Seizing opportunities

Annual report and accounts 2003

STATOIL

Statoil 2003

Statoil is an integrated oil and gas company with substantial international activities. Represented in 28 countries, the group had 19 326 employees at the end of 2003. Nearly 40 per cent of these employees work outside Norway.

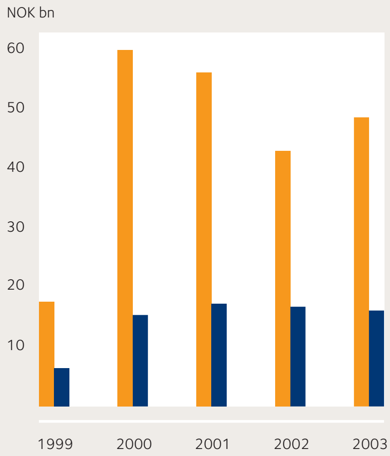
Statoil is the leading producer on the Norwegian continental shelf and is operator for 20 oil and gas fields. The group's international production is enjoying strong growth, and Statoil is a leading retailer of petrol and oil products in Scandinavia, Ireland, Poland and the Baltic states. One of the major suppliers of natural gas to the European market, Statoil is also one of the world's biggest sellers of crude oil.

As one of the world's largest operators for offshore oil and gas activities, Statoil has been used to tackling major challenges with regard to safety and the environment from the very start. Today, we are one of the world's most environmentally-efficient producers and transporters of oil and gas.

Our goal is to generate good financial results for our shareholders through a sound and proactive business performance. It is our ambition to achieve good results across three bottom lines – financial, environmental and social – which strengthen each other in the long term and contribute to building a robust company. We hope that this annual report successfully conveys this ambition, and the results achieved in 2003 which contribute to realising it.

Key figures

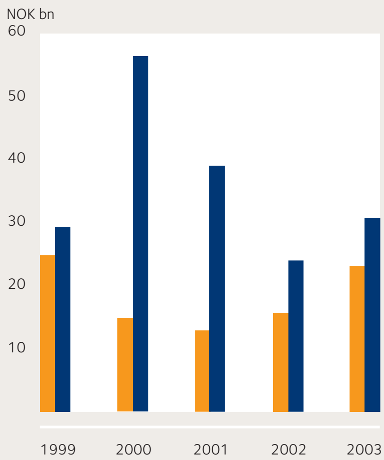
INCOME



Income before financial items, other items, income taxes and minority interests

Net income

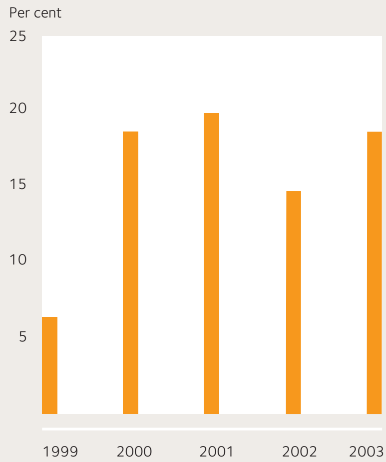
CASH FLOW



Cash flow used in investing activities

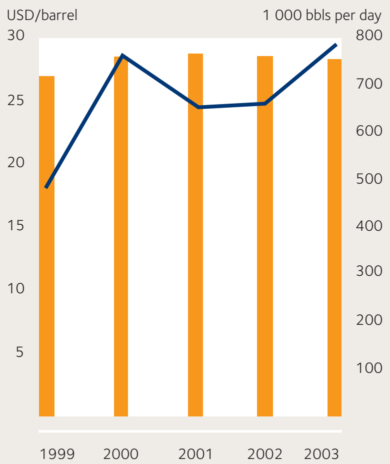
Cash flow provided by operating activites

RETURN



Return on average capital employed after tax

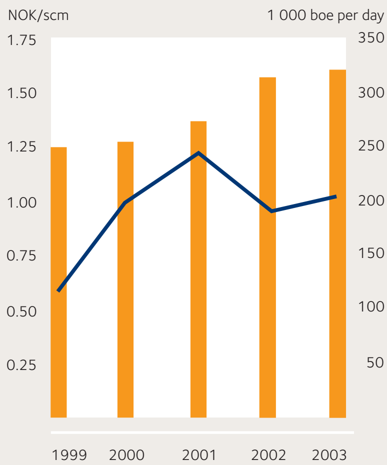
OIL PRODUCTION/PRICE



Entitlement oil production

Average oil price Brent Blend

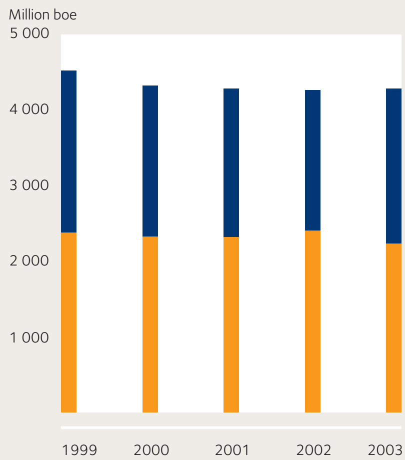
GAS PRODUCTION/PRICE



Sales equity gas production

Average gas price

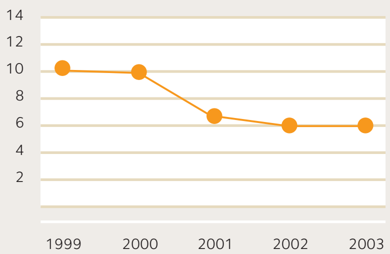
PROVEN OIL/GAS RESERVES



Natural gas

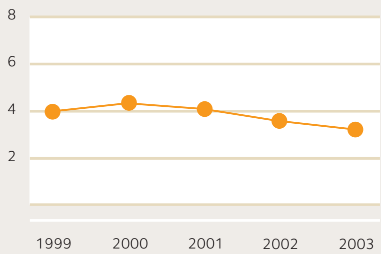
Oil and NGL

TOTAL RECORDABLE INJURY FREQUENCY



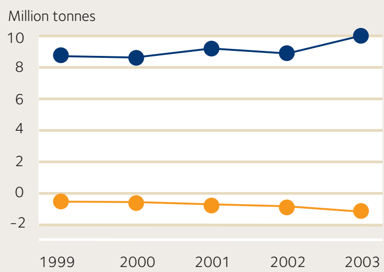
Number of total recordable injuries per million working hours

SERIOUS INCIDENT FREQUENCY



Number of serious incidents per million working hours

CARBON DIOXIDE (CO_2)



CO_2 reductions made through measures implemented between 1997 and 2003 for Statoil operations

Total CO_2 emissions from Statoil operations

USGAAP – Financial highlights

	2003	2002	2001	2000	1999
Financial information (NOK million)					
Total revenues	**249,375**	243,814	236,961	230,425	150,132
Income before financial items, other items, income taxes and minority interest	**48,916**	43,102	56,154	59,991	17,578
Net income	**16,554**	16,846	17,245	16,153	6,409
Cash flow provided by operating activities	**30,797**	24,023	39,173	56,752	29,610
Cash flow used in investing activities	**23,198**	16,756	12,838	16,014	24,988
Interest-bearing debt	**37,278**	37,128	41,795	36,982	50,497
Net interest-bearing debt	**20,906**	23,592	34,080	23,379	42,856
Net debt to capital employed	**22.6%**	28.7%	39.0%	25.0%	42.6%
Return on average capital employed after tax	**18.7%**	14.9%	19.9%	18.7%	6.4%
Operational information					
Combined oil and gas production (thousand boe/day)	**1 080**	1 074	1 007	1 003	967
Proven oil and gas reserves (million boe)	**4 264**	4 267	4 277	4 317	4 511
Production cost (USD/boe)	**3.2**	3.0	2.8	3.0	3.4
Finding and development cost (USD/boe, 3-year average)	**5.9**	6.2	9.1	8.2	8.7
Reserve replacement ratio (3-year average)	**0.95**	0.78	0.68	0.86	1.03
Share information					
Net income per share	**7.64**	7.78	8.31	8.18	3.24
Net income per share adjusted for special items(1)	**7.32**	7.72	7.32	8.18	4.54
Share price at Oslo Stock Exchange 30 December	**74.75**	58.50	61.50	–	–
Weighted average number of ordinary shares outstanding	**2,166,143,693**	2,165,422,239	2,076,180,942	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”.

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 shareholders’ equity 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.

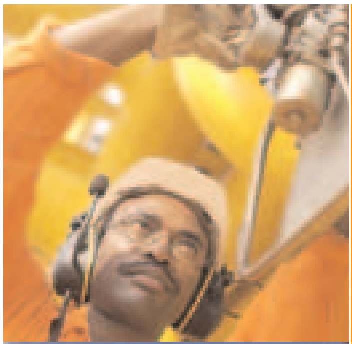
Reserve replacement ratio =
Additions to proven reserves, including acquisitions and disposals, divided by volumes produced.

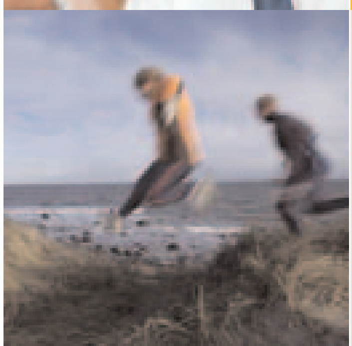
Barrel of oil equivalent (boe) =
Oil and gas volumes expressed as a common unit of measurement. One boe is equal to one barrel of crude, or 159 standard cubic metres of gas.

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 1997-2003.

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.





Corporate strategy

The main strategy of Statoil is to:

- enhance value creation on the Norwegian continental shelf (NCS)
- develop a broad European gas position
- attain substantial growth in production internationally
- strengthen downstream operations in selected areas

Considerable growth

Statoil's ambition is to become a leading international oil and gas group with up to 40 per cent of production taking place outside Norway in 2010-2012. Production outside Norway at present accounts for eight per cent. Oil and gas production forms the basis for the group's business and Statoil expects output to be high in the next few years. The gas business is expected to become increasingly important.

International focus

While a strong international commitment is necessary to ensure the group's long-term growth, the NCS will remain the cornerstone of Statoil for a long time to come.

Output from known fields will decline towards the end of this decade. With production growth up to 2007 secured through identified and sanctioned projects, the challenge will be to secure access to reserves that will provide new long-term production.

Critical factors

Statoil's continued involvement on the NCS and the development of international production depend on several key factors.

Good results for health, safety and the environment (HSE) are basic to achieving long-term value creation. Systematic work on continuous improvements is necessary to meet the main objectives:

- zero harm to people or the environment
- zero material damage or losses.

People and the organisation

In order to meet the goal of becoming a leading international oil and gas group, it is necessary to develop a common set of values and modes of working. It is also necessary to secure the best possible use and further development of personnel and expertise. It is therefore important to strengthen efforts within management and personnel development.

Access and trust

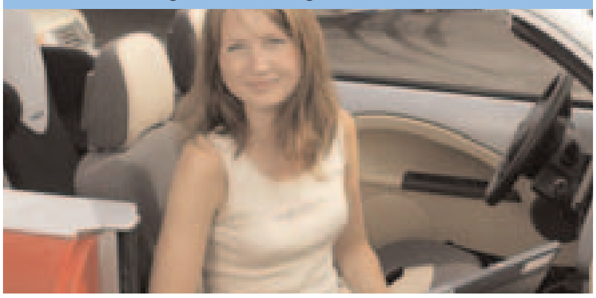
Statoil needs access to resources through formal licences from the relevant authorities and is dependent on society's confidence in the group's activities. The Horton affair in the autumn of 2003 revealed how vulnerable the group's reputation is, and showed how important it is that business is conducted within accepted norms. Continuous and systematic efforts are necessary to improve the group's performance along the three bottom lines of financial results, environmental performance and social responsibility.

Exploration & Production Norway

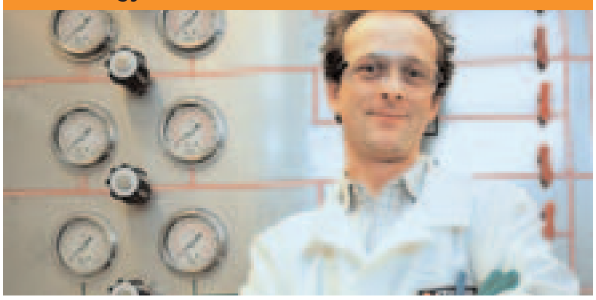
International Exploration & Production

Natural Gas

Manufacturing & Marketing



Technology



Business strategies

Strategy	Prospects
It is the business area's ambition to become the industry's best production operator on the NCS. Statoil currently produces about one million barrels of oil equivalent per day off Norway. The goal is to maintain this level until 2008, or even longer if possible. Proven reserves must be developed and access to new exploration acreage must be secured.	Access to new exploration acreage will be vital if the current level of activity is to be maintained. The government decision to reopen the Barents Sea for exploration operations is positive. Through improvement processes, measures have been identified to reduce cost levels for fields operated by Statoil. 2004 will be an important year for realising the ambitions declared at the time of the group's flotation in 2001, as regards production, operating costs and investment framework.

Strategy	Prospects
Secure future growth through production from international core areas, each delivering more than 100 000 barrels of oil equivalent per day. Build on Statoil's experience as a national oil company to form partnerships with national and international oil companies in resource-rich areas. It is important to access high-quality exploration and exploit a competitive edge in establishing and operating complex gas value chains.	International production will increase from 89 000 barrels of oil equivalent per day in 2003 to more than 300 000 in 2007 from Statoil's positions in the UK, Angola, Azerbaijan, Venezuela, Iran and Algeria. The group will continue high-priority screening of basins globally, and extending exploration activities in countries in which it is already present. The main areas of interest are the Atlantic margins, the Middle East and the Caspian region.

Strategy	Prospects
The gas strategy is rooted in a unique position, characterised by large reserves, substantial market shares secured through long-term contracts, an efficient and integrated transport infrastructure and wide-ranging technical and commercial expertise. Future earnings will be secured by maximising the value of long-term contracts combined with efficient operation of processing and transport facilities. Further growth will be achieved through developing supply solutions and new markets.	European consumption of natural gas continues to rise. For a long time to come Statoil's main markets will be in north-western Europe, and the company will be in a good position to meet the UK's increasing demand for gas imports. Additional gas from the Caspian region, Algeria, west Africa, Snøhvit LNG and other sources, will enable Statoil to supply more countries in Europe and the USA in a cost-effective manner.

Strategy	Prospects
Manufacturing & Marketing will create value through integration and brand and utilise profitable opportunities for synergy and growth. Through our market position we will maximise the value of Statoil's and the Norwegian state's access to crude oil, rich gas and refined products. We will further develop Mongstad and Tjeldbergodden as industrial centres in the value chain, and strengthen our position in retail marketing and sale of traditional oil products in our core markets.	The average price of North Sea oil in 2003 was USD 28.8 per barrel. That is the highest price since 1985. The market prospects are uncertain but continued growth in the demand for oil is expected, at a level of 1-1.5 million barrels per day. An upturn in the world economy will help to improve earnings in the markets for refined products and plastic raw materials.

Strategy

The technology strategy will result in value creation through skilful application of technology. It consists of two main elements: the main business challenges to be solved through research and technology development, and identification of the most important areas of technology.

Business challenges:
- Increasing recovery from subsea wells
- Tail-end production
- Finding and developing new resources
- New business opportunities.

Key areas of technology:
- Exploration and reservoir management
- Well design
- Subsea field development
- Cost-effective, reliable and regular operation
- Development of the gas value chain
- The environment.

Fit for the future

Statoil is ready to face the future. Impressive efforts from the whole organisation have secured a record-high level of production and reduced costs – and laid the basis for a strong financial result in 2003.

Continuous improvement and concentration on creating value have provided our shareholders with a competitive return. Strong financial results and considerable strategic progress pave the way for profitable growth in the years ahead.

The Norwegian continental shelf (NCS) will constitute the foundation of Statoil's operations for many years to come. Safe and effective operations, development of good projects and purposeful exploration activity will secure Statoil's leading position on the NCS. Good results have given rise to big ambitions.

This also applies to our international operations which will be Statoil's most important source of growth in the years ahead. Concentrated efforts in a limited number of countries are now providing results in the form of important contributions to the group's reserves and production. Farming into two big gas fields in Algeria provides interesting prospects for the natural gas business.

Running our business without causing harm to people or the environment is a prerequisite for success. We are working hard to improve behaviour and attitudes, and we have launched the safe behaviour programme to motivate employees and improve safety at work. Covering 18 000 permanent employees and contractor personnel working on the NCS, the extent of this programme illustrates how seriously we take efforts to improve safety in the group. Statoil will pursue its business in a profitable, safe and ethical manner. It will also show consideration to the environment and accept social responsibility. This is the core of Statoil's focused efforts for sustainable development. Through these efforts we will gain the confidence of our employees, partners and owners.

The "Horton affair" last year reminds us how Statoil can be harmed when we do not succeed in practising openness and compliance with our own ethical guidelines. However, the matter was taken extremely seriously, and I am convinced that confidence will be restored in Statoil.

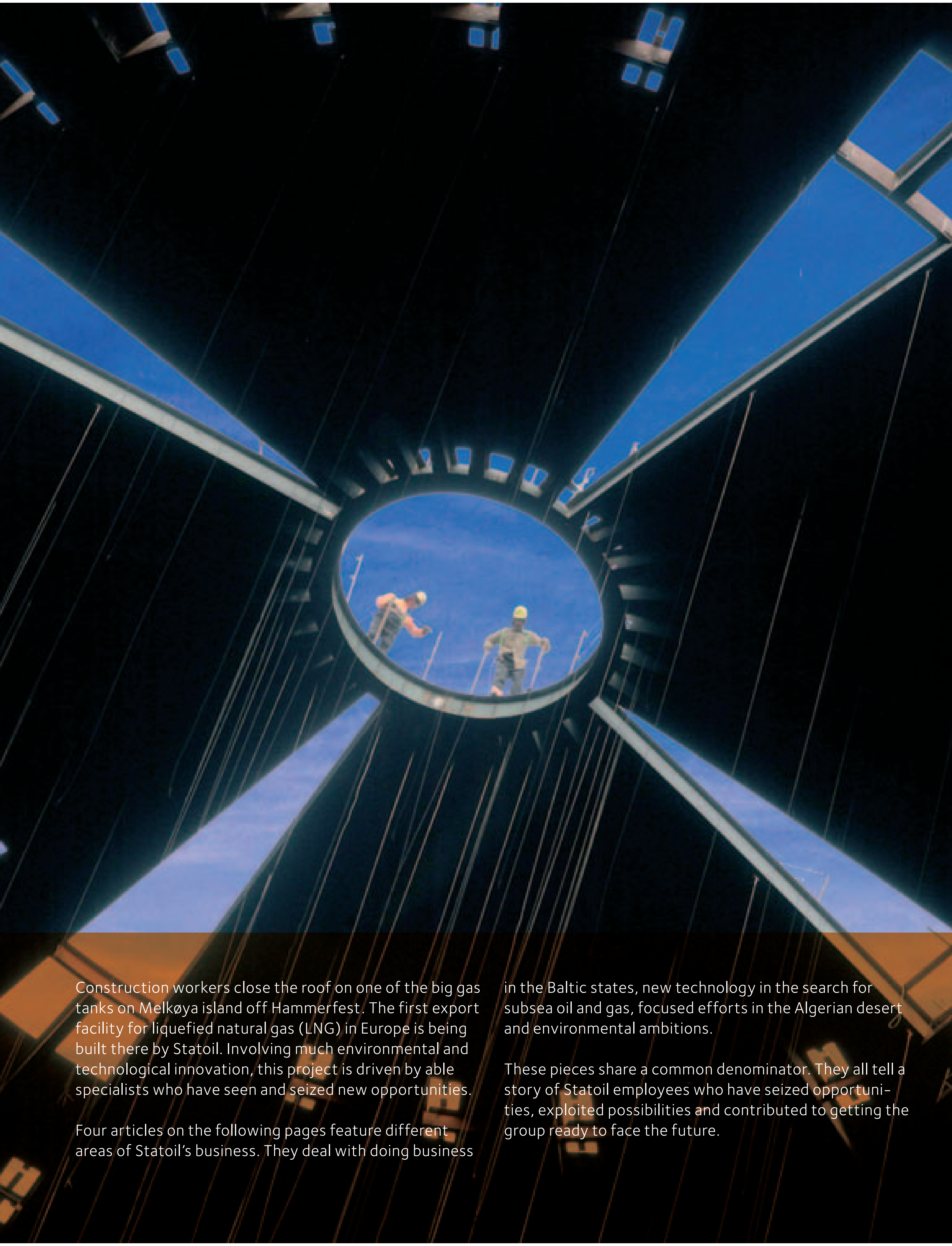
Changes in our surroundings and competitive conditions are taking place at an ever-increasing tempo. Our response must show an ability to adapt quickly and to seize the right opportunities. These are the qualities that underpin our success over recent years.

Statoil has a good basis on which to continue its success in the time ahead. We have a solid industrial platform based on valuable experience and we have competent, motivated employees. Last but not least, we have a robust strategy which already yields good results.

It is with a sense of pride in our achievements and with expectation, that we welcome Helge Lund as Statoil's new chief executive.

Our job in Statoil is to exploit our advantages to build the Statoil of the future, providing maximum value creation for its owners, employees and society. Statoil's employees are looking forward to doing this together with our new chief executive.

Erling Øverland
Acting chief executive



Construction workers close the roof on one of the big gas tanks on Melkøya island off Hammerfest. The first export facility for liquefied natural gas (LNG) in Europe is being built there by Statoil. Involving much environmental and technological innovation, this project is driven by able specialists who have seen and seized new opportunities.

Four articles on the following pages feature different areas of Statoil's business. They deal with doing business in the Baltic states, new technology in the search for subsea oil and gas, focused efforts in the Algerian desert and environmental ambitions.

These pieces share a common denominator. They all tell a story of Statoil employees who have seized opportunities, exploited possibilities and contributed to getting the group ready to face the future.

Baltic success

Three women, three countries, three success stories – one way to sum up Statoil's story in Estonia, Latvia and Lithuania. Since September 2001, the female trio of Epp Kiviaed, Baiba Rubess and Anne Martory has led Statoil's subsidiaries in these Baltic states. And they have done well, with their 1 700 employees creating good results.

Statoil ranks as the largest petrol retailer in Estonia and Latvia, and as one of the 10-12 largest enterprises in these countries. In Lithuania, the group comes second in the fight for customers. Equally important, it is earning good money from its 156 service stations in the Baltic states.

Significant factors in explaining this performance must include a management style characterised by good humour and plenty of laughter. Meeting the three national presidents is no dull experience.

"We're different, and have intense though humour-filled discussions – but we reach agreement," says Ms Martory. She is French, but has lived most of her adult life in Norway and has 22 years of experience from various parts of Statoil's business. A Lithuanian magazine recently called her one of the 15 best business leaders in the country.

Ms Rubess and Ms Kiviaed grew up in Canada and Sweden respectively, and came to Latvia and Estonia soon after these countries regained their independence. They belong to a large group of well-educated young people who upped stakes to help build the nations which their parents left under the Soviet yoke.

Statoil's arrival in the Baltic states also coincided more or less with independence. The group established its first subsidiary in Estonia even before the USSR collapsed. An early entry is part of Statoil's success story. Its first service stations opened in 1992.

Ms Kiviaed highlights another reason for success. Rather than concentrating on franchise agreements, the group opted to own its forecourts directly and employ all their staff.

"This required more resources and yielded lower revenues in the early years, but gave us the chance to build a solid organisation from the ground up on the basis of Statoil's values," she says. "We're reaping the fruits of this personnel policy today, with very loyal and motivated employees."

Statoil acquired Shell's service stations in the Baltic states in 2002, and 52 of these forecourts were rebranded during 2003. The three presidents describe this takeover as a complex but rewarding process, providing a solid market boost.

Having three women in charge of three oil companies is unique in the Baltic states, which are otherwise a male-dominated world.

"They're tough men who play hard," says Ms Rubess, who makes it clear that she can also play hard.

"We have 23 per cent of the Latvian market, and we're going to get that up to 30 per cent," she affirms.

Statoil has a strong position in these three states. In addition, a new trademark has emerged there – the group's "1 2 3" fully-automated forecourts were developed in Latvia and Estonia.
"We're very proud that our concept has been approved and adopted by the parent company," says Ms Rubess

Estonia
1.4 million inhabitants
30 per cent market share
44 stations plus three unstaffed
618 employees

Latvia
2.3 million inhabitants
23 per cent market share
47 stations plus five unstaffed
Oil terminal in Riga
593 employees

Lithuania
3.7 million inhabitants
18 per cent market share
53 stations plus four unstaffed
585 employees

Baiba Rubess (left), Anne Martory and Epp Kiviaed head Statoil's subsidiaries in Latvia, Lithuania and Estonia. Operations in the three states cover 1 700 employees and 156 service stations.

Cleaner results

The requirement is clear. All fields on the NCS must have reduced harmful discharges to the sea to zero by the end of 2005. This represents one of Statoil's most important environmental challenges, and its commitment on the Åsgard B gas platform in the Norwegian Sea is already yielding results.

Zero harmful discharges means that discharges on a field must be within the carrying capacity of the ecosystem. In plain language, no marine organisms must suffer from their coexistence with oil and gas operations. The big saithe hauled over the railings on Åsgard B by Kristin Øye (facing page) has also grown fine and big as a neighbour to the installations on this field.

Motivating work

Ms Øye is environmental coordinator on Åsgard, a large field compriing the Midgard, Smørbukk and Smørbukk South discoveries. The B platform serves as its centre for processing gas, and ranks as the world's largest floating unit of its kind.

"We've implemented extensive measures to look after the environment," Ms Øye explains. "For an oil and gas company which wants to be a leader in the environmental area, this is motivating work. We regard it as spending money to make money."

Demanding conditions

Åsgard has been one of the most complex development tasks ever undertaken by the oil industry. Its 10 reservoirs lie at depths from 2 300 to 4 870 metres beneath the seabed. Very different in terms of content, pressure, temperature and geology, they make heavy demands on the technological solutions chosen and on safety and environmental measures.

"These waters are a sensitive area, with large fish resources and great biological diversity," comments Ms Øye. "We regard it as entirely natural to want to meet both official standards and our own environmental targets."

Emissions of carbon dioxide, one of the greenhouse gases, from the platform have been cut by about 30 per cent as a result of energy optimisation in the process facilities. Low nitrogen oxide turbines also reduce emissions of these gases by more than 80 per cent.

Discharges to the sea also represent a challenge for an oil and gas field, and a number of measures have been initiated on Åsgard.

Its flowlines are in 13 per cent chrome steel, eliminating the need for corrosion-inhibiting chemicals. That in turn reduces discharges of such substances. Direct heating of flowlines is another measure which cuts out the need for chemicals to inhibit the formation of hydrate – ice-like solids which can form in gas/oil mixtures. An amine plant for removing hydrogen sulphide substantially reduces the need for chemicals to strip out the hydrogen sulphide, and thereby cuts discharges of such substances.

The fishing and oil industries must be able to flourish side by side, says environmental coordinator Kristin Øye, pictured here hauling a fine saithe over the railings of the Åsgard B platform.

Footprints in the sand

"We're here to stay for a long time," says Statoil's Ola Krumsvik as he eyes the footprints in the desert sand. The group has become an equal partner and operator with BP and Sonatrach on Algeria's major In Salah and In Amenas gas fields.

Mr Krumsvik has been named vice president for gas operations at In Salah when this field comes on stream during the summer of 2004. He brings with him first-class experience from operations on the NCS, where his previous jobs include platform manager on Gullfaks and operations vice president for Åsgard. He has also served as a chief engineer and held several important managerial posts for technology and production.

Special challenges

"Coming from a platform on the NCS to a production facility deep inside the Sahara will involve a number of differences," Mr Krumsvik admits.

"In technical terms, the process plant is the same as the ones we're familiar with in Norway and other parts of the world. I imagine it's rather simpler to operate on land than offshore, even though the desert undoubtedly has its own special challenges – with snakes and scorpions among the lurking hazards. This represents a fantastic opportunity to participate in gas production from large and rich deposits beneath the desert sand."

Algeria looks like becoming a core asset in Statoil's purposeful international commitment, says Ottar Rekdal, executive vice president for International Exploration & Production. Involvement with production facilities under a burning Saharan sun brings the group a long step forward in its internationalisation efforts. The agreement on acquisitions from BP in the summer of 2003 means that Statoil will have 32 per cent of In Salah and 50 per cent of In Amenas. Farming into these two fields will add roughly 50 000 barrels of oil equivalent to the group's daily production within a few years.

Plateau production

In Salah is due to reach its plateau output of nine billion cubic metres of gas annually within a few years. Plans call for In Amenas to come on stream in late 2005, with an estimated annual production of nine billion cubic metres of gas at plateau. This will be supplemented by liquids corresponding to 60 000 barrels of oil per day.

"Algeria will be our third avenue, with these reserves strengthening our position as a long-term and stable gas supplier to customers in Europe," says Algeria manager Terje Halmø at Statoil, who has his head office in the capital, Algiers.

"Our first avenue runs from the NCS and the second is now taking shape from the Caspian to Turkey, with opportunities for an extension to the continental European market."

Ola Krumsvik (left) will be operations vice president for the In Salah and In Amenas gas fields. Pictured here with Ottar Rekdal, head of international exploration and production activities, and Kåre Røssandhaug, who is responsible for operations in Algeria.

An ear to the seabed

Oil explorers have been provided with an extended organ of hearing by advanced receivers installed on the seabed before electromagnetic waves are transmitted into the subsurface.

This seabed logging (SBL) service is offered by Statoil's newly-created Electromagnetic GeoServices (EMGS) subsidiary at 10 per cent of the cost of drilling an exploration well. Based on logging echoes from electromagnetic waves transmitted underground, this solution can distinguish hydrocarbons from water with a high degree of probability. The new technology is described as a major leap forward in oil and gas exploration.

It all started in 1997 as an idea on the drawing board at Statoil's research centre in Trondheim. Within a few years, the solution has been commercialised and readied for international marketing. EMGS started with a staff of three, but this number has increased 10-fold and the company's annual turnover is more than NOK 100 million. The future looks bright for an innovative company which has secured customers world-wide and attracted much attention. World Oil, the international petroleum journal, has awarded EMGS its prestigious prize for new exploration solutions.

Recognised product

"That means recognition for us, not only in Norway but also internationally," says Terje Eidesmo, president of EMGS. He has many years of technological experience from Statoil, primarily in well logging.

"We're no longer just a newcomer, but have an acclaimed product which gives us a position in the exploration industry."

He adds that SBL with electromagnetic waves represents an important supplement to traditional seismic surveying, where sound waves sent into the subsurface are measured as they bounce back.

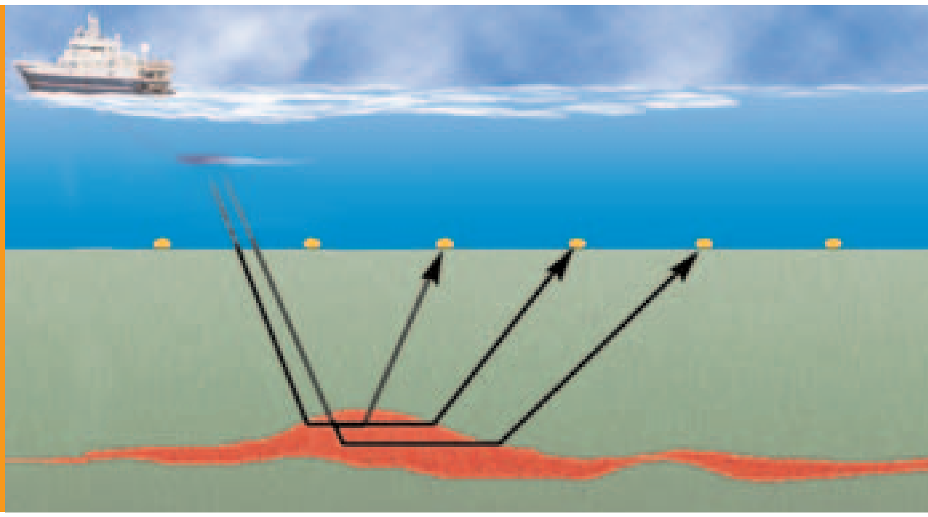
That can identify structures, but fails to distinguish between hydrocarbons and water in the way achieved by the new EMGS method.

More information

"We get out key information about the subsurface to supplement traditional seismic surveys," says Mr Eidesmo. "These data are available before we decide to drill a well, which reduces the risk of drilling a duster. With SBL, in reality, we bring the well up to the seabed. In that way, we can obtain supplementary information which was previously inaccessible without drilling."

The industry is very interested in SBL. Mr Eidesmo says that Statoil and Norsk Hydro, through their operations on the NCS, have played a crucial role in the adoption of the new technology.

SBL is currently confined to water depths beyond 300 metres, which are found across much of the NCS and in exploration provinces in many other parts of the world. Mr Eidesmo believes that the new method is very relevant for the Barents Sea, and just over 30 areas have so far been investigated with its aid. These include both Troll and Ormen Lange.



Svein Ellingsrud (left) and Terje Eidesmo have helped develop a research idea into a commercial product which is described as a considerable innovation in the search for subsea oil and gas.

The Statoil group

Statoil is an integrated oil and gas company. It is the biggest operator on the NCS and has considerable operations internationally. Represented in 28 countries, the group has 19 326 employees. Statoil is one of the world's most environmentally-efficient producers and transporters of oil and gas. In 2003, the group had a turnover of NOK 249 billion and a net income of NOK 16.6 billion.

Statoil's goals

When Statoil was floated on the stock market in 2001, it announced a set of targets for 2004. These were operational objectives associated with increasing production, enhancing efficiency and improving profitability. In 2003 the group announced a new set of targets for the period up to 2007.

Improved profitability and efficiency

Statoil has set a target to increase its return on capital employed in 2004 to 12 per cent, normalised for prices, margins and currency effects. At 31 December 2003, the return was 12.4 per cent. The target for 2007 is set at 12.5 per cent, but changes in normalised factors mean that the target remains a demanding one.

Strong production growth

Statoil's oil and gas production totalled 1 080 000 barrels of oil equivalent (boe) per day in 2003 and the goal is to increase this figure to 1 120 000 boe in 2004 and 1 350 000 boe in 2007. An output of 1 350 000 barrels in 2007 entails an annual growth of six per cent in the period 2004-2007. Production growth is expected to take place internationally, since the ambition for the NCS is to maintain production at today's level in the years ahead.

Improvement programme

The group is conducting a programme to improve financial results by NOK 3.5 billion from 2004, through increased efficiency and reduced costs in the upstream area, higher gas sales and improved profitability in the downstream business. At the end of 2003, the effect of measures implemented was calculated to contribute annual improvements of NOK 2.8 billion from 2004.

The table below shows Statoil's targets and results so far for return on capital employed, increased access to reserves in relation to production and expenditures for exploration, development and operation.

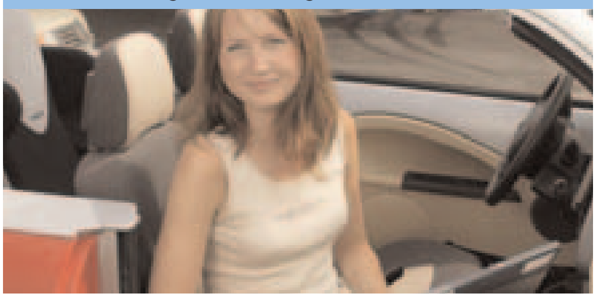
Financial and operational results and targets:	2001	2003	2004
Return on capital employed			
(at USD 16/ per boe)*	9.4%	12.4%	12%
Production (1 000 boe per day)	1 007	1 080	1 120
Reserve replacement ratio**	0.68	0.95	>1.0
Finding and development costs (USD/boe)**	9.1	5.9	<6.0
Production cost (USD/boe)*	3.2	2.8	<2.7
* Normalised			
** 3-year average			

Exploration & Production Norway

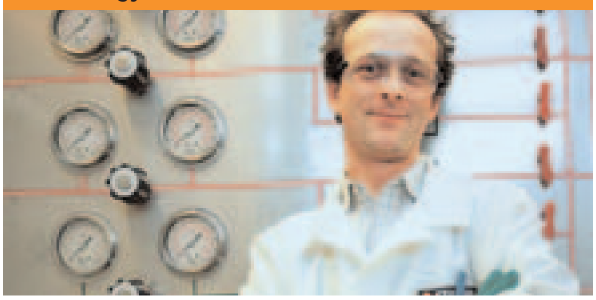
International Exploration & Production

Natural Gas

Manufacturing & Marketing



Technology



The business areas

Facts	Highlights in 2003
The business area is responsible for Statoil's operations on the NCS. The fields operated by the group account for roughly 60 per cent of total Norwegian oil and gas output. Statoil is operator for 20 oil and gas fields, which comprise 18 platforms and production ships with crew, four unstaffed installations and 19 remotely controlled subsea facilities. Employees: 6 405, of whom 3 384 work offshore.	• Gas deliveries from the Mikkel field started. Development costs 20 per cent lower than planned. • Vigdis extension project started production more than two months ahead of schedule. Costs 14 per cent lower than planned. • Topsides for Kvitebjørn platform installed; the largest and heaviest lift Statoil has ever carried out offshore. • Statoil bought Hydro's and Svenska Petroleum's interests in Snøhvit – raising its holding to 33.53 per cent.

Facts	Highlights in 2003
The business area is responsible for Statoil's exploration, development and production of oil and gas outside the NCS. Its responsibility for natural gas sales outside Europe was transferred to the Natural Gas business area on 1 January 2004. Statoil has substantial positions in the Caspian region, northern and western Africa, western Europe and Venezuela. Employees: 606, of whom 268 work outside Norway.	• Agreement with BP on farming into major Algerian gas projects. • First development phase launched for the Shah Deniz gas field in the Caspian. • Statoil became operator for a gas sales company in Azerbaijan and commercial operator for a pipeline company. • Exploration success in Angola, and two fields brought on stream.

