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82- SUBMISSIONS FACING SHEET

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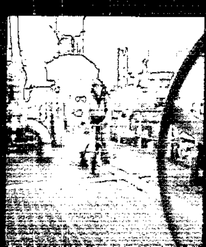
Annual Report on Form 20-F 2002



The front-cover picture was taken by photographer Guri Dahl. She met Statoil personnel in their working environment on

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 20-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR 12 (g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2002

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (NO FEE REQUIRED)**

For the Transaction period from ________ to ___________

Commission File No. 1-15200

Statoil ASA

(Exact name of registrant as specified in its charter)

Norway
(Jurisdiction of incorporation or organization)

Forusbeen 50, N-4035 Stavanger, Norway
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code + 47 51 99 00 00

Securities to be registered pursuant to Section 12(b) of the Exchange Act:

Title of each class	Name of each exchange on which registered
Ordinary shares of NOK 2.50 each	New York Stock Exchange*

Securities to be registered pursuant to Section 12(g) of the Exchange Act: None
Securities for which there is a reporting obligation pursuant to Section 15 (d) of the Exchange Act: None

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the Annual Report:.

Ordinary shares of NOK 2.50 each 2,166,143,626

Indicate by check mark whether the registrant (1) has filed all reports to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2), has been subject to such filing requirements for the past 90 days. Yes __X___ No ______

Indicate by check mark which statement item the registrant has elected to follow. Item 17 ______Item 18 ___X___

* Listed, not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

Table of Contents

Terms and Measurements relating to the Oil and Gas Industry

References to:

- bbl means barrel
- mbbls means thousand barrels
- mmbbls means million barrels
- boe means barrels-of-oil equivalent
- mboe means thousand barrels-of-oil equivalent
- mmboe means million barrels-of-oil equivalent
- mmcf means million cubic feet
- bcf means billion cubic feet
- tcf means trillion cubic feet
- scm means standard cubic meter
- mcm means thousand cubic meters
- mmcm means million cubic meters
- bcm means billion cubic meters
- km means kilometer
- one billion means one thousand million

Equivalent measurements are based upon:

- 1 barrel equals 0.134 tonnes of oil (33 degrees API)
- 1 barrel equals 42 US gallons
- 1 barrel equals 0.159 standard cubic meters
- 1 barrel of oil equivalent equals 1 barrel of crude oil
- 1 barrel of oil equivalent equals 159 standard cubic meters of natural gas
- 1 barrel of oil equivalent equals 5,612 cubic feet of natural gas
- 1 barrel of oil equivalent equals 0.122 tonnes of NGLs
- 1 billion standard cubic meters of natural gas equals 1 million standard cubic meters of oil equivalent
- 1 cubic meter equals 35.3 cubic feet
- 1 km equals 0.62 miles
- *1 square kilometer equals 0.39 square miles*
- 1 cubic meter of natural gas equals one standard cubic meter of natural gas
- 1,000 standard cubic meters of natural gas equals 6.29 boe
- 1 standard cubic foot equals 0.0283 standard cubic meter
- 1 standard cubic foot equals 1,000 British thermal units (btu)
- 1 tonne of NGLs equals 1.3 standard cubic meters of oil equivalents
- 1 degree Celsius equals minus 32 plus five-ninths of the number of degrees Fahrenheit
- 1 bar equals 100 dynes per square meter
- 1 bar equals 2,089 pounds per square foot

Miscellaneous terms:

- Condensates means the heavier natural gas components, such as pentane, hexane, iceptane and so forth, which are liquid under atmospheric pressure - also called natural gasoline or naphtha
- Crude oil, or oil, includes condensate and natural gas liquids
- LNG, or liquefied natural gas, means lean gas - primarily methane - converted to liquid form through refrigeration to minus 163 degrees Celsius under atmospheric pressures
- LPG means liquefied petroleum gas and consists primarily of propane and butane, which turn liquid under a pressure of six to seven atmospheres. LPG is shipped in special vessels
- Naphtha is an inflammable oil obtained by the dry distillation of petroleum
- Natural gas is petroleum that consists principally of light hydrocarbons. It can be divided into

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- Natural gas is petroleum that consists principally of light hydrocarbons. It can be divided into
  - lean gas, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and
  - wet gas, primarily ethane, propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure• NGL means natural gas liquids light hydrocarbons consisting mainly of ethane, propane and butane which are liquid under pressure at normal temperature
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- Petroleum is a collective term for hydrocarbons, whether solid, liquid or gaseous. Hydrocarbons are compounds formed from the elements hydrogen (H) and carbon (C). The proportion of different compounds, from methane and ethane up to the heaviest components, in a petroleum find varies from discovery to discovery. If a reservoir primarily contains light hydrocarbons, it is described as a gas field. If heavier hydrocarbons predominate, it is described as an oil field. An oil field may feature free gas above the oil and contain a quantity of light hydrocarbons - also called associated gas

PART I

Item 1 Identity of Directors, Senior Management and Advisors

Not applicable.

Item 2 Offer Statistics and Expected Timetable

Not applicable.

Item 3 Key Information

Selected Financial Data

The following tables set forth selected consolidated financial and statistical data of Statoil.

You should read the following data together with Item 5–Operating and Financial Review and Prospects and Item 11–Quantitative and Qualitative Disclosures about Market Risk and our consolidated financial statements, including the notes to those financial statements included in this Annual Report on Form 20-F.

Solely for the convenience of the reader, the financial data at the twelve months ended December 31, 2002 have been translated into US dollars at the rate of NOK 6.9375 to USD 1.00, the noon buying rate on December 31, 2002. The financial data has been derived from our financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States, or USGAAP. The financial, reserve, production and sales information in these tables reflects our acquisition of the Norwegian State's direct financial interest (SDFI) assets in 2001 and were prepared as if the SDFI assets acquired by us had been part of Statoil throughout the financial periods presented. Such information in these tables, however, assumes that our purchase of the SDFI assets was financed with equity and, therefore, does not reflect the impact of the actual financing of the purchase of the SDFI assets. The actual financing, including our transfer of pipeline and other assets, is reflected in the consolidated financial information as from and including the year ended December 31, 2001.

	YEAR ENDED DECEMBER 31,					
(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)	*1998 NOK*	*1999 NOK*	*2000 NOK*	*2001 NOK*	*2002 NOK*	*2002 USD*
Income Statement						
Revenues:						
Sales	114,034	149,598	229,832	231,712	242,178	34,909
Equity in net income (loss) of affiliates	614	(745)	523	439	366	53
Other income	0	1,279	70	4,810	1,270	183
Total revenues	114,648	150,132	230,425	236,961	243,814	35,144
Expenses:						
Cost of goods sold	(53,449)	(79,508)	(119,469)	(126,153)	(147,899)	(21,319)
Operating expenses	(25,776)	(25,657)	(28,883)	(29,422)	(28,308)	(4,080)
Selling, general and administrative expenses	(6,528)	(6,688)	(3,891)	(4,297)	(5,466)	(788)
Depreciation, depletion and amortization	(14,471)	(17,579)	(15,739)	(18,058)	(16,844)	(2,428)
Exploration expenses	(4,137)	(3,122)	(2,452)	(2,877)	(2,195)	(316)
Total expenses before financial items	(104,361)	(132,554)	(170,434)	(180,807)	(200,712)	(28,931)
Income before financial items, income taxes and minority interest	10,287	17,578	59,991	56,154	43,102	6,213
Net financial items	(1,862)	1,431	(2,898)	65	8,233	1,187
Income before income taxes and minority interest	8,425	19,009	57,093	56,219	51,335	7,400
Income taxes	(6,809)	(12,856)	(40,456)	(38,486)	(34,336)	(4,949)
Minority interest	24	256	(484)	(488)	(153)	(22)
Net income	1,640	6,409	16,153	17,245	16,846	2,428
Net income per ordinary share(1)(2)	0.83	3.24	8.18	8.31	7.78	1.12
Dividends paid per ordinary share(2)(3)	2.43	3.47	10.81	26.69	2.85	0.41

(1) The weighted average number of shares outstanding was 1,975,885,600 up to and including the year 2000, and 2,076,180,942 and 2,165,422,239 in 2001 and 2002, respectively.

(2) There is no notional impact on the number of ordinary shares resulting from the assumed equity financing of the SDFI transaction.

(3) See Item 8–Financial Information–Dividend Policy and Item 3–Key Information–Dividends below for a description of how dividends are determined.

(IN MILLIONS, EXCEPT SHARE AMOUNTS)	AT DECEMBER 31, 1998 NOK	1999 NOK	2000 NOK	2001 NOK	2002 NOK	2002 USD
Balance Sheet						
Assets:						
Cash and cash equivalents	602	4,061	9,745	4,395	6,702	966
Short-term investments	6,123	3,604	3,857	2,063	5,267	759
Accounts receivable	19,257	28,421	29,871	26,208	32,057	4,621
Accounts receivable - related parties	0	1,972	2,177	1,531	1,893	273
Inventories	4,172	4,294	4,226	5,276	5,422	782
Prepaid expenses and other current assets	4,316	11,235	5,447	9,184	6,856	988
Total current assets	34,470	53,587	55,323	48,657	58,197	8,389
Investments in affiliates	8,652	9,852	10,214	9,951	9,629	1,388
Long-term receivables	4,516	4,789	8,165	7,166	7,138	1,029
Net properties, plants and equipments	120,117	128,967	132,278	126,500	122,379	17,640
Other assets	4,283	7,287	7,669	7,421	8,087	1,166
TOTAL ASSETS	172,038	204,482	213,649	199,695	205,430	29,612
Liabilities and Shareholders' Equity:						
Short-term debt	9,682	9,190	2,785	6,613	4,323	623
Accounts payable	12,393	19,324	15,266	10,970	19,603	2,826
Accounts payable – related parties	4,173	10,083	11,454	10,164	5,649	814
Accrued liabilities	8,836	8,666	11,228	13,831	11,590	1,671
Income taxes payable	2,477	6,366	14,877	16,618	18,358	2,646
Total current liabilities	37,561	53,629	55,610	58,196	59,523	8,580
Long-term debt	34,579	41,307	34,197	35,182	32,805	4,729
Deferred income taxes	38,198	43,020	43,331	42,354	43,153	6,220
Other liabilities	7,455	8,831	10,205	10,693	11,382	1,641
Total liabilities	117,793	146,787	143,343	146,425	146,863	21,169
Minority interest	1,838	1,590	2,480	1,496	1,550	223
Common stock (NOK 2.50 nominal value) 2,189,585,600 shares authorized and issued (1,975,885,600 prior to initial public offering)	4,940	4,940	4,940	5,474	5,474	789
Treasury shares (23,441,974 and 25,000,000 shares)	0	0	0	(63)	(59)	(9)
Additional paid-in capital	25,111	29,759	45,628	37,728	37,728	5,438
Retained earnings	20,422	19,978	14,768	6,682	17,355	2,502
Accumulated other comprehensive income	1,934	1,428	2,490	1,953	(3,481)	(502)
Total shareholders' equity	52,407	56,105	67,826	51,774	57,017	8,219
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	172,038	204,482	213,649	199,695	205,430	29,612

	YEAR ENDED DECEMBER 31, 1998	1999	2000	2001	2002
Other financial information					
Net debt to capital employed(1)	44.1%	42.6%	25.0%	39.0%	28.7%
After-tax return on average capital employed(2)	3.2%	6.4%	18.7%	19.9%	14.9%

(1) Net debt to capital employed is the net debt divided by capital employed. Net debt is interest-bearing debt less cash and cash equivalents and short-term investments, less interest bearing receivables of NOK 1,567 million in 2002 and NOK 1,257 million in 2001. Capital employed is net debt, shareholders' equity and minority interest.

(2) After-tax return on average capital employed is equal to net income before minority interest plus after tax net financing costs, divided by average capital employed over the last 12 months.

Summary Oil and Gas Production Information

The following table sets forth our Norwegian and international production of crude oil and natural gas for the periods indicated. The stated production volumes are the volumes that Statoil is entitled to in accordance with conditions laid down in concession agreements and production sharing agreements, or PSAs. The production volumes are net of royalty oil paid in kind and of gas used for fuel or flare. Our production is based on our proportionate participation in fields with multiple owners and does not include production of the Norwegian State's oil and natural gas.

PRODUCTION	YEAR ENDED DECEMBER 31, 2000	2001	2002
Norway:			
Crude oil (mmbbls)(1)	254	252	245
Natural gas (bcf)	495	511	653
Natural gas (bcm)	14.0	14.5	18.5
Combined oil and gas (mmboe)	342	343	361
International:			
Crude oil (mmbbls)	21	22	29
Natural gas (bcf)	19	16	12
Natural gas (bcm)	0.5	0.4	0.3
Combined oil and gas (mmboe)	24	25	31
Total:			
Crude oil (mmbbls)	275	274	274
Natural gas (bcf)	514	527	665
Natural gas (bcm)	14.6	14.9	18.8
Combined oil and gas (mmboe)	367	368	392

(1) Crude oil includes NGL and condensate production.

Sales Volume Information

We market and sell oil and gas owned by the Norwegian State through the Norwegian State's share in production licenses, known as the State's direct financial interest, or SDFI, together with our own production. For additional information see Item 7–Major Shareholders and Related Party Transactions. The following table sets forth SDFI and Statoil sales volume information for crude oil and natural gas for the periods indicated. The sales volumes for Statoil shown below include royalty oil we sell on behalf of the Norwegian State and volumes purchased from third parties for resale.

SALES VOLUMES	YEAR ENDED DECEMBER 31, 2000	2001	2002
Statoil:			
Crude oil (mmbbls) (1)	425	466	506
Natural gas (bcf)	519	533	704
Natural gas (bcm)	14.7	15.1	19.9
Combined oil and gas (mmboe)	517	561	631
SDFI assets retained by the Norwegian State:			
Crude oil (mmbbls) (1)	384	395	381
Natural gas (bcf)	602	667	830
Natural gas (bcm)	17.0	18.9	23.5
Combined oil and gas (mmboe)	491	514	529
Total:			
Crude oil (mmbbls) (1)	809	861	887
Natural gas (bcf)	1,121	1,200	1,535
Natural gas (bcm)	31.7	34.0	43.4
Combined oil and gas (mmboe)	1,008	1,075	1,160

(1) Sales volumes of crude oil include NGL and condensate.

Exchange Rates

The table below shows the high, low, average and period end noon buying rates in The City of New York for cable transfers in foreign currencies as certified for customs purposes by the Federal Reserve Bank of New York for Norwegian kroner per USD 1.00. The average is computed using the noon buying rate on the last business day of each month during the period indicated.

YEAR ENDED DECEMBER 31,	*LOW*	*HIGH*	*AVERAGE*	*END OF PERIOD*
1998	7.3130	8.3200	7.5549	7.5800
1999	7.3970	8.0970	7.8351	8.0100
2000	7.9340	9.5890	8.8307	8.8010
2001	8.5400	9.4638	9.0330	8.9724
2002	6.9375	9.1110	7.9253	6.9375

The table below shows the high and low noon buying rates for each month during the six months prior to the date of this Annual Report on Form 20-F.

YEAR 2002	*LOW*	*HIGH*
October	7.3895	7.6450
November	7.2219	7.3990
December	6.9375	7.3140

YEAR 2003	*LOW*	*HIGH*
January	6.8290	7.0020
February	6.9130	7.1980
March (up to and including March 14)	7.0590	7.2530

On March 14, 2003 the noon buying rate for Norwegian kroner was USD 1.00 = NOK 7.2530

Fluctuations in the exchange rate between the Norwegian kroner and the US dollar will affect the US dollar amounts received by holders of ADSs on conversion of dividends, if any, paid in Norwegian kroner on the ordinary shares and may affect the US dollar price of the ADSs on the New York Stock Exchange.

Dividends

Dividends in respect of the fiscal year are declared at our annual general meeting in the following year. Under Norwegian law, dividends may only be paid in respect of a financial period as to which audited financial statements have been approved by the annual general meeting of shareholders, and any proposal to pay a dividend must be recommended by the board of directors, accepted by the corporate assembly and approved by the shareholders at a general meeting. The shareholders at the annual general meeting may vote to reduce, but may not increase, the dividend proposed by the board of directors.

Dividends may be paid in cash or in kind and are payable only out of our distributable reserves. The amount of our distributable reserves is defined by the Norwegian Public Limited Companies Act, which requires such reserves to be calculated under Norwegian GAAP and consist of:

- annual net income according to the income statement approved for the preceding financial year, and
- retained net income from previous years (adjusted for any reclassification of our equity),

after deduction for uncovered losses, book value of research and development, goodwill and net deferred tax assets as recorded in the balance sheet for the preceding financial year, and the aggregate value of treasury shares that we have purchased or been granted security in and of credit and security given by us pursuant to sections 8-7 to 8-9 of the Norwegian Public Limited Companies Act during preceding financial years.

We cannot distribute any dividends if our equity, according to the Statoil ASA unconsolidated balance sheet, amounts to less than 10% of the total assets reflected on our unconsolidated balance sheet without following a creditor notice procedure as required for reducing the share capital. Furthermore, we can only distribute dividends to the extent compatible with good and careful business practice with due regard to any losses which we may have incurred after the last balance sheet date or which we may expect to incur. Finally, the amount of dividends we can distribute is calculated on the basis of our unconsolidated financial statements. Retained earnings available for distribution is based on Norwegian accounting principles and legal regulations and amounts to NOK 39,482 million (before provisions for dividend for the year ended December 31, 2002 of NOK 6,282 million) at December 31, 2002.

Although we currently intend to pay annual dividends on our ordinary shares, we cannot assure you that dividends will be paid or as to the amount of any dividends. Future dividends will depend on a number of factors prevailing at the time our board of directors considers any dividend payment.

Dividends paid historically are not representative of dividends to be paid in the future. Dividends paid prior to 2002 include 100% of the cash flows from the SDFI assets transferred from the Norwegian State, and a percentage of net income after tax (calculated on a Norwegian GAAP basis) for all other activities. The following table shows the amounts paid to the Norwegian State on a per share basis and in the aggregate, during each of the four fiscal years from 1998 to 2001, and dividends to be paid in 2003 on our ordinary shares for the fiscal year 2002.

	PER ORDINARY SHARE(1)		TOTAL (IN MILLIONS)	
YEAR	NOK	USD(2)	NOK	USD(2)
1998	2.43	0.35	4,802	692
1999	3.47	0.50	6,853	788
2000	10.81	1.56	21,363	3,079
2001(3)	26.69	3.85	55,415	7,988
2002	2.90	0.42	6,282	906

(1) Based on 2,166,143,626 shares in 2002, 2,076,180,942 shares in 2001 and 1,975,885,600 shares prior to 2001, being the weighted average number of ordinary shares for each year.

(2) The USD amounts are based on the noon buying rate for Norwegian kroner on December 31, 2002, which was NOK 6.9375 to USD 1.00.

(3) Total dividends paid in 2001 include a cash settlement for the SDFI assets amounting to NOK 19.65 (USD 2.83) per share. Ordinary dividend for 2001 of NOK 2.85 was declared on May 7, 2002, and paid to shareholders registered in the Norwegian Central Securities Depository as of that date on May 28, 2002.

The increases in dividends for 2000 and 2001 were due to increase in cash flows generated from SDFI properties transferred from the Norwegian State and increased net income after tax for all other activities.

Dividends we paid in periods prior to 2002 reflected our status as wholly owned by the Norwegian State and should not be considered indicative of our future dividend policy.

Since we will only pay dividends in Norwegian kroner, exchange rate fluctuations will affect the US dollar amounts received by holders of ADSs after the ADR depositary converts cash dividends into US dollars.

Risk Factors

Risks Related to Our Business

A substantial or extended decline in oil or natural gas prices would have a material adverse effect on us.

Historically, prices for oil and natural gas have fluctuated widely in response to changes in many factors. We do not and will not have control over the factors affecting prices for oil and natural gas. These factors include:

- global and regional economic and political developments in resource-producing regions, particularly in the Middle East;
- global and regional supply and demand;
- the ability of the Organization of Petroleum Exporting Countries and other producing nations to influence global production levels and prices;
- prices of alternative fuels which affect our realized prices under our long-term gas sales contracts;
- Norwegian and foreign governmental regulations and actions;
- global economic conditions;
- price and availability of new technology; and
- weather conditions.

It is impossible to predict future oil and natural gas price movements with certainty. Declines in oil and natural gas prices will adversely affect our business, results of operations and financial condition, liquidity and our ability to finance planned capital expenditures. For an analysis of the impact on income before financial items, taxes and minority interest from changes in oil and gas prices, see Item 5–Operating and Financial Review and Prospects–Operating Results–Factors Affecting Our Results of Operations. Lower oil and natural gas prices also may reduce the amount of oil and natural gas that we can produce economically or reduce the economic viability of projects planned or in development.

Exploratory drilling involves numerous risks, including the risk that we will encounter no commercially productive oil or natural gas reservoirs, which could materially adversely affect our results.

We are exploring in various geographic areas, including new resource provinces such as the Norwegian Sea, the Barents Sea and deepwater offshore Angola, where environmental conditions are challenging and costs can be high. We are also considering exploration activities in additional international areas where costs may be high. In addition, our use of advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies. The cost of drilling, completing and operating wells is often uncertain. As a result, we may incur cost overruns or may be required to curtail, delay, or cancel drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment. For example, we have entered into long-term leases on drilling rigs which are not required for the originally intended operations and we cannot be certain that these rigs will be re-employed or at what rate they will be re-employed. Our overall drilling activity or drilling activity within a particular project area may be unsuccessful. Such failure will have a material adverse effect on our results of operations and financial condition.

If we fail to acquire or find and develop additional reserves, our reserves and production will decline materially from their current levels.

The majority of our proved reserves are on the Norwegian Continental Shelf (NCS), a maturing resource province. Except to the extent we conduct successful exploration and development activities or acquire properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. In addition, the volume of production from oil and natural gas properties generally declines as reserves are depleted. For example, two of our major fields, Statfjord and Gullfaks, are dependent on satellite fields to maintain production, and, unless efforts to improve the development of satellite fields are successful, production will gradually decline. Our future production is highly dependent upon our success in finding or acquiring and developing additional reserves. If we are unsuccessful, we may not meet our production targets, and our total proved reserves and production will decline and adversely affect our results of operations and financial condition.

We encounter competition from other oil and natural gas companies in all areas of our operations, including the acquisition of licenses, exploratory prospects and producing properties.

The oil and gas industry is extremely competitive, especially with regard to exploration for, and exploitation and development of new sources of oil and natural gas.

Some of our competitors are much larger, well-established companies with substantially greater resources, and in many instances they have been engaged in the oil and gas business for much longer than we have. These larger companies are developing strong market power through a combination of different factors, including:

- diversification and reduction of risk;
- financial strength necessary for capital-intensive developments;
- exploitation of benefits of integration;
- exploitation of economies of scale in technology and organization;
- exploitation of advantages of expertise, industrial infrastructure and reserves; and
- strengthening of positions as global players.

These companies may be able to pay more for exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects, including operatorships and licenses, than our financial or human resources permit. For more information on the competitive environment, see Item 4–Information on the Company–Business Overview.

As we face a variety of challenges in executing our strategic objective of successfully exploiting growth opportunities available to us, the growth of our business may be compromised if we are unable to execute on our strategy and our financial and production targets may be revised as a result of acquisitions made in accordance with our strategy.

An important element of our strategy is to continue to pursue attractive growth opportunities available to us, both in enhancing our asset portfolio and expanding into new markets. The opportunities that we are actively pursuing may involve acquisitions of businesses or properties that complement or expand our existing portfolio. Our ability to implement this strategy successfully will depend upon a variety of factors, including our ability to:

- identify acceptable opportunities;
- negotiate favorable terms;
- develop the performance of new market opportunities or acquired properties or businesses promptly and profitably;
- integrate acquired properties or businesses into our operations; and
- arrange financing, if necessary.

As we pursue business opportunities in new and existing markets, we anticipate that significant investments and costs will be related to the development of such opportunities. We may incur or assume unanticipated liabilities, losses or costs associated with assets or businesses acquired. Any failure by us to pursue and execute new business opportunities successfully could result in financial losses, and could inhibit growth.

