pre-tax gains related to the sale of interests on the NCS, the sale of our interest in the Kashagan oil field in Kazakhstan and the sale of Statoil's operations in Vietnam.

In 2002, 2001 and 2000, our income before financial items, income taxes and minority interest margins, measured as a percentage of revenues, was approximately 18%, 24% and 26%, respectively for reasons discussed above.

Net financial items. In 2002 we reported net financial items of NOK 8.2 billion, compared to NOK 0.1 billion in 2001 and a net expense of NOK 2.9 billion in 2000. The changes from year to year resulted principally from changes in unrealized currency gains and losses on the US dollar portions of our debt outstanding due to changes in the US dollar rate against the NOK. The currency mix of the debt portfolio changed during 2001, from 80% to nearly 100% US dollar. The debt portfolio including the effect of swaps was as at year-end 2002 nearly 100% held in US dollars.

Income taxes. Our effective tax rates were 66.9%, 68.5% and 70.9% in 2002, 2001 and 2000, respectively. Our effective tax rate is our income taxes divided by our income before income taxes and minority interest. Fluctuations in the effective tax rates from year to year are principally a result of changes in the components of income between Norwegian oil and gas production, taxed at a marginal rate of 78%, other Norwegian income, including onshore portion of net financial items, taxed at 28%, and income in other countries taxed at the applicable income tax rates.

Minority interest. Minority interest in net profit in 2002 was NOK 153 million, compared to NOK 488 million in 2001 and NOK 484 million in 2000. Minority interest consists primarily of Shell's 21% interest in the Mongstad crude oil refinery, which Shell acquired effective January 1, 2000, and the Norwegian State's 35% interest in the crude oil terminal at Mongstad, which was transferred to the Norwegian State effective June 1, 2001 as part of the SDFI transaction. Minority interest also included Rasmussengruppen's 20% equity interest in Navion until October 1, 2001, when we, as part of restructuring our ownership in Navion, acquired the Rasmussengruppen's equity interest in the company.

Net income. Net income in 2002 was NOK 16.8 billion compared to NOK 17.2 billion in 2001 and NOK 16.2 billion in 2000 for reasons discussed above.

Business Segments

The following table details certain financial information for our four business segments. In combining segment results, we eliminate inter-company sales. These include transactions recorded in connection with our oil and natural gas production in the E&P Norway or International E&P segments and also in connection with the sale, transport or refining of our oil and natural gas production in the Manufacturing and Marketing or Natural Gas segments. Our E&P Norway business segment produces oil, which it sells internally to the trading arm of our Manufacturing and Marketing business segment, which then sells the oil on the market. E&P Norway also produces natural gas, which it sells internally to our Natural Gas business segment, also to be sold on the market. As a result, we have established a market price-based transfer pricing policy whereby we set an internal price at which our E&P Norway business area sells oil and natural gas to the Manufacturing and Marketing and the Natural Gas business segments.

Historically, for sales of oil from E&P Norway to Manufacturing and Marketing, the transfer price with respect to oil types where prices are quoted on the market consists of the applicable market price less a margin of NOK 2.15 per barrel and, for all other oil types, the transfer price consists of the estimated "norm price" less a margin of NOK 2.15 per barrel. As of June 17, 2001, the transfer price with respect to all types of oil is the applicable market reflective price less a margin of NOK 0.70 per barrel. For sales of gas from E&P Norway to Natural Gas, the transfer price is indexed based on a base oil price of USD 15 per barrel and a fixed internal rate of return to E&P Norway of 11% for each natural gas field, with a minimum transfer price of NOK 0.07 per scm. The transfer price for sales from E&P Norway to Natural Gas is recalculated quarterly to take into account the oil price in the previous six month period.

The table below sets forth certain financial information for our business segments, including inter-company eliminations for the three-year period ending December 31, 2002.

		YEAR ENDED DECEMBER 31,		
	2000	*2001*	*2002*	*2002*
(IN MILLION)	*NOK*	*NOK*	*NOK*	*USD*
E&P Norway				
Revenues	71,135	65,655	56,290	8,114
Income before financial items, income taxes and minority interest	46,715	40,697	31,463	4,535
Long-term assets	79,864	77,550	77,001	11,099
International E&P				
Revenues	9,027	7,693	6,769	976
Income before financial items, income taxes and minority interest	773	1,291	1,086	157
Long-term assets	19,465	21,530	20,655	2,976
Natural Gas				
Revenues	20,624	23,468	24,536	3,537
Income before financial items, income taxes and minority interest	7,893	9,629	8,918	1,285
Long-term assets	13,030	10,500	10,312	1,486
Manufacturing and Marketing				
Revenues	201,585	203,387	211,152	30,436
Income before financial items, income taxes and minority interest	4,559	4,480	1,637	236
Long-term assets	32,925	30,432	27,958	4,030
Other and Eliminations				
Revenues	(71,946)	(63,867)	(54,933)	(7,918)
Income before financial items, income taxes and minority interest	51	57	(2)	0
Long-term assets	13,042	11,026	11,307	1,629
Total income before financial items, income taxes and minority interest	59,991	56,154	43,102	6,213

E&P Norway

The following table sets forth certain financial and operating data regarding our E&P Norway business segment and percentage change for the three years ended December 31, 2002.

FINANCIAL AND OPERATING DATA	2000	2001	YEAR ENDED DECEMBER 31, % CHANGE	2002	% CHANGE
Financial data (in NOK million):					
Revenues	71,135	65,655	(8%)	56,290	(14%)
Depreciation, depletion and amortization	11,225	11,805	5%	11,861	0%
Exploration expense	1,310	2,008	53%	1,420	(29%)
Income before financial items, income taxes and minority interest	46,715	40,697	(13%)	31,463	(23%)
Production (lifting):					
Oil (mbbls/day)	676.2	697.1	3%	666.7	(4%)
Natural gas (mmcf/day)	1,365	1,380	1%	1,784	29%
Total production (lifting) (mboe/day)	919.2	942.7	3%	985.5	5%
Reserve replacement rate(1)(2)	0.85	0.77	(9%)	0.63	(18%)
Finding cost (USD per boe)(1)	1.68	1.53	(9%)	0.81	(47%)
Finding and development costs (USD per boe)(1)	10.65	9.35	(12%)	5.89	(37%)
Unit production (lifting) cost (USD per boe)(3)	2.82	2.77	(2%)	3.03	9%

(1) Reserve replacement rate, finding cost and finding and development costs are calculated as a rolling three-year average based on our proved reserves estimated in accordance with the SEC definitions.
(2) The reserve replacement rate is defined as the total additions to proved reserves, including acquisitions and disposals, divided by produced reserves.
(3) Our unit production (lifting) cost is calculated by dividing operating costs relating to the production of oil and natural gas by total production (lifting) of petroleum in a given year.

Years ended December 31, 2002, 2001 and 2000

E&P Norway generated revenues of NOK 56.3 billion in 2002, compared to NOK 65.7 billion in 2001 and NOK 71.1 billion in 2000. The 14% decrease in revenues from 2001 to 2002 resulted primarily from an approximately 11% decrease in the exchange rate between US dollars and NOK. The transfer price of natural gas sold from E&P Norway to Natural Gas has decreased 23% from 2001 to 2002, partly offset by a 2% increase in average realized crude oil prices. In addition, revenues in 2001 included approximately NOK 1.4 billion in non-taxable gains related to the sale of our interest in the Grane, Jotun and Njord fields and 12 percentage points of our interest in the Snøhvit field (reducing our interest to 22.29%). The 8% decrease in revenues from 2000 to 2001 resulted primarily from an approximately 15% decrease in our average realized crude oil prices, partly offset by a 15% increase in the price of natural gas sold from E&P Norway to Natural Gas that was mainly due to an increase in our realized price of natural gas. The reduction in oil prices was also partly offset by a 2% increase in the exchange rate between US dollars and NOK.

Average daily oil production (lifting) in E&P Norway decreased to 666,700 barrels in 2002 from 697,100 barrels in 2001 and from 676,200 barrels in 2000. The 4% decrease in average daily oil production from 2001 to 2002 was primarily due to lower production from fields like Statfjord, Sleipner and Oseberg, which are on decline. Yme was decommissioned during 2001 and Njord and Jotun were sold in 2001. Varg was sold in 2002. The planned maintenance periods in 2002 were longer and included more fields than in 2001. In addition the Norwegian government on December 17, 2001 decided to reduce oil production on the NCS by 150,000 barrels per day, covering the period January 1 to June 30, 2002. Our share was approximately 18,500 barrels per day in this period. This decrease was partly offset by higher production from Åsgard where we experienced operating difficulties on Åsgard B in 2001 and the fact that Glitne and Huldra both began producing in late 2001.

The 3% increase in average daily oil production from 2000 to 2001 resulted primarily from start up of the Gullfaks Satellites Phase II, Glitne, Huldra, Snorre North and Troll C fields and from increased production from the Åsgard, Norne, Sygna, Oseberg Satellites and Snorre South fields. The increase in production was partly offset by reduced production from the Statfjord, Gullfaks, Heidrun and Sleipner fields being in decline and the decommissioning of the Yme field in 2001.

Average daily gas production was 50.7 mmcm (1,784 mmcf) in 2002, as compared to 39.1 mmcm (1,380 mmcf) in 2001, and 38.6 mmcm (1,365 mmcf) in 2000. Gas production increased by 29% between 2001 and 2002 and by 1% between 2000 and 2001, primarily due to an increase in long term contracted gas volumes to continental Europe and an increase in short term sales, mainly to the UK.

Unit production cost was USD 2.8 per boe in 2000, USD 2.8 per boe in 2001 and USD 3.0 per boe in 2002. The increase from 2001 to 2002 is due primarily to the effect of a weaker USD against the NOK since costs are primarily incurred in NOK. However, production costs measured in NOK have decreased from NOK 24.9 per boe in 2001 to NOK 24.0 per boe in 2002.

Depreciation, depletion and amortization expenses were NOK 11.9 billion in 2002, NOK 11.8 billion in 2001 and NOK 11.2 billion in 2000. The minor increase from 2001 to 2002 resulted primarily from higher production. The 5% increase from 2000 to 2001 was primarily due to the start of production from our new fields Glitne, Huldra, Gullfaks Satellites Phase II, Snorre North and Troll C.

Exploration expenditure (activity) decreased from 2001 to 2002, while there was an increase from 2000 to 2001. Exploration expenditure was NOK 1.4 billion in 2002, compared to NOK 2.0 billion in 2001 and NOK 1.7 billion in 2000. The 30% decrease from 2001 to 2002 is primarily due to postponement of three wells to 2003, which resulted in fewer wildcat exploration wells drilled from floating drilling rigs in 2002 compared to 2001. This reduction was to some extent caused by a lack of interesting drilling acreage. The increase from 2000 to 2001 resulted primarily from an increase in exploration activity. We still have confidence in the NCS and expect our exploration activity, given access to acreage, to exceed the 2002 level in coming years.

Exploration expense in 2002 was NOK 1.4 billion, compared to NOK 2.0 billion in 2001 and NOK 1.3 billion in 2000. The 30% decrease in expensed exploration from 2001 to 2002 and the 53% increase from 2000 to 2001 are consistent with changes in expenditure levels due to variations in exploration activity. Fifteen exploration and appraisal wells were completed in 2002, of which ten resulted in discoveries. In addition, five extensions on production wells were completed, of which four resulted in discoveries. In comparison, 18 exploration and appraisal wells and two extensions on production wells were completed in 2001, of which 15 resulted in discoveries, and 14 exploration and appraisal wells were completed in 2000, of which ten resulted in discoveries. Furthermore, exploration expense in 2002 included NOK 0.5 billion of expenditure capitalized in previous years, but written off in 2002, compared to NOK 0.7 billion of expenditure written off in 2001. In 2000, exploration expense included NOK 0.4 billion of exploration expenditure capitalized in previous years, but written off in 2000.

Income before financial items, income taxes, and minority interest for E&P Norway was NOK 31.5 billion compared to NOK 40.7 billion in 2001 and NOK 46.7 billion in 2000. The 23% decrease in income before financial items, income taxes and minority interest from 2001 to 2002 was primarily the result of the reduction in sales revenues. Excluding the gains on sale from the Njord, Grane and Jotun fields and 12 percentage points of our interest in the Snøhvit field, the income before financial items, income taxes and minority interest in 2001 was NOK 39.3 billion, compared to NOK 31.5 billion in 2002. This was primarily due to lower oil prices in NOK, and the lower transfer price of natural gas sold from E&P Norway to Natural Gas. In addition, there have been lower production of crude oil, and higher costs related to accruals for future rig losses. The decline in income before financial items, income taxes and minority interest has been partly offset by increased sales of natural gas, decreased exploration expenses and reduced operating costs.

The 13% decrease in income before financial items, income taxes and minority interest from 2000 to 2001 was primarily the result of the reduction in sales revenues. This was primarily due to lower oil prices in NOK, increased depreciation due to higher production and new fields coming on stream, and increased exploration expense. The decline in income before financial items, income taxes and minority interest was partly offset by a higher transfer price for natural gas paid by Natural Gas, increased production of crude oil, increased sales of natural gas and reduced operating costs.

International E&P

The following table sets forth certain financial and operating data regarding our International E&P business segment and percentage change in each of the three years ended December 31, 2002.

FINANCIAL AND OPERATING DATA	*2000*	*2001*	*YEAR ENDED DECEMBER 31, % CHANGE*	*2002*	*% CHANGE*
Financial data (in NOK million):					
Revenues	9,027	7,693	(15%)	6,769	(12%)
Depreciation, depletion and amortization	1,704	3,371	98%	2,355	(30%)
Exploration expense	1,141	866	(24%)	775	(11%)
Income before financial items, income taxes and minority interest	773	1,291	67%	1,086	(16%)
Production (lifting):					
Oil (mbbls/day)	57.1	57.8	1%	81.5	41%
Natural gas (mmcf/day)	53	41	(23%)	33	(20%)
Total production (lifting) (mboe/day)	66.6	65.2	(2%)	87.4	34%
Reserve replacement rate(1)(2)(3)	3.62	2.14	(32%)	2.79	30%
Finding cost (USD per boe)(1)	1.73	2.15	24%	1.51	(30%)
Finding and development costs (USD per boe)(1)(3)	5.09	8.58	69%	6.93	(19%)
Unit production (lifting) cost (USD per boe)(4)	6.61	5.16	(22%)	3.33	(35%)

(1) Reserve replacement rate, finding cost and finding and development costs are calculated as a rolling three-year average based on our proved reserves estimated in accordance with the SEC definitions.
(2) The reserve replacement rate is defined as the total additions to proved reserves, including acquisitions and disposals, divided by produced reserves.
(3) Adjusted for the sale of Statoil Energy Inc in the year 2000.
(4) Our unit production (lifting) cost is calculated by dividing operating costs relating to the production of oil and gas by total production (lifting) of petroleum in a given year.

Years ended December 31, 2002, 2001 and 2000

International E&P generated revenues of NOK 6.8 billion in 2002, compared to NOK 7.7 billion in 2001 and NOK 9.0 billion in 2000. The 12% decrease from 2001 to 2002 was mainly due to the gain of NOK 2.9 billion from the divestments of the Kashagan and Vietnam assets in 2001, compared with the NOK 1.0 billion divestment of the Denmark assets in 2002. In addition, the decrease was affected by lower oil and natural gas prices measured in NOK. This was partly offset by a 34% increase in total lifting of oil and natural gas. The 15% decrease in revenues from 2000 to 2001 was mainly due to lower production levels and lower prices for crude oil. These factors accounted for NOK 0.9 billion of the decrease. In addition, the decrease was impacted by the absence of revenues of NOK 3.3 billion due to the sale of the marketing, power generation and energy trading business of Statoil Energy Inc. in 2000. This decrease was partly offset by the approximately NOK 2.9 billion in gains from the divestments of the Kashagan and Vietnam assets in 2001.

Average daily oil production (lifting) was 81,500 barrels per day in 2002, compared to 57,800 barrels per day in 2001 and 57,100 barrels per day in 2000. The 41% increase in average daily production of oil from 2001 to 2002 resulted primarily from increased production from the Girassol field in Angola and the Sincor field in Venezuela due to start up of the upgrading plant. Sincor in Venezuela met our increased production targets for 2002, but was temporarily closed down for 71 days due to the political situation in the country. Production was restarted on February 23, 2003. The effect of the shutdown on production in 2003 is approximately 108,000 barrels. The Girassol field started production in December 2001. These increases were partly offset by declining production from the Siri field in Denmark, which we sold as of July 1, 2002, the Lufeng field in China and the Alba field in the UK. The 1% increase in average daily production of oil from 2000 to 2001 resulted primarily from increased production from the Azeri-Chirag-Gunashli field in Azerbaijan and Sincor in Venezuela. These increases were almost offset by declining production from the Siri field in Denmark and Lufeng field in China.

Average daily gas production in 2002 was 0.9 mmcm (33 mmcf) compared to 1.2 mmcm (41 mmcf) in 2001 and 1.5 mmcm (53 mmcf) in 2000. The 20% decrease from 2001 to 2002 resulted from the Jupiter gas field in the UK being in decline. The 23% decrease from 2000 to 2001 also resulted from the Jupiter gas field in the UK being in decline, as well as production difficulties due to hydraulic problems with three of the wells at Jupiter during the second half of 2001.

Reserve replacement rate on a three-year average improved by 30% from 2001, mainly due to an increase in proved reserves. Finding and development cost on a three-year average is lower by 19% from 2001 to 2002, due to the lower exploration costs in 2002 as compared to 1999, which is not included in the 2002 three-year average, and reserve extensions in 2002. Unit production cost on a 12 months' average is improved by 35% from 2001 due to more cost effective fields now in production.

Depreciation, depletion and amortization expenses were NOK 2.4 billion in 2002, compared to NOK 3.4 billion in 2001 and NOK 1.7 billion in 2000. The 30% decrease in 2002 as compared to 2001 is primarily related to the NOK 2.0 billion impairment of the LL652 oil field in Venezuela in 2001, partly offset by a NOK 0.8 billion impairment charge for writing down the LL652 field in 2002. The 98% increase in 2001 as compared to 2000 is primarily related to the NOK 2.0 billion writedown of the LL652 oil field in Venezuela in 2001. The writedowns were mainly due to reductions in the projected volumes of oil recoverable during the remaining contract period of operation.

Exploration expenditure (activity) was NOK 0.9 billion in 2002, compared to NOK 0.7 billion in 2001 and NOK 1.8 billion in 2000. The 40% increase in exploration expenditure from 2001 to 2002 was mostly related to increased exploration activity in 2002, and the 61% decrease in exploration expenditure from 2000 to 2001 was primarily due to lower exploration activity in 2001. We expect the exploration expenditure to increase significantly in 2003.