Facts	Highlights in 2003
The business area is responsible for transporting, processing and marketing Statoil's own gas from the NCS to Europe and for the group's international gas marketing. Statoil also markets the Norwegian state's gas, and thereby accounts for two-thirds of Norwegian gas exports. Statoil has substantial interests in, and operational responsibility for, export pipelines and land-based treatment plants and terminals The business area is responsible for Statoil's commitment to LNG. Employees: 994, of whom 147 work outside Norway.	• Statoil received responsibility for planning and constructing a new trunkline from the Ormen Lange gas field to the UK. • Contract signed with Electricité de France National for the supply of gas from Statoil over 15 years, with deliveries to start in 2005. • Statoil sold its 5.26 per cent share in German Verbundnetz Gas. • First deliveries of liquefied natural gas (LNG) from Statoil to the USA.

Facts	Highlights in 2003
The business area covers Statoil's downstream oil operations, and methanol and petrochemical business. Responsible for selling Statoil's and the Norwegian state's crude oil, rich gas and refined products. Also sells natural gas to the Nordic countries. It is responsible for operating and developing refineries and methanol production. Statoil has more than 2 000 service stations in nine countries and has a 50 per cent share in the Borealis petrochemicals group. Employees: 8 447, of whom 6 941 work outside Norway.	• Successful sale of Navion. • Letter of intent signed with ICA covering the acquisition by Statoil of ICA's 50 per cent holding in retailer Statoil Detaljhandel Skandinavia AS. • Price of North Sea crude in 2003, measured in USD, the highest in 18 years. New petrol desulphurisation plant at Statoil's Mongstad refinery came on stream. • Production record set at the Tjeldbergodden methanol plant.

Facts	Highlights in 2003
The technology entity is responsible for maintaining the group's long-term technology development. Its function is to provide the cost-effective technical solutions and top expertise that it would not be practical for the business areas to invest in independently. It is responsible for the commercialisation of technology and industrial rights, and for the management and quality assurance of decision-making processes. Employees: 998, of whom 22 work outside Norway.	• New light well intervention method for subsea wells boosts earnings. • Intensified efforts to develop new forms of energy such as hydrogen and electricity production without emissions of carbon dioxide. • New technology developed for treating produced water before discharge into the sea. • Demonstration plant for gas-to-liquid (GTL) technology under construction in South Africa.

Exploration & Production Norway

Statoil's oil and gas production from the NCS in 2003 was roughly on a par with 2002, averaging 991 200 barrels of oil equivalent per day. While oil output declined slightly, this was largely offset by higher gas sales to the group's European customers.

Key figures (NOK million)	2003	2002	2001
Total revenues	62,494	58,780	67,245
Income before financial items, other items, taxes and minority interest	37,589	33,953	42,287
Gross investments	13,412	11,023	10,759

Two Statoil-operated fields and one with Statoil participation came on stream in 2003. The Mikkel gas field has been developed with a subsea installation tied back to the Åsgard B platform. Its gas is being piped through the Åsgard Transport trunkline to the Kårstø processing complex. Vigdis Extension embraces the Borg North/West and Vigdis East structures, and represents a further development of existing subsea installations on Vigdis which are tied back to Snorre A. Operated by Norsk Hydro, Fram West is a subsea development comprising two templates tied back to Troll C.

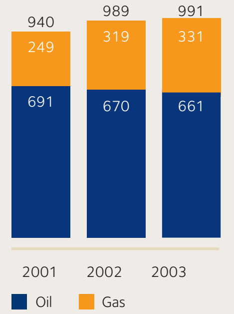
Development of the Kvitebjørn field east of Gullfaks is on schedule. The upper part of the platform jacket was installed in the spring of 2003, followed by the 10 000-tonne topside in May. Laying of the oil and gas pipelines from this installation took place in April-May. Gas deliveries from the field are due to start on 1 October 2004.

The Kristin gas development in the Norwegian Sea is in full swing but the project has a very tight schedule. After the largest and most important contracts were placed in 2002, the main activities in 2003 were concentrated on hull, topside and module fabrication for the floating platform, and manufacturing of subsea production equipment. Four templates were installed in June-July.

With the high pressure and temperature found in its reservoir, Kristin represents the most demanding field so far sanctioned for development on the NCS. That applies both to equipment quality and reservoir drainage.

Tight schedule for Snøhvit

Development of the Snøhvit project is running mainly according to plan and remains within the revised investment budget of NOK 45.3 billion. The progress plan for the project is however very tight due to delays in the construction of the process plant for the gas liquefaction plant. More than 1 000 people were employed at the site on



Oil and gas production, Norwegian continental shelf	2003	2002	2001
Oil (thousand boe per day)	661	670	691
Natural gas (thousand boe per day)	331	319	249
Total production (thousand boe per day)	991	989	940

He hangs high, but safe. Are Christiansen in Linjebygg Offshore has a spectacular workplace on the outside of the derrick during a turnaround on the Gullfaks A platform in the North Sea.

Melkøya island outside Hammerfest at 1 January 2004. Services there have been provided by 350 companies so far, with 35 nations represented among the workforce.

Recruitment of personnel for the operations organisation was in full swing during the autumn, and 90 people – just over half the total required – had been appointed at 31 December.

Spin-offs from Snøhvit

Contracts totalling NOK 20.8 billion had been placed for the Snøhvit project by 31 December 2003. This development includes the first Norwegian and European export facility for liquefied natural gas (LNG).

NOK 8.7 billion of contract value has gone to Norwegian suppliers, including NOK 1.5 billion placed in northern Norway. The west Finnmark region has secured work worth NOK 1.1 billion. This is gratifying, since the original estimate for contract value going to northern Norway was NOK 600 million.

Statoil expanding in Snøhvit

In January 2004 Statoil agreed with Norsk Hydro to buy Hydro's 10 per cent interest in the Snøhvit field. Statoil has also signed an agreement to acquire Svenska Petroleum's 1.24 per cent share in Snøhvit. These two acquisitions raise Statoil's holding from 22.29 per cent to 33.53 per cent. They will strengthen Statoil's gas production and the group's position in a strongly expanding LNG market.

Statfjord late life

Once one of the world's largest offshore oil fields, Statfjord is now producing less than 100 000 barrels per day. To ensure continued production and profitability, future operation of the field has been studied by the Statfjord late life project. Statoil is recommending to the partnership that the best development solution for this field and the rest of the Tampen area in the North Sea will be to remove

www.statoil.com/snohvit

Statoil's oil and gas production - Norwegian continental shelf

1000 barrels of oil equivalent/day

Field	2003	Statoil's share
Statfjord	84.6	51.88%
Statfjord East	10.5	25.05%
Statfjord North	11.9	21.88%
Sygna	7.0	24.73%
Gullfaks	168.7	61.00%
Snorre	36.3	14.40%
Vigdis	16.6	28.22%
Visund	11.5	32.90%
Tordis	22.7	28.22%
Troll Gas	98.6	20.80%
Sleipner West	107.2	49.50%
Sleipner East	25.0	49.60%
Gungne	17.7	52.60%
Veslefrikk	5.6	18.00%
Huldra	13.8	19.66%
Glitne	17.1	58.90%
Norne	40.4	25.00%
Heidrun	22.5	12.41%
Åsgard	104.1	25.00%
Mikkel	2.6	35.10%
Total Statoil-operated	828.0	
Total partner-operated	163.2	
Total production	991.2	
Underlifting	-9.1	
Total lifted production	982.1	

The Snøhvit development has provided jobs for companies in many countries. Here a river barge transports two heat exchangers for the gas liquefaction plant. The voyage through Germany follows the Danube and the Rhine, from Passau on the Austrian border to Bremen in northern Germany. The journey to Hammerfest will continue in 2005.

At Melkøya outside Hammerfest the construction of the gas liquefaction plant is making progress. At the end of 2003 this engaged a workforce of 1 000. The facility should be ready to export LNG in 2006.

bottlenecks in the production system through efficiency enhancements and improvements to existing installations. A decision on what to do will be taken at the end of 2004.

Exploration

Nine wildcat and appraisal wells were completed during 2003. Six of the wells resulted in discoveries, with the oil find in Ellida as the most interesting. In 2003, the Norwegian government announced a first annual licensing round in predefined areas near existing infrastructure. Statoil secured four operatorships in this round, including three in the Halten/Nordland area and one in Troll/Sleipner. The group forecasts a substantial expansion in exploration activity during 2004, not least because of the reopening of licences/acreage already awarded in the Barents Sea. It expects to drill several wells in both the Barents and the Norwegian Seas during 2004.

Collaboration with suppliers and partners

Statoil established a management forum in 2003 to pursue cooperation with suppliers at chief executive level. Regular meetings are held within this framework with the largest and most important suppliers. The forum is intended to allow participants to exchange information. Extensive collaboration is also pursued by Statoil with its joint venture partners over both development and operation. On the basis of the group's long experience in executing major pipeline projects, development operator Norsk Hydro and the other partners in the Ormen Lange gas field have commissioned it to design and build the gas export system from Nyhamna via Sleipner East to Easington in the UK. Hydro has also given Statoil responsibility for steel pipe deliveries to Ormen Lange.

Benchmarking

Statoil came top for efficient drilling operations in a benchmarking of 18 operator companies in Europe carried out by Rushmore Associates. Ranking the group as best or one of the best in every category, this exercise was based on 280 European offshore wells drilled in 2002. Statoil accounted for 60 of these, and was the biggest participant in the benchmarking. Similar studies focused on platform operation show that the group is steadily narrowing the gap between it and the very best North Sea operators. Statoil's ambition to be the industry's best production operator remains unchanged.

www.statoil.com/fields_ncs

Statoil is involved in more than 25 projects which are being planned or developed on the NCS. Total investments in the licences amount to NOK 170 billion. The most important projects are shown below.

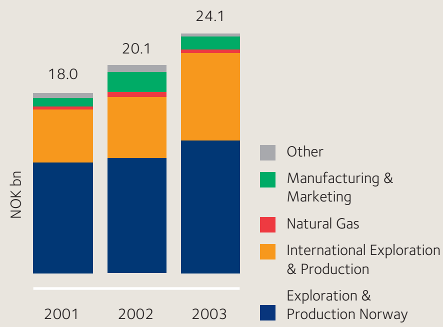
Projects under development

Field	Statoil's share	Statoil's investment[1]	Production start	Plateau production Statoil's share[2]	Lifetime
Ormen Lange[3]	10.84%	6.1	2007	48 000	30
Snøhvit	33.53%	15.2	2006	44 000	30
Kristin	46.60%	7.6	2005	105 000	12
Kvitebjørn	50.00%	4.9	2004	105 000	17
Sleipner West Alfa North	49.50%	1.4	2004	23 000	13
Tyrihans	46.81%	4.4	2007	41000	16
Skarv/Idun[3]	36.00%	5.9	2008	55 000	18

1) Estimated in NOK bn 2) Boe/day 3) Partner-operated project

On the Kvitebjørn field the 10 000-tonne platform topside was lifted onto the jacket in May 2003. The topside was built by ABB Offshore Systems in Haugesund.

INVESTMENTS PER BUSINESS AREA



International
Exploration & Production

International exploration and production operations are becoming increasingly significant in Statoil's overall business. International production is expected to rise from 89 000 barrels of oil equivalent per day in 2003 to more than 300 000 barrels per day by the end of 2007.

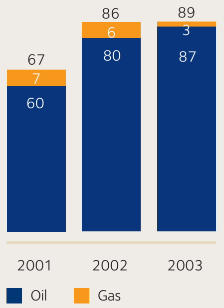
Key figures (NOK million)	2003	2002	2001
Total revenues	6,980	6,769	7,693
Income before financial items, other items, taxes and minority interest	1,702	1,086	1,291
Gross investments	8,147	5,995	5,027

An important step forward in Statoil's internationalisation process was taken in June 2003, when the group reached agreement with BP on farming into Algeria's third and fourth largest gas projects and becoming their joint operator. Statoil's interests will be 32 per cent in the In Salah project and 50 per cent in the In Amenas project. With development due to be completed for In Salah in 2004 and for In Amenas in late 2005, these two projects are expected to increase Statoil's production by 50 000 barrels of oil equivalent per day. That corresponds to no less than 62 per cent of current international output by the group. The price paid for these holdings is USD 740 million, plus costs relating to the transferred interests incurred from 1 January 2003. Statoil will invest a total of USD 1.3 billion in the two projects.

Operator in Iran

Statoil concluded a contract in the autumn of 2002 on developing phases six-eight of South Pars in the Persian Gulf, which ranks as the world's largest gas field. The group is operator for installing three offshore production platforms and pipelines to land. This project is well under way, and the first platform jacket was installed in early January 2004.

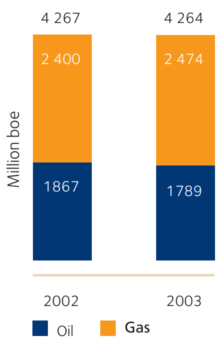
To ensure access to future projects, Statoil is pursuing considerable activities aimed at business development in Iran. The main priorities relate to converting gas to liquid fuels and studies of opportunities for improved oil recovery (IOR) for three fields in the Zagros region of southern Iran. This trio – Ahwaz, Marun and Bibi Hakimeh – are among the country's largest oil deposits and account for 40 per cent of its current production. Applying best practice from the NCS, these studies have identified substantial IOR opportunities for these old fields.



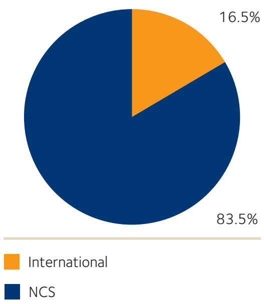
Oil and gas production outside Norway	2003	2002	2001
Oil (thousand boe per day)	87	80	60
Natural gas (thousand boe per day)	3	6	7
Total production (thousand boe per day)	89	86	67

Sincor's plant in Venezuela, where heavy crude oil is upgraded to sulphur-free crude. Statoil owns 15 per cent, and its share of production in 2003 was 20 300 barrels per day.

STATOIL'S OIL AND GAS RESERVES



DISTRIBUTION OF RESERVES IN 2003



Developing Shah Deniz

In Azerbaijan, Statoil is involved in production from and continued development of the Azeri-Chirag-Gunashli oil field and in the development of, and gas sales from, Shah Deniz.

The first development phase for Shah Deniz was approved in February 2003 on the basis of a gas sales agreement with Azerbaijan, Georgia and Turkey. A 650-kilometre pipeline will be laid from Azerbaijan through Georgia to the Turkish border. Statoil is operator for the Azerbaijan Gas Supply Company and commercial operator for the South Caucasus Pipeline company.

Early production from the Azeri-Chirag-Gunashli development yielded 10 000 barrels of oil per day for Statoil in 2003. The construction work aiming at a full development of the field is proceeding as planned. The next phase is due to be ready to come on stream in January 2005.

When the whole field is completed in 2008, the group's share of output will be about 80 000 barrels per day.

Statoil's international oil and gas production

(1 000 barrels of oil equivalent/day)

Field	2003	Statoil's share
Girassol	26.0	13.30%
Jasmim	0.2	13.33%
Xikomba	1.1	13.33%
Azeri-Chirag-Gunashli	9.7	8.56%
Sincor	20.3	15.00%
LL652	1.3	27.00%
Lufeng	3.9	75.00%
Alba	14.1	17.00%
Dunlin	2.0	28.76%
Merlin	0.1	2.35%
Schiehallion	6.1	5.88%
Caledonia	1.7	21.32%
Total oil	86.5	
Jupiter (gas)	2.5	30.00%
Total	89.1	

Two new fields on stream

The Xikomba and Jasmim fields came on stream off Angola in November 2003. Jasmim produces from a subsea installation tied back to the production ship on Girassol, where Statoil has a 13.3 per cent interest. Girassol is the group's largest international producer, providing it with an average of 26 700 barrels per day in 2003. This has risen to 28 500 daily barrels with the addition of Jasmim's production.

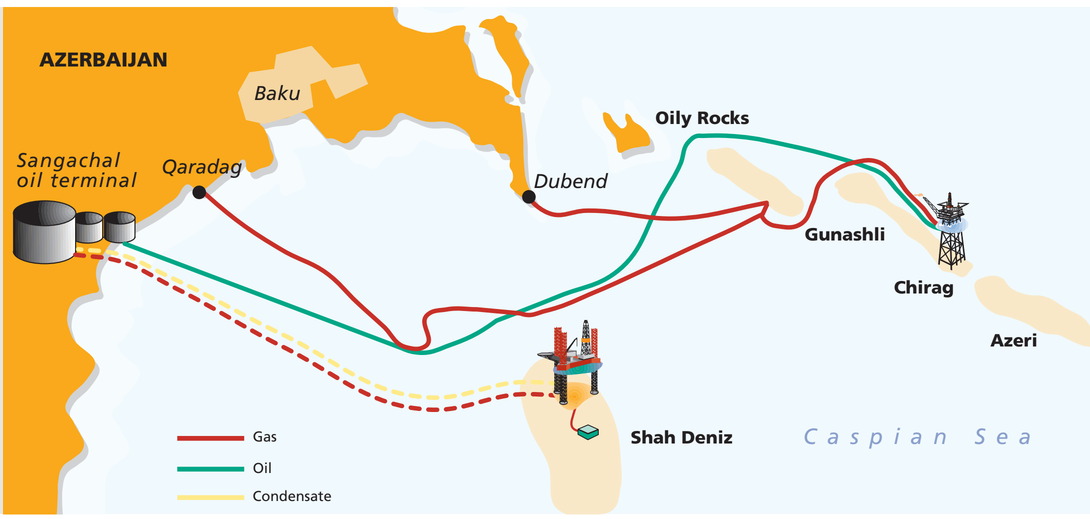
Xikomba is producing 70 000 barrels per day from a small production ship.

Dalia is the next large field with a Statoil holding under development off Angola. The project was approved in 2003, and will yield a daily production of 225 000 barrels – rather higher than Girassol. Statoil's share will be 30 000 barrels per day. Operated by Total, Dalia is due to come on stream in 2006 from a production ship.

Field development in Nigeria

Work is under way on unitising interests in the Agbami-Ekoli field off Nigeria, which straddles a deepwater block operated by Statoil and another block with ChevronTexaco as operator. Plans envisage a ship able to produce 250 000 barrels per day, and

The first development phase of the Shah Deniz gas and condensate field was approved in February 2003. Statoil has a 25.5 per cent interest, and its share of oil production from Azeri-Chirag-Gunashli is roughly 10 000 barrels per day.



possible start to production in 2007. Statoil's share of this output would be in the order of 40 000 barrels per day.

Spudding in Venezuela

Statoil plans to spud its first wildcat in the Plataforma Deltana licence off Venezuela during the second quarter of 2004. The group is committed to drilling three wells over four years on this acreage, which was awarded in February 2003.

Production from Sincor was hit by a strike in Venezuela and had to be shut down for 10 weeks early in the year with the loss of 17 per cent of planned production for 2003. Despite this, a third of the shortfall was recovered. Statoil's share of output in 2003 averaged 20 000 barrels per day.

Exploration and business development

Exploration success was achieved by Statoil off west Africa in 2003, and securing new exploration acreage in the Angolan and Nigerian sectors will be important over the next few years. Future exploration activity will also cover the Atlantic margin, the Middle East and the Caspian region.

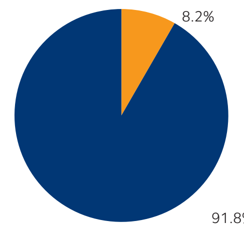
Russia is regarded as a possible new core asset, with interest focused particularly on its northern regions – including the Barents and Pechora Seas.

It has also been decided to open an office in the Kazakhstan capital, Astana, primarily to support the business area in achieving an important exploration agreement in this country.

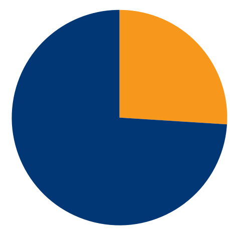
Employee development

Growing international activity means that an increasing proportion of Statoil's workforce will hail from countries other than Norway. Ensuring that such employees find their feet in the group is therefore important. Human resource policy and management must reflect this. Much work has been done by the business area on communication and personnel development, including the creation of an International Business School in 2003 to strengthen training and expertise development.

PRODUCTION IN 2003



PLANNED PRODUCTION IN 2007



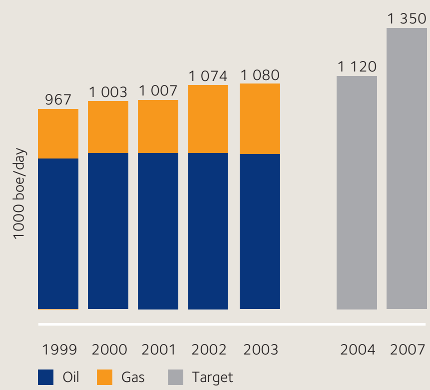
Projects under development

Field	Statoil's share	Statoil's investment[1]	Production start	Plateau production Statoil's share[2]	Lifetime
ACG Azeri	8.56%	5.5	2005	61 000	20
Kizomba A	13.33%	3.7	2004	30 000	22
Kizomba B	13.33%	3.3	2005	30 000	21
Dalia	13.33%	3.6	2006	27 000	22
Corrib[4]	36.50%	2.6	2007	20 000	19
South Pars 6, 7 and 8	Up to 40%	2.5	2006	19 000	4 [3]
In Salah	31.85%	4.1	2004	40 000	24
In Amenas	50.00%	4.5	2005	15 000	18
Shah Deniz	25.50%	4.4	2006	37 000	15

1) Estimated in NOK bn. 2) Boe/day. 3) Pay-back period. 4) Awaiting sanctioning by authorities.

A worker on the In Salah gas field in Algeria covers up his face to protect himself from the desert sand.

ANNUAL OIL AND GAS PRODUCTION



Natural Gas

There is continued growth in Statoil's sales of natural gas from the Norwegian continental shelf. In 2003 it sold 20.8 billion cubic metres (scm) of gas, an increase of 1.2 billion cubic metres, or six per cent, from the previous year. In addition the group sold 25.6 billion scm on behalf of the state's direct financial interest (SDFI). The corresponding figure for 2001 was 23.5 billion scm.

Key figures (NOK million)	2003	2002	2001
Total revenues	25,087	24,536	23,468
Income before financial items, other items, taxes and minority interest	6,350	6,428	8,039
Gross investments	456	465	671

In 2002 consumption of natural gas in Europe was 490 billion scm. Consumption rose by four per cent in 2003 according to preliminary figures from Eurostat, the EU's statistical office. The number of customers has increased in all sectors and a medium-to-high rise in gas consumption by the power sector has been noted in most European countries. The improved economic situation in 2003 has also led to higher consumption by industry. Over the past 10 years European gas consumption has risen by over 40 per cent.
The International Energy Agency (IEA) expects this to rise to 588 billion scm in 2010 and to 734 billion scm in 2020.

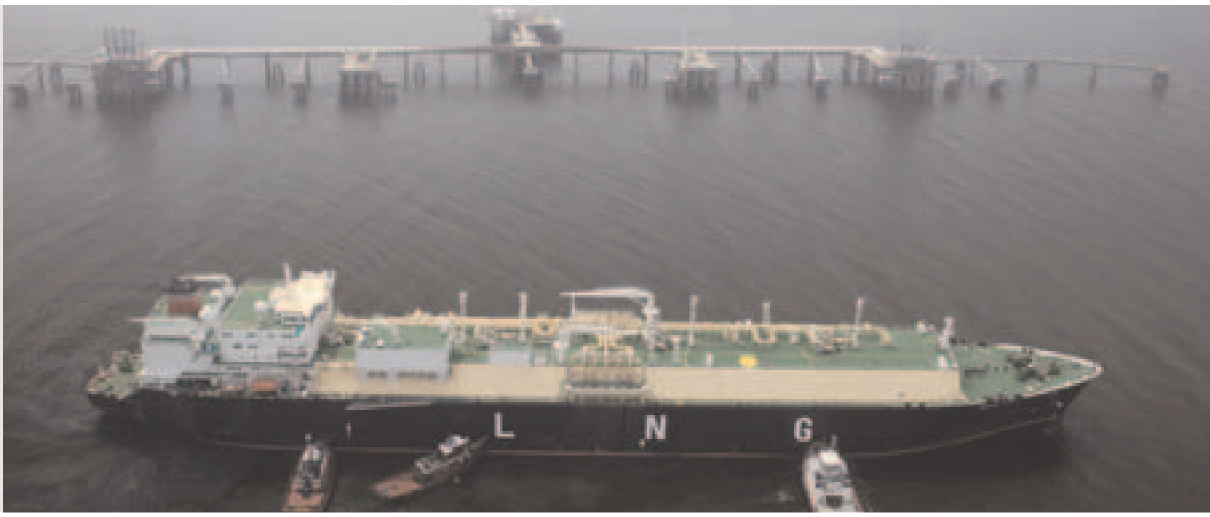
Statoil's position

Statoil enjoys a strong position in the European gas market, particularly in north-western Europe. Through its sales of equity gas and SDFI gas the group now covers nearly 10 per cent of OECD Europe's consumption. The largest volumes are placed in Germany and France, where Ruhrgas and Gaz de France are the biggest customers. The largest growth area at present is the UK, where Statoil has strengthened its position through sales to BP and Centrica as well as by its own marketing efforts. Centrica is the largest supplier of gas to the UK household market.

Statoil has signed a contract with British Gas Trading, a wholly-owned subsidiary of Centrica, to deliver two billion cubic metres of gas per year. Deliveries started on 1 October 2003 and the contract will run for three years. The group had already signed a contract with British Gas Trading for the delivery of five billion cubic metres of gas over a period of 10 years, starting in 2005.

New sales to electricity sector

In April, Statoil signed an agreement with the French electricity company Electricité de France National (EDF), to deliver one bil-



Statoil's first cargo of liquefied natural gas (LNG) was delivered to the USA in September 2003. The picture shows an LNG tanker docking at the Cove Point receiving terminal in Maryland, the entry point for Statoil's LNG shipments to the USA.

Statoil chef Charles Tjessem prepares a meal over a gas flame. In January 2003 Mr Tjessem won the unofficial world championship for master chefs in Lyons.

lion cubic metres of natural gas annually for a period of 15 years. Deliveries start on 1 October 2005. Another agreement was signed in September with EDF's subsidiary, EDF Trading Limited, for the delivery of 900 million cubic metres of gas in the period from 1 January 2004 to 1 October 2005. EDF is one of the world's largest electricity companies.

In February 2004 an agreement was signed with the Dutch energy company Essent for the sale of 6.5 billion cubic metres of natural gas over a five-year period, with deliveries starting at the end of 2004. Statoil already has gas sales agreements with several other European electricity companies. The electricity sector in general represents the greatest growth potential in respect of demand for gas in Europe.

Collaboration on gas storage facility

Statoil and Scottish and Southern Energy (SSE) have entered into an agreement in principle to set up a joint venture for the development of an underground gas storage facility at Aldbrough, near Hull, on the UK's east coast. One third of the total storage capacity of nine underground caverns will be at Statoil's disposal. According to the plan, the facility will be ready to deliver gas by the third quarter of 2007, while the construction period for the complete facility is expected to last until 2009.

Agreement on gas transportation

British and Norwegian authorities have reached agreement on the main principles of a new treaty between the two nations setting the framework conditions for new pipelines from the NCS to the UK. This will provide the basis for constructing a 1 200-kilometre pipeline for transporting gas to the UK from the Ormen Lange field in the Norwegian Sea. The pipeline will be laid via the Sleipner facilities in the North Sea to Easington on the east coast of England. Statoil shares responsibility for planning and pipelaying with the operator, Hydro. If everything goes according to plan, Statoil will be able to start exporting gas from Ormen Lange through this pipeline in the autumn of 2007. The Sleipner connection means that by the autumn of 2006 Statoil will also be able to send other gas to the UK market through this system.

Revision of gas deliveries to Poland

Statoil and the Polish Oil and Gas Company (POGC) no longer consider that they have a basis for the previously signed agreement for substantial volumes of gas to Poland. This was the last agreement to be signed with the former Norwegian Gas Negotiating Committee (GFU), but in 2001, when the Norwegian authorities decided to introduce company-based sales of gas from the NCS, the agreement with POGC was split between the original sellers.

Selling out of VNG

Statoil has sold its 5.26 per cent holding in the German gas company Verbundnetz Gas (VNG) to EWE AG, Germany. VNG is a regional gas company operating mainly in Germany's eastern states. Statoil acquired its stake in the company in 1991. German authorities wanted to privatise VNG as part of the process of selling out companies previously owned by the state in the former German Democratic Republic.

New gas pipeline and terminal company

With effect from 1 January 2003 Statoil coordinated its ownership interests in the biggest Norwegian gas pipelines and terminals in the Gassled partnership. Statoil has a holding of 21 per cent and is technical operator for most of the Gassled pipelines and terminals. As of 1 February 2004 the Kollsnes

The market for imported gas to the USA will expand in coming years, and much of the gas will be used to produce electricity.

plant, previously owned by Troll, will be incorporated into Gassled. This will not change the holdings in the partnership.

Kårstø expanding

A special development project for processing gas from the Statoil-operated Mikkel field in the Norwegian Sea got off to a flying start on 1 October 2003. The project was completed in a shorter time than planned, and cost 20 per cent less than budgeted for. Furthermore, Gassled and Etanor DA decided to invest NOK 5.74 billion, to permit the landing and processing of gas from the Statoil-operated Kristin field in the Norwegian Sea. Etanor DA specialises in the separation and sale of ethane to Borealis' petrochemical plants in Norway and Sweden.

These two projects will mean an increase in capacity of more than 40 per cent at the Kårstø gas processing plant. Statoil is technical service provider and will implement the development on behalf of the operator, Gassco. The plant's ethane-recovery capacity will also be expanded by more than 50 per cent.

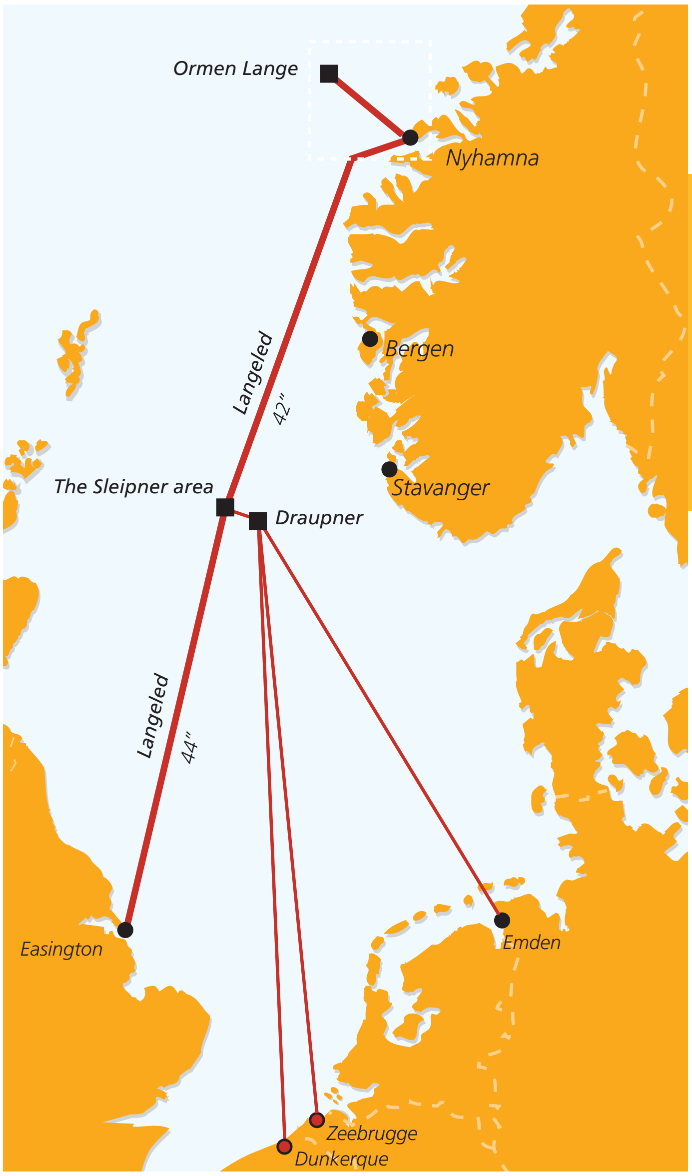
LNG to the USA

Statoil has secured access to the US market for liquefied natural gas (LNG) via the Cove Point terminal in the state of Maryland. A substantial increase in LNG exports to the USA is expected in the years ahead. From 2006 Statoil will be able to export LNG to the USA from the Snøhvit field. Snøhvit will supply the US market with up to 2.4 billion cubic metres annually for a period of 17 years, from 2006 to 2023. Pending the gas exports from Snøhvit LNG, Statoil has secured deliveries from the Algerian company Sonatrach and the Belgian company Tractebel. Statoil made its first delivery of LNG to the Cove Point terminal in September 2003. The group has signed a letter of intent which will secure access to extra capacity at this terminal for a 20-year period.

International gas

Statoil's participation in gas activities outside Europe has been organised by the International Exploration & Production business area through the international gas and power (IGAS) business cluster. On 1 January 2004 this business cluster was transferred to the Natural Gas business area. Functions in IGAS relate to the value chain for LNG, gas transport and sale from the Shah Deniz field off Azerbaijan and the downstream activities in Turkey.

www.statoil.com/kep2005



The gas trunkline from Ormen Lange will be laid via Sleipner to the UK. This decision strengthens Sleipner's position as a gas hub in the North Sea. Gas from other fields can be mixed with the gas from Ormen Lange, and gas from this field can be delivered to other markets.

www.statoil.com/pipelines

Erik Kjos-Hanssen, head of Statoil operations in the UK, sees new opportunities for gas sales with a new pipeline to the UK market.

Manufacturing & Marketing

Statoil is one of the world's largest net sellers of crude oil and it traded an average of 2.3 million barrels per day in 2003. The group's entitlement oil accounted for 32 per cent of this total, crude purchased from the Norwegian state for 41 per cent and oil acquired from third parties for 27 per cent. Statoil's most important oil customers are its own refining business and large oil companies in Scandinavia, Europe, the USA and Asia.

Key figures (NOK million)	2003	2002	2001
Total revenues	218,642	211,152	203,387
Income before financial items, other items, taxes and minority interest	3,555	1,637	4,480
Gross investments	1,546	1,771	811

www.statoil.com/marketing

The international market for crude oil was affected in 2003 by high prices measured in USD, reflecting production discipline in the Opec countries, uncertainties over Iraqi production and the loss of volumes from Venezuela. Demand also expanded much faster than in previous years, with growth particularly high in China. Stocks were low, particularly in the USA. Russian production continued to increase substantially, while North Sea output declined.

High oil prices

The per-barrel price of Brent Blend reference crude fluctuated between USD 34.7 immediately before the Iraq war and USD 22.9 immediately afterwards. It averaged USD 28.8 over the year, as against USD 25 in 2002. Quoted prices for Brent Blend in 2003 were again tied to prices for Oseberg and Forties crude, improving the liquidity underlying this pricing and providing more representative pricing than was the case before this arrangement began in 2002.

Refining margins developed well in 2003 compared with the year before. They were driven up early in the year by unrest in Venezuela, fears of conflict in Iraq and the actual war when it came. Statoil refined about a third of its entitlement oil in 2003 and produced 14 million tonnes of products. The principal markets for refined products are the Scandinavian countries, the Baltic region, the rest of north-western Europe and North America. Two-thirds of Statoil's refined products were sold through its own marketing system.

Refinery investment

Just under NOK 1 billion was invested at Mongstad in a new petrol desulphurisation plant. This became operational in the first quarter of 2003, in good time before new EU standards

Statoil's road tankers covered a total distance of 44 million kilometres in 2003 – the equivalent of driving from Oslo to Rome roughly 18 000 times.

Statoil is the first chain of service stations in Europe to offer wireless internet access at its forecourts. At the end of 2003 this service was available at 150 stations in Norway and all 44 stations in Estonia.

come into force on 1 January 2005. Statoil invested in equipment at Kalundborg to produce low-sulphur diesel oil which meets the same standards. In the first quarter of 2003, this refinery also started using a new facility which allows it to produce environmental class 1 diesel oil for the Swedish market. Further investments have been sanctioned to increase capacity for low-sulphur and environment class 1 diesel from the second quarter of 2005.

Methanol production up

Annual output from the methanol plant at Tjeldbergodden increased by 100 000 tonnes in 2000-03 through improved regularity and capacity increases. Unit costs were cut by 26 per cent over the same period. This facility ranks as the largest, most modern and most efficient methanol producer in Europe. In 2003 Statoil sat a new production record, producing 915 518 tonnes of methanol. Statoil is a major player in the European market for this commodity, and its production corresponds to 15 per cent of Europe's methanol consumption. The continent is a net importer of methanol, which

Improvement for Borealis in 2003

The Borealis petrochemicals group owned 50 per cent by Statoil was affected by weak margins in 2003. These reflected both high feedstock prices and pressure on prices for polyethylene and polypropylene. Europe's generally low rate of economic growth led to weak growth in demand for these polyolefins. However, an improvement was noted during the year, with the second half considerably better than the first. Overall results increased marginally from 2002, but remained unsatisfactory.