If we are successful in the pursuit of our strategy and the making of such acquisitions, and no assurances can be given that we will be, our ability to achieve our financial, capital expenditure and production targets may be materially affected. Any such new projects we acquire will require additional capital expenditure and will increase our finding and development expenditure. It is likely that such acquisitions will be in the exploratory or development phase and not in the production phase, which will have a material adverse effect on our net return in proportion to our average capital employed. These projects may also have different risk profiles than our existing portfolio. These and other effects of such acquisitions could result in us having to revise some or all of our targets with respect to ROACE, capital expenditure amounts and allocations, unit production costs, finding and development costs, reserves replacement rate and production.

In addition, the pursuit of acquisitions or new business opportunities could divert financial and management resources away from our day-to-day operations to the integration of acquired operations or properties. We have no current intention to issue additional equity; we may, however, require additional debt or equity financing to undertake or consummate future acquisitions or projects, which financing may not be available on terms satisfactory to us, if at all, and may, in the case of equity, be dilutive to our earnings per share.

Our development projects involve many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our development projects may be delayed or unsuccessful for many reasons, including cost overruns, lower oil and gas prices, equipment shortages, mechanical and technical difficulties and industrial action. These projects will also often require the use of new and advanced technologies, which can be expensive to develop, purchase and implement, and may not function as expected. In addition, some of our development projects will be located in deepwater or other hostile environments, such as the Barents Sea, or produced from challenging reservoirs, which can exacerbate such problems. For example, developing the large and complex facilities of the Åsgard chain has been one of the most demanding developments we have undertaken. We experienced substantial cost overruns caused by changes in the scope and magnitude of the project, delays in the final stages of the project, employee strikes and several unforeseen technical problems. As a result, we have problems associated with volume and regularity, and we have to fulfill our delivery commitments associated with Åsgard by providing the volumes required from other fields, which may not always be possible. There is a risk that other development projects that we undertake may suffer from similar or additional problems, such as the Snøhvit project where we have encountered cost overruns.

Our development projects on the NCS also face the challenge of remaining profitable where we are increasingly developing smaller satellite fields in mature areas and our projects are subject to the Norwegian State's relatively high taxes on offshore activities. Our other development projects in mature fields in Western Europe also face potentially higher operating costs. In addition, our development projects, particularly those in remote areas, could become less profitable, or unprofitable, if we experience a prolonged period of low oil or gas prices.

Many of our mature fields are producing increasing quantities of water with oil and gas. Our ability to dispose of this water in acceptable ways may impact our oil and gas production.

We may not be able to produce some of our oil and gas economically due to a lack of necessary transportation infrastructure when a field is in a remote location.

Our ability to exploit economically any discovered petroleum resources beyond our proved reserves will be dependent upon, among other factors, the availability of the necessary infrastructure to transport oil and gas to potential buyers at a commercially acceptable price. Oil is usually transported by tankers to refineries, and gas is usually transported by pipeline to processing plants and end-users. The transportation of oil and natural gas from our holdings in Azerbaijan face a number of significant obstacles that could prevent sales to international markets, including obtaining necessary approvals for pipelines from several governments which may not share a common development strategy, capacity constraints and general political and economic instability. We may not be successful in our efforts to secure transportation and markets for all of our potential production.

Some of our international interests are located in politically, economically and socially unstable areas, which could disrupt our operations.

We have assets located in unstable regions around the world. For example, there was war and civil strife in the Caspian region through much of the 1990s. In addition, the states bordering the Caspian Sea dispute ownership and distribution of proceeds from the Caspian's seabed and subsoil resources. Our activities in the Persian Gulf may be subject to disruption due to, for example, war and terrorism. Other countries, such as Venezuela, Nigeria and Angola, where we also have operations, have experienced expropriation or nationalization of property, civil strife, strikes, acts of war, guerrilla activities and insurrections.

Our activities in Iran could lead to US sanctions

In August 1996, the United States adopted the Iran and Libya Sanctions Act, referred to as ILSA, which authorizes the President of the United States to impose sanctions (from a list that includes denial of financing by the export-import bank and limitations on the amount of loans or credits available from US financial institutions) against persons found by the President to have knowingly made investments in Iran of USD 20 million or more that directly and significantly contribute to the enhancement of Iran's ability to develop its petroleum resources. We take part in certain exploration projects or study activities with respect to Iran. In October 2002, we signed a participation agreement with Petropars of Iran which provides that we assume the operatorship for the offshore part of phases six, seven and eight of the South Pars gas development project in the Persian Gulf, and our capital commitment over the period of the contract is anticipated to amount to USD 300 million. We cannot predict interpretations of or the implementation policy of the US Government under ILSA with respect to our current or future activities in Iran or other areas. It is possible that the United States may determine that these or other activities will constitute activity covered by ILSA and will subject us to sanctions.

We are exposed to potentially adverse changes in the tax regimes of each jurisdiction in which we operate.

We operate in 25 countries around the world, and any of these countries could modify its tax laws in ways that would adversely affect us. Most of our operations are subject to changes in tax regimes in a similar manner as other companies in our industry. In addition, in the long-term, the marginal tax rate in the oil and gas industry tends to change in correlation with the price of crude oil. Significant changes in the tax regimes of countries in which we operate could have a material adverse affect on our liquidity and results of operation.

We are not insured against all potential losses and could be seriously harmed by natural disasters or operational catastrophes

Exploration for and production of oil and natural gas is hazardous, and natural disasters, operator error or other occurrences can result in oil spills, blowouts, cratering, fires, equipment failure, and loss of well control, which can injure or kill people, damage or destroy wells and production facilities, and damage property and the environment. Offshore operations are subject to marine perils, including severe storms and other adverse weather conditions, vessel collisions, and governmental regulations as well as interruptions or termination by governmental authorities based on environmental and other considerations. Losses and liabilities arising from such events would significantly reduce our revenues or increase our costs and have a material adverse effect on our operations or financial condition.

The crude oil and natural gas reserve data in this Annual Report on Form 20-F are only estimates, and our actual production, revenues and expenditures with respect to our reserves may differ materially from these estimates.

The reliability of proved reserve estimates depends on:

- the quality and quantity of our geological, technical and economic data;

- whether the prevailing tax rules and other government regulations, contracts, oil, gas and other prices will remain the same as on the date estimates are made;
- the production performance of our reservoirs; and
- extensive engineering judgments.

Many of the factors, assumptions and variables involved in estimating reserves are beyond our control and may prove to be incorrect over time. Results of drilling, testing and production after the date of the estimates may require substantial upward or downward revisions in our reserve data. Any downward adjustment could lead to lower future production and thus adversely affect our financial condition, future prospects and market value.

We face foreign exchange risks that could adversely affect our results of operations.

Our business faces foreign exchange risks because a large percentage of our revenues and cash receipts are denominated in US dollars while a significant portion of our operating expenses and income taxes accrue in Norwegian kroner, reflecting our operations on the NCS. Movements between the US dollar and Norwegian kroner may adversely affect our business. While an increase in the value of the US dollar against the Norwegian kroner can be expected to increase our reported earnings, such an increase would also be expected to increase our operating expenses and the value of our debt, which would be recorded as a financial expense, and, accordingly, would adversely affect our net income. See Item 5–Operating and Financial Review and Prospects–Liquidity and Capital Resources–Risk Management.

Risks Related to the Regulatory Regime

Competition is expected to increase in the European gas market, currently our main market for gas sales, as a result of new European Union, or EU, directives which could adversely affect our ability to expand or even maintain our current market position or result in reduction in prices in our gas sales contracts.

Fundamental changes are now taking place in the organization and operation of the European gas market, with the objective of opening national markets to competition and integrating them into a single market for natural gas. This process started with the EU Gas Directive, which became effective in August 2000. The Directive was included into the EEA Agreement in June 2002, and all necessary changes in order to implement the Directive into Norwegian legislation were made during 2002. The Directive requires EEA states to take certain minimum steps to open their gas markets to greater competition. Each state must specify annually the wholesale and final gas customers inside its territory that have the legal capacity to contract for or be sold natural gas by the gas supplier of their choice.

Customers designated by any given member state must result in an opening of that state's gas market equal to at least 20% of the total annual gas consumption. This level must rise to 28% by 2003 and 33% by 2008. The Directive also requires that eligible customers be given the right to negotiate agreements for using gas transport systems directly or rights of access based on tariffs or other mechanisms. A number of EU member states have already decided to exceed the minimum steps set out in the Directive and to open their gas markets to a greater extent. In addition, new proposals are currently under discussion within the EU through which the process of market opening would be accelerated and new measures adopted to promote the process.

Most of our gas is sold under long-term gas contracts to customers in the EU, a gas market that will be affected by changes in EU regulations.

We may incur material costs to comply with, or as a result of, health, safety and environmental laws and regulations.

Compliance with environmental laws and regulations in Norway and abroad could materially increase our costs. We incur and expect to continue to incur, substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety, including costs to reduce certain types of air emissions and discharges to the sea and to remediate contamination at various owned and previously-owned facilities and at third-party sites where our products or wastes have been handled or disposed.

In our capacity as holder of licenses on the NCS under the Norwegian Petroleum Act of November 29, 1996, we are subject to statutory strict liability in respect of losses or damages suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of our licenses. This means that anyone who suffers losses or damages as a result of pollution caused by operations at any of our NCS license areas can claim compensation from us without needing to demonstrate that the damage is due to any fault on our part. If the pollution is caused by a force majeure event, however, a Norwegian court may reduce the level of damages to the extent it considers reasonable.

Whether in Norway or abroad, new laws and regulations, the imposition of tougher requirements in licenses, increasingly strict enforcement of or new interpretations of existing laws and regulations, or the discovery of previously unknown contamination may require future expenditures to:

- modify operations;
- install pollution control equipment;
- perform site clean-ups; or
- curtail or cease certain operations.

In particular, we may be required to incur significant costs to comply with the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change, known as the Kyoto Protocol, and other pending EU laws and directives. In addition, increasingly strict environmental requirements, including those relating to gasoline sulphur levels and diesel quality, affect product specifications and operational practices. Future expenditures to meet such specifications could have a material adverse effect on our operations or financial condition.

Political and economic policies of the Norwegian State could affect our business.

The Norwegian State plays an active role in the management of NCS hydrocarbon resources. In addition to its direct participation in petroleum activities through the SDFI and its indirect impact through tax and environmental laws and regulations, the Norwegian State awards licenses for reconnaissance, production and transportation and approves, among other things, exploration and development projects, gas sales contracts and applications for (gas) production rates for individual fields. The Norwegian State may also, if important public interests are at stake, direct us and other oil companies to reduce production of petroleum. Reductions of up to 7.5% have been imposed in the past. By a royal decree of December 19, 2001, the Norwegian government decided that Norwegian oil production should be reduced by 150,000 barrels per day from January 1, 2002 until June 30, 2002. This amounted to roughly a 5% reduction in output.
Further, in the production licenses in which the SDFI holds an interest, the Norwegian State retains the ability to direct petroleum licensees' actions in certain circumstances.

If the Norwegian State were to take additional action pursuant to its extensive powers over activities on the NCS or to change laws, regulations, policies or practices relating to the oil and gas industry, our NCS exploration, development and production activities and results of operations could be materially and adversely affected. For more information about the Norwegian State's regulatory powers, see Item 4–Information on the Company—Regulation.

Risks Related to Our Ownership by the Norwegian State

The interests of our majority shareholder, the Norwegian State, may not always be aligned with the interests of our other shareholders, which may affect our decisions relating to the NCS.

The Norwegian Parliament, known as the Storting, and the Norwegian State have resolved that the Norwegian State's shares in Statoil and the SDFI's interests in NCS licenses must be managed pursuant to a coordinated ownership strategy for the Norwegian State's oil and gas interests. Under this strategy, the Norwegian State has required us to continue to market the Norwegian State's oil and gas together with our own as a single economic unit.

Pursuant to the coordinated ownership strategy for the Norwegian State's shares in us and the SDFI, the Norwegian State requires us in our activities on the NCS to take account of the Norwegian State's interests in all decisions which may affect the development and marketing of our own and the Norwegian State's oil and gas.

The Norwegian State holds more than a two-thirds majority of our shares. Accordingly, the Norwegian State has the power to determine matters submitted for a vote of shareholders, including amending our articles of association and electing all of the members of the corporate assembly except employee representatives. The employees may claim the right to be represented by up to one third of the members of the board of directors as well as the corporate assembly. The corporate assembly is responsible for electing our board of directors and communicates its recommendations concerning the board of directors' proposals about the annual accounts, balance sheets, allocation of profits and coverage of losses of our company to the general meeting. The interests of the Norwegian State in deciding these and other matters and the factors it considers in exercising its votes, especially pursuant to the coordinated ownership strategy for the SDFI and our shares held by the Norwegian State, could be different from the interests of our other shareholders. Accordingly, when making commercial decisions relating to the NCS, we have to take into account the Norwegian State's coordinated ownership strategy and we may not be able to fully pursue our own commercial interests, including those relating to our strategy on development, production and marketing of oil and gas.

If the Norwegian State's coordinated ownership strategy is not implemented and pursued in the future, then our mandate to continue to sell the Norwegian State's oil and gas together with our own as a single economic unit is likely to be prejudiced. Loss of the mandate to sell the SDFI's oil and gas could have an adverse effect on our position in our markets. For further information about the Norwegian State's coordinated ownership strategy, see Item 7–Major Shareholders and Related Party Transactions–Major Shareholders.

Forward-Looking Statements

This Annual Report on Form 20-F contains forward-looking statements that involve risks and uncertainties, in particular under Item 4–Information on the Company and Item 5–Operating and Financial Review and Prospects. In some cases, we use words such as "believe", "intend", "expect", "anticipate", "plan", "target" and similar expressions to identify 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. You should not place undue reliance on these forward-looking statements. Our actual results could differ materially from those anticipated in the forward-looking statements for many reasons, including the risks described above in Item 3–Key Information, below in Item 5–Operating and Financial Review and Prospects, and elsewhere in this Annual Report on Form 20-F.

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; and other factors discussed elsewhere in this report.

Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot assure you that our future results, level of activity, performance or achievements will meet these expectations. Moreover, neither we nor any other person assumes responsibility for the accuracy and completeness of the forward-looking statements. Unless we are required by law to update these statements, we will not necessarily update any of these statements after the date of this Annual Report, either to conform them to actual results or to changes in our expectations.

Statements Regarding Competitive Position

Statements made in Item 4–Information on the Company, referring to Statoil's competitive position, are based on our belief, and in some cases rely on a range of sources, including investment analysts' reports, independent market studies and our internal assessments of market share based on publicly available information about the financial results and performance of market participants.

Item 4 Information on the Company

History and Development of the Company

Statoil ASA is a public limited company organized under the laws of Norway with its registered office at Forusbeen 50, N-4035 Stavanger, Norway. Our telephone number is +47 51 99 00 00. Our registration number in the Norwegian Register of Business Enterprises is 923 609 016. Statoil ASA was incorporated on September 18, 1972 under the name Den norske stats oljeselskap a.s. At an extraordinary general meeting held on February 27, 2001, it was resolved to change our company name to Statoil ASA and convert into a public listed company, or ASA.

Business Overview

We are an integrated oil and gas company, headquartered in Stavanger, Norway. Based on both production and reserves we are a major international oil and gas company and the largest in Scandinavia. Our proved reserves as of December 31, 2002 consisted of 1,867 million barrels of oil, or mmbbls, and 382 billion standard cubic meters, or bcm (13.5 trillion standard cubic feet, or tcf) of natural gas, which represents an aggregate of 4,267 million barrels of oil equivalent, or mmboe. Our operations commenced in 1972 with a primary focus on the exploration, development and production of oil and natural gas from the Norwegian Continental Shelf, or NCS. Since then, we have grown both domestically and internationally into a company with 17,115 employees as of December 31, 2002 and business operations in 25 countries.

At our request, DeGolyer and MacNaughton, independent petroleum engineering consultants, have carried out an independent evaluation of proved reserves at December 31, 2002 for our properties. The results obtained by DeGolyer and MacNaughton do not differ materially from those reported by us when compared on the basis of net equivalent barrels of oil. DeGolyer and MacNaughton has delivered to us its summary letter report describing its procedures and conclusions, a copy of which appears as Appendix A hereto. Reserve engineering is a process of forecasting the recovery and sale of oil and gas from a reservoir and is in part subjective. It is clearly associated with considerable uncertainty, often positive, but also negative. The accuracy of any reserve information is a function of the quality of available data and of engineering and interpretation and judgment. The requirements of the SEC with respect to the calculation of proved reserves set a standard for estimating reserves which results in values that are reasonably certain technically, and consistent with the economic, regulatory and operating conditions at the time the estimates are made. See Supplementary Information on Oil and Gas Producing Activities beginning on page F-27 for further details of our proved reserves.

We are the leading producer of crude oil and gas on the technologically demanding NCS and are well positioned internationally, having participated in a number of high-quality discoveries outside the NCS. We are the largest supplier of natural gas from the NCS (including sales we make on behalf of the Norwegian State) to the growing Western European gas market. We are one of the market leaders in the retail gasoline business in Scandinavia through our 50% holding in Statoil Detaljhandel Skandinavia AS, with a market share of 22%. We are one of the largest net sellers of crude oil worldwide, including sales of crude oil purchased from the Norwegian State.

We divide our operations into four business segments: Exploration and Production Norway, International Exploration and Production, Natural Gas and Manufacturing and Marketing.

The following table sets forth the income before financial items, income taxes and minority interest for each segment for the periods indicated.

	YEAR ENDED DECEMBER 31,			
	2000	2001	2002	
(IN MILLIONS)	*NOK*	*NOK*	*NOK*	*USD*
Income before financial items, income taxes and minority interest of:				
E&P Norway	46,715	40,697	31,463	4,535
International E&P	773	1,291	1,086	157
Natural Gas	7,893	9,629	8,918	1,285
Manufacturing and Marketing	4,559	4,480	1,637	236
Other	51	57	(2)	0
Total	**59,991**	**56,154**	**43,102**	**6,211**

Exploration and Production Norway. E&P Norway includes our exploration, development and production operations on the NCS. Our NCS operations are organized in four core areas, of which three are currently producing hydrocarbons: Troll/Sleipner, Halten/Nordland, Tampen, and one, Tromsøflaket, is expected to begin production in 2006. We operate 20 developed fields in our three producing core areas. These fields produced a total of 2.27 mmboe per day in 2002, 51% of total NCS daily production. Throughout 2002, our daily equity oil production was 670,000 barrels of oil and daily equity gas production was 50.7 mmcm (1,790 mmcf), compared to 691,000 barrels of oil and daily equity gas production of 39.7 mmcm (1,401 mmcf) in 2001. We are also well positioned in three promising but less mature areas: the Møre/Vøring and Lofoten areas of the Norwegian Sea and the Barents Sea. As of December 31, 2002, E&P Norway had proved reserves of 1,286 million barrels of crude oil and 374 bcm (13.2 tcf) of natural gas, which represents an aggregate of 3,641 mmboe. Our experience over the last 30 years in the challenging NCS environment has helped us develop expertise in managing complex, integrated projects. We are continuously improving our returns through both an aggressive cost saving program and portfolio management. We believe that this business segment will continue to provide strong returns, and, as a large source of natural gas, allow us to capitalize on anticipated increased demand for natural gas across Europe.

International Exploration and Production. International E&P includes all of our exploration, development and production operations outside Norway. We have established positions in four core areas: Caspian, Western Africa (Angola and Nigeria), Western Europe and Venezuela. As of December 31, 2002, International E&P had proved reserves of 580 million barrels of crude oil and 7.2 bcm (255 bcf) of natural gas, which represents an aggregate of 626 mmboe. We participated in six of the largest finds in the world in the period from 1997 through 2001, and in 2002 we discovered hydrocarbons in eight out of nine exploration wells in which we participated internationally. In 2002 we produced 79,700 barrels of oil and 0.94 mmcm (33 mmcf) of gas per day from our international operations, compared to 59,700 barrels of oil and 1.2 mmcm (41 mmcf) of gas for 2001. We believe that this business segment is important in providing long-term profitable growth for our company.

Natural Gas. The Natural Gas segment transports, processes and sells natural gas from our upstream positions on the NCS and abroad. We are one of the leading suppliers of natural gas to the European market and the largest corporate owner in the world's largest offshore pipeline network. This network, Gassled, allows us flexibility in the way we source, blend and deliver our natural gas to any one of four landing points in Europe and through to the European gas transmission system. We have a 21.133% interest in the Gassled joint venture, which includes Europe's largest gas processing facility at Kårstø in Norway. Given our upstream reserves, access to a flexible transportation network and security of supply, we believe that we can expand our sales and market share in the expected environment of increased demand and market deregulation. We believe that this business segment will provide significant opportunities for growth in the near to medium term. In 2002 we sold approximately 43.1 bcm (1.5 tcf) of natural gas, which includes natural gas sold by us on behalf of the Norwegian State, compared to 33.6 bcm (1.2 tcf) in 2001.

Manufacturing and Marketing. The Manufacturing and Marketing segment comprises downstream activities including sales and trading of crude oil, NGL and petroleum products, refining, industrial marketing, retail marketing of oil products, methanol production and sales and petrochemical operations through our 50%-owned joint venture Borealis. We believe that further benefits will result from continued operational integration of our downstream and upstream activities and from further capitalizing on our brand name and strong marketing presence in the Scandinavian region, Poland, Ireland and the Baltic states. We sold our shares in our shipping subsidiary Navion to Norsk Teekay AS, which is a wholly-owned subsidiary of Teekay Shipping Corporation, effective January 1, 2003, and expect to close the sale during the second quarter of 2003.

Strategy and Opportunities

Our strategic objective is to exploit the profitable growth opportunities available to us on the NCS and internationally while maintaining strict capital discipline. Factors crucial to our competitiveness include:

- our high level of operational expertise in the use of advanced technology and experience in the management of complex exploration and production projects;
- our large reserves of both crude oil and natural gas;
- our location and transportation infrastructure in Northwest Europe and experience in gas sales and marketing and the advantages they provide in targeting the growing European gas market; and
- our proven track record of cost improvements, portfolio restructuring and enhanced oil recovery.

In pursuit of our strategic objectives, we intend to:

Maximize shareholder value through strict capital discipline. Our key financial target is to achieve an underlying return on average capital employed, or ROACE, of 12% by 2004, adjusting our actual return assuming a long-term 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 NOK 8.20. All prices are measured in real 2000 terms. We intend to deliver underlying returns at or above this target through organic growth based on our stringent allocation of capital resources, continuing cost reduction and ongoing restructuring of our asset portfolio. However, this target is subject to revision and excludes the possible effects of acquisitions as set forth below in Item 5—Operating Review and Prospects—Trend Information. We have increased the focus on our managers' performance by introducing performance related bonus schemes. We will continue to strengthen the use of our remuneration scheme to have a strong linkage between managers' rewards and our financial results.

Continue to grow returns in E&P Norway. We are the leading operator and producer of oil and gas on the NCS, a region with significant remaining resources as well as restructuring potential. We intend to sustain the present production level at one million barrels per day towards 2007. The sustainability is not dependent on exploration and new discoveries, but is to be achieved by developing reserves that have already been discovered. We have an ambition to sustain this level also towards 2012 through focused exploration efforts on the NCS.

We have reduced and are continuing to reduce the costs in E&P Norway and are well on track to meet our near-term goals in 2004. To fulfill our medium-term goal and our long-term ambition we will focus on enhanced oil recovery measures and technology improvements in order to increase production and profitability in our three core producing areas Tampen, Troll/Sleipner and Halten/Nordland. In the mature Tampen area we are preparing a new industrial plan to reduce the level of operating costs and thus secure profitable long-term production. In order to increase production in the Troll/Sleipner area, the core of our gas machine, we plan to increase step-by-step the total capacity throughout the related onshore facilities at Kollsnes to a level of 150 mmcm per day.

In the Halten/Nordland area, our growth area, we see that maximum value creation is closely linked to long-term utilization of the infrastructure investments that we have made so far, both with respect to the gas production from our offshore facilities on Åsgard, Norne and Heidrun, the Haltenpipe gas line and Tjeldbergodden facilities and the gas transportation infrastructure out of the Halten/Nordland area, i.e., Åsgard Transport and the onshore facilities at Kårstø.

Our longer-term options are primarily in the Norwegian Sea and the Barents Sea. We consider the potential in the Norwegian Sea to be significant. With the approval of the plan for Snøhvit by the Ministry of Petroleum and Energy, we have reduced the threshold for developing additional reserves in the Barents Sea and are well positioned to take the first step towards the Russian part of the Barents Sea.