Exploration expense in 2002 was NOK 0.8 billion compared to NOK 0.9 billion in 2001 and NOK 1.1 billion in 2000. The 11% decrease in exploration expense from 2001 to 2002 was a result of greater success in exploration activity in Angola, partly offset by expensing the Nnwa-2 well in license 218 in Nigeria. In total, eight exploration and appraisal wells were completed in 2002, of which seven resulted in discoveries and six remain capitalized. The 24% decrease in exploration expense from 2000 to 2001 was primarily a result of lower exploration activity, partly offset by the 50% writedown of the signature bonus in Angola block 31 due to the dry well in the Jupiter prospect. In total, nine exploration and appraisal wells were completed in 2001. Of these wells, three resulted in discoveries.

Income before financial items, income taxes and minority interest for International E&P in 2002 was NOK 1.1 billion compared to NOK 1.3 billion in 2001 and NOK 0.8 billion in 2000. The higher average lifted volumes in 2002 compared to 2001 contributed approximately NOK 1.6 billion, while the oil and gas price development measured in USD contributed NOK 0.2 billion. These positive effects are offset by the weakening of the USD measured against NOK and the net effect of asset divestments in 2001 and 2002. Excluding asset sales and impairment, Income before financial items, income taxes and minority interest was NOK 0.9 billion in 2002, compared to NOK 0.4 billion in 2001.

The 67% increase from 2000 to 2001 is mainly due to the gain of NOK 2.9 billion from the divestments of the Kashagan and Vietnam assets, partly offset by the NOK 2.0 billion writedown of the LL652 oil field in Venezuela. Excluding these items the income before financial items, income taxes and minority interest was NOK 0.4 billion in 2001. Lower oil prices were the main reason for the decline in the 2001 income before financial items, income taxes and minority interest compared to 2000. This was partly offset by a reduction in operating costs due principally to lower production and lower production cost per barrel, reduced depreciation and reduced exploration expense.

Natural Gas

The following table sets forth certain financial and operating data for our Natural Gas business segment and percentage change in each of the three years ended December 31, 2002.

FINANCIAL AND OPERATING DATA	2000	2001	YEAR ENDED DECEMBER 31, % CHANGE	2002	% CHANGE
Financial data (in NOK million):					
Revenues	20,624	23,468	14%	24,536	5%
Natural gas sales	16,060	18,984	18%	20,844	10%
Processing and transportation	4,564	4,484	(2%)	3,692	(18%)
Income before financial items, income taxes and minority interest	7,893	9,629	22%	8,918	(7%)
Volumes marketed:					
For our own account (bcf)	499.7	517.8	4%	691.4	34%
For the account of the SDFI (bcf)	601.5	666.9	11%	829.5	24%
For our own account (bcm)	14.1	14.7	4%	19.6	34%
For the account of the SDFI (bcm)	17.0	18.9	11%	23.5	24%

Years ended December 31, 2002, 2001 and 2000

Revenues in the Natural Gas business consist mainly of gas sales derived from long-term gas sales contracts, tariff revenues from pipelines, transportation and income from our share in the Kårstø processing facility. Natural Gas generated revenues of NOK 24.5 billion in 2002, compared to NOK 23.5 billion in 2001 and NOK 20.6 billion in 2000. The 5% increase in 2002 over 2001 resulted mainly from a 34% average increase in natural gas sales volumes, which is partly offset by a 22% reduction in natural gas prices and a 18% reduction in processing and transportation revenues as a result of reduced ownership in Statpipe from 58.25% to 25% effective from June 1, 2001.

Natural gas sales were 19.6 bcm (691.4 bcf) in 2002, 14.7 bcm (517.8 bcf) in 2001 and 14.1 bcm (499.7 bcf) in 2000. The 34% increase in gas sales from 2001 to 2002 was primarily due to deliveries under our long-term supply contracts combined with increased short-term gas sales. Of the total natural gas sales in 2002, Statoil produced 18.5 bcm (653.1 bcf). Our long-term gas sales contracts specify a minimum volume of gas to be purchased by a customer during a particular year and in each day of that year, in each case within a particular range. By the end of each year, a customer is obligated to purchase at least the volume agreed to or to compensate us for the difference between the minimum volumes contracted for and the volumes actually taken. Under these contracts, the range of gas volumes, which a customer may purchase per day, is considerably wider than the corresponding range for gas volumes that must be purchased by year-end. Accordingly, a customer is free to vary the volume he takes in each day within the agreed range, and as a result also in each quarter, as long as he has purchased at least the specified volume by year-end. Additional long-term gas sales contracts have been entered into in 2002. We expect our currently contracted gas volumes to increase until 2008 because our gas sales contracts contain scheduled annual volume delivery increases. As customers may contractually vary their daily gas purchases, quarterly gas sales may increase or decrease without affecting the total contracted volume, which a customer must purchase by the end of a given gas year.

Income before financial items, income taxes and minority interest for Natural Gas in 2002 was NOK 8.9 billion, compared to NOK 9.6 billion in 2001 and NOK 7.9 billion in 2000. The 7% decrease in income before financial items, income taxes and minority interest from 2001 to 2002 was primarily the result of a 22% reduction in natural gas prices, an 18% reduction in processing and transportation revenues as a result of reduced ownership in Statpipe from 58.25% to 25% effective from June 1, 2001. In addition cost of goods sold and operating, selling and administrative expenses increased due to higher volumes. This was partly offset by a 10% increase in gas sales revenues due to higher natural gas sales volumes.

The 22% increase in income before financial items, income taxes and minority interest from 2000 to 2001 was primarily the result of increased revenues from gas sales, mainly due to higher gas prices that were on average 23% higher than in 2000. This increase has partly been offset by increased cost of goods sold due to higher transfer prices paid to E&P Norway, as well as increased transportation cost due to increased sales volumes, partly offset by reduced transportation tariffs. In addition, the contribution from Statpipe declined as a consequence of our interest being reduced from 58.25% to 25% from June 1, 2001.

Manufacturing and Marketing

Years ended December 31, 2002, 2001 and 2000

Manufacturing and Marketing generated revenue of NOK 211.2 billion in 2002, compared to NOK 203.4 billion in 2001 and NOK 201.6 billion in 2000. The 4% increase in revenue in 2002 over 2001 resulted primarily from higher sold volumes of crude and higher prices in USD for crude oils, but was partly offset by the strengthening of the Norwegian currency versus the US dollar. The 1% increase in revenue in 2001 over 2000 resulted principally from the effect of the implementation of the owner's instruction for our SDFI sales. There is an offsetting effect on cost of goods sold. Excluding this effect, revenues decreased by 11% due to declining crude and product prices, partly offset by increased sold volumes of third party crude oil.

Depreciation, depletion and amortization totaled NOK 1.7 billion in 2002, as compared to NOK 1.9 billion in 2001 and NOK 1.7 billion in 2000.

Income before financial items, income taxes and minority interest for Manufacturing and Marketing was NOK 1.6 billion in 2002, as compared with NOK 4.5 billion in 2001 and NOK 4.6 billion in 2000. Income in 2002 was negatively affected by the strengthening of the Norwegian currency versus the US dollar. Lower refining margins were the main reason for a reduction in income from refining activity by NOK 1.8 billion from 2001 to 2002. Average refining margin (FCC-margin) was 39% lower, equaling USD 1.4 per barrel, from 2001 to 2002, and the effect was even higher in NOK due to the strong NOK. The result was also negatively affected by planned maintenance shutdowns at the refineries at Mongstad and Kalundborg. In oil trading, profits in 2002 were on the same level as in 2001. The retail marketing profit increased by NOK 0.1 billion in 2002, compared to 2001. The increase was mainly due to higher volumes and cost reductions. The 2001 result was also affected by a small gain from the sale of an office building in Denmark. The results for Methanol in 2002 decreased by NOK 0.2 billion compared to 2001. Average contract price on methanol was about 22% lower in 2002 than in 2001. The price of methanol, however, increased during the second half of 2002.

Lower refining margins were the main reason for the reduction in income from refining activity in 2001 compared to 2000. Average refining margin (FCC-margin) was 30% lower, equaling USD 1.5 per barrel, from 2000 to 2001. In oil trading, profits in 2001 increased by NOK 1.1 billion compared to 2000. The increase was mainly due to good positioning in a volatile market with declining prices and improved risk management within trading. The retail marketing profit increased by NOK 0.7 billion in 2001, compared to 2000. The increase was mainly due to improved margins and cost reductions as well as a small gain from the sale of an office building in Denmark. The results for Methanol in 2001 increased by NOK 0.2 billion compared to 2000. Average contract price on methanol was about 20% higher than in 2000. The price of methanol, however, declined during the second half of 2001. Additionally, two unplanned cracker shutdowns at the Mongstad refinery, lower shipping rates and low prices within the petrochemical business adversely affected income before financial items, income taxes and minority interest in 2001 as compared to 2000.

Navion contributed NOK 0.4 billion to income before financial items, income taxes and minority interest of the Manufacturing and Marketing business segment in 2002, as compared to an income before financial items, income taxes and minority interest of NOK 1.5 billion in 2001 and an income before financial items, income taxes and minority interest of NOK 2.1 billion in 2000. The net result for 2002 was negatively affected by lower shipping rates and lower capacity utilization of the offshore loading fleet in 2002, compared to 2001. The net result for 2001 was negatively affected by lower shipping rates and lower capacity utilization of the offshore loading fleet in the second half of 2001 compared to 2000. On December 15, 2002, Statoil signed a contract to sell 100% of the shares in Navion ASA to Norsk Teekay AS, which is a wholly owned subsidiary of Teekay Shipping Corporation. The sales price for the fixed assets of Navion, excluding *Odin* and Navion's 50% share in the *West Navion* drill ship, which are not included in the sale, is approximately USD 800 million. The effective date of the transaction is January 1, 2003, and the sale will be booked at closing, which is expected to take place in the second quarter of 2003, pending satisfactory assignment of certain contracts. Based on the exchange rate at December 31, 2002, and the book value of the assets sold on the same date, the effect on net income from the transaction is immaterial.

The contribution from our retail affiliate Statoil Detaljhandel Skandinavia to Manufacturing and Marketing's income before financial items, income taxes and minority interest was NOK 221 million in 2002, compared with NOK 222 million in 2001 and NOK 194 million in 2000. The increase of NOK 28 million from 2000 to 2001 was primarily due to increases in revenues from non-fuel sales.

The contribution from our affiliate Borealis to Manufacturing and Marketing's income before financial items, income taxes and minority interest was an income of NOK 53 million in 2002, a loss of NOK 146 million in 2001 and an income of NOK 244 million in 2000. The contribution from Borealis increased from 2001 to 2002 mainly due to an increase in volumes sold by 4% and contribution from an ongoing improvement program. The margins, however, were reduced by 25 euro per tonne, approximately 19%, from 2001 to 2002. The contribution from Borealis declined from 2000 to 2001 mainly due to reductions in margins in the range of EUR 30 per tonne, approximately 18%, as a consequence of weaker market conditions for polyolefin and olefin products.

Other operations

Years ended December 31, 2002, 2001 and 2000

Our other operations consist of the activities of Corporate Services, Corporate Center, Group Finance and Technology. In connection with our other operations, we recorded a loss before financial items, income taxes and minority interest of NOK 2 million in 2002. Income before financial items, income taxes and minority interest was NOK 57 million in 2001 and NOK 51 million in 2000.

Liquidity and Capital Resources

Cash Flows Provided by Operating Activities

Our primary source of cash flow is funds generated from operations. Net funds generated from operations for 2002 amounted to NOK 24.0 billion, as compared to NOK 39.2 billion for 2001 and NOK 56.8 billion for 2000. Cash flows in 2001 were significantly affected by the SDFI transaction in which the Norwegian state transferred interests in certain SDFI properties to Statoil. The decline in cash flows provided by operating activities in 2002 of NOK 15.2 billion, compared to 2001, is partly due to increased working capital of NOK 1.1 billion (excluding taxes payable, short-term interest bearing debt and cash). In addition, NOK 12.0 billion of the reduction is related to the decrease in cash flow from operations before tax, mainly due to lower prices, margins and the decline in the NOK/ USD exchange rate, and NOK 2.0 billion in increased tax payments.

The 31% decrease from 2000 to 2001 was primarily due to change in taxes paid, income taxes related to the transferred SDFI assets, and the effect of lower oil prices on our cash flow.

Cash Flows used in Investing Activities

Net cash flows used in investing activities amounted to NOK 16.8 billion in 2002, as compared to NOK 12.8 billion for 2001 and NOK 16.0 billion for 2000. Gross investments (1), defined as additions to property, plant and equipment and capitalized exploration expenditures, declined from NOK 18.7 billion in 2000 to NOK 17.4 billion in 2001 and increased to NOK 20.1 billion in 2002. The 31% increase in net cash flows used in investment activities from 2001 to 2002 is primarily related to higher investment levels in E&P Norway, International E&P and Manufacturing and Marketing, as well as reduced cash flow from sale of assets compared to 2001.

The 20% decline in net cash flows used in investment activities from 2000 to 2001 is mainly due to lower gross investments, an increase in repayment of long-term loans granted and other long-term items and reduction in proceeds from sales of assets compared to 2000.

Cash Flows used in/provided by Financing Activities

Net cash flows used in financing activities amounted to NOK 4.6 billion for 2002, as compared to NOK 31.5 billion for 2001 and NOK 35.2 billion in 2000. New long-term borrowing in 2002 decreased by NOK 4.2 billion compared to 2001, while repayment of long-term debt decreased by NOK 0.3 billion. In 2001, an additional NOK 12.9 billion in proceeds were received from the issuance of new shares in our initial public offering. We used the proceeds to repay the Norwegian State for the subordinated debt incurred in the restructuring of the SDFI assets. The change in net cash flows from financing activities from 2001 to 2002 was due primarily to the restructuring of the SDFI assets and proceeds from issuance of new shares in 2001.

We paid a dividend of NOK 6.2 billion in 2002. Dividends paid in 2001 were NOK 55.4 billion, while dividends paid in 2000 amounted to NOK 21.4 billion. The high level of dividends in 2000 was due to increased cash flows generated from SDFI properties that prior to June 1, 2001 were fully paid as dividends and increased net income after tax for all other activities. The dividend for 2001 includes payment of the transferred SDFI assets of approximately NOK 40.8 billion. The dividends we paid in the past reflected our status as wholly owned by the Norwegian State and should not be considered indicative of our future dividend policy.

Working Capital

Working capital (current assets less current liabilities) was negative by NOK 1.3 billion as of December 31, 2002, NOK 9.5 billion as of December 31, 2001 and NOK 0.3 billion as of December 31, 2000. We believe that, taking into consideration Statoil's established liquidity reserves (including committed credit facilities), credit rating and access to capital markets, we have sufficient liquidity and working capital to meet our present and future requirements. Our sources of liquidity are described below.

Liquidity

Our cash flow from operations is highly dependent on oil and gas prices and our levels of production, and is only to a small degree influenced by seasonality. Fluctuations in oil and gas prices will cause changes in our cash flows. We will use available liquidity and new loans to finance Norwegian petroleum tax payments (due April 1 and October 1 each year) and any dividend payment. Our investment program is spread across the year.

(1) Gross investments also include investments in intangible assets and long-term share investments.

As of December 31, 2002, we had liquid assets of NOK 12.0 billion, including approximately NOK 5.3 billion of domestic and international capital market investments, primarily government bonds, but also other investment grade short- and long-term debt securities, and NOK 6.7 billion in cash and cash equivalents. As of December 31, 2002, approximately 75% of our cash and cash equivalents were held in NOK, 15% in US dollars, 5% in euro and 5% in other currencies, before the effect of currency swaps and forward contracts. Euros and US dollars are sold in order to meet our obligations in NOK. Capital market investments increased by NOK 3.2 billion during 2002, as compared to year-end 2001. Cash and cash equivalents increased by NOK 2.3 billion during 2002, as compared to year-end 2001. The reason for this increase is mainly related to liquidity management.

As of December 31, 2001, we had liquid assets of NOK 6.5 billion, including NOK 2.1 billion of domestic and international capital market investments and NOK 4.4 billion in cash and cash equivalents. As of December 31, 2001, approximately 60% of our cash and cash equivalents were held in euro, 15% in US dollars, 10% in NOK and 15% in other currencies, before the effect of currency swaps and forward contracts. The high level of euros held at year-end 2001 was mostly related to the effects of slight delays in the scheduled and regular exchanges to NOK in anticipation of the tax payment in April 2002. As of December 31, 2000, we had liquid assets of NOK 13.6 billion, including NOK 3.9 billion of domestic and international capital market investments and NOK 9.7 billion in cash and cash equivalents. As of December 31, 2000, approximately 50% of our cash and cash equivalents were held in US dollars, 30% in NOK and 20% in other currencies.

Our general policy is to maintain a minimum amount of liquidity reserves in the form of cash and cash equivalents while maintaining the balance of our liquidity reserves in the form of committed, unused credit facilities and credit lines to ensure that we have sufficient financial resources to meet our short-term requirements. Long-term funding is raised when we identify a need for such financing based on our business activities and cash flows as well as when market conditions are considered favorable.

As of December 31, 2002, the Group had available a USD 1 billion-committed revolving credit facility from a group of international banks, including a USD 500 million swingline facility. This facility was entered into by us in 2000 and is available for drawdowns until November 2005. At year-end 2002 no amounts had been drawn. In addition, a USD 600 million five-year revolving credit facility was signed in January 2003, and is available for drawdowns until January 2008.

The Group's borrowing needs are mainly covered through short-term and long-term securities issues, including utilization of a US Commercial Paper Program and a Euro Medium Term Note (EMTN) Program, and through draw downs under committed credit facilities and credit lines. In 2002, a total of JPY 10 billion and EUR 150 million of fixed rate notes and EUR 50 million of floating rate notes were issued under our EMTN Program. Maturities range from five to ten years. Two ten-year loans totaling JPY 8 billion and one JPY 5 billion five-year loan were established directly with Japanese life insurance companies. Two lines of credit totaling EUR 242 million that had been established in our favor on a bilateral basis by an international financial institution in 2000 were drawn down towards the end of 2002. The loan equivalent to EUR 200 million has a maturity of ten years, whereas the loan equivalent to EUR 42 million will be repaid over 13.5 years. After the effect of currency swaps, our borrowings are nearly 100% in US dollars. As of December 31, 2002, our long-term debt portfolio totaled NOK 32.8 billion, with a weighted average maturity of approximately 11.2 years and a weighted average interest rate of approximately 5.2% per annum. As of December 31, 2001, our long-term debt portfolio totaled NOK 35.2 billion with a weighted average maturity of approximately 12 years and a weighted average interest rate of approximately 5.2% per annum.