More feedstock from Statoil

Statoil reached agreement with Borealis in 2003 on increasing sales of ethane to the latter's Norwegian operations. Borealis intends to pursue an extensive improvement programme to expand production capacity on the basis of these extra feedstock supplies. It is also pursuing an extensive improvement programme in Austria which involves building a new polyethylene plant, based on its proprietary Borstar polyolefin technology, and shutting down two old production lines. A good year was experienced in the United Arab Emirates, where Borealis owns 40 per cent of the Borouge petrochemicals complex, with production above design capacity and a good financial result. Production capacity for polyethylene at this complex is due to be expanded by almost 30 per cent during 2004.

www.borealisgroup.com

In 2003 the methanol plant at Tjeldbergodden set a production record of over 900 000 tonnes. This represents 15 per cent of all methanol consumption in Europe.

makes the Tjeldbergodden plant well positioned in this market.

Total supplier of energy
Statoil sells heating oils, lubricants, marine and aviation fuels and liquefied petroleum gases (LPG) and is responsible for selling natural gas in Scandinavia. With more than 300 000 customers in the consumer and industrial segments, the group has a 25 per cent share of the market. Statoil has about 40 per cent of the LPG market.

The range of energy products is being expanded, with a special focus on gas and renewables. In Denmark, Statoil acquired EcoNordic in 2003 to become the largest player for wood pellets with 40 per cent of the market.

More than 2 000 service stations
A network of more than 2 000 service stations makes Statoil one of the leading players in Scandinavia, the Baltic states, Poland and Ireland. The group also has forecourts in the Murmansk area of Russia. Sales of petrol and diesel oil totalled 4.7 billion litres in 2003. Retailing operations in Scandinavia are organised through the Statoil Detaljhandel Skandinavia (SDS) company owned 50-50 with ICA. ICA and Statoil have signed a letter of intent concerning the sale of ICA's holding to Statoil.

The acquisition of Shell's service stations in Estonia, Latvia and Lithuania has made Statoil the leading player in the Baltic states (see page 6). Development of the station network in Poland will continue to be pursued with full vigour. Acquiring Preem in 2003 means that Statoil now has more than 200 Polish forecourts.

Strengthened HSE commitment
Manufacturing & Marketing has strengthened its commitment to avoiding injuries to people and harm to the environment. Results for total recordable injuries, lost-time injuries and serious incidents showed a positive trend in 2003.

In addition to the group's overall management system, local management systems have been implemented in parts of the business where they are required. Several entities have been certified to the ISO 9001:2000 and 14001:1996 standards for quality assurance systems and environmental management systems respectively. Some entities have implemented both standards.

Women currently occupy 27 per cent of the business area's senior management positions.

Expertise enhancement
Systematic long-term measures for enhancing employee expertise are pursued by the various business units, in close cooperation with other entities in the group. In addition, commercially-and-technically-tailored educational programmes have been established for employees. The O&S Business School is a case in point. Manufacturing & Marketing pursues planned training and rotation of managers, both within and outside the business area. Collaboration with union officials is good and constructive.

Brand
Statoil has developed a strong brand and pursues a clear and consistent use of this trademark in its marketing operations. Analyses show that the Statoil brand is well entrenched. Statoil is perceived as serious, competent and professional.

Statoil	Market share (petrol)	Market position	Number of stations
Norway	26%	1	496
Sweden	25%	1	583
Denmark	14%	3	304
Ireland	20%	1	237
Poland	5%	3	207
Lithuania	18%	2	57
Latvia	23%	1	52
Estonia	30%	1	47

Statoil also has six service stations in Murmansk, Russia, and 16 on the Faroe Islands.

Technology

The Technology entity in Statoil consists of three main areas:

- the technical staff function, which is responsible for best practice and decision-making processes.
- research and technology, responsible for delivering research products and providing specialist services.
- industrial development, responsible for industrial and commercial development of technology.

In 2003, efforts in the Technology entity were concentrated on delivering good results relating to the requirements outlined in Statoil's technology strategy. The strategy comprises two main elements. One of these outlines the most important business challenges to be solved with the aid of research and technology development. The other specifies the most important areas of technology to be focused on to solve the business challenges.

The strategy also provides clear financing and implementation guidelines. Efficiency will be increased through greater collaboration with external players, new models of collaboration and organisation into multidisciplinary projects.

Statoil's research work in 2003 cost NOK 1 billion.

Several benchmarking exercises between Statoil and leading international oil companies were conducted in 2003. According to Independent Project Analysis Inc, an independent survey company, Statoil is among the leaders in the development of offshore oil and gas reserves. Statoil is the company to make the most frequent use of new technology to find profitable development solutions.

Good results in our own technology and expertise development, in close collaboration with suppliers and research organisations, help us to achieve these good results in comparison with our competitors.

In 2003 Statoil achieved good results in a number of areas.

A new method has been developed for use of electromagnetic waves to obtain information about possible underground oil reserves. The Electromagnetic GeoServices (EMGS) subsidiary was formed to exploit this method. EMGS was awarded the World Oil Award for the best exploration solution. (see article on page 12).

New world-leading technology has been developed to obtain the necessary data for modelling oil recovery from sandstone reservoirs. Better data, and consequently greater knowledge of the reservoir, have led to improved recovery. The technology provides a better basis for decisions concerning recovery methods and reservoir management. Transferring this method

Statoil has developed a special technology for converting gas to diesel. Franz Marx opens the gate to the testing facility, where the technology will now be tested over an 18-month period. The plant was built in Mossel Bay, South Africa, in cooperation with South African state oil company PetroSA.

Researcher Bernd Schmid is a staff engineer in oil refining. His job involves testing materials at Statoil's Rotvoll research centre in Trondheim.

and applying it to carbon reservoirs will mean better exploitation of the carbon fields which contain most of the world's remaining resources.

Sophisticated data communication

Statoil's research centre and several operating entities have been working together to develop new technology based on an "intelligent field" concept. Previously real-time data transfer was by satellite. Today many fields use sophisticated data communication via fibreoptic cables. This allows for more advanced real-time interaction between data, expertise and work processes offshore and onshore. Statoil will utilise this in the Onshore Support Centre, the group's first facility for real-time operational support. This centre is at the forefront as regards the implementation of new and existing technology. Given an optimum location of wells, this will enable an increase in production of 19 million barrels of oil, worth NOK 3 billion. A ten per cent increase in earnings has already been demonstrated in one well.

www.statoil.com/DARTandOSC

Water treatment technology

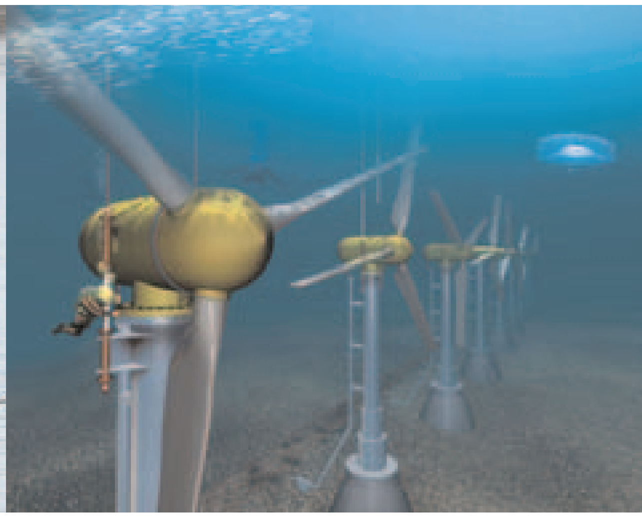
The oil companies face major challenges relating to the discharge of produced water into the sea from the production platforms. Great efforts have therefore been put into developing new technology to reduce the environmental load and the cost of dealing with produced water. Condensate (light oil) has proven an effective cleanser of produced water, and is the central element in the patented CTour technology, which uses condensate from own production to remove environmentally-harmful hydrocarbons from produced water. The technology will be installed on all the Statfjord fields by 2005 to meet the regulatory requirements for marine discharges.

From gas to diesel

Transportation by pipeline is normally the best option for gas fields in the proximity of a commercial market. If it has to be transported over long distances the cooling down of the gas to a liquid form (LNG) has traditionally been the only commercially viable solution. Gas-to-liquid (GTL), a high-value diesel product, is now beginning to emerge as an interesting alternative. There is an almost unlimited fuel market for GTL. Previously, the disadvantage of GTL was its high cost level, but recent developments have gone a long way to ironing out the cost difference in relation to LNG. Statoil's GTL research started around 1985. A plant is currently under construction in Mossel Bay in South Africa to demonstrate that the GTL technology has reached a commercial stage. This project is being conducted in collaboration with South African state oil company PetroSA.

In 2002 Statoil set up a business development unit for new energy, whose remit was to develop business solutions leading to more sustainable energy production and increased use of clean energy carriers. New energy works in the areas of renewable energy, more efficient energy, handling of carbon dioxide and hydrogen. In concrete terms, the market is being developed for small-scale power and heat production, wood pellets and the use of carbon dioxide for improved oil recovery.

The world's first tidal power station opened in the Kval Sound south of Hammerfest in November 2003. The pictures show one of the water turbines being installed, and an illustration of the turbine park. Statoil has a 46 per cent interest and has also contributed to the project in the form of project management and subsea technology.



New well technology boosts earnings

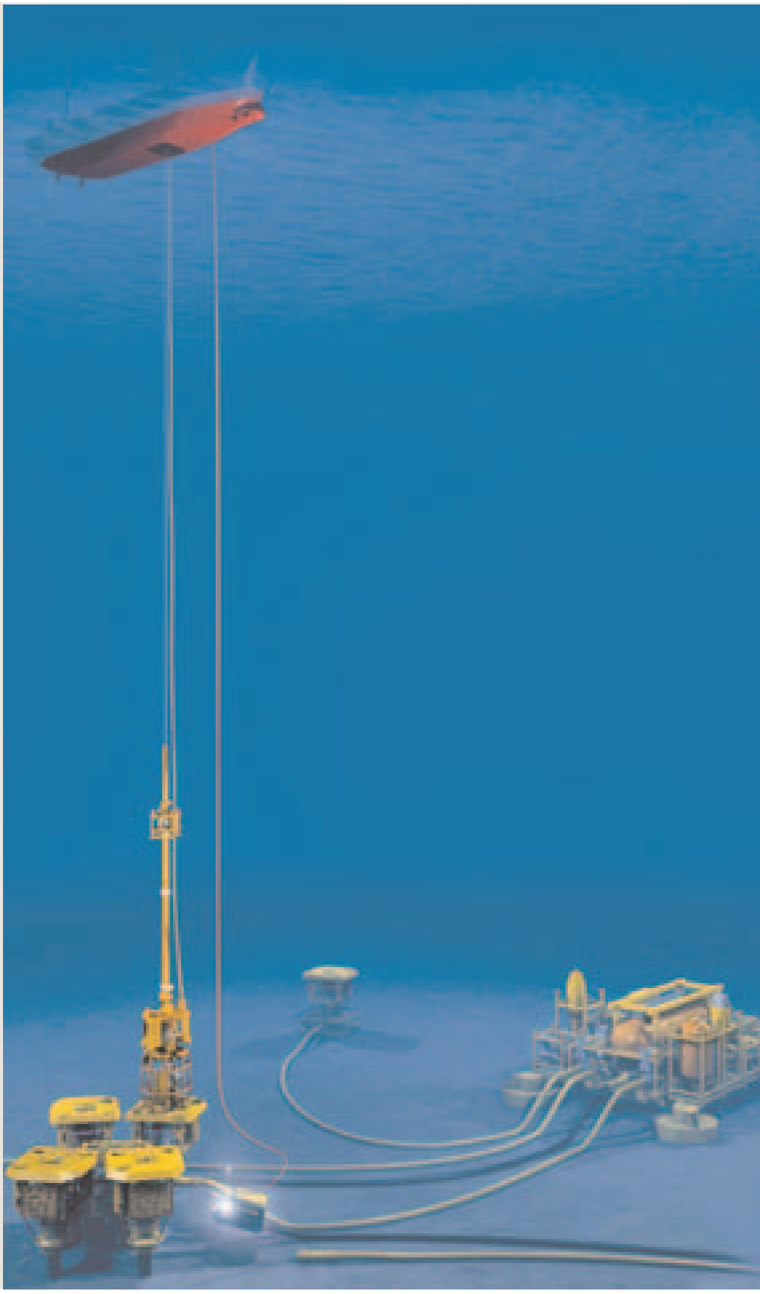
Statoil has developed a new and pioneering technology for light well intervention in subsea wells that is expected to reduce the costs of well maintenance to a third of the present level. The new technology will reduce operating costs, extend the life of, and increase recovery from, the subsea fields.

Statoil believes that the new technology will give substantial gains in addition to lower maintenance costs. It also believes that it will be possible to increase the recovery factor for subsea fields from today's level of 43 per cent to 55 per cent. In terms of increased oil production, this means a recovery of approximately one billion extra barrels of oil from the NCS as a whole. Based on the rate of exchange and prices at 31 December 2003, the additional value will be approximately NOK 200 billion.

Virtually nowhere in the world are there as many subsea wells as on the NCS. However, the problem with these wells is that there is no direct access to them, as there is from a platform. To date, maintenance work has involved hiring in costly floating rigs. The extra quantities of oil that can be extracted are often not worth the expense of the maintenance work or the efforts required to increase recovery.

No need for rigs

The new technology allows downhole tools to be deployed under pressure without the need for a floating rig. The technology has been developed by Statoil, in collaboration with Prosafe and FMC Kongsberg Subsea.



Together with Prosafe and FMC Kongsberg Subsea, Statoil has developed a new technology for work on subsea production wells. The technology enables work to be carried out on the wells without the use of floating rigs. Maintenance costs will be reduced to a third, and the recovery factor should improve considerably.

Statoil has patented a total of 415 different inventions that are active today. In 2003 it applied for patents for 36 of its inventions. The corresponding figures for 2002 and 2001 were 45 and 55, respectively.

People and society

Integrity, honesty and reliability are central to Statoil's values and the foundation for building a good reputation. The latter is important for the group's ability to realise its commercial ambitions. The basis for this reputation is laid through the attitudes and behaviour of the individual employee. That makes the way the business is conducted as important as the commercial results achieved.

Develop corporate culture

The development of a strong, collective corporate culture, rooted in clear values, is dependent on managers demonstrating a correspondence between word and deed. Statoil's base values and its requirement for uniform practice form the cornerstones of its management training programmes. During 2003, 40 of the group's most senior management teams and more than 300 other managers completed the top management programme established in 2002.

An introductory programme was developed in 2003 which all externally-recruited managers and other key personnel must take soon after joining Statoil.

During 2003, the group implemented a training programme on labour standards for externally-recruited managers. It is also completing work on a governing document which deals with labour relations in mergers and acquisitions.

Expertise

The Statoil School of Business and Technology was established in 2002 with 17 decentralised educational units. It is intended to help strengthen the group as a learning organisation, where changes in commercial challenges determine the expertise required. The link between commercial needs and measures to develop the expertise of individual employees is ensured through Statoil's management and personnel development system. The performance evaluation and planning (PEP) discussion, which defines personal development measures, occupies a central place here. Ninety-two per cent of employees had a PEP discussion in 2003.

In-house expertise development at Statoil comprises a large number of different measures. In 2003, these involved 75 000 student days in traditional courses and 8 000 in the form of e-learning programmes. These figures do not include the IT step 2 programme, which employees pursued in their free time.

Statoil ranks as one of Norway's largest companies for apprentice training. It recruited 111 apprentices on two-year contracts in 2003. The two-year corporate trainee programme for newly-qualified graduates continued in 2003, and 2 600 applications were received for 23 positions.

In 2003 Statoil was assessed as the most attractive employer by final-year Norwegian students of technology and economics. The group was also rated as the most attractive employer in a "Young professionals" survey of 2 000

At 31 December 2003 Statoil had 19 326 employees, an increase of 2 211 from the previous year. Of Statoil's employees, 7 491 (39 per cent) work outside Norway. This represents an increase of 1 590 during 2003.

Geographical distribution of employees (at 31 December 2003)

Norway	11 835	Lithuania	585	Faroe Islands	126
Poland	2 367	Latvia	593	Belgium	43
Ireland	1 287	Estonia	618	Germany	45
Denmark	762	UK	162	Asia	152
Sweden	500	Russia	124	America	79
				Africa	48

Linda Kolstø, a 20-year-old apprentice crane operator from Karmøy, is pictured here in a crane cabin on the Gullfaks C platform. Statoil takes on a large number of apprentices each year – 111 joined the group in 2003.

newly-qualified Norwegian university graduates.

New learning portal
A new web-based learning portal accessible to all employees was introduced in 2003 to help make training measures more effective through standardisation, reuse and a clear-out of parallel and overlapping programmes. The portal provides information about the various educational units in the Statoil School and the expertise development programmes available. Employees can sign up for new and traditional courses, order programmes based on CD-Roms, and take web-based courses. The system registers courses completed and updates the individual's CV automatically.

Statoil is committed to a diverse workforce in terms of gender, age and cultural background. Studies have shown that such diversity provides a better working environment and improves an organisation's ability to develop.

Women in the workforce
Women account for more than 30 per cent of Statoil's current workforce. An important future challenge will be to increase the proportion of females on the specialist career ladder.

On an overall basis, the 2005 target of women occupying 20 per cent of top managerial posts was reached in 2003, but some entities still have a way to go. The target has therefore been left standing, with attention focused on those entities which have yet to reach it.

Employees in the parent company, Statoil ASA, are remunerated in accordance with their position and competence. Weight is given to results achieved when awarding individual pay increases. In the annual pay awards for individual employees, Statoil also applies the principle of equal pay for equal work. Employees on maternity leave maintain their salary grade during their leave of absence.

As a general rule, all permanent parent company employees are employed on a full-time basis. The company can grant a temporary reduction in working hours on health, social or other weighty welfare grounds when this is possible without causing particular problems for the business. Women account for the majority of those applying to reduce their working hours.

Occupational health and the working environment
Results from the working environment survey conducted in the autumn of 2003 indicate that Statoil generally has a working environment and an organisation with many positive qualities. Despite negative media coverage because of the Horton affair, the chief executive's resignation and challenges in the international arena, the survey shows progress on questions relating to job satisfaction and motivation.

As in 2002, 13 per cent of respondents felt they had health problems which could derive from their work. An analysis shows a clear relationship between heavy pressure of work and experience of health difficulties. Women also suffered more from such problems than men. To some extent, health problems among offshore personnel also increase with age.

Local care work in Statoil has been strengthened and systematised since the parent company joined Norway's inclusive workplace (IA) programme in 2002. Great emphasis is given to the integrated place of IA efforts in everyday work and Statoil has achieved good results. That part of the group covered by the IA agreement with Norway's national insurance service can report a decline in such absence from 4.1 per cent in 2002 to 3.5 per cent in 2003.

A computer tool for managing chemicals was adopted in 2003 for operations on the NCS. Risk assessments relating to health as well as to the working and natural environments are carried out before a chemical is purchased, and the group has substituted and reduced the number of chemicals used.

Statoil pursues production around the clock, and night-shift working can cause considerable

Women in Statoil 2003
32% of the total workforce
23% in managerial positions
30% of parent company apprentices
28% of new parent company recruits

www.statoil.com/hse

The safe behaviour programme is an important measure in achieving long-lasting safety improvement on the NCS. A total of 18 000 Statoil employees and contractor personnel are taking part in seminars and follow-up work at their individual workplaces.

reductions in the amount and quality of sleep. These disruptions are burdensome and increase the risk of suffering a range of health problems and incidents.

Strengthened commitment to improving safety

Statoil's goal is zero injuries, accidents and losses, and ensuring that its business is conducted without any hazardous incidents.

The group suffered two fatal accidents in 2003, which both involved contractor personnel. Two Statoil employees and four contractor personnel died in 2002. The number of total recordable injuries per million working hours was six for 2003, unchanged from 2002.

Following a review of safety work in Statoil, America's DuPont Safety Resources identified a number of improvement measures which are now being pursued. The aim is to improve attitudes and behaviour in all parts of the organisation in order to avoid injuries and accidents.

The safe behaviour programme, initiated by the Exploration & Production Norway (UPN) business area, embraces 18 000 Statoil employees and contractor personnel, and represents the group's biggest commitment so far to developing a strong HSE culture.

This programme builds on experience gained with the open safety dialogue tool, which has been used since 2002 to reduce risky behaviour at work. The people responsible for this measure were awarded the chief executive's HSE prize for 2003.

Robberies and road tanker accidents account for a large proportion of serious incidents in the Manufacturing & Marketing business area. Efforts to avoid robberies and attempted robberies, and to promote defensive driving, represent important priorities in the distribution chain. Statoil suffered 82 robberies or attempted robberies in 2003, as against 110 in 2002.

Social commitment

Transparency is essential if society is to be able to assess Statoil's contribution to social development in the countries in which it operates. This year's sustainability report, *Transparency and trust*, addresses this challenge in detail. The group's most important contribution to society is measured as value creation – principally through the impact of its investments on jobs, procurement of goods and services, transfer of technology and expertise, infrastructure development and tax revenues.

Statoil also seeks to contribute to social development through social investment projects. These are intended to contribute to local capacity building in education, health and human rights, and the funds for this are channelled through non-governmental organisations pursuing local development work. In its international operations Statoil has spent NOK 33 million on social development projects in 2003. Of that amount, NOK 22 million has been provided to projects selected by the group. The rest has been allocated through the field operators.

Work on human rights

In 2003 Statoil formulated special guidelines for relations with indigenous peoples in its operations. These guidelines clarify the principles on how we are to behave towards indigenous peoples and their rights, and accord with relevant international conventions.

In Nigeria the group has extended its collaboration with three human rights organisations which started in 2002, and the long-term village development project in Akassa in the Niger Delta continues. In Venezuela the judge training programme run by the United Nations Development Programme (UNDP) and Amnesty International Venezuela is entering its third phase, and includes training in human rights. All the schemes supported by the group accord with the UN's principles for development work. In 2003 Statoil extended its collaboration agreements with the Norwegian Refugee Council, the UN High Commissioner for Refugees (UNHCR), Amnesty International and the Norwegian Red Cross.

Statoil has been successful with its safety work on the Lufeng field in the South China Sea. No injuries were recorded on the *Munin* production ship in 2003. Lufeng has been operated by Statoil since 1997.

The environment

Statoil's objective is to operate without harm to people or the environment. Its environmental ambition is to be among the front runners in pursuing its business in an acceptable manner. The group works purposefully and continuously to improve its performance, and will contribute to developing alternative energy sources and bearers.

Emissions to the air are largely regulated by international agreements. The Kyoto protocol on reducing greenhouse gas emissions and the Gothenburg protocol, involving commitments 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. The oil content in produced water released to the sea must not exceed 30 milligrams per litre from 2006, when the total annual volume of oil discharged must be 15 per cent lower than in 2000.

Stricter standards

Norwegian government regulations require oil and gas installations to have "zero discharges" by 31 December 2005. Defined in White Paper 25 of 2002-03, this concept involves ceasing or significantly cutting the release of defined 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 also applies to operations in Norway, and 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

Producing oil and gas involves emissions and discharges to the natural environment. Their level is influenced by each field's reservoir conditions and age as well as the design, technology and operational regularity of its installations. Emissions relating to oil and gas processing depend on the type of feedstock involved and the products being produced.

Emissions to the air include carbon dioxide, methane, VOC, and sulphur and nitrogen oxides. These contribute to the greenhouse effect, the formation of ground level ozone and acid precipitation. 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 released by the group.

Increased water production

Discharges to the sea embrace oil, organic compounds and chemicals,

and derive principally from produced 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 bio accumulation.

Operations on the NCS are the biggest source of Statoil's discharges to the sea. The volume of produced water released is rising because several of the large oil 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.

Environment-friendlier production

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 focused measures on existing and future installations.

Discharges to the sea attracted particular attention in 2003. Work was devoted to developing new technological solutions and to phasing out chemicals which represent a possible hazard to the environment. Statoil is well on its way to meeting government requirements for zero harmful discharges from its oil and gas fields by 2005.

Managing chemicals was an important priority area in 2003. A common database for material safety data sheets has been established with other operator companies on the NCS, and updated product data sheets have been made easily accessible over the internet. Apart from product details, the database provides information on where the chemicals are in use.

Chemicals released from Statoil's offshore operations declined from 63 100 tonnes in 2002 to 59 500 tonnes in 2003. Of chemicals used in 2003, 87 per cent (2002: 89 per cent) posed little or no environmental risk while 13 per cent (2002: 10 per cent) had acceptable environmental properties. Only 0.6 per cent (unchanged from 2002) are environmentally questionable, and efforts are being made to phase these 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 by 2010, compared with the amount which would be emitted without special measures. At 31 December 2003, the group had met 23 per cent of the 2010 target.

Statoil supports the Kyoto protocol as the first step towards a more far-reaching international agreement and the introduction of emission trading as an instrument for limiting the release of greenhouse gases in a cost-effective manner. The group is making the necessary preparations for utilising the Kyoto mechanisms and for participating in emission trading in order to meet future requirements for lower greenhouse gas emissions. Through its USD 10 million investment in the World Bank's prototype carbon fund (PCF), it is involved in roughly 30 projects which will yield substantial emission reductions.

Biological diversity

Preserving biological diversity is crucial for sustainable development. Statoil's goal is to protect such diversity by conserving natural ecosystems, avoiding the introduction of alien species and seeking not to affect the level of plant and animal populations through its operations.

In 2003 some 100 million tonnes of cargo were transported by tanker from fields, terminals and refineries to customers all over the world. Safety and quality requirements pertaining to vessels are strict. This picture is from Mongstad.

Statoil collaborates over a range of activities with other companies and environmental organisations to promote protection of biodiversity by the oil and gas industry. These include the energy and biodiversity initiative (EBI), the International Petroleum Industry Environmental Conservation Association/International Association of Oil & Gas Producers (IPIECA/OGP) working group and the Proteus programme of the UN Environmental Programme's World Conservation Monitoring Centre (UNEP - WCMC). The group works to integrate biodiversity in its management systems and governing documents. Specific activities relating to biodiversity will be incorporated in exploration and development projects.

Strict transport requirements
About 100 million tonnes of hydrocarbons were shipped by tanker from fields, terminals and refineries to customers world wide, with northern Europe as the main recipient. Statoil's requirements for tanker quality exceed national and international standards. Tanker operations in 2003 caused no significant oil or chemical spills.

Road tankers belonging to Statoil or hired by the group covered about 44 million kilometres in 2003 delivering products to service stations and customers. Carbon dioxide emissions relating to these consignments are estimated at some 45 800 tonnes, or roughly 0.5 per cent of the total carbon dioxide 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 oils with good environmental properties.

Products better adapted to the environment
Statoil produces and sells a number of products, such as crude oil, natural gas, automotive fuels, heating oils, methanol, wood pellets, chemicals, lubricating oils and electricity. Its objective is for these commodities to rank among the best for technical user qualities and environmental properties.

Burning oil and gas products can have a negative impact on the environment 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.

The group has invested in a new desulphurisation plant at its Mongstad refinery, and in equipment for producing low-sulphur diesel at the Kalundborg facility.

Biofuels reduce emissions
Using automotive biofuels cuts greenhouse gas emissions. Such fuels are sold by Statoil on the Swedish market in the form of petrol containing bioethanol and diesel with rapeseed oil. The group has also introduced a more environment-friendly heating oil in Scandinavia, with a reduced sulphur content and additives which keep furnaces clean throughout the year. This cuts consumption and reduces emissions.

Statoil is steadily increasing deliveries of renewable energy through the production and sale of wood pellets made from forest industry waste. This product provides an alternative to heating oil, natural gas and electricity.

Investments and costs
A provision of NOK 16.5 billion was made at 31 December 2003 to meet the future cost of shutting down and removing oil and gas production facilities. NOK 1.2 billion was charged against income.

Reusing offshore installations and equipment offers financial and environmental gains. In 2003, Statoil earned NOK 30 million from the sale of surplus materials.

Annual carbon dioxide tax paid for 2003 on emissions from Statoil operated installations on the NCS totalled NOK 768 million.

On the Kvitebjørn field oily water and drill cuttings are to be injected into a subsurface well. Safety manager Ellinor Nesse shows where the well is to be drilled.

HSE accounting for 2003

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. Statoil's management system relating to corporate governance is certified to the international ISO 9001 standard. In addition, several entities have been certified in accordance with this standard as well as the environmental standard ISO 14001 (an overview of certified units can be found at www.statoil.com/hse).

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 compiled 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 financial results. These results are posted to the group's intranet and its internet site. In 2003 Statoil launched an HSE site (www.statoil.com/hse) where quarterly HSE statistics are compiled and made more easily accessible.

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 their technical operation.

All of the group's main activities are included in the HSE accounting section. 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 two fatal accidents in 2003:

On 24 March a contractor employee died as a result of a working accident on board the *Saipem 7000* crane barge in the North Sea.

On 25 September a contractor employee died in an accident at the Iranian yard which is building the jackets for the gas platforms on South Pars phases six-eight.

Both accidents have been investigated, their causes recorded and improvement measures initiated.

The HSE accounting shows the development of the performance indicators over the past five years. Use of resources, emissions and waste volumes for Statoil's largest land-based plants and operations on the NCS are shown in separate environmental overviews. See also the information on health, safety and the environment in the review of Statoil's operations (pages 38-43) and the directors' report.

More than 92 million hours worked in 2003 (including contractors) form the basis for the HSE accounting. This is an increase of 13 million hours from 2002. The rise is mainly due to new operatorship for the Snorre, Tordis, Vigdis and Visund fields on the NCS, as well as several development projects. Contractors handle a large proportion of the assignments for which Statoil is responsible as operator or principal enterprise.

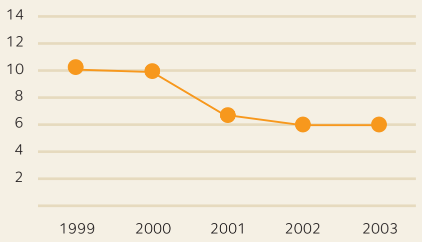
Overall, the total recordable injury frequency (covering Statoil employees and contractors) is unchanged compared with 2002, but the lost-time injury frequency (injuries leading to absence from work) and serious incident frequency both show an improvement in 2003 compared with 2002.

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

Fines totalling NOK 1.2 million were imposed on Statoil in 2003 for HSE-related matters. Of this amount, a fine of NOK 1.0 million was imposed following a fatal accident on a drilling rig in the North Sea in April 2002, when a contractor employee lost his life.

Statoil's performance indicators for HSE

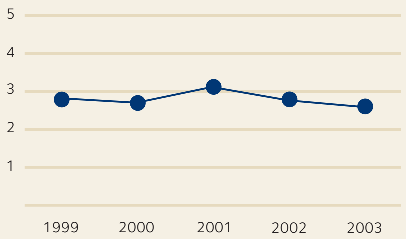
TOTAL RECORDABLE INJURY FREQUENCY



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) is 6.0 in 2003, the same as in 2002. There has been an improvement for Statoil employees, from 4.2 in 2002 to 3.7 in 2003, while the result for our contractors shows a negative trend, from 7.6 in 2002 to 7.9 in 2003.

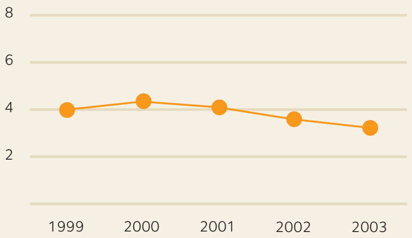
LOST-TIME INJURY FREQUENCY



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) has improved from 2.8 in 2002 to 2.6 in 2003. This frequency has been measured since 1987 and it has never been as low as the 2003 level. There has been an improvement for Statoil employees, from 2.4 in 2002 to 1.8 in 2003. The result for our contractors shows a negative trend, from 3.1 in 2002 to 3.3 in 2003.

SERIOUS INCIDENT FREQUENCY

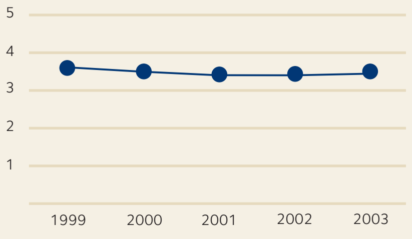


Definition: The number of incidents of a very serious nature per million working hours (1).

Developments: The serious incident frequency (including both Statoil employees and contractors) has improved considerably and has never before been so low. The serious incident frequency was 3.2 in 2003 as against 3.8 in 2002, while the number of serious incidents remains at the same level as in 2002, with 299 in 2003, compared with 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.

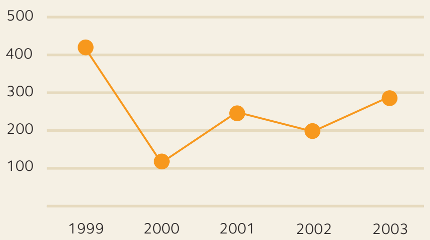
SICKNESS ABSENCE



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

Developments: Sickness absence was 3.5 per cent in 2003, as against 3.4 per cent in 2002. Sickness absence has been stable over the entire five-year period. This result is well below the Norwegian average (6.9 per cent in 2002, according to a study by the Confederation of Norwegian Business and Industry). The part of the Statoil group which is covered by the inclusive workplace (IA) agreement with the Norwegian national insurance service, (roughly 11 000 employees), shows a decline in sickness absence from 4.1 per cent in 2002 to 3.5 per cent in 2003. It is mainly long-term absence that has declined.

OIL SPILLS

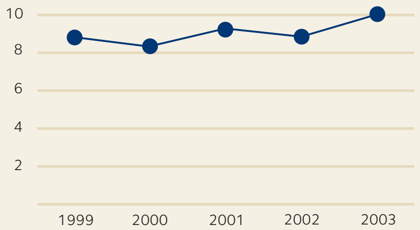


Definition: Unintentional oil spills to the external environment from Statoil operations (in cubic metres) (2).

Developments: The number of unintentional oil spills has increased (542 in 2003 as against 432 in 2002). The volume of unintentional spills has also increased from 200 cubic metres in 2002 to 288 in 2003. The increased volume is mainly due to a sizeable spill of 170 cubic metres at the Kalundborg refinery in Denmark. (That spill caused no damage outside Statoil's area). The figure shows the volume of oil spills in cubic metres.

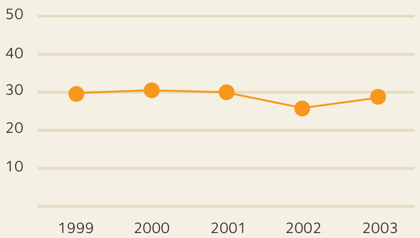
(2) All unintentional oil spills are included in the figures with the exception of those collected inside a facility (platform/plant) and which accordingly cause no harm to the surrounding environment. However, such spills are included for downstream operations.

CARBON DIOXIDE EMISSIONS



Definition: Total emissions of carbon dioxide in million tonnes from Statoil operations (3).
Developments: Carbon dioxide emissions totalled 10.0 million tonnes in 2003 as against 8.9 million in 2002. This increase is largely due to the takeover of operatorship for the Snorre, Tordis, Vigdis and Visund fields on the NCS as of 1 January 2003, as well as a high production rate at our land facilities (Kalundborg, Mongstad and Tjeldbergodden) in the Manufacturing & Marketing business area.
(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's road tankers or boats 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.

NITROGEN OXIDE EMISSIONS

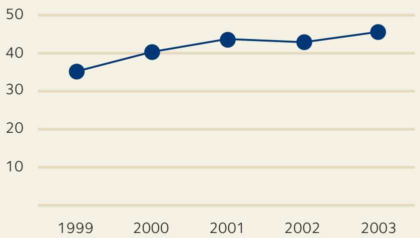


Definition: Total emissions of nitrogen oxides in tonnes from Statoil operations (4).

Developments: Emissions of nitrogen oxides totalled 29 900 tonnes in 2003 as against 26 400 tonnes in 2002. One important reason for this is the takeover of operatorships 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.

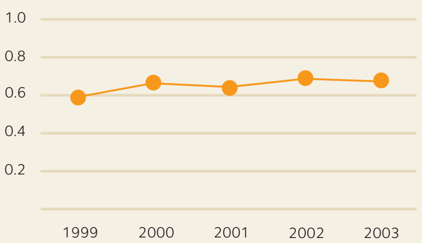
ENERGY CONSUMPTION



Definition: Total energy consumption in terawatt-hours (TWh) 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 increased from 42.1 TWh in 2002 to 47.0 TWh in 2003. This increase is largely due to the takeover of operatorship for the Snorre, Tordis, Vigdis and Visund fields on the NCS as of 1 January 2003, as well as a high production rate at our land facilities (Kalundborg, Mongstad and Tjeldbergodden) in the Manufacturing & Marketing business area.

WASTE RECOVERY FACTOR



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 2003 was 0.67, as against 0.68 in 2002. The trend over the past years is relatively stable. The Manufacturing & Marketing and Natural Gas business areas and the Technology entity have increased their recovery rate by comparison with 2002, but the other business areas have a lower waste recovery factor in 2003 compared with 2002.

(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 utilisation. Hazardous waste is defined by national legislation in each individual country.