Grow our international production through further developing existing quality assets and leveraging our strengths. Having targeted and concentrated our international exploration and production activities in selected areas, and having participated in six of the largest oil and gas discoveries since 1997, we are focusing our efforts on establishing significant production and increasing our influence in our core areas: Caspian, Western Africa, Western Europe and Venezuela. We are also exploring additional opportunities in other areas that support our strategy and leverage our skills and competence from the NCS. In 2002 we entered into a contract in Iran for the development of the South Pars field phases 6, 7 and 8. We will pursue attractive opportunities as they arise and as our capital budgets permit. These opportunities may include acquisitions of companies or oil or gas assets in development phase or production phase that complement or expand our existing portfolio. We will also continue to manage our portfolio of assets to seek to further increase profitability and secure operating influence and, where beneficial, operatorships.

Capitalize on our strong positions in European gas markets to take advantage of expected growth in demand, and expand beyond traditional markets and supply areas. As a leading supplier of gas to Europe, we are well positioned to benefit from growing demand for gas and the deregulation of gas markets, and will adapt to new commercial opportunities. We intend to actively manage our upstream portfolio and transportation capacities to maximize the income from existing long-term natural gas contracts, and we aim to exploit economies of scale in marketing of gas. In particular, we intend to capitalize on the trading and optimization opportunities that will arise with the anticipated increase in demand for imports of gas in the United Kingdom, a market we are well positioned to supply. We will also increase our ability to realize additional margin and optimize synergies by extracting and commercializing NGL streams to meet internal and external demand for NGLs. Moreover, we aim to build gas value chains from supply areas other than the Norwegian Continental Shelf into Europe, and proceed from our positions in the Snøhvit LNG project and the Cove Point LNG terminal to build an Atlantic LNG business and a US gas marketing business. We may also leverage our natural gas value chain and marketing expertise to capture exploration and development opportunities elsewhere.

Enhance our downstream position through increased focus on core activities, building on integration with our upstream businesses, and more efficient distribution of our products to the end user. We are one of the largest retailers of gasoline in Scandinavia through our 50/50 joint venture in SDS with ICA/Ahold supermarket group. The purpose of our joint venture is to strengthen our leading brand further and accelerate non-fuel sales growth. In refining, partially through our joint venture with the Shell group, we intend to continue with our cost reductions and productivity improvements to increase utilization and efficiency of existing capacity and develop the refineries in order to meet the EU's product specification requirements for the year 2005. Borealis plans to improve its position in petrochemicals based on cost improvement programs and site restructuring.

Exploration and Production Norway

Introduction

E&P Norway is the cornerstone of our business, consisting of exploration, development and production operations on the NCS. We participate in the majority of the 45 producing oil and gas fields on the NCS and as of December 31, 2002, we were the operator for 16 of these. Effective January 1, 2003, we took over the operatorship of Visund, Snorre, Tordis and Vigdis, and thereby became the sole operator in the Tampen area. We are also the operator of the Troll gas field in the Troll/Sleipner area. Other major oil and gas fields in the Troll/Sleipner area include Sleipner, where we are operator, and Oseberg. The main producing fields in the Halten/Nordland area include Heidrun, Åsgard and Norne, all of which we operate. E&P Norway reported income before financial items, income taxes and minority interest of NOK 31,463 million, or 73% of our total income before financial items, income taxes and minority interest in 2002. In the year ended December 31, 2002, we produced 989,000 barrels of oil equivalent per day.

The following table presents key financial information about this business segment.

	YEAR ENDED DECEMBER 31,			
	2000	*2001*	*2002*	
(IN MILLIONS)	*NOK*	*NOK*	*NOK*	*USD*
Revenues	71,135	65,655	56,290	8,114
Depreciation, depletion and amortization	11,225	11,805	11,861	1,710
Exploration expenditure	1,657	2,020	1,352	195
Income before financial items, income taxes and minority interest	46,715	40,697	31,463	4,535
Capital expenditure	12,992	10,759	11,023	1,588
Long-term assets	79,864	77,550	77,001	11,099

The NCS. We are the leading exploration, production and transport company on the NCS. We currently hold exploration licenses covering a total area of approximately 41,000 square kilometers and production licenses, in respect of approximately 3,641 mmboe of proved reserves as of December 31, 2002, compared to 3,664 mmboe as of December 31, 2001.

Commercial petroleum deposits were first proved on the NCS in the late 1960's. Norwegian oil production began in 1971 and accounted for most of the production growth until the late 1990's. Since then, the growth has been in gas production. Production from the NCS is expected to plateau over the next five to ten years before going into a gradual decline. In order to counteract this in coming years, our recovery rate must continue to be improved, resources not presently covered by development plans must be brought on stream, and new oil and gas discoveries must be made. We believe that significant opportunities remain on the NCS. In addition to the possibility of large discoveries, production will focus on a large number of smaller fields, many of which will be characterized by complex geology. These fields will require the innovative application of advanced technologies, for which we have a proven record of success.

Core Producing Areas. We have three core producing areas on the NCS: Troll/Sleipner, Halten/Nordland and Tampen. The fields in each area use common infrastructure, such as production installations, and oil and gas transport facilities where possible, which together reduce the investment necessary to develop new fields. Our efforts in the core areas will also focus on developing smaller fields through the use of existing infrastructure and enhancing production by improving recovery factors. We are working actively to extend the production from our fields through improved reservoir management and application of new technology. Key elements in our improved recovery efforts include:

- seabed and time lapse seismic methods to map reservoirs more accurately and identify remaining (by-passed) oil as targets for drilling of additional wells;
- drilling of long-reach wells, horizontal wells and "designer" wells (wells drilled with a curve in the horizontal plane) for optimal drainage of reservoirs; and
- use of gas injection, combinations of water and gas injection (WAG) and microbial recovery methods.

We believe that much of the improvement in expected ultimate recovery factors that we have seen over the last decade can be attributed to our systematic reservoir and production management and the use of improved oil recovery methods.

Potential Producing Areas

In addition to our core areas, we are well positioned in the central and southern parts of the North Sea, in the Møre/Vøring and Lofoten areas of Norwegian Sea and in the Barents Sea, all of which we believe to have significant hydrocarbon resource potential.

North Sea. Two producing core areas, Tampen and Troll/Sleipner, are located in the North Sea. Outside these areas we have further interests in 10 exploration licenses covering approximately 3,500 square kilometers in the central and southern parts of the North Sea. We operate five of these licenses. Two exploration wells were scheduled for drilling in 2002 in this area. Amerada Hess found traces of oil in their well drilled in the southern part of the region. Drilling of the second well, operated by ConocoPhillips, is delayed until the first quarter of 2003 due to late arrival of the drilling-rig. We applied for new acreage in the 2002 North Sea licensing round for which the application deadline was January 28, 2003. The award of new licenses is expected in the second quarter of 2003.

Møre/Vøring. We have interests in approximately 12,800 square kilometers of licensed acreage in the Møre/Vøring area of the Norwegian Sea, which is a deepwater area with depths ranging from 400 meters to 2,000 meters, situated approximately 100 to 400 kilometers from the Norwegian coast. Our license interests in the Møre/Vøring area include the Ormen Lange and Nyk gas discoveries. In the 17th licensing round in 2002 we applied for and were awarded two licenses, with total acreage of 4,823 square kilometers. We became operator for the new PL281 license located in the vicinity of the large Ormen Lange find. The first exploration well in this license will be drilled in 2003.

Lofoten. The Lofoten area of the Norwegian Sea, located in the coastal region of northern Norway, is one of several major oil provinces left to explore on the NCS. We have interests in 250 square kilometers of licensed acreage. The Ministry of Environment is currently working on an "Impact Assessment Plan" covering the impact of exploration drilling activities on the fishing industry and environment in the Lofoten and Barents Sea regions. No drilling activities are permitted in the area until this plan is completed and presented in the autumn of 2003. The drilling of the scheduled Norsk Hydro exploration well in the area is therefore postponed pending the outcome of the assessment.

Barents Sea. Our fourth core area, Tromsøflaket, is located in the southwestern part of the Barents Sea. This area includes our gas discovery Snøhvit, which is scheduled to be on stream late in 2006 and is currently under development. In addition to this core area, we have further interests in 2,700 square kilometers of licensed acreage and 15,300 square kilometers of seismic option areas. Under the terms of the seismic option agreement, the license group is committed to do specified seismic evaluation of the area and at any time prior to May 15, 2007, the license group has the right to obtain a production license with the obligation to drill exploration wells. New seismic data are acquired over the areas and interpretation of the data is ongoing. The new evaluation will be completed in 2004. The Barents Sea area is included in the Government "Impact Assessment Plan" and therefore there was no exploration drilling in the region in 2002. Preparations have started for a common drilling campaign in the area to take place early in 2004 of three exploration wells - operated by Norsk Agip, Norsk Hydro and Statoil, respectively.

Although most companies active on the NCS have interests in licenses and seismic areas in the Barents Sea, activity and competition have been modest for some years. As new petroleum reserves are discovered, we expect competition for new licenses to increase. The development of the Snøhvit field, described below –Exploration and Development, could serve as a cornerstone for the area's future development.

Portfolio Management

In 2002 we continued our strategy of focusing on core areas and aligning ownership interests for more effective resource management. We have signed the following agreements:

- Sale of 28% share in the Varg field in the Troll/Sleipner area to Pertra AS.
- Sale of 14.9% of our share in the Mikkel Unit in the Halten/Nordland area to Norsk Agip and Fortum Petroleum AS.
- Swap agreement with SDFI to align interests in the Oseberg Area resulting in a Statoil share of 15.3% in all licenses.

In January 2003 we signed a sales agreement for 30% and 25% in the exploration licenses PL143 and PL239 to Paladin Resources Norge AS.

Exploration and Development

We have been engaged in exploration and drilling on the NCS since 1975 and have drilled a total of 279 exploration and appraisal wells as of December 31, 2002. Approximately 70% of all exploration and appraisal wells that we drilled in the last three years have yielded discoveries or positive appraisals that have confirmed our assessments regarding hydrocarbons in-place.

Our exploration and development program is designed to strengthen our position on the NCS through increasing reserves and leveraging of existing infrastructure and to enable the development of new core areas. We coordinate the development of new fields so as to minimize required new investments in infrastructure. In the Tampen area, new fields were developed on a schedule to allow existing infrastructure to be used continuously at near peak capacity, thereby limiting the need for new infrastructure.

In 2002, we participated in 20 exploration and appraisal wells, of which five were exploration extensions on production wells. We were the operator for 13 of these wells. In 2001, we participated in 21 exploration and appraisal wells of which we were the operator of 11. Of the 13 Statoil-operated wells in 2002, 10 were successful, and of the seven partner-operated wells, four were successful. Our exploration expenditure on the NCS in 2002, including expenditure in respect of field development studies for Ormen Lange and Halten/Nordland prospects, totaled NOK 1,352 million, of which NOK 483 million was capitalized. The corresponding figures for 2001 were NOK 2,020 million and NOK 677 million respectively. Additionally, exploration expenditure of NOK 551 million, which was capitalized in earlier years, was expensed in 2002 compared to NOK 665 million in 2001.

Of our 2002 NCS exploration expenditures, approximately 67% was spent in our three core producing areas (approximately 36% was spent in the Halten/Nordland area and another 31% in the Troll/Sleipner and Tampen areas) and the remainder mostly in our potential production areas in the North Sea and Norwegian Sea. Our expenditure on development on the NCS totaled NOK 10.4 billion in 2002 and NOK 9.7 billion in 2001. In 2002 we participated in 141 development wells, and in 2001 we participated in 138 development wells. Of our 2002 NCS development budget, approximately 95% was spent in our three core producing areas (approximately 19% in the Halten/Nordland area, 44% in the Troll/Sleipner area and 32% in the Tampen area) and the remainder in our potential production areas in the Barents and Norwegian Seas. The allocation of our exploration and development budgets among the areas may be revised to reflect the results of our exploration activities.

Of our 2003 NCS development budget, approximately 87% will be spent in our three core producing areas (approximately 29% in the Halten/Nordland area, 31% in the Troll/Sleipner area and 27% in the Tampen area) and the remainder in our new core area Tromsøflaket and potential producing areas in the Barents Sea and the Norwegian Sea.

The following table sets forth our exploratory and development wells drilled on the NCS, including a breakdown of successful or productive wells and dry wells, drilled by core area for the three years ended 2000, 2001 and 2002.

	YEAR ENDED DECEMBER 31,		
(IN MILLIONS)	*2000*	*2001*	*2002*
Troll/Sleipner			
Statoil Operated Exploratory			
Successful	1	1	—
Dry	—	3	—
Total	1	4	—
Development	14	5	10
Partner Operated Exploratory			
Successful	1	2	1
Dry	2	1	2
Total	3	3	3
Development	59	52	56
Halten/Nordland			
Statoil Operated Exploratory			
Successful	2	3	3
Dry	—	—	1
Total	2	3	4
Development	25	23	20
Partner Operated Exploratory			
Successful	3	3	2
Dry	—	—	—
Total	3	3	2
Development	—	—	—
Tampen			
Statoil Operated Exploratory			
Successful	—	2	7
Dry	—	—	2
Total	—	2	9
Development	38	28	27

(IN MILLIONS) YEAR ENDED DECEMBER 31,	2000	2001	2002
Partner Operated Exploratory			
Successful	1	2	0
Dry	—	1	0
Total	1	3	0
Development	20	14	17
Other Areas			
Statoil Operated Exploratory			
Successful	—	1	0
Dry	1	1	0
Total	1	2	0
Development	—	—	—
Partner Operated Exploratory			
Successful	2	1	1
Dry	1	—	1
Total	3	1	2
Development	—	16	14
Totals			
Exploratory			
Successful	10	15	14
Dry	4	6	6
Total	14	21	20
Development	156	138	144

We calculate our finding costs as a three-year average. We define these costs as total exploration expenditure divided by changes in proved reserves attributable to improved recovery, revisions, and extensions and discoveries. Our finding costs in Norway have been relatively low compared to other operators on the NCS, as much of our activity has been concentrated in the mature areas. In 2000, 2001 and 2002, our finding costs were USD 1.68, USD 1.50 and USD 0.81 per boe respectively. The reduction in the three-year average finding cost in 2002 compared to previous years is mainly due to the acquisition cost allocated to unexplored prospects in 1999, which was part of the Saga deal.

We are currently the operator of seven ongoing field development projects on the NCS, which in order of scheduled production are: Mikkel, Vigdis extension, Sleipner West Alfa North, Kvitebjørn, Kristin, Visund Gas and Snøhvit. We also have a share in the Fram development operated by Norsk Hydro.

Mikkel. Mikkel, a gas and condensate development which was discovered in 1987, lies in 220 meters of water on Haltenbank East in the Halten/Nordland core area, about 40 kilometers away from both Åsgard's Midgard deposit and Draugen. In the beginning of 2002 we sold 14.9% of our share to Norsk Agip and Fortum, reducing our share to 41.62%. Our partners are ExxonMobil (33.48%), Norsk Hydro (10.0%) and Norsk Agip (14.9%, including the acquisition of Fortum (7%), which is still pending government approval). The plan for development and operation of Mikkel was approved by the Ministry of Petroleum and Energy in September 2001, and the development is under way with the aim to commence gas deliveries in 2003. Production will be tied to the subsea installation at Midgard for onward transport to the Åsgard B gas-processing platform. Plans call for the rich gas to be piped through the Åsgard transportation pipeline to the gas-processing facilities at Kårstø for separation of the NGLs. Commercial gas deliveries are scheduled to reach a capacity of 6 mmcm (212 mmcf) per day by 2004. The development is expected to cost NOK 2.0 billion, of which NOK 1.45 billion has been invested as of December 31, 2002.

Vigdis Extension. The Vigdis extension development is based on a cluster of small oil discoveries located in the central part of the Tampen area, 7 kilometers southwest of the Snorre TLP platform. The water depth in the area is 220-300 meters. The development was sanctioned by the owners in July 2002 and received the Ministry of Petroleum and Energy approval for development in December 2002. We took over the operatorship from Norsk Hydro on January 1, 2003 and our interest is 28.22%. Our partners are the SDFI (30%), ExxonMobil (10.5%), RWE –DEA (2.8%), Idemitsu (9.60%), Norsk Hydro (13.28%) and Total (5.6%). The Vigdis extension will be developed by subsea stations and satellites tied into the Snorre TLP via existing subsea production facilities at the Vigdis field. The oil will be exported to Gullfaks A for storage and loading. Production is expected to start in December 2003, and to reach an expected plateau production of 44,000 barrels oil per day by 2004. Total development costs are estimated to be NOK 3.0 billion, of which NOK 280 million has been invested as of December 31, 2002.

Sleipner West Alfa North. Sleipner West Alfa North is the development of the northern part of the Sleipner West field and a part of the overall Sleipner West development, which received approval from the authorities in 1993. The owners approved the Alfa North development in July 2002, and it will be produced through subsea facilities with the well stream tied back with an 18-kilometer flow line to Sleipner T. The umbilical for controlling the satellite will be tied back to Sleipner A. Our interest is 49.5% and our partners are Exxon Mobil (32.24%), Norsk Hydro (8.85%) and Total (9.1%). Production is planned to start in October 2004, with a total development cost for Alfa North estimated at approximately NOK 3.1 billion of which NOK 100 million has been invested as of December 31, 2002. Production from Alfa North is being phased in as a part of the total Sleipner West production profile, with a reached gas export capacity of 21 mmcm per day (731 mmcf).

Kvitebjørn. Discovered in 1994, Kvitebjørn lies about 20 km southeast of our Gullfaks field in the Tampen area. We operate the license with a 50% participating interest. Our partners are the SDFI (30%), Norsk Hydro (15%) and Total (5%). The plan for development and operations was approved in 2000, and an extension covering a large part of the Kvitebjørn reservoirs was approved by the Ministry of Petroleum and Energy in 2001. The field is being developed with a fixed steel platform for production, drilling and quarters. Initial processed gas and condensate will be transported in separate pipelines to receiving facilities for final processing and transport. Gas is transported through existing pipeline to the treatment plant at Kollsnes near Bergen. In addition, a new oil pipeline is being built connecting the Kvitebjørn development to the Mongstad refinery in the same region. We expect to reach an estimated production of 16 mmcm (565 mmcf) of gas per day in 2006. Commercial gas deliveries are scheduled to start in October 2004. Total investment is estimated to be NOK 10 billion, of which NOK 5.4 billion has been invested as of December 31, 2002.

Kristin. Kristin, discovered in 1997, is a gas condensate field in the southwestern part of the Halten/Nordland area, about 20 kilometers southwest of Åsgard's Smørbukk field. Our interest is 46.6% and our partners are the SDFI (18.9%), Norsk Hydro (12.9%), ExxonMobil (10.5%), Norsk Agip (9.0%) and Total (3.0%). The Kristin development, approved by the Storting in 2001, will drain a reservoir almost 5,000 meters beneath the seabed by 12 subsea production wells. The reservoir is characterized by very high temperature and pressure. The Kristin project will be the first high temperature and pressure field developed with subsea installations. To reduce the pressure, the well stream is choked down at the subsea production stations before transportation through infield pipelines and flexible risers to a floating processing platform. The stabilized condensate will be exported to a joint Åsgard and Kristin storage vessel and the rich gas will be transported to shore via the Åsgard transportation pipeline to the gas processing facility at Kårstø. Commercial gas deliveries are scheduled to start in October 2005. The estimated total investment cost for this project is NOK 17.0 billion, of which NOK 2.0 billion has been invested as of December 31, 2002. The field production capacity is expected to reach 13 mmcm (459 mmcf) per day by 2006. Further work is under way on a possible development of the other discoveries in the area – Lavrans, Morvin, Ragnfrid and Erlend – using the Kristin processing facilities as a field center.

Visund Gas. The Visund field, discovered in 1986, is located 22 kilometers northeast of our Gullfaks field in the Tampen area. The development of the Visund field was separated in an oil production phase, which came on stream in 1999, and a later gas production phase, Visund Gas, which was approved by the Ministry of Petroleum and Energy in October 2002. We took over as the operator from Norsk Hydro on January 1, 2003 and our interest is 32.9 %. Our partners are the SDFI (30%), Norsk Hydro (20.3%), Total (7.7%) and ConocoPhillips (9.1%). Gas export will be made possible by modifying the platform with new gas-compressor and export facilities to allow gas export and at the same time keeping the initial gas injection rate. In addition, a new pipeline will be laid from Visund to the Kvitebjørn pipeline in order to transport the gas to the treatment plant at Kollsnes for final processing. Commercial gas deliveries are scheduled to start in October 2005, and a gas production level of about 6 mmcm (208 mmcf) gas per day is expected to be reached in 2006. The gas export capacity can be increased when gas injection is reduced and more gas compression capacity becomes available, currently expected in 2011. Total development costs are estimated to be NOK 2.6 billion, of which NOK 90 million has been invested as of December 31, 2002.

Snøhvit. Snøhvit, discovered in 1984, is the largest gas field in the Norwegian sector of the Barents Sea and is located in the central part of the Hammerfest basin. Our interest in Snøhvit is 22.29%, and our partners are the SDFI (30%), Total (18.40%), Gaz de France (12%), Norsk Hydro (10%), Amerada Hess (3.26%), RWE-DEA (2.81%) and Svenska Petroleum (1.24%). We were originally the operator of five of the seven licenses; however, following a swap agreement with Norsk Hydro, we are now the operator of all the unitized licenses. The unitization agreement for the area was approved by the Ministry of Petroleum and Energy in July 2000. The Snøhvit field, and its neighboring Askeladd and Albatross fields, are being developed with subsea production installations, a pipeline to shore and a gas liquefaction plant based on cryogenic technology located at Melkøya near Hammerfest in northern Norway. The main product, LNG (liquefied natural gas), will be shipped to customers in purpose-built vessels. Carbon dioxide separated from the gas will be piped back to the field and injected. There will also be produced some LPG (liquefied petroleum gas) and condensate. Long-term sales contracts for the liquefied natural gas were entered into in October 2001 and the Storting approved the plan for development and operation in March 2002. The project start-up was delayed to June 2002 due to the ESA treatment of the tax position for the Snøhvit development. The total development costs for the project, which reflect the difficult development conditions, are estimated to be NOK 45.3 billion, of which NOK 2.4 billion has been invested as of December 31, 2002. In addition, four new vessels will be purpose built for transportation of the LNG from the field. Statoil will lease capacity and be a part owner in three of the vessels with an average 32% share both as charterer and owner. The present value of the lease rentals for our proportion is about NOK 1.3 billion. Following a project review, the investment cost estimate was increased by NOK 5.8 billion (fully reflected in the NOK 45.3 billion estimate of total investments) in the autumn of 2002, due to underestimated scope of work and the delayed start-up. In addition, we strengthened the supervision of work on the gas treatment and liquefaction plant with focus both on its own organization and in relation to the main contractor, Linde. The field development plan calls for production to start in 2006. The production capacity is expected to reach about 17 mmcm (614 mmcf) of LNG per day by October 2006.

Other developments

We are also a partner in the development project operated by Norsk Hydro on Fram in the Troll/Sleipner area. Our interest in the Fram project, which is an oil field, is 20%, and our partners are Norsk Hydro (25%), ExxonMobil (25%), Idemitsu (15%) and Gaz de France (15%). The Fram field development is a subsea tie-in to existing infrastructure (Troll C) for processing and transport. The plan for development and operation for the first phase was approved by the Ministry of Petroleum and Energy in March 2001. We estimate that the development will cost NOK 4.1 billion, of which NOK 2.1 billion had been invested as of December 31, 2002. Production is expected to start in October 2003. The oil production capacity is expected to reach 60,000 barrels per day by 2004.

Late in 2003 we expect to submit to the Ministry of Petroleum and Energy a plan for the development and operation (PDO) for the Ormen Lange deepwater gas field, currently operated by Norsk Hydro and with Norske Shell as operator in the production phase. Ormen Lange extends across three production licenses, and our current interest in Ormen Lange Pre-Unit is 10.77%. In addition to the two operators, our partners are BP, ExxonMobil and Petoro. The selected development concept is an extensive seabed development at depths ranging from 800 to 1,000 meters, an onshore processing and export plant and a pipeline taking the gas via Sleipner to continental Europe or the UK. The preliminary estimate of total investments is approximately NOK 50 billion, including the export gas pipeline to Sleipner. Current plans expect production to start in October 2007 with a daily plateau production estimated at 60 mmcm of gas per day, while condensate production is expected to plateau at approximately 40,000 barrels per day.