Our financing strategy considers funding sources, maturity profile, currency mix, interest rate risk management instruments and the liquidity reserve and we use a multicurrency liability model (MLM) to manage debt-related risks. Accordingly, in general, we select the currencies of our debt obligations, either directly when borrowing or through currency swap agreements, in order to help hedge our foreign currency exposures with the objective of optimizing our debt portfolio based on underlying cash flow. Our borrowings are denominated in, or have been swapped into, US dollars, because the most significant part of our net cash flow is denominated in that currency. In addition, we hedge our interest rate exposures through the use of interest rate derivatives, primarily interest rate swaps, based on an approved range for the interest reset profile of our total loan portfolio.

New long-term borrowings totaled NOK 5.4 billion in 2002, NOK 9.6 billion in 2001, and NOK 1.2 billion in 2000. We repaid approximately NOK 4.8 billion in 2002, approximately NOK 4.5 billion in 2001, and approximately NOK 13.3 billion in 2000. At December 31, 2002, NOK 2.0 billion of our borrowings were due for repayment within one year, NOK 8.5 billion were due for repayment between two and five years, and NOK 24.3 billion were due for repayment after five years. This compares to NOK 5.4 billion, NOK 8.6 billion and NOK 26.6 billion, respectively, as of December 31, 2001, and NOK 1.1 billion, NOK 8.0 billion and NOK 26.2 billion, respectively, as of December 31, 2000.

The following table summarizes our principal contractual obligations at December 31, 2002. The table below includes contractual obligations, excluding derivatives and other hedging instruments. See Item 11—Quantitative and Qualitative Disclosures About Market Risk.

		PAYMENT DUE BY PERIOD			
CONTRACTUAL OBLIGATIONS (IN NOK MILLION)	TOTAL	LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	AFTER 5 YEARS
Long-term debt	34,823	2,018	6,501	3,628	22,676
Finance lease obligations	66	11	25	30	0
Operating leases	20,544	4,070	5,869	3,988	6,617

Contractual obligations in respect of capital expenditure amount to NOK 19,298 million of which payments of NOK 8,633 million are due within one year as at December 31, 2002. We expect to fund this through cash flow provided by operating activities. See below for a discussion of the amount and purpose of our estimated capital expenditures for the years 2003 to 2004 for our four principal business segments.

The following table summarizes our principal commercial commitments at December 31, 2002.

		AMOUNT OF COMMITMENTS EXPIRATION PER PERIOD			
OTHER COMMERCIAL COMMITMENTS (IN NOK MILLION)	TOTAL	LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	AFTER 5 YEARS
Standby letters of credit	1,604	373	6	0	1,226

The treasury function provides a centralized service for overall funding activities, foreign exchange and interest rate management. Treasury operations are conducted within a framework of policies and guidelines authorized and reviewed regularly by our Board of directors. Our debt portfolio is managed in cooperation with our corporate risk management department, and we use a number of derivative instruments. The internal control is reviewed regularly for risk assessment by our internal auditors. Further details regarding our risk management are provided in —Risk Management below.

Research and Development

In addition to the technology developed through field development projects, substantial amounts of our research is carried out at our research and technology development center in Trondheim, Norway. Our internal research and development is done in close cooperation with Norwegian universities, research institutions, other operators and the supplier industry.

Research expenses were NOK 736 million, NOK 633 million and NOK 656 million in 2002, 2001 and 2000 respectively.

Return on Capital Employed and Capital Expenditure Targets

Our business is capital intensive. Furthermore, our capital expenditures include several significant projects that are characterized by lead times of several years and expenditures that individually may involve large amounts. Given this capital intensity, we use Return on Average Capital Employed, or ROACE, as a key performance indicator to measure our success in utilizing capital. We define ROACE as follows:

$$\text{Return on Average Capital Employed} = \frac{\text{Net Income + Minority Interest + After-Tax Net Financial Costs}}{\text{Net Financial Debt + Shareholders' Equity + Minority Interest}}$$

Average capital employed reflects an average of capital employed at the beginning and the end of the financial period. Our historic ROACE for 2000, 2001 and 2002 was 18.7%, 19.9% and 14.9%, respectively.

For purposes of measuring our performance against our ROACE targets, we are assuming an average realized oil price of USD 16 per barrel, natural gas price of NOK 0.70 per scm, refining margin of USD 3.0 per barrel, Borealis margin of euro 150 per tonne, and a NOK/ USD exchange rate of NOK 8.20. All prices are measured in real 2000 terms. Under the same price assumptions, we are targeting a 12% ROACE by 2004. In 2000, using the assumptions mentioned, the ROACE was 7.5% adjusted on a pro forma basis for our transfer in 2001 of certain assets to the Norwegian State. For the year ended December 31, 2001, our ROACE was 9.4%, and 10.8% in 2002. In order to achieve our targeted ROACE by 2004, we aim to allocate capital only to those projects that meet our strict financial return criteria. Net present value is calculated by discounting projected future real after-tax cash flows from the project by 8% per annum for projects on the NCS or by 9% per annum for projects outside the NCS. Projects must have a positive net present value, and must also meet our robustness criteria.

The following table shows our ROACE calculation based on reported figures, figures excluding special items, and normalized figures:

Reconciliation of normalized ROACE calculation 2002

	NOK MILLION	ROACE % (1)
ROACE	12,647	14.9%
Special items (2)	(144)	(0.2%)
ROACE excluding special items	12,502	14.8%
Effect of normalized prices and margins	(3,832)	(4.5%)
Effect of normalized NOK/ USD exchange rate	446	0.5%
Normalized ROACE	9,117	10.8%

(1) Based on a denominator of average capital employed in 2002 of NOK 84,754 million.
(2) Special items are after tax and relate to the sale of assets in Denmark and the writedown of certain assets in Venezuela.

While continuing to focus on our overall objective of strict capital discipline, we believe that the improvement program from 2001 to 2004 targeting an improvement of Income before financial items, income taxes and minority interest of NOK 3.5 billion, our organic production growth and enhanced operating efficiencies, will help us reach our 12% ROACE target. In addition, our portfolio restructuring continued in 2002, including the sales of our E&P operations in Denmark and the agreement for sale of Navion in the first half of 2003. We anticipate that these divestments will further reduce our costs and capital employed as the divestments will fully affect our capital employed from 2003 going forward.

We are also committed to pursuing the following objectives to enhance operational efficiencies from 2002 to 2004:
- reducing unit production costs from 3.1 USD/ boe in 2002 to lower than 2.8 USD/ boe in 2004;
- reducing finding and development costs (3 years average) from 6.2 USD/ boe in 2002 to below 6.0 USD/ boe in 2004;
- improving the operational efficiency of the Mongstad refinery and maintaining the operational efficiency of the Kalundborg refinery relative to competitors;
- continuing to restructure our core area assets on the NCS and internationally; and
- increasing profitability in retail marketing, Nordic Energy operations and refining.

All targets are based on a continued organic development of Statoil and exclude possible effects related to acquisitions, which may affect our targets materially and cause us to revise our targets as a result of the impact of such acquisitions. We are seeking to expand our international portfolio and are actively pursuing potential opportunities, including possible acquisitions of properties or businesses. If we are successful in making such acquisitions, and no assurances can be given that we will be, the new projects we acquire will require additional capital expenditure and will increase our finding and development expenditure. It is likely that such acquisitions will be in the exploratory or development phase and not in the production phase, and thus could materially affect our net return in proportion to our average capital employed over the next few years. These projects may also have different risk profiles than our existing portfolio. In addition, although we have no current intentions to issue additional equity, we may require additional debt or equity financing to undertake or consummate future acquisitions or projects, which would affect our average capital employed and other key components of our targets. These and other effects of such acquisitions could result in our having to revise some or all of our targets with respect to ROACE, capital expenditure amounts and allocations, unit production costs, finding and development costs, reserves replacement rate and production.

In the period 2002-2007, we expect to increase, through organic growth, our oil and natural gas production to a total of 1,120 mboe per day in 2004, and 1,260 mboe per day in 2007. Our expected production growth through 2007 is based on the current characteristics of our reservoirs, our planned capital expenditure and our development budget, and is exclusive of non-organic growth, if any.

Our ROACE in any financial period and our ability to meet our target ROACE will be affected by our ability to generate net income. Our level of net income, including our targets to reduce production costs and finding and development costs, and our expected organic production growth are subject to numerous risks and uncertainties as described in –Factors Affecting Our Results of Operations. These risks include, among others, fluctuation in demand, retail margin, effects of acquisitions, changes in our oil and gas production volumes and trends in the international oil industry.

Set forth below are our capital expenditures in our four principal business segments for 2000-2002, including the allocation per segment as a percentage of gross investments.

CAPITAL EXPENDITURES PER SEGMENT (AMOUNTS IN MILLION)	YEAR ENDED DECEMBER 31, 2000		2001		2002	
	NOK	%	NOK	%	NOK	%
E&P Norway	12,992	59.0	10,759	60.0	11,023	55.0
International E&P	5,070	23.0	5,027	28.0	5,995	29.9
Natural Gas	810	3.7	671	3.7	465	2.3
Manufacturing and Marketing	2,860	13.0	811	4.5	1,771	8.8
Other	300	1.3	685	3.8	799	4.0
Total	22,032	100	17,953(1)	100	20,053	100

(1) Gross investments, which represent cash flow spent on property, plant and equipment and capitalized exploration expenditures amount to NOK 17,414 million in 2001. For 2001 this is included in our NOK 95 billion target for the period 2001-2004.

Years 2003 – 2004

The table below sets out for our four principal business segments our estimated capital expenditures for the years 2003 to 2004 of potential capital expenditure requirements for the principal investment opportunities available to us and other capital projects currently under consideration, including an estimated percentage allocation per segment in percent. All figures are based on an organic development of Statoil and exclude possible expenditures related to acquisitions. Therefore, the expenditure estimates and allocations below could differ materially from the actual expenditures and allocations of these expenditures among segments.

Our opportunities and projects under consideration could be sold, delayed or postponed in implementation, reduced in scope or rejected. Accordingly, the figures for 2003-2004 are only estimates and our actual capital expenditures will change based on decisions by our management and our board of directors, who expect to exploit these restructuring and asset trading opportunities and respond to changes in our business environment as they occur.

BUSINESS SEGMENT (IN NOK MILLION)	ESTIMATES OF CAPITAL EXPENDITURES IN 2003-2004	
E&P Norway	28,800	50%
International E&P	23,000	40%
Natural Gas	2,900	5%
Manufacturing and Marketing	2,900	5%
Total	57,500	100%

E&P Norway. Based on our current business plan, we estimate that E&P Norway's investments will require about NOK 28.8 billion over the period 2003-2004. A substantial portion of our 2003-2004 capital expenditure is allocated to the ongoing development projects in Kvitebjørn, Kristin and Snøhvit.

International E&P. We estimate that International E&P's investments will require approximately NOK 23 billion over the period 2003-2004. We currently estimate that the substantial portion of our 2003-2004 capital expenditure will be allocated to the ongoing and planned development projects: Azeri-Chirag-Gunashli including the Baku-Tbilisi-Ceyhan pipeline, Shah Deniz including the South Caucasus pipeline, Dalia, Kizomba A and B, South Pars phase 6-8 and Corrib.

Natural Gas. We estimate that Natural Gas' investments will require approximately NOK 2.9 billion over the period 2003-2004. Our main focus will be to increase the capacity and flexibility of our gas transportation and processing infrastructure. This will be done through expansion of the Kårstø processing plant, the possible development of a new pipeline to the UK, and the Aldbrough gas storage project on the east coast of England.

Manufacturing and Marketing. We estimate that Manufacturing and Marketing's investments will require approximately NOK 2.9 billion over the period 2003-2004. We are focusing our capital expenditure on expanding our retail network in Poland and the Baltics, upgrading the service stations in Ireland, and possible upgrading of the refineries to increase flexibility and meet expected EU and US refined product environmental requirements.

Finally, it should be noted that we may alter the amount, timing or segmental or project allocation of our capital expenditures in anticipation or as a result of a number of factors outside our control including, but not limited to:

- exploration and appraisal results, such as favorable or disappointing seismic data or appraisal wells;
- cost escalation, such as higher exploration, production, plant, pipeline or vessel construction costs;
- government approvals of projects;
- government awards of new production licenses;
- partner approvals;
- development and availability of satisfactory transport infrastructure;
- development of markets for our petroleum and other products including price trends;
- political, regulatory or tax regime risk;
- accidents and natural hazards such as rig blowups or fires;
- adverse weather conditions;
- environmental problems such as development restrictions, costs of regulatory compliance or the effects of petroleum discharges or spills; and
- acts of war, terrorism and sabotage

As of the date of filing of this Annual Report, the outlook for future changes in, for instance, prices of oil, natural gas and petroleum products, as well as the NOK/ USD exchange rate, and thus the information contained in this section, is highly uncertain due to the military conflict and unusually unpredictive situation in and surrounding Iraq.

Impact of Inflation

Our results in recent years have not been substantially affected by inflation. Inflation in Norway as measured by the general consumer price index during the years ended December 31, 2002, 2001, and 2000 was 1.3%, 3.0% and 3.1%, respectively.

Critical Accounting Policies

The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States, which require Statoil to make estimates and assumptions. Statoil believes that of its significant accounting policies (see Note 2 to the consolidated financial statements), the following may involve a higher degree of judgment and complexity, which in turn could materially affect the net income if various assumptions were changed significantly.

Proved oil and gas reserves. Statoil's oil and gas reserves have been estimated by its experts in accordance with industry standards under the requirements of the US Securities and Exchange Commission (SEC). An independent third party has in all material aspects verified Statoil's estimates. 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, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements but not on escalations based upon future conditions.

Proved reserves are used when calculating the unit of production rates used for depreciation, depletion, amortization as well as for decommissioning and removal provisions. Reserve estimates are also used when testing upstream assets for impairment. Future changes in proved oil and gas reserves, for instance as a result of changes in prices, could have a material impact on unit of production rates for depreciation, depletion and amortization and for decommissioning and removal provisions, as well as for the impairment testing of upstream assets.

Exploration and leasehold acquisition costs. In accordance with Statement of Financial Accounting Standards (FAS) No. 19, Statoil temporarily capitalizes the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. Statoil also capitalizes leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Exploratory wells that are believed to contain potentially economic quantities of oil and gas in an area where a major capital expenditure (i.e., a pipeline or an offshore platform) would be required before production could begin are often dependent on Statoil finding additional reserves to justify a development of the potential oil and gas field. It is not unusual for such exploratory wells to remain in "suspense" on the balance sheet for several years while the company performs additional appraisal drilling and seismic work on the potential field. Management continuously reviews the results of the additional drilling and seismic work and expenses the suspended well costs if no further activity is planned for the near future.

Leasehold acquisition costs are periodically assessed to determine whether they have been impaired. This assessment is based on the result of exploration activity on the leasehold and adjacent leasehold.

Decommissioning and removal liabilities. Statoil has significant legal obligations to decommission and remove offshore installations at the end of the production period. The estimated undiscounted costs to decommission and remove these installations are accrued using the unit-of-production method. It is difficult to estimate the costs of these activities which are based on today's regulations and technology. Most of the removal activities are many years into the future and the removal technology and costs are constantly changing.

Derivative financial instruments and hedging activities. In June 1998, the Financial Accounting Standards Board (FASB) issued Statement No. 133, «Accounting for Derivative Instruments and Hedging Activities». The Statement requires Statoil to recognize all derivatives on the balance sheet at fair value. Changes in fair value of derivatives that do not qualify as hedges are included in income.

The application of relevant rules requires extensive judgment and the choice of designation of individual contracts as qualifying hedges can impact the timing of recognition of gains and losses associated with the derivative contracts, which may or may not correspond to changes in the fair value of our corresponding physical positions, contracts and anticipated transactions, which are not required to be recorded at market in accordance with Statement No. 133. Establishment of non-functional currency swaps in our debt portfolio to match expected underlying cash flows may result in gains or losses in the profit and loss statement as hedge accounting is not allowed, even if the associated economical risk of the transactions are considered.

When not directly observable in the market or available through broker quotes, the fair value of derivative contracts must be computed internally based on internal assumptions as well as directly observable market information, including forward and yield curves for commodities, currencies and interest. Although the use of models and assumptions are according to prevailing guidance provided by FASB and best estimates, changes in internal assumptions and forward curves could have material effects on the internally computed fair value of derivative contracts, particularly long-term contracts, resulting in corresponding income or loss in the profit and loss statement.

New Accounting Standards

In June 2001, the FASB issued Statements of Financial Accounting Standards (FAS) No. 141, Business Combinations, and No. 142, Goodwill and Other Intangible Assets, effective for fiscal years beginning after December 15, 2001. Under the new rules, goodwill and intangible assets deemed to have indefinite lives will no longer be amortized but will be subject to annual impairment tests as described in the Statements. Other intangible assets will continue to be amortized over their useful lives. The impact of the adoption of FAS 141 and FAS 142 from January 1, 2002, was immaterial.

In June 2001, the FASB issued FAS 143, Accounting for Asset Retirement Obligations, which is effective for fiscal years beginning after June 15, 2002. The Statement requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The Company will adopt the new rules on asset retirement obligations on January 1, 2003. Application of the new standard is expected to result in an increase in net property, plant and equipment of NOK 2.8 billion, an increase in accrued asset retirement obligation of NOK 7.3 billion, a reduction in deferred tax assets of NOK 1.4 billion, and a long-term receivable of NOK 5.8 billion. The receivable represents the expected refund by the Norwegian state of an amount equivalent to the actual removal costs multiplied by the effective tax rate over the productive life of the asset. Removal costs on the Norwegian continental shelf are, unlike decommissioning costs, not deductible for tax purposes. The implementation effect on the net income and shareholders' equity is not expected to be material.

In August 2001, the FASB issued FAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which addresses financial accounting and reporting for the impairment or disposal of long-lived assets and supersedes FAS 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of, and the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations for a disposal of a segment of a business. FAS 144 is effective for fiscal years beginning after December 15, 2001. The adoption of FAS 144 from January 1, 2002, did not have any impact on the Company's financial position and results of operations.

Risk Management

Overview. We are exposed to a number of different market risks arising from our normal business activities. Market risk is the possibility that changes in currency exchange rates, interest rates, refining margins, petrochemical margins and oil and natural gas prices will affect the value of our assets, liabilities or expected future cash flows. We are also exposed to operational risk, which is the possibility that we may experience, among others, a loss in oil and gas production or an offshore catastrophe. Accordingly, we use a "top-down" approach to risk management, which highlights our most important market and operational risks and then use a sophisticated risk optimization model to manage these risks.