Environmental data for 2003

NORWEGIAN CONTINENTAL SHELF[1)]

ENERGY

Diesel[2)]	1 100 GWh
Electricity	16 GWh
Fuel gas	24 300 GWh
Flare gas	3 300 GWh

RAW MATERIALS[3)]

Oil/condensate	91.7 mill scm
Gas[4)]	86.0 bn scm
Water	97.8 mill scm

UTILITIES

Chemicals process/prodn	42 600 tonnes
Chemicals drilling/well	135 000 tonnes

OTHER

Injection water as Pressure support	169 mill scm

PRODUCTS

Oil/condensate	91.7 mill scm
Gas for sale	59.4 mrd scm

EMISSIONS TO AIR

CO_2	6 210 000 tonnes
nmVOC[5)]	133 000 tonnes
Methane[5)]	22 400 tonnes
NO_x	25 400 tonnes
SO_2	215 tonnes

DISCHARGES TO WATER[7)]

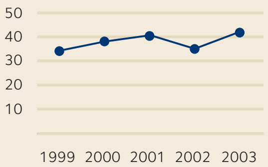
Produced water	91.5 mill scm
Oil in oily water	1 770 tonnes
Unintentional oil spills	25.0 m^3
Chemicals:[6)]	
Process/production	20 600 tonnes
Drilling/well	38 900 tonnes
Unintentional chemical spills	577 m^3

WASTE

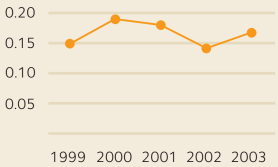
Waster for landfill	3 150 tonnes
Waste for recovery	7 500 tonnes
Recovery factor	0.70
Hazardous waste:	
Oily cuttings/mud	44 300 tonnes
Other	10 600 tonnes

1) Includes UK sector of Statfjord. Excludes the Troll gas treatment plant at Kollsnes and the Snøhvit project
2) Represents 94 900 tonnes
3) Includes 2.5 mill scm o e supplies from third party (Sigyn)
4) Includes fuel gas (2.06 bn scm), flare gas (0.28 bn scm) and injected gas for pressure support, etc (24.2 bn scm)
5) Includes buoy loading
6) Includes 51 500 tonnes water and green chemicals
7) Regulatory requirements have been met for all parameters on an annual basis. Unintentional spills are in addition (the goal is zero unintentional spills)

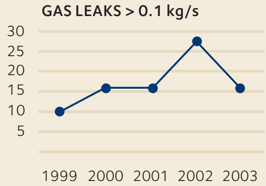
CO_2
kg emissions per delivered scm o e



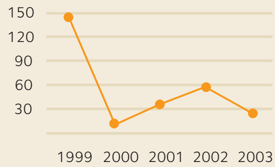
NO_x
kg emissions per delivered scm o e



NUMBER OF GAS LEAKS > 0.1 kg/s



OIL SPILLS
m^3



TROLL GAS TREATMENT PLANT, KOLLSNES

ENERGY

Electricity	855 GWh
Fuel gas	51.3 GWh
Flare gas	72.7 GWh

RAW MATERIALS

Rich gas Troll A	22.2 bn scm
Rich gas Troll B	2.03 bn scm
Rich gas Troll C	1.97 bn scm

UTILITIES

Monoethylene glycol	45 m^3
Caustics	24 m^3
Other chemicals	60 m^3

PRODUCTS

Gas	26.2 bn scm
Condensate	0.63 mill scm

EMISSIONS TO AIR[1)]

CO_2	24 300 tonnes
NO_x	9.3 tonnes
CO	10.1 tonnes
nmVOC	475 tonnes
Methane	872 tonnes

DISCHARGES TO WATER[1) 3)]

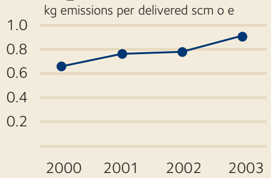
Treated water/effluent	134 000 m^3
Total organic carbon (TOC)	2.83 tonnes
Monoethylene glycol	5.44 tonnes
Methanol	0.28 tonnes
Hydrocarbons	0.06 tonnes
Ammonium	0.01 tonnes
Phenol	0.01 tonnes

WASTE[2)]

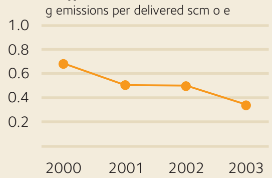
Waste for landfill	257 tonnes
Waste for recovery	503 tonnes
Recovery factor	0.66
Hazardous waste:	
Sludge from treatment plant	122 tonnes
Other	41 tonnes

1) Regulatory requirements have been met for all parameters for 2003 except nmVOC and methane
2) Includes waste from project activities at Kollsnes
3) No unintentional oil spills to sea or ground

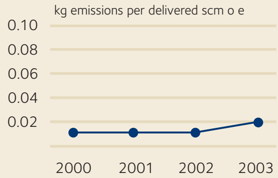
CO_2
kg emissions per delivered scm o e



NO_x
g emissions per delivered scm o e



nmVOC
kg emissions per delivered scm o e



MONGSTAD [1]

ENERGY

Electricity	426 GWh
Fuel gas and steam	5 970 GWh
Flare gas	345 GWh

RAW MATERIALS

Crude oil	8 083 000 tonnes
Other process raw materials	1 809 000 tonnes
Blending components	145 000 tonnes

UTILITIES

Acids	630 tonnes
Caustics	1 370 tonnes
Additives	1 800 tonnes
Process chemicals	4 000 tonnes

PRODUCTS

PRODUCTS	9 634 000 tonnes
Propane	Butane
Naphtha	Gas oil
Petrol	Petchoke/sulphur
Jet fuel	

EMISSIONS TO AIR[3]

CO_2	1 587 000 tonnes
SO_2	988 tonnes
NO_x	1 730 tonnes
nmVOC refinery	9 510 tonnes
nmVOC terminal	6 070 tonnes
Methane	2 190 tonnes

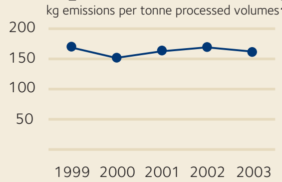
DISCHARGES TO WATER[3]

Oil in oily water	3.5 tonnes
Unintentional oil spills	0.1 m^3
Phenol	1.5 tonnes
Ammonium	44.5 tonnes

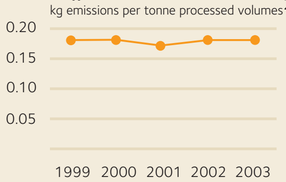
WASTE

Waste for landfill	818 tonnes
Waste for recovery	911 tonnes
Recovery factor	0.53
Hazardous waste[4]	58 400 tonnes

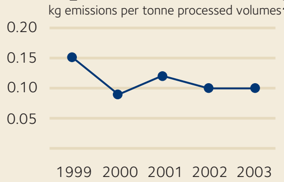
CO_2
kg emissions per tonne processed volumes[2]



NO_x
kg emissions per tonne processed volumes[2]



SO_2
kg emissions per tonne processed volumes[2]



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 noise level towards the neighbourhood
4) 94% goes to recovery, including 50 000 tonnes of water for treatment

KALUNDBORG

ENERGY

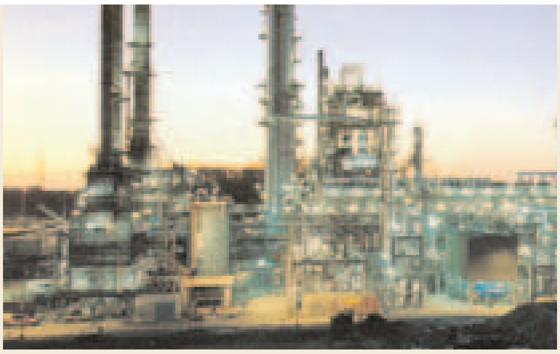
Electricity	168 GWh
Steam	71 GWh
Fuel gas and oil	2 440 GWh
Flare gas	89 GWh

RAW MATERIALS

Crude oil	4 697 000 tonnes
Other process raw materials	40 000 tonnes
Blending components	257 000 tonnes

UTILITIES

Acids	566 tonnes
Caustics	964 tonnes
Additives	0 tonnes
Process chemicals	326 tonnes
Ammonia (liquid)	2 770 tonnes



PRODUCTS

PRODUCTS	4 810 000 tonnes
Propane	Butane
Naphtha	Gas oil
Petrol	Fuel oil
Jet fuel	ATS (fertiliser)

EMISSIONS TO AIR[2]

CO_2	523 000 tonnes
SO_2	297 tonnes
NO_x	514 tonnes
nmVOC	2 400 tonnes
Methane	600 tonnes

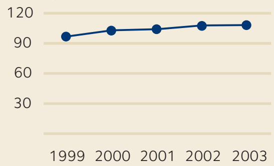
DISCHARGES TO WATER[2]

Oil in oily water	0.95 tonnes
Unintentional oil spills[3]	0 m^3
Phenol	0.02 tonnes
Suspended matter	20.8 tonnes
Sulphide	0.17 tonnes
Nitrogen	12.8 tonnes

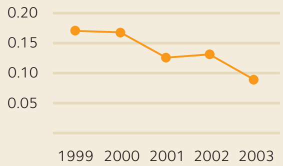
WASTE

Waste for landfill	72 tonnes
Waste for recovery	641 tonnes
Recovery factor	0.90
Hazardous waste	729 tonnes

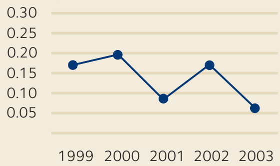
CO_2
kg emissions per tonne processed volumes[1]



NO_x
kg emissions per tonne processed volumes[1]



SO_2
kg emissions per tonne processed volumes[1]



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)
3) One discharge of heavy crude in the plant area (approx 170 m^3) was recovered

TJELDBERGODDEN

ENERGY

Diesel	1 GWh
Electricity	54 GWh
Fuel gas	1 740 GWh
Flare gas	145 GWh

RAW MATERIALS

Rich gas	480 000 tonnes
Condensate	0 tonnes

UTILITIES

Caustics	236 tonnes
Acids	57 tonnes
Other chemicals	22 tonnes

PRODUCTS

Methanol	916 000 tonnes
Oxygen	9 940 tonnes
Nitrogen	45 000 tonnes
Argon	11 100 tonnes
LNG	12 500 tonnes

EMISSIONS TO AIR 1)

CO_2	329 000 tonnes
nmVOC	180 tonnes
Methane	90 tonnes
NO_x	435 tonnes
SO_2	0.18 tonnes

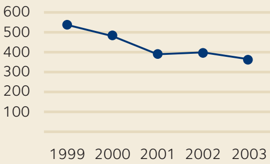
DISCHARGES TO WATER 1)

Cooling water	165 000 000 m^3
Total organic carbon (TOC)	1.1 tonnes
Suspended matter	1.1 tonnes
Nitrogen	1.2 tonnes

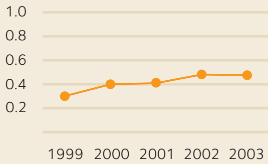
WASTE

Waste for landfill	17 tonnes
Waste for recovery	73 tonnes
Recovery factor	0.81
Hazardous waste:	
Sludge from treatment plant	117 tonnes
Other	5 tonnes

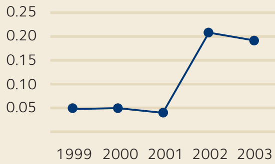
CO_2
kg emissions per tonne product
(methanol+LNG)



NO_x
kg emissions per tonne product
(methanol+LNG)



nmVOC
kg emissions per tonne product 2)
(methanol+LNG)



1) Regulatory requirements have been met for all parameters except TOC, SS and pH (concentrations per day)
2) A new method of measuring methane and nmVOC was adopted in 2002

KÅRSTØ GAS PROCESSING PLANT AND TRANSPORT SYSTEMS*

ENERGY 1)

Fuel gas	5 280 GWh
Electricity bought	139 GWh
Diesel	3 GWh
Flare gas	173 GWh

RAW MATERIALS 2)

Rich gas	17.7 mill tonnes
Condensate	5.10 mill tonnes

UTILITIES

Hydrochloric acid	175 tonnes
Sodium hydroxide	100 tonnes
Ammonia	37 tonnes
Methanol	297 tonnes
Other chemicals	5.2 tonnes

PRODUCTS 6)

Lean gas	14.1 mill tonnes
Propane	2.76 mill tonnes
I-butane	0.59 mill tonnes
N-butane	1.04 mill tonnes
Naphtha	0.56 mill tonnes
Condensate	3.15 mill tonnes
Ethane	0.52 mill tonnes
Electricity sold	36 GWh

EMISSIONS TO AIR 3) 5)

SO_2	2.24 tonnes
NO_x	990 tonnes
nmVOC	2 750 tonnes
Methane	1 220 tonnes
CO_2	1 217 000 tonnes

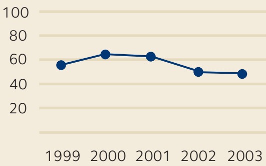
DISCHARGES TO WATER 5)

Cooling water	12.4 mill m^3
Treated water	0.42 mill m^3
Oil in oily water 7)	257 kg
Total organic carbon (TOC)	1.9 tonnes

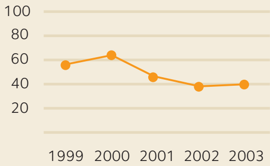
WASTE 4)

Waste for landfill	170 tonnes
Waste for recovery	1 090 tonnes
Recovery factor	0.86
Hazardous waste	459 tonnes

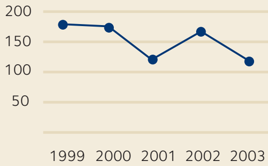
CO_2
kg emissions per tonne product
Processing plant



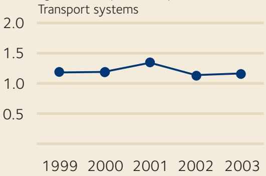
NO_x
g emissions per tonne product
Processing plant



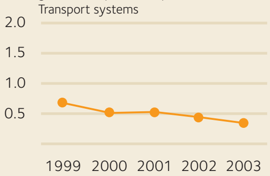
nmVOC
g emissions per tonne product
Processing plant



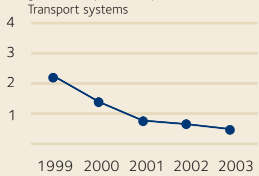
CO_2
kg emissions per tonne product
Transport systems



NO_x
g emissions per tonne product
Transport systems



nmVOC
g emissions per tonne product
Transport systems



* Gassco is operator for the facilities, and Statoil is technical service provider
1) Includes energy consumption for transport systems: 267 GWh fuel gas, 8 GWh electricity, 2.4 GWh diesel and 2.5 GWh flare gas
2) Excludes gas transport by transport systems: 64 mill tonnes, and 0.39 mill tonnes gas from Sleipner which is transported via Kårstø to Europipe II
3) Includes emissions from transport systems: 74 650 tonnes CO_2, 33 tonnes NO_x, 19 tonnes nmVOC and 180 tonnes methane
4) Includes waste from transport systems: 17 tonnes for landfill, 44 tonnes for recovery, 20 tonnes hazardous waste
5) All regulatory emission requirements have been met for 2003
6) Products from the processing plant
7) In addition four unintentional oil spills totalling 0.8 m^3 oil (recovered)

Report from Ernst & Young AS

To the corporate executive committee of Statoil ASA

We have reviewed the annual health, safety and environment accounting for Statoil ASA in 2003, as presented in the annual report and accounts for 2003 on pages 44-50. 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 last year's changes to 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 for the HSE accounting. Our focus areas have included traceability of data, consistency of the reporting routines and factors for calculating emissions to air. In this context, we have reviewed Statoil's central HSE accounting and reporting system and chosen eight reporting entities for site visits.
- testing a selection of data 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.
- testing a selection of data to verify that the HSE figures presented are based on defined and consistent 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 44-50:

- 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 defined and consistent 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, 3 March 2004
ERNST & YOUNG AS

Gustav Eriksen
Gustav Eriksen
State authorised public accountant

Jostein Johannessen
Jostein Johannessen
State authorised public accountant

Corporate governance

Statoil's fundamental objective is to create value for its owners through profitable operations and sustainable commercial development. Good management and control will ensure the effective use of the group's resources and the greatest possible value creation. Value created in Statoil will benefit shareholders, employees and society.

Statoil works to maintain a leading position among the world's oil and gas companies by combining good financial results with a responsibility for safety, the environment and the community. This review of Statoil's corporate governance shows how the group is managed and how the business is governed.

Governing bodies

The group's governing bodies comprise the annual general meeting (AGM), the corporate assembly and the board of directors. While working to safeguard the owners' interests, the board is also accountable to the employees, authorities, partners, suppliers, customers and the general public.

The governing principles established will ensure good management and control of the business. These principles are continuously adapted to ensure that the group's operations comply with relevant legislation, but also to ensure that business is run in accordance with best practice.

Statoil puts great emphasis on exercising good corporate governance and treating shareholders equally. The group has only one class of shares and thereby equal rights for all shareholders.

Annual general meeting

The AGM is the company's highest body. All shareholders who are registered with the Norwegian Central Securities Depository (VPS) receive an invitation to the AGM. They have the right to submit proposals and may vote either directly or by proxy at the AGM which is held before the end of June each year.

The AGM approves the annual accounts, allocates the net income and resolves other important matters as stipulated in the articles of association for Statoil ASA.

The corporate assembly

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 work of the board and the chief executive in managing the company, makes a statement to the AGM regarding the board's proposal for the accounts and takes decisions in investment matters of considerable size. It also expresses its opinion in cases of rationalisation or restructuring of the business which would involve major changes or reallocation of the workforce. The corporate assembly met six times in 2003.

The election committee

The duties of the election committee are to present a proposal to the AGM regarding the election of shareholder-elected members and deputies to the corporate assembly, and to present a proposal to the corporate assembly regarding the election of shareholder-elected members and deputies to the board of directors. The committee's members are elected for a period of two years and comprise the chair of the corporate assembly, a representative elected by the corporate assembly's shareholder-elected members and two representatives elected by the AGM.

The board's work

Managing the company is a board responsibility. The board is to ensure that the business is adequately organised and is responsible for establishing control systems and ensuring that the business is run in accordance with the company's values basis and ethical guidelines. It sets targets for financial structures and takes decisions on Statoil's plans and budgets. Matters of major strategic or economic significance for the business are dealt with by the board, and it is responsible for Statoil's quarterly accounts. The board determines the company's dividend policy, presents a proposal for allocation of net income to the AGM and sends out invitations to the latter.

The board appoints the chief executive. The working instructions, powers of attorney and salary for the chief executive are also determined by the board.

Statoil's corporate executive committee is not represented on the board which comprises nine members. The members of the board have no business relations with Statoil, nor do the shareholder-elected directors have other ties to the company.

The corporate assembly elects the board members, three of whom are elected among Statoil's employees. They are normally elected for two years at a time. The board's chair received an annual remuneration of NOK 300 000 for 2003 and the other directors each received NOK 165 000.

The board of directors held 16 meetings in 2003.

The board's audit committee

An audit committee comprising three directors was established by the board in the summer of 2003. The audit committee is a sub-committee of the board and its objective is to perform more thorough assessments of specific matters.

The committee prepares cases for the board and supports the board in exercising its management and supervision responsibilities. It also ensures that the requirements set in connection with the group's flotation are met. The committee reviews Statoil's external accounting reports, focusing on validity and completeness of information, and makes sure that the group has an independent, effective internal and external audit system.

Statoil's top management

The chief executive is responsible for the day-to-day operation of the business and submits proposals for budgets and accounts as well as important investments. In addition, the chief executive provides the board with an overview of cash flows, financial position, project progress and risk issues. 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.

Remuneration for top management

The basic salary for the chief executive in 2003 was NOK 3 500 000 excluding other remuneration. The board has devised an incentive scheme for the chief executive, with a performance element which has a ceiling of 30 per cent of basic salary. The size of the amount 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 with an

Values and attitudes

Respect for society and the environment forms the basis for the business and for the group's values and attitudes. Statoil's management philosophy is based on openness, honesty, integrity and compliance. Its 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.

individual performance element which allow for a bonus of up to 20 per cent of basic salary. The system has no connection with shares or share options. 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 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 underpin the manager's targets.

Statoil has also established a bonus system which applies to all other employees of the parent company. This involves an annual bonus of up to five per cent of basic salary, depending on whether the company reaches its financial targets. Separate performance pay schemes have been established for personnel in sales and trading.

Statoil is introducing a share investment plan for its employees. The proposed scheme, which will allow employees to buy shares for up to five per cent of their pay, will be submitted to the AGM for approval.

Social responsibility

Statoil's main objective is to create value for its owners through profitable operations and sustainable development. Statoil is increasingly being asked to account for how it contributes to positive, sustainable development and the values it creates locally. This year, the group is issuing its third annual sustainability report, which highlights further social responsibility, 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 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. The company is thus exposed to changes in feedstock and product prices, exchange rates and interest rate fluctuations. Statoil has devised an extensive system which identifies, quantifies and handles different risk categories. The system for risk management is reviewed by the board's audit committee.

A committee headed by the chief financial officer is responsible for monitoring financial risk management in Statoil. This committee works throughout the group recommending measures for exposure and risk management. Operational risk management is a line responsibility in the different business areas.

Auditor

Ernst & Young has been Statoil's external auditor since 1988. The auditor is appointed by the AGM which also determines the audit fees. The auditor does no work for the company which could lead to conflicts of integrity, and the board is responsible for ensuring that the auditor's independent role is maintained. The board has assessed several other companies for the role of external auditor for Statoil ASA and it will present its recommendation to the corporate assembly during 2004.

Internal auditor

Statoil's internal corporate 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 to the chief executive and to the board.

The head of corporate audit is secretary for the board's audit committee.

Corporate executive committee


Erling Øverland (51)
Acting president and CEO *


Henrik Carlsen (57)
Executive vice president
Exploration & Production Norway


Ottar Inge Rekdal (54)
Executive vice president
International Exploration & Production


Peter Mellbye (54)
Executive vice president
Natural Gas


Einar Strømsvåg (48)
Acting executive vice president
Manufacturing & Marketing


Terje Overvik (52)
Executive vice president
Technology


Eldar Sætre (48)
Chief financial officer and
executive vice president
Corporate Centre and Services


Elisabeth Berge (49)
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: Kåre Thomsen, 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
Country analysis and social responsibility: Rolf Magne Larsen, senior vice president
Public affairs: Wenche Skorge, vice president
Investor relations: Mari Thjømøe, vice president
Promotion and media: Hans-Aasmund Frisak, vice president

*Helge Lund was appointed new president and CEO on 7 March 2004. Erling Øverland is acting chief executive until Mr Lund takes up his position on 15 August 2004.

Directors' report 2003

Statoil's financial position is strong at the start of 2004. Production is higher and unit costs are lower than ever before in the group's history. Ambitious improvement targets, planned development of a robust project portfolio and important strategic progress lay a sound foundation for profitable growth in the years to come.

Results for 2003

The Statoil group's net income in 2003 came to NOK 16.6 billion, which is NOK 0.3 billion lower than in 2002. Income before financial items, other items, tax and minority interest totalled NOK 48.9 billion in 2003 as against NOK 43.1 billion the year before. The return on average capital employed after tax was 18.7 per cent, as against 14.9 per cent in 2002. Normalised for market factors, the return on capital employed was 12.4 per cent in 2003, which is 1.6 percentage points higher than in 2002.

High levels of oil and gas production contributed to the good result. Average oil and gas production totalled 1 080 000 barrels of oil equivalent (boe) per day, compared with 1 074 000 boe in 2002. Decreased output from fields which have passed plateau production contributed to a reduction in production on the Norwegian continental shelf (NCS) in 2003. At the same time, new fields made important contributions to the total production.

The board is satisfied that production in 2003 supports the goal of maintaining the production level on the NCS up to 2007. Statoil's ambition is to increase oil and gas production by an average of six per cent in 2004-2007, to 1 350 000 boe per day.

A the end of 2003, remaining proven oil and gas reserves amounted to almost 4.3 billion boe. The reserve replacement rate was 99 per cent, compared with 98 per cent in 2002. Over the last three years the average reserve replacement rate has been 95 per cent.

In order to reach the group's goal of a 12 per cent normalised return on capital employed in 2004, an extensive improvement programme has been initiated. The aim is to realise cost reductions and improved earnings equivalent to an improvement in annual income before financial items of NOK 3.5 billion in 2004, compared to 2001. At the end of 2003, the estimated effect of the implemented measures is NOK 2.8 billion from 2004, compared to the final target of NOK 3.5 billion. In the board's view, the group is still on track to delivering in accordance with its objectives.

The board proposes that the annual general meeting allocates a dividend of NOK 2.95 per share for 2003, as against NOK 2.90 for 2002.

Good results for health, safety and the environment are very

Jannik Lindbæk
Chair of the board

important to the group. Unfortunately, two fatal accidents occurred in connection with Statoil's operations in 2003. However, the frequency of total recordable injuries and lost-time injuries has declined. The board places emphasis on the continuous improvement of HSE results and will continue to monitor closely the group's efforts in this area.

Statoil's chair, chief executive and executive vice president for International Exploration & Production all resigned in September 2003 after it had emerged that a consultancy agreement relating to business development in Iran, known as the Horton affair, was not compatible with the group's ethical guidelines. Norway's National Authority for Investigation and Prosecution of Economic and Environmental Crime (Økokrim) has brought a preliminary charge against Statoil ASA alleging violations of the Norwegian general penal code provision relating to illegal influencing of foreign government officials. Økokrim is carrying out an investigation to clarify whether any criminal offence has been committed in connection with the Horton Investments contract. Statoil has also been notified by the US Securities & Exchange Commission (SEC) that it is conducting its own inquiry into the consultancy agreement to determine whether any violations of US federal securities laws have occurred. On the board's initiative, an external legal adviser has been engaged to conduct a comprehensive legal review of all aspects of the Horton agreement. The board emphasises that the ambitions for Statoil's internationalisation will be upheld and implemented to high ethical standards. The board is convinced that Statoil can succeed internationally without becoming engaged in operations which breach recognised ethical norms and rules.

Statoil's principal markets

After a downturn in the global economy in 2001 and 2002, an improvement was noted in 2003.

The scope of the global economic conditions had a substantial influence on Statoil's markets and the oil prices in 2003 were higher than many had expected. The annual average for Statoil's realised oil price was USD 29.1 per barrel, compared with USD 24.7 per barrel in 2002. Due to a strengthening of the Norwegian krone against the US dollar during the year, the oil price measured in NOK rose by a modest five per cent to NOK 206 per barrel in 2003.

The demand for gas continued to rise in western Europe in 2003. The average realised gas price was NOK 1.02 per standard cubic metre (scm) as against NOK 0.95 in 2002. With a flattening out of gas production in Europe and continuing rising demand, the market prospects for natural gas look good. This applies in particular to the UK, where the country's own production will supply an ever smaller portion of the demand.

The average refining margin (fluid catalytic cracker margin) rose from USD 2.2 per barrel in 2002 to USD 4.4 per barrel in 2003, and the refining market is characterised as good at the beginning of 2004. The average contract price for methanol rose from EUR 172 per tonne in 2002 to EUR 226 in 2003.

High feedstock prices and weak growth in the end-user markets caused the market conditions for the Borealis petrochemicals group to continue to be characterised by weak margins. However the market rallied somewhat during the year and the margins increased by 11 per cent in 2003 compared with the year before.

Statoil ASA awarded contracts for goods and services worth NOK 52.7 billion in 2003.

Over the past 10 years, Norwegian suppliers have provided just over two-thirds of Statoil's total contracts. In 2003 the Norwegian share was about 75 per cent.

Kaci Kullmann Five

Kaci Kullmann Five
Deputy chair

Bjørn Erik Egeland.

Bjørn Erik Egeland

A marked weakening of the competitiveness of Norwegian industry has led to several large contracts being awarded to contractors outside Norway in recent years. This includes the contract awarded in February 2003 for the processing plant at the Melkøya gas liquefaction plant. A lower NOK exchange rate and more moderate pay rises in Norwegian industry led to an improvement in its competitiveness last year. As a result, more and more Norwegian suppliers have won contracts amid international competition in 2003.

Exploration & Production Norway

Income before financial items, other items, tax and minority interest totalled NOK 37.6 billion in 2003 as against NOK 34.0 billion in 2002. This increase primarily reflects higher oil prices measured in NOK, increased gas sales and reduced operating costs at facilities and platforms.

Statoil's production from the NCS averaged 991 000 boe per day in 2003, an increase of 2 000 boe per day compared with 2002. While oil output declined slightly, this was largely offset by higher gas sales to the group's European customers.

Statoil's ambition is to be the industry's best production operator on the NCS. Cost-efficiency continued to improve in 2003 and the improvement targets for 2004 are within reach.

In 2003 Statoil recommended to the partnership in the Tampen area that efficiency enhancements and improvements to existing installations in the area should be carried out. Statoil is the sole operator for all fields in the Tampen area, and adjusted its organisation in 2003 to realise coordination gains and economies of scale.

Two Statoil-operated fields and one with Statoil participation came on stream in 2003. These are, the Mikkel gas field, Vigdis Extension and Fram West, a subsea development operated by Hydro.

The board attaches importance to field projects being developed in a profitable and confidence-inspiring manner, and will follow them closely. The development of the Kvitebjørn field is proceeding according to plan but the schedule is tight. Gas deliveries from Kvitebjørn start on 1 October 2004. High pressure and high temperature in the reservoir make Kristin the most demanding field on the NCS. The complexity of the reservoir has led to a discussion on a drainage solution for parts of the reservoir. This means that the Kristin project could face a cost increase, but the solution could also boost revenues. Through its economic, technological and strategic weight, Snøhvit is also an important project for Statoil. Progress is following the revised cost estimates, but the schedule is also tight for the Snøhvit project.

Statoil participated in a total of nine exploration and appraisal wells during 2003, six of which resulted in discoveries. These finds are relatively small but the oil find in the Ellida prospect off mid-Norway gives cause for some optimism for the prospects in new areas. The board attaches importance to maintaining exploration activity in order to lay the basis for long-term production and activity on the NCS. This requires regular access to new quality exploration acreage.

International Exploration & Production

Income before financial items, other items, tax and minority interest totalled NOK 1.7 billion in 2003, as against NOK 1.1 billion the year before. This increase primarily reflects higher oil prices measured in NOK.

Average international oil and gas output rose from 86 000 boe per day in 2002 to 89 000 boe in 2003. Production cost per unit produced remained unchanged from 2002, at USD 3.9 per boe.

Statoil's international E&P operations lay an important basis for the group's ambitions for growth in the years ahead. In

Stein Bredal

Marit Bakke

Angola, the partner-operated Xikomba and Jasmim fields came on stream. In Azerbaijan the development decision for phase one of Shah Deniz was taken by the licensees, and in Iran the development of the Statoil-operated South Pars field phases six-eight is well underway.

Statoil and BP have signed an agreement whereby Statoil will acquire 49 per cent of BP's interest in the In Salah gas project and 50 per cent of BP's interest in the In Amenas gas project, both in Algeria. The two companies will work together with Sonatrach, the Algerian state oil and gas company, in a joint operation of the two projects. The deal accords with Statoil's international strategy and provides interesting perspectives for natural gas activities.

Statoil had good international exploration results in 2003, particularly associated with activities off western Africa. The group took part in 14 exploration and appraisal wells in international waters. Of these, 11 resulted in finds. Future exploration will also take place in Venezuela, the Gulf of Mexico, the Middle East and the Caspian region.

The Horton affair created unrest relating to Statoil's business development in Iran towards the end of 2003 and raised doubts about the group's ability to comply with its own ethical guidelines in its international operations. Statoil has taken important steps forward in its international upstream operations during recent years and the board emphasises that the group's international strategy will proceed to high ethical standards.

Natural Gas

Income before financial items, other items, tax and minority interest totalled NOK 6.4 billion in 2003, down NOK 0.1 billion from 2002.

Statoil's gas sales from the NCS continued to grow, from 19.6 billion cubic metres in 2002, to 20.8 billion cubic metres in 2003, an increase of six per cent. Operating costs also rose in 2003, chiefly due to higher costs of goods sold. The business area is doing well as regards the improvement targets for 2004.

The Kårstø gas processing complex has been expanded to be able to receive gas from the Mikkel field, on time and at a cost 30 per cent lower than planned.

In December 2003 the Ormen Lange licence sanctioned the Langeled gas export pipeline from Nyhamna in mid-Norway, via the Sleipner Riser platform in the North Sea, to Easington in the UK.

Plans call for the southern section of the line, from Sleipner to Easington, to come on stream in 2006. The Ormen Lange field and the northern section of the line are due to start operating in 2007.

The key to future value creation lies in Statoil's ability to maximise the value of long-term gas sales contracts, secure new gas sales and arrange for the most efficiently possible operation of processing plants and transport infrastructure.

Manufacturing & Marketing

Income before financial items, other items, tax and minority interest totalled NOK 3.6 billion in 2003, as against NOK 1.6 billion the year before. This increase is mainly due to improved market conditions for the manufacturing area in addition to the effect of measures to reduce costs.

Statoil is the world's third largest net seller of crude, and has substantial international market positions. The group has also built a strong global position for natural gas liquids (NGL). Sales of crude oil, refined products and NGL gave good results in 2003. After weak results in 2002, the manufacturing activities showed a marked improvement throughout 2003. Statoil's refining margin showed a strong improvement in 2003 and capacity utilisation at the refineries also developed well.

Retailing operations showed stable results from 2002 to 2003, with positive development in all countries except Denmark.

Eli Sætersmoen

Finn A Hvistendahl

On the initiative of ICA, Statoil has signed a letter of intent covering the acquisition by Statoil of ICA's 50 per cent stake in Statoil Detaljhandel AS.

Borealis made a profit of NOK 0.1 billion in 2003, compared with an equivalent loss the year before. The improvement is mainly due to an increase in the petrochemical margins, but this market remains weak.

In April 2003, Statoil sold its wholly-owned shipping company Navion to Norsk Teekay AS, a wholly-owned subsidiary of Teekay Shipping Corporation.

The sale of Navion took effect on 1 January 2003 in accounting terms. Statoil received just over NOK 6 billion through the sale.

Health, safety and the environment

The board attaches particular importance to Statoil's active and purposeful efforts to avoid harm to people or the environment. There were unfortunately two fatalities in the group's operations in 2003. In 2002 there were six fatal accidents.

A contractor employee died on 24 March 2003 following an accident while working on the *Saipem 7000* crane vessel in the North Sea. On 25 September 2003 a contractor employee was killed in an accident at the Iranian yard which is building the jackets for the gas platforms for South Pars phases six-eight. Both accidents have been investigated and improvement measures have been implemented.

Calculated per million working hours, the total recordable injury frequency (including both Statoil employees and contractors) remains unchanged from 2002, at 6.0. The frequency for Statoil's own employees was 3.7, and has never been lower. The number of lost-time injuries per million working hours fell from 2.8 to 2.6. The results for 2003 also show an improvement in the number of serious incidents per million working hours – the frequency shows a decline from 3.8 in 2002 to 3.2.

In the third quarter a fine of NOK 1 million was imposed on Statoil following an accident on the *Byford Dolphin* drilling rig on 17 April 2002, when one person died.

High priority is given to safety work. A number of measures are being prepared to improve behaviour and attitudes throughout the organisation. One of the most significant is the safe behaviour programme, which covers 18 000 Statoil employees and contractor personnel working for Statoil on the NCS.

Sickness absence remains low, although the frequency rose from 3.4 per cent in 2002 to 3.5 per cent in 2003. Statoil is now working actively to promote a good working environment and prevent sickness absence. In Norway, Statoil has signed an agreement with the authorities to pursue a more inclusive workplace (IA), and this has had a positive effect in terms of sickness absence in the areas where it has been adopted. The board takes a positive view of the group's successful IA work and stresses the importance of continuing it.

Statoil works continuously to reduce the rise in greenhouse gas emissions. Total carbon dioxide emissions from Statoil-operated facilities rose from 8.9 million tonnes in 2002 to 10.0 million tonnes in 2003. This is primarily due to the takeover of operatorship for Snorre, Tordis, Vigdis and Visund on the NCS and a high rate of production at our land-based plants.

In accordance with the authorities' requirements, the group is pursuing its plan to achieve zero harmful discharges to the sea by 2005. Efforts to maintain a good natural environment in connection with the Snøhvit development in the Barents Sea in particular are being closely monitored, and the board considers the measures implemented to avoid environmental harm to be satisfactory.

Grace Skaugen

Knut Åm

Sustainable development

For the board, sustainable development means creating good financial, environmental and social results. Statoil will pursue its business in a profitable, safe and ethical manner. It will also demonstrate environmental awareness and social responsibility. The group's third sustainability report is being published at the same time as the annual report and accounts.

Statoil has worked systematically to tackle its environmental challenges. Knowledge and expertise have been central factors, and this has produced good results. The group's low carbon dioxide emissions per produced unit are currently among the best in the world, and the group constantly receives recognition for its development and application of new environmental technology.

Diversity in terms of gender, age and cultural background are an important part of Statoil's values base. The group strives to achieve a balanced age distribution among the employees, and to develop an organisation which reflects the cultural diversity of the countries in which it operates.

At the end of 2003 women represented 32 per cent of the group's employees. The target has been that women should hold at least 20 per cent of all leading posts by 2005. At the end of 2003, 23 per cent of the managers were women.

Employees are rewarded according to their position and expertise. For individual pay increases, importance is attached to the results achieved. Through the annual individual pay adjustments, the principle of equal pay for equal work is also practised.

As a rule, all staff are employed on a full-time basis. Statoil demonstrates flexibility towards employees who apply for temporarily reduced working hours due to health, social or other weighty welfare reasons. Of employees applying for such an arrangement, women are in a clear majority.

Financial developments for the group

In 2003 total revenues for Statoil came to NOK 249.4 billion, an increase of 5.6 billion from the year before.

Income before financial items, other items, tax and minority interests totalled NOK 48.9 billion as against NOK 43.1 billion in 2002. Net income came to NOK 16.6 billion, compared with NOK 16.8 billion in 2002.

Earnings per share came to NOK 7.64, as against NOK 7.78 in 2002.

In June 2003 the Norwegian parliament (Storting) decided to replace its Act on reimbursement of expenses for removal of installations on the NCS with ordinary tax deductions for the actual removal expenses. This change meant that Statoil's calculated receivable from the Norwegian state of NOK 6.0 billion in 2003 was booked under other items. Correspondingly, a deferred tax benefit of NOK 6.7 billion was included under income taxes. This resulted in net income in 2003 of NOK 0.7 billion.

Cash flow provided by operations was NOK 30.8 billion in 2003, compared with NOK 24.0 billion in 2002. This is due to higher prices and margins. Cash flow to investments in 2003 amounted to NOK 23.2 billion, as against NOK 16.8 billion in 2002.