Other projects

In addition to the field development projects described above, there are several major modification projects ongoing at producing fields and facilities.

The Sleipner West compression project is an ongoing project estimated to cost NOK 1 billion that aims to modify the Sleipner facilities to prepare for low-pressure production in the later stages of the field life. The project is to be accomplished in two phases with the first rebuilding successfully finalized in October 2002. The second phase will be finalized in October 2004.

In connection with the decision to land the rich gas from the Kvitebjørn field at the Troll facilities at Kollsnes, the Troll owners have decided to build a new NGL fractionation plant at Kollsnes. A plan for development and operation of such a plant was approved by the Ministry of Petroleum and Energy in May 2002. Total investment for the plant is estimated to be approximately NOK 2.7 billion, of which NOK 0.5 billion has been invested as of December 31, 2002. According to the development plan, production is expected to start in October 2004. The NGL plant will treat rich gas from the Kvitebjørn field and gas from other future field developments in the northern part of the North Sea. Processing capacity for the plant will be 26 mmcm (918 mmcf) gas per day.

A similar modification as the Sleipner West compression project is described in the Troll Gas plan for development and operations. Preparation for installation of pre-compression facilities at Troll A is ongoing. The cost estimate is approximately NOK 3.5 billion, of which NOK 0.4 billion has been invested as of December 31, 2002.

The statements regarding our exploration projects and production estimates contained in the above section are forward-looking and subject to significant risks and uncertainties. Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot assure you that our actual levels of activity, production or performance will meet these expectations. See Item 3—Key Information—Risk Factors.

Oil and Gas Reserves

As of the end of 2002, we had a total of 1,286 million barrels of proved oil reserves and 375 bcm (13.2 tcf) of proved natural gas reserves in Norway. Based on boe, our proved reserves consist of 35% oil and 65% natural gas, based on total proved reserves in Norway of 3,641 mmboe.

The following table sets forth our Norwegian crude oil and natural gas proved reserves as of the end of the periods indicated. The table provides data on: revisions of previous estimates; extensions and discoveries; improved recovery; purchases of reserves-in-place; sales of reserves-in-place; production and proved developed reserves. The table provides data on condensates and NGLs and is stated net of royalties in kind, but including reserves attributable to our account based on our proportionate participation in fields with multiple participants. Royalty in kind ranges from 8% to 16% and is only paid from fields approved for development on or after January 1, 1986. Royalty obligations from Statfjord were abolished January 1, 2003, and royalty obligations from Gullfaks and Oseberg will be abolished by 2006. During 2002, we sold our 28% interest in the Varg field and 14.9% of our share in the Mikkel Unit. We also aligned interests in the Oseberg licenses with SDFI resulting in a Statoil share of 15.3% in all licenses. No major discovery or other favorable or adverse event has occurred since December 31, 2002 that would cause a significant change in the estimated proved reserves as of that date.

YEAR		OIL/NGL mmbbls	bcm	NATURAL GAS bcf	TOTAL mmboe
1999	**Proved reserves end of year**	**1,675**	**374.3**	**13,213**	**4,029**
	of which, proved developed reserves	*934*	*212.6*	*7,505*	*2,271*
2000	Revisions and improved recovery	8	1.6	56	18
	Extensions and discoveries	79	0.8	27	84
	Purchases of reserves-in-place	0	0.0	0	0
	Sales of reserves-in-place	(2)	0.0	0	(2)
	Production	(254)	(14.0)	(495)	(342)
	Proved reserves end of year	**1,506**	**362.7**	**12,802**	**3,787**
	of which, proved developed reserves	*940*	*244.5*	*8,630*	*2,478*
2001	Revisions and improved recovery	68	7.1	252	113
	Extensions and discoveries	124	5.3	188	158
	Purchases of reserves-in-place	0	0.0	0	0
	Sales of reserves-in-place	(54)	0.0	(1)	(54)
	Production	(246)	(14.8)	(523)	(339)
	Proved reserves end of year	**1,398**	**360.3**	**12,718**	**3,664**
	of which, proved developed reserves	*948*	*256.9*	*9,069*	*2,564*
2002	Revisions and improved recovery	108	6.7	237	151
	Extensions and discoveries	31	26.7	942	199
	Purchases of reserves-in-place	4	1.0	35	10
	Sales of reserves-in-place	(13)	(2.1)	(73)	(26)
	Production	(242)	(18.3)	(645)	(357)
	Proved reserves end of year	**1,286**	**374.4**	**13,215**	**3,641**
	of which, proved developed reserves	*919*	*264.1*	*9,321*	*2,580*

Production

In Norway in 2002, our total equity oil production was 245 million barrels after deductions for royalty oil, and gas production for our own account was 18.5 bcm (651 bcf), which represents an aggregate 361 mmboe (1). Currently, our production is in our three core producing areas of Troll/Sleipner, Halten/Nordland and Tampen. We participate in the majority of the 45 producing fields in the NCS. As of December 31, 2002, we were the operator for 16 of them. Effective January 1, 2003, we took over the operatorship of Visund, Snorre, Tordis, Vigdis and Borg, and thereby became the sole operator in the Tampen area. We are responsible as operator for approximately 39% of Norway's current oil output and approximately 84% of current gas output.

On December 17, 2001 the Norwegian government decided to reduce oil production on the NCS by 150,000 barrels per day, covering the period January 1 to June 30, 2002. Our share was 18,500 barrels per day.

The following table shows the NCS production fields and field areas in which we currently participate, the number of producing wells, the date on which the field came on stream, license expiry date and the operator of the field, with average daily equity production data for 2002. Amounts are stated net of royalties. Field areas are groups of fields operated as a single entity.

(1) The reason for the slightly different production numbers compared to the reserve table above is that the NGL volumes that we buy from the other Troll owners are not included in the reserves table. The difference in gas volumes results because produced volumes are stated with a calorific value of 40 MJ per standard cubic meter, while the reserves table states actual produced volumes with actual field calorific values.

AREA	STATOIL'S EQUITY INTEREST	OPERATOR	ON STREAM	LICENSE EXPIRY DATE	PRODUCING WELLS OIL	GAS	AVERAGE DAILY PRODUCTION IN 2002 mboe/DAY
Troll/Sleipner							
Sleipner East	49.60%	Statoil	1993	2023	—	17	34.8
Sleipner West	49.50%	Statoil	1996	2026	—	14	119.4
Glitne	58.90%	Statoil	2001	2013	5	—	21.9
Gungne	52.60%	Statoil	1996	2026	—	2	16.3
Huldra	19.66%	Statoil	2001	2015	—	6	12.4
Troll Phase 1	20.80%	Statoil	1996	2030	—	39	100.9
Troll Phase 2	20.80%	Norsk Hydro	1995	2030	95	—	76.3
Veslefrikk	18.00%	Statoil	1989	2015	14	—	5.5
Varg (1)	28.00%	Pertra	1998	2028	4	—	2.4
Oseberg (2)	15.30%	Norsk Hydro	1988	2018	46	—	35.0
Oseberg South	15.30%	Norsk Hydro	2000	2018	10	—	12.5
Oseberg East	15.30%	Norsk Hydro	1999	2018	9	—	7.9
Heimdal	20.00%	Norsk Hydro	1985	2015	—	5	0.4
Ekofisk area	0.95%	ConocoPhillips	1971	2028	114	—	4.3
Frigg	12.16%	Total	1977	2015	—	9	0.5
Togi	20.80%	Norsk Hydro	1991	2030	—	5	2.8
Brage	12.70%	Norsk Hydro	1993	2023	20	—	5.2
Sigyn	50.00%	ExxonMobil	2002	2018	1	2	0.0
Total Troll/Sleipner					**318**	**99**	**458.5**
Halten/Nordland							
Heidrun	12.43%	Statoil	1995	2025	33	—	24.2
Åsgard	25.00%	Statoil	1999	2027	25	9	84.8
Norne	25.00%	Statoil	1997	2027	11	—	48.7
Total Halten/Nordland					**69**	**9**	**157.7**
Tampen							
Statfjord Unit (Norwegian Part)	51.88%	Statoil	1979	2009	92	—	98.1
Statfjord North	21.88%	Statoil	1995	2009	8	—	9.5
Statfjord East	25.05%	Statoil	1994	2024	8	—	9.8
Sygna	24.73%	Statoil	2000	2022	2	—	7.7
Gullfaks	61.00%	Statoil	1986	2016	106	4	159.1
Snorre	14.40%	Statoil	1992	2024	30	—	33.7
Tordis area	28.22%	Statoil	1994	2024	9	—	25.0
Vigdis area	28.22%	Statoil	1997	2024	8	—	14.9
Visund	32.90%	Statoil	1999	2023	14	—	14.0
Murchison (Norwegian Part) (3)	51.88%	Kerr-McGee	1980	2009	18	—	0.9
Total Tampen					**295**	**4**	**372.7**
Total NCS					**682**	**112**	**988.9**

(1) Our share in Varg was sold August 1, 2002.

(2) We have aligned interest in the Oseberg licenses with SDFI resulting in a Statoil share of 15.3% in all licenses (July 1, 2002).

(3) Located principally in the UK sector of the North Sea.

The following table sets forth our average daily equity production for oil, including NGLs and condensates, and natural gas, for the years ended 2000, 2001 and 2002.

	YEAR ENDED DECEMBER 31,								
	2000			2001			2002		
AREA	OIL AND NGL mbbls	NATURAL GAS mmcm	TOTAL mboe	OIL AND NGL mbbls	NATURAL GAS mmcm	TOTAL mboe	OIL AND NGL mbbls	NATURAL GAS mmcm	TOTAL mboe
Troll/Sleipner	212	33	416	219	30	408	227	37	459
Halten/Nordland	123	1	132	118	4	145	119	6	158
Tampen	360	4	387	354	5	387	324	8	372
Total	**695**	**38**	**936**	**692**	**39**	**940**	**670**	**51**	**989**

Troll/Sleipner

The Troll, Sleipner and Oseberg fields are the main oil and gas fields within this area. Our share of the area's production in 2002 was 227,000 barrels of oil and 36.8 mmcm (',296 mmcf) of gas per day, or 458 mboe in total per day. In 2002 we aligned our combined interests in the area with those of SDFI, resulting in an overall 15.3% share in the Oseberg fields. Sigyn, a new gas/condensate field, started producing in December 2002. In December 2002 the partnership decided that the gas from Ormen Lange will be exported via Sleipner. This decision will strengthen Sleipner as a gas hub and have positive results for the field over many years. Our production target for 2004 is 397 mboe per day.

Troll. Discovered in 1979, Troll lies in the North Sea and still has large amounts of dry gas as well as oil, rich gas and condensate reserves. The production capacity of the Troll facility is approximately 100 mmcm (3.53 bcf) per day. Troll is the primary source of supply for gas sales from the NCS to Europe. Our interest in Troll is 20.80%, and our partners are the SDFI (56%), Norsk Hydro (9.78%), Norske Shell (8.10%), Total (3.70%) and ConocoPhillips (1.62%).

Troll comprises two main structures: Troll East and Troll West. A thin oil layer underlies the whole Troll area but is thick enough for commercial recovery only in the Troll West region. A staged development has therefore taken place with Phase I covering gas reserves in Troll East and Phase II focusing on the oil reserves in Troll West. Gas production from Troll East started in 1996. Oil production from Troll West started in 1999.

We succeeded the development operator, Norske Shell, as operator for the production phase of Troll Phase I in 1996. The Troll East development comprises the Troll A platform, the gas processing plant at Kollsnes, in which we have a 20.80% interest and the 60 kilometers of pipelines linking the Troll A platform with the Kollsnes processing plant.

Troll was the first major nstallation to transfer from an offshore to an onshore facility the processing of the multiphase output, meaning that the output contained oil, condensates and water. At Troll, through a system that we implemented, the output is processed at Kollsnes, which dries and compresses gas for pipeline export to continental Europe. The liquid natural gas portion of the gas stream is also extracted at the plant and transported to the Mongstad refinery.

Norsk Hydro is the operator for the oil production of Troll Phase II in Troll West. The Troll West development comprises the Troll B and Troll C floating production platforms. Crude oil is produced from the oil province with horizontal wells tied back to Troll B and Troll C. The oil produced from Troll B and Troll C is transported through Troll Oil Pipeline I and Troll Oil Pipeline II, respectively, to the terminal at Mongstad. The associated gas from Troll B and Troll C is exported via Troll A.

Sleipner. Sleipner includes Sleipner West and Sleipner East, discovered in 1974 and 1981, respectively. Our interest in Sleipner East is 49.60%, and our partners are ExxonMobil (30.40%), Norsk Hydro (10%) and Total (10%). Our interest in Sleipner West is 49.50%, and our partners are ExxonMobil (32.24%), Norsk Hydro (9.41%) and Total (8.85%). We are the operator of both fields.

Condensates from the Sleipner fields are transported to the gas processing plant at Kårstø. Transportation rights have been secured through existing transportation systems. Sleipner East is produced through the Sleipner A platform. Sleipner West is produced through two installations: the Sleipner B wellhead platform and the Sleipner T gas treatment facility. Sleipner West is tied back to Sleipner East. Unprocessed well streams from Sleipner B are piped 12 kilometers to Sleipner T, which is linked by a bridge to Sleipner A. Sleipner West has large reserves of carbon dioxide-rich gas. We extract the CO2 at the field and re-inject it into a sand layer that lies underneath the seabed, thereby reducing the CO2 emissions into the air, which has environmental benefits and, insofar as it reduces environmental taxes, it has financial benefits as well.

Oseberg. Oseberg, the third main field in the Troll/Sleipner area, is operated by Norsk Hydro. We have a 15.3% interest, and our partners are the SDFI (33.6%), Norsk Hydro (34%), Total (10%), ExxonMobil (4.7%) and ConocoPhillips (2.4%). The first development phase for Oseberg comprised a two-platform field center at the southern end of the field. The second development phase involved Oseberg C, a drilling platform with equipment for some processing. Total processing capacity for Oseberg is about 500,000 barrels of oil per day. Oil from Oseberg is piped through the Oseberg Transport System to Sture near Bergen. The last development completed in 1999 comprises a new gas treatment platform, Oseberg D, which is bridged to Oseberg A.

The Oseberg East and Oseberg South Satellites are tied back to the main field installations for processing. Our and our partners' interests in these fields are the same as for Oseberg.

Glitne. The Glitne oil field, discovered in 1995, lies in the Troll/Sleipner area of the Norwegian North Sea. The field was further defined with an additional well two years later. Our interest in this field is 58.9%, and our partners are Total (21.8%), Det Norske Oljeselskap (10%) and DONG (9.3%). Glitne is the smallest field development on the NCS using a stand-alone floating production system. Development work on the field began in October 2000, and Glitne has been in production since August 2001.

Huldra. Huldra, a high temperature and high-pressure gas and condensate field in the Troll/Sleipner area, was discovered in 1982. We are the field operator and our interest in this field is 19.66%, and our partners are the SDFI (31.96%), Total (24.33%), ConocoPhillips (23.34%), Paladin Resources (0.50%) and Svenska Petroleum (0.21%). The development concept for the field includes an unmanned platform in 125 meters of water, tied back to processing facilities for condensate and gas at Veslefrikk and Heimdal respectively. Production started in November 2001.

Veslefrikk. Veslefrikk is a mature oil field in block 30/3 of the Troll/Sleipner area. The field was discovered in 1981. We are the field operator and our interest in the field is 18%. Our partners are SDFI (37%), Paladin Resources (27%, pending acceptance from authorities for taking over 18% from Total), RWE DEA (13.5%) and Svenska Petroleum (4.5%). The field is developed with a fixed wellhead platform Veslefrikk A, including a drilling unit connected by bridge to a floating semi submersible processing platform, Veslefrikk B. Production started in December 1989. The main reservoir drive mechanisms are water injection and injection of associated gas. Oil is exported to the Sture terminal via the Oseberg Field Center while gas is exported to Kårstø. Starting from December 2001, Veslefrikk has been processing condensate from the Huldra field for further export through the OTS oil transportation system.

PL 072 Sigyn. Sigyn is a gas / condensate field located 12 km southeast of the Sleipner A installation. The gas is exported from Sleipner A and the condensate is delivered at Kårstø. The plan for development and operation was approved by the Ministry of Petroleum and Energy in August 2001. Our interest is 50%, and our partners are ExxonMobil (40%) and Norsk Hydro (10%). The Sigyn Development Project was undertaken on behalf of ExxonMobil, the operator. The development consists of three production wells on one subsea template, with two pipelines and one umbilical connecting it to the Sleipner A platform. Necessary modifications on Sleipner A were included in the total investment budget of NOK 2 billion. The project was successfully completed as the production started in December 2002, four months ahead of the PDO plan.

Halten/Nordland

Our producing fields in the Halten/Nordland area are Åsgard, Heidrun and Norne, and the main participants, in addition to us, are the SDFI, Norsk Hydro, Agip, ConocoPhillips and ExxonMobil. Our share of the area's production in 2002 was 119,000 barrels of oil and 6.2 mmcm (218 mmcf) of gas, or 158 mboe per day. Our production target for these fields for 2004 is 193 mboe per day.

This region is characterized by petroleum reserves located at water depths reaching between 250 and 500 meters. The reserves are to some extent under high pressure and at high temperatures. These conditions may make development and production more difficult and have challenged the participants to develop new kinds of platforms and new technology, such as floating processing systems with subsea production templates. We plan to increase efficiency by further coordinating our operations in the area and by stemming the declining production from the mature fields by increasing seismic activity and well maintenance. In addition, we will expand our activities by utilizing our installed production and transportation capacity before building new infrastructure.

Åsgard. Åsgard, lying on the Haltenbank in the Norwegian Sea, comprises the Midgard, Smørbukk and Smørbukk South discoveries, made in 1981, 1984 and 1985, respectively. Our interest in the Åsgard development is 25%, and our partners are the SDFI (35.5%), Norsk Hydro (9.6%), Norsk Agip (14.9%, including the acquisition of Fortum (7%), which is still pending government approval), Total (7.65%), and ExxonMobil (7.35%). The field was developed with the Åsgard A production ship for oil, the Åsgard B semi-submersible floating production platform for gas and the Åsgard C storage vessel. The subsea production installations on the field are the most extensive in the world, with a total of 50 wells grouped in 16 seabed templates. Further, the Åsgard B platform is the largest floating gas processing center, and Åsgard A is one of the largest floating production ships ever built.

The Åsgard development links the Haltenbank area to Norway's gas transport system in the North Sea, realizing long-standing plans for a pipeline connection to continental Europe. Gas from the field is piped through the Åsgard Transport pipeline to the processing plant at Kårstø and on to receiving terminals in Emden and Dornum in Germany. Oil produced at the Åsgard A vessel and condensate from the Åsgard C storage vessel is shipped from the field by shuttle tanker.

Weaknesses in subsea flow line end connections welds were discovered in Åsgard during 2001. It was decided to repair all 72 welded joints. By the end of June 2002, 61 out of 72 subsea welds had been repaired, one cancelled, two repaired by pretension of flow line end connection and eight postponed to 2003. The Midgard T valve repair has been postponed to 2003 to allow for further evaluations to allow more time for completing the preparations and testing of the complex repair-equipment. The repair program and costs have been within established plans.

Heidrun. The Heidrun field was discovered in 1985 on the Haltenbank. The Heidrun platform is the largest concrete tension leg platform ever built. Our interest in this field is 12.43% and our partners are the SDFI (64.16%), ConocoPhillips (18.29%) and Fortum (5.12%). Heidrun was discovered by Conoco, which served as operator for the exploration and development phase. We became the production operator in 1995. Oil from this field is primarily shipped by shuttle tanker to our Mongstad crude oil terminal for onward transport to customers. Gas from Heidrun provides the feedstock for our methanol plant at Tjeldbergodden, Norway. Export of gas to Europe is linked with the Åsgard Transport pipeline. The Heidrun field is in need of pressure support to keep up volumes from its production wells. The installation of a water re-injection module and a sulphate removal module as part of the Heidrun water injection project initiated in 2001 is planned to be completed by November 2003.

Norne. The Norne field lies about 80 kilometers north of the Heidrun field and roughly 200 kilometers from the Norwegian coast. Our interest in this field is 25%, and our partners are the SDFI (54%), Norsk Hydro (8.1%), Norsk Agip (6.9%) and Norske Shell (6%). We are the operator of the Norne field. The field has been developed with a production and storage ship tied to subsea templates. Flexible risers carry the reservoir's output to the vessel, which swivels around a cylindrical turret moored to the seabed. This ship carries processing facilities on its deck and storage tanks for oil. Processed crude oil can be transferred over the stern to shuttle tankers. Like Heidrun, Norne is connected to gas markets in continental Europe through a link with the Åsgard Transport system.

Tampen

The Tampen area offers rich petroleum resources in a compact geographic area. Our main producing fields in the Tampen area are Statfjord, Gullfaks and Snorre. Our share of the area's production in 2002 was 324,000 barrels of oil and 7.7 mmcm (271 mmcf) of gas, or 373 mboe per day. We became the sole operator from January 1, 2003, when we took over the operatorship of Visund, Snorre, Tordis and Vigdis. Other major participants in the Tampen area are the SDFI, ExxonMobil, Norsk Hydro and ConocoPhillips. Tampen is the leading oil producing area on the NCS, and even after twenty years of production, we believe there are substantial opportunities remaining. Our production target for 2004 is 410 mboe per day.

Accumulated investments in Tampen are about NOK 300 billion. Several of the production facilities will be closed down before 2010 unless we do not change the way we operate these facilities. However, we believe that there will be substantial opportunities for synergy of operations, such as better utilization of drilling completion units, common logistics and transportation. Taking over as operator for Snorre and Visund is the first step in an area optimization plan for production. We are also looking at new area solutions starting with the 'Statfjord late life' project. The project also includes looking at different infrastructure solutions for the whole area and alternative ways of operating the platforms in order to maximize the future income and production from the Tampen area.

Statfjord. Discovered in 1974, Statfjord has produced more than 3.9 billion barrels of oil as of the end of December 2002. It straddles the Norway/UK sector line, and a unitization agreement between the UK and Norwegian licensees gives Norway 85.47% of the Statfjord reserves. Our interest in the Statfjord Unit is 44.34%, and our partners are ExxonMobil (21.37%), ConocoPhillips (Norway) (10.33%), Norske Shell (9.44%), ConocoPhillips (UK) (4.84%), Chevron UK (4.84%) and BP (4.84%). Statfjord has been developed with three fully integrated platforms supported by gravity base structures featuring concrete storage cells. Each platform is tied to offshore loading systems for loading oil into tankers. Three satellite fields (Statfjord North, Statfjord East and Sygna) have been developed and are each tied back to the C platform.

Gullfaks. Discovered in 1978, Gullfaks has produced more than 1.94 billion barrels of oil as of the end of December 2002. Gullfaks was developed with three large concrete production platforms. It was the first major offshore field that we developed and produced as the operator. Our interest in the field is 61%, and our partners are the SDFI (30%) and Norsk Hydro (9%). Oil is loaded directly into shuttle tankers on the field, while associated gas is piped to our Kårstø gas processing plant and then on to continental Europe. Three satellite fields, Gullfaks South, Rimfaks and Gullveig, have been developed with subsea wells remotely controlled from the Gullfaks A and B platforms.

Snorre. Snorre was discovered in 1979 and had produced around 655 million barrels as of the end of December 2002. The field has been developed with two platforms and one subsea production system connected to one of the platforms (Snorre TLP). Oil and gas is exported to Statfjord for final processing, storage and loading. Our interest in the field is 14.4%, and our partners are the SDFI (30%), Norsk Hydro (17.65%), ExxonMobil (11.16%), Idemitsu (9.60%), RWE-DEA (8.88%), Total (5.95%), Amerada Hess (1.18%) and Norske Shell (1.18%). One satellite field, Vigdis, has been developed with a subsea tie-back to Snorre TLP. In 2002 it was also decided to connect the new development of Vigdis Extension to Snorre TLP. The field was operated by Norsk Hydro until January 1, 2003, at which time we took over as operator.