We have developed a comprehensive model, which encompasses our most significant market and operational risks and takes into account correlation, different tax regimes, capital allocation on various levels and value at risk, or VaR, figures on different levels, with the goal of optimizing risk exposure and return. Our model also utilizes Sharpe ratios, which provide a risk-adjusted return measure in the context of a specific risk taken, rather than an absolute rate of return, to measure the potential risks of various business activities. Our Corporate Risk Committee, which is headed by our Chief Financial Officer and which includes, among others, representatives from our principal business segments, is responsible for defining and implementing our strategic market risk policy. The Corporate Risk Committee meets monthly to determine our risk management strategies, including hedging and trading strategies and valuation methodologies.

We divide risk management into insurable risks which are managed by our captive insurance company operating in the Norwegian and international insurance markets, tactical risks, which are short-term trading risks based on underlying exposures and which are managed by line management, and strategic risks, which are long-term fundamental risks and are monitored by our Corporate Risk Committee. To address our tactical and strategic risks, we have developed policies aimed at managing the volatility inherent in certain of these natural business exposures and in accordance with these policies we enter into various transactions using derivative financial and commodity instruments (derivatives). Derivatives are contracts whose value is derived from one or more underlying financial instruments, indices or prices, which are defined in the contract.

Strategic Market Risks

We are exposed to strategic risks, which we define as long-term risks fundamental to the operation of our business. Strategic market risks are reviewed by our Corporate Risk Committee with the objective of avoiding suboptimization, reducing the likelihood of experiencing financial distress and supporting the group's ability to finance future growth even in down markets. Based on these objectives, we have implemented policies and procedures designed to reduce our overall exposure to strategic risks. For example, our multicurrency liability management model discussed under —Liquidity above seeks to optimize our debt portfolio based on expected future corporate cash flow and thereby serves as a significant strategic risk management tool. In addition, our downside protection program for crude oil price risk is intended to ensure that our business will remain robust even in the case of a drop in the price of crude oil.

Tactical Market Risks

All tactical risk management activities occur within and are continuously monitored against established mandates.

Commodity price risk. Commodity price risk constitutes our most important tactical risk. To minimize the commodities price volatility and conform costs to revenues, we enter into commodity-based derivative contracts, which consist of futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity.

Derivatives associated with crude oil and petroleum products are traded mainly on the International Petroleum Exchange (IPE) in London, the New York Mercantile Exchange (NYMEX), in the OTC Brent market, and in crude and refined products swaps markets. Derivatives associated with natural gas and electricity are mainly OTC physical forwards and options, Nordpool forwards, as well as futures traded on the IPE.

Foreign exchange and interest rate risk. We are also subject to interest rate risk and foreign exchange risk. Interest rate risk and currency risk are assessed against mandates based on a pre-defined scenario. In market risk management and in trading, we use only well-understood, conventional derivative instruments. These include futures and options traded on regulated exchanges, and OTC swaps, options and forward contracts.

Foreign exchange risk. Fluctuations in exchange rates can have significant effects on our results. Our cash flows are largely in currencies other than NOK. Cash receipts in connection with oil and gas sales are mainly in foreign currencies and cash disbursements are to a large extent in NOK. Accordingly, our exposure to foreign currency rates exists primarily with US dollars versus NOK, European euro, Danish kroner, Swedish kroner and UK pounds sterling. We enter into various types of foreign exchange contracts in managing our foreign exchange risk. We use forward foreign exchange contracts primarily to risk manage existing receivables and payables, including deposits and borrowing denominated in foreign currencies. Currency options, purchased in the OTC market for a premium, provide us with the right to buy or sell an agreed amount of currency at a specified exchange rate at the end of a specified period.

Interest rate risk. The existence of assets and liabilities earning or paying variable rates of interest expose us to the risk of interest rate fluctuations. We enter into various types of interest rate contracts in managing our interest rate risk. We enter into interest rate derivatives, particularly interest rate swaps, to alter interest rate exposures, to lower funding costs and to diversify sources of funding. Under interest rate swaps, we agree with other parties to exchange, at specified intervals, the difference between interest amounts calculated by reference to an agreed notional principal amount and agreed fixed or floating interest rates.

Fair market values of financial and commodity derivatives. Fair market values of commodity based futures and exchange traded option contracts are based on quoted market prices obtained from the New York Mercantile Exchange or the International Petroleum Exchange. The fair values of swaps and other commodity over-the counter arrangements are established based on quoted market prices, estimates obtained from brokers, and other appropriate valuation techniques. Where Statoil records elements of long-term physical delivery commodity contracts at fair market value under the requirements of FAS 133, such fair market value estimates are based on quoted forward prices in the market, underlying indexes in the contracts, and assumptions of forward prices and margins where market prices are not available. Fair market values of interest and currency swaps and other instruments are estimated based on quoted market prices, estimates obtained from brokers, prices of comparable instruments, and other appropriate valuation techniques. The fair value estimates approximate the gain or loss that would have been realized if the contracts had been closed out at year-end, although actual results could vary due to assumptions used.

The following table contains the net fair market value of non-exchange traded (i.e. over-the-counter) commodity and financial derivatives as so accounted for under FAS 133, as at December 31, 2002, based on maturity of contracts and the source of determining the fair market value of contracts, respectively:

SOURCE OF FAIR MARKET VALUE AT DECEMBER 31, 2002 (IN NOK MILLION)	*NET FAIR MARKET VALUE MATURITY LESS THAN 1 YEAR*	*MATURITY 1 – 3 YEARS*	*MATURITY 4 –5 YEARS*	*MATURITY IN EXCESS OF 5 YEARS*	*TOTAL NET FAIR VALUE*
Commodity based derivatives:					
Prices actively quoted	(176)	4	0	0	(172)
Prices provided by other external sources	111	19	0	17	147
Prices based on models or other valuation techniques	(70)	(17)	0	91	4
Total commodity based derivatives	(135)	6	0	108	(21)
Financial derivatives:					
Prices actively quoted	0	0	0	0	0
Prices provided by other external sources	187	104	187	1,664	2,142
Prices based on models or other valuation techniques	0	0	0	0	0
Total financial derivatives	187	104	187	1,664	2,142

In the above table, other external sources for commodities mainly relate to broker quotes. The fair market values of interest and currency swaps and other financial derivatives are computed internally by means of standard financial system models and based consistently on quoted market yield and currency curves.

The following table contains a reconciliation of changes in the fair market values of all commodity and financial derivatives, including exchange traded derivatives, in the books at either December 31, 2002, or December 31, 2001, net of margin calls. Derivatives entered into and subsequently terminated during the course of the year 2002 have not been included in the table:

(IN NOK MILLION)	*COMMODITY DERIVATIVES*	*FINANCIAL DERIVATIVES*
Net fair value of derivative contracts outstanding as at December 31, 2001	691	(923)
Contracts realized or settled during the period	(767)	115
Fair value of new contracts entered into during the period	274	629
Changes in fair value attributable to changes in valuation techniques or assumptions	8	0
Other changes in fair values	(169)	2,321
Net fair value of derivative contracts outstanding as at December 31, 2002	37	2,142

Derivatives and Credit risk

Futures contracts have little credit risk because organized exchanges are the counter-parties. The credit risk from Statoil's over-the-counter (OTC) commodity-based derivative contracts derives from the counter-party to the transaction. Brent forwards, other forwards, swaps and all other OTC instruments are traded subject to internal assessment of creditworthiness of counter-parties, which are primarily oil and gas companies and trading companies.

Credit risk related to commodity-based instruments is managed by maintaining, reviewing and updating lists of authorized counter-parties by assessing their financial position, by monitoring credit exposure for counter-parties, by establishing internal credit lines for counter-parties, and by requiring collateral or guarantees when appropriate under contracts and required by internal policies. Collateral will typically be in the form of cash or bank guarantees from first class international banks.

Credit risk from interest rate swaps and currency swaps, which are OTC transactions, derive from the counter-parties to these transactions. Counter-parties are highly rated financial institutions. The credit ratings are, at a minimum, reviewed annually and counter-party exposure is monitored to ensure exposure does not exceed credit lines and complies with internal policies. Non debt related foreign currency swaps usually have terms of less than 1 year, and the terms of debt related interest swaps and currency swaps are up to 26 years, in line with that of corresponding hedged or risk managed long-term loans.

The following table contains the fair market value of OTC commodity and financial derivative assets as at December 31, 2002, split by our assessment of the counter-party's credit risk:

OTC DERIVATIVE ASSETS SPLIT BY COUNTER-PARTY'S CREDIT RATING (IN NOK MILLION)	*FAIR MARKET VALUE*
Internal Statoil rating of counter-party:	
Investment grade, rated A or above	4,452
Other investment grade	259
Non investment grade or not rated	79

Credit rating categories in the table above are based on the Statoil Group's internal credit rating policies, and do not correspond directly with ratings issued by the major Credit Rating Agencies. Internal ratings are harmonized with external ratings where available, but could occasionally vary somewhat due to internal assessments. Consistent with Statoil policies, commodity derivative counter-parties have been assigned credit ratings corresponding to those of their respective parent companies, while there will not necessarily be a parent company guarantee from such parent companies if highly rated.

Operational Risks

We are also exposed to operational risks, including reservoir risk, risk of loss of oil and gas production and offshore catastrophe risk. All of our installations are insured, which means that replacement cost will be covered by our captive insurance company, which also has a reinsurance program. Under this reinsurance program, as of December 31, 2002, approximately 70% of the approximately NOK 110 billion total insured amount was reinsured in the international reinsurance markets. Our captive insurance company also works with our corporate risk management department to manage other insurable operational risks.

FORWARD-LOOKING STATEMENTS

This Annual Report contains certain forward-looking statements that involve risks and uncertainties. All statements other than statements of historical facts, including, among others, statements such as those regarding Statoil's production forecasts, targets and margins; performance and growth targets; operating costs for 2004; and expected exploration and development activities or expenditures, are forward-looking statements. These forward-looking statements reflect current views with respect to future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. There are a number of factors that could cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements, including levels of industry product supply, demand and pricing; currency exchange rates; political stability and economic growth in relevant areas of the world; development and use of new technology; geological or technical difficulties; the actions of competitors; the actions of field partners; natural disasters and other changes to business conditions. Additional information, including information on factors which may affect our business, is contained in our Registration Statement on Form F-1 filed with the US Securities and Exchange Commission and will be contained in our Annual Report on Form 20-F expected to be filed with the US Securities and Exchange Commission in March 2003.

Jan Varming manages the first new service station to feature an extension of Statoil's forecourt design concept. This architectonic solution is characterised by a light canopy structure and more discrete use of colour. Located on the E18 motorway in Asker outside Oslo, the station opened in late 2002. The revised design will be applied in building new stations and modernising forecourts throughout the Statoil Detaljhandel Skandinavia network.

Statoil group – USGAAP

Statoil group – USGAAP

CONSOLIDATED STATEMENTS OF INCOME – USGAAP

(IN NOK MILLION)	*2002*	*YEAR ENDED DECEMBER 31, 2001*	*2000*
Sales	**242,178**	231,712	229,832
Equity in net income of affiliates	**366**	439	523
Other income	**1,270**	4,810	70
Total revenues	**243,814**	236,961	230,425
Cost of goods sold	**(147,899)**	(126,153)	(119,469)
Operating expenses	**(28,308)**	(29,422)	(28,883)
Selling, general and administrative expenses	**(5,466)**	(4,297)	(3,891)
Depreciation, depletion and amortization	**(16,844)**	(18,058)	(15,739)
Exploration expenses	**(2,195)**	(2,877)	(2,452)
Total expenses before financial items	**(200,712)**	(180,807)	(170,434)
Income before financial items, income taxes and minority interest	**43,102**	56,154	59,991
Net financial items	**8,233**	65	(2,898)
Income before income taxes and minority interest	**51,335**	56,219	57,093
Income taxes	**(34,336)**	(38,486)	(40,456)
Minority interest	**(153)**	(488)	(484)
Net income	**16,846**	17,245	16,153
Net income per ordinary share	7.78	8.31	8.18
Weighted average number of ordinary shares outstanding	2,165,422,239	2,076,180,942	1,975,885,600

Revenues are net of excise tax of NOK 18,745, 18,571, and 19,507 million in 2002, 2001 and 2000, respectively.

See notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS – USGAAP

(IN NOK MILLION)	*AT DECEMBER 31,* *2002*	*2001*
ASSETS		
Cash and cash equivalents	**6,702**	4,395
Short-term investments	**5,267**	2,063
Cash, cash equivalents and short-term investments	**11,969**	6,458
Accounts receivable	**32,057**	26,208
Accounts receivable - related parties	**1,893**	1,531
Inventories	**5,422**	5,276
Prepaid expenses and other current assets	**6,856**	9,184
Total current assets	**58,197**	48,657
Investments in affiliates	**9,629**	9,951
Long-term receivables	**7,138**	7,166
Net property, plant and equipment	**122,379**	126,500
Other assets	**8,087**	7,421
TOTAL ASSETS	**205,430**	199,695
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	**4,323**	6,613
Accounts payable	**19,603**	10,970
Accounts payable - related parties	**5,649**	10,164
Accrued liabilities	**11,590**	13,831
Income taxes payable	**18,358**	16,618
Total current liabilities	**59,523**	58,196
Long-term debt	**32,805**	35,182
Deferred income taxes	**43,153**	42,354
Other liabilities	**11,382**	10,693
Total liabilities	**146,863**	146,425
Minority interest	**1,550**	1,496
Common stock (NOK 2.50 nominal value), 2,189,585,600 shares authorized and issued	**5,474**	5,474
Treasury shares, 23,441,974 and 25,000,000 shares	**(59)**	(63)
Additional paid-in capital	**37,728**	37,728
Retained earnings	**17,355**	6,682
Accumulated other comprehensive income (loss)	**(3,481)**	1,953
Total shareholders' equity	**57,017**	51,774
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**205,430**	199,695

See notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY – USGAAP

(IN NOK MILLION, EXCEPT SHARE DATA)	NUMBERS OF SHARES ISSUED	SHARE CAPITAL	TREASURY SHARES	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS	ACCUM OTHER COMPREHENSIVE INCOME	TOTAL
At January 1, 2000	1,975,885,600	4,940	0	29,759	19,978	1,428	56,105
Net income					16,153		16,153
Cumulative translation adjustment						1,062	1,062
Total comprehensive income							17,215
Contribution from shareholder				15,869			15,869
Dividends					(21,363)		(21,363)
At December 31, 2000	1,975,885,600	4,940	0	45,628	14,768	2,490	67,826
Net income					17,245		17,245
Cumulative translation adjustment						(537)	(537)
Total comprehensive income							16,708
Issuance of treasury shares	25,000,000	63	(63)				0
Issuance of shares	188,700,000	471		12,419			12,890
Contribution from shareholder				9,440			9,440
Dividends related to SDFI properties				(30,084)	(19,663)		(49,747)
Adjustment related to the SDFI transaction				325			325
Ordinary dividend					(5,668)		(5,668)
At December 31, 2001	2,189,585,600	5,474	(63)	37,728	6,682	1,953	51,774
Net income					16,846		16,846
Cumulative translation adjustment						(5,434)	(5,434)
Total comprehensive income							11,412
Bonus shares distributed			4		(4)		0
Ordinary dividend					(6,169)		(6,169)
At December 31, 2002	2,189,585,600	5,474	(59)	37,728	17,355	(3,481)	57,017

Other comprehensive income amounts are net of income tax (expense)/benefit of NOK (78), 84 and (199) million at 2002, 2001 and 2000, respectively.

Dividends paid per share were NOK 2.85, NOK 26.69 and NOK 10.81 in 2002, 2001 and 2000, respectively. The dividends prior to the public offering are strongly affected by cash flows relating to the SDFI transaction.

Contributions from shareholder represent primarily income taxes for properties transferred from SDFI which are imputed but not paid. See note 1 Organization and Basis of Presentation for further details.

CONSOLIDATED STATEMENTS OF CASH FLOWS – USGAAP

(IN NOK MILLION)	*2002*	*YEAR ENDED DECEMBER 31, 2001*	*2000*
OPERATING ACTIVITIES			
Consolidated net income	**16,846**	17,245	16,153
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Minority interest in income	**153**	488	484
Depreciation, depletion and amortization	**16,844**	18,058	15,739
Exploration costs written off	**554**	935	410
(Gains) losses on foreign currency transactions	**(8,771)**	180	1,643
Deferred taxes	**628**	848	1,222
Income taxes of transferred SDFI properties	**0**	5,952	14,109
(Gains) losses on sales of assets and other items	**(1,589)**	(4,990)	637
Changes in working capital (other than cash):			
• (Increase) decrease in inventories	**(146)**	(1,050)	132
• (Increase) decrease in accounts receivables	**(6,211)**	4,522	(1,199)
• (Increase) decrease in other receivables	**3,107**	(1,543)	(291)
• (Increase) decrease in short-term investments	**(3,204)**	1,794	(254)
• Increase (decrease) in accounts payable	**4,118**	(3,852)	(3,146)
• Increase (decrease) in other payables	**1,095**	(1,629)	9,427
Increase (decrease) in other non-current obligations	**599**	2,215	1,686
Cash flows provided by operating activities	**24,023**	39,173	56,752
INVESTING ACTIVITIES			
Additions to property, plant and equipment	**(17,907)**	(16,649)	(17,292)
Exploration expenditures capitalized	**(652)**	(765)	(1,379)
Change in long-term loans granted and other long-term items	**(1,495)**	(539)	(3,343)
Proceeds from sale of assets	**3,298**	5,115	6,000
Cash flows used in investing activities	**(16,756)**	(12,838)	(16,014)

See notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS – USGAAP

(IN NOK MILLION)	*2002*	*YEAR ENDED DECEMBER 31, 2001*	*2000*
FINANCING ACTIVITIES			
New long-term borrowings	**5,396**	9,609	1,191
Repayment of long-term borrowings	**(4,831)**	(4,548)	(13,258)
Distribution to minority shareholders	**(173)**	(1,878)	0
Ordinary dividend paid	**(6,169)**	(5,668)	(1,702)
Amounts paid to shareholder, related to SDFI properties	**0**	(49,747)	(19,661)
Capital contribution related to SDFI properties	**0**	8,460	0
Net proceeds from issuance of new shares	**0**	12,890	0
Net short-term borrowings, bank overdrafts and other	**1,146**	(588)	(1,730)
Cash flows used in financing activities	**(4,631)**	(31,470)	(35,160)
Net increase (decrease) in cash and cash equivalents	**2,636**	(5,135)	5,578
Effect of exchange rate changes on cash and cash equivalents	**(329)**	(215)	106
Cash and cash equivalents at beginning of year	**4,395**	9,745	4,061
Cash and cash equivalents at end of year	**6,702**	4,395	9,745
Interest paid	**1,782**	3,793	3,204
Taxes paid	**31,634**	33,320	16,614

Imputed income taxes related to transferred SDFI properties, are included in financing activities as cash flows to shareholder until May 31, 2001 when the transaction became effective, and result in an adjustment to reconcile net income to net cash flows provided by operating activities.