The group's gross interest-bearing debt at 31 December 2003 was NOK 37.3 billion, as against NOK 37.1 billion in 2002. The group's debt-equity ratio, defined as net interest-bearing debt in relation to capital employed, was 23 per cent at 31 December 2003, compared with 29 per cent in 2002. The reduction is mainly due to an increase in total liquid assets and increased shareholders' equity.

The group had NOK 16.6 billion in bank deposits and other liquid assets at 31 December 2003, up NOK 4.7 billion from 2002.

At 31 December, Statoil managed a portfolio of NOK 21.5 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 difference 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 2003 have been prepared on that basis.

Net income for the Statoil ASA parent company according to NGAAP was NOK 17.1 billion in 2003.

The board proposes that the annual general meeting allocates a dividend of NOK 2.95 per share. The amount of the dividend comprises 40 per cent of the USGAAP result adjusted for special items. 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	6 390
Retained earnings	7 037
Reserve for valuation variances	3 637
Total allocated	17 064

The company's distributable equity after allocations amounts to NOK 43.1 billion.

Statoil's governing bodies

The owners' representatives in Statoil's corporate assembly were elected at the annual general meeting in 2002. There were no changes in 2003, and the corporate assembly still comprises the following representatives elected by the owners: Anne Kathrine Slungård (chair), Wenche Meldahl (deputy chair), Kjell Bjørndalen, Kirsti Høegh Bjørneset, Erlend Grimstad, Gunnar Mathisen, Anita Roarsen and Asbjørn Rolstadås. The other representatives are Arvid Færaas, Einar Arne Iversen, Hans M Saltveit and Åse Karin Staupe, elected by the employees.

Following Leif Terje Løddesøl's resignation as chair of the Statoil board in September 2003, Kaci Kullmann Five was elected acting chair. The corporate assembly then elected Jannik Lindbæk as the new chair, and he took up office on 1 November 2003. Since then the board of directors has comprised the following representatives elected by the owners: Jannik Lindbæk (chair), Kaci Kullmann Five (deputy chair), Finn A Hvistendahl, Grace Reksten Skaugen, Eli Sætersmoen and Knut Åm. The other directors are Marit Bakke, Stein Bredal and Bjørn Erik Egeland, elected by the employees. Statoil puts great emphasis on good corporate governance. For the owners, this is practised through the group's board, corporate assembly and annual general meeting.

A separate audit committee was set up in 2003 as a preparatory body for the board in accounting and audit matters. The committee members are Finn A Hvistendahl (chair), Marit Bakke and Eli Sætersmoen. US regulations require that Statoil reports whether one or more of the committee members is an accounting expert as defined by the US Securities and Exchange Commission.

Further developments for the group

Following several years of good results, Statoil has entered 2004 with a strong position financially, operationally and strategically. The board therefore finds it natural that its ambitions should be raised, and this is reflected in the new financial and operational targets for 2007. The production target for 2007 is 1 350 000 barrels of oil equivalent per day. Profitability is to increase to 13 per cent in the same period, measured as return on average capital employed with normalised prices, exchange rates and refining margins.

Planned expertise and manager development is a focus area. The Statoil School, established in 2003, is an important tool for training and expertise enhancement. The group has also devoted substantial resources to a top management training programme which will provide systematic manager development and ensure that the group's activities are based on a uniform set of values and commercial goals.

The development and application of new technology is important to Statoil's success. Surveys conducted in 2003 show that the group has consolidated its competitive position in the area of technology. A more purposeful technology strategy has been developed and implemented in 2003. The board attaches importance to the fact that Statoil's technology development work is commercially-oriented at all times.

Statoil's strong position on the NCS will form the basis for the group's activities for many years to come. Exploration & Production Norway is to maintain stable production at roughly one billion barrels of oil equivalent per day for as long as possible. This calls for continuous efforts to achieve more cost-efficient operations, the successful development of new field projects and exploration success in both mature and less well-explored areas.

The internationalisation of Statoil is a prerequisite for securing growth opportunities for the group. The international strategy builds on more than 30 years' experience as a national oil company on the NCS. First-class reservoir expertise, seabed technology and knowledge of gas value chains now lay the basis for international business development and partnerships in resource-rich areas.

Maximum utilisation of market prospects for natural gas are central to Statoil's strategic adjustment in the years ahead. The board is satisfied that Statoil has worked systematically to improve its market position in the UK in 2003, and important milestones have been passed.

The manufacturing and marketing business has been developed to maximise the value of Statoil's oil and gas reserves. Maintaining Statoil's leading position in the international crude oil market is therefore an important task. The land-based plants are also to be further developed and improved, to best underpin this strategy. In retail marketing the main focus will be on strengthening profitable market positions where Statoil has a competitive advantage in the Nordic countries/Baltic area.

The board's fundamental objective is to secure for Statoil's owners the best possible return on their shares in the group. Efforts to ensure continued improvement and efficiency therefore have high priority on the board's agenda. The board will also contribute to maintaining strict capital discipline.

The point of departure for the growth ambitions which Statoil has communicated is organic growth. After several years of good results, the group has built up financial strength which permits alternative measures to develop the group. The board will also continuously assess non-organic measures as part of Statoil's further development. A prerequisite for such initiatives is that they underpin the group's main strategic direction, and that they contribute to long-term value creation for the group's shareholders.

Stavanger, 3 March 2004
The board of directors
of Statoil ASA

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 and the other information contained elsewhere in this Annual Report.

Overview of Our Results of Operations

In the year ended December 31, 2003, we had total revenues of NOK 249.4 billion and net income of NOK 16.6 billion. In the year ended December 31, 2003, we produced 273 million barrels of oil and 19.3 bcm (683 bcf) of natural gas, resulting in a total production of 395 million barrels of oil equivalent (boe). Our proved reserves as of December 31, 2003 consisted of approximately 1.8 billion barrels of crude oil and NGL and 393 bcm (13.9 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;
- Natural Gas, which is responsible for the processing, transport and sales of natural gas to the European market from our upstream operations on the NCS, and from January 1, 2004, to international markets from our international upstream operations, and
- Manufacturing and Marketing, which comprises downstream activities including sales and trading of crude oil, NGL and refined products, refining, methanol production and sales, retail and industrial marketing and petrochemical operations through our 50% interest in Borealis.

Portfolio changes. An overall review of our strategy and asset portfolio has been carried out over the last few years and we will continue to seek to engage in portfolio management in order to optimize the value of our asset portfolio. 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, 2003, 2002 and 2001—Income before financial items, other items, income taxes and minority interest.

In E&P Norway we restructured our portfolio as follows:

In 2003 we have sold 7.9% of our interest in the Tyrihans field and farmed out 13% of our interests in exploration license 261B. We also purchased 0.21% interest in Huldra bringing our total interest in Huldra to 19.87% as at December 31, 2003. There have also been minor changes in the portfolio of exploration licenses. In addition, a 1.24% interest in the Snøhvit field was purchased from Svenska Petroleum and effective from January 1, 2004, subject to government approval, a 10% interest in the Snøhvit field was purchased from Norsk Hydro increasing our interest in the Snøhvit field to 33.53%. Further, 2% of the Kristin field was sold to Hydro, effective from January 1, 2004.

In 2002, we sold our entire interest 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 also aligned interests in 2002 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.

We restructured our International E&P portfolio as follows:

In June 2003 Statoil we agreed to acquire direct ownership interests in two Algerian assets, In Salah (a 31.85% interest) and In Amenas (a 50% interest) from BP. Statoil paid USD 740 million for these assets, which was paid in 2003 as well and has in addition covered the expenditures incurred after January 1, 2003 related to the acquired interests. The agreement remains subject to necessary approval by Algerian authorities.

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 Natural Gas, we restructured our portfolio as follows:

We signed a contract to sell our 5.26% stake in the VNG Verbundnetz Gas AG, a German gas merchant company, to EWE AG in December 2003. The sale was completed in January 2004 with a gain of approximately NOK 0.6 billion before tax (approximately NOK 0.4 after tax).

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 date was April 7, 2003. 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 Navigator* and 100% of the multi-purpose vessel *Odin*, although we have agreed to sell *Odin* to Marathon Petroleum and its Alvheim project partners.

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. *Odin* is no longer in the Manufacturing and Marketing business area and the expected sale will consequently not impact Manufacturing and Marketing´s results.

Subsequent Events

In January 2004, Statoil signed a letter of intent with Dominion, concerning increased access to capacity at the LNG terminal Cove Point in Maryland, USA.

In 2003, Statoil ASA and ICA AB have, initiated by ICA, signed a Letter of Intent regarding sale of ICA's 50% ownership in Statoil Detaljhandel Skandinavia (SDS) to Statoil. Final agreement has to be approved by the board of directors of each of Statoil and ICA, and pending such approval the transaction is expected to be completed during the first half of 2004.

Factors Affecting Our Results of Operations

Our results of operations substantially depend on:

- crude oil prices, which on average in US dollars decreased in 2001 but increased slightly in 2002 and further increased in 2003;
- natural gas contract prices in NOK, which on average strengthened considerably in 2001, but decreased in 2002 and increased in 2003, but not to 2001 levels;
- 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 and co-operation in recovering oil and gas from those reserves.

Our results will also be affected by trends in the international oil industry, including:

- volatility in oil prices, possible actions by the Norwegian Government, or possible or continued actions by members of the Organization of Petroleum Exporting Countries affecting price levels and volumes;
- 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.

The following table shows the yearly average crude oil trading prices, natural gas contract prices and NOK/USD exchange rates for 2001, 2002 and 2003.

	2001	2002	2003
Crude oil (USD/bbl Brent blend)	24.4	25.0	28.8
Natural gas (1) (NOK per scm)	1.22	0.95	1.02
NOK/USD average daily exchange rate	8.99	7.97	7.08

(1) From the Norwegian Continental Shelf.

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, other items, income taxes and minority interest and our net income assuming activity at levels achieved in 2003.

Sensitivities on 2003 results

(in NOK billion)	Change in income before financial items, other items, income taxes and minority interest	Change in net income
Oil price (+/- USD 1/bbl)	1.9	0.5
Gas price (+/- NOK 0.1/scm)	1.9	0.4
Refining margins (+/- USD 1/bbl)	0.8	0.6
US dollar exchange rate impact on revenues and costs (+/- NOK 0.50)	3.7	1.0
US dollar exchange rate impact on financial debt (+/- NOK 0.50)	-	1.3

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, and the effect of any hedging programs in place.

Our oil and gas price 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 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. No such protection has been entered into for 2004, but we have entered into downside protection for prices below USD 18 per barrel for some of the production for the last three quarters of 2005. Natural gas is primarily sold under price formulas that establish time lags for the change of the gas price. For 2004, approximately 25% of the refining margin was hedged to reflect our view of the markets.

Fluctuating foreign exchange rates can have a significant impact on our operating results. Our revenues and cash flows are mainly denominated in or driven by 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. This debt policy is an integrated part of our total risk management program. We are also engaging in foreign currency hedging to cover our non-USD need which are primarily in NOK. 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 USD against the NOK can be expected to increase our reported earnings. However, because our debt outstanding is in USD, the benefit to Statoil would be offset in the near term by the value of our debt, which will be recorded as a financial expense and, accordingly, would adversely affecct 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 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 has remained the same as prior to the initial public offering.

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 68,479 million (336 mmboe), NOK 72,298 million (374 mmboe), and NOK 53,291 million (265 mmboe) in 2003, 2002 and 2001, 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 2003 are Gullfaks and Oseberg, which together represented 27%, 24% and 16% of our total NCS petroleum production in 2001, 2002 and 2003 respectively. The change from 2002 to 2003 was primarily the result of the royalty being abolished at Statfjord, as of January 1, 2003. The royalty is generally paid in kind, and varies from 8% to 16% of the oil produced. We purchase from the Norwegian government at "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 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.

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,		
	2001	2002	2003
CONSOLIDATED STATEMENTS OF INCOME			
Revenues:			
Sales	97.8%	99.3%	99.7%
Equity in net income (loss) of affiliates	0.2%	0.2%	0.2%
Other income	2.0%	0.5%	0.1%
Total revenues	100%	100%	100%
Expenses:			
Cost of goods sold	53.4%	60.7%	60.0%
Operating expenses	12.5%	11.6%	10.7%
Selling, general and administrative expenses	1.5%	2.2%	2.2%
Depreciation, depletion and amortization	7.6%	6.9%	6.5%
Exploration expenses	1.2%	0.9%	1.0%
Total expenses before financial items	76.2%	82.3%	80.4%
Income before financial items, other items, income taxes and minority interest	23.8%	17.7%	19.6%

Years ended December 31, 2003, 2002 and 2001

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 248.5 billion in 2003, compared to NOK 242.2 billion in 2002 and NOK 231.7 billion in 2001. The 3% increase in sales revenues from 2002 to 2003 was mainly due to 5% increased oil prices (contributing NOK 8 billion) and 7% increased realized prices of natural gas (contributing NOK 1.5 billion) measured in NOK as well as increased sales of third party oil and a 5% increase in sales of equity natural gas (contributing NOK 1.0 billion). A significant increase in the refining margin (FCC-margin) from USD 2.2 in 2002 to USD 4.4 in 2003 and other improvements in the downstream activity also contributed to the increased sales revenues in 2003 compared to 2002. This is partly offset by the reduction of oil volumes sold reducing revenues by NOK 9.0 billion, mainly related to volumes sold on behalf of the Norwegian State (SDFI). The sale of the shipping activity in the subsidiary Navion, reduced sales revenues by NOK 2.0 billion compared to 2002. The sale of the activity on the Danish continental shelf in 2002, reduced sales revenues by NOK 1.0 billion in 2003, compared to 2002.

Our average daily oil production (lifting) decreased from 748,200 barrels in 2002 to 737,500 barrels in 2003. The 1% decrease in average daily oil production from 2002 to 2003 was primarily due to lower production from declining fields including Statfjord, Sleipner East, Norne and Lufeng. Some operational difficulties at Snorre, Gullfaks, Visund and Åsgard reduced regularity of production somewhat in 2003 compared to 2002. This reduction was partly offset by production from new fields coming on stream in the fourth quarter of 2003, Xikomba, Jasmim, Fram West, as well as increased production from the fields Sincor in Venezuela and Girassol in Angola and Sigyn coming on stream in the fourth quarter of 2002. At the end of 2003, we are in an underlift position of 9,000 boe per day compared to a minor underlift position in 2002.

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 proportional share of this reduction was approximately 18,500 barrels per day.

The decrease in average daily oil production 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 19.3 bcm (683 bcf) in 2003, compared to 18.8 bcm (666 bcf) in 2002 and 14.9 bcm (527 bcf) in 2001. Gas volumes increased primarily due to an increase in long-term contracted gas volumes to continental Europe as well as an increase in short-term sales, mainly to the UK.

We record revenues from sales of production based on lifted volumes. The term "production" as used in this section means lifted volumes. 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 and our 50% equity interest in Statoil Detaljhandel Skandinavia (SDS), our 50% equity interest in the drill ship *West Navigator*, 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 616 million in 2003, NOK 366 million in 2002 and NOK 439 million in 2001. The increase from 2002 to 2003 was primarily due to increased contribution from Borealis, due to increased margins and volumes, and increased contribution from miscellaneous interest related to the natural gas business. This increase was partly offset by reduced contribution from the retail business in SDS in 2003 as compared to 2002. The reduction from 2001 to 2002 was primarily due to increased losses from investments in *West Navigator* as well as decreased income from miscellaneous other affiliates.

Other income. Other income was NOK 0.2 billion in 2003, NOK 1.3 billion in 2002 and NOK 4.8 billion in 2001. The NOK 0.2 billion income in 2003 is mainly related to the sale of the Navion assets. 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 to Gaz de France, 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 149.6 billion in 2003 from NOK 147.9 billion in 2002 and NOK 126.2 billion in 2001. The 1% increase in 2003 compared to 2002, is mainly due to increased oil prices measured in NOK. This was partly offset by the 11% weakening of the NOK/USD exchange rate, as well as reduced volumes purchased from the SDFI.

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.

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 26.7 billion in 2003 compared to NOK 28.3 billion in 2002 and NOK 29.4 billion in 2001.

The 6% decrease from 2002 to 2003 is mainly related to the shipping activities in Navion being sold in 2003, as well as reduced processing costs. The 4% decrease from 2001 to 2002 was mainly related to reduced platform costs and lower future site removal costs due to updated removal estimates. This was partly offset by increased insurance costs and variable costs due to the higher production volume in 2002 compared with 2001.

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 2003, compared to NOK 5.3 billion in 2002 and NOK 4.3 billion in 2001.

The increase from 2002 to 2003 was primarily due to increased spending in Manufacturing and Marketing business as compared to 2002, mainly due to expansion of the retail network into Poland and the Baltic countries. This is partly offset by a reduction in business development spending in International E&P. The rig provisions increased by NOK 0.4 billion during 2003, most of which affected selling, general and administrative expenses from. This is NOK 0.2 billion higher than the provisions made for such losses in 2002.

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 selling, general and administrative expenses from. This is partly offset by a reduction in selling, general and administrative expenses in our Manufacturing and Marketing business segment.

Over the period 1998-2003 we provided approximately NOK 2.1 billion for the anticipated reduction in market value of company exposed fixed-price mobile drilling rig contracts. At December 31, 2003, the remaining provision for these losses was approximately NOK 1.4 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 were reassessed based on the most current information as of the end of the year 2003. Contracts have been entered into for both drilling rigs for most of 2004.

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 write-down of impaired long-lived assets. Depreciation, depletion and amortization expenses were NOK 16.3 billion in 2003, NOK 16.8 billion in 2002 and NOK 18.1 billion in 2001.

The decrease is mainly related to the write-down of the LL652 field in Venezuela of NOK 0.8 billion in 2002, while the 2003 figure includes the NOK 0.2 billion write-down of the Dunlin field in the UK. This decrease was partly offset by the increase related to the repeal of the Removal Grants Act, which entails that depreciation related to asset retirement increased by NOK 0.6 billion compared to 2002. New fields coming on stream in 2003 also increased deprecation. The NOK 2.0 billion write-down on the LL652 field in 2001 accounts for most of the reduction from 2001 to 2002. This was however, partly offset by higher depreciation from new fields coming on stream.

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 2.4 billion in 2003, NOK 2.4 billion in 2002, and NOK 2.9 billion in 2001.

	Year ended December 31,		
Exploration (in NOK million)	**2001**	**2002**	**2003**
Exploration expenditure (activity)	2,703	2,507	2,445
Expensed, previously capitalized exploration costs	935	554	256
Capitalized share of current period's exploration activity	(765)	(651)	(331)
Exploration expenses	2,877	2,410	2,370

The reduction of 2% in exploration expense from 2002 to 2003 was mainly due to a lower level of exploration activity within E&P Norway, partly offset by higher exploration activity within International E&P. Exploration expenditure capitalized in previous years but written off in 2003 was NOK 0.3 billion lower than in 2002. A total of 23 exploration and appraisal wells were completed in 2003, of which 17 resulted in discoveries.

The reduction of 16% 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 as compared to 2001. 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.

Income before financial items, other items, income taxes and minority interest. Income before financial items, other items, income taxes and minority interest totaled NOK 48.9 billion in 2003, NOK 43.1 billion in 2002 and NOK 56.2 billion in 2001.

The 13% increase from 2002 to 2003 is mainly related to increased oil and natural gas prices measured in NOK and higher margins in the downstream segment. Oil prices in 2003 measured in USD increased by 18% compared to 2002. Measured in NOK, however, the oil price increased by 5%, and the natural gas prices increased by 7% compared with 2002. Refining and petrochemical margins were also higher in 2003 compared to 2002, which contributed to increased contribution from downstream activities totaling NOK 1.9 billion.

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 to 2001. Refining, petrochemical and shipping margins were also lower in 2002 compared to 2001, due to weaker markets. The income for the downstream area was also negatively affected by the stronger NOK measured against the USD.

Income before financial items, other items, income taxes and minority interest for 2002 included a gain of NOK 1.0 billion before tax related to the sale of the upstream activity in Denmark, partly offset by an impairment of LL652 in Venezuela in 2002 of NOK 0.8 billion before tax. 2001 included net gains of NOK 2.3 billion before tax.

In 2003, 2002 and 2001, our income before financial items, other items, income taxes and minority interest margins, measured as a percentage of revenues, was approximately 20%, 18%, and 24%, respectively, for the reasons discussed above.

Net financial items. In 2003 we reported net financial items of NOK 1.4 billion, compared to NOK 8.2 billion in 2002 and NOK 0.1 billion in 2001. The changes from year to year resulted principally from changes in unrealized currency gains and losses on the US dollar portions of our long-term debt outstanding due to changes in the NOK/USD exchange rate. During 2002, the NOK strengthened by NOK 2.05, while the NOK strengthened by NOK 0.29 during 2003. The reduction in net financial items from 2002 to 2003 is mainly related to fluctuations in the NOK/USD exchange rate. The currency mix of the debt portfolio changed during 2001, from 80% to nearly 100% US dollar-denomination. The debt portfolio including the effect of swaps was as at year-end 2003 nearly 100% held in US dollars.

Interest income and other financial income amounted to NOK 1.2 billion in 2003 compared to NOK 1.8 billion in 2002. The reduction is mainly due to lower interest income following the general reduction in interest rates in 2003 compared to 2002. In 2001 Interest income and other financial income was NOK 2.1 billion.

Interest costs and other financial costs amounted to NOK 0.9 billion in 2003 compared to NOK 2.0 billion in 2002. The reduced costs are mainly due to lower short-term USD interest rates, which reduced the interest charge on the group's long-term debt, as well as shorter interest reset profiles and reduced average NOK/USD exchange rate in 2003 compared to 2002. In 2001 Interest cost and other financial cost amounted to NOK 2.7 billion.

The result from management of the portfolio of security investments, mainly in equity securities and held by our insurance captive Statoil Forsikring AS, provided a gain in 2003 of NOK 0.9 billion compared to a loss in 2002 of 0.6 billion, and a loss in 2001 of 0.3 billion.

The Central Bank of Norway's closing rate for NOK/USD was 9.01 on December 31, 2001, 6.97 on December 31, 2002, and 6.68 on December 31, 2003. These exchange rates have been applied in Statoil's financial statements.

Other items. The Norwegian parliament voted in June 2003 to replace grants for costs related to the removal of installations on the NCS with an equivalent tax deduction for such costs. Previously, removal costs were refunded by the Norwegian state based on a percentage of the taxes paid over the productive life of the removed installation. As a consequence of the changes in legislation, we charged the receivable of NOK 6.0 billion from the Norwegian State related to the refund of removal costs to income under Other items in the second quarter of 2003. Furthermore, the resulting deferred tax benefit of NOK 6.7 billion was recognized. As a result the net effect on the income in 2003 was NOK 0.7 billion.

Income taxes. Our effective tax rates were 62.0%, 66.9% and 68.5% in 2003, 2002 and 2001, respectively. The reduction in tax rate from 2002 to 2003 is mainly related to the repeal of the Removal Grants Act, which entailed NOK 6.7 billion being recorded as income and reduced deferred taxes, whereas NOK 6.0 billion was recorded as an expense under other items. Adjusted to exclude the effect of the repeal of the Removal Grants Act in 2003, the effective tax rate would have been 67.9%. Our effective tax rate is calculated as 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 2003 was NOK 289 million, compared to NOK 153 million in 2002 and NOK 488 million in 2001. Minority interest consists primarily of Shell's 21% interest in the Mongstad crude oil refinery, 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 2003 was NOK 16.6 billion compared to NOK 16.8 billion in 2002 and NOK 17.2 billion in 2001 for the reasons discussed above.

Improvement Program. Statoil has specified a set of improvement efforts necessary to reach its target of return on average capital employed in 2004 of 12%, based on normalized assumptions. To meet this target, Statoil determined that, among other improvements, it would need to reduce certain costs and increase revenue items by a total of NOK 3.5 billion in 2004, compared to 2001. As at the end of 2003, Statoil has identified annual, sustainable improvements in both costs and revenues, which it estimates will contribute NOK 2.8 billion toward the NOK 3.5 billion target for 2004. For further discussion of the improvement program, see Use of Non-GAAP Financial Measures.

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. As of the first quarter of 2003, a new method for calculating the transfer price for sales of gas from E&P Norway to Natural Gas has been adopted. The new price amounts to NOK 0.32 per standard cubic meter, adjusted quarterly by the average USD oil price over the last six months in proportion to USD 15 per barrel. Segment reporting for prior periods has been adjusted to reflect the new pricing formula.

The table below sets forth certain financial information for our business segments, including inter-company eliminations for each of the years in the three-year period ending December 31, 2003.

(in million)	Year ended December 31, 2001 NOK	2002 NOK	2003 NOK	2003 USD
E&P Norway				
Revenues	67,245	58,780	62,494	9,375
Income before financial items, other items, income taxes and minority interest	42,287	33,953	37,589	5,639
Long-Term Assets	77,550	77,001	80,681	12,103
International E&P				
Revenues	7,693	6,769	6,980	1,047
Income before financial items, other items, income taxes and minority interest	1,291	1,086	1,702	255
Long-Term Assets	21,530	20,655	33,102	4,966
Natural Gas				
Revenues	23,468	24,536	25,087	3,763
Income before financial items, other items, income taxes and minority interest	8,039	6,428	6,350	953
Long-Term Assets	10,500	10,312	10,555	1,583
Manufacturing and Marketing				
Revenues	203,387	211,152	218,642	32,800
Income before financial items, other items, income taxes and minority interest	4,480	1,637	3,555	533
Long-Term Assets	30,432	27,958	23,351	3,503
Other and Eliminations				
Revenues	(64,832)	(57,423)	(63,828)	9,574
Income before financial items, other items, income taxes and minority interest	57	(2)	(280)	(42)
Long-Term Assets	11,026	11,307	14,742	2,211
Total income before financial items, other items, income taxes and minority interest	56,154	43,102	48,916	7,338

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, 2003.

Income statement data (in NOK million)	2001	2002	Year ended December 31, change	2003	change
Total revenues	67,245	58,780	(13%)	62,494	6%
Operating, general and administrative expenses	11,145	11,546	4%	11,438	(1%)
Depreciation, depletion and amortization	11,805	11,861	0%	12,102	2%
Exploration expense	2,008	1,420	(29%)	1,365	4%
Income before financial items, other items income taxes and minority interest	42,287	33,953	(20%)	37,589	11%
Operational data:					
Production (lifting):					
Oil (mbbl/day)	697.1	666.7	(4%)	651.9	(2%)
Natural gas (mmcf/day)	1,380	1,784	29%	1,857	4%
Total Production (lifting) (mboe/day)	942.7	985.5	5%	982.4	0%
Reserve replacement ratio (1)(2)	0.77	0.63	(18%)	0.79	25%
Finding cost (USD per boe) (1)	1.53	0.81	(47%)	0.63	(17%)
Finding and Development Costs (USD per boe) (1)	9.35	5.89	(37%)	5.24	(11%)
Unit Production (lifting) Cost (USD per boe)(3)	2.66	2.87	8%	3.15	10%
Unit Production (lifting) Cost (NOK per boe)(3)	23.91	22.85	(4%)	22.30	(2%)

(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. Figures for 2001 and 2002 have been restated.

Years ended December 31, 2003, 2002 and 2001

E&P Norway generated revenues of NOK 62.5 billion in 2003, compared to NOK 58.8 billion in 2002 and NOK 67.2 billion in 2001. The 6% increase in revenues from 2002 to 2003 resulted primarily from an 18% increase in the average realized crude oil price in USD, a 19% increase in the transfer price in NOK of natural gas sold from E&P Norway to Natural Gas. This was partly offset by a 13% decrease in the NOK/USD exchange rate and a reduction in lifted volumes of oil. The 13% decrease in revenues from 2001 to 2002 resulted primarily from an 11% decrease in the NOK/USD exchange rate and a decrease in the transfer price of natural gas sold from E&P Norway to Natural Gas of 16%. This was partly offset by a 2% increase in average realized crude oil prices.

Average daily oil production (lifting) in E&P Norway decreased to 651,900 barrels in 2003 from 666,700 barrels in 2002 and from 697,100 barrels in 2001. The 2% decrease in average daily oil production from 2002 to 2003 was primarily due to decline from large fields like Statfjord, Sleipner Øst and Norne being past production plateau. The new fields Mikkel, Fram Vest and Vigdis Extension, which started production in the fourth quarter could not fully replace the production decline from the old fields.

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 decided on December 17, 2001 to reduce oil production on the NCS by 150,000 barrels per day, covering the period January 1, to June 30, 2002. Our share of this reduction was approximately 18,500 barrels per day over that 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.

Average daily gas production was 52.6 mmcm (1,857 mmcf) in 2003, as compared to 50.7 mmcm (1,784 mmcf) in 2002, and 39.1 mmcm (1,380 mmcf) in 2001. Gas production increased by 4% between 2002 and 2003 and by 29% between 2001 and 2002, 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 2.66 per boe in 2001, USD 2.87 per boe in 2002 and USD 3.15 per boe in 2003. The increase from 2002 to 2003 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 23.91 per boe in 2001, to NOK 22.85 per boe in 2002 and to NOK 22.30 per boe in 2003.

Depreciation, depletion and amortization expenses were NOK 12.1 billion in 2003, NOK 11.9 billion in 2002 and NOK 11.8 billion in 2001. The increase from 2002 to 2003 is mainly due to depreciation of asset retirement assets pursuant to new removal accounting principle, which increased the depreciation base, and start of production from new fields in late 2002 and 2003, namely Sigyn, Mikkel, Fram Vest and Vigdis Extension. This was partly offset by increased reserves and lower lifted oil volumes. The minor increase from 2001 to 2002 resulted primarily from higher production.

Exploration expenditure (activity) decreased both from 2002 to 2003 and from 2001 to 2002. Exploration expenditure was NOK 1.2 billion in 2003, compared to NOK 1.4 billion in 2002 and NOK 2.0 billion in 2001. The 14% decrease from 2002 to 2003 is mainly due to fewer identified drilling opportunities which we believe would be successful in some of the areas where we have interests in acreage and lack of support for drilling of wells suggested by Statoil in the licenses. This resulted in fewer wells being drilled in 2003 than in 2002. 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 due to fewer identified drilling opportunities. We still have confidence in the NCS and expect our exploration activity, given access to acreage, to exceed the 2002 and 2003 level in coming years.

Exploration expense both in 2003 and 2002 was NOK 1.4 billion, compared to NOK 2.0 billion in 2001. The difference in activity in 2003 and 2002 was offset by lower capitalized exploration in 2003 than in 2002 and lower expenditure capitalized in previous years, but written off in 2003 than in 2002. In 2003 nine exploration and appraisal wells were completed, of which six resulted in discoveries. In comparison, fifteen exploration and appraisal wells were completed in 2002, of which ten resulted in discoveries. In addition, five extensions on production wells were completed in 2002, of which four resulted in discoveries. The 30% decrease in expensed exploration from 2001 to 2002 is consistent with changes in expenditure levels due to variations in exploration activity. Eighteen exploration and appraisal wells and two extensions on production wells were completed in 2001, of which 15 resulted in discoveries. Exploration expense in 2003 included NOK 0.3 billion of expenditure capitalized in previous years, but written off in 2003, compared to NOK 0.5 billion of expenditure written off in 2002 and NOK 0.7 billion in 2001.

Income before financial items, other items, income taxes, and minority interest for E&P Norway was NOK 37.6 billion, compared to NOK 34.0 billion in 2002 and NOK 42.3 billion in 2001. The 11% increase in income before financial items, other items, income taxes and minority interest from 2002 to 2003 was primarily the result of an increase in revenues due to the 5% increase in the average realized crude oil price measured in NOK and the 19% increase in the transfer price of natural gas sold from E&P Norway to Natural Gas. Operating expenses are reduced by 2%, but the reduction was offset by a 2% increase in depreciation, depletion and amortization expenses.

The 23% decrease in income before financial items, other 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 a 12% interest in the Snøhvit field, the income before financial items, other 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, other items, income taxes and minority interest was partly offset by increased sales of natural gas, decreased exploration expenses 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, 2003.

Income statement data (in NOK million)	2001	2002	Year ended December 31, change	2003	change
Total revenues	7,693	6,769	(12%)	6,980	3%
Depreciation, depletion and amortization	3,371	2,355	(30%)	1,784	(24%)
Operating, general and administrative expenses	2,165	2,338	8%	2,489	6%
Exploration expense (1)	866	990	14%	1,005	2%
Income before financial items, other items income taxes and minority interest	1,291	1,086	(16%)	1,702	57%
Operational data:					
Production (lifting):					
Oil (mbbl/day)	57.8	81.5	41%	85.6	5%
Natural Gas (mmcf/day)	41	33	(20%)	14	(58%)
Total Production (lifting) (mboe/day)	65.2	87.4	34%	88.2	1%
Reserve replacement ratio(2)(3)	2.14	2.79	30%	2.96	6%
Finding Cost (USD per boe)(2)	2.15	1.72	(20%)	1.58	(8%)
Finding and Development Costs (USD per boe)(2)	8.60	7.15	(17%)	7.88	10%
Unit Production (lifting) Cost (USD per boe)(4)	4.78	3.85	(19%)	3.93	2%

(1) Geology and Geophysics related costs of NOK 0.2 billion reclassified in 2002 from business development to exploration costs.
(2) 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. Finding costs does not include effects of acquisitions and disposals.
(3) The reserve replacement rate is defined as the total additions to proved reserves, including acquisitions and disposals, divided by produced reserves. Reserve replacement rate for International E&P was 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. Figures for 2001 and 2002 have been restated.

Years ended December 31, 2003, 2002 and 2001

International E&P generated revenues of NOK 7.0 billion in 2003, compared to NOK 6.8 billion in 2002 and NOK 7.7 billion in 2001. The 3% increase from 2002 to 2003 was mainly due to higher prices for crude oil contributing to an increase of NOK 1.3 billion and revenues from the LNG terminal at Cove Point of NOK 0.3 billion. This increase was partly offset by the NOK 1.0 billion divestment of the Denmark assets in 2002. 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 to a gain of NOK 1.0 billion related to the divestment of the assets on the Danish Continental Shelf in 2002. The gains from divestments are included as other income under Total revenues. 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.

Average daily oil production (lifting) was 85,600 barrels per day in 2003, compared to 81,500 barrels per day in 2002 and 57,800 barrels per day in 2001. The 5% increase in average daily production of oil from 2002 to 2003 resulted primarily from increased production of 6,500 boe per day from the Sincor field in Venezuela, 3,600 boe per day from the Girassol field in Angola and 3,000 boe per day from the Alba field in the UK. New fields came into production in 2003 both in the UK, - the Caledonia field, -and in Angola, -the Jasmim field and the Xikomba field. These increases were partly offset by the declining production of 1,400 boe per day from the Lufeng field in China and the sales of the Siri field and Lulita field in Denmark, which in 2002 contributed production of 6,600 boe per day. The 41% increase in average daily production of oil from 2001 to 2002 resulted primarily from increased production from the Girassol field in Angola of 23,200 boe per day and the Sincor field in Venezuela of 9,700 boe per day due to start up of the upgrading plant. The Girassol field started production in December 2001. These increases were partly offset by declining production of 4,000 boe per day from the Siri field in Denmark, which we sold as of July 1, 2002, 1,400 boe per day of the Lufeng field in China, and 2,100 boe per day from the Alba field in the UK.

Average daily gas production in 2003 was 0.4 mmcm (14 mmcf) compared to 0.9 mmcm (33 mmcf) in 2002 and 1.2 mmcm (41 mmcf) in 2001. The 58% decrease from 2002 to 2003 resulted from the Jupiter gas field in the UK being in decline. The 20% decrease from 2001 to 2002 also resulted from the Jupiter gas field in the UK being in decline.

Unit production cost on a 12-month average increased by 2% from 2002 to 2003, mainly due to cost increases on the UK fields measured in USD due to the changes in the GBP/USD exchange rate. Unit production cost on a 12 month average decreased by 19% from 2001 to 2002 due to more cost effective fields coming on stream, primarily Girassol.

Depreciation, depletion and amortization expenses were NOK 1.8 billion in 2003, compared to NOK 2.4 billion in 2002 and NOK 3.4 billion in 2001. The 24% decrease in 2003 as compared to 2002 is primarily related to the NOK 0.8 billion impairment charge for writing down the LL652 field in Venezuela in 2002, partly offset by a NOK 0.2 billion write-down of the Dunlin field in the UK in 2003. The 30% decrease in 2002 as compared to 2001 is primarily related to the NOK 2.0 billion write-down 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 write-downs were mainly due to reductions in the projected volumes of oil recoverable during the remaining contract period of operation.

Exploration expenditure (activity) was NOK 1.2 billion in 2003, compared to NOK 1.2 billion in 2002 and NOK 0.7 billion in 2001. The 71% increase in exploration expenditure from 2001 to 2002 was mostly related to increased exploration activity in 2002, including geological and geophysical work related to surveying opportunities in potential new areas.

Exploration expense in 2003 was NOK 1.0 billion compared to NOK 1.0 billion in 2002 and NOK 0.9 billion in 2001. In total, 14 exploration and appraisal wells were completed in 2003, of which 11 resulted in discoveries and remained capitalized. The 14% increase in exploration expense from 2001 to 2002 is due to the inclusion of geological and geophysical work related to potential new areas, and by expensing the Nnwa-2 well in license 218 in Nigeria in 2002. This was partly offset by greater success in exploration activity in Angola. In total, eight exploration and appraisal wells were completed in 2002, of which seven resulted in discoveries and six remain capitalized. In 2001 a total of nine exploration – and appraisal wells were completed, of which three resulted in discoveries.