PL 089. The asset includes the Vigdis field and the fields in the Tordis Area, Tordis, Tordis East, Tordis Southeast and Borg. Vigdis and Tordis were discovered in 1988 and 1987 respectively. The Vigdis field and the Tordis Area have produced approximately 144 million barrels and approximately 226 million barrels at the end of 2002 respectively. The Vigdis field is developed with three subsea templates with well stream through pipelines connected to Snorre TLP where the oil is stabilized and exported to Gullfaks for storage and loading. The Tordis area is developed with seven subsea satellites and two templates tied back to Gullfaks C where the oil and gas is processed and stored for offshore loading and export. Our interest in the PL 089 asset is 28.22 % and our partners are the SDFI (30%), Norsk Hydro (13.28%), ExxonMobil (10.5%), Idemitsu (9.60%), Total (5.6%) and RWE –DEA (2.8%). The fields were operated by Norsk Hydro until January 1, 2003, at which time we took over as operator. The Vigdis extension development was sanctioned by the license in July 2002. The project is further described in 'Exploration and Development'.

Visund. The Visund field was first discovered in 1986. Oil production from Visund started in April 1999 and the field had produced approximately 50 million barrels as at the end of 2002. The field is developed with one platform and two subsea satellites wells. The oil is exported to Gullfaks A for storage and loading. The gas produced is now injected in the reservoir. Our interest in Visund is 32.9 % and our partners are the SDFI (30%), Norsk Hydro (20.3%), ConocoPhillips (9.1%) and Total (7.7%). Norsk Hydro operated the field until January 1, 2003, at which time we took over as operator. The partnership sanctioned the project to prepare for the gas export from Visund in July 2002. Gas export will be made possible by increasing the compressor capacity and by installing gas metering equipment and an exporting pipeline. The gas will be exported to Kollsnes via Kvitebjørn pipeline. Gas export is planned to start in October 2005. The project is further described in 'Exploration and Development'.

Decommissioning

The Norwegian government has set forth strict procedures for the removal and disposal of offshore oil installations under the Convention for the Protection of the Marine Environment of the Northeast Atlantic, or the OSPAR Convention. The decommissioning of Yme, completed in December 2001, took into account considerations relating to the environment, fisheries and safety. This included removal of all structures and equipment on the field except for buried flow lines and suction anchors. Total cost for the project was NOK 305 million, of which our share was approximately NOK 198 million, equal to our participation in the field of 65%.

Tommeliten, a gas field which ceased production in 1998, was decommissioned during the second half of 2001.The sub sea template was removed and the six wells were plugged, at a total cost of NOK 113 million, of which our share was approximately NOK 80 million, equal to our participation in the field of 70.64%. Tommeliten made use of facilities on the Edda platform (PL018), and we are, therefore, committed to participate in the decommissioning of this platform. As of December 31, 2001 we have recorded a provision of NOK 61 million in our books to account for this commitment, covering modifications made on the Edda platform and the facilities for transportation of oil.

Domestic Production Costs Data

Production costs are influenced by the distribution between new and mature fields in the portfolio and the cost effectiveness of the different installations. We calculate this indicator as annual production-related costs compared with the volume of oil and gas produced in the same period. Based on industry benchmarks, we believe that we are one of the lowest cost producers on the NCS.

The following table sets forth our average production costs per boe, average sales price per barrel of oil and average sales price by Statoil per scm of gas sold for the years ended December 31, 2000, 2001 and 2002.

	YEAR ENDED DECEMBER 31,		
	2000	*2001*	*2002*
Average cost per boe			
NOK	24.8	24.9	24.1
USD	2.82	2.77	3.03
Average sales price per barrel of oil			
NOK	250.2	216.7	196.5
USD	28.4	24.1	24.7
Average sales price per scm of gas			
NOK	0.99	1.22	0.95
USD	0.11	0.14	0.12
NOK/USD (average daily exchange rate)	8.81	8.99	7.97

Oil and Gas Transportation

Most of our oil production is lifted offshore by shuttle tankers and transported to oil terminals in Norway and abroad. Troll and Oseberg crude oil is transported by pipeline to the Mongstad and Sture terminals, respectively, and Ekofisk production is transferred by pipeline to Teesside, UK. We transport gas, which is exported through the gas pipeline system established on the NCS.

We, together with other Norwegian oil and gas producers, have built an extensive transportation infrastructure network to transport crude oil and gas produced on the North Sea to terminals in Norway, the UK and the continental Europe. The following are oil pipelines in which we have an ownership interest:

Troll Oil Pipelines I & II. The Troll Oil Pipeline I transports oil from the Troll B platform to the terminal at Mongstad near Bergen. The Troll Oil Pipeline II carries oil from Troll C to the terminal at Mongstad. The Troll Oil Pipelines I & II have a transport capacity of 42,500 and 47,500 cubic meters per day, respectively (265,000 and 300,000 barrels per day, respectively). We are the operator and 20.85% owner of the Troll Oil Pipelines I & II.

Norpipe. ConocoPhillips is the operator of, and we are a 20% owner of, the Norpipe oil pipeline, which starts at Ekofisk Center and crosses the UK continental shelf to come ashore at Teesside in the UK. The Norpipe oil pipeline has a transport capacity of 900,000 barrels per day.

Frostpipe. Frostpipe, operated by Total, is used to transport oil and condensate from Frigg to Oseberg where it links to the Oseberg Transport System, covers 82 kilometers and can carry 100,000 barrels per day. The pipeline has not been in use since March 2001. Although we have a 20% interest in this pipeline, we currently have no plans to use it for our own oil or condensate.

Oseberg Transport System. The Oseberg Transport System transports oil from Veslefrikk, Brage, Lille-Frigg, Frøy, Oseberg South, Oseberg East, Tune and Huldra via Oseberg A to Sture. Our interest in the Oseberg Transport System is 14%. The Oseberg Transport System has a capacity of 765,000 barrels per day.

For details about our interests in gas pipelines, see below –under Natural Gas–Norwegian Gas Transportation System and Other Facilities.

International Exploration and Production

Introduction

International E&P consists of exploration, development and production operations outside of Norway. We are focusing our efforts on establishing significant production and increasing our influence in our core areas. We are also actively pursuing additional opportunities in other areas to expand our international portfolio, which support our strategy and leverage our skills and competence from the NCS. We hold interests in 10 producing fields in the Caspian, Western Africa (Angola and Nigeria), Western Europe and Venezuela. In addition, we are the operator of a development project in Iran and the Plataforma Deltana exploration project off Venezuela. We are also the commercial operator of the Shah Deniz field in Azerbaijan, with the responsibility for gas sales, contract administration and business development. We also have exploration or production licenses in Brazil and China.

International E&P reported income before financial items, income taxes and minority interest of NOK 1,086 million in 2002 compared to NOK 1,291 million in 2001.

The following table presents key financial information about this business segment. The changes from 2001 to 2002 are primarily a result of higher production, lower writedown of assets (NOK 0.8 billion in 2002 versus NOK 2.0 billion in 2001), and lower gain from divestments of assets (NOK 1.0 billion in 2002 versus NOK 2.9 billion in 2001).

	YEAR ENDED DECEMBER 31,			
	2000	*2001*		*2002*
(IN MILLIONS)	*NOK*	*NOK*	*NOK*	*USD*
Revenues	9,027	7,693	6,769	976
Depreciation, depletion and amortization	1,704	3,371	2,355	339
Exploration expenditure	1,764	683	941	136
Income before financial items, income taxes and minority interest	773	1,291	1,086	157
Capital expenditure	5,070	5,027	5,995	864
Long-term assets	19,465	21,530	20,655	2,977

Internationally, we have participated in six of the largest oil and gas discoveries since 1997: Kashagan in Kazakhstan, Shah Deniz in Azerbaijan, Agbami (Ekoli) in Nigeria, and Dalia, Kizomba A and Kizomba B in Angola.

We plan to increase our investment in international upstream and midstream development projects significantly in 2003 compared to 2002. We also plan on significant increases in exploration expenditures in 2003. Investments in 2002 were lower then originally forecasted primarily as a result of delayed startup in some of our projects, lower drilling cost and the divestment of our Danish assets. The strengthening of the Norwegian kroner against the US dollars also yielded less spending in NOK than originally forecasted.

We believe that we are well positioned to continue to secure attractive international investment projects that will allow us opportunities to exploit the group's technology and expertise developed on the NCS. The technology and expertise includes maximum field recovery through improved oil recovery techniques, subsea solutions and conversion of gas-to-liquids. Our expertise also includes the management of large complex development projects and in gas chain development.

Portfolio Management

Through asset swaps, sales and acquisitions, we have been restructuring our international interests in order to focus on core areas where we own quality assets, develop new attractive commercial opportunities, and optimize our capital employed.

In 2000, we divested our exploration interests in the Gulf of Mexico, and we sold the downstream parts of Statoil Energy Inc.

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).
We relinquished our licenses in Greenland by the end of 2001.

In July 2002, we sold our operations in Denmark for a gain before taxes of NOK 1.0 billion (0.7 billion NOK after tax).

In December 2002, Statoil acquired El Paso's capacity rights at the LNG regasification terminal at Cove Point, Maryland, USA. At the same time, Statoil also purchased from El Paso the purchase contract for delivery of an annual volume of 2.4 bcm of LNG for the period 2006 to 2023 initially entered into in October 2001 between El Paso and the Snøhvit seller group, and in which Statoil holds a 32% interest. The payment to El Paso was USD 210 million in cash.

In 2002, we also acquired two licenses in Brazil, one through the 4th Licensing Round and one through a farm-in to a Phillips/Conoco operated block. We also farmed into 10% of Tranche 44, operated by Agip, in UK Rockall.

Reserves

In 2002, we increased our proved reserves by 2%. The change principally reflects increases in Angola. Further, we have booked new reserves in Iran related to the offshore development of South Pars phases 6, 7 and 8. The reserves in the Venezuelan field LL 652 have been further written down in 2002 based on updated geological assessment performed after slower than anticipated response to water and gas injection and results from development wells. Our international proved oil and NGL reserves were 580 mmbbls oil, and we had 7.2 bcm (255 bcf) of proved natural gas reserves at the end of 2002, together representing 15% of the group's total proved reserves. Over the period 2000-2002, we had an international reserve replacement rate, calculated based on a three year average, of 2.8. Our unit finding costs in our international operations were USD 1.51 per boe in 2002, calculated as an average number over the last three years.

The following table sets forth our total international proved reserves as at December 31 of each of the last three years.

YEAR		*OIL/NGL mmboe*	*NATURAL GAS bcm*	*NATURAL GAS bcf*	*TOTAL mmboe*
1999	**Proved reserves at end of year**	**462**	**3.3**	**114**	**482**
	of which, proved developed reserves	*85*	*1.9*	*68*	*97*
2000	Revisions and improved recovery	30	(0.3)	(11)	28
	Extensions and discoveries	18	4.8	170	48
	Purchases of reserves-in-place	0	0.0	0	0
	Sales of reserves-in-place	0	(0.5)	(19)	(3)
	Production	(21)	(0.5)	(19)	(24)
	Proved reserves at end of year	**488**	**6.6**	**234**	**530**
	Proved reserves at end of year include:				
	Proved developed reserves	*187*	*1.8*	*65*	*198*
	Proved reserves under PSA and buy-back agreements	*204*			*204*
	Volumes under PSA and buy-back agreements received during the year	*3*			*3*
2001	Revisions and improved recovery	30	(0.2)	(7)	29
	Extensions and discoveries	69	6.4	225	109
	Purchases of reserves-in-place	0	0.0	0	0
	Sales of reserves-in-place(1)	(1)	(4.8)	(170)	(31)
	Production	(22)	(0.4)	(15)	(25)
	Proved reserves at end of year	**565**	**7.6**	**267**	**612**
	Proved reserves at end of year include:				
	Proved developed reserves	*166*	*1.2*	*42*	*173*
	Proved reserves under PSA and buy-back agreements	*302*			*302*
	Volumes under PSA and buy-back agreements received during the year	*3*			*3*
2002	Revisions and improved recovery	(25)	0	0	(25)
	Extensions and discoveries	73	0	0	73
	Purchases of reserves-in-place	0	0	0	0
	Sales of reserves-in-place(2)	(2)	0	0	(2)
	Production	(29)	(0.3)	(12)	(31)
	Proved reserves at end of year	**580**	**7.2**	**255**	**626**

YEAR	OIL/NGL mmboe	bcm	NATURAL GAS bcf	TOTAL mmboe
Proved reserves at end of year include:				
Proved developed reserves	*137*	*0.8*	*30*	*143*
Proved reserves under PSA and buy-back agreements	*349*			*349*
Volumes under PSA and buy-back agreements received during the year	*12*			*12*

(1) Sale of Vietnam assets.

(2) Sale of Danish assets.

Production

Our petroleum production outside Norway amounted to an average of 85,600 boe per day in 2002. The following table sets forth our total international production for each of the last three years. The Girassol field in Angola started production in December 2001 and reached plateau production capacity of 200,000 barrels of oil per day in February 2002. The commercial production of syncrude for the Sincor project began in March 2002. During the initial production period, diluted heavy oil was exported. Sincor production met our expectations for the year, but was temporarily shut down for 71 days due to the political situation in the country. The shutdown caused a reduction in our 2002 production of approximately 450,000 barrels. Production was restarted on February 23, 2003. The effect of the shutdown on production in 2003 is approximately 1,430,000 barrels.

	YEAR ENDED DECEMBER 31, 2000	2001	2002
Average daily oil (mbbls)	57	60	80
Average daily natural gas (mmcm/mmcf)	1.5 / 53	1.2 / 41	0.9/34
Average daily boe (mboe)	67	67	86

The following table shows the production fields in which we currently participate and the producing wells as of, and production for the year ended December 31, 2002.

FIELD	STATOIL'S EQUITY INTEREST	OPERATOR	ON STREAM	LICENSE EXPIRY	PRODUCING WELLS	PRODUCTION(1) mboe/d
Caspian						
Azerbaijan: Azeri-Chirag-Gunashli (early oil production)	8.56%	AIOC (BP)	1997	2024	12	9.6
Western Europe						
Denmark: Lulita Unit (5)	18.82%	Maersk	1998	2026	1	0.1
Denmark: Siri(2) (5)	40.00%	Statoil	1999	2027	6	6.6
UK: Alba	17.00%	ChevronTexaco	1994	2018	21	10.4
UK: Schiehallion	5.88%	BP	1998	2017	16	6.1
UK: Merlin	2.35%	Shell	1997	2017	3	0.1
UK: Dunlin	28.76%	Shell	1978	2017	18	3.2
UK: Jupiter	30.00%	Conoco	1995	2010	12	5.6
Western Africa						
Angola: Girassol	13.33%	Total	2001	2023	13	23.4
Venezuela						
LL 652 reactivation	27.00%	ChevronTexaco	1998	2018	178	2.0
Sincor(3)	15.00%	Sincor JV	2001	2037	229(4)	13.7
Other						
China: CA 17/22 Lufeng	75.00%	Statoil	1997	2013	5	4.8
Total International E&P					**514**	**85.6**

(1) Production figures are after deductions for royalties, production sharing and profit sharing.

(2) Includes Stine Segment 2.

(3) Initial production commenced in January 2001 and commercial production started in March 2002.

(4) This number excludes 8 wells that were ready for production as of December 31, 2002.

(5) The producing assets in the Danish sector were sold to DONG as of July 1, 2002.

Our unit cost for international production averaged approximately USD 3.3 per boe in 2002. The unit production cost declined by USD 1.9 per boe compared to 2001. The main reason for the reduction in unit production cost is that a larger share of production is coming from more cost effective fields, such as Girassol.

Core Areas

We are currently active in four core areas; Caspian, Western Africa (Angola and Nigeria), Western Europe and Venezuela. Our international portfolio, with the exception of some fields in Western Europe, consists primarily of new and developing areas that have either not yet commenced production or are in early stages. Accordingly, we describe all of our operations by area as opposed to stage of development.

Caspian

The discovery of large oil fields in the Caspian region, the latest being Kashagan in Kazakhstan, shows that despite 150 years of oil production, the Caspian region still contains significant reserves of oil, NGL and gas.

There is still risk for increased economic, social and political instability in the Caspian region. However, the general situation has improved in recent years, with the war and civil strife that characterized this region in the early 1990s having largely abated. Still, some disputes remain unresolved:

- The cease-fire between Azerbaijan and Armenia negotiated in 1994 over the Nagorno-Karabakh area is still in place. Although the two countries technically are still at war, high-level negotiations are ongoing to find a permanent settlement. No such settlement is imminent.

- In Georgia, President Shevardnadze contained the dispute between the central government and the breakaway regions of Abkhazia and South Ossetia. The resurgence of fighting between Russian forces and Chechen rebels indirectly affects Georgia in the border areas.

For the energy industry, three issues relating to political and economic development are particularly important: political succession, Caspian title issue and export of hydrocarbons. In addition, there is a shortage of construction and yard capacity, as the region is faced with several major oil and gas developments.

Political succession. In the political systems of the Caucasus, political power rests with personalities rather than institutions. The presidents of Georgia and Azerbaijan have been strong promoters of domestic stability throughout the 1990s. The presidents are now 80 and 75 years old, respectively, and there is uncertainty regarding the successor political regimes. However, due to their national importance for economic development and political independence, neither upstream or midstream activities are likely to be permanently affected by any change of political regime.

Caspian title issue. A binding legal regime governing the division of the Caspian Sea among the five border states of Azerbaijan, Iran, Kazakhstan, Turkmenistan and Russia is yet to be found. This has on occasion led to disputes over rights to hydrocarbon resources between Azerbaijan and Iran and between Turkmenistan and Azerbaijan. The principal point of dispute is whether the Caspian Sea is to be considered a "lake" or a "sea". If the Caspian is treated as a "lake", then sovereign borders are recognized through the water, thereby dividing up not only underlying hydrocarbon reserves but also shipping and fishing rights along these borders. If the Caspian is treated as a "sea", then the concepts of territorial waters and continental shelves would apply, although the rights of the littoral states would overlap.

Despite some positive developments through ongoing negotiations in 2002, a permanent solution does not appear imminent. There are currently bilateral agreements in place between Russia and Azerbaijan, between Russia and Kazakhstan and between Kazakhstan and Azerbaijan although the details including the division of the seabed and the water columns remain to be settled. Turkmenistan and Iran have to date been unwilling to enter into similar agreements.

Iran's naval intervention against a research vessel on Alov in July 2001 has left further fieldwork pending an agreement where work can commence under safe circumstances. Technical evaluations of the field are continuing in accordance with obligations under the relevant production sharing agreements. We do not expect these title issues to be resolved in the near future, but there appears to be political will to sort out the differences.

Export of hydrocarbons. The Caspian Sea is landlocked without direct access to open sea. The export of oil is therefore dependent on onshore pipelines. Currently, crude oil from Azeri-Chirag-Gunashli is transported through a pipeline through Georgia to the Black Sea Port at Supsa, with an alternative route to Novorossiysk. The export capacity of the current infrastructure will be insufficient as the production volumes increase from the next stages of development on Azeri-Chirag-Gunashli and other fields. To secure transportation capacity, we are participating in the Baku-Tbilisi-Ceyhan pipeline with an 8.71% share. Development of the 1,750 kilometer Baku-Tbilisi-Ceyhan pipeline will ensure export flexibility through multiple pipelines, and thereby diversify risk involved in commercializing the land-locked upstream resources. The Baku-Tbilisi-Ceyhan pipeline was sanctioned in 2002 and the land acquisition and construction phase is currently ongoing. The Baku-Tbilisi-Ceyhan pipeline is expected to commence operations by year-end 2004 when ACG Phase I is ready to go on stream. The pipeline is estimated to cost USD 3.6 billion.

Azerbaijan. In September 1994, Azerbaijan signed the first production sharing agreement, or PSA, with foreign companies. Azerbaijan has since entered into another 20 PSAs, of which 15 PSAs are offshore in the Caspian Sea. The Caspian Sea is regarded as a promising exploration area, boosted by the large Shah Deniz gas and condensate discovery in 1999 in which we participated. Recent exploration results have not met expectations, but the Southern Caspian is still in an early phase of exploration.

We established a presence in the Caspian Sea in 1992, as one of the first international oil companies. Since then, we have entered into three PSAs in Azerbaijan, and we are among the largest foreign oil companies in the country in terms of proved reserves and production. At present, we hold interests in three PSAs offshore in the Azeri sector of the Caspian Sea: the Azeri-Chirag-Gunashli, or ACG, oil field, the Shah Deniz gas and condensate field and the Alov, Araz and Sharg prospects. In addition, we are partner in the Baku-Tbilisi-Ceyhan major oil transportation pipeline, and the South Caucasus Pipeline.

Azeri-Chirag-Gunashli. We are a partner with an 8.56% share in the Azeri-Chirag-Gunashli PSA. BP is the operator (34.14%), and the other partners are: Unocal (10.28%), Inpex (previously held by Lukoil) (10%), State Oil Company of the Azerbaijan Republic, or SOCAR (10%), ExxonMobil (8%), Turkish Petroleum, or TPAO (6.75%), Devon (previously held by Pennzoil) (5.63%), Itochu (3.92%) and Delta Hess ACG (2.72%).

ACG is currently in the early oil production phase, which is based on an existing steel substructure, a rebuilt topside of the Chirag 1 platform and the installation of a 24-inch oil pipeline to a newly built oil terminal at Sangashal. From the terminal, the oil is currently transported through a dedicated 850-kilometer pipeline, the Western Route, with a daily capacity of 140,000 barrels from Sangashal to Supsa, located on the Georgian coast of the Black Sea, for tanker shipment through the Bosphorous and the Mediterranean to the international markets. Oil production from Chirag began in November 1997 and in 2002 averaged close to 130,000 barrels per day. Continuous work is being undertaken to increase production, and we expect that the field will have the capacity to produce an annual average of 135,000 barrels per day in 2003. The ACG fields will be further developed in three phases.

The ACG Phase I development plan calls for the construction of a new production, drilling and quarter platform with a design capacity of roughly 400,000 barrels per day. In addition, a bridge-linked gas compression and water injection platform, as well as additional pipelines for oil and gas to Sangashal and oil terminal expansion, will be installed. ACG Phase I is estimated to cost USD 3.3 billion from 2001 to 2004. We expect the ACG Phase I production platform and infrastructure to be completed during late 2004, and the injection platform approximately one year later. The partnership sanctioned ACG Phase I in August 2001.

ACG Phase II development was sanctioned in September 2002, and we expect that the development will be completed by 2006, including a new 30-inch oil pipeline to shore and a production capacity of up to an additional 450,000 barrels of oil per day. This development will concentrate on West Azeri and Far East Azeri reservoirs including required development drilling and processing capacity expansions with a total investment estimate of USD 5 billion. The two projects are now managed as one, the Azeri Development Project.

ACG Phase III will complete the full development of the ACG field with the development of the deepwater Gunashli field. After completion, we expect overall daily production from the ACG field to exceed one million barrels per day from seven installed platforms by 2010/2011.

We estimate overall investments for the ACG full field development to be approximately USD 15 billion. This estimate covers all three phases of upstream development and early oil production, but excludes the BTC export pipeline.

Shah Deniz. The Shah Deniz area covers 860 square kilometers and lies in a water depth between 50 and 500 meters. We have completed a four-year exploration phase involving a three-dimensional seismic survey and the drilling of three wells. Gas and condensate were encountered in the first exploration well drilled in 1999. The partnership submitted a Notification of Discovery and its Commerciality in March 2001 and entered into a 30-year development and production period. We are the commercial operator of the development, responsible for gas sales, contract administration and business development for the South Caucasus Pipeline, and hold a 25.5% interest in Shah Deniz. Our partners are BP (25.5% and field operator), Total (10%), LUKAgip (10%), Naftiran Intertrade Co. Ltd (NICO) (10%), TPAO (9%) and SOCAR (10%).

The field will be developed in stages. The Stage 1 development on the east flank of the reservoir and a 680 km 42" pipeline, from the landing terminal through Azerbaijan and Georgia to the Turkish border (the South Caucasus Pipeline – SCP), was sanctioned by the partnership in February 2003, and we were appointed as operator of the pipeline. Turkey is the main market for gas from Shah Deniz, stage 1. A Gas Sales and Purchase Agreement was signed between SOCAR and the Turkish gas company Botas in March 2001, covering a contractual level of 6.6 bcm annually. During the fall of 2001, all intergovernmental and host governmental agreements between Turkey, Georgia and Azerbaijan were signed. In order to further secure a long-term market for our Shah Deniz gas, we have, together with the Turkish KOÇ group, opened a gas marketing office in Turkey.

We expect first production to commence in the second half of 2006. The plateau production level of Stage 1 is expected to be approximately 8.5 bcm (300 bcf) per year and will be reached after three to four years of production. The SCP system will be prepared for expanded capacity to facilitate future development stages. The partnership estimates the total capital investment for the development to be approximately USD 3.2 billion, which includes offshore facilities, wells, pipelines to shore, gas processing plant and the SCP.