See notes to the consolidated financial statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – USGAAP

1. Organization and Basis of Presentation

Statoil ASA was founded in 1972, as a 100% Norwegian State-owned company. Statoil's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products. In 1985, the Norwegian State transferred certain properties from Statoil to the State's direct financial interest (SDFI), which were also 100% owned by the Norwegian State.

In conjunction with a partial privatization of Statoil in June 2001, the Norwegian State restructured its holdings in oil and gas properties on the Norwegian Continental Shelf. In this restructuring, the Norwegian State transferred to Statoil certain SDFI properties with a book value of approximately NOK 30 billion, in consideration for which NOK 38.6 billion in cash plus interest and currency fluctuation from the valuation date of NOK 2.2 billion (NOK 0.7 billion after tax), and certain pipeline and other assets with a net book value of NOK 1.5 billion were transferred to the Norwegian State. The transaction was completed June 1, 2001 with a valuation date of January 1, 2001 with the exception of the sale of an interest in the Mongstad terminal which had a valuation date of June 1, 2001.

The total amount paid to the Norwegian State was financed through a public offering of shares for NOK 12.9 billion, issuance of new debt of NOK 9 billion and the remainder from existing cash and short term borrowings.

The transfers of properties from the SDFI have been accounted for as transactions among entities under common control and, accordingly, the results of operations and financial position of these properties have been combined with those of Statoil at their historical book value for all periods presented. However, certain adjustments have been made to the historical results of operations and financial position of the properties transferred to present them as if they had been Statoil's for all periods presented. These adjustments primarily relate to imputing of income taxes and capitalized interest, and calculation of royalty paid in kind consistent with the accounting policies used to prepare the consolidated financial statements of Statoil. Income taxes, capitalized interest and royalty paid in kind are imputed in the same manner as if the properties transferred to Statoil had been Statoil's for all periods presented. Income taxes have been imputed at the applicable income tax rate. Interest is capitalized on construction in progress based on Statoil's weighted average borrowing rate and royalties paid in kind are imputed based on the percentage applicable to the production for each field. Properties transferred from Statoil to the Norwegian State are not given retroactive treatment as these properties were not historically managed and financed as if they were autonomous. As such, the contribution of properties is considered a contribution of capital and is presented as additional paid-in capital in shareholder's equity at the beginning of January 1, 1996. The cash payment and net book value of properties transferred to the Norwegian State in excess of the net book value of the properties transferred to Statoil, is shown as a dividend. The final cash payment is contingent upon review by the Norwegian State, which is expected to be completed in the first half of 2003. The adjustment to the cash payment, if any, will be recorded as a capital contribution or dividend as applicable.

From June 2001, Statoil no longer acts as an agent to sell SDFI oil production to third parties. As such all purchases and sales of SDFI oil production are recorded as Cost of goods sold and Sales, respectively, whereas before, the net result of any trading activity was included in Sales.

Certain reclassifications have been made to prior periods' figures to be consistent with current period's presentation.

2. Summary of Significant Accounting Policies

The consolidated financial statements of Statoil ASA and its subsidiaries (the Company or the group) are prepared in accordance with United States generally accepted accounting principles (USGAAP).

Consolidation
The consolidated financial statements include the accounts of Statoil ASA and subsidiary companies owned directly or indirectly more than 50%. Inter-company transactions and balances have been eliminated. Investments in companies in which Statoil does not have control, but has the ability to exercise significant influence over operating and financial policies (generally 20 to 50% ownership), are accounted for by the equity method. Undivided interests in joint ventures in the oil and gas business, including pipeline transportation, are consolidated on a pro rata basis.

Foreign currency translation
Each foreign entity's financial statements are prepared in the currency in which that entity primarily conducts its business (the functional currency). For most of Statoil's foreign subsidiaries the local currency is the functional currency, with the exception of certain upstream subsidiaries, where the US dollar is the functional currency.

When translating foreign functional currency financial statements to Norwegian kroner, year-end rates are applied to asset and liability accounts, whereas average annual rates are applied to income statement accounts. Adjustments resulting from this process are included in the Accumulated other comprehensive income account in shareholders' equity, and do not affect net income.

Transactions denominated in currencies other than the entity's functional currency are remeasured into the functional currency using current exchange rates. Gains or losses from this remeasurement are included in income.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – USGAAP

Revenue recognition
Revenues associated with sales and transportation of crude oil, natural gas, petroleum and chemical products and other merchandise are recorded when title passes to the customer at the point of delivery of the goods based on the contractual terms of the agreements. Revenue is recorded net of customs, excise taxes and royalties paid in kind on petroleum products. Revenues from the production of oil and gas properties in which Statoil has interests with other companies are recorded on the basis of sales to customers. There are no significant differences between these sales and Statoil's share of production.

Cash and cash equivalents
Cash and cash equivalents include cash, bank deposits and all other monetary instruments with original maturities of three months or less.

Short-term investments
Short-term investments include bank deposits and all other monetary instruments and marketable equity and debt securities with a maturity of between three and twelve months at the date of purchase. The portfolios of securities are considered trading securities and are valued at fair value (market). The resulting unrealized holding gains and losses are included in financial income and expense. Investment income is recorded when earned.

Inventories
Inventories are valued at the lower of cost or market. Costs of crude oil and refined products held at refineries are determined under the last-in, first-out (LIFO) method. Cost for all other inventories is determined under the first-in, first-out (FIFO) method.

Use of estimates
Preparation of the financial statements requires the Company to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as disclosures of contingencies. Actual results may ultimately differ from the estimates and assumptions used.

The nature of Statoil's operations, and the many countries in which it operates, are subject to changing economic, regulatory and political conditions. Statoil does not believe it is vulnerable to the risk of a near-term severe impact as a result of any concentration of its activities.

Property, plant and equipment
Property, plant and equipment are carried at historical cost less accumulated depreciation, depletion and amortization. Expenditures for significant renewals and improvements are capitalized. Ordinary maintenance and repairs are charged against income when performed. Provisions are made for costs related to periodic maintenance programs.

Depreciation of production installations and field-dedicated transport systems for oil and gas is calculated using the unit of production method based on proved reserves expected to be recovered during the concession period. Ordinary depreciation of transport systems used by several fields and of other assets is calculated on the basis of their economic life expectancy, using the straight-line method. The economic life of such transport systems is normally the production period of the related fields, limited by the concession period. Straight-line depreciation of other assets is based on the following estimated useful lives:

Machinery and equipment	5 — 10 years
Production plants onshore	15 — 20 years
Buildings	20 — 25 years
Vessels	20 — 25 years

Oil and gas accounting
Statoil uses the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, and geological and geophysical and other exploration costs are expensed. Pre-production costs are expensed as incurred.

Unproved oil and gas properties are periodically assessed on a property-by-property basis, and a loss is recognized to the extent, if any, that the cost of the property has been impaired. Capitalized costs of producing oil and gas properties are depreciated and depleted by the unit of production method.

Impairment of long-lived assets
Long-lived assets, identifiable intangible assets and goodwill, are written down when events or a change in circumstances during the year indicate that their carrying amount may not be recoverable.

Impairment is determined for each autonomous group of assets (oil and gas fields or licenses, or independent operating units) by comparing their carrying value with the undiscounted cash flows they are expected to generate based upon management's expectations of future economic and operating conditions.

Should the above comparison indicate that an asset is impaired, the asset is written down to fair value, generally determined based on discounted cash flows.

Decommissioning and removal liabilities

The estimated costs of decommissioning and removal of major producing facilities are accrued using the unit-of-production method based on proved reserves expected to be recovered over the concession period. These costs represent the estimated future undiscounted costs of decommissioning and removal based on existing regulations and technology.

Leased assets

Material capital leases, which provide Statoil with substantially all the rights and obligations of ownership, are classified as assets under Property, plant and equipment and as liabilities under Long-term debt valued at the present value of minimum lease payments. The assets are subsequently depreciated and the liability is reduced for lease payments less the effective interest expense.

Statoil accrues for expected losses between fixed-price drilling rig contract rates and estimated sub-contract rates for excess rig capacity.

Research and development

Research and development costs are expensed when incurred.

Transactions with the Norwegian State

Statoil markets and sells the Norwegian State's share of oil and gas production from the Norwegian continental shelf (NCS). From June 2001, Statoil no longer acts as an agent to sell SDFI oil production to third parties. As such all purchases and sales of SDFI oil production are recorded as Cost of goods sold and Sales, respectively, whereas before, the net result of any trading activity was included in Sales.

All oil received by the Norwegian State as royalty in kind from fields on the NCS is purchased by Statoil. Statoil includes the costs of purchase and proceeds from the sale of this royalty oil in its Cost of goods sold and Sales respectively.

Income taxes

Deferred income tax expense is calculated using the liability method. Under this method, deferred tax assets and liabilities are determined by applying the enacted statutory tax rates applicable to future years to the temporary differences between the carrying values of assets and liabilities for financial reporting and their tax basis. Deferred income tax expense is the change during the year in the deferred tax assets and liabilities relating to the operations during the year. Effects of changes in tax laws and tax rates are recognized at the date the tax law changes.

Derivative financial instruments and hedging activities

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement No. 133, Accounting for Derivative Instruments and Hedging Activities (FAS 133). The Statement requires Statoil to recognize all derivatives on the balance sheet at fair value. Derivatives that are not hedges must be adjusted to fair value through income.

Statoil operates in the worldwide crude oil, refined products, and natural gas markets and is exposed to fluctuations in hydrocarbon prices, foreign currency rates and interest rates that can affect the revenues and cost of operating, investing and financing. Statoil's management has used and intends to use financial and commodity-based derivative contracts to reduce the risks in overall earnings and cash flows. Statoil applies hedge accounting in certain circumstances as allowed by the Statement, and enters into derivatives which economically hedge certain of its risks even though hedge accounting is not allowed by the Statement or is not applied by Statoil.

For derivatives where hedge accounting is used, Statoil formally designates the derivative as either a fair value hedge of a recognized asset or liability or unrecognized firm commitment, or a cash flow hedge of an anticipated transaction. Statoil also documents the designated hedging relationship upon entering into the derivative, including identification of the hedging instrument and the hedged item or transaction, strategy and risk management objective for undertaking the hedge, and the nature of the risk being hedged. Furthermore, each derivative is assessed for hedge effectiveness both at the inception of the hedging relationship and on a quarterly basis, for as long as the derivative is outstanding. Hedge accounting is only applied when the derivative is deemed to be highly effective at offsetting changes in fair values or anticipated cash flows of the hedged item or transaction. For hedged forecasted transactions, hedge accounting is discontinued if the forecasted transaction is no longer probable of occurring. Any previously deferred hedging gains or losses would be recorded to earnings when the transaction is considered to be probable of not occurring. Earnings impacts for all designated hedges are recorded in the Consolidated Statement of Income generally on the same line item as the gain or loss on the item being hedged.

Statoil records all derivatives at fair value as assets or liabilities in the Consolidated Balance Sheet. For fair value hedges, the effective and ineffective portions of the change in fair value of the derivative, along with the gain or loss on the hedged item attributable to the risk being hedged, are recorded in earnings as incurred. For cash flow hedges, the effective portion of the change in fair value of the derivative is deferred in accumulated Other comprehensive income in the Consolidated Balance Sheet until the transaction is reflected in the Consolidated Statement of Income, at which time any deferred hedging gains or losses are recorded in earnings. The ineffective portion of the change in the fair value of a derivative used as a cash flow hedge is recorded in earnings in Sales or Cost of goods sold as incurred.

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Prior to implementing FAS 133, Statoil applied the following accounting principles:

- Substantially all of Statoil's commodity-based derivatives (futures, forwards, options, swaps) are accounted for using the fair value method, whereby derivatives are carried on the balance sheet at fair value, including derivative positions utilized to manage price risk associated with corresponding physical positions, contracts, or anticipated transactions as a result of the instruments not meeting the criteria for deferral accounting. The gains and losses associated with the changes in the derivatives' fair value are recognized in Sales or Cost of goods sold in the period the change occurs.

- The deferral method of accounting, whereby gains and losses from the derivatives are deferred and recognized in earnings or as adjustments to the carrying amounts, when the hedged transaction occurs, is used for certain derivatives and related option premiums which are used to hedge anticipated transactions. At inception, these instruments are matched and designated to the underlying hedged commodity and changes in the market value of such instruments have a high correlation to the price changes of the hedged commodity. When an anticipated transaction is no longer likely to occur or is terminated before maturity, as appropriate, any deferred gain or loss that has arisen on the derivative is recognized in the income statement together with any gain or loss on the terminated item.

- Interest rate differentials to be paid or received as a result of interest rate swap agreements are accrued and recognized as an adjustment of interest expense related to the designated debt. Discounts or premiums from foreign currency forward contracts are accreted or amortized to interest expenses over the contract period of the agreements using the straight-line method while realized and unrealized gains and losses are offset against losses or gains on the items hedged.

Recorded amounts related to derivative contracts are included in other assets or liabilities, as appropriate. The fair values of interest rate swap agreements, currency swap agreements, and foreign currency forward contracts designated as hedges, are not recognized in the financial statements. Instruments, which are not designated as hedges, are marked to market and the related unrealized gains or losses are recorded in the income statement at each accounting period.

Realized and unrealized gains or losses related to terminated interest rate swaps are deferred and amortized as an adjustment to interest expense over the original period of interest exposure, provided the designated liability continues to exist or is probable of occurring.

New Accounting Standards

In June 2001, the FASB issued Statements of Financial Accounting Standards (FAS) No. 141, Business Combinations, and No. 142, Goodwill and Other Intangible Assets, effective for fiscal years beginning after December 15, 2001. Under the new rules, goodwill and intangible assets deemed to have indefinite lives will no longer be amortized but will be subject to annual impairment tests as described in the Statements. Other intangible assets will continue to be amortized over their useful lives. The impact of the adoption of FAS 141 and FAS 142 from January 1, 2002, was immaterial.

In June 2001, the FASB issued FAS 143, Accounting for Asset Retirement Obligations, which is effective for fiscal years beginning after June 15, 2002. The Statement requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The Company will adopt the new rules on asset retirement obligations on January 1, 2003. Application of the new standard is expected to result in an increase in net property, plant and equipment of NOK 2.8 billion, an increase in accrued asset retirement obligation of NOK 7.3 billion, a reduction in deferred tax assets of NOK 1.4 billion, and a long-term receivable of NOK 5.8 billion. The receivable represents the expected refund by the Norwegian State of an amount equivalent to the actual removal costs multiplied by the effective tax rate over the productive life of the assets. Removal costs on the Norwegian continental shelf are, unlike decommissioning costs, not deductible for tax purposes. The implementation effect on the net income and shareholders' equity is not expected to be material.

In August 2001, the FASB issued FAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which addresses financial accounting and reporting for the impairment or disposal of long-lived assets and supersedes FAS 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of, and the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations for a disposal of a segment of a business. FAS 144 is effective for fiscal years beginning after December 15, 2001. The adoption of FAS 144 from January 1, 2002, did not have any impact on the Company's financial position and results of operations.

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3. Segment and geographic information

Statoil operates in four segments - Exploration and Production Norway, International Exploration and Production, Natural Gas and Manufacturing and Marketing.

Operating segments are determined based on differences in the nature of their operations, geographic location and internal management reporting. The composition of segments and measure of segment profit are consistent with that used by management in making strategic decisions. The accounting policies of the reportable segments are the same as those described in the Summary of Significant Accounting Policies. Statoil evaluates performance and allocates resources based on segment net income, which is, net income before financial items and minority interest.

Segment data as of and for the years ended December 31, 2002, 2001 and 2000 is presented below:

(IN NOK MILLION)	*EXPLORATION AND PRODUCTION NORWAY*	*INTERNATIONAL EXPLORATION AND PRODUCTION*	*NATURAL GAS*	*MANUFACTURING AND MARKETING*	*OTHER AND ELIMINATIONS*	*TOTAL*
Year ended December 31, 2002						
Revenues third party	1,706	5,749	24,236	210,653	1,104	243,448
Revenues inter-segment	54,585	1,020	168	194	(55,967)	0
Income (loss) from equity investments	(1)	0	132	305	(70)	366
Total revenues	56,290	6,769	24,536	211,152	(54,933)	243,814
Depreciation, depletion and amortization	11,861	2,355	592	1,686	350	16,844
Income before financial items, income taxes and minority interest	31,463	1,086	8,918	1,637	(2)	43,102
Segment income taxes	(23,355)	(381)	(6,629)	(401)	(20)	(30,786)
Segment net income	8,108	705	2,289	1,236	(22)	12,316
Year ended December 31, 2001						
Revenues third party	3,622	5,926	23,297	202,264	1,413	236,522
Revenues inter-segment	61,913	1,767	36	936	(64,652)	0
Income (loss) from equity investments	120	0	135	187	(3)	439
Total revenues	65,655	7,693	23,468	203,387	(63,242)	236,961
Depreciation, depletion and amortization	11,806	3,371	664	1,855	362	18,058
Income before financial items, income taxes and minority interest	40,697	1,291	9,629	4,480	57	56,154
Segment income taxes	(29,589)	(387)	(6,919)	(1,305)	(18)	(38,218)
Segment net income	11,108	904	2,710	3,175	39	17,936

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(IN NOK MILLION)	*EXPLORATION AND PRODUCTION NORWAY*	*INTERNATIONAL EXPLORATION AND PRODUCTION*	*NATURAL GAS*	*MANUFACTURING AND MARKETING*	*OTHER AND ELIMINATIONS*	*TOTAL*
Year ended December 31, 2000						
Revenues third party	1,419	6,308	20,539	200,851	785	229,902
Revenues inter-segment	69,610	2,752	8	413	(72,783)	0
Income (loss) from equity investments	106	(33)	77	321	52	523
Total revenues	71,135	9,027	20,624	201,585	(71,946)	230,425
Depreciation, depletion and amortization	11,225	1,704	730	1,734	346	15,739
Income before financial items, income taxes and minority interest	46,715	773	7,893	4,559	51	59,991
Segment income taxes	(35,054)	(242)	(5,584)	(1,271)	0	(42,151)
Segment net income	11,661	531	2,309	3,288	51	17,840

Borrowings are managed at a corporate level and interest expense is not allocated to segments. Income tax is calculated on income before financial items and minority interest. Additionally, income tax benefit on segments with net losses is not recorded. As such, segment income tax and net income can be reconciled to income taxes and net income per the Consolidated Statements of Income as follows:

(IN NOK MILLION)	*YEAR ENDED DECEMBER 31,* 2002	2001	2000
Segment net income	12,316	17,936	17,840
Net financial items	8,233	65	(2,898)
Tax on financial items and other tax adjustments	(3,550)	(268)	1,695
Minority interest	(153)	(488)	(484)
Net income	16,846	17,245	16,153
Segment income taxes	30,786	38,218	42,151
Tax on financial items and other tax adjustments	3,550	268	(1,695)
Income taxes	34,336	38,486	40,456

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The Exploration and Production Norway and International Exploration and Production segments explore for, develop and produce crude oil and natural gas, and extract natural gas liquids, sulfur and carbon dioxide. The Natural Gas segment transports and markets natural gas and natural gas products. Manufacturing and Marketing is responsible for petroleum refining operations and the marketing of all refined petroleum products except gas.