Income before financial items, other items, income taxes and minority interest for International E&P in 2003 was NOK 1.7 billion compared to NOK 1.1 billion in 2002 and NOK 1.3 billion in 2001. The oil and gas price development measured in USD contributed NOK 1.3 billion and decreased business development costs contributed NOK 0.1 billion in 2003 compared to 2002. In addition, there was a NOK 0.8 billion write-down of the LL652 oil field in Venezuela in 2002. These positive effects are partly offset by the weakening of the USD measured against the NOK of NOK 0.8 billion, the net effect of asset divestments in 2002 of NOK 1.0 billion and 2003, and the write-down of the Dunlin field in the UK of NOK 0.2 billion. 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 the effect of asset sales and write-downs, Income before financial items, other items, income taxes and minority interest was NOK 1.9 billion in 2003, compared to NOK 0.9 billion in 2002.

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 last three years ended December 31, 2003.

Income statement data (in NOK million)	2001	2002	Year ended December 31, change	2003	change
Total revenues	23,468	24,536	5%	25,087	2%
Natural gas sales	18,984	20,844	10%	20,728	(1%)
Processing and transportation	4,484	3,692	(18%)	4,359	18%
Cost of goods sold	9,898	11,859	19.8%	12,629	6%
Operating, selling and administrative expenses	4,867	5,657	(16%)	5,622	(1%)
Depreciation, depletion and amortization	664	592	(10.8%)	486	(18%)
Income before financial items, other items, income taxes and minority interest	8,039	6,428	(20%)	6,350	(1%)
Prices:					
Natural gas price (NOK/scm)	1.22	0.95	(22%)	1.02	7%
Transfer price natural gas (NOK/scm)	0.59	0.50	(15%)	0.59	18%
Volumes marketed:					
For our own account (bcf)	517.8	691.4	34%	734.5	6%
For the account of the SDFI (bcf)	666.9	829.5	24%	903.7	9%
For our own account (bcm)	14.7	19.6	34%	20.8	6%
For the account of the SDFI (bcm)	18.9	23.5	24%	25.6	9%

Years ended December 31, 2003, 2002 and 2001

Revenues in the Natural Gas business consist mainly of gas sales derived from long-term gas sales contracts and tariff revenues from transportation and processing facilities. Natural Gas generated revenues of NOK 25.1 billion in 2003, compared to NOK 24.5 billion in 2002 and NOK 23.5 billion in 2001. The 2% increase in 2003 over 2002 was mainly caused by an 18% increase in processing and transportation revenues. From January 1, 2004, total revenues will include revenues from Cove Point and other international mid- and downstream gas activities, which were transferred from International E&P to Natural Gas as of January 1, 2004.

Natural gas sales were 20.8 bcm (734.5 bcf) in 2003, 19.6 bcm (691.4 bcf) in 2002 and 14.7 bcm (517.8 bcf) in 2001. The 6% increase in gas volumes sold from 2002 to 2003 was mainly caused by an increase in the gas sales contract portfolio, partially due to the start up of delivery under the Centrica contract. Of the total natural gas sales in 2003, Statoil produced 19.1 bcm (674.4 bcf). Average gas prices were NOK 1.02 per scm in 2003 compared to NOK 0.95 per scm in 2002, an increase of 7%. The increased price is mainly due to the increase in the NOK/EUR exchange rate. Cost of goods sold increased by 6%, mainly due to a higher transfer price to E&P Norway for gas as well as higher volumes of both Statoil produced volumes and third party volumes.

Some of the UK volumes, which in 2003 were accounted net, meaning that the sale of such volumes is accounted for by crediting natural gas sales with the margin or spread associated with the sale, were in 2002 accounted gross, meaning that the costs of such volumes were included in costs of goods sold and the total revenue generated by selling such volumes were included in natural gas sales as if the volumes had been taken into inventory. The change has no effect on income before financial items, other items, income taxes and minority interest, but affects comparisons on revenues and costs between the years.

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 gas-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 that, 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 2003. 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 that a customer must purchase by the end of a given gas year.

Income before financial items, other items, income taxes and minority interest for Natural Gas in 2003 was NOK 6.35 billion, compared to NOK 6.43 billion in 2002 and NOK 8.04 billion in 2001. The 1% decrease in income before financial items was primarily a result of increased sales and a 7% increased external gas price, which was more than offset by an increase in cost of goods mainly due to a higher transfer price for gas.

In 2003, a total of NOK 62 million was expensed related to an estimated change in the value of certain gas sales contracts viewed as derivatives that are valued at market price, compared to a loss related to these contracts of NOK 115 million in 2002.

Manufacturing and Marketing

			Year ended December 31,		
Income statement data (in NOK million)	**2001**	**2002**	**change**	**2003**	**change**
Total revenues	203,387	211,152	4%	218,642	4%
Cost of goods sold	180,732	193,353	7%	200,453	4%
Operating, selling and administrative expenses	16,320	14,476	11%	13,215	(9%)
Depreciation, depletion and amortization	1,855	1,686	(9%)	1,419	(16%)
Total expenses	198,907	209,515	5%	215,087	3%
Income before financial items, other items, income taxes and minority interest	4,480	1,637	(63%)	3,555	117%
Operational data:					
FCC margin (USD/bbl)	3.6	2.2	(39%)	4.4	100%
Contract price methanol (EUR/ton)	220	172	(22%)	226	31%
Petrochemical margin (EUR/ton)	132	107	(19%)	119	11%

Years ended December 31, 2003, 2002 and 2001

Manufacturing and Marketing generated revenues of NOK 218.6 billion in 2003, compared with NOK 211.2 billion in 2002 and NOK 203.4 billion in 2001. The 4% increase in revenue in 2003 over 2002 resulted primarily from higher prices in USD for crude oil, but was partly offset by the strengthening of the NOK versus the USD and a decrease in total sold volumes of crude oil of 6%. The 4% increase in revenues in 2002 over 2001 resulted primarily from higher sold volumes of crude and higher prices in USD for crude oil, but was partly offset by the strengthening of the NOK versus the USD.

Cost of goods sold increased from NOK 180.7 billion in 2001, to NOK 193.4 billion in 2002 and to NOK 200.5 billion in 2003. The increase from 2002 to 2003 resulted primarily from higher prices in USD for crude oil.

Depreciation, depletion and amortization totaled NOK 1.4 billion in 2003, compared with NOK 1.7 billion in 2002 and NOK 1.9 billion in 2001. The NOK 0.3 billion decrease from 2002 to 2003 was mainly due to the effects of the divestment of Navion, effective from April 7, 2003.

Income before financial items, other items, income taxes and minority interest for Manufacturing and Marketing was NOK 3.6 billion in 2003, compared with NOK 1.6 billion in 2002 and NOK 4.5 billion in 2001. Higher refining margins from manufacturing activity were the main reason for the increase in income contributing NOK 1.3 billion from 2002 to 2003. Average refining margin (FCC-margin) was 100% higher, equaling USD 2.2 per barrel, from 2002 to 2003, but due to the strengthening of the NOK versus the US dollar, the effect in NOK on the FCC-margin was an increase of 78%. Average contract price on methanol was about 40% higher in NOK in 2003 than in 2002. In oil trading, profits increased by NOK 0.3 billion in 2003, compared with 2002, mainly due to better results from leased refinery capacity. The retail marketing profit increased by NOK 0.1 billion in 2003, compared with 2002. The increase was due to higher volumes, improved margins and cost reductions.

Lower refining margins were the main reason for a reduction in income from manufacturing activity by NOK 1.6 billion from 2001 to 2002. Average refining margin (FCC-margin) was 39% lower, equal to USD 1.4 per barrel, from 2001 to 2002, and the effect of this margin decrease was even greater measured in NOK due to the strong NOK. Average contract price on methanol was about 30% lower in 2002 in NOK than in 2001. The result was also negatively affected by planned maintenance shut downs at the refineries at Mongstad and at 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.

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 Navigator* (1) drill ship, which were not included in the sale, was approximately USD 800 million. The effective date of the transaction was January 1, 2003, and the sale was booked at closing on April 7, 2003. The income from the sales transaction was immaterial, but Navion contributed NOK 0.5 billion to income before financial items, income taxes and minority interest of the Manufacturing and Marketing business segment, compared with NOK 0.4 billion for the whole of 2002 and NOK 1.5 billion in 2001. 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 contribution from our retail affiliate Statoil Detaljhandel Skandinavia (SDS) to Manufacturing and Marketing's income before financial items, other items, income taxes and minority interest was NOK 152 million in 2003, compared with NOK 221 million in 2002 and NOK 222 million in 2001. The decrease of NOK 69 million from 2002 to 2003 was primarily due to bad results in the Danish retail business related to reduced margins, mainly as a consequence of fierce competition in the Danish retail market. Statoil ASA and ICA AB have, initiated by ICA, signed a letter of intent regarding the sale of ICA's 50% ownership in SDS to Statoil. Final agreement has to be approved by the Board of Directors of each of Statoil and ICA, and the transaction is intended to be completed in the first half of 2004 subject to negotiation of definitive agreements.

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 106 billion in 2003, an income of NOK 53 million in 2002 and a loss of NOK 146 million in 2001. The contribution from Borealis increased from 2002 to 2003 mainly due to an increase in margins by EUR 12 per tonne equal to NOK 148 per tonne due to the weakening of the NOK versus the Euro, as well as a 2% increase in production. 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 EUR 25 per tonne, approximately 19%, from 2001 to 2002.

Other operations

Years ended December 31, 2003, 2002 and 2001

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, other items, income taxes and minority interest of NOK 280 million in 2003. Income before financial items, income taxes and minority interest was a loss of NOK 2 million in 2002 and an income before financial items, other items, income taxes and minority interest of NOK 57 million in 2001.

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 2003 was NOK 30.8 billion, as compared to NOK 24.0 billion in 2002, and NOK 39.2 billion for 2001.

The increase of NOK 6.8 billion from 2002 to 2003 is primarily due to an increase of NOK 8.9 billion in cash flow before tax, mainly due to higher prices and margins, as well as increased working capital items of NOK 0.2 billion (excluding taxes payable, short-term debt and cash). Changes in working capital items resulting from the disposal of the subsidiary Navion in the second quarter of 2003, are excluded from cash flows provided by operating activities and classified as proceeds from

(1) Following the sale of the shipping activity in the subsidiary Navion, the drilling ship *West Navion* was renamed as the *West Navigator*. Statoil continues to own 50% of the drilling ship through P/R West Navigator DA.

sale of assets. This is partly offset by a NOK 2.3 billion increase in taxes payable. In 2003 a NOK 6.2 billion increase in deferred tax assets was recorded as income, of which the repeal of the Removal Grants Act represented NOK 6.7 billion. The deferred tax income was NOK 0.6 billion in 2002. As a result of the changes in legislation, Statoil's claim against the Norwegian state totaled NOK 6.0 billion. The net recording to income related to the repeal of the Removal Grants Act in the second quarter of 2003 amounted to NOK 0.7 billion, which had no cash effect in the period.

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, as well as NOK 2.0 billion in increased tax payments.

Cash Flows used in Investing Activities

Net cash flows used in investing activities amounted to NOK 23.2 billion in 2003, as compared to NOK 16.8 billion in 2002, and NOK 12.8 billion for 2001. Gross investments, defined as additions to property, plant and equipment and capitalized exploration expenditures, increased from NOK 17.4 billion in 2001, to NOK 20.1 billion in 2002 and to NOK 24.1 billion in 2003. Gross investments also include investments in intangible assets and long-term share investments. The increase from 2002 to 2003 is mainly related to increased investments in the E&P Norway and International E&P business areas as a result of an increased number of development projects. The difference between cash flows to investment activities and gross investments is mainly related to the divestment of Navion in the second quarter of 2003. Furthermore the prepayment made in 2003 of USD 1.0 billion for the two assets in Algeria, In Salah and In Amenas , is included in Cash flow used in investment activities, but is not reported as investment in 2003, as the transaction is subject to approval by Algerian authorities.

The 31% increase in net cash flows used in investment activities from 2001 to 2002 was 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.

Cash Flows used in Financing Activities

Net cash flows used in financing activities amounted to NOK 7.9 billion for 2003, as compared to NOK 4.6 billion for 2002 and NOK 31.5 billion in 2001. New long-term borrowing in 2003 decreased by NOK 2.2 billion compared to 2002, while repayment of long-term debt decreased by NOK 2.1 billion. The NOK 3.3 billion increase in cash flows used in financing activities from 2002 to 2003 is mainly related to changes in cash flow related to net short-term borrowings and bank overdrafts. The amount reported in 2003 includes a dividend paid to shareholders of NOK 6.3 billion, while the dividend paid to shareholders in 2002 was NOK 6.2 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 the issuance of new shares in 2001.

We paid dividends amounting to NOK 6.3 billion in 2003. Dividends paid in 2002 totaled NOK 6.2 billion, while dividends paid in 2001 amounted to NOK 55.4 billion. 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 (total current assets less current liabilities) increased by NOK 3.0 billion from 2002 to 2003, from a negative working capital of NOK 1.3 billion as of December 31, 2002 to a positive working capital of NOK 1.7 billion as of December 31, 2003. Working capital as of December 31, 2001 was negative by NOK 9.5 billion. 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, which are outside of our control will cause changes in our cash flows. We will use available liquidity 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. The level of oil and gas prices as well as levels of production will consequently influence the financing of investments. The level of investments in the coming years is expected to increase from its current level, along with expected growth as well in cash flow from operations due to anticipated increase in production, assuming that decreases in oil and gas prices do not outweigh increases in production. There will however most likely be a gap between funds from operations and funds necessary to cover the cash needed to fund investments. In 2004, Statoil prepares for funding from external sources, but it is our intention to maintain the level of net debt to capital below 40%-45%. The absolute level of debt issued will depend highly on the oil and gas prices throughout the year, influencing available cash.

As of December 31, 2003, we had liquid assets of NOK 16.6 billion, including approximately NOK 9.3 billion of domestic and international capital market investments, primarily government bonds, but also other investment grade short-term debt securities, and NOK 7.3 billion in cash and cash equivalents. As of December 31, 2003, approximately 70% of our cash and cash equivalents were held in NOK, 10% in US dollars, 15% 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 4.0 billion during 2003, as compared to year-end 2002. Cash and cash equivalents increased by NOK 0.6 billion during 2003, as compared to year-end 2002. The reason for this increase is mainly related to liquidity management.

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.

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.

Our general policy is to **maintain a liquidity reserve** in the form of cash and cash equivalents on our balance sheet and 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, 2003, the Group had available USD 1.6 billion in committed revolving credit facilities from international banks, including a USD 0.5 billion swingline facility. The facilities were entered into by us in 2000 (USD 1.0 billion) and 2003 (USD 0.6 billion), and are available for drawdowns until November 2005 and January 2008, respectively. At year-end 2003 no amounts had been drawn under either facility. Our short- and long-term ratings from Moody's and Standard & Poor's, respectively, are P-1/A1 and A-1/A. In June 2003 Standard & Poor's revised their outlook on Statoil from stable to negative.

Interest-bearing debt. Gross interest-bearing debt was NOK 37.3 billion at the end of 2003 compared to NOK 37.1 billion at the end 2002. Despite new investments, interest-bearing debt was maintained at a relatively stable level, mainly due to the access to liquidity due to increased cash flow from operations. At December 31, 2001 gross interest-bearing debt was NOK 41.8 billion.

Net interest bearing debt is calculated as interest-bearing debt excluding cash, cash equivalents and short-term investments. Net interest-bearing debt was NOK 20.9 billion as of December 31, 2003 compared to NOK 23.6 billion as of December 31, 2002. Although total interest-bearing debt has slightly increased, net interest-bearing debt has been reduced, which is mainly due to an increase in cash, cash equivalents and short-term investments of NOK 2.9 billion during the period. At December 31, 2001 net interest-bearing debt was NOK 34.1 billion. Our methodology of calculating net interest bearing debt makes certain adjustments and may therefore be considered to be a Non-GAAP financial measure. See- Use of Non-GAAP Financial Measures for reconciliation.

Net debt to capital employed ratio, defined as net interest-bearing debt to capital employed, was 22.6% as of December 31, 2003, compared to 28.7% as of December 31, 2002 and 39.0% as of December 31, 2001. The decrease in the net debt to capital ratio is mainly due to an increase in cash, cash equivalents and short-term investments, as well as increased shareholders' equity. The net debt to capital ratio for 2003 also reflects the prepayment of certain expenditures related to Statoil's intended share of the In Salah and In Amenas assets in Algeria, which reduced cash, cash equivalent and short term-investments by NOK 6.8 billion. Our methodology of calculating the net debt to capital ratio makes certain adjustments outlined below and may therefore be considered to be a Non-GAAP financial measure. See- Use of Non-GAAP Financial Measures.

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 2003, a total of JPY 10 billion and USD 30 million of fixed rate notes and EUR 200 million of floating rate notes were issued under our EMTN Program, equivalent to a total of NOK 2.8 billion. Maturities range from two to seven years. NOK 500 million of five-year bonds was issued in the Norwegian market in 2003. After the effect of currency swaps, our borrowings are nearly 100% in US dollars. As of December 31, 2003, our long-term debt portfolio totaled NOK 33.0 billion, with a weighted average maturity of approximately 11 years and a weighted average interest rate of approximately 4.8% per annum. 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.

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 3.2 billion in 2003, NOK 5.4 billion in 2002 and NOK 9.6 billion in 2001. We repaid approximately NOK 2.8 billion in 2003, approximately NOK 4.8 billion in 2002 and approximately NOK 4.5 billion in 2001. At December 31, 2003, NOK 3.2 billion of our borrowings were due for repayment within one year, NOK 9.3 billion were due for repayment between two and five years and NOK 23.7 billion were due for repayment after five years. This compares to NOK 2.0 billion, NOK 8.5 billion and NOK 24.3 billion, respectively, as of December 31, 2002, and NOK 5.4 billion, NOK 8.6 billion and NOK 26.6 billion, respectively, as of December 31, 2001.

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 is provided in —Risk Management below.

Table of Principal Contractual Obligations and Other Commercial Commitments

The following table summarizes our principal contractual obligations and other commercial commitments as at December 31, 2003. The table below includes contractual obligations, but excludes derivatives and other hedging instruments.

		Payment due by period			
Contractual obligations (in NOK million)	**Total**	**Less than 1year**	**1-3 years**	**4-5 years**	**After 5 years**
Long-term debt	36,159	3,168	4,819	4,479	23,693
Finance lease obligations	75	19	36	19	1
Operating leases	9,170	2,999	3,373	845	1,953
Transport capacity and similar obligations	47,155	3,002	6,859	6,106	31,188
Total contractual obligations	92,559	9,188	15,087	11,449	56,835

		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	1,777	457	418	0	902

Contractual obligations in respect of capital expenditure amount to NOK 20.9 billion of which payments of NOK 13.1 billion are due within one year. Pension obligations are NOK 17.6 billion, of which Statoil has an existing pension fund of NOK 15.1 billion as at December 31, 2003. Total prepaid pensions amount to NOK 2.1 billion.

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 expenditure were NOK 1,004 million, NOK 736 million and NOK 633 million in 2003, 2002 and 2001, respectively.

Corporate Targets

This section contains a discussion of our corporate targets. We use these targets in order to measure our progress in enhancing production, utilizing capital efficiently and enhancing operational efficiencies. We have announced targets for the fiscal year 2004 for the measures normalized return on average capital employed (normalized ROACE), production, finding and development cost, normalized production cost and reserve replacement rate. We have announced targets for the fiscal year 2007 for the measures normalized return on average capital employed (normalized ROACE), production, reserve replacement rate, finding and development cost and normalized production cost. This section contains a discussion of those target measures and reports the results of those measures for the current period. For a discussion of historical and projected gross investment and capital expenditure, see —Trend Information below.

The following discussion of corporate targets uses several measures, which are "non-GAAP financial measures" as defined by the U.S. Securities and Exchange Commission. These are return on average capital employed (ROACE), normalized return on average capital employed (normalized ROACE), normalized production cost per barrel and net debt to capital employed ratio. For more information on these measures and for a reconciliation of these measures to measures calculated in accordance with US GAAP, see —Use of Non-GAAP Financial Measures below.

Summary of targets –2004

We are targeting:

- a ROACE of 12% on a normalized basis for the year 2004, 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 EUR 150 per tonne, and a NOK/USD exchange rate of 8.20, as described below; and
- oil and natural gas production of 1,120 mboe per day through 2004.

Further, we are committed to pursuing the following objectives to enhance operational efficiencies from 2004:

- reducing unit production costs from 2.8 USD/ boe in 2003 to lower than 2.7 USD/ boe in 2004, normalized at a NOK/USD exchange rate of 8.20;
- maintaining finding and development costs (3 year average) below 6.0 USD/ boe for the three year period to December 31, 2004.

The 2004 targets (other than the reserve replacement rate target) are based on a continued organic development of Statoil and exclude possible effects related to acquisitions.

Summary of targets –2007

We are targeting:

- a ROACE of 12.5% on a normalized basis for the year 2007, assuming an average realized oil price of USD 18 per barrel, natural gas price of NOK 0.80 per scm, refining margin (FCC) of USD 3.3 per barrel, Borealis margin of 165 EUR/ton and a NOK/USD exchange rate of 7.50, as described below; and
- oil and natural gas production of 1,350 mboe per day in 2007.

Further, we are committed to pursuing the following objectives to enhance operational efficiencies through 2007:

- reducing unit production costs to lower than 3.1 USD/ boe, normalized at a NOK/USD exchange rate of 7.50 (the equivalent of 2.7 USD/ boe normalized at a NOK/USD exchange rate of 8.20); and
- maintaining finding and development costs (3 year average) below 6.0 USD/ boe for the period through 2007.

The 2007 targets include the effects of the Algerian transaction with respect to the In Salah and In Amenas fields, due to the fact that the transaction was known, when we set the targets and when we will start reporting towards the 2007 target. However, on a going-forward basis the 2007 targets (other than the reserve replacement rate target) are based on a continued organic development of Statoil and exclude possible effects related to any additional, but not known, acquisitions, which may affect our targets materially and cause us to revise our targets as a result of the impact of such acquisitions.

For the sake of comparability, the targets for 2007 are shown in the third column in the table below, with the equivalents of the 2007 targets calculated based on the 2004 normalization shown in the fourth column.

Corporate targets	2004	2007 (new normalization)	2007 (based on 2004 normalization)
ROACE*	12.0%	12.5%	13%
Production (1000 boe per day)	1,120	1,350	1,350
Reserve replacement rate**	>1.0	>1.3	>1.3
Finding and development cost (USD/ boe)**	<6.0	<6.0	<5.25
Production cost* (USD/boe)	<2.7	<3.1	<2.7

* Normalized
** 3-year average

The forecasted production growth to 2007 is based on the current characteristics of our reservoirs, our planned capital expenditures and our development budget. There are a number of factors that could cause actual results and developments to differ materially from the targets included here, including levels of industry product supply, demand and pricing; currency exchange rates; political and economic policies of Norway and other oil-producing countries; general economic conditions; political stability and economic growth in relevant areas of the world; global political events and actions, including war, terrorism and sanctions; the timing of bringing new fields on stream; material differences from reserves estimates; inability to find and develop reserves; adverse changes in tax regimes; 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. One of the main factors which could cause results to differ from our expectations would be possible delays in sanctioned development projects.

Return on Average Capital Employed

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:

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

Average capital employed reflects an average of capital employed at the beginning and the end of the financial period. In the calculation of average capital employed, Statoil makes certain adjustments to net interest bearing debt, which makes the number a Non-GAAP financial measure. For a reconciliation of the adjusted net interest bearing debt to the most comparable GAAP measure, see Use of Non –GAAP Financial Measures. Using average capital employed without these adjustments to net interest-bearing debt, our ROACE for 2003 was 18.6%, Our historic ROACE using average capital employed with these adjustments for 2001, 2002 and 2003 was 19.9%, 14.9% and 18.7%, respectively.

ROACE and normalized ROACE are Non-GAAP financial measures. See-Use of Non-GAAP Financial Measures.

For purposes of measuring our performance against our 2004 ROACE target, 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 EUR 150 per tonne, and a NOK/USD exchange rate of 8.20. All prices and margins are adjusted for inflation from 2000. In the calculation of the normalized return, adjustments are made to exclude items of a non-frequent nature. These items are viewed as activities or events which management considers as being of such a nature, that their inclusion into the ROACE calculation will not provide indications on the company's underlying performance. The 2004 target is based on organic development and therefore the effects of the acquisition of the Algerian assets In Salah and In Amenas are excluded. Normalization is done in order to exclude factors that Statoil cannot influence from its performance targets. For reconciliation of the ROACE and normalized ROACE figures to items calculated in accordance with GAAP, see the table below. We are targeting a 12% ROACE.

Normalized ROACE was 9.4% for the year ended December 31,2001, 10.8% in 2002, and 12.4% in 2003. When we started out measuring the ROACE 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. 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.

While continuing to focus on our overall objective of strict capital discipline, we believe that through additional efforts, including the improvement program from 2001 to 2004 targeting an improvement of both costs and revenues of NOK 3.5 billion from 2004 as compared to 2001, our organic production growth and enhanced operating efficiencies, will help us reach our 12% ROACE target for 2004.

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 is subject to numerous risks and uncertainties as described above.

As described above, Statoil introduced new targets for 2007, where a normalized ROACE of 12.5% was one of the targets. When normalizing the reported ROACE we assume an oil price of USD 18 per barrel, natural gas price of NOK 0.80 per scm, refining margin (FCC) of USD 3.3 per barrel, Borealis margin of 165 EUR/ton and a NOK/USD exchange rate of 7.50. All prices and margins are adjusted for inflation from 2004. These changed assumptions for purposes of our 2007 targets reflect changes in the underlying prices and margins from the assumptions made when we set our targets for 2004. These assumptions do not reflect actual prices and margins at the time the assumptions were set or at any specific point in time and do not comprise our expectations with respect to the future movements of such prices and margins, but are based on movements over a broader time frame and function to allow comparability across periods.

Production cost per boe for the last 12 months was USD 3.2 per boe for the year 2003, compared to USD 3.0 per boe for the year 2002 and USD 2.8 for the year 2001. The increase compared to 2002 and 2001 is due to a lower NOK/USD exchange rate, because costs are primarily incurred in NOK. Correspondingly, the production costs in NOK were NOK 22.8 per boe for the year 2003, compared to NOK 23.5 per boe in 2002 and NOK 25.2 for the year 2001. Normalized to a NOK/USD exchange rate of 8.20, in order to exclude currency effects, the production cost for 2003 is USD 2.8 per boe compared to USD 2.9 per boe for 2002 and USD 3.0 for 2001. Normalized production cost is a Non-GAAP financial measure as a result of its normalization at a set NOK/USD exchange rate. See —Use of Non-GAAP Financial Measures.

Finding and development cost

Statoil's finding and development costs in 2003 were USD 7.7 per boe, compared to USD 5.3 per boe in 2002 and USD 4.6 per boe in 2001. The average finding and development cost for the last three years was USD 5.9 per boe, as compared to USD 6,2 in 2002 and USD 9.1 in 2001 The year 2001 was a very good year, mainly due to increased booking of proved reserves, compared to previous years. The target for 2004 is below USD 6.0. The finding and development costs are calculated using costs of exploration and development divided by new proved reserves, according to the SEC definition, excluding reserves purchases and sales.

Finding and development costs (USD/BOE)*	2001	2002	2003
Corporate	9.12	6.20	5.87
E&P Norway	9.35	5.89	5.24
International E&P	8.60	7.15	7.88

*3-year average

Reserve replacement rate

Proved oil and gas reserves were 4,264 million boe at the end of 2003, compared with 4,267 million boe at the end of 2002 and 4,277 million boe at the end of 2001. The reserve replacement rate was 99 per cent in 2003, compared to 98 per cent in 2002 and 89 per cent in 2001. The average replacement rate for the last three years was 95 per cent. Reserve replacement rate includes the effect of transactions and was lower in 2001, than in 2002 and 2003, although production has increased throughout the three year period, mainly due to transactions made on the NCS in 2001. The target for reserve replacement is an average of 100% for the three years from 2002-2004.

Reserve replacement rate (3-year average)	2001	2002	2003
Corporate	0.68	0.78	0.95
E&P Norway	0.77	0.63	0.79
International E&P*	2.14	2.79	2.96

* Reserve replacement rate for International E&P is adjusted for the sale of Statoil Energy Inc. in 2000.

Production

Total oil and gas production in 2003 was 1,080,000 barrels of oil equivalent (boe) per day compared to 1,074,000 boe per day in 2002, and 1,007,000 boe per day in 2001. The target production for 2004 is 1,120,000 boe per day.

Our expected production growth through 2007 is based on the current characteristics of our reservoirs, our planned capital expenditure and our development budget. Including acquisition of interest in the two assets In Salah and In Amenas, the production target for 2007 is set at 1,350,000 boe per day.

Trend Information

The forecasted growth in the coming years will require an increase in investments from its current level and will consequently depress ROACE in 2005 and 2006. However, based on current projections we currently do not expect that the normalized ROACE will go below 10%. Based on current projections we currently expect the normalized ROACE to increase in 2007. Out of the projects expected to contribute to reaching this production target for 2007 nearly 95% are already sanctioned projects.

Capital Expenditures

Set forth below are our capital expenditures in our four principal business segments for 2001-2003, including the allocation per segment as a percentage of gross investments.

Capital expenditures (1) per segment (amounts in million)	Year ended December 31, 2001 NOK	2001 %	2002 NOK	2002 %	2003 NOK	2003 %
E&P Norway	10,759	60.0	11,023	55.0	13,412	55.7
International E&P	5,027	28.0	5,995	29.9	8,147	33.8
Natural Gas	671	3.7	465	2.3	456	1.9
Manufacturing and Marketing	811	4.5	1,771	8.8	1,546	6.4
Other	685	3.8	799	4.0	530	2.2
Total	17,953(1)	100	20,053	100	24,091	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 these gross investments are included in our NOK 95 billion target and guidance for the period 2001-2004 which was communicated at the IPO. The difference between capital expenditures and gross investments in 2001 is mainly related to Change in long term loans granted and other long-term items of NOK 0.5 billion, which was included in the capital expenditure figure for 2001, but not included in the definition of the gross investments figure.

The year 2004

This section describes our estimated capital expenditure for 2004 in respect of potential capital expenditure requirements for the principal investment opportunities available to us and other capital projects currently under consideration. The figure is based on an organic development of Statoil and exclude possible expenditures related to acquisitions. Therefore, the expenditure estimates and descriptions with respect to investments in the segment descriptions below could differ materially from the actual expenditures.

Our opportunities and projects under consideration could be sold, delayed or postponed in implementation, reduced in scope or rejected. Accordingly, the figure for 2004 is only an estimate 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. Total capital expenditure for 2004 is expected to be approximately NOK 30 billion excluding the investments related to the two Algerian assets, In Salah and In Amenas and the possible repurchase of the 50% interest in SDS from ICA AB. This will bring the total investment level for 2001-2004 to approximately NOK 92 billion. Of the investments related to the two Algerian assets, a prepayment of USD 1 billion was made in 2003, which will be included in investments for 2004, subject to the necessary approval of Algerian authorities. Including these investments, capital expenditure is expected to be at the level of approximately NOK 40 billion in 2004. We expect the allocation of capital expenditures between the segments to be in line with previous years.

E&P Norway. A substantial portion of our 2004 capital expenditure is allocated to the ongoing development projects in Kvitebjørn, Kristin and Snøhvit.

International E&P. We currently estimate that a substantial portion of our 2004 capital expenditure will be allocated to the ongoing and planned development projects: In Salah, In Amenas, Azeri-Chirag-Gunashli including the Baku-Tbilisi-Ceyhan pipeline, Shah Deniz, Dalia, Kizomba A and B.

Natural Gas. 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 development of a new pipeline to the UK, and the Aldbrough gas storage project on the east coast of the UK and the South Caucasus Pipeline related to the Shah Deniz field.

Manufacturing and Marketing. 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, as well as the possible acquisition of 50% share of SDS.

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;
- fulfillment of necessary preconditions to consummation of acquisitions such as In Salah, In Amenas and SDS;
- 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 such as rig blowups or fires, and natural hazards;
- 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.

Use of Non-GAAP Financial Measures

The U.S. Securities and Exchange Commission adopted regulations regarding the use of "Non-GAAP financial measures" in public disclosures, effective March 28, 2003. Non-GAAP financial measures are defined as numerical measures that either exclude or include amounts that are not excluded or included in the comparable measures calculated and presented in accordance with GAAP.

These Non-GAAP financial measures are:

- Return on Average Capital Employed (ROACE).
- Normalized Return on Average Capital Employed (normalized ROACE).
- Normalized production cost per barrel.
- Net debt to capital employed ratio.

Statoil uses **ROACE** to measure the return on capital employed regardless of whether the financing is through equity or debt. This measure is viewed by management as providing useful information, both for management and investors, regarding performance for the period under evaluation. Statoil's management makes regular use of this measure to evaluate its operations. Statoil's use of ROACE, should not be viewed as an alternative to income before financial items, other items, income taxes and minority interest, or to net income, which are the measures calculated in accordance with generally accepted accounting principles.

Statoil uses **normalized ROACE** to measure the return on capital employed, while excluding the effects of the market development over which Statoil has no control. Therefore the effects of oil price, natural gas price, refining margin, Borealis margin and the NOK/USD exchange rate are excluded from the normalized figure.

This measure is viewed by management as providing a better understanding of Statoil's underlying performance over time and across periods, by excluding from the performance measure factors that Statoil cannot influence. Statoil's management makes regular use of this measure to evaluate its operations.

The figures used for calculating the normalized ROACE towards the 2004 target are (each adjusted for inflation from 2000):

- oil price at 16 USD;
- natural gas price of NOK 0.70/scm;
- FCC-refining margin of USD 3.0 per barrel;
- petrochemical margin of EUR 150 per tonne; and
- NOK/USD exchange rate of 8.20.

By keeping certain prices which are key value drivers, as well as the important NOK/USD exchange rate, constant Statoil is able to utilize this measure to focus on operating cost and efficiency improvements, and is able to measure performance on a comparable basis across periods. Such a focus would be more challenging to maintain in periods in which prices are high and exchange rates are favorable. In the period 2001 to 2003, during which Statoil has been using normalized ROACE, as a tool of measuring performance, the normalization procedures have on average resulted in lower normalized earnings compared to the earnings based on realized prices. Normalized results, however, should not be seen as an alternative to measures calculated in accordance with GAAP when measuring financial performance. Management reviews both realized and normalized results, when measuring performance. However, management finds the normalized results to be especially useful when realized prices, margins and exchange rates are above the normalized set of assumptions. Normalized ROACE is based on organic development and 2003 figures exclude the effects related to the acquisition of the two Algerian assets from BP, In Salah and In Amenas. For future measurement towards the 2007 targets, this acquisition is not excluded from the figures, since the acquisition was known when starting reporting towards the new targets, which, however, was not the case with the 2004 targets.

Statoil also defines certain items as of such a nature that they will not provide good indications of the company's underlying performance when included in the key indicators. These items are therefore excluded from calculations of ROACE.

The following table shows our ROACE calculation based on reported figures, adjusted figures, which in 2003 consisted of the repeal of the Removal Grants Act, and normalized figures:

Calculation nominator and denominator used in ROACE calculation (in NOK million)	**2003**	**2002**	**2001**
Net income for the last 12 months	16,554	16,846	17,245
Minority interests for the last 12 months	289	153	488
After tax net financial items for the last 12 months	(496)	(4,352)	262
Net income adjusted for minority interests and after tax net financial items (A1)	16,347	12,647	17,995
Adjustments for effects of changes in the Removal Grants Act	(687)	0	0
Adjustments made in 2002 and 2001*	0	(144)	(2,100)
Net income adjusted for items above (A2)	15,660	12,503	15,895
Numerator adjustments for costs In Salah, In Amenas	35	0	0
Effect of normalized prices and margins	(6,998)	(3,832)	(6,237)
Effect of normalized NOK /USD exchange rate	1,712	446	(1,112)
Normalized net income (A3)	10,410	9,117	8,546
Computed average capital employed:			
Average capital employed (B1)**	88,016	86,167	91,147
Adjusted average capital employed (B2) **	87,361	84,755	90,518
Denominator adjustments on average capital employed In Salah, In Amenas ***	(3,422)	0	0
Average capital employed adjusted for In Salah, In Amenas (B3)	83,939	84,755	90,518

* Adjustments on the nominator made in 2001 consisted of a gain related to the sale of the operations in Vietnam of NOK 1.3 billion before tax and NOK 0.9 billion after tax, and the write-down of LL652 oil field in Venezuela NOK 2.0 billion before tax and NOK 1.4 billion after tax, and also included a non-taxable gain of NOK 1.4 billion related to the sale of the Grane, Njord, Jotun fields and a 12 per cent interest in the Snøhvit field off Norway and a gain related to the sale of the 4.76 per cent interest in the Kashagan oil discovery in the Caspian Sea (NOK 1.6 billion before tax, NOK 1.2 billion after tax). Adjustments made in the 2002 figures consisted of the sale of the exploration and operations activity on the Danish continental shelf (profit NOK 1.0 billion before tax and NOK 0.7 billion after tax), as well as a write-down of the LL652 field in Venezuela (NOK 0.8 billion before tax, NOK 0.6 billion after tax).

** See Use of Non-GAAP Financial Measures – Calculation of capital employed for a reconciliation of average capital employed and adjusted average capital employed. Average capital employed used when calculating the ROACE is the average of the opening and closing balance of a year.

*** Corresponds to 50% of the prepayment. The prepayment was made in 2003 and is therefore excluded from the closing balance of 2003, which implies a net effect of 50% of the prepayment on average capital employed.