Alov, Araz and Sharg. We signed an exploration, development and production sharing agreement covering the structures Alov, Araz and Sharg in July 1998. Located roughly 150 kilometers southeast of the Azeri capital of Baku, the contract area covers about 1,400 square kilometers and is located at water depths of 450 to 800 meters. The structures are located in the area of the Caspian Sea that is disputed between Azerbaijan and Iran, and Iran has claimed parts of the area to be in Iranian waters since the contract was signed and work has ceased following the Iranian naval intervention in 2001, as described above. We have a 15% interest, and our partners are SOCAR (40%), BP (15% and operator), ExxonMobil (15%), TPAO (10%) and Alberta Energy (5%). Three-dimensional seismic data was acquired in 1999 over the entire area. The first well out of three in the area is planned to be drilled in 2004. Negotiations with SOCAR have granted an extension of the exploration period until six months after the completion of the third well, currently scheduled for mid-2006.

Western Africa

Angola. Angola has been an oil producing country since 1955. Current production is about 930,000 boe per day, most of which comes from shallow water fields. The civil war which ravaged Angola for 30 years came to an end in February 2002. The country has to date provided a stable fiscal environment for the oil companies.

The Girassol discovery made by Total in 1996 in block 17 was the first Angolan deepwater discovery. Since then the deepwater area has yielded approximately 20 discoveries of varying sizes.

The blocks in Angola are typically very large, between 4,000 and 5,000 square kilometers, or ten times the size of a Norwegian block. The small number of blocks, however, provides limited opportunities to become operator for prospective licenses.

We are well positioned in two key deepwater blocks, Blocks 15 and 17, and in the ultra deepwater Block 31. For each block, a PSA with the state oil company Sonangol is in effect. Production licenses have for the last few years generally been granted for a period of 25 years from when the partners declare a discovery commercial. Our expertise in floating production, subsea production, drilling and contracting has been used extensively to further field development.

Block 17. This block spans approximately 5,000 square kilometers and includes discoveries at Girassol, Dalia, Jasmim and the Rosa Lirio Cravo area. The water depth varies between 500 and 1,600 meters. Exploration started in 1994. A total of 17 exploration wells and nine appraisal wells have been drilled, and 13 discoveries have been made. All commitments in the PSA have been met. One further appraisal well is planned for 2003 as part of the development license. We have a 13.33% interest, and our partners are Total (40% and operator), ExxonMobil (20%), BP (16.67%) and Norsk Hydro (10%).

Girassol, the first development project in this block, came on stream in December 2001. The field was discovered in 1996 and was sanctioned for development in 1998. The production license expires in 2023. The development includes a floating production, storage and off take facility (FPSO) and subsea tieback wells for production and injection. Girassol reached plateau production capacity of 200,000 barrels of oil per day on February 15, 2002. Production target for 2002 was achieved. We expect that the total investment for the field will be USD 3 billion, of which USD 2.7 billion had been invested by the end of 2002.

Jasmim, a subsea tieback to the Girassol FPSO, was sanctioned for development in 2001 and is expected to come on stream in late 2003. The production license expires in 2026. The development included minor tie-in modifications on the FPSO and subsea tieback wells for production and injection. Total production from this field is expected to peak at 50,000 barrels of oil per day by 2005.

Dalia is expected to be sanctioned in 2003. Dalia is scheduled to reach its plateau production of 225,000 barrels of oil per day by 2007. We expect that the investments for the field will be USD 2.7 billion in the period 2003 to 2006. The production license expires in 2024. The oil in this discovery is heavier than at Girassol, approximately 22 degrees API.

Rosa, Lirio and Cravo are expected to be developed as subsea tiebacks to the Girassol FPSO. Total is currently working on the development and timing. Sanction of the project is expected in 2003. Total is also evaluating the discoveries Orchidea, Violetta and others for development.

Three exploration wildcat wells were drilled in the second half of 2002 in the eastern portion of the block, close to the Perpetua discovery. All three, Zinia, Hortensia and Acacia, were discoveries and may form the basis for a third stand-alone development on Block 17. The exploration period for Block 17 expired at year-end 2002.

Block 15. This block is approximately 4,000 square kilometers and includes developments at Kizomba A, B and Xikomba. The water depth varies between 800 and 1,600 meters. The first discovery was made in 1997. A total of 15 exploration wells and seven appraisal wells have been drilled to date, and 12 discoveries have been made. Remaining exploration drilling is currently planned for the first half of 2003. We have a 13.33% interest in Block 15, and our other partners are ExxonMobil (40% and operator), BP (26.67%) and Agip (20%).

Kizomba A was declared commercial in February 2001 and sanctioned for development in June 2001. The production license expires in 2026. The development plan is based on a tension leg wellhead platform with a nearby moored FPSO. Production should start late in 2004, and we expect peak production of 250,000 barrels of oil per day by the end of 2006. We estimate total investment for the field to be approximately USD 3.7 billion, of which USD 1.5 billion is invested by year-end 2002.

Xikomba is a small isolated discovery being developed and to be produced by a leased FPSO. The project was sanctioned in February 2002 with first oil expected by year-end 2003.

Kizomba B was sanctioned in December 2002. The field encompasses the Kissanje and Dikanza discoveries, which will be co-developed with a floating wellhead platform on Kissanje, with a nearby moored FPSO. Dikanza will be a subsea installation, tied back to Kissanje. The FPSO and a wellhead platform is to a large extent identical to the ones planned for Kizomba A. Production is expected to start early 2006, with peak production of 250,000 barrels per day by end of 2006. We estimate total investments for the field to USD 3 billion.

Mondo 1 was discovered in 2000 and could, with the addition of the Batuque and Saxi discoveries (also discovered in 2000), form the basis for a third development, tentatively named Kizomba C. The Mondo-2 appraisal well, drilled in May 2002 confirmed similar quality oil on the north flank of Mondo. The Marimba, Mavacola discoveries and Reco-Reco discovered in 2002 is likely be tied back to either Kizomba A or B.

Block 31. This ultra deepwater block is located west of Block 15 at the northern end of Angola's continental shelf and covers approximately 5,500 square kilometers. The water depth is between 1,600 and 2,200 meters. The block was awarded in 1999, and three-dimensional seismic surveys were performed in 2000. One exploration well, of the four wells commitment, was drilled in 2001 with disappointing results. The second commitment well, Plutao-1, completed in August 2002, was the first discovery in ultra deep water off Angola. Further exploration success will be necessary to form the basis for a potential clustered development. Two additional exploration wells are planned for 2003. We have a 13.33% interest in Block 31, and our partners are BP (26.66% and operator), ExxonMobil (25%), Sonangol (20%), Marathon (10%) and Total (5%).

Gas utilization. All discoveries in Angola contain significant volumes of associated gas. The gas can be used for gas injection or stored for a limited period. Sonangol owns the associated gas not required for the production facilities. An LNG option is being evaluated by Sonangol and the oil industry in Angola.

Nigeria. Nigeria is a major oil producing country, and the largest producer in Sub-Saharan Africa. Nigerian deepwater areas covering water depths down to approximately 2,000 meters were opened to the international oil industry in the early 1990s. Initial results were disappointing, but recently there have been four interesting oil discoveries of which we participated in one, Agbami/Ekoli in Blocks 216 and 217 with ChevronTexaco and Statoil as operators, respectively. ExxonMobil and Shell are the two biggest participants in the deepwater areas. We, as well as Total, ChevronTexaco and the two indigenous companies, Famfa and Sapetrol, also hold important positions. Nigeria's political development is affected by many strong forces, based on factors such as ethnicity, religion and economic inequality which have led to political unrest and violence, and such occurrences cause difficulties and disruptions for the oil industry, particularly in the Delta area. Projects on the Nigerian continental shelf may also be influenced by potential political instability. All of our activities are in the deepwater areas off Nigeria.

We entered Nigeria in 1993. We operate two exploration licenses, OPL217 and OPL218, with an interest of 53.85%. ChevronTexaco holds the remaining 46.15% in both licenses. The exploration licenses were granted for a period of ten years, and they expire in mid 2003. We have submitted a proposal to convert the license to a mining license (i.e., production license), and we are negotiating with the Nigerian authorities over the area to be relinquished. These production licenses will be valid for 20 years. We have drilled a total of seven exploration wells in the two license areas 217 and 218, resulting in one oil discovery, Ekoli, and one gas discovery, Nnwa.

The Ekoli 1 well proved oil and confirmed the extension of ChevronTexaco's adjacent Agbami discovery in Block 216. Agreements to trade data are being undertaken as a prelude to unitization. ChevronTexaco is currently doing field development work, in which we are participating. Partner discussions are ongoing to determine the final unitization between license OPL 216 and license OPL217.

The latest well Nnwa-2, drilled in 2002, confirmed a significant gas discovery and small amounts of oil. The discovery extends into the Shell operated Block 219, and is proven by Shell's Doro-1 well. At present, fiscal terms for deep-water gas development do not exist in Nigeria, but an announcement of terms is expected in 2003. Under an MOU with Shell, the Nigerian Government and other companies, a feasibility study for floating LNG will be finished at the end of the third quarter 2003. Statoil leads this work. Future plans for NnwaDoro include seismic reprocessing and one to two wells (Shell and Statoil operated) in 2004/5.

Western Europe

We have interests in Ireland, the Faroes and the UK. Our interests in Denmark were sold in July 2002. We believe that future discoveries on the Atlantic Margin, the outer part of the continental shelf running from Norway's Lofoten Islands to west of Ireland, predominantly contain gas. We have an exploration portfolio of licenses on the Atlantic Margin with gross acreage of approximately 15,000 square kilometers.

Ireland. In Ireland, we have interests in three exploration licenses, including operatorship of one large exploration license immediately north of the Corrib field development in which we are a partner.

Corrib. The Corrib gas field lies on the Atlantic Margin north west of Ireland. It was discovered in 1996 and was the first significant find offshore Ireland since Kinsale Head in 1973. The Corrib field development was sanctioned in February 2001, and the production license was granted in late 2001 with a 30-year duration. We have a 36.5% interest in Corrib gas field, and our partners are Shell (45% and operator) and Marathon (18.5%).

The development will incorporate seven subsea wells in 350 meters water depth with export directly through a pipeline to an onshore terminal. This receiving facility will be constructed on the coast of County Mayo. The Corrib project was sanctioned for a scheduled production start-up in October 2003. Due to the objections received relating to the planning permission for the gas terminal, the start up is delayed until early 2005. This is based on the assumption of the planning permission being granted early in 2003. The development cost of the Corrib field is estimated at USD 0.8 billion.

Ireland is increasingly dependent on imported gas as the Kinsale Head gas field is in decline. Total Irish gas demand is now approximately 4.2 bcm (148 bcf) per year and continues to grow rapidly, particularly due to new gas-fired power stations being built. An interconnector between the UK and continental Europe today supplies approximately 75% of the market. We are currently in discussions with gas buyers but have decided not to enter into any firm gas sales contract yet. We are partners in the Synergen gas-fired power plant, which began test operations in January 2002. Our share of the Corrib gas could be delivered to this plant, which would be able to accommodate approximately 60% of the plateau production. The gas from the Corrib field will be transported via a link in to Ireland's existing gas transmission system. The state-owned Bord Gáis Éireann is responsible for the timely completion of the extended national infrastructure.

We acquired and processed a three-dimensional seismic survey covering License 5/94 (Slyne-Erris) offshore Ireland in 2001. Statoil, as operator and holding a 40% share, has one well commitment on this license. We plan to fulfill this well commitment in 2003. Statoil's partners in this license are Shell (45%) and Murphy Eastern Oil Company (15%).

Faroes. We were awarded the operatorships for two exploration licenses in the first licensing round on the Faroes' Shelf in the North Atlantic in 2000. A total of seven licenses were granted to 12 oil companies organized in five groups. We have been evaluating the potential of the Faroes' area of the continental shelf since the early 1990s. The area presents technical challenges, primarily seismic imaging, as much of the area has been covered by thick layers of basalt.

The Statoil-operated License 003 lies in the Foinaven sub-basin and was granted in 2000 for a period of six years. The terms of the license require us to drill two exploration wells. We drilled the first well in late summer 2001, at a location about 180 kilometers south of Torshavn and 60 kilometers northwest of the producing UK oil field Schiehallion, with disappointing results. Three-dimensional seismic was acquired on the license towards the end of 2002. We have a 35% interest, and our partners are Phillips (30%), Shell (20%) and PetroCanada (15%). The Amerada Hess Group, however, made a gas and light oil discovery in License 001, and we are now evaluating if this discovery has any direct impact on our adjacent License 003 and our block in the nearby UK sector 176/25.

The Statoil-operated License 006 lies on the East Faroe Ridge, and was awarded during 2000 for a period of nine years. The license obligation requires us to perform seismic surveys. We have a 27.5% interest, and our partners are Anadarko (27.5%), Phillips (20%), Shell (15%) and PetroCanada (10%).

United Kingdom. We are a partner in several producing licenses on the UK continental shelf, holding interests in the Alba, Schiehallion, Dunlin and Merlin oil fields and the Jupiter gas field. We farmed into the Agip operated Tranche 44 exploration license in the Rockall Basin west of Scotland in 2002. This license is located immediately east of the Statoil operated Tranche 43. A structure called Antaeus straddles both tranches, but is located mainly in Tranche 44. The well drilled to test this feature in late 2002 was unfortunately dry.

Although we are exploring some areas of the relatively mature UK continental shelf, our major exploration focus is on the less explored Atlantic Margin. We participate in 12 exploration licenses and one production license (Schiehallion) within the UK part of the Atlantic Margin.

Schiehallion. The Schiehallion field is located 150 kilometers west of the Shetland Islands, close to the border with the Faroes. Schiehallion produces from thin turbiditic sands at a total depth of 1,800 meters, 1,400 meters beneath the seabed. The license was awarded in 1985, oil was discovered in 1993 and production began in 1998. Current production is approximately 110,000 boe per day. The Schiehallion license will expire in August 2017. We have a 5.88% interest in the Schiehallion field, and our partners are BP (33.35% and operator), Shell (33.35%), Amerada Hess (15.66%), Murphy (5.88%) and OMV (5.88%).

The Schiehallion field has been developed as a subsea development tied back to a new FPSO, which is owned by the field participants. The FPSO also acts as the host facility for the BP and Shell-owned Loyal field, which is located north of Schiehallion. The original sanctioned development drilling was completed in 2000; however, additional phases are planned to recover the reserve volumes fully. The field development is assisted through regular seismic evaluation, the most recent of which was acquired in 2000.

Oil is exported by a dedicated shuttle tanker to the Sullom Voe terminal. Associated gas is currently used for power generation with the residual being exported via a pipeline to Sullom Voe and onto the BP-operated Magnus field where it will be used for enhanced oil recovery.

Alba. The Alba sandstone reservoir is located at a depth of 1,850 meters and lies 215 kilometers northeast of Aberdeen, Scotland, and 37 kilometers from the border with the NCS. The UK government awarded the license containing Alba in 1972, oil was discovered in 1984 and production began in 1994. Peak production of 72,000 to 80,000 barrels of oil per day is expected to continue until the end of 2004. The Alba license period expires in March 2018. We hold a 17% interest in the Alba field, and our partners are ChevronTexaco (21.17% and operator), BP (15.5%), Total (12.65%), ConocoPhillips (23.43%), Energy Africa (8%) and Shell (2.25%).

The Alba field is a two-stage development. The first phase, now completed, involved the use of a single steel platform in combination with a floating storage unit, both located in the northern sector of the field. The second phase, representing continued operational investment, contains the development of the extreme south area of the field. The second stage development was sanctioned in 2001 and the first oil was delivered in October 2002. Two more wells were brought on stream during February 2003. The investments for this phase are expected to be GBP 140 million from 2001 to early 2003. Additional gas management and debottlenecking improvements are being undertaken during 2003.

Caledonia. The Caledonia field is a new development located immediately north of the Alba field and contained within the same block. This small oil discovery was made during 1977 with the first well, with appraisal drilling following during the 1990s. The single horizontal production well was drilled in the third quarter 2002 and tied back via a subsea template and pipeline to the Britannia platform where the fluids will be processed and oil exported through the Forties Pipeline. Production commenced in February 2003 at approximately 11,000 barrels of oil per day. We have a 21.32% interest in the field, and our partners are ChevronTexaco (27.37% and operator), Dana Petroleum (25.77%), Total (12.65%), Energy Africa (10.06%) and Shell (2.83%).

Dunlin. The Dunlin field is located east of the Shetland Islands, close to the border with the NCS. Dunlin produces oil from reservoir sands at a depth of 2,740 meters. The UK government awarded licenses containing Dunlin in 1971, oil was discovered in 1973 and production began in 1978. Dunlin reached peak production of 116,000 boe per day in 1979. Average daily production during 2002 was 11,000 barrels of oil. The Dunlin license expires in August 2017. We have a 28.76% interest in the Dunlin field, and our partners are Shell (28.43% and operator), ExxonMobil (28.43%), and OMV (14.38%). The field is in post-plateau decline, but the platform receives tariff income from processing satellite Merlin and Osprey oil accumulations. The co-mingled production stream is exported via the Brent System Pipeline to the Sullom Voe Terminal located on the Shetland Islands.

Merlin. The Merlin field is located east of the Shetland Islands, seven kilometers west of the Dunlin field. Oil is produced from sands at a depth of 3,624 meters via subsea wells tied back to the Dunlin processing facility. The license was awarded in 1971, oil was discovered in early 1997 and production began later the same year. Merlin reached plateau production of 17,000 barrels of oil per day in 1999. The field is now in decline, with an average production during 2002 of 5,800 barrels of oil per day. The Merlin license will expire in August 2017. We have a 2.35% interest in the Merlin field, and our partners are Shell (50.88% and operator) and ExxonMobil (46.77%).

Jupiter. The Jupiter fields are located 150 kilometers east of the Theddlethorpe gas terminal and consists of six gas accumulations: Ganymede, Callisto South, Callisto North, Europa, Sinope North and Bell. BP's adjacent Bessemar field will also be produced via Jupiter facilities. All gas is produced from sandstone reservoirs at a depth of 2,510 meters. The license was awarded in 1964, gas was discovered in 1972 and production began in 1995. Current production is approximately 18,000 boe per day. The Jupiter license will expire in 2010. We hold a 30% interest in the Jupiter gas field, and our partners are ConocoPhillips (20% and operator) and ExxonMobil (50%).

Venezuela

Venezuela has the largest oil reserves in the western hemisphere and has traditionally been one of the most important oil provinces in the Americas. Although many areas in Venezuela are mature, considerable exploration potential is thought to remain, especially offshore.

The country was opened to foreign investments during the period of 1994 to 1997 in order to give new impetus to the development of the oil industry. This resulted in a number of large new projects, mainly in heavy oil (Orinoco belt). The former political establishment was replaced by a new coalition in 1998, led by President Hugo Chávez. The political situation in the country resulted in a general strike at the end of 2002 that caused serious disruptions in the production and shipment of oil. The new Hydrocarbon Law was introduced on January 1, 2002. It prescribes higher royalties, and taxes for many oil (not gas) industry activities, as well as greater national participation. Since then, ongoing dialogue with the authorities has resulted in some opening up for change, and confirmation regarding the grandfathering of royalties arrangements in existing heavy oil contracts.

LL652. We have a 27% interest in the LL652 oil field located in Venezuela's Lake Maracaibo. Our partners in LL652 are ChevronTexaco (27%), BP (36%) and P&GI (10%). The field has been in production since the 1950s. A reactivation program started after the takeover of operations by the joint venture partnership from Petroleos de Venezuela, or PDVSA, in 1998. The reactivation involved construction of new processing facilities for oil handling, gas compression and water injection, which were completed in July 2000.

The operating services contract for LL 652 is valid until 2018, during which time a phased approach of investments will be tailored according to reservoir performance. In 2001 and 2002 Statoil has taken a full writedown of the book values in LL652 based on new geologic assessment performed after slower than anticipated response to water and gas injection projects and development well. Through the writedowns in 2001 and 2002, we recognized pre-tax losses of NOK 2.8 billion (NOK 2.0 billion after tax).

Sincor. The Sincor project involves producing heavy crude oil in the Orinoco Belt, transporting the crude to the coast and upgrading it into a light, low-sulphur crude oil. Sincor is a strategic joint venture managed jointly and owned by us (15%), PDVSA (38%) and Total (47%). Sincor is the operator and is responsible for development, operation, upgrading and oil marketing. We have filled several key positions in Sincor with secondments from Statoil. The partners approved the project in August 1998. The project required the construction of a main station, a pipeline system, a solids terminal for petcoke and sulphur and an extra heavy oil upgrader, which is the main component of the project.

The project includes an initial production phase and a commercial phase. The initial production phase in which diluted extra heavy oil was produced started in January 2001, and concluded when the extra heavy oil upgrader began operation in March 2002. The commercial phase is planned to last for 35 years and is expected to reach plateau production by 2006 at a production level of 180,000 boe per stream day of 30-32 degree API, low sulphur syncrude, which Sincor markets under the name of Zuata Sweet. In addition, Sincor produces sulphur and petroleum coke, known as petcoke, for sale on the international market. The total investment in the project up to commercial production was USD 4.2 billion.

Plataforma Deltana. In February 2003, Statoil has been awarded the operatorship for Block 4 in Plataforma Deltana off the eastern coast of Venezuela. Statoil committed to drill three exploration wells during the coming four years to establish the resource potential in the block.

New Areas

We are also exploring additional opportunities outside our four core areas. We have recently been focusing on our efforts on Iran and are also considering opportunities in the Former Soviet Union, Caspian Region, North Africa, Latin America and the Middle East.

Iran. We consider Iran to be a promising country for business opportunities given the large undeveloped reserves and the large estimated remaining undiscovered hydrocarbon resources.

In November 2000, we signed an Exploration Study Agreement with the National Iranian Oil Company, or NIOC, a company owned by the Iranian government, for the Hormoz Strait and Oman Sea areas. This study is still ongoing, and final results will be delivered in the second quarter of 2003. The agreement gives Statoil exclusive rights to negotiate exploration contracts for parts of the area. At the same time we signed a non-binding protocol with NIOC to evaluate several projects in Iran within the areas of enhanced oil recovery, gas-to-liquids processing and field developments. During 2001 we entered into three agreements with NIOC for enhanced oil recovery study activities for the Ahwaz, the Marun and the Bibi Hakimeh fields. Together these fields produce around 1.5 million barrels of oil per day. Related agreements to carry out studies in respect of gas-to-liquids processing and field development are currently under discussion.

South Pars phases 6, 7 and 8. On December 12, 2002, Statoil became operator for the development of the offshore part of the South Pars 6, 7 and 8 project with a 40% share during the development phase. Statoil's total investment in the project is planned to be USD 300 million. The South Pars phase 6, 7 and 8 offshore project's scope consists of three wellhead platforms with three pipelines, condensate loading line and associated single buoy mooring, drilling of 27 production wells, hook-up of 3 pre-drilled wells, and required reservoir management. The project is managed from Tehran. The project is in accordance with Norwegian foreign policy of increased trade relations with Iran. See Item 3—Key Information—Risk Factors for additional information concerning the risk of US sanctions because of our activities in Iran.

Caspian Region. We sold our interest in the large Kashagan field in 2001, but decided to continue efforts to win other opportunities in the region. A protocol was signed with Kazakhoil to identify exploration opportunities together. Other exploration opportunities in the North and Central Caspian are also under evaluation. On November 11, 2002 Statoil signed an MOU with Lukoil during President Putin's visit to Norway, which commits the two parties to a closer look at collaboration opportunities in the Russian part of the Caspian.

Brazil. In 2001 we acquired a 25% interest in two Santos Basin blocks in the 3rd Licensing Round. BM-S-17, operated by Petrobras and BM-S-19 operated by Repsol. Shell holds a 25% equity in both blocks, with the remaining 50% owned by Petrobras. Both blocks have now undergone a three-dimensional seismic survey.

In 2002, through the 4th Licensing Round, we acquired a 40% interest in Block BM-J-3 with Petrobras the operator (60%). A 3D seismic survey is planned for 2003. Our fourth license was acquired in 2002 through a 30% farm-in to the Phillips/Conoco operated block BM-ES-11 in the Espirito Santo

Basin. Interpretation is ongoing to enable drilling of this block at the earliest opportunity, which we expect will be late 2003 to early 2004.