Inter-segment revenues are sales to other business segments within Statoil and are at estimated market prices. These inter-company transactions are eliminated for consolidation purposes. Segment income taxes are calculated on the basis of income before financial items and minority interest.

(IN NOK MILLION)	*ADDITION TO LONG-LIVED ASSETS*	*INVESTMENTS IN AFFILIATES*	*OTHER LONG-TERM ASSETS*
Year ended December 31, 2002			
Exploration and Production Norway	11,023	1,284	75,717
International Exploration and Production	5,995	0	20,655
Natural Gas	465	1,423	8,889
Manufacturing and Marketing	1,771	6,868	21,090
Other	800	54	11,253
Total	20,054	9,629	137,604
Year ended December 31, 2001			
Exploration and Production Norway	10,759	212	77,338
International Exploration and Production	5,027	0	21,530
Natural Gas	671	1,506	8,994
Manufacturing and Marketing	811	8,222	22,210
Other	685	11	11,015
Total	17,953	9,951	141,087
Year ended December 31, 2000			
Exploration and Production Norway	12,992	125	79,739
International Exploration and Production	5,070	0	19,465
Natural Gas	810	1,340	11,690
Manufacturing and Marketing	2,860	8,124	24,801
Other	300	625	12,417
Total	22,032	10,214	148,112

Revenues by geographic areas

		YEAR ENDED DECEMBER 31,	
(IN NOK MILLION)	*2002*	*2001*	*2000*
Norway	216,541	206,026	178,509
Europe (excluding Norway)	30,274	30,798	36,201
United States	27,654	27,163	38,243
Other areas	10,638	8,880	13,784
Eliminations	(41,659)	(36,345)	(36,835)
Total revenues (excluding equity in net income of affiliates)	243,448	236,522	229,902

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Long-lived assets by geographic areas

(IN NOK MILLION)	*2002*	*AT DECEMBER 31, 2001*	*2000*
Norway	114,007	114,303	126,429
Europe (excluding Norway)	23,399	29,772	25,538
United States	25	70	20
Other areas	15,894	18,016	15,315
Corporate and eliminations	(6,578)	(11,717)	(9,170)
Total long-lived assets (excluding long-term deferred tax assets)	146,747	150,444	158,132

4. Significant Acquisitions and Dispositions

In 2001, Statoil sold specific interests in Norwegian oil and gas licenses, its 4.76% interest in the Kashagan oil field in Kazahkstan and its activity in Vietnam which resulted in total gains of NOK 4.3 billion before tax charges of NOK 0.8 billion.

In 2002, Statoil sold its interests in the Siri and Lulita oil fields on the Danish continental shelf. The sale resulted in a gain included in the International Exploration and Production segment of NOK 1.0 billion before tax and NOK 0.7 billion after tax.

On December 15, 2002, Statoil signed a contract to sell 100% of the shares in Navion ASA to Norsk Teekay AS, a wholly-owned subsidiary of Teekay Shipping Corporation. The operations of Navion are shuttle tanking and conventional shipping. The sales price for the fixed assets of Navion, excluding *Navion Odin* and Navion's 50% share in the *West Navion* drill ship which are not included in the sale, is approximately US$ 800 million. The effective date of the transaction is January 1, 2003, and the sale will be booked at closing, which is expected to take place in the second quarter of 2003. Based on the exchange rate at December 31, 2002, and the book value of the assets sold, the effect on net income from the transaction is immaterial.

5. Asset Impairments

In 2001, a charge of NOK 2 billion before tax (NOK 1.4 billion after tax) was recorded in depreciation, depletion and amortization in the International Exploration and Production segment to write down the Company's 27% interest in the LL652 oil-field in Venezuela to fair value. In 2002, an additional impairment charge of NOK 0.8 billion before tax (NOK 0.6 billion after tax) was recorded related to the Company's interest in LL652. The write-downs are mainly due to reductions in the projected volumes of oil recoverable during the remaining contract period of operation. Fair value is calculated based on estimated future cash flows.

6. Restructuring and Other Charges

In 1999, Statoil made the decision to restructure its US upstream, natural gas trading, and electric power generation operations. In conjunction with this, Statoil established a restructuring provision of NOK 1,400 million primarily for asset write-downs, future lease costs, facilities closure costs and separation costs for approximately 180 employees. The provision at December 31, 2001 amounted to NOK 144 million. At December 31, 2002 only immaterial accruals remain in the provision. The provision is recorded in the International Exploration and Production segment of Statoil.

During the period 1995-1998, based on estimated future needs for exploration and production drilling services on Statoil-operated licenses in the North Sea, Statoil, on a sole risk basis, entered into several long-term fixed-price drilling rig contracts. A decline in worldwide oil prices resulted in reduced work programs for the licenses, and Statoil was left with significant excess drilling rig capacity in a depressed market for drilling rig services. In 1998 and 1999 Statoil recorded as Operating expenses a total of NOK 1.6 billion for expected losses on these purchased drilling rig service contracts. In 2001, NOK 150 million of the provision was reversed due to a reduction in the estimated losses on the contracts. In 2002 the provision was increased by NOK 231 million due to higher estimated losses on the contracts due to changes in the estimated sub-contract market rates. Estimated sub-contract market rates were based on rates quoted by rig brokers, new drilling rig contracts entered into by other oil companies and Statoil's evaluation of drilling needs and drilling rig availability through the contract period. The remaining contracts periods for the rigs last from one to four years. The accrual is Statoil's best estimate of the loss between fixed-price drilling rig contracts and the estimated sub-contract market rates.

At December 31, 2001 and December 31, 2002 the remaining provision for drilling service contracts was NOK 734 million and NOK 960 million, respectively. During 2000, 2001 and 2002, NOK 172 million, NOK 76 million and NOK 5 million, respectively, of contract payments were charged against the provision. These charges impact the Exploration and Production Norway segment.

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7. Inventories

The lower of cost or market test is measured, and the results are recognized separately, on a country-by-country basis, and any resulting write-downs to market, if required, are recorded as permanent adjustments to the cost of inventories. There have been no liquidations of LIFO layers which resulted in a material impact to net income for the reported periods.

	AT DECEMBER 31,	
(IN NOK MILLION)	*2002*	*2001*
Crude oil	2,766	2,919
Petroleum products	2,647	2,567
Other	844	593
Total - inventories valued on a FIFO basis	6,257	6,079
Excess of current cost over LIFO value	(835)	(803)
Total	5,422	5,276

8. Summary Financial Information of Unconsolidated Equity Affiliates

Statoil's investments in affiliates include a 50% interest in Borealis, a petrochemical production company, and a 50% interest in Statoil Detaljhandel Skandinavia AS (SDS), a group of retail petroleum service stations.

Summary financial information for affiliated companies accounted for by the equity method is shown below. Statoil's investment in these companies is included in Investments in affiliates. Accounts receivable - related parties in the Consolidated Balance Sheets relate to amounts due from equity affiliates.

Equity method affiliates - gross amounts

	BOREALIS			*SDS*		
(IN NOK MILLION)	*2002*	*2001*	*2000*	*2002*	*2001*	*2000*
At December 31,						
Current assets	5,909	7,694	10,753	2,798	3,189	3,014
Non-current assets	17,432	19,710	18,121	6,029	6,105	6,333
Current liabilities	6,063	6,108	9,740	3,288	2,894	3,277
Long-term debt	5,787	8,787	5,870	2,488	3,382	3,242
Other liabilities	2,187	2,201	2,570	0	0	0
Net assets	9,304	10,310	10,694	3,051	3,018	2,828
Year ended December 31,						
Gross revenues	25,617	29,819	30,465	23,112	24,563	26,069
Income before taxes	215	(193)	686	423	411	328
Net income	43	(330)	488	302	290	233
Capital expenditures	978	1,182	2,117	721	552	592

Dividends received from Borealis amounted to NOK 0, 16 and 187 million for 2002, 2001 and 2000, respectively. No dividends have been received from SDS.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – USGAAP

Equity method affiliates - detailed information

(AMOUNTS IN MILLIONS)	*CURRENCY*	*PAR VALUE*	*SHARE CAPITAL*	*OWNERSHIP*	*BOOK VALUE*	*PROFIT SHARE*
Statoil Detaljhandel Skandinavia AS	NOK	1,300	2,600	50%	1,152	221
Borealis A/S	DKK	2,000	4,000	50%	4,775	53
P/R West Navion DA	NOK	-	-	50%	1,115	(56)
Other companies	-	-	-	-	2,587	148
Total					9,629	366

Ownership corresponds to voting rights.

The difference between the book value and equity interest of the investment in SDS represents the difference between the book value and the fair value on the sale of Statoil's 50% interest in SDS in 1999 which is being amortized. P/R West Navion DA owns the drillship *West Navion*, and its only activity pertains to this drillship.

9. Investments

Short-term investments

(IN NOK MILLION)	*AT DECEMBER 31, 2002*	*2001*
Short-term deposits	51	189
Certificates	5,073	1,692
Bonds	50	180
Other	93	2
Total short-term investments	5,267	2,063

The cost price of short-term investments for the years ended December 31, 2002 and 2001 was NOK 5,261 and 2,053 million, respectively.

All short-term investments are considered to be trading securities and are recorded at fair value with unrealized gains and losses included in income.

Long-term investments included in Other assets

(IN NOK MILLION)	*AT DECEMBER 31, 2002*	*2001*
Shares in other companies	1,166	943
Certificates	1,031	680
Bonds	2,749	3,324
Marketable equity securities	1,270	1,596
Total long-term investments	6,216	6,543

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10. Property, plant and equipment

(IN NOK MILLION)	MACHINERY, EQUIPMENT AND TRANSPORTATION EQUIPMENT	PRODUCTION PLANTS OIL AND GAS, INCL PIPELINES	PRODUCTION PLANTS ONSHORE	BUILDINGS AND LAND	VESSELS	CONSTRUCTION IN PROGRESS	CAPITALIZED EXPLORATION COST	TOTAL
Cost at January 1, 2002	10,891	205,862	26,651	6,521	8,221	11,941	4,281	274,368
Accumulated depreciation, depletion and amortization at January 1, 2002	(8,253)	(119,999)	(15,664)	(1,811)	(2,204)	64	0	(147,867)
Additions and transfers	1,131	11,275	5,094	292	0	673	98	18,563
Disposals at book value	(26)	(136)	(7)	(20)	0	(222)	(7)	(418)
Expensed expl cost capitalized prior years	0	0	0	0	0	0	(552)	(552)
Depreciation, depletion and amortization for the year	(584)	(14,476)	(1,234)	(200)	(286)	0	0	(16,780)
Foreign currency translation	(168)	(2,001)	(1,697)	(416)	(84)	(239)	(330)	(4,935)
Book value at December 31, 2002	2,991	80,525	13,143	4,366	5,647	12,217	3,490	122,379
Estimated useful life (years)	5-10	*	15-20	20-25	20-25			

*Unit of production, see note 1.

In 2002, 2001 and 2000, NOK 382, 723 and 1,494 millon, respectively, of interests were capitalized.
In addition to depreciation, depletion and amortization specified above intangible assets have been amortized by NOK 64 million in 2002.

11. Provisions

Provisions against assets (other than property, plant and equipment and intangible assets) recorded during the past three years are as follows:

(IN NOK MILLION)	AT JANUARY 1,	EXPENSE	RECOVERY	WRITE-OFF	OTHER	AT DECEMBER 31,
Year 2002						
Provisions for other long-term assets	16	0	(16)	0	0	0
Provisions for accounts receivables	212	47	(59)	(33)	(14)	153
Year 2001						
Provisions for other long-term assets	90	0	0	0	(74)	16
Provisions for accounts receivables	224	44	0	(12)	(44)	212
Year 2000						
Provisions for other long-term assets	90	0	0	0	0	90
Provisions for accounts receivables	174	33	43	(23)	(3)	224

12. Financial Items

(IN NOK MILLION)	YEAR ENDED DECEMBER 31, 2002	2001	2000
Interest and other financial income	1,311	2,107	2,426
Currency exchange adjustments, net	9,009	912	(3,389)
Interest and other financial expenses	(1,952)	(2,713)	(2,035)
Dividends received	457	18	82
Gain (loss) on sale of securities	(228)	(97)	371
Unrealized gain (loss) on securities	(364)	(162)	(353)
Net financial items	8,233	65	(2,898)

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13. Income Taxes

Net income before taxes consist of

	YEAR ENDED DECEMBER 31,		
(IN NOK MILLION)	*2002*	*2001*	*2000*
Norway			
• Offshore	42,519	49,651	52,307
• Onshore	5,394	5,843	3,052
Other countries	3,422	725	1,734
Total	51,335	56,219	57,093

Significant components of income tax expense were as follows

	YEAR ENDED DECEMBER 31,		
(IN NOK MILLION)	*2002*	*2001*	*2000*
Norway			
• Offshore	34,253	37,942	39,542
• Onshore	885	1,169	979
Other countries 1)	352	253	529
Uplift benefit	(1,782)	(1,726)	(1,816)
Current income tax expense	33,708	37,638	39,234
Norway			
• Offshore	(707)	317	528
• Onshore	250	383	254
Other countries 1)	1,085	148	440
Deferred tax expense	628	848	1,222
Total income tax expense	34,336	38,486	40,456

1) Includes taxes in Norway on activities in other countries.

Significant components of deferred tax assets and liabilities were as follows

	AT DECEMBER 31,	
(IN NOK MILLION)	*2002*	*2001*
Net operating loss carry-forwards	1,157	2,120
Impairment	1,058	1,365
Decommissioning	4,733	4,277
Other	3,665	4,911
Valuation allowance	(2,140)	(2,135)
Total deferred tax assets	8,473	10,538
Property, plant and equipment	35,518	35,144
Capitalized exploration expenditures and interest	8,914	8,668
Other	6,293	8,370
Total deferred tax liabilities	50,725	52,182

Deferred taxes are classified as followed

(IN NOK MILLION)	AT DECEMBER 31, 2002	2001
Short-term deferred tax asset	(415)	(113)
Long-term deferred tax asset	(486)	(597)
Long-term deferred tax liability	43,153	42,354

A valuation allowance has been provided as Statoil believes that available evidence creates sufficient uncertainty as to the realizability of certain deferred tax assets. Statoil will continue to assess the valuation allowance and to the extent it is determined that such allowance is no longer required, the tax benefit of the remaining net deferred tax assets will be recognized in the future.

Reconciliation of Norwegian nominal statutory tax rate of 28% to effective tax rate

(IN NOK MILLION)	2002	2001	2000
Calculated income taxes at statutory rate	14,374	15,741	15,969
Petroleum surtax	20,538	24,342	26,159
Uplift benefit	(1,782)	(1,726)	(1,816)
Other, net	1,206	129	144
Income tax expense	34,336	38,486	40,456

Revenue from oil and gas activities on the NCS is taxed according to the Petroleum tax law. This stipulates a surtax of 50% after deducting uplift, a special investment tax credit, in addition to normal corporate taxation. Uplift credits are deducted as they arise, 5% each year for six years, as from initial year of investment. Uplift credits not utilized of NOK 8.9 billion can be carried forward indefinitely.

At the end of 2002, Statoil had tax loss carry-forwards of NOK 3.3 billion, primarily in the US and in Ireland. Only a minor part of the carry-forward amounts expires before 2006.

14. Short-term Debt

(IN NOK MILLION)	AT DECEMBER 31, 2002	2001
Bank loans and overdraft facilities	2,258	948
Current portion of long-term debt	2,018	5,364
Other	47	301
Total	4,323	6,613
Weighted average interest rate (%)	5.28	4.62

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – USGAAP

15. Long-term Debt

	WEIGHTED AVERAGE INTEREST RATES IN %		*BALANCE IN NOK MILLION AT DECEMBER 31,*	
	2002	*2001*	*2002*	*2001*
Unsecured debentures bonds				
US dollar (US$)	5.74	5.79	16,590	19,006
Norwegian kroner (NOK)	7.50	5.67	20	255
Euro (EUR)	4.66	4.58	5,780	4,518
Swiss franc (CHF)	3.14	2.87	3,548	4,652
Japanese yen (JPY)	1.83	2.09	2,994	1,808
Great British pounds (GBP)	-	6.13	-	3,080
Total			28,932	33,319
Unsecured bank loans				
US dollar (US$)	1.77	6.00	2,193	3,510
Secured bank loans				
US dollar (US$)	3.82	6.43	2,902	2,879
Other debt			796	838
Grand total debt outstanding			34,823	40,546
Less current portion			(2,018)	(5,364)
Total long-term debt			32,805	35,182

Statoil has an unsecured debenture bond agreement for US$ 500 million with a fixed interest rate of 6.5%, maturing in 2028, callable at par upon change in tax law. At December 31, 2002 and 2001, NOK 3,435 million and NOK 4,441 million were outstanding, respectively. The interest rate of the bond has been swapped to a LIBOR-based floating interest rate.

Statoil has also an unsecured debenture bond agreement for EUR 500 million, with a fixed interest rate of 5.125%, maturing in 2011. At December 31, 2002 and 2001, NOK 3,601 million and NOK 3,933 million were outstanding, respectively. EUR 200 million of the bond has been swapped through an interest rate swap agreement to a LIBOR-based floating interest rate.

Statoil has also an unsecured debenture bond agreement for US$ 375 million, with a fixed interest rate of 5.75%, maturing in 2009. At December 31, 2002 and 2001, NOK 2,591 million and NOK 3,347 million were outstanding, respectively.