ROACE calculation	2003	2002	2001
Calculated ROACE using average capital employed (A1/B1)	18.6%	14.7%	19.7%
Calculated ROACE using adjusted average capital employed (A1/B2)	18.7%	14.9%	19.9%
Calculated adjusted ROACE (A2/B2)	17.9%	14.8%	17.6%
Normalized ROACE (A3/B3)	12.4%	10.8%	9.4%

Improvement program

The information contained herein on the improvement program may contain forward-looking non-GAAP financial information for which at this time there is no comparable GAAP measure and which at this time cannot be quantitatively reconciled to comparable GAAP financial information.

Normalized production cost per barrel in USD is used to evaluate the underlying development in the production cost. Statoil's production costs are mainly incurred in NOK. In order to exclude currency effects and to reflect the change in the underlying production cost, the NOK/USD exchange rate is held constant.

Normalized production costs per boe is in the table below reconciled to the most comparable GAAP measure, production cost ber boe.

Production costs per boe	2001	2002	2003
Total production costs last 12 months (in NOK million)	9,257	9,196	8,892
Lifted volumes last 12 months (mill. boe)	368	392	391
Average NOK/USD exchange rate	8.99	7.97	7.08
Production cost per boe	**2.8**	**3.0**	**3.2**
Normalization of production cost per boe			
Total production costs last 12 months (in NOK million)	9,257	9,196	8,892
Production costs last 12 months E&P Norway (in NOK million)	8,233	8,217	7,998
Normalized exchange rate (NOK/USD)	8.20	8.20	8.20
Production costs last 12 months E&P Norway, normalized at NOK/USD 8.20	1,004	1,002	975
Production costs last 12 months International E&P (in USD million)	114	123	127
Total production costs last 12 months in USD (normalized)	1,118	1,125	1,102
Lifted volumes last 12 months (mill. boe)	368	392	391
Production cost per boe normalized at NOK/USD 8.20	3.0	2.9	2.8

Net debt to capital employed ratio

The calculated net debt to capital employed ratio is by management viewed to provide a more complete picture of the company's current debt situation. The calculation uses balance sheet items related to total debt and adjusts for current liquidity. Two further adjustments are made for two different reasons:

- Project financing through an external bank or similar will, since different legal entities in the group lend to and from the investment banks, overreport the debt stated in the balance sheet compared to the underlying exposure.
- Some interest–bearing elements are classified together with non-interest bearing elements, and are therefore included when calculating the net interest bearing debt.

The net interest-bearing debt adjusted for these two items is included in the adjusted average capital employed, which is also used in the calculation of the ROACE. The table below reconciles net interest-bearing debt, capital employed and net debt to capital employed ratio to the most directly comparable financial measure or measures calculated in accordance with GAAP.

Calculation of capital employed (in NOK million)	2001	2002	2003
Total shareholders' equity	51,774	57,017	70,174
Minority interest	1,496	1,550	1,483
Total equity and minority interest (A)	53,270	58,567	71,657
Net interest bearing debt			
Short-term debt	6,613	4,323	4,287
Long-term debt	35,182	32,805	32,991
Gross interest bearing debt	41,795	37,128	37,278
Cash and cash equivalents	(4,395)	(6,702)	(7,316)
Short-term investments	(2,063)	(5,267)	(9,314)
Cash, cash equivalents and short-term investments	(6,458)	(11,969)	(16,630)
Net interest bearing debt (B)	35,337	25,159	20,648
Capital employed (A+B)	88,607	83,726	92,305
Average capital employed	91,147	86,167	88,016
Net debt to capital employed (B/(A+B))	39.9%	30.2%	22.3%
Calculation of adjusted net interest bearing debt			
Adjustment of net interest bearing debt for project loan*	(1,257)	(1,567)	(1,500)
Adjustment of net interest bearing debt for other items**	0	0	1,758
Net interest bearing debt after adjustments (C)	34,080	23,592	20,906
Calculation of adjusted capital employed			
Adjusted capital employed (A+C)	87,350	82,159	92,563
Average adjusted capital employed	90,518	84,755	87,361
Net debt to capital employed A/(A+C)	39.0%	28.7%	22.6%

* Adjustment for intercompany project financing through an external bank.

** Adjustment made for deposits received for financial derivatives. Although these deposits are classified as liquid assets, they are interest bearing and are therefore not excluded from gross interest bearing debt when calculating our net interest bearing debt.

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, 2003, 2002, and 2001 was 1.5%, 1.3% and 3.0%, 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 evaluated Statoil's proved reserves estimates and the results of such evaluation do not differ materially from 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, and amortization. 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 used for depreciation, depletion and amortization and for decommissioning and removal provisions, as well as for the impairment testing of upstream assets, which could have a material adverse effect on net income as a result of increased deprecation, depletion and amortization or impairment charges.

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 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. As at year-end 2003 Statoil had recognized NOK 3.8 billion in capitalized exploration costs on assets in the exploration phase.

Decommissioning and removal liabilities. Statoil has significant legal obligations to decommission and remove offshore installations at the end of the production period. In June 2001, the Financial Accounting Standards Board (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. Statoil adopted the new rules on asset retirement obligations on January 1, 2003. Application of the new standard resulted in an increase in net property, plant and equipment of NOK 2.8 billion, an increase in accrued asset retirement obligation of NOK 7.1 billion, a reduction in deferred tax assets of NOK 1.5 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. Until changes in the legislation in June 2003 removal costs on the Norwegian continental shelf were, unlike decommissioning costs, not deductible for tax purposes. The implementation effect of NOK 33 million after tax is recorded as Operating expenses in the segment Other and eliminations.

Is it difficult to estimate the costs of these decommissioning and removal activities, which are based on current regulations and technology. Most of the removal activities are many years into the future and the removal technology and costs are constantly changing. As a result, the initial recognition of the liability and the capitalized cost associated with decommissioning and removal obligations, and the subsequent adjustment of these balance sheet items, involves the application of significant judgment. As at year-end 2003 Statoil had recognized NOK 2.8 billion in increased assets and liabilities related to asset retirement obligations amounting to NOK 16.5 billion.

Derivative financial instruments and hedging activities. In June 1998, 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 value 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.

Off-balance Sheet Arrangements

As a condition for being awarded oil and gas exploration and production licenses, participants may be committed to drill a certain number of wells. At the end of 2003, Statoil was committed to participate in 6 wells off Norway and 9 wells abroad, with an average ownership interest of approximately 35 per cent. Statoil's share of expected costs to drill these wells amounts to approximately NOK 1.9 billion.

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 based on booked volume capacity. In addition the Group has entered into certain obligations for entry capacity fees and terminal capacity commitments. The following table outlines nominal minimum obligations for future years. Corresponding expense for 2003 was NOK 2,712 million. Where the Group reflects both ownership interests and transport capacity cost for a pipeline in the consolidated accounts, the amounts in the table include the transport commitments that exceed Statoil's ownership share. For specification of Transport capacity and similar obligations at December 31, 2003 see table Contractual obligations under Liquidity and Capital resources.

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. See details of our financing strategy above concerning the objective of our debt portfolio to mitigate currency exchange risks. 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 reviewing, defining and developing our strategic market risk policies. 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, who advises and recommends specific actions to our Executive 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 sub optimization, 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.

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, 2003, based on maturity of contracts and the source of determining the fair market value of contracts, respectively:

Source of Fair Market Value	**Net Fair Market Value**				
At December 31, 2003 (in NOK million)	**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	23	0	0	0	23
Prices provided by other external sources	62	8	0	0	70
Prices based on models or other valuation techniques	3	6	5	2	16
Total commodity based derivatives	88	14	5	2	109
Financial derivatives:					
Prices actively quoted	788	254	857	2,652	4,551
Prices provided by other external sources	0	0	0	0	0
Prices based on models or other valuation techniques	0	0	0	0	0
Total financial derivatives	788	254	857	2,652	4,551

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, 2003, or December 31, 2002, net of margin calls. Derivatives entered into and subsequently terminated during the course of the year 2003 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, 2002	37	2,142
Contracts realized or settled during the period	158	(221)
Fair value of new contracts entered into during the period	16	830
Changes in fair value attributable to changes in valuation techniques or assumptions	0	0
Other changes in fair values	(85)	1,799
Net fair value of derivative contracts outstanding as at December 31, 2003	126	4,551

Derivatives and Credit risk

Futures contracts have little credit risk because organized exchanges are the counter-parties. The credit risk from Statoil's 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 derivative 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. As at year-end 2003, we had called and received a total of NOK 1,758 million in cash as collateral for unrealized gains on OTC derivatives.

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 one year, and the terms of debt related interest swaps and currency swaps are up to 25 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, net of netting agreements and collateral as at December 31, 2003, split by our assessment of the counter-party's credit risk:

OTC derivative assets split per counter- party (in NOK million)	Fair Market Value
Counter-party rated:	
Investment grade, rated A or above	3,354
Other investment grade	89
Non investment grade or not rated	80

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, 2003, approximately 67% of the approximately NOK 122 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

All statements other than statements of historical facts, including, among others, statements regarding our future financial position, business strategy, budgets, reserve information, projected levels of capacity and production, projected operating costs, estimates of capital expenditure, expected exploration and development activities and plans and objectives of management for future operations, 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 and economic policies of Norway and other oil-producing countries; general economic conditions; political stability and economic growth in relevant areas of the world; global political events and actions, including war, terrorism and sanctions; the timing of bringing new fields on stream; material differences from reserves estimates; inability to find and develop reserves; adverse changes in tax regimes; 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 20F expected to be filed with the US Securities and Exchange Commission in March 2004.

Statoil group – USGAAP

CONSOLIDATED STATEMENTS OF INCOME – USGAAP

(in NOK million)	2003	Year ended December 31, 2002	2001
REVENUES			
Sales	**248,527**	242,178	231,712
Equity in net income of affiliates	**616**	366	439
Other income	**232**	1,270	4,810
Total revenues	**249,375**	243,814	236,961
EXPENSES			
Cost of goods sold	**(149,645)**	(147,899)	(126,153)
Operating expenses	**(26,651)**	(28,308)	(29,422)
Selling, general and administrative expenses	**(5,517)**	(5,251)	(4,297)
Depreciation, depletion and amortization	**(16,276)**	(16,844)	(18,058)
Exploration expenses	**(2,370)**	(2,410)	(2,877)
Total expenses before financial items	**(200,459)**	(200,712)	(180,807)
Income before financial items, other items, income taxes and minority interest	**48,916**	43,102	56,154
Net financial items	**1,399**	8,233	65
Other items	**(6,025)**	0	0
Income before income taxes and minority interest	**44,290**	51,335	56,219
Income taxes	**(27,447)**	(34,336)	(38,486)
Minority interest	**(289)**	(153)	(488)
Net income	**16,554**	16,846	17,245
Net income per ordinary share	**7.64**	7.78	8.31
Weighted average number of ordinary shares outstanding	**2,166,143,693**	2,165,422,239	2,076,180,942

Revenues are net of excise tax of NOK 20,753 million, NOK 18,745 million and NOK 18,571 million in 2003, 2002 and 2001, respectively.

See notes to the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS – USGAAP

(in NOK million)	At December 31, 2003	2002
ASSETS		
Cash and cash equivalents	**7,316**	6,702
Short-term investments	**9,314**	5,267
Cash, cash equivalents and short-term investments	**16,630**	11,969
Accounts receivable	**28,048**	32,057
Accounts receivable - related parties	**2,144**	1,893
Inventories	**4,993**	5,422
Prepaid expenses and other current assets	**7,354**	6,856
Total current assets	**59,169**	58,197
Investments in affiliates	**11,022**	9,629
Long-term receivables	**14,261**	7,138
Net property, plant and equipment	**126,528**	122,379
Other assets	**10,620**	8,087
TOTAL ASSETS	**221,600**	205,430
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	**4,287**	4,323
Accounts payable	**17,977**	19,603
Accounts payable - related parties	**6,114**	5,649
Accrued liabilities	**11,454**	11,590
Income taxes payable	**17,676**	18,358
Total current liabilities	**57,508**	59,523
Long-term debt	**32,991**	32,805
Deferred income taxes	**37,849**	43,153
Other liabilities	**21,595**	11,382
Total liabilities	**149,943**	146,863
Minority interest	**1,483**	1,550
Common stock (NOK 2.50 nominal value), 2,189,585,600 shares authorized and issued	**5,474**	5,474
Treasury shares, 23,441,885 shares	**(59)**	(59)
Additional paid-in capital	**37,728**	37,728
Retained earnings	**27,627**	17,355
Accumulated other comprehensive income	**(596)**	(3,481)
Total shareholders' equity	**70,174**	57,017
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**221,600**	205,430

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, 2001	1,975,885,600	4,940	0	45,628	14,768	2,490	67,826
Net income					17,245		17,245
Translation adjustment and other comprehensive income						(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
Translation adjustment and other comprehensive income						(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
Net income					16,554		16,554
Translation adjustment and other comprehensive income						2,885	2,885
Total comprehensive income							19,439
Ordinary dividend					(6,282)		(6,282)
At December 31, 2003	2,189,585,600	5,474	(59)	37,728	27,627	(596)	70,174

Other comprehensive income amounts are net of income tax benefit of NOK 81 million, NOK 78 million and NOK 4 million at 2003, 2002 and 2001, respectively.

Dividends paid per share were NOK 2.90, NOK 2.85 and NOK 26.69 in 2003, 2002 and 2001, 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)	2003	Year ended December 31, 2002	2001
OPERATING ACTIVITIES			
Consolidated net income	**16,554**	16,846	17,245
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Minority interest in income	**289**	153	488
Depreciation, depletion and amortization	**16,276**	16,844	18,058
Exploration costs written off	**256**	554	935
(Gains) losses on foreign currency transactions	**781**	(8,771)	180
Deferred taxes	**(6,177)**	628	848
Income taxes of transferred SDFI properties	**0**	0	5,952
(Gains) losses on sales of assets and other items	**5,719**	(1,589)	(4,990)
Changes in working capital (other than cash and Cash equivalents):			
• (Increase) decrease in inventories	**349**	(146)	(1,050)
• (Increase) decrease in accounts receivable	**2,054**	(6,211)	4,522
• (Increase) decrease in other receivables	**(1,511)**	3,107	(1,543)
• (Increase) decrease in short-term investments	**(4,047)**	(3,204)	1,794
• Increase (decrease) in accounts payable	**(949)**	4,118	(3,852)
• Increase (decrease) in other payables	**2,436**	(645)	(3,370)
• Increase (decrease) in taxes payable	**(682)**	1,740	1,741
(Increase) decrease in non-current items related to operating activities	**(551)**	599	2,215
Cash flows provided by operating activities	**30,797**	24,023	39,173
INVESTING ACTIVITIES			
Additions to property, plant and equipment	**(22,075)**	(17,907)	(16,649)
Exploration expenditures capitalized	**(331)**	(652)	(765)
Change in long-term loans granted and other long-term items	**(7,682)**	(1,495)	(539)
Proceeds from sale of assets	**6,890**	3,298	5,115
Cash flows used in investing activities	**(23,198)**	(16,756)	(12,838)

See notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS – USGAAP

(in NOK million)	2003	Year ended December 31, 2002	2001
FINANCING ACTIVITIES			
New long-term borrowings	**3,206**	5,396	9,609
Repayment of long-term borrowings	**(2,774)**	(4,831)	(4,548)
Distribution to minority shareholders	**(356)**	(173)	(1,878)
Dividends paid	**(6,282)**	(6,169)	(5,668)
Amounts paid to shareholder, related to SDFI properties	**0**	0	(49,747)
Capital contribution related to SDFI properties	**0**	0	8,460
Net proceeds from issuance of new shares	**0**	0	12,890
Net short-term borrowings, bank overdrafts and other	**(1,656)**	1,146	(588)
Cash flows used in financing activities	**(7,862)**	(4,631)	(31,470)
Net increase (decrease) in cash and cash equivalents	**(263)**	2,636	(5,135)
Effect of exchange rate changes on cash and cash equivalents	**877**	(329)	(215)
Cash and cash equivalents at January 1	**6,702**	4,395	9,745
Cash and cash equivalents at December 31	**7,316**	6,702	4,395
Interest paid	**1,336**	1,782	3,793
Taxes paid	**34,230**	31,634	33,320

Imputed income taxes related to transferred SDFI properties, are included in financing activities as cashflows to shareholder until May 31, 2001 when the transaction became effective, and result in an ajustment to reconcile net income to net cash flows provided by operating activities. Changes in working capital items resulting from the disposal of the subsidiary Navion in 2003 are excluded from Cash flows provided by operating activities and classified as Proceeds from sale of assets.

See notes to the consolidated financial statements.

1. Organization and Basis of Presentation

Statoil ASA was founded in 1972, as a 100 per cent 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 per cent 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 of 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 2004. The adjustment to the cash payment, if any, will be recorded as a capital contribution or dividend as applicable.

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 per cent. 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 per cent ownership), are accounted for by the equity method. Undivided interests in unincorporated 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 Statoil's foreign subsidiaries the local currency is the functional currency, with the exception of some upstream subsidiaries, where the US dollar is the functional currency.

When translating foreign functional currency financial statements to Norwegian kroner, year-end exchange rates are applied to asset and liability accounts, and average 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 re-measured into the functional currency using current exchange rates. Gains or losses from this re-measurement are included in income.

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 by oil and gas properties are recorded on the basis of sales to customers.

Cash and cash equivalents
Cash and cash equivalents include cash, bank deposits and all other monetary instruments with three months or less to maturity at the date of purchase.

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 Net financial items. Income from short-term investments is recorded when earned.

Inventories
Inventories are valued at the lower of cost or market. Costs of crude oil held at refineries and the majority of refined products are determined under the last-in, first-out (LIFO) method. Certain inventories of crude oil, refined products and non-petroleum products are 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 Statoil 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 to 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 other assets and of transport systems used by several fields is calculated on the basis of their economic life expectancy, using the straight-line method. The economic life of nonfield-dedicated 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 expenditures 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.

Assets held for sale
Assets held for sale are classified as short-term if the appropriate accounting criteria are met. The main criteria are that management with the authority to do so commit to a plan to sell the assets and expects to record the transfer of the assets as a completed sale within one year. Assets held for sale are measured at the lower of its carrying amount or fair value less costs to sell.

Asset retirement obligation
Financial Accounting Standard (FAS) 143, Accounting for Asset Retirement Obligations was effective from January 1, 2003. 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. Fair value is estimated based on existing technology and regulation. Upon initial recognition of a liability, the costs are capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. Changes in asset retirement obligation estimates are capitalized as part of the long-lived asset and expensed prospectively over the remaining useful life of the asset.

The discount rate used when estimating the fair value of the asset retirement obligation is credit-adjusted risk-free interest rate with the same expected maturity as the removal obligation.

Prior to application of FAS 143 the estimated costs of decommissioning and removal of major producing facilities were accrued using the unit-of-production method. These costs represented the estimated future undiscounted costs of decommissioning and removal based on existing regulations and technology.

Leased assets
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 over their expected economic life, and the liability is reduced for lease payments less the effective interest expense.

Employee retirement plans
Pension liabilities are calculated in accordance with FAS 87. Prior service costs, due to plan amendments, are amortized on a straight-line basis over the average remaining service period of active participants. Accumulated gains and losses in excess of 10 per cent of the greater of the benefit obligation or the fair value of assets are amortized over the remaining service period of active plan participants.

Research and development
Research and development expenditures 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
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 that do not qualify for the normal purchase and normal sales exemption at fair value as assets or liabilities in the Consolidated Balance Sheets. 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 Sheets until the transaction is reflected in the Consolidated Statements 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.

Reclassifications

Statoil has adjusted the formula for calculating the inter-segment price for deliveries of natural gas from Exploration and Production Norway to Natural Gas, see note 3.

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

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, 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 adopted the new rules on asset retirement obligations on January 1, 2003. Application of the new standard resulted in an increase in net property, plant and equipment of NOK 2.8 billion, an increase in accrued asset retirement obligation of NOK 7.1 billion, a reduction in deferred tax assets of NOK 1.5 billion, and a long-term receivable of NOK 5.8 billion. The receivable represented 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 were, unlike decommissioning costs, not deductible for tax purposes. The implementation effect of NOK 33 million after tax is expensed as Operating expenses in the segment Other and eliminations. If the standard had been applied as of the beginning of 2001 the effect on net income and shareholders' equity for the years ended 2001 and 2002 would have been immaterial.

The Norwegian Parliament decided in June 2003 to replace governmental refunds for removal costs on the Norwegian continental shelf with ordinary tax deduction for such costs. Previously, removal costs were refunded by the Norwegian State based on the company's percentage for income taxes payable over the productive life of the removed installation. As a consequence of the changes in legislation, Statoil has charged the receivable of NOK 6.0 billion against the Norwegian State related to refund of removal costs to income under Other items in the second quarter of 2003. Furthermore, the resulting deferred tax benefit of NOK 6.7 billion has been taken to income under Income taxes.

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.

3. Segments

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 income are consistent with that used by management in making strategic decisions.

A new method for calculating the inter-segment price for deliveries of natural gas from Exploration and Production Norway to Natural Gas was adopted from January 1, 2003. The new price amounts to NOK 0.32 per standard cubic meter, adjusted quarterly by the average USD oil price over the last six months in proportion to USD 15. The new price applies to all volumes, while previously the price was calculated on a field-by-field basis, and the formula used differentiated between gas fields and fields delivering associated gas. The new method is partly a result of the Norwegian Gas Negotiating Committee being abolished, and replaced by company-based sales. Prior periods have been adjusted to reflect the new pricing formula.

Segment data for the years ended December 31, 2003, 2002 and 2001 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, 2003						
Revenues third party	2,250	2,522	24,420	218,169	1,398	248,759
Revenues inter-segment	60,170	4,458	445	120	(65,193)	0
Income (loss) from equity investments	74	0	222	353	(33)	616
Total revenues	62,494	6,980	25,087	218,642	(63,828)	249,375
Depreciation, depletion and amortization	12,102	1,784	486	1,419	485	16,276
Income before financial items, other items, income taxes and minority interest	37,589	1,702	6,350	3,555	(280)	48,916
Segment income taxes	(27,869)	(653)	(4,416)	(755)	(15)	(33,708)
Segment net income	9,720	1,049	1,934	2,800	(295)	15,208
Year ended December 31, 2002						
Revenues third party	1,706	5,749	24,236	210,653	1,104	243,448
Revenues inter-segment	57,075	1,020	168	194	(58,457)	0
Income (loss) from equity investments	(1)	0	132	305	(70)	366
Total revenues	58,780	6,769	24,536	211,152	(57,423)	243,814
Depreciation, depletion and amortization	11,861	2,355	592	1,686	350	16,844
Income before financial items, other items, income taxes and minority interest	33,953	1,086	6,428	1,637	(2)	43,102
Segment income taxes	(25,297)	(381)	(4,687)	(401)	(20)	(30,786)
Segment net income	8,656	705	1,741	1,236	(22)	12,316

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Other and eliminations	Total
Year ended December 31, 2001						
Revenues third party	3,622	5,926	23,297	202,264	1,413	236,522
Revenues inter-segment	63,503	1,767	36	936	(66,242)	(0)
Income (loss) from equity investments	120	0	135	187	(3)	439
Total revenues	67,245	7,693	23,468	203,387	(64,832)	236,961
Depreciation, depletion and amortization	11,806	3,371	664	1,855	362	18,058
Income before financial items, other items, income taxes and minority interest	42,287	1,291	8,039	4,480	57	56,154
Segment income taxes	(30,829)	(387)	(5,679)	(1,305)	(18)	(38,218)
Segment net income	11,458	904	2,360	3,175	39	17,936

Borrowings are managed at a corporate level and interest expense is not allocated to segments. Income tax is calculated on income before financial items, other items, income taxes 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)	2003	Year ended December 31, 2002	2001
Segment net income	15,208	12,316	17,936
Net financial items	1,399	8,233	65
Other items (see note 2)	(6,025)	0	0
Change in deferred tax due to new legislation (see note 2)	6,712	0	0
Tax on financial items and other tax adjustments	(451)	(3,550)	(268)
Minority interest	(289)	(153)	(488)
Net income	16,554	16,846	17,245
Segment income taxes	33,708	30,786	38,218
Change in deferred tax due to new legislation (see note 2)	(6,712)	0	0
Tax on financial items and other tax adjustments	451	3,550	268
Income taxes	27,447	34,336	38,486

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 crude oil and refined petroleum products.

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, other items, income taxes and minority interest.

(in NOK million)	Addition to long-lived assets	Investments in affiliates	Other long-term assets
At December 31, 2003			
Exploration and Production Norway	13,412	1,324	79,357
International Exploration and Production	8,147	370	32,732
Natural Gas	456	1,636	8,919
Manufacturing and Marketing	1,546	7,655	15,696
Other	530	37	14,705
Total	24,091	11,022	151,409
At 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
At 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

Revenues by geographic areas

		Year ended December 31,	
(in NOK million)	2003	2002	2001
Norway	223,139	215,231	204,791
Europe (excluding Norway)	30,152	31,449	36,002
United States	26,524	27,655	27,164
Other areas	8,014	9,253	6,206
Eliminations	(39,070)	(40,140)	(37,641)
Total revenues (excluding equity in net income (loss) of affiliates)	248,759	243,448	236,522

Long-lived assets by geographic areas

(in NOK million)	2003	At December 31, 2002	2001
Norway	112,672	113,629	114,355
Europe (excluding Norway)	39,845	28,550	32,010
United States	638	25	70
Other areas	21,563	11,586	13,755
Eliminations	(12,913)	(7,043)	(9,746)
Total long-lived assets (excludes long-term deferred tax assets)	161,805	146,747	150,444

4. Significant Acquisitions and Dispositions

In 2001, Statoil sold specific interests in Norwegian oil and gas licenses, its 4.76 per cent 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 and NOK 3.5 billion after tax.

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.

Effective January 1, 2003 Statoil sold 100 per cent 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 per cent share in the *West Navigator* drillship which were not included in the sale, was approximately USD 800 million. The sale was accounted for in the second quarter of 2003, and the effect on net income was immaterial.

Statoil and BP signed an agreement in June 2003 whereby Statoil will acquire 49 per cent of BP's interests in the In Salah gas project and 50 per cent of BP's interest in the In Amenas gas condensate project, both in Algeria. Statoil has paid BP USD 740 million, and has in addition covered the expenditures incurred after January 1, 2003 related to the acquired interests. As part of the agreement, the two companies will work together with Sonatrach, the Algerian State Oil and Gas Company, in a joint operation of the two projects under development in Algeria. Following this transaction, Statoil will have a 31.85 per cent interest in the In Salah revenue sharing contract and a 50 per cent interest in the In Amenas production sharing contract. In September 2003 Sonatrach confirmed that they will not exercise their pre-emption rights. The terms of the agreement were submitted to the European Commission for clearance of change of control of the In Salah gas project under the EU Merger Control Regulation, and were approved by EU in December 2003. In addition, amendments to the two projects' co-operation agreements implementing Statoil as participant in the projects will be submitted to the Algerian Ministry of Energy and Mining, the Algerian petroleum industry regulator, for necessary approval by the Council of Ministers and final authorization of the transaction through gazettal publication. The payments made by Statoil have been accounted for as long-term prepayments at year-end 2003, pending such final approval.

In January 2004, Statoil sold its 5.26 per cent shareholding in the German company Verbundnetz Gas, generating a gain of approximately NOK 0.6 billion before tax (approximately NOK 0.4 billion after tax). The shares are classified as assets held for sale in Prepaid expenses and other current assets in the balance sheet at year-end 2003.

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 per cent 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 discounted estimated future cash flows.

6. Provison for Rig Rental Contracts

Statoil provides for estimated losses on long-term fixed price rental agreements for mobile drilling rigs. The losses are calculated as the difference between estimated market rates and the fixed price rental agreements.

(in NOK million)	2003	2002	2001
Provision at January 1	960	734	960
Increase (decrease) during the year	454	231	(150)
Cost incurred during the year	(54)	(5)	(76)
Provision at December 31	1,360	960	734

7. Inventories

Inventories are valued at the lower of cost or market. Costs of crude oil held at refineries and the majority of refined products are determined under the last-in, first-out (LIFO) method. Certain inventories of crude oil, refined products and non-petroleum products are determined under the first-in, first-out (FIFO) method. 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)	2003	2002
Crude oil	2,192	2,766
Petroleum products	2,470	2,647
Other	1,065	844
Total - inventories valued on a FIFO basis	5,727	6,257
Excess of current cost over LIFO value	(734)	(835)
Total	4,993	5,422

8. Summary Financial Information of Unconsolidated Equity Affiliates

Statoil's investment in affiliates includes a 50 per cent interest in Borealis A/S, a petrochemical production company, and a 50 per cent interest in Statoil Detaljhandel Skandinavia AS (SDS), a group of retail petroleum service stations.

Summary of 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. In addition Statoil has given a long-term sub-ordinated loan of EUR 30 million to Borealis A/S.

Equity method affiliates - gross amounts

	Borealis A/S			SDS		
(in NOK million)	2003	2002	2001	2003	2002	2001
At December 31,						
Current assets	7,286	5,909	7,694	2,799	2,798	3,189
Non-current assets	19,085	17,432	19,710	6,787	6,029	6,105
Current liabilities	7,058	6,063	6,108	3,717	3,288	2,894
Long-term debt	6,140	5,787	8,787	1,951	2,488	3,382
Other liabilities	2,375	2,187	2,201	444	0	0
Net assets	10,798	9,304	10,310	3,474	3,051	3,018
Year ended December 31,						
Gross revenues	30,936	25,617	29,819	24,615	23,112	24,563
Income before taxes	126	215	(193)	210	423	411
Net income	135	43	(330)	148	302	290
Capital expenditures	1,002	978	1,182	779	721	552

No dividends have been received from Borealis for 2003 and 2002. For 2001 the dividend amounted to NOK 16 million. Statoil received NOK 65 million in dividend from SDS in 2003. No dividends have been received from SDS for the years 2001 and 2002.

Equity method affiliates - detailed information

(amounts in million)	Currency	Par value	Share capital	Ownership	Book value	Profit share
Borealis A/S	EUR	268	536	50%	5,405	106
Statoil Detaljhandel Skandinavia AS	NOK	1,300	2,600	50%	1,173	152
P/R West Navigator DA	NOK	–	–	50%	1,100	(78)
Other companies	–	–	–	–	3,344	436
Total					11,022	616

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 per cent interest in SDS in 1999 which is being amortized. P/R West Navigator DA owns the drillship *West Navigator*, and its only activity pertains to this drillship.

9. Investments

Short-term investments

(in NOK million)	At December 31, 2003	2002
Short-term deposits	1,358	51
Certificates	7,848	5,073
Bonds	35	50
Other	73	93
Total short-term investments	9,314	5,267

The cost price of short-term investments for the years ended December 31, 2003 and 2002 was NOK 9,284 million and NOK 5,261 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, 2003	2002
Shares in other companies	1,608	1,166
Certificates	2,005	1,031
Bonds	2,291	2,749
Marketable equity securities	1,934	1,270
Total long-term investments	7,838	6,216

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*	9,301	222,586	31,356	6,626	7,317	12,223	3,490	292,899
Acc depr depletion and amortization at January 1*	(6,310)	(139,413)	(18,213)	(2,260)	(1,670)	(6)	0	(167,872)
Additions and transfers	824	9,928	1,804	540	15	9,605	651	23,367
Disposal at booked value	(36)	(29)	(304)	(92)	(5,064)	(6)	(40)	(5,571)
Expensed expl costs capitalized earlier year	0	0	0	0	0	0	(256)	(256)
Depr, depletion and amortization for the year	(718)	(14,108)	(1,174)	(220)	(2)	0	0	(16,222)
Foreign currency translation	286	(181)	(73)	306	0	(102)	(53)	183
Balance specified at December 31, 2003	3,347	78,783	13,396	4,900	596	21,714	3,792	126,528
Estimated useful life (years)	5-10	**	15-20	20-25	20-25			

* The impact of new accounting principle regarding decommissioning and removal costs is included in acquisition cost, and accumulated depreciation, depletion and amortization at January 1, 2003.

** Depreciation according to Unit of production, see note 2.

Capitalized exploration costs in suspense include signature bonuses and other aquired exploration rights of NOK 940 million and NOK 1,045 million as at the end of 2002 and 2003, respectively. Should a balance sheet reclassification of such exploration rights to intangible assets be required, an issue currently being adressed by the FASB Emerging IssuesTask Force (EITF), it is not expected to affect the statements of income and cash flows.

In 2003, 2002 and 2001, NOK 442 million, NOK 382 million and NOK 723 million, respectively, of interests were capitalized. In addition to depreciation, depletion and amortization specified above intangible assets have been amortized by NOK 54 million in 2003.

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)	Balance at January 1,	Expense	Recovery	Write-off	Other 1)	Balance at December 31,
Year 2003						
Provisions against other long-term assets	0	0	0	0	0	0
Provisions against accounts receivable	153	59	(5)	(5)	73	275
Year 2002						
Provisions against other long-term assets	16	0	(16)	0	0	0
Provisions against accounts receivable	212	47	(59)	(33)	(14)	153
Year 2001						
Provisions against other long-term assets	90	0	0	0	(74)	16
Provisions against accounts receivable	224	44	0	(12)	(44)	212

1) Other in 2003 is primarily related to provisions against accounts receivable in acquired companies.

12. Financial Items

(in NOK million)	For the year ended December 31, 2003	2002	2001
Interest and other financial income	1,057	1,311	2,107
Currency exchange adjustments, net	98	9,009	912
Interest and other financial expenses	(877)	(1,952)	(2,713)
Dividends received	179	457	18
Gain (loss) on sale of securities	205	(228)	(97)
Unrealized gain (loss) on securities	737	(364)	(162)
Net financial items	1,399	8,233	65

13. Income Taxes

Net income before income taxes and minority interest consists of

(in NOK million)	Year ended December 31, 2003	2002	2001
Norway			
• Offshore	43,516	42,519	49,651
• Onshore	3,121	5,394	5,843
Other countries 1)	3,678	3,422	725
Other items (see note 2)	(6,025)	0	0
Total	44,290	51,335	56,219

Significant components of income tax expense were as follows

(in NOK million)	Year ended December 31, 2003	2002	2001
Norway			
• Offshore	34,754	34,253	37,942
• Onshore	2	885	1,169
Other countries 1)	737	352	253
Uplift benefit	(1,869)	(1,782)	(1,726)
Current income tax expense	33,624	33,708	37,638
Norway			
• Offshore	(376)	(707)	317
• Onshore	859	250	383
Other countries 1)	52	1,085	148
Change in deferred tax due to new legislation (see note 2)	(6,712)	0	0
Deferred tax expense	(6,177)	628	848
Total income tax expense	27,447	34,336	38,486

1) Includes taxes in Norway on activities in other countries.

Significant components of deferred tax assets and liabilities were as follows

(in NOK million)	At December 31, 2003	2002
Net operating loss carry-forwards	1,612	1,157
Impairment	1,071	1,058
Decommissioning	12,204	4,733
Other	4,918	3,665
Valuation allowance	(1,775)	(2,140)
Total deferred tax assets	18,030	8,473
Property, plant and equipment	40,532	35,518
Capitalized exploration expenditures and interest	8,236	8,914
Other	6,491	6,293
Total deferred tax liabilities	55,259	50,725
Net deferred tax liability	37,229	42,252

Deferred taxes are classified as follows

(in NOK million)	At December 31, 2003	2002
Short-term deferred tax asset	0	(415)
Long-term deferred tax asset	(620)	(486)
Long-term deferred tax liability	37,849	43,153
Net deferred tax liability	37,229	42,252

A valuation allowance has been provided as Statoil believes that available evidence creates 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 per cent to effective tax rate

(in NOK million)	2003	Year ended December 31, 2002	2001
Calculated income taxes at statutory rate	14,088	14,374	15,741
Petroleum surtax	22,579	20,538	24,342
Uplift benefit	(1,869)	(1,782)	(1,726)
Other	(639)	1,206	129
Change in deferred tax due to new legislation	(6,712)	0	0
Income tax expense	27,447	34,336	38,486

Revenue from oil and gas activities on the NCS is taxed according to the Petroleum tax law. This stipulates a surtax of 50 per cent after deducting uplift, a special investment tax credit, in addition to normal corporate taxation. Uplift credits are deducted as the credits arises, 5 per cent each year for six years, as from initial year of investment. Uplift credits not utilized of NOK 9.0 billion can be carried forward indefinitely.

At the end of 2003, Statoil had tax losses carry-forwards of NOK 5.3 billion, primarily in the US and Ireland. Only a minor part of the carry-forward amounts expires before 2006.

14. Short-Term Debt

(in NOK million)	At December 31, 2003	2002
Bank loans and overdraft facilities	1,071	2,258
Current portion of long-term debt	3,168	2,018
Other	48	47
Total	4,287	4,323
Weighted average interest rate (per cent)	4.06	5.28

15. Long-Term Debt

	Weighted average interest rates in per cent		Balance in NOK million at December 31,	
	2003	2002	2003	2002
Unsecured debentures bonds				
US dollar (USD)	6.62	5.74	11,052	14,404
Norwegian kroner (NOK)	2.85	7.50	499	21
Euro (EUR)	4.11	4.66	8,282	5,616
Swiss franc (CHF)	3.15	3.14	3,665	3,443
Japanese yen (JPY)	1.47	1.83	3,391	2,633
Great British pounds (GBP)	6.13	6.13	2,949	2,805
Total			29,838	28,922
Unsecured bank loans				
US dollar (USD)	2.10	1.77	3,018	2,194
Secured bank loans				
US dollar (USD)	3.10	3.82	2,638	2,945
Other currencies	4.90	-	26	-
Other debt			639	762
Grand total debt outstanding			36,159	34,823
Less current portion			(3,168)	(2,018)
Total long-term debt			32,991	32,805

The table above contains market values of loans per currency and loan type, and does therefore not illustrate the economic effects of agreements entered into to swap the various currencies to USD.