US. In December 2002, Statoil acquired El Paso's capacity rights at the LNG regasification terminal at Cove Point, Maryland. At the same time, Statoil also purchased the contract initially entered into between El Paso and the Snøhvit seller group, in which Statoil holds a 32% interest, in October 2001. According to the contract with the Snøhvit seller group, deliveries of LNG to the terminal will start in 2006 when the Snøhvit field in the Norwegian part of the Barents Sea is expected to come on stream. The contract has a duration of 17 years with two extension options for three years each thereafter. The LNG terminal is expected to come into operation in the summer of 2003 after having been shut down for many years. Statoil intends to utilize the capacity until the start up of Snøhvit through the purchase of third party LNG. Statoil's import capacity is 2.4 bcm per year, which is one third of the total import capacity in the terminal. The owner of the terminal is Dominion Resources and the other import capacity holders are BP and Shell. Based on the owner's instruction related to marketing of oil and gas from NCS, Petoro / SDFI will cover a proportion of the costs related to this investment based on a proportional share of volumes.

Mexico. In March 2001, we signed a protocol with Pemex regarding the possibility for future exploration and production operation.

Other Existing Areas

China. We operate the Lufeng 22-1 oil field and hold a 75% interest in the project. Our partner is the China National Offshore Oil Company (25%). Assuming crude oil prices at December 2002 levels, the field could stay in production until early 2004.

Natural Gas

Introduction

Our Natural Gas business segment transports, processes and sells natural gas from production fields to purchasers. In 2002, we sold on our own behalf 19.6 bcm (692 bcf) of natural gas as well as approximately 23.5 bcm (830 bcf) on behalf of the Norwegian State. We are the largest exporter and marketer of Norwegian natural gas. Our volumes and volumes sold on behalf of the Norwegian State represent approximately two-thirds of the entire NCS contract portfolio.

We expect Norwegian natural gas production to increase over the next few years. Given our strong existing position as a producer, transporter and marketer of natural gas from the NCS, we expect to play a central role in supplying the growing European gas market.

We have a significant interest in the world's largest offshore gas pipeline transportation system that extends more than 5,000 kilometers. This extensive network links Norway's offshore gas fields with gas treatment plants on the Norwegian mainland and to terminals at four landing points, located in France, Germany, Belgium and the United Kingdom, providing us with flexible access to customers throughout Europe.

We operated most of the Norwegian natural gas transportation system until January 1, 2002, when the operatorship was transferred to Gassco AS, a new gas transportation company wholly owned by the Norwegian State. Effective January 1, 2003 the ownership to a majority of the transportation and processing facilities was unitized into a single joint venture Gassled. The technical operation of most of the natural gas transport system including the Kårstø Gas Treatment Plant, such as system maintenance, is still carried out by us on a cost-recovery basis.

We have a large long-term gas sales contract portfolio, described below, and are currently evaluating midstream and downstream opportunities to take further advantage of our existing infrastructure, large supply and experience in marketing natural gas. Our downstream strategies may differ from region to region depending on our particular position in the area. In Europe, we intend to extract greater efficiency from our existing infrastructure in order to deliver larger volumes and to enter into a wider range of sales arrangements in order to reach a broader customer base. We intend to focus on supplying the commercial, industrial and wholesale markets and currently have no plans to enter the residential gas market.

The following table sets forth key financial information about this business segment.

	YEAR ENDED DECEMBER 31,			
	2000	2001	2002	
(IN MILLIONS)	*NOK*	*NOK*	*NOK*	*USD*
Revenues	20,624	23,468	24,536	3,537
Depreciation, depletion and amortization	730	664	592	85
Income before financial items, income taxes and minority interest	7,893	9,629	8,918	1,285
Capital expenditure	810	671	465	67
Long-term assets	13,030	10,500	10,312	1,486

European Gas Market

According to the International Energy Agency (IEA) annual natural gas consumption in OECD-Europe rose from 485 bcm (17.1 tcf) in 2001 to 490 bcm (17.3 tcf) in 2002 (preliminary figures based on estimate for the fourth quarter of 2002). The estimated annual growth in gas consumption in the period 2000-2010 is 3%. The gas share of total primary energy consumption represented 22% in 2000, and is expected to grow to 26% in 2010. Around 60% of the growth in gas consumption in the period 2000-2010 is assumed to come from the electricity sector. OECD-Europe consists of the following countries: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland, Turkey and the United Kingdom. The IEA expects a growth in demand for all sub sectors of the

OECD-Europe natural gas market over the next nine years.

We market and sell our gas together with the Norwegian State's natural gas, and taken together, we are one of the four major suppliers to the European market. The other major suppliers are Gazprom from Russia, Sonatrach from Algeria and Gasunie from the Netherlands. We believe that the Norwegian natural gas we market is competitive because of its reliability, access to the transportation infrastructure and proximity to the European market.

As the European energy market undergoes deregulation and structural changes, we believe that natural gas will play an increasingly important role. In particular, the use of natural gas as a source for electricity generation is growing.

Our analysis, based on data released by Wood Mackenzie in 2002, an industry consultant, and National Grid Transco (NGT), the UK gas transportation company, suggests that the United Kingdom's own natural gas supply, excluding exports, will fall short of annual domestic demand starting in 2004 or 2005. This analysis indicates that the significant and sustained drop in indigenous medium- to long-term supplies will trigger the need for new imports. Given our current and planned infrastructure, we believe that we are well positioned to take advantage of the UK's increased demand for imported natural gas and to participate in one of Europe's largest and most liberalized natural gas markets. Norwegian gas exporters are considering further strengthening of the infrastructure towards the UK. However, a number of competing projects are being developed to transport gas to the UK, including increased Bacton Zeebrugge Interconnector import capacity. Other projects like a new pipeline from Netherlands and various LNG projects are also being considered.

Although we expect to face a more competitive downstream natural gas market in continental Europe as the August 1998 EU Gas Directive concerning deregulation and market liberalization takes increased effect, we believe that our established market positions, long-term relationships with large customers, experience in the marketing of natural gas and established points of entry will place us in a strong competitive position. For more information about the EU Gas Directive, please refer to —Regulation below.

Gas Sales and Marketing

Our major export markets for NCS gas are Germany, France, United Kingdom, Belgium, Italy and the Netherlands. Our customers are mainly large national or regional gas companies, such as Ruhrgas, Gaz de France, ENI Gas & Power, Distrigaz and Gasunie. In addition, we sell to large end-users. Natural gas is sold to these customers under long-term, take-or-pay contracts. Our long-term contract portfolio, including sales of SDFI gas, will increase by approximately 40% from 2000 to 2005. In 2005, we have contracted to sell approximately 50 bcm (1.8 tcf) on our behalf and for the Norwegian State, of which 45% in 2002 will be for our own account. In 2002, our three largest customers represented approximately half of our total sales volumes; however, their relative share will decrease over time. These contracts expire between 2025 and 2029.

We are required to market and sell the Norwegian State's natural gas together with our own natural gas pursuant to our articles of association. An extraordinary general meeting was held on May 25, 2001, at which the Norwegian State, as our sole shareholder, approved a resolution containing an instruction by the Norwegian State relating to this requirement. For more information, see Item 7—Major Shareholders and Related Party Transactions—The Norwegian State as a Shareholder—Major Shareholders–The Norwegian State's Direct Participation in Petroleum Operations on the NCS—Marketing and Sale of the SDFI's Oil and Gas and Item 5—Operating and Financial Review and Prospects–Operating Results–Factors Affecting Our Results of Operations.

In the United Kingdom, we market our gas towards large industrial customers, power generators and wholesalers, and participate in the UK spot market. In 2002, we imported 1.8 bcm (65 bcf) of NCS gas to UK via the Vesterled pipeline and delivered close to 1.7 bcm (60 bcf) to the industrial and commercial sector in the UK. Our group-wide gas trading activity is mainly focused around the UK gas market which is a significant market in terms of size and one of the most progressive in terms of deregulation when compared with other European markets. Our UK trading activities are now focused on optimizing NCS volumes to the UK and Europe by profiling NCS deliveries to match the highest priced spot market periods. This strategy leads to additional value above and beyond the sales contract profit. In addition, we signed up to the North Western European Hub Company (NWE Hub) in 2002. The North West European Hub will enable Statoil to utilize the flexibility inherent in its Norwegian gas assets and optimize their value.

In June 2002 we signed a new long-term gas contract with Centrica, the largest marketer of gas in the UK. The 10-year deal, which starts on the October 1, 2005, is for a maximum of 5 bcm (177 bcf) per year of natural gas, which represents approximately 5% of total forecasted UK demand. The gas sales contract is for a flat volume delivered to the UK's liquid trading hub (national balancing point) and priced to a UK market gas price index. We anticipate that Statoil together with SDFI will supply close to 10% of the UK market by 2005: The Centrica contract and the existing agreements with BP (1.6 bcm – 57 bcf), Synergen (0.6 bcm – 21 bcf) and our end user market ambitions (2 bcm– 71 bcf).

In December 2002, we acquired full control of Aldbrough Gas Storage Company Limited (AGSCL) from the energy company Intergen. The Aldbrough storage project involves the development of three underground salt caverns on the east coast of the UK. When completed in 2006, the facility will provide us with a rapid response, fast injection/withdrawal gas storage plant. Aldbrough will add value to our UK gas sales through short term trading and optimizing and will also provide some insurance against interruptions to NCS supply. Based on the owner's instruction related to marketing of oil and gas from NCS, Petoro / SDFI is engaged in this investment based on a proportional share of volumes.

Synergen, the power project located at Dublin in the Republic of Ireland in which we have a 30% interest, with Electricity Supply Board (ESB) owning the remaining 70%, formally took over the plant in August 2002. The Ringsend plant has been operating commercially since then.

In Germany, we hold a 21.8% stake in the Norddeutsche Erdgas-Transversale, or Netra, overland gas transmission pipeline, a 5.3% stake in VNG Verbundnetz Gas AG, a German gas merchant company, and a 20.1% stake in Etzel Gas Storage.

During 2002, Statoil established the HubCo - North West European Hub Service Company GmbH together with Ruhrgas AG and BEB Erdöl und Erdgas GmbH. HubCo provides hub services in the Emden and Bunde/Oude area in north-west Germany. The hub area is the crossroad for gas flows between the Norwegian Continental shelf and the Dutch and German gas system. Since November 2002, HubCo offers its customers nomination, allocation and title tracking for gas traded at the hub. Physical access to the hub is possible through several pipeline interconnections located in the hub area. The hub is an important prerequisite for setting up a traded market for short-term gas deliveries in northwestern Europe.

A major gas sales agreement was entered into on September 3, 2001 with the Polish Oil and Gas Company, for a cumulative sale of 73.5 bcm from Norway to Poland over a 16-year period starting in 2008. The Statoil/SDFI share of the deliveries is 72.8% (53.5 bcm). However, the contract has not been finalized, as conditions under the agreement have not been fulfilled. It is regarded as increasingly uncertain whether it will be possible to fulfill remaining conditions prior to the current deadline, October 1, 2005.

Growth in gas demand from power generation

IEA expects more than 60% of the total growth in gas demand in OECD Europe in the period 1997 to 2010 to come from power generation. Gradual retirement of ageing nuclear and thermal generation plants, together with continued moderate growth in demand for electricity, should lead to demand for new power generation capacity. When new capacity is required, gas fired generation plants are usually the lowest cost option, and also politically more acceptable than coal, oil and nuclear. Renewable sources tend to have strong political support, but will only to a limited extent be able to fill the supply gap.

Statoil aims to capture growth from this segment, both as a seller of gas to power generators and as an investor in targeted generation assets. In 2002 Statoil started supplying natural gas to Dublin Bay Power Plant in Ireland, in which we also have an ownership share of 30%. Statoil promotes gas-fired power plants in Norway and seeks on the Continent to develop gas-fired Combined Heat and Power plants for supply of heat and power to industrial customers.

Even if the IEA and others forecast strong demand growth from power generation, there are uncertainties regarding the strength of demand growth. The pace of plant retirements and electricity demand growth are dependent on both economical and political factors. The competitiveness of new gas-fired generation is influenced by gas prices and fuel taxation.

Norwegian Gas Transportation System and Other Facilities

In order to transport Norwegian natural gas to European customers, we and other Norwegian gas producers have built an extensive gas pipeline system, connecting gas fields to gas processing plants on the Norwegian mainland and to Europe. The system is now operated by Gassco AS, the new operator for the natural gas transportation system, wholly owned by the Norwegian State. Gassco AS took over as operator of the system at no cost on January 1, 2002. We are carrying out most of the technical aspects of operating parts of the transportation systems on a cost recovery basis. We, together with SDFI, are the largest owner of these operated facilities. In 2002, the system transported 64.3 bcm (2.3 tcf) of Norwegian gas, although at this export level, the system has an additional 14 to 18 bcm (0.5 to 0.6 tcf) per year capacity.

To cater for existing commitments and expected new gas sales to the UK, increased transportation capacity will be required. Different solutions are being evaluated, aiming at an investment decision in the first half of 2003.

As from January 1, 2003 the ownership interests of the Zeepipe, Franpipe, Europipe II, Åsgard Transport, Statpipe, Oseberg Gas Transport and Vesterled joint ventures and Norpipe AS were transferred to a new joint venture called Gassled. This also includes the terminals in Statpipe and Vesterled, the Europipe Receiving Facilities and the Europipe Metering Station. The ownership interest in Zeepipe Terminal JV and Dunkerque Terminal DA will also be adjusted. Gassco AS will be the operator of Gassled.

Our initial direct ownership interest will be 20.379% in Gassled (21.133% including our indirect interest through our 25% holding in Norsea Gas AS), 9.98571% in Zeepipe Terminal JV and 13.24635% in Dunkerque Terminal DA. From January 1, 2011, our ownership interest in Gassled will be reduced to 17.179% due to an increased ownership interest for SDFI. Similar adjustments of the ownership interest in Zeepipe Terminal JV and Dunkerque Terminal DA will also be made. In addition, our ownership interest in Gassled may also change as a result of inclusion of existing or new infrastructure or if Gassled undertakes further investments without participation from its owners in the same ratio as their ownership interests in Gassled.

The organization of the gas transportation systems in one joint venture will prepare for a more efficient operation and development of the system. Gassled has a license period to 2028.

The Norwegian authorities have by a royal decree approved in the Kings Council on December 20, 2002, set the rules and regulations for access to Gassled, new tariffs for capacity and implementation of the EU Gas Marketing Directive in the EEC in the upstream gas transportation system.

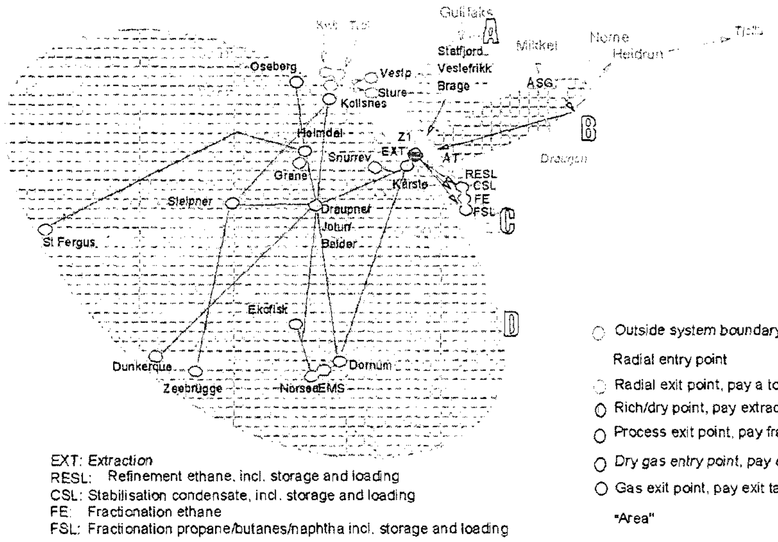
Gassled is divided into four areas; area A is the Statfjord – Kårstø pipeline, area B is the Åsgard – Kårstø Pipeline, area C is the Kårstø Gas Treatment Plant and area D is all the dry gas pipelines, as illustrated in the figure on the following page.

The pipelines intersect at platforms, tie-in locations and processing plants, providing us with a flexible network to transport natural gas from various fields and gas processing plants to our entry points into the European market, depending on our customers' contracted daily and annual natural gas sales requirements. Our ability to route our supply of natural gas from various fields enables us to provide regular and reliable gas deliveries to our customers. Each field operates with an account system, permitting fields to borrow and repay gas volumes as needed to meet their supply needs. If, for instance, one platform is forced to shut down production temporarily, another field can increase production to cover temporarily the supply shortfall, thereby providing the end user with uninterrupted supply. This supply and source flexibility is also advantageous since it permits us to blend natural gas from different fields to modulate natural gas quality.

Technological developments have enabled us to reduce significantly the cost per meter to lay pipelines from the time we began construction on Statpipe in 1982 to the Åsgard transportation system in 1998. We have developed new solutions to connect the pipelines to each other with less waste, providing for a more efficient and environmentally sound transport system. We believe that our ability to link production to our customers in a cost effective manner will help us increase our natural gas sales at low incremental cost to us.

The major costs associated with running a pipeline system are maintenance and compression costs that result from operating compression facilities to increase gas throughput. Most transport agreements are based on a tariff per unit transported, which covers the operating cost of the transport system and provides a return on the capital invested. The Ministry of Petroleum and Energy sets such tariffs. The pipelines are maintained under an annual maintenance plan approved by the Norwegian Petroleum Directorate.

Gassled area A, B, C and D



The following table sets out the major NCS gas transportation systems in which we have an interest, the transportation routes and capacities. All of the pipelines and terminals are operated by Gassco AS, except for Norpipe and the Norsea Gas AS terminals, which are operated by Phillips Petroleum Norge.

Transportation systems included in Gassled from January 1, 2003

JOINT VENTURE	*STARTUP DATE*	*PRODUCT*	*START POINT*	*END POINT*	*TRANSPORT CAPACITY MMSm3/d*
Zeepipe					
Zeepipe 1	1993	Dry gas	Sleipner riser platform	Zeebrugge	41.7
Zeepipe 2A	1996	Dry gas	Kollsnes	Sleipner riser platform	55.4
Zeepipe 2B	1997	Dry gas	Kollsnes	Draupner E	59.5
Europipe 1	1995	Dry gas	Draupner E	Dornum/Emden	53.6
Franpipe	1998	Dry gas	Draupner E	Dunkerque	52.2
Europipe II	1999	Dry gas	Kårstø	Dornum	68.1
Norpipe AS	1977	Dry gas	Norpipe Y (Ekofisk Area)	Emden	43.0
Åsgard Transport	2000	Rich gas	Åsgard	Kårstø	66.0
Statpipe					
Zone 1	1985	Rich gas	Statfjord	Kårstø	29.0
Zone 4A	1985	Dry gas	Heimdal	Draupner S	29.0
		Kårstø	Draupner S	23.0	
Zone 4B	1985	Dry gas	Draupner S	Norpipe Y (Ekofisk Area)	43.0
Oseberg Gas Transport*	2000	Dry gas	Oseberg	Heimdal	41.0
Vesterled					
(Frigg Transport)	2001	Dry gas	Heimdal	St. Fergus	33.0

*Interest owned by E&P Norway.

Terminals included in Gassled from January 1, 2003

TERMINAL FACILITIES	STARTUP DATE	PRODUCT	LOCATION
Zeepipe JV			
Europipe receiving facilities	1995	Dry gas	Dornum, Germany
Europipe metering station	1995	Dry gas	Emden, Germany
Norsea Gas AS	1977	Dry gas	Gas Terminal, Emden, Germany
Statpipe JV	1985	Dry gas/NGL	Kårstø gas treatment plant, Norway
Etanor DA	2000	Ethane	Ethane plant at Kårstø, Norway
Vesterled JV (Frigg terminal)	1978	Dry gas	St. Fergus, Scotland

Pipelines not included in Gassled

JOINT VENTURE	STARTUP DATE	PRODUCT	START POINT	END POINT	TRANSPORT CAPACITY MMSm3/d	STATOIL SHARE
Norne gas transportation system	2001	Rich gas	Norne field	Åsgard transport Tjeldbergodden/ Åsgard	11.0	25.00%
Haltenpipe	1996	Rich gas	Heidrun field transport		7.1	19.06%

Terminals not included in Gassled

JOINT VENTURE	STARTUP DATE	PRODUCT	LOCATION	STATOIL SHARE
Zeepipe terminal JV	1993	Dry gas	Gas terminal, Zeebrugge; Belgium	13.73678%
Dunkerque terminal DA	1998	Dry gas	Gas terminal, Dunkerque, France	10.35542%

As from January 1, 2003, Statoil's share in Zeepipe terminal is 13.73678% (2003-2010) and 11.57975% (2011-2028). These interests include Statoil's 25% in Norsea Gas AS.

As from January 1, 2003, Statoil's share in Dunkerque terminal is 10.35542% (2003-2010) and 8.72935% (2011-2028). These interests include Statoil's 25% in Norsea Gas AS

Ownership structure Gassled

	PERIOD 2003-2010	PERIOD 2011-2028
Petoro *	38.293%	47.982%
Statoil	20.379%	17.179%
Hydro	11.134%	9.386%
Total	9.038%	7.619%
Esso	5.179%	4.366%
Shell	4.681%	3.946%
Mobil	4.576%	3.857%
Norsea Gas AS	3.018%	2.544%
Conoco	2.033%	1.714%
Agip	0.862%	0.727%
Fortum	0.807%	0.680%
Statoil equity interest including 25% of Norsea Gas AS	21.133%	17.815%

* Petoro holds the participating interest on behalf of SDFI

Kårstø Gas Treatment Plant (Area C)

Effective from January 1, 2002, the formal operatorship of Statpipe was transferred to Gassco AS. We are responsible for the technical aspects of the operation of the Kårstø gas treatment plant. Kårstø processes rich gas and condensate, or light oil, from the NCS received via the Statfjord – Kårstø pipeline (area A) pipe, the Åsgard - Kårstø pipeline (area B) and the Sleipner condensate pipeline. Kårstø ranks as Europe's largest gas processing facility. Products produced at Kårstø include ethane, propane, iso-butane, normal butane and naphtha, and stabilized condensate. In 2002, Kårstø produced 4.4 million tonnes of LPG and 3.4 million tonnes of condensate exported to customers worldwide.

We entered into a 15-year contract on June 2, 1997 to sell ethane from Kårstø to Borealis at its plant in Stenungsund, Sweden and to Borealis and Norsk Hydro at their plants in Rafnes, Norway. Of the ethane extracted at Kårstø, half is shipped by Navion to Stenungsund and sold to Borealis, and half is shipped to Rafnes.

We began operations at a new facility to process rich gas from the Haltenbank area in October 2000 and completed a new export pipeline, the Kårstø – Dornum pipeline, to connect Kårstø to the receiving terminal in Dornum, Germany in 1999. In addition, we are modifying the plant to accommodate gas from the Mikkel field in 2003 and from the Kristin field in 2005. With these expansions, processing capacity will be increased to approximately 85% of the capacity of the gas pipelines connected to the plant.

After the expansion in 2000, the Norwegian Pollution Control Authority (SFT) required Kårstø to reduce its NOx emissions. The final permit was received in June 2001, and requires a reduction of 165 tonnes of NOx per year starting in 2005. Alternative initiatives to meet this requirement have been identified and applications have been issued to SFT. The estimated installation costs are between NOK 50 million and NOK 190 million. Kårstø, however, is in compliance with its current permit, which is applicable until new provisions are finalized.

Gas Sales Agreements

All NCS gas sales agreements are subject to the approval of the Ministry of Petroleum and Energy, whether for domestic use or export. Generally, we and other gas producers have in the past not developed natural gas fields for production until after contractual commitments have been secured for the purchase of the natural gas. From 1977 to 1986, gas sales contracts were generally structured as depletion contracts and covered all of the natural gas reserves from a particular field. A depletion contract places risk on the buyer that the stipulated supply will be found in the reserves in the field in question. In general, the reserves in the Ekofisk, Frigg, Statfjord, Gullfaks and Heimdal fields have all been sold under depletion contracts to buyers on the European continent and in the UK.

In 1986, the Troll licensees entered into a set of gas sales agreements with European buyers, commonly known as the Troll gas sales agreements. These agreements cover the majority of the Norwegian gas sales agreements. Said agreements allow for delivery from NCS sources other than the Troll reservoirs, including associated gas from oil and condensate fields. The Ministry of Petroleum and Energy has previously decided which fields will be granted the right to deliver gas under the Troll gas sales agreements.