In addition to the unsecured debentures bond debt of NOK 16,590 million, denominated in US dollars, Statoil utilizes foreign currency swaps to manage foreign exchange risk on its long-term debt. As a result, an additional NOK 10,899 million of Statoil's unsecured debentures bond debt has been swapped to US dollars. The foreign currency swaps are not reflected in the table above as the swaps are separate legal agreements. The foreign currency swaps do not qualify as hedges according to FAS 133 as the swaps are not to functional currency, although they qualify as economic hedges. The stated interest rate on the majority of the long-term debt is fixed. Interest rate swaps are utilized to manage interest rate exposure.

Substantially all unsecured debenture bond and unsecured bank loan agreements contain provisions restricting the pledging of assets to secure future borrowings without granting a similar secured status to the existing bondholders and lenders.

Statoil has 21 debenture bond agreements outstanding, which contain provisions allowing Statoil to call the debt prior to its final redemption at par if there are changes to the Norwegian tax laws or at certain specified premiums. The agreements are, net after buyback, at the December 31, 2002 closing rate valued at NOK 24,315 million.

Reimbursements of long-term debt fall due as follows:

(IN NOK MILLION)	
2003	2,018
2004	3,235
2005	1,465
2006	1,801
2007	2,036
Thereafter	24,268
Total	34,823

Statoil has an agreement with an international bank syndicate for committed long-term revolving credit facility totalling US$ 1.0 billion, all undrawn. Commitment fee is 0.105% per annum.

As of December 31, 2002 and 2001 respectively, Statoil had no committed short-term credit facilities available or drawn.

16. Financial Instruments and Risk Management

Statoil uses derivative financial instruments to manage risks resulting from fluctuations in underlying interest rates, foreign currency exchange rates and commodity (such as oil, natural gas and refined petroleum products) prices. Because Statoil operates in the international oil and gas markets and has significant financing requirements, it has exposure to these risks, which can affect the cost of operating, investing and financing. Statoil has used and intends to use financial and commodity-based derivative contracts to reduce the risks in overall earnings and cash flows. Derivative instruments creating essentially equal and offsetting market exposures are used to help manage certain of these risks. Management also uses derivatives to establish certain positions based on market movements although this activity is immaterial to the consolidated financial statements.

Interest and currency risks constitute significant financial risks for the Statoil group. Total exposure is managed at portfolio level in accordance with the strategies and mandates issued by the Enterprise-Wide Risk Management Program and monitored by the Corporate Risk Committee. Statoil's interest rate exposure is mainly associated with the group's debt obligations and management of the assets in Statoil Forsikring AS. Statoil mainly employs interest rate swap and currency swap agreements to manage interest rate and currency exposure.

Statoil uses swaps, options, futures, and forwards to manage its exposure to changes in the value of future cash flows from future purchases and sales of crude oil and refined oil products. The term of the oil and refined oil products derivatives is usually less than one year. Natural gas and electricity swaps, options, forwards, and futures are likewise utilized to manage Statoil's exposure to changes in the value of future sales of natural gas and electricity. These derivatives usually have terms of approximately three years or less. Most of the derivative transactions are made in the over-the-counter (OTC) market.

Cash Flow Hedges

Statoil has designated certain derivative instruments as cash flow hedges to hedge against changes in the amount of future cash flows related to the sale of oil and refined petroleum products over a period not exceeding 12 months and cash flows related to interest payments over a period not exceeding 25 months. Hedge ineffectiveness related to Statoil's outstanding cash flow hedges was immaterial and recorded to earnings during the year ended December 31, 2002. The net change in Other comprehensive income associated with the current year hedging transactions was NOK 116 million (after tax), and the net amount reclassified into earnings during the year was immaterial. At December 31, 2002, the net deferred hedging loss in Accumulated other comprehensive income was NOK 118 million (after tax), the majority of which will affect earnings over the next 12 months. There were no cash flow hedges discontinued during the year because it was probable that the original forecasted transaction would not occur by the end of the originally specified time period.

Fair Value Hedges

Statoil has designated certain derivative instruments as fair value hedges to hedge against changes in the value of financial liabilities. There was no gain or loss component of a derivative instrument excluded from the assessment of hedge effectiveness related to fair value hedges during the year ended December 31, 2002. The net gain recognized in earnings in Net financial items during the year for ineffectiveness of fair value hedges was immaterial.

Fair Value of Financial Instruments

Except for the recorded amount of fixed interest long-term debt, the recorded amounts of cash and cash equivalents, receivables, bank loans, other interest bearing short-term debt, and other liabilities approximate their fair values. Marketable equity and debt securities are also recorded at their fair values.

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The following table contains the carrying amounts and estimated fair values of financial derivative instruments, and the carrying amounts and estimated fair value of long-term debts. Commodity contracts capable of being settled by delivery of commodities (oil and oil products, natural gas, electricity) are excluded from the summary.

(IN NOK MILLION)	*FAIR MARKET VALUE OF ASSETS*	*FAIR MARKET VALUE OF LIABILITIES*	*NET CARRYING AMOUNT*
At December 31, 2002			
Debt-related instruments	2,153	(150)	2,003
Non-debt-related instruments	143	(5)	138
Long-term fixed interest debt	-	(28,475)	(25,465)
Crude oil and Refined products	568	(844)	(276)
Gas and Electricity	265	(212)	53
At December 31, 2001			
Debt-related instruments	602	(1,518)	(916)
Non-debt-related instruments	25	(32)	(7)
Long-term fixed interest debt	-	(30,730)	(29,246)
Crude oil and Refined products	701	(360)	341
Gas and Electricity	67	(46)	21

Fair values are estimated using quoted market prices, estimates obtained from brokers, prices of comparable instruments, and other appropriate valuation techniques. The fair value estimates approximate the gain or loss that would have been realized if the contracts had been closed out at year-end, although actual results could vary due to assumptions utilized.

Credit risk management

Statoil manages credit risk concentration with respect to financial instruments by holding only investment grade securities distributed among a variety of selected issuers. A list of authorized investment limits by commercial issuer is maintained and reviewed regularly along with guidelines which include an assessment of the financial position of counter-parties as well as requirements for collateral.

Credit risk related to commodity-based instruments is managed by maintaining, reviewing and updating lists of authorized counter-parties by assessing their financial position, by frequently monitoring credit exposure for counter-parties, by establishing internal credit lines for counter-parties, and by requiring collateral or guarantees when appropriate under contracts and required in internal policies. Collateral will typically be in the form of cash or bank guarantees from first class international banks.

Credit risk from interest rate swaps and currency swaps, which are over-the-counter (OTC) transactions, derive from the counter-parties to these transactions. Counter-parties are highly rated financial institutions. The credit ratings are reviewed minimum annually and counter-party exposure is monitored on a continuous basis to ensure exposure does not exceed credit lines and complies with internal policies. Non-debt-related foreign currency swaps usually have terms of less than one year, and the terms of debt related interest swaps and currency swaps are up to 26 years, in line with that of corresponding hedged or risk managed long-term loans.

The credit risk concentration with respect to receivables is limited due to the large number of counter-parties spread worldwide in numerous industries.

The credit risk from Statoil's over-the-counter derivative contracts derives from the counter-party to the transaction, typically a major bank or financial institution, a major oil company or a trading company. Statoil does not anticipate non-performance by any of these counter-parties, and no material loss would be expected from any such unexpected non-performance. Futures contracts and exchange-traded options have a negligible credit risk as they are principally traded on the New York Mercantile Exchange or the International Petroleum Exchange of London.

Consequently, Statoil does not consider itself exposed to a significant concentration of credit risk.

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17. Employee Retirement Plans

Pension benefits

Statoil and many of its subsidiaries have defined benefit retirement plans, which cover substantially all of their employees. Plan benefits are generally based on years of service and final salary levels. Some subsidiaries have defined contribution or multi-employer plans.

Net periodic pension cost

	YEAR ENDED DECEMBER 31,		
(IN NOK MILLION)	*2002*	*2001*	*2000*
Benefit earned during the year, net of participants' contributions	738	690	678
Interest cost on prior period benefit obligation	719	626	578
Expected return on plan assets	(856)	(793)	(761)
Amortization of loss	34	10	14
Amortization of prior service cost	44	44	44
Amortization of net transition assets	(16)	(16)	(16)
Defined benefit plans	663	561	537
Defined contribution plans	19	21	21
Multi-employer plans	4	4	4
Total net periodic pension cost	686	586	562

Change in projected benefit obligation (PBO)

(IN NOK MILLION)	*2002*	*2001*
Projected benefit obligation at beginning of year	12,000	10,632
Benefits earned during the year	738	690
Interest cost on prior period benefit obligation	719	626
Actuarial gain (loss)	(13)	471
Benefits paid	(401)	(391)
Foreign currency translation	(18)	(28)
Projected benefit obligation at end of year	13,025	12,000

Change in pension plan assets

(IN NOK MILLION)	*2002*	*2001*
Fair value of plan assets at beginning of year	13,068	12,310
Retained earnings in the pension trusts reclassified to plan assets	0	954
Actual return on plan assets	(770)	(15)
Company contributions	412	8
Benefits paid	(183)	(170)
Foreign currency translation	(47)	(19)
Fair value of plan assets at end of year	12,480	13,068

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Status of pension plans reconciled to balance sheet

(IN NOK MILLION)	*AT DECEMBER 31, 2002*	*2001*
Funded status of the plans at end of year	(545)	1,068
Unrecognized net loss	1,868	769
Unrecognized prior service cost	363	462
Unrecognized net transition asset	(15)	(31)
Total net prepaid pension recognized	1,671	2,268
Amounts recognized in the balance sheet:		
Prepaid pension	3,861	4,046
Accrued pension liabilities	(2,190)	(1,778)
Net amount recognized	1,671	2,268

Weighted-average assumptions at end of year

Discount rate	6.0%	6.0%
Expected return on plan assets	6.5%	6.5%
Rate of compensation increase	3.0%	3.0%

The projected benefit obligation, accumulated benefit obligation, and fair value of plan assets for pension plans with accumulated benefit obligations in excess of plan assets were NOK 3,102 million, NOK 2,235 million and NOK 425 million, respectively, at December 31, 2002, and NOK 3,352 million, NOK 2,430 million and NOK 422 million, respectively, at December 31, 2001.

18. Decommissioning and Removal Liabilities

At December 31, 2002 and 2001, NOK 8,056 million and NOK 7,521 million, respectively, had been accrued for future well closure, decommissioning and removal of offshore installations and are included in Other liabilities. Statoil's share of the estimated total future well closure, decommissioning and removal costs is NOK 10,700 million and NOK 13,300 million at December 31, 2002 and 2001, respectively.

19. Research Expense

Research expenses were NOK 736 million, NOK 633 million and NOK 656 million in 2002, 2001 and 2000, respectively.

20. Leases

Statoil leases certain assets, notably shipping vessels.

In 2002, rental expense was NOK 5,595 million. In 2001 and 2000 rental expenses were NOK 7,687 and 6,455 million, respectively.

The information below shows future minimum lease payments under non-cancelable leases at December 31, 2002.

(IN NOK MILLION)	*OPERATING LEASES*	*CAPITAL LEASES*
2003	4,070	11
2004	3,087	12
2005	2,782	13
2006	2,350	14
2007	1,638	16
Thereafter	6,617	0
Total future rents	20,544	66
Interest component		(10)
Net present value		56

Property, plant and equipment include the following amounts for leases that have been capitalized at December 31, 2002 and 2001.

(IN NOK MILLION)	*AT DECEMBER 31, 2002*	*2001*
Vessels	107	217
Less accumulated depreciation	(80)	(177)
Net	27	40

21. Other Commitments and Contingencies

Contractual commitments

(IN NOK MILLION)	*IN 2003*	*THEREAFTER*	*TOTAL*
Contractual commitments made	8,633	10,665	19,298

These contractual commitments comprise acquisition and construction of tangible fixed assets.

Guarantees

The group has provided guarantees of NOK 0.7 billion for short-term commercial transactions and contractual commitments.

Contingent liabilities and insurance

Like any other licensee, Statoil has unlimited liability for possible compensation claims arising from its offshore operations, including transport systems. The Company has taken out insurance to cover this liability up to about NOK 5.6 billion for each incident, including liability for claims arising from pollution damage. Most of the group's production installations are covered through Statoil Forsikring AS, which reinsures a major part of the risk in the international insurance market. About 30% is retained.

Other commitments

As a condition for being awarded oil and gas exploration and production licenses, participants are committed to drill a certain number of wells. At the end of 2002, Statoil was committed to participating in 15 wells off Norway and 12 wells abroad, with an average ownership interest of approximately 32%. The cost to drill these wells is estimated to NOK 1.4 billion.

As owner in BTC Co Ltd Statoil is committed to, directly or indirectly, to finance, or to provide guarantees for financing of a development of the BTC pipeline system of approximately US$ 425 million in total. As a participant in the Transportation Agreement between BTC Co Ltd and the owners of the Azeri-Chirag-Gunashli oil field Statoil has entered into a ship and pay arrangement.

In addition, Statoil has entered into agreements for pipeline transportation for most of its prospective gas sale contracts. These agreements ensure the right to transport the production of gas through the pipelines, but also impose an obligation to cover Statoil's proportional share of the transportation costs. On the Norwegian continental shelf, Statoils ownership interest in the pipeline transportation systems exceeds its share of the transported volumes.

During the normal course of its business Statoil is involved in legal proceedings and a number of unresolved claims are currently outstanding. The ultimate liability in respect of litigation and claims cannot be determined at this time. Provisions in the accounts for these items are based on the Company's best judgment. Statoil is of the opinion that neither the financial position, results of operations nor cash flows will be material adverse affected by the resolution of these legal proceedings.

22. Related Parties

Total purchases of oil and natural gas liquid from the Norwegian State amounted to NOK 72,298 million (374 million barrels oil equivalents), NOK 53,291 million (265 million barrels oil equivalents) and NOK 42,290 million (173 million barrels oil equivalents), in 2002, 2001 and 2000, respectively. Amounts payable to the Norwegian State for these purchases are included as Accounts payable - related parties in the Consolidated Balance Sheets. The prices paid by Statoil for the oil purchased from the Norwegian State are estimated market prices. In addition Statoil sells the Norwegian State's natural gas, in its own name, but for the account and risk of the Norwegian State.

In addition to Accounts payable - related parties and Accounts receivable - related parties Statoil has a long term receivable of NOK 780 million against the Norwegian State included in Long-term receivables.

23. Shareholders' equity

Upon Statoil's inception in September 1972, 50,000 ordinary shares at NOK 100 nominal value were issued. There have been several subsequent issuances of ordinary shares, the last increase before the public offering of shares being in June 1989 for 19,962,140 ordinary shares issued at NOK 100 nominal value.

On May 10, 2001, an extraordinary general meeting approved a common stock split by which the existing 49,397,140 ordinary shares with nominal value of NOK 100 per share was replaced by 1,975,885,600 ordinary shares with nominal value of NOK 2.50 per share. All references to the number of ordinary shares and per share common amounts have been restated to give retroactive effect to the stock split for all periods presented.

At an extraordinary general meeting held on May 25, 2001, it was resolved to increase the share capital by NOK 62,500,000 through the issuance of 25 million ordinary shares through a transfer of capital from "Additional paid-in capital" to share capital (a bonus issue). Pursuant to this resolution, the Norwegian State waived its rights to receive the new shares, which was issued to the Company as treasury shares. In 2002 1,558,026 of the treasury shares were distributed as bonus shares in favor of retail investors in the initial public offering in 2001. Distribution of treasury shares requires approval by the general meeting.

At an extraordinary general meeting, held on June 17, 2001 it was further resolved to increase the share capital by NOK 471,750,000 from NOK 5,002,214,000 to NOK 5,473,964,000 through the issuance of 188,700,000 new ordinary shares of NOK 2.50 nominal value each. In June 2001, the Company completed a public offering of shares, which raised NOK 12,890 million, net of expenses, on the issuance of 188,700,000 shares of common stock.

There exists only one class of shares and all have voting rights.

Retained earnings available for distribution of dividends at December 31, 2002, is limited to the retained earnings of the parent company based on Norwegian accounting principles and legal regulations and amounts to NOK 39,482 million (before provisions for proposed dividend for the year ended December 31, 2002 of NOK 6,282 million). This differs from retained earnings in the financial statements of NOK 17,355 million mainly due to the impact of the transfer of the SDFI properties to Statoil, which is not reflected in the Norwegian GAAP accounts until the second quarter of 2001. Distribution of dividends is not allowed to reduce the shareholders' equity in the unconsolidated accounts of the parent company below 10 percent of total assets.

24. Auditors' remuneration

Total remuneration to the external auditors for the fiscal year 2002 amounted to NOK 22.8 million for audit services and NOK 13.7 million for other services, including NOK 5.2 million for audit related services.

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

In accordance with Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities and regulations of the US Securities and Exchange Commission (SEC), Statoil is making certain supplemental disclosures about oil and gas exploration and production operations. While this information was developed with reasonable care and disclosed in good faith, it is emphasized that some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgment involved in developing such information. Accordingly, this information may not necessarily represent the present financial condition of Statoil or its expected future results.

All the tables presented include the impact from the SDFI transaction. See note 1.

Oil and gas reserve quantities

Statoil's oil and gas reserves have been estimated by its experts in accordance with industry standards under the requirements of the SEC. Reserves are net of royalty oil paid in kind, and quantities consumed during production. Statements of reserves are forward-looking statements.

The determination of these reserves is part of an ongoing process subject to continual revision as additional information becomes available.

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, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Statoil is selling its oil and gas together with the oil and gas of the Norwegian state (SDFI).

Under this arrangement, Statoil and SDFI will deliver gas to its customers in accordance with certain supply type sales contracts. The commitments will be met using a schedule that provides the highest possible total value for our oil and gas and the Norwegian State's oil and gas. Our gas reserves will be drawn on to supply this gas in the proportion that we own production from the fields that from time to time are chosen to deliver gas against these commitments. The commitments to be met by Statoil and SDFI under this arrangement were on December 31, 2002 to deliver a total of 36.9 tcf (41.7 trillion MJ @1.13 MJ/cf).

Statoil's and SDFI's delivery commitments for the contract years 2002, 2003, 2004 and 2005 are 1,568, 1,570, 1,592 and 1,911 bcf respectively (1,777, 1,779, 1,804 and 2,166 billion MJ). These commitments may be met by production from proved reserves of fields were both Statoil and the Norwegian State participates and by deliveries that the Norwegian State makes from fields where Statoil does not participate.

The principles for booking of proved gas reserves are limited to contracted gas sales and gas with access to a market. New contracted sales from the Norwegian continental shelf are recorded as Extensions and discoveries.

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

In 1997, Statoil entered into a service contract in Venezuela. The group's share of base production is not included in the reserves. Expected recovery of the field's proved reserves over and above quantities provided for in the service contract as base production is included in the International Exploration and Production oil reserves.