Statoil has an unsecured debenture bond agreement for USD 500 million with a fixed interest rate of 6.5 per cent, maturing in 2028, callable at par upon change in tax law. At December 31, 2003 and 2002, NOK 3,293 million and NOK 3,435 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 per cent, maturing in 2011. At December 31, 2003 and 2002, NOK 4,166 million and NOK 3,601 million were outstanding, respectively. This bond has been swapped to USD dollars with a LIBOR-based floating interest rate.

Statoil has also an unsecured debenture bond agreement for USD 375 million, with a fixed interest rate of 5.75 per cent, maturing in 2009. At December 31, 2003 and 2002, NOK 2,486 million and NOK 2,591 million were outstanding, respectively. Net after buyback this amounts to NOK 2,156 million and NOK 2,244 million at year-end exchanges rates.

In addition to the unsecured debentures bond debt of NOK 11,052 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 18,747 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's secured bankloan in USD has been secured by a guarantee commitment of USD 41.45 million, together with mortgage in shares in a subsidiary and a bank deposit with a book value of NOK 1,769 million and NOK 1,499 million, respectively.

Statoil has 24 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, 2003 closing rate valued at NOK 25,527 million.

Reimbursements of long-term debt fall due as follows:

(in NOK million)	
2004	3,168
2005	3,261
2006	1,558
2007	2,356
2008	2,123
Thereafter	23,693
Total	36,159

Statoil has two agreements with international bank syndicates for committed long-term revolving credit facility totaling USD 1.6 billion, all undrawn. Commitment fee is 0.108 per cent per annum.

As of December 31, 2003 and 2002 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 refined petroleum products over a period not exceeding 12 months and cash flows related to interest payments over a period not exceeding 13 months. Hedge ineffectiveness related to Statoil's outstanding cash flow hedges was immaterial and recorded to earnings during the year ended December 31, 2003. The net change in Other comprehensive income associated with the current year hedging transactions was immaterial, and the net amount reclassified into earnings during the year was NOK 97 million. At December 31, 2003 the net deferred hedging loss in Accumulated other comprehensive income was NOK 24 million (after tax), an immaterial amount 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, 2003. The net gain recognized in earnings in Net financial items during the year for ineffectiveness of fair value hedges was NOK 17 million.

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.

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 and 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, 2003			
Debt-related instruments	4,235	(36)	4,200
Non-debt-related instruments	367	(15)	351
Long-term fixed interest debt	0	(29,188)	(26,281)
Crude oil and Refined products	282	(246)	36
Gas and Electricity	272	(222)	50
At December 31, 2002			
Debt-related instruments	2,153	(150)	2,003
Non-debt-related instruments	143	(5)	138
Long-term fixed interest debt	0	(28,475)	(25,465)
Crude oil and Refined products	568	(844)	(276)
Gas and Electricity	265	(212)	53

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 counterparties, 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 25 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.

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 multiemployer plans.

Net periodic pension cost

		Year ended December 31,	
(in NOK million)	2003	2002	2001
Benefit earned during the year, net of participants' contributions	849	738	690
Interest cost on prior years benefit obligation	791	719	626
Expected return on plan assets	(843)	(856)	(793)
Amortization of loss	54	34	10
Amortization of prior service cost	34	44	44
Amortization of net transition assets	(15)	(16)	(16)
Defined benefit plans	870	663	561
Defined contribution plans	27	19	21
Multiemployer plans	0	4	4
Total net pension cost for the year	897	686	586

Change in projected benefit obligation (PBO)

(in NOK million)	2003	2002
Projected benefit obligation at January 1	13,025	12,000
Benefits earned during the year	849	738
Interest cost on prior years' benefit obligation	791	719
Actuarial loss (gain)	3,310	(13)
Benefits paid	(332)	(401)
Acquisitions	(95)	0
Foreign currency translation	94	(18)
Projected benefit obligation at December 31	17,642	13,025

Change in pension plan assets

(in NOK million)	2003	2002
Fair value of plan assets at January 1	12,480	13,068
Actual return on plan assets	1,684	(770)
Company contributions	1,129	412
Benefits paid	(169)	(183)
Acquisitions	(61)	0
Foreign currency translation	80	(47)
Fair value of plan assets at December 31	15,143	12,480

Status of pension plans reconciled to Consolidated Balance Sheet

(in NOK million)	2003	2002
Defined benefit plans		
Funded status of the plans at December 31	(2,499)	(545)
Unrecognized net loss	4,248	1,868
Unrecognized prior service cost	329	363
Unrecognized net transition asset	0	(15)
Total net prepaid pension recognized at December 31	2,078	1,671

Amounts recognized in the Consolidated Balance Sheet:

(in NOK million)	2003	2002
Prepaid pension	4,881	3,861
Accrued pension liabilities	(3,372)	(2,190)
Intangible assets	331	0
Other comprehensive income	238	0
Net amount recognized at December 31	2,078	1,671

Weighted-average assumptions at the end of year

	2003	2002
Discount rate	5.50%	6.00%
Expected return on plan assets	6.00%	6.50%
Rate of compensation increase	3.50%	3.00%

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

	At December 31,	
(in NOK million)	2003	2002
Projected benefit obligation	4,580	3,102
Accumulated benefit obligation	3,189	2,235
Fair value on plan assets	251	425

The accumulated benefit obligation was NOK 13,800 million at December 31, 2003.

Pension assets allocated on respective investments classes

	At December 31,	
	2003	2002
Equity securities	17%	9%
Debt securities	25%	38%
Sertificates	39%	36%
Real estate	10%	11%
Other assets	9%	6%
Total	100%	100%

In its asset management, the pension fund aims at achieving long-term returns which contribute towards meeting future pension liabilities. Assets are managed to achieve a return as high as possible within a framework of public regulation and prudent risk management policies. The pension fund's target returns require a need to invest in riskier assets than risk-free investments. Risk is reduced through maintaining a well diversified asset portfolio. Assets are diversified both in terms of location and different asset classes. Derivatives are used within set limits to facilitate effective asset management.

Statoil's pension funds invest in both financal assets and real estate. The expected rate of return on real estate is expected to be something between the rate of return on equity securities and debt securities. The table below presents the portfolio weight and expected rate of return of the finance portfolio, as approved by the board of the Statoil pension funds for 2004.

Finance portfolio Statoils pension funds	Portfolio weight 1)		Expected rate of return 2)
Equity securities	25%	(+/- 5%)	X + 4%
Debt securities	37.5%	(+/- 5%)	X
Sertificates	37.5%	(+19%/-5%)	X - 0.4%
Total finance portfolio	100%		-

1) The brackets express the scope of tactical deviation by Statoil Kapitalforvaltning ASA (the asset manager).
2) The asset manager expect the long-term return on equities to be 4% higher than riskfree rate (debt securities), as well as the rate of return on sertificates to be 0.4% lower than the return on debt securities.
X = Long-term rate of return on debt securities

The long-term expected return on pension assets is based on long-term risk-free rate adjusted for the expected long-term risk premium for the respective investment classes.

Pension benefits paid are mainly related to employees in Norway. This payment may either be paid in cash or be deducted from the pension premium fund. Statoil has a relatively large amount classified as pension premium fund. The decision wether to pay in cash or deduct from pension premium fund is made on an annual basis. If the benefit payable for 2004 is decided to be paid, the payments the next five years will be approximately NOK 1 billion yearly. The benefit payment in 2003 was NOK 0.8 billion. The main reason for the increase is changes in constraints related to benefit payments from Norwegian authorities. This change will only affect the benefits paid.

18. Decommissioning and Removal Liabilities

On January 1, 2003 Statoil implemented Statement of Financial Standards no. 143, Accounting for Asset Retirement Obligations (ARO). The obligation is related to future well closure-, decommissioning- and removal-costs. The accretion expense is classified as Operating expenses.

(in NOK million)	2003
Asset retirement obligation at January 1	15,049
Liabilities incurred	655
Accretion expense	539
Revision in estimates	307
Incurred removal cost	(56)
Asset retirement at December 31	16,494

(in NOK million)	2003
Long-lived asset related to ARO at January 1	2,451
Assets incurred / revision in estimates	962
Depreciation	(656)
Long-lived asset related to ARO at December 31	2,757

19. Research Expenditure

Research expenditures were NOK 1,004 million, NOK 736 million and NOK 633 million in 2003, 2002 and 2001, respectively.

20. Leases

Statoil leases certain assets, notably shipping vessels and drilling rigs.

In 2003, rental expense was NOK 4,893 million. In 2002 and 2001 rental expenses were NOK 5,595 million and NOK 7,687 million, respectively.

The information in the table below shows future minimum lease payments under non-cancellable leases at December 31, 2003. In addition, subleases of certain assets amounting to a rental income of NOK 544 million have been entered into for 2004.

Statoil has entered into a number of general or field specific long-term frame agreements mainly related to loading and transport of crude oil. Main contracts expire in 2007 or later, up until the end of respective field lives. Such contracts are not included in the below table of future lease payments unless they entail specific minimum payment obligations.

Amounts related to capital leases include future lease payments for assets in the books at year-end 2003.

(in NOK million)	Operating leases	Capital leases
2004	2,999	19
2005	2,072	18
2006	1,301	18
2007	434	18
2008	411	1
Thereafter	1,953	1
Total future lease payments	9,170	75
Interest component		(14)
Net present value		61

Property, plant and equipment include the following amounts for leases that have been capitalized at December 31, 2003 and 2002:

	At December 31,	
(in NOK million)	2003	2002
Vessel and equipment	119	107
Accumulated depreciation	(86)	(80)
Capitalized amounts	33	27

21. Other Commitments and Contingencies

Contractual commitments

(in NOK million)	In 2004	Thereafter	Total
Contractual commitments made	13,061	7,828	20,889

These contractual commitments comprise acquisition and construction of fixed assets.

Guarantees

The Group has provided guarantees of NOK 1.1 billion for commercial transactions and contractual commitments at year-end 2003.

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 33 per cent is retained.

Other commitments
As a condition for being awarded oil and gas exploration and production licenses, participants may be committed to drill a certain number of wells. At the end of 2003, Statoil was committed to participate in 6 wells off Norway and 9 wells abroad, with an average ownership interest of approximately 35 per cent. Statoil's share of expected costs to drill these wells amounts to approximately NOK 1.9 billion.

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 based on booked volume capacity. In addition the Group has entered into certain obligations for entry capacity fees and terminal capacity commitments. The following table outlines nominal minimum obligations for future years. Corresponding expense for 2003 was NOK 2,712 million. Where the Group reflects both ownership interests and transport capacity cost for a pipeline in the consolidated accounts, the amounts in the table include the transport commitments that exceed Statoil's ownership share.

Transport capacity and similar obligations at December 31, 2003:

(in NOK million)	
2004	3,002
2005	3,406
2006	3,453
2007	3,021
2008	3,085
Thereafter	31,188
Total	47,155

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. Statoil has provided in its accounts for these items based on the Company's best judgement. Statoil does not expect that either the financial position, results of operations nor cash flows will be materially adversely affected by the resolution of these legal proceedings.

On October 10, 2003 the Norwegian Supreme Court ruled in the case raised by Statoil and several other companies against the Norwegian State, represented by the Ministry of Finance, regarding the tax assessment of income from the joint venture Statpipe for the years 1993 and 1994. The Supreme Court instructed the Oil Taxation Board to reassess the basis for taxation. The ruling will also affect subsequent years. The effect of the reassessment can not be estimated with a reasonable degree of certainty. For accounting purposes, the disputed taxes have been expensed.

The Norwegian National Authority for Investigation and Prosecution of Economic and Environmental Crime (Økokrim) has issued a preliminary charge against the Company alleging violations of the Norwegian General Civil Penal Code provision concerning illegal influencing of foreign government officials and is conducting an investigation concerning a consulting agreement which Statoil entered into in 2002 with Horton Investments Ltd. The Company has also been notified by the U.S. Securities and Exchange Commission that the Commission is conducting an inquiry into the consultancy arrangement to determine if there have been any violations of U.S. federal securities laws.

22. Related Parties

Total purchases of oil and natural gas liquid from the Norwegian State amounted to NOK 68,479 million (336 million barrels oil equivalents), NOK 72,298 million (374 million barrels oil equivalents), and NOK 53,291 million (265 million barrels oil equivalents), in 2003, 2002 and 2001, 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.

The Norwegian State compensates Statoil for its relative share of the expenditures related to certain Statoil natural gas storage and terminal investments and related activities.

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. During 2002 and 2003 a number of 1,558,115 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 shares have voting rights.

Retained earnings available for distribution of dividends at December 31, 2003 is limited to the retained earnings of the parent company based on Norwegian accounting principles and legal regulations and amounts to NOK 49,511 million (before provisions for proposed dividend for the year ended December 31, 2003 of NOK 6,390 million). This differs from retained earnings in the financial statements of NOK 27,627 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 per cent of total assets.

24. Auditors' Remuneration

(in NOK million)	Year ended December 31, 2003	2002
Audit fees	27.0	26.2
Audit-related fees	2.8	1.8
Tax fees	14.5	8.5
All other fees	0.9	0.0
Total	45.2	36.5

25. Subsequent Events

In January 2004, Statoil acquired in all 11.24 per cent of the Snøhvit Field, 10 per cent from Norsk Hydro and 1.24 per cent from Svenska Petroleum, respectively. Following these transactions, Statoil will have an ownership share of 33.53 per cent of the Snøhvit Field. The transactions will be made with economic effect from January 1, 2004 and are subject to approval by the Norwegian authorities.

After year-end 2003 Statoil as an owner in BTC Co Ltd has entered into guarantee commitments for financing the development of the BTC pipeline amounting to USD 140 million (NOK 0.9 billion).

ICA AB and Statoil have signed a letter of intent covering the acquisition by Statoil of ICA's holding in Statoil Detaljhandel Skandinavia AS (SDS). ICA and Statoil currently own 50 per cent each of SDS. Subject to approval by the boards of Statoil and ICA, the finalized deal is expected to be implemented during the spring of 2004.

Statoil has signed a letter of intent with the US-based energy company Dominion. This will secure Statoil access to additional capacity at the Cove Point liquefied natural gas (LNG) terminal in Maryland, USA, for a 20-year period. The transaction is subject to the successful negotiation of a final agreement and approval by the supervisory bodies of both companies.

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.

On the Norwegian Continental Shelf Statoil sells 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.

In addition, Statoil has entered into a gas sales contract with Turkey, Georgia and Azerbaijan where gas will be supplied from Shah Deniz.

The total commitments to be met by the Statoil/SDFI arrangement and Statoil's separate commitments were on December 31, 2003 to deliver a total of 37.0 tcf .

Statoil's and SDFI's delivery commitments for the contract years 2003, 2004, 2005 and 2006 are 1,691, 1,690, 1,973 and 1,960 bcf. These commitments may be met by production of proved reserves from fields were Statoil and/or the Norwegian State participates.

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, while shifts of forecasted deliveries between fields are recorded as Revisions and improved recovery.

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

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
Proved reserves 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
Purchase of reserves-in-place	0	0	0	0	0	0	0	0	0
Sales of reserves-in-place	(54)	(1)	(55)	(1)	(170)	(171)	(54)	(31)	(85)
Production	(246)	(22)	(268)	(523)	(15)	(538)	(339)	(25)	(364)
Proved reserves 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)
Proved reserves 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
Revisions and improved recovery	110	41	151	311	1	312	165	41	206
Extensions and discoveries	27	15	43	503	303	806	117	69	186
Purchase of reserves-in-place	0	0	0	0	0	0	0	0	0
Sales of reserves-in-place	0	0	0	0	0	0	0	0	0
Production	(239)	(31)	(271)	(695)	(6)	(700)	(363)	(33)	(395)
Proved reserves at December 31, 2003	1,184	605	1,789	13,334	552	13,886	3,560	703	4,264
Of which:									
Proved developed reserves	876	163	1,039	9,582	25	9,606	2,584	167	2,751
Proved reserves under PSA and buy-back agreements	0	364	364	0	303	303	0	418	418
Production from PSA and buy-back agreements	0	13	13	0	0	0	0	13	13

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 expenditures related to Oil and Gas producing activities

(in NOK million)	At December 31, 2003	2002
Unproved Properties	3,792	3,490
Proved Properties, wells, plants and other equipment, including removal obligation assets	244,621	230,510
Total Capitalized Expenditures	248,414	233,998
Accumulated depreciation, depletion, amortization and valuation allowances	(147,441)	(139,337)
Net Capitalized Expenditures	100,973	94,661

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

These costs include both amounts capitalized and expensed. Certain reclassifications have been done from other operating expenses to exploration expenses in 2002.

(in NOK million)	Norway	Outside Norway	Total
Year ended December 31, 2003			
Exploration costs, including signature-bonuses	1,220	1,538	2,758
Development costs 1)	13,284	6,071	19,355
Acquired unproved properties	0	54	54
Total	14,504	7,663	22,167
Year ended December 31, 2002			
Exploration costs, including signature-bonuses	1,350	1,398	2,748
Development costs	10,269	4,088	14,357
Total	11,619	5,486	17,105
Year ended December 31, 2001			
Exploration costs, including signature-bonuses	2,020	683	2,703
Development costs	9,707	4,452	14,159
Total	11,727	5,135	16,862

1) Development costs include investments in Norway in facilities for liquefaction of natural gas and storage of LNG amounting to NOK 614 million.

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.

A new method for calculating the inter-segment price for deliveries of natural gas from E&P Norway to Natural Gas has been adopted as of the first quarter of 2003. The new price amounts to NOK 0.32 per standard cubic meter, adjusted quarterly by the average USD oil price over the last six months in proportion to USD 15. The new price applies to all volumes, including associated gas, while previously the price was calculated on a field-by-field basis. Prior periods segment reporting has been adjusted to reflect the new pricing formula.

The calculation of production cost has been changed as of the third quarter of 2003. Statoil decided to change the classification of administration cost and revenue and costs from the sale of processing capacity between fields. The reason for this change is that Statoil wants to better reflect the real costs of the underlying activity related to production.

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, 2003			
Sales	352	1,944	2,296
Transfers	60,143	4,455	64,598
Total revenues	60,495	6,399	66,894
Exploration expenses	(1,365)	(1,005)	(2,370)
Production costs	(7,998)	(894)	(8,892)
Accretion expense	(479)	(48)	(527)
Special items 1)	0	(151)	(151)
DD&A 3)	(12,104)	(1,625)	(13,729)
Total costs	(21,946)	(3,723)	(25,669)
Results of operations before taxes	38,549	2,676	41,225
Tax expense	(29,093)	(948)	(30,040)
Results of producing operations	9,456	1,729	11,184
Year ended December 31, 2002			
Sales	351	4,672	5,024
Transfers	57,075	1,018	58,093
Total revenues	57,426	5,690	63,117
Exploration expenses	(1,420)	(990)	(2,410)
Production costs	(8,217)	(979)	(9,196)
Special items 2)	0	(766)	(766)
DD&A 3)	(12,402)	(1,738)	(14,140)
Total costs	(22,039)	(4,473)	(26,512)
Results of operations before taxes	35,387	1,218	36,605
Tax expense	(26,484)	(723)	(27,207)
Results of producing operations	8,903	495	9,398

(in NOK million)	Norway	Outside Norway	Total
Year ended December 31, 2001			
Sales	339	2,883	3,222
Transfers	63,503	1,766	65,269
Total revenues	63,842	4,649	68,491
Exploration expenses	(2,008)	(866)	(2,874)
Production costs	(8,233)	(1,024)	(9,257)
Special items 2)	0	(2,000)	(2,000)
DD&A 3)	(12,636)	(1,477)	(14,113)
Total costs	(22,877)	(5,367)	(28,244)
Results of operations before taxes	40,964	(718)	40,246
Tax expense	(31,386)	215	(31,171)
Results of producing operations	9,579	(503)	9,075

1) Impairment of the Dunlin field in the UK.
2) Impairment of the oil field LL652 in Venezuela.
3) Include provisions made for future decommissioning and removal costs in years 2001 and 2002. For 2003, the amount includes the amortization of removal assets recorded due to implementation of FAS 143 on January 1, 2003.

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 per cent 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 and removal 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 per cent 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, 2003			
Future net cash inflows	644,003	132,884	776,887
Future development costs	(39,207)	(17,029)	(56,236)
Future production costs	(179,686)	(26,509)	(206,195)
Future net cash flow pre-tax	425,110	89,346	514,456
Future income tax expenses	(320,763)	(19,998)	(340,761)
Future net cash flows	104,347	69,348	173,695
10% annual discount for estimated timing of cash flows	(47,303)	(37,810)	(85,113)
Standardized measure of discounted future net cash flows	57,044	31,538	88,582
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 flow 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
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

Of a total of NOK 56,236 million of estimated future development costs as of December 31, 2003, an amount of NOK 38,387 million is expected to be spent within the next three years, as allocated in the table below.

Future development costs

(in NOK million)	2004	2005	2006	Total
Norway	12,484	8,470	4,751	25,705
Outside Norway	6,608	3,985	2,089	12,682
Total	19,092	12,455	6,840	38,387
Future development cost expected to be spent on proved undeveloped reserves	16,208	10,422	5,431	32,061

In 2003, Statoil incurred NOK 19,355 million in development costs, of which NOK 14,355 million related to proved undeveloped reserves. The comparable amounts for 2002 were NOK 14,357 million and NOK 9,964 million, and for 2001 NOK 14,159 million and NOK 8,386 million, respectively.

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Changes in the standardized measure of discounted future net cash flows from proved reserves:

(in NOK million)	2003	2002	2001
Standardized measure at January 1	91,700	79,217	98,850
Net change in sales and transfer prices and in production (lifting) costs related to future production	28,007	(297)	(70,193)
Changes in estimated future development costs	(6,971)	(6,115)	(10,560)
Sales and transfers of oil and gas produced during the period, net of production costs	(62,099)	(56,994)	(62,283)
Net change due to extensions, discoveries, and improved recovery	7,907	9,790	2,064
Net change due to purchases and sales of minerals in place	(19)	(1,802)	(1,652)
Net change due to revisions in quantity estimates	24,675	9,791	11,604
Previously estimated development costs incurred during the year	19,355	14,357	14,159
Accretion of discount	(3,877)	33,342	57,721
Net change in income taxes	(10,095)	10,411	39,508
Total change in the standardized measure during the year	(3,117)	12,483	(19,632)
Standardized measure at December 31	88,582	91,700	79,217

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, 2003.

A "gross" value reflects to wells or acreage in which Statoil has interests (calculated as 100 per cent). The net value corresponds to the sum of whole or fractional working interest in gross wells or acreage.

At December 31, 2003		Norway	Outside Norway	Total
Number of productive oil and gas wells				
Oil wells	— gross	695	628	1,323
	— net	180	119	299
Gas wells	— gross	71	13	84
	— net	26	4	30

At December 31, 2003 (in thousands of acres)		Norway	Outside Norway	Total
Developed and undeveloped oil and gas acreage				
Acreage developed	— gross	497	339	836
	— net	111	71	182
Acreage undeveloped	— gross	9,462	10,060	19,522
	— net	3,323	2,695	6,018

Remaining terms of leases and concessions are between one and 32 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, 2003.

(number of wells)	Norway	Outside Norway	Total
Number of wells in progress			
— gross	22	17	39
— net	6.7	2.0	8.7

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 2003			
Net productive and dry exploratory wells drilled	4.3	2.5	6.8
– Net dry exploratory wells drilled	1.7	1.0	2.7
– Net productive exploratory wells drilled	2.6	1.5	4.1
Net productive and dry development wells drilled	25.3	18.1	43.4
– Net dry development wells drilled	2.4	0.0	2.4
– Net productive development wells drilled	22.9	18.1	41.0
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
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

Average sales price and production cost per unit

	Norway	Outside Norway
Year ended December 31, 2003		
Average sales price crude in USD per bbl	29.1	27.6
Average sales price natural gas in NOK per Sm3	1.02	0.83
Average production costs, in NOK per boe	22.3	27.8
Year ended December 31, 2002		
Average sales price crude in USD per bbl	24.7	23.7
Average sales price natural gas in NOK per Sm3	0.95	0.65
Average production costs, in NOK per boe	22.9	30.7
Year ended December 31, 2001		
Average sales price crude in USD per bbl	24.1	22.3
Average sales price natural gas in NOK per Sm3	1.22	0.97
Average production costs, in NOK per boe	23.9	43.0

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, 2003 and 2002, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our 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, 2003 and 2002, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States.

Stavanger, March 3, 2004
ERNST & YOUNG AS

Gustav Eriksen
State Authorised Public Accountant
(Norway)

Jostein Johannessen
State Authorised Public Accountant
(Norway)

Proved reserves report

DEGOLYER AND MACNAUGHTON
4925 GREENVILLE AVENUE, SUITE 400, ONE ENERGY SQUARE, DALLAS, TEXAS 75206

February 16, 2004

Statoil ASA
Forusbeen 50
N-4035 Stavanger
Norway

Gentlemen:
Pursuant to your request, we have prepared estimates of the proved oil, condensate, liquefied petroleum gas (LPG), and natural gas reserves, as of December 31, 2003, of certain properties in Angola, Azerbaijan, China, Iran, Norway, the United Kingdom, and Venezuela owned by Statoil ASA (STATOIL). The estimates are discussed in our "Report as of December 31, 2003 on Proved Reserves of Certain Properties owned by Statoil ASA" (the Report). We also have reviewed STATOIL's estimates of the reserves, as of December 31, 2003, of the same properties included in the Report.

In our opinion, the information relating to proved reserves estimated by us and referred to herein has been prepared in accordance with Paragraphs 10–13, 15, and 30(a)–(b) of Statement of Financial Accounting Standards No. 69 (November 1982) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(13) of Regulation S–X of the United States Securities and Exchange Commission (SEC).

STATOIL represents that its estimates of the proved reserves, as of December 31, 2003, attributable to STATOIL's interests in the properties included in the Report are as follows, expressed in millions of barrels (MMbbl) or billions of cubic feet (Bcf):

Oil, Condensate, and LPG (MMbbl)	Natural Gas (Bcf)	Net Equivalent (MMbbl)
1,789	13,886	4,264

Note: Net equivalent million barrels is based on 5,612 cubic feet of gas being equivalent to 1 barrel of oil, condensate, or LPG.

STATOIL has advised us that its estimates of proved oil, condensate, LPG, and natural gas reserves are in accordance with the rules and regulations of the SEC. It is our opinion that the guidelines and procedures that STATOIL has adopted to prepare its estimates are in accordance with generally accepted petroleum reserves evaluation practices and are in accordance with the requirements of the SEC.

Our estimates of the proved reserves, as of December 31, 2003, attributable to STATOIL's interests in the properties included in the Report are as follows, expressed in millions of barrels (MMbbl) or billions of cubic feet (Bcf):

Oil, Condensate, and LPG (MMbbl)	Natural Gas (Bcf)	Net Equivalent (MMbbl)
1,774	13,849	4,242

Note: Net-equivalent million barrels is based on 5,612 cubic feet of gas being equivalent to 1 barrel of oil, condensate, or LPG.

In comparing the detailed reserves estimates prepared by us and those prepared by STATOIL for the properties involved, we have found differences, both positive and negative, in reserves estimates for individual properties. These differences appear to be compensating to a great extent when considering the reserves of STATOIL in the properties included in the Report, resulting in overall differences not being substantial. It is our opinion that the reserves estimates prepared by STATOIL on the properties reviewed by us and referred to above, when compared on the basis of net equivalent million barrels of oil do not differ materially from those prepared by us.

Submitted,
DeGOLYER and MacNAUGHTON

Shares and shareholder matters

Statoil aims to give shareholders a competitive return on their invested capital, so that owning shares in Statoil becomes an attractive option. Returns will be realised by a combination 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. In some years, the need to maintain the group's financial flexibility can mean that the level of dividends may vary, depending on the group's cash flows, financing requirements and investment plans. In the group's communication with the market, increasing emphasis has been put on stability of dividends measured in NOK per share.

A dividend of NOK 2.85 per share was paid out for 2001, NOK 2.90 for 2002 and the proposed dividend for 2003 is NOK 2.95. This entails a steady increase in current money, but overall, payments are lower than 45-50 per cent of net income, which reflects the good market conditions for Statoil during this period.

Information and equal treatment

Statoil puts emphasis on keeping the stock market and the general public well informed about developments in the group's results and future prospects. Information to the stock market must be characterised by openness and equal treatment, with the objective of ensuring that shareholders get correct, clear, relevant and timely information to provide the basis for a correct valuation of the group. Statoil is listed in Oslo and New York and the company distributes all information relevant to the share price to the Oslo Stock Exchange, the New York Stock Exchange and the US Securities and Exchange Commission.

Trading of the Statoil share increased on average in 2003 from 2.9 million shares per day in 2002 to 3.3 million per day. The investors perceive this as positive and it leads to a more effective valuation and pricing of the company.

In 2003, medium-sized oil companies in general had very good share-price results. By comparison with the largest companies in the oil sector, 2003 was a good year for Statoil. At the Oslo exchange the Statoil share rose by 34 per cent overall during 2003. This put the group on top, also among its competitors. Investors who have bought

shares at the Oslo exchange, based on the USD, have in addition benefited from developments in the exchange rate, and their figures show a high return for 2003.

Shareholders who have benefited from the bonus programme launched at Statoil's flotation on 18 June 2001 have had a dividend yield of 36 per cent. Shareholders who did not take part in the bonus programme received a dividend yield of 19 per cent for the same period.

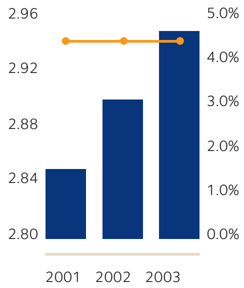
The group's investor relations function reports to the corporate executive committee and maintains an active dialogue with the capital markets in Norway and the USA. Investor relations is responsible for distributing and registering information to comply with the guidelines applicable where Statoil's securities are listed. An internet site for investor relations at www.statoil.com/ir is the group's channel for providing information about results and news. Financial presentations are broadcast live, and reports and presentations are provided along with other relevant information. Statoil received the Norwegian Stockman prize in 2003 for good information to the capital markets.

www.statoil.com/ir

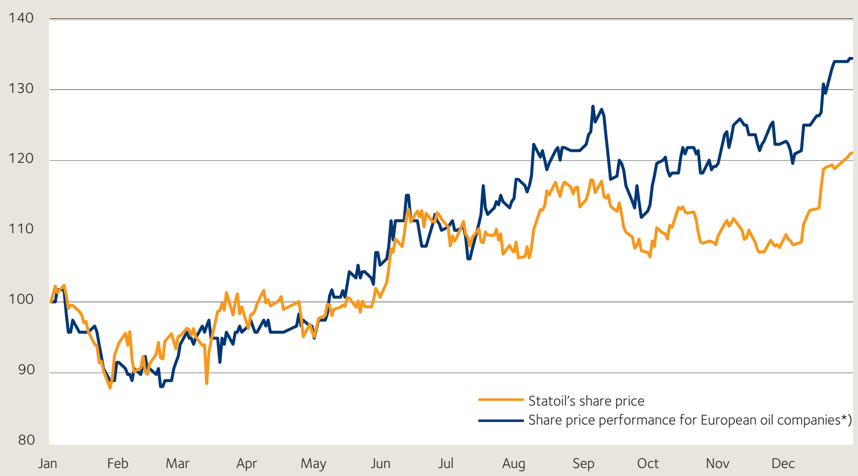
20 largest shareholders in 2003		
1	81.72%	THE NORWEGIAN STATE
2	1.96%	STATE STREET BANK & TRUST CO.*
3	1.67%	JPMORGAN CHASE BANK*
4	0.96%	MELLON BANK AS AGENT*
5	0.64%	BANK OF NEW YORK*
6	0.56%	THE NORTHERN TRUST CO.*
7	0.47%	JPMORGAN CHASE BANK*
8	0.41%	DEUTSCHE BANK AG (GCS) LONDON
9	0.37%	CLEARSTREAM BANKING*
10	0.33%	FOLKETRYGDFONDET
11	0.30%	VITAL FORSIKRING ASA
12	0.29%	THE NORTHERN TRUST CO.*
13	0.27%	EUROCLEAR BANK S.A./N.V. ('BA')*
14	0.26%	MELLON BANK AS AGENT*
15	0.25%	SKANDINAVISKA ENSKILDA BANKEN*
16	0.22%	JPMORGAN CHASE BANK*
17	0.21%	MORGAN STANLEY & CO.*
18	0.17%	STATE STREET BANK & TRUST CO.*
19	0.17%	SKANDINAVISKA ENSKILDA BANKEN
20	0.17%	ROYAL TRUST CORPORATION OF CANADA*

* Client accounts or similar.

DIVIDEND AND AVERAGE YIELD 2001-2003



* Yield is determined by dividing the annual dividend by the closing share price on the day that the AGM approves the dividend. For 2003, the closing price on 30 December is used. The line in the figure shows the average for 2001-2003.



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

Performance of the Statoil share in 2003 compared with the average for competitors.

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 Wednesday 5 May 2004 at 5.30 pm.

Shareholders who would like to attend the annual general meeting are asked to give notification of this by 12 noon on Friday 30 April to:
DnB NOR Bank ASA
Verdipapirservice
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 25 May 2004 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 5 May 2004.

Reporting of results
The following dates have been set for the quarterly reports in 2004:

1st quarter	5 May
2nd quarter	2 August
3rd quarter	27 October

The results will be published at 8.30 am.
Statoil reserves the right to change these 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.

Shareholders who are registered in the VPS as owners in Statoil will now be able to receive the group's annual report and accounts and notice of annual general meeting electronically.

If you wish to make use of this opportunity or want to find more information, please go to www.vps.no/erapport.html on the internet.

Addresses
Statoil's head office has the following address:
Statoil ASA, 4035 Stavanger, Norway.

Telephone:	+47 51 99 00 00
Telefax:	+47 51 99 00 50
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/address

Articles of association for Statoil ASA

Article 1

The name of the Company is Statoil ASA. The Company is a Public Limited Company and the Company's shares are recorded in the Norwegian Central Securities Depository *(Verdipapirsentralen)*. The corporate object of Statoil ASA is, either by itself or through participation in or together with other companies, to carry out exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, as well as other business.

Article 2

The Company shall be situated in Stavanger.

Article 3

The share capital of the Company is NOK 5,473,964,000 divided into 2,189,585,600 shares of NOK 2.50 each.

Article 4

The Board of Directors of the Company shall be composed of at least five and a maximum of 11 directors. The Board of Directors, including the chair and the deputy chair, shall be elected by the Corporate Assembly. Five deputy directors may be elected in respect of the directors elected by and among the employees, and these deputies shall be summoned in the order in which they are elected. Two deputy directors may be elected in respect of the other directors, one as first deputy and one as second deputy. The normal term of office for the directors is two years.

Article 5

Any two directors jointly may sign for the Company. The Board may grant power of procuration.

Article 6

The Board shall appoint the Company's chief executive officer and stipulate his/her salary.

Article 7

The Company shall have a Corporate Assembly consisting of 12 members. Members and deputies shall be elected for two years at a time.
The Annual General Meeting shall elect eight members and three deputy members for these eight. Four members and deputies for these four shall be elected by and among the employees of the Company in accordance with regulations pursuant to the Public Limited Companies Act concerning the rights of employees to be represented on the Board of Directors and in the Corporate Assembly of limited companies.
The Corporate Assembly shall elect a chair and deputy chair from and among its members.
The Corporate Assembly shall hold at least two meetings annually.

Article 8

The Annual General Meeting shall be held each year before the end of June. Annual General Meetings shall be held in Stavanger or in Oslo.

Article 9

The Annual General Meeting shall deal with and decide the following matters:
Adoption of the profit and loss account and the balance sheet.
Application of the annual profit or coverage of loss as shown in the adopted balance sheet, and the declaration of dividends.
Adoption of the consolidated profit and loss account and the consolidated balance sheet.
Any other matters which are referred to the Annual General Meeting by statute law or the Articles of Association.

Article 10

The Company shall be responsible for the marketing and sale of the state's petroleum which is produced from the state's direct financial interest (SDFI) on the Norwegian continental shelf, as well as for the marketing and sale of petroleum paid as royalty in accordance with the Petroleum Act of 29 November 1996 No 72. The Annual General Meeting of the Company may by simple majority decide on further instructions concerning the marketing and sale.

Article 11

The Company shall have an Election Committee. The tasks of the Election Committee are to make recommendations to the Annual General Meeting regarding the election of shareholder-elected members and deputy members of the Corporate Assembly, and to make recommendations to the Corporate Assembly regarding the election of shareholder-elected members and deputy members of the Board of Directors. The chair of the Board of Directors and the chief executive officer of the group shall, without having the right to vote, be summoned to at least one meeting of the Election Committee before it delivers its final recommendations.

The Election Committee shall consist of four members who shall be shareholders or representatives of shareholders. The chair of the Corporate Assembly shall be a permanent member and chair of the Election Committee. Two members shall be elected by the Annual General Meeting, and one member shall be elected by and among the Corporate Assembly's shareholder-elected members. The members of the Election Committee are elected for a term of two years. The shareholder-elected members of the Corporate Assembly may, following recommendations from the shareholder-elected members of the Board of Directors, adopt instructions for the Election Committee.

Article 12

The provisions of the Public Limited Companies Act shall be supplementary to these Articles of Association.

Adopted at the Annual General Meeting of 7 May 2002.

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Kjetil Alsvik:	page 7, 38, 40, 56, 57, (Egeland), 58, 59, 60,
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Guro Dahl:	page 13, 33
Knud Helge Robberstad:	page 18
Rune Johansen:	page 19
Cameron Davidson:	page 24
Nina Eirin Rangøy:	page 25
Allan Klo:	page 34
FMC Kongsverg subsea:	page 35
Marit Hommedal:	page 37
Håkon Vold:	page 41
Dag Magne Søyland:	page 42
Scan Pix:	page 57 (Kaci Kullman Five)

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