In 2002, Statoil entered into a buy-back contract in Iran. Statoil also participates in a number of production sharing agreements (PSA). Reserves from such agreements are based on the volumes to which Statoil has access (cost oil and profit oil), limited to available market access. Proved reserves at end of year associated with PSA and buy-back agreements are disclosed separately.

The totals in the following tables may not equal the sum of the amounts shown due to rounding.

	NET PROVED OIL AND NGL RESERVES IN MILLION BARRELS			*NET PROVED GAS RESERVES IN BILLION STANDARD CUBIC FEET*			*NET PROVED OIL, NGL AND GAS RESERVES IN MILLION BARRELS OIL EQUIVALENTS*		
	NORWAY	*OUTSIDE NORWAY*	*TOTAL*	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
At December 31, 1999	1,675	462	2,136	13,213	114	13,328	4,029	482	4,511
Proved developed reserves	934	85	1,019	7,505	68	7,574	2,271	97	2,368
Revisions and improved recovery	8	30	38	56	(11)	45	18	28	46
Extensions and discoveries	79	18	97	27	170	197	84	48	132
Sales of reserves-in-place	(2)	0	(2)	0	(19)	(19)	(2)	(3)	(5)
Production	(254)	(21)	(275)	(495)	(19)	(514)	(342)	(24)	(367)
At December 31, 2000	1,506	488	1,994	12,802	234	13,036	3,787	530	4,317
Of which:									
Proved developed reserves	940	187	1,127	8,630	65	8,695	2,478	198	2,677
Proved reserves under PSA and buy-back agreements	0	204	204	0	0	0	0	204	204
Production from PSA and buy-back agreements	0	3	3	0	0	0	0	3	3
Revisions and improved recovery	68	30	98	252	(7)	245	113	29	142
Extensions and discoveries	124	69	193	188	225	413	158	109	267
Sales of reserves-in-place	(54)	(1)	(55)	(1)	(170)	(171)	(54)	(31)	(85)
Production	(246)	(22)	(268)	(523)	(15)	(538)	(339)	(25)	(364)
At December 31, 2001	1,398	565	1,963	12,718	267	12,985	3,664	612	4,277
Of which:									
Proved developed reserves	948	166	1,113	9,069	42	9,112	2,564	173	2,737
Proved reserves under PSA and buy-back agreements	0	302	302	0	0	0	0	302	302
Production from PSA and buy-back agreements	0	3	3	0	0	0	0	3	3
Revisions and improved recovery	108	(25)	83	237	0	237	151	(25)	125
Extensions and discoveries	31	73	104	942	0	942	199	73	272
Purchase of reserves-in-place	4	0	4	35	0	35	10	0	10
Sales of reserves-in-place	(13)	(2)	(16)	(73)	0	(73)	(26)	(2)	(29)
Production	(242)	(29)	(271)	(645)	(12)	(657)	(357)	(31)	(388)
At December 31, 2002	1,286	580	1,867	13,215	255	13,470	3,641	626	4,267
Of which:									
Proved developed reserves	919	137	1,056	9,321	30	9,351	2,580	143	2,722
Proved reserves under PSA and buy-back agreements	0	349	349	0	0	0	0	349	349
Production from PSA and buy-back agreements	0	12	12	0	0	0	0	12	12

The conversion rates used are 1 standard cubic meter = 35.3 standard cubic feet, 1 standard cubic meter oil equivalent = 6.29 barrels of oil equivalent and 1,000 standard cubic meter gas = 1 standard cubic meter oil equivalent.

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Statoil has historically marketed and sold the Norwegian State's oil and gas as a part of its own production. The Norwegian State has elected to continue this arrangement. Accordingly, at an extraordinary general meeting held on February 27, 2001, the Norwegian State, as sole shareholder, revised Statoil's articles of association by adding a new article which requires Statoil to continue to market and sell the Norwegian State's oil and gas together with Statoil's own oil and gas in accordance with an instruction established in shareholder resolutions in effect from time to time. At an extraordinary general meeting held on May 25, 2001, the Norwegian State, as sole shareholder, approved a resolution containing the instructions referred to in the new article. This resolution is referred to as the owner's instruction. For natural gas acquired by Statoil for its own use, its payment to the Norwegian State will be based on market value. For all other sales of natural gas to Statoil or to third parties the payment to the Norwegian State will be based on either achieved prices, a net back formula or market value. All of the Norwegian State's oil and NGL will be acquired by Statoil. Pricing of the crude oil will be based on market reflective prices; NGL prices will be either based on achieved prices, market value or market reflective prices.

The Norwegian State may at any time cancel the owner's instruction. Due to this uncertainty and the Norwegian State's estimate of proved reserves not being available to Statoil, it is not possible to determine the total quantities to be purchased by Statoil under the owner's instruction from properties in which it participates in the operations.

Capitalized costs related to Oil and Gas producing activities

(IN NOK MILLION)	*AT DECEMBER 31, 2002*	*2001*
Unproved Properties	3,490	4,281
Proved Properties, wells, plants and other equipment	222,494	208,446
Total Capitalized Costs	225,984	212,727
Accumulated depreciation, depletion, amortization and valuation allowances	(133,925)	(117,450)
Net Capitalized Costs	92,059	95,277

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

These costs include both amounts capitalized and expensed.

(IN NOK MILLION)	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Year ended December 31, 2002			
Exploration costs	1,350	942	2,292
Development costs	10,269	4,088	14,357
Total	11,619	5,030	16,649
Year ended December 31, 2001			
Exploration costs	2,020	683	2,703
Development costs	9,707	4,452	14,159
Total	11,727	5,135	16,862
Year ended December 31, 2000			
Exploration costs	1,657	1,764	3,421
Development costs	11,470	3,628	15,098
Total	13,127	5,392	18,519

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Results of Operation for Oil and Gas Producing Activities

As required by Statement of Financial Accounting Standards No. 69, the revenues and expenses included in the following table reflect only those relating to the oil and gas producing operations of Statoil.

Activities included in Statoil's segment disclosures in note 3 to the financial statements but excluded from the table below relates to gas trading activities, transportation and business development as well as effects of disposals of oil and gas interests.

Income tax expense is calculated on the basis of statutory tax rates in addition to uplift and tax credits only. No deductions are made for interest or overhead.

Transfers are recorded approximating market prices.

(IN NOK MILLION)	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Year ended December 31, 2002			
Sales	1,199	4,744	5,943
Transfers	54,585	1,018	55,603
Total revenues	55,784	5,762	61,546
Exploration expenses	(1,420)	(775)	(2,195)
Production costs	(8,617)	(774)	(9,391)
Special items 1)	0	(766)	(766)
DD&A 2)	(12,402)	(1,738)	(14,140)
Total costs	(22,439)	(4,053)	(26,492)
Results of operations before taxes	33,345	1,709	35,054
Tax expense	(25,203)	(870)	(26,073)
Results of producing operations	8,142	839	8,981
Year ended December 31, 2001			
Sales	1,379	2,957	4,336
Transfers	61,913	1,767	63,680
Total revenues	63,292	4,724	68,016
Exploration expenses	(2,011)	(866)	(2,877)
Production costs	(8,557)	(1,102)	(9,659)
Special items 1)	0	(2,000)	(2,000)
DD&A 2)	(12,637)	(1,477)	(14,114)
Total costs	(23,205)	(5,445)	(28,650)
Results of operations before taxes	40,087	(721)	39,366
Tax expense	(30,958)	216	(30,742)
Results of producing operations	9,129	(505)	8,624

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

(IN NOK MILLION)	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Year ended December 31, 2000			
Sales	1,418	5,804	7,222
Transfers	69,610	1	69,611
Total revenues	71,028	5,805	76,833
Exploration expenses	(1,310)	(1,141)	(2,451)
Production costs	(8,338)	(1,414)	(9,752)
Special items	0	130	130
DD&A 2)	(12,468)	(1,815)	(14,283)
Total costs	(22,116)	(4,240)	(26,356)
Results of operations before taxes	48,912	1,565	50,477
Tax expense	(36,851)	(250)	(37,101)
Results of producing operations	12,061	1,315	13,376

1) Impairment of the oil field LL652 in Venezuela.

2) Include provisions made for future decommissioning and removal costs.

Standardized measure of discounted future net cash flows relating to proved oil and gas reserves

The table below shows the standardized measure of future net cash flows relating to proved reserves presented. The analysis is computed in accordance with FASB Statement No. 69, by applying year-end market prices, costs, and statutory tax rates, and a discount factor of 10% to year-end quantities of net proved reserves. The standardized measure is a forward-looking statement.

Future price changes are limited to those provided by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions. Future net cash flow pre-tax is net of decommissioning costs. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using 10% mid-period discount factors. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced. The information provided does not represent management's estimate of Statoil's expected future cash flows or value of proved oil and gas reserves. Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, identified reserves and contingent resources, that may become proved in the future, are excluded from the calculations. The standardized measure of valuation prescribed under FASB Statement No. 69 requires assumptions as to the timing and amount of future development and production costs and income from the production of proved reserves. This does not reflect management's judgment and should not be relied upon as an indication of Statoil's future cash flow or value of its proved reserves.

(IN NOK MILLION)	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
At December 31, 2002			
Future net cash inflows	644,327	127,460	771,787
Future development costs	(44,983)	(17,396)	(62,379)
Future production costs	(192,779)	(22,146)	(214,925)
Future net cash flows pre-tax	406,565	87,918	494,483
Future income tax expenses	(302,254)	(17,468)	(319,722)
Future net cash flows	104,311	70,450	174,761
10% annual discount for estimated timing of cash flows	(44,336)	(38,725)	(83,061)
Standardized measure of discounted future net cash flows	59,975	31,725	91,700

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

(IN NOK MILLION)	NORWAY	OUTSIDE NORWAY	TOTAL
At December 31, 2001			
Future net cash inflows	660,247	107,074	767,321
Future development costs	(40,379)	(16,563)	(56,942)
Future production costs	(185,281)	(23,008)	(208,289)
Future net cash flow pre-tax	434,587	67,503	502,090
Future income tax expenses	(327,141)	(17,497)	(344,638)
Future net cash flows	107,446	50,006	157,452
10% annual discount for estimated timing of cash flows	(49,566)	(28,669)	(78,235)
Standardized measure of discounted future net cash flows	57,880	21,337	79,217
At December 31, 2000			
Future net cash inflows	757,634	103,859	861,493
Future development costs	(34,614)	(13,624)	(48,238)
Future production costs	(187,119)	(22,331)	(209,450)
Future net cash flow pre-tax	535,901	67,904	603,805
Future income tax expenses	(396,223)	(18,221)	(414,444)
Future net cash flows	139,678	49,683	189,361
10% annual discount for estimated timing of cash flows	(61,605)	(28,906)	(90,511)
Standardized measure of discounted future net cash flows	78,073	20,777	98,850

Of a total of NOK 62,379 million of estimated future development costs as of December 31, 2002, an amount of NOK 43,397 million is expected to be spent within the next three years, as allocated in the table below.

Future development costs

(IN NOK MILLION)	2003	2004	2005	TOTAL
Norway	13,118	10,620	6,183	29,921
Outside Norway	5,897	4,912	2,667	13,476
Sum future development costs	19,015	15,532	8,850	43,397
Future development costs expected to be spent on proved undeveloped reserves	15,996	13,156	7,293	36,445

In 2002, Statoil incurred NOK 14,357 million in development costs, of which NOK 9,964 million related to proved undeveloped reserves. The comparable amounts for 2001 were NOK 14,159 million and NOK 8,386 million, and for 2000 NOK 15,098 million and NOK 11,840 million, respectivily.

Changes in the standardized measure of discounted future net cash flows from proved reserves

(IN NOK MILLION)	2002	2001	2000
Standardized measure at beginning of year	79,217	98,850	82,952
Net change in sales and transfer prices and in production (lifting) costs related to future production	(297)	(70,193)	206,251
Changes in estimated future development costs	(6,115)	(10,560)	(6,316)
Sales and transfers of oil and gas produced during the period, net of production costs	(56,994)	(62,283)	(70,246)
Net change due to extensions, discoveries, and improved recovery	9,790	2,064	10,292
Net change due to purchases and sales of minerals in place	(1,802)	(1,652)	(160)
Net change due to revisions in quantity estimates	9,791	11,604	(6,279)
Previously estimated development costs incurred during the period	14,357	14,159	15,098
Accretion of discount	33,342	57,721	(79,383)
Net change in income taxes	10,411	39,508	(53,359)
Total change in the standardized measure during the year	12,483	(19,632)	15,898
Standardized measure at end of year	91,700	79,217	98,850

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Operational statistics

Productive oil and gas wells and developed and undeveloped acreage

The following tables show the number of gross and net productive oil and gas wells and total gross and net developed and undeveloped oil and gas acreage in which Statoil had interests at December 31, 2002.

A "gross" value reflects to wells or acreage in which Statoil has interests (calculated as 100%). The net value corresponds to the sum of whole or fractional working interest in gross wells or acreage.

AT DECEMBER 31, 2002		*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Number of productive oil and gas wells				
Oil wells	— gross	791	518	1,309
	— net	200	102	302
Gas wells	— gross	108	12	120
	— net	34	4	37

AT DECEMBER 31, 2002 (IN THOUSANDS OF ACRES)		*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Developed and undeveloped oil and gas acreage				
Acreage developed	— gross	560	313	873
	— net	134	76	210
Acreage undeveloped	— gross	9,536	9,813	19,349
	— net	3,240	2,632	5,872

Remaining terms of leases and concessions are between one and 30 years.

Exploratory and development drilling activities

The following table shows the number of exploratory and development oil and gas wells in the process of being drilled by Statoil at December 31, 2002.

(NUMBER OF WELLS)	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Number of wells in progress			
— gross	25	18	43
— net	6.5	1.9	8.4

Net productive and dry oil and gas wells

The following tables show the net productive and dry exploratory and development oil and gas wells completed or abandoned by Statoil in the past three years. Productive wells include wells in which hydrocarbons were found, and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing in sufficient quantities to justify completion.

	NORWAY	*OUTSIDE NORWAY*	*TOTAL*
Year 2002			
Net productive and dry exploratory wells drilled	9.6	1.5	11.0
— Net dry exploratory wells drilled	2.5	0.1	2.6
— Net productive exploratory wells drilled	7.1	1.3	8.4
Net productive and dry development wells drilled	27.3	13.5	40.8
— Net dry development wells drilled	0.0	0.3	0.3
— Net productive development wells drilled	27.3	13.2	40.5

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

	NORWAY	*OUTSIDE NORWAY*	*TOTAL*
Year 2001			
Net productive and dry exploratory wells drilled	9.7	2.2	11.9
— Net dry exploratory wells drilled	3.2	1.2	4.4
— Net productive exploratory wells drilled	6.5	1.0	7.6
Net productive and dry development wells drilled	32.8	27.4	60.2
— Net dry development wells drilled	0.7	0.3	1.0
— Net productive development wells drilled	32.1	27.1	59.2
Year 2000			
Net productive and dry exploratory wells drilled	4.7	4.8	9.5
— Net dry exploratory wells drilled	2.0	1.5	3.5
— Net productive exploratory wells drilled	2.7	3.3	6.0
Net productive and dry development wells drilled	30.6	71.4	102.0
— Net dry development wells drilled	0.8	0.0	0.8
— Net productive development wells drilled	29.8	71.4	101.2

Average sales price and production cost per-unit

	NORWAY	*OUTSIDE NORWAY*
Year ended December 31, 2002		
Average sales price crude in US$ per bbl	24.7	23.3
Average sales price natural gas in NOK per Sm^3	0.95	0.65
Average production costs, in NOK per boe	24.2	26.7
Year ended December 31, 2001		
Average sales price crude in US$ per bbl	24.1	22.3
Average sales price natural gas in NOK per Sm^3	1.22	0.97
Average production costs, in NOK per boe	24.9	46.4
Year ended December 31, 2000		
Average sales price crude in US$ per bbl	28.4	27.5
Average sales price natural gas in NOK per Sm^3	0.99	-
Average sales price natural gas in US$ per Sm^3	-	0.10
Average production costs, in NOK per boe	24.8	58.2

To the Board of Directors and Shareholders of Statoil ASA

Report of independent auditors – USGAAP accounts

We have audited the accompanying consolidated balance sheets of Statoil ASA and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatements. 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 the management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Statoil ASA and subsidiaries at December 31, 2002 and 2001, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

Stavanger, February 17, 2003
ERNST & YOUNG AS

Gustav Eriksen
State Authorised Public Accountant
(Norway)

Jostein Johannessen
State Authorised Public Accountant
(Norway)

General information

Annual general meeting

The annual general meeting in Statoil ASA will be held at Stavanger Forum, Gunnar Warebergs gate 13, Stavanger, Norway on Thursday 8 May 2003 at 5pm.

Shareholders who would like to attend the annual general meeting are asked to give notification of this by 12 noon on Monday 5 May to:
Den Norske Bank ASA
c/o DnB Registrars, Stranden 21, N-0021 Oslo, Norway
Telephone: +47 22 48 35 84
Telefax: +47 22 48 11 71

Shareholders who wish to attend the general meeting by proxy must give notice of this in writing. Notice of the annual general meeting will be published in the Norwegian newspapers *Stavanger Aftenblad, Aftenposten, Dagens Næringsliv* and *Finansavisen*.

Dividend

The board's proposal for the distribution of dividend will be resolved at the annual general meeting, with 23 May 2003 as the planned date for payments. Dividend payments will be made to persons listed in the register of shareholders in the Norwegian Central Securities Depository (VPS) on 8 May 2003.

Reporting of results

The following dates have been set for the quarterly reports in 2003:

1st quarter	28 April
2nd quarter	4 August
3rd quarter	27 October

The results will be published at 8.30am. Statoil reserves the right to change the dates.

Information from Statoil

The annual report is available in printed and electronic versions, in Norwegian and English. Quarterly reports in both languages are available electronically. The group also prepares a report in English once a year, Form 20-F, and quarterly reports, Form 6-K, as required by the Securities and Exchange Commission in the USA. These reports, together with further information about the group's operations, can be obtained by contacting investor relations or public affairs in Statoil.

Addresses

Statoil's head office has the following address:
Statoil ASA, 4035 Stavanger, Norway.

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E-mail:	statoil@statoil.com
Investor relations :	ir@statoil.com
Internet:	www.statoil.com

A complete list of addresses and telephone numbers is available at

www.statoil.com/addresses

Statoil qualified for inclusion in the Dow Jones sustainability index in 2002. This puts Statoil among the top 10 per cent of oil companies in the world for sustainable development.

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