In 1987, the Norwegian State established the Gas Negotiation Committee, known as the GFU, as an integrated resource management instrument. In the period from 1987 to 2001, the GFU, which we chaired, was given the task to negotiate all NCS gas sales contracts. These contracts are generally long-term supply contracts in which the purchasers agree to take daily and annual quantities of gas and, if the gas is not taken, are obliged to pay for the contracted quantity. All such contracts have been entered into subject to the approval and allocation of the contract to specific fields by the Ministry of Petroleum and Energy. This approval and allocation system has been abandoned and replaced with a new company based sales system. For more information, see —Recent Changes to the Norwegian Gas Resource Management System below.

Our long-term contracts generally run for 20 years or more. Under a significant portion of our current long-term sales contracts, the quantities are scheduled to increase rapidly toward the plateau level to be reached between 2005 and 2008. The quantities that we are currently committed to supply, together with quantities contracted on behalf of the SDFI, will increase by approximately 40% in the period from 2000 to 2004.

Prices in these contracts are generally tied to a formula based on prevailing prices of a customer's principal alternative fuels to natural gas, mainly heavy fuel oil and gas oil. Consequently, there can be significant price fluctuations during the life of the contract. Prices in these contracts are generally adjusted quarterly and are calculated on the basis of prices prevailing in the three to nine months prior to the date of adjustment as published in reference indices. By contrast, a recent long-term gas sales contract in the UK, is priced with reference to a daily UK market gas price index. The price formula, calling for monthly or quarterly adjustment, however, is not able to capture all trends in the market place in either the gas or competing fuel markets, i.e. changes in taxation of gas and competing fuels imposed by national governments. Therefore, most of our long-term gas contracts contain contractual price adjustment mechanisms that can be triggered at regular intervals by either buyer or seller to revise the price formula. Under our long-term sales contracts either party may choose to enter into a price review process under certain circumstances as set forth in the contract.

Several price reviews have occurred since 1986, and historically, we have found that the reviews have adjusted the price formula without materially altering the commercial value of the contract. Approximately two-thirds of the quantities represented in our existing long-term sales contracts were eligible for potential price review in October 2001 and we have reached agreement with almost all of the buyers during 2002 with close to neutral effect on value.

Recent Changes to the Norwegian Gas Resource Management System

The structural changes that are now taking place in the European gas market prompted the Norwegian State to consider whether changes to the present gas resource management system on the NCS could contribute to enhance the efficiency for Norwegian gas producers. Accordingly, the Norwegian State has, by royal decree dated June 1, 2001, announced that the King-in-Council adopted recommendations of the Ministry of Petroleum and Energy to change the gas resource management system from the GFU system described above, to a system based on individual company marketing and sales of gas. Necessary changes have been made to the institutional, legal and commercial arrangements, including existing license, supply and transportation agreements. As a part of the restructuring the Troll Commercial Model, which distributed rights and obligations under the Troll gas sales agreement has been abandoned. In addition, the licensees have established new lifting arrangements in the individual licenses.

The immediate effect of this royal decree was that the previous system of non-field specific disposal of gas from the NCS through the GFU, and the authorities' allocation of approved gas sales contracts to contract and delivery fields was terminated as from the end of 2001. Furthermore, the system of gas sales through the GFU was suspended as of the date of the royal decree, June 1, 2001, within the EEA. This system has been replaced by a system whereby an individual licensee company itself can manage the disposal of its own gas. Necessary adjustments in legislation, gas sales agreements, license agreements and other existing contracts have been made and were effective as of October 1, 2002.

With the transition from the GFU to company based sales, we are seeking to capitalize on the increased flexibility in the new market environment. We intend to leverage our experience in marketing natural gas, our flexible infrastructure and our established points of entry to enhance our competitiveness and profitability.

The EU Commission decided in July 2002 to withdraw the Statement of Objections issued against Statoil and other companies on the NCS regarding alleged breach of EU competition rules for marketing of Norwegian gas by the GFU. The Competition Directorate General of the European Commission and Statoil on July 17, 2002 agreed an amicable settlement of the "GFU case". Pursuant to the settlement, the EU Commission withdrew the case and Statoil undertook for the period from June 1, 2001 to September 30, 2005 to offer for sale on commercially competitive terms and conditions a total of 13 billion cubic meters of natural gas to "new customers". The definition of a new customer is all creditworthy undertakings within the EEA, which were not among Statoil's long-term customers prior to 2001. As Statoil's undertaking is retroactive to June 1, 2001 a portion of this gross volume has already been sold to such new customers. Statoil will endeavor to distribute the volume evenly over the period.

Statoil has undertaken the above without any admission that the company's marketing and GFU gas marketing activities constituted an infringement of the competition rules of the EC or the EEA.

Manufacturing and Marketing

Introduction

The Manufacturing and Marketing business segment comprises our downstream activities, including sales and trading of crude oil and refined products, refining, retail and industrial marketing of oil products, methanol production and sales and petrochemical operations through our 50% interest in Borealis. We sold our shares in Navion to Norsk Teekay AS, which is a wholly owned subsidiary of Teekay Shipping Corporation, effective January 1, 2003, and expect to close the sale during the second quarter of 2003.

The following table sets forth key financial information about this business unit.

	YEAR ENDED DECEMBER 31,			
	2000	2001	2002	
(IN MILLIONS)	*NOK*	*NOK*	*NOK*	*USD*
Revenues	201,585	203,387	211,152	30,436
Depreciation, depletion and amortization	1,734	1,855	1,686	243
Income before net financial items, income taxes and minority interest	4,559	4,480	1,637	236
Capital expenditure	2,860	811	1,771	255
Long-term assets	32,925	30,432	27,958	4,030

Oil Trading and Supply

We are one of the largest net sellers of crude oil in the world, operating out of sales offices in Stavanger, London, Singapore and Stamford, Connecticut, selling and trading crude oil, NGLs and refined products. We market and sell the Norwegian State's crude oil together with our own. In 2002, we sold 784 million barrels of crude, or almost 2.1 million barrels per day, including sales to our own refineries and other internal divisions. Crude oil sales in 2002 were 4% lower than sales in 2001. Our main crude oil market is in northwest Europe, and we also sell large volumes into North America and Asia. Most of our oil volumes are sold on spot market terms, based on worldwide prices and quotations. Of the volumes we sold in 2002, approximately 31% were our own volumes. We purchase crude oil from third parties in order to obtain other qualities of oil for sale and blending, and to increase our flexibility with respect to shipping and storage.

We are required to market and sell the Norwegian State's oil and royalty oil together with our own oil pursuant to our articles of association. At an extraordinary general meeting held on May 25, 2001, the Norwegian State, as our sole shareholder at that time, approved a resolution containing an instruction related to this requirement. For further information, see Item 7 —Major Shareholders and Related Party Transactions —Major Shareholders— The Norwegian State as a Shareholder —and Gas and Item 5 — Operating and Financial Review and Prospects—Operating Results—Factors Affecting Our Results of Operations.

The main markets for our refined products, NGLs and condensate are in northwest Europe and the countries around the Baltic Sea rim. We are a large supplier of condensate in Europe, providing this very light crude oil to refiners and the petrochemical industry. In addition, condensate cargoes are sold in the US and Far East markets. In 2002, we sold approximately 22.5 million tonnes of refined oil products, the majority of which was refined at our refineries at Mongstad and Kalundborg, and approximately 6.5 million tonnes of natural gas liquids.

Refining

We are majority owner (79%) and operator of the Mongstad refinery in Norway, which has a crude oil distillation capacity of 179,000 barrels per day, and owner (100%) and operator of the Kalundborg refinery in Denmark, which has a crude oil and condensate distillation capacity of 118,000 barrels per day. In addition, we own 10% of the production capacity at the Shell-operated refinery in Pernis, the Netherlands, which has a crude oil distillation capacity of 400,000 barrels per day.

Over the last several years, the refining industry has experienced extensive restructuring, mainly due to several years of thin margins and more stringent environmental requirements. We have improved our refineries' competitiveness by:

- operating our refineries safely and efficiently, aiming at the top quartile in Europe;
- exploiting our feedstock position, the market's demand for products, and our locations;

- meeting new product specifications in a timely and cost efficient manner; and
- strengthening our business through alliances.

The following table gives operating characteristics of the refineries at Mongstad and Kalundborg. Throughput was reduced in 2002 due to low margins, and both refineries had planned turnarounds (major maintenance shutdowns) in part of the refineries.

	YEAR ENDED DECEMBER 31, 2000			2001			2002		
	THROUGH-PUT(1)	DISTILLATION CAPACITY(2)	UTILIZATION RATE(3)	THROUGH-PUT(1)	DISTILLATION CAPACITY(2)	UTILIZATION RATE(3)	THROUGH-PUT(1)	DISTILLATION CAPACITY(2)	UTILIZATION RATE(3)
Refinery									
Mongstad	10.0	8.7	94.2%	9.5	8.7	91.9%	8.9	8.7	92.4%
Kalundborg	5.3	5.5	88.8%	5.0	5.5	88.2%	4.7	5.5	84.0%

(1) *Actual throughput of crude oils, condensates, feed and blendstock, measured in million tonnes*

(2) Nominal crude oil and condensate distillation capacity

(3) Composite rate for all processing units at refinery

Mongstad. The Mongstad refinery is directly linked to offshore fields through two crude oil pipelines and indirectly linked through a NGL/condensate pipeline from the crude oil terminal at Sture and the gas terminal at Kollsnes, making Mongstad an attractive site for landing and processing hydrocarbons and for further development of our oil and gas reserves. The main facilities at Mongstad, in addition to the refinery, are a crude oil terminal and an NGL terminal.

Effective January 1, 2000, we swapped 21% of our holding in Mongstad with Shell for a 10% interest in its refinery at Pernis in the Netherlands. As a result of this transaction, we have access to products in Rotterdam, and Shell is able to supply the Norwegian market. In addition, we have a service agreement with Shell Global Solutions, Shell's subsidiary, which will provide technical operational support, project development support and general technical advice for Mongstad. Through this agreement, we can access support from a world-leading refiner.

The Mongstad refinery, built in 1975 and significantly expanded and upgraded in the late 1980s, is a medium-sized, modern and sophisticated refinery. The products are principally high value light products such as naphtha, gasoline, jet fuel, diesel and light heating oil. The refinery does not produce low value residue because this crude oil component is upgraded to gasoline and gasoils in the residue cracker and the delayed coker. More recent upgrading projects include a new gasoil desulphurization plant, a plant for reducing benzene in gasoline and a NGL/condensate project involving a pipeline to Mongstad plus NGL terminal and refinery expansion and revamp at Mongstad. We will invest close to NOK 1 billion in 2001–2003, building a unit that will desulphurize cracker naphtha and make it a more valuable component for gasoline blending and export. Planned startup of the new unit is in March 2003.

As a result of the swap with Shell, an increased share of Mongstad's products are delivered to Scandinavian markets. Approximately 60% of Mongstad's total production is exported to northwest Europe and the United States. Although the transportation costs are higher than those of refineries located closer to these markets, Mongstad's overall competitive position benefits from its proximity to feedstock supplies.

The following table sets forth approximate quantities of refined products (million tonnes) manufactured by Mongstad for the periods indicated. In addition to crude, as shown below, the Mongstad refinery upgrades large volumes of fuel feedstock (up to one million tonnes per year) and, from the end of 1999, Oseberg NGL and Troll condensate.

MONGSTAD PRODUCT YIELDS AND FEEDSTOCK	YEARS ENDED DECEMBER 31, 2000		2001		2002	
LPG	307	3%	289	3%	303	3%
Gasoline/naphtha	3,941	40%	3,755	40%	3,611	40%
Jet/kero	702	7%	543	6%	516	6%
Gasoil	3,881	39%	3,696	40%	3,534	40%
Fuel oil	311	3%	262	3%	200	2%
Coke/sulphur	218	2%	223	2%	224	2%
Fuel, flare and loss	596	6%	584	6%	555	6%
Total throughput	**9,956**	**100%**	**9,352**	**100%**	**8,943**	**100%**
North Sea crude oils:						
Troll, Yme (FOB crude oils)	3,426	34%	2,382	25%	2,261	25%
Other North Sea crude oils (CIF crude oil)	4,802	48%	5,213	56%	5,125	57%
Residue	983	10%	768	8%	654	7%
Other fuel and blendstock	745	7%	989	11%	902	10%

Note: *Changes in throughput and yields are partly due to maintenance shutdowns. There were no maintenance shutdowns in 2000, but there were* two extraordinary cracker shutdowns in 2001,and planned maintenance shutdown in the cracker unit in 2002.

The Mongstad refinery is geared for efficient production of commodity fuels and has considerable flexibility in producing products to different specifications through its ability to do in-line blending during ship loading. Given stricter EU and US product specifications expected to be effective from 2005, we decided to invest significantly in improvements at Mongstad.

We have a cost improvement program in place, supported by the technical services agreement with Shell, which focuses on maintenance, procurement and cost management. We are also identifying measures in order to improve energy efficiency. The improvement program is somewhat behind our original plan, partly due to unplanned shutdowns. The program goals remain unchanged. After high loss due to two cracker breakdowns in 2001, a number of minor modifications have been carried out, and the unit had high reliability in 2002.

Kalundborg. In 1986, we purchased the Kalundborg refinery, built in 1961, from Exxon as part of a purchase of Exxon's downstream operations in Denmark. In 1995, we expanded the facility by installing a condensate upgrading plant, which increased our total annual distillation capacity by 1.5 million tonnes to a total of 5.5 million tonnes. The condensate facility was built to process condensate from the Sleipner fields. In addition to condensate, the refinery processes low sulphur North Sea crude oils. Kalundborg produces products such as gasoline, jet fuel, diesel oil, propane, and fuel oil to supply markets in Denmark and Sweden. The refinery is connected through a pipeline to our terminal at Hedehusene close to Copenhagen. Kalundborg's refined products are also supplied to the northwest European market, mainly Germany and France.

The following table gives approximate quantities of refined products (in million tonnes) manufactured by Kalundborg for the periods indicated.

KALUNDBORG PRODUCT YIELDS AND FEEDSTOCK				*YEARS ENDED DECEMBER 31,*		
		2000		*2001*		*2002*
LPG	117	2%	103	2%	101	2%
Gasoline/naphtha Gasoline/naphtha	1,708	32%	1,683	34%	1,533	32%
Jet/kero	281	5%	268	5%	232	5%
Gasoil	1,902	36%	1,843	37%	1,825	39%
Fuel oil	1,083	21%	923	18%	866	18%
Coke/sulphur	4	0%	4	0%	3	0%
Fuel, flare and loss	176	3%	177	4%	170	4%
Total throughput	**5,271**	**100%**	**5,001**	**100%**	**4,731**	**100%**
North Sea crude oils:						
Sleipner, Åsgard condensates	1,188	23%	1,146	23%	1,270	27%
Other North Sea crude oils	3,638	69%	3,511	70%	3,076	65%
Other fuel and blendstock	445	8%	344	7%	385	8%

Note: Changes in throughput and yields are partly due to maintenance shutdowns and expansions. There were no maintenance shutdowns in 2000 or 2001, but a maintenance shutdown occurred in the old part of the refinery in 2002, and also some longer, unplanned shutdowns.

Although it is a relatively small and simple refinery, Kalundborg is a plant with high energy efficiency and low cash operating costs for a plant of its size and configuration. The refinery has improved its performance significantly in the last five years through several small investment projects to increase flexibility and improve yield/product quality. It produces high quality products including low sulphur gasoline in accordance with EU specifications. In addition, we invested a total of NOK 400 million in 2001 and 2002 to upgrade the refinery in order to increase our feedstock flexibility and to enable us to produce refined products that meet the expected 2005 EU requirements for low sulphur diesel. The new unit started production in June 2002.

Nordic Energy

Our Nordic Energy unit, with approximately 1,400 employees, consists of three national sales organizations for refined products to consumer and industrial markets in Scandinavia. Nordic Energy sells Statoil-branded refined products for heating, such as fuel oil, LPG, environmentally friendly energy solutions, and transportation fuel, such as diesel, jet fuel, marine fuel and lubricants. We also have operations for lubricants and LPG in Poland and the Baltic States. In addition, we manage the logistics of petrol delivery for Statoil-branded service stations in Scandinavia. We have a strong market position based on our approximately 325,000 customers and annual sales of six billion liters. In the liquefied petroleum gas market, we have approximately 38% of the Scandinavian market share of the necessary infrastructure to supply customers within the Scandinavian markets. Our portfolio also includes ownership interests in gas distribution companies and planned gas-fired power generation sites in several locations in Norway.

Due mainly to lower demand for heating oil and gas oils and resulting reduced margins, Nordic Energy's profitability has suffered in recent years. To address the profitability gap, we focus our business on areas where we can utilize Statoil's resources and brand name, and improve cost efficiency in our existing business. The latter is starting to show effect with improved results in 2001 and 2002 compared with 2000. In the longer term, we are evaluating opportunities to expand our energy product offerings. Nordic Energy's competence and customer portfolio in the LPG market will provide additional leverage as we evaluate options relating to the future marketing of gas.

In March 2003, we announced that we had entered into a joint venture with Naturgas Fyn of Denmark. We will initially own 30% of the joint venture, named Statoil Gazelle, but we have an option to increase the share. Statoil Gazelle will focus on marketing and selling gas and oil products in the Danish market.

Retailing

Our retail distribution network consists of almost 1,900 Statoil-branded service stations in nine countries, including one of the two largest networks of stations in Scandinavia. These stations provide automotive fuels, car accessories and simple vehicle service, and nearly all offer goods such as fast food, convenience products and basic groceries. In 2002, these stations sold approximately 4.5 billion liters of gasoline and diesel.

The following table lists these retail outlets by region or country as of December 31, 2002, and our volume of automotive fuel sales for the year ended December 31, 2002.

	SCANDINAVIA	IRELAND	POLAND	BALTICS	RUSSIA	TOTAL
Retail Outlets						
Statoil or SDS-owned and operated	291	52	132	89	6	570
Dealer owned and Statoil or SDS operated	0	11	0	0	0	11
Statoil or SDS-owned and dealer-operated	590	15	0	1	0	606
Dealer owned and operated	453	184	0	0	0	637
123- (automate) stations	49	0	0	10	0	59
Total	**1,383**	**262**	**132**	**100**	**6**	**1,883**
Volume of Petrol Sold						
Gasoline (millions of liters)	2,190	484	278	242	23	3,217
Diesel (millions of liters)	474	548	133	165	2	1,322
Total	**2,664**	**1,032**	**411**	**407**	**25**	**4,539**

Scandinavia is our home retail market, where Statoil-branded stations have a gasoline market share of approximately 22%, according to data from the petroleum institutes in each country. All of the Scandinavian stations are owned or franchised by a separate company established in 1999, Statoil Detaljhandel Skandinavia AS, or SDS. SDS is owned equally by us and the ICA/Ahold supermarket group. SDS has a cost-efficiency program in place and SDS is also renegotiating the terms of its franchise contracts with the dealers, to align the incentives between the franchisees and SDS.

We believe that SDS effectively combines the strong Statoil brand name and our skills in retailing oil products with ICA's strong brand name and expertise in marketing groceries. SDS has introduced ICA Express convenience stores, which are significantly larger and aim to meet a wider range of customer needs than the more limited convenience supplies offered at SDS's other service stations. SDS co-brands service stations where ICA Express stores are located, meaning that the overall site and fueling station is branded Statoil while the convenience store is branded ICA Express. There were 161 ICA Express convenience stores as of December 31, 2002, compared with 99 at December 31, 2001 and 65 at December 31, 2000, and we have plans for further expansion at primary locations in the coming years.

Statoil's other service stations are located in Ireland, Poland, Russia and the Baltics, which includes Estonia, Lithuania and Latvia. We rank as a market leader in Ireland, Estonia and Latvia with approximately 24%, 20% and 16% respectively of the retail gasoline market in 2002. After an acquisition of Shell's retail network in the three Baltic countries effective early 2003, Statoil's presence and network will be strengthened. As of December 31, 2002, 58 of the Irish stations included our convenience stores. We have introduced automated, unmanned stations under the name 1-2-3 in the Baltics and Scandinavia. To date we have 10 automated stations in the Baltics and 49 in Scandinavia. In Poland we have a market share of 3.1%, but we believe that Poland has significant growth potential, and that we are well positioned for future growth. The acquisition of Preem's retail network in Poland, effective early 2003, is estimated to increase our market share in 2003 to about 3.5%.

We are focusing on increasing profitability and earnings in our existing network by increasing non-fuel sales, lowering costs and using customer loyalty schemes in all countries.

Methanol

Our methanol operations consist of our 81.7% stake in Europe's newest gas-based methanol plant at Tjeldbergodden, Norway, which has a design capacity of 830,000 tonnes per year and actual output during 2002 of 814,000 tonnes compared with 867,000 tonnes in 2001. The reduction in production compared to 2001 is due to a regular four-week maintenance stop every second year. Actual output in 2002 equaled approximately 14% of Western European consumption. Conoco owns 18.3% of the facility. We have the sole marketing rights for the plant. During 2002 we established customer contacts and storage facilities in Canada. We estimate sales to this new market to be approximately 10% of the Tjeldbergodden capacity.

We believe that the plant's location at Tjeldbergodden provides a competitive advantage primarily because it is close to an economical source of feedstock, the Heidrun field. The plant's location also enables us to supply our product in smaller vessels, giving us flexibility and access to all sizes of ports in Western Europe, increasing our competitiveness compared to overseas suppliers.

Approximately 75% of global methanol production is consumed in chemical applications. The remaining 25% is used for the production of MTBE. MTBE is an additive used in gasoline to enhance octane and improve air quality. We are cooperating with other companies in order to develop new markets for methanol. The MTP (Methanol to Propylene) pilot plant at Tjeldbergodden, which was built in 2001 with the German company Lurgi AG, has performed according to expectations. The testing will be continued in 2003, in order to verify the commercial viability of this technology. We are also working with various companies, including DaimlerChrysler, BP, BASF, Methanex and Xcellsis, on the possibility of using methanol to power fuel cells, which is a device that converts chemical energy directly into electrical energy.

We also hold 50.9% of Tjeldbergodden Luftgassfabrikk DA, the largest Air Separation Unit (ASU) in Scandinavia, which also owns the first Norwegian natural gas liquefaction plant located at Tjeldbergodden with an annual gas capacity of 35 mmcm (1,236 mmcf). Our partners are AGA (37.8%) and Conoco (11.3%). The ASU supplies oxygen to the methanol plant and AGA markets and sells industrial gases produced.

In addition, at Tjeldbergodden we have commissioned the world's first bioprotein plant based on natural gas. The plant is designed to produce approximately 10,000 tonnes of bioproteins annually using natural gas as feedstock. Bioproteins' initial application is for animal and fish feed, but it can also be used for human consumption. On February 13, 2003 Du Pont and Statoil signed an agreement to form a joint venture on a 50/50 basis to further develop the business. Statoil's part of the new company will still report to the Technology and Development unit.

Borealis

Borealis was established in 1994 by merging our petrochemical operations with those of the Finnish company, Neste. We own 50% of Borealis, with the remaining interests held equally by our partners OMV, the Austrian oil and gas company, and the International Petroleum Investment Company (IPIC), Abu Dhabi's national company for foreign investment in the petroleum business. Borealis has 5,100 employees and operations in 11 countries. Its principal products are the plastic raw materials polyethylene and polypropylene, collectively known as polyolefins, as well as the base petrochemicals ethylene and propylene, known as olefins. Borealis's polyolefin capacity is the second largest in Western Europe and the fifth largest globally. Of this, over 30% are specialty products which sell at a higher price and are less cyclical in nature than commodity polyolefins. Borealis sells its products to customers in the wire and cable, pipe, automotive, and appliance industries, among others. In 2002, Borealis's gross sales were EUR 3.5 billion (NOK 26 billion), in 2001 EUR 3.7 billion (NOK 30 billion at the exchange rate as of the end of the period), and in 2000 EUR 3.7 billion (NOK 31 billion at the exchange rate as of at the end of the period).

Borealis is a stand-alone company, managed independently by its own supervisory board, executive board and management. It conducts all of its business with Statoil on a commercial, arm's-length basis.

The following table shows Borealis's total annual production volumes (in million tonnes) for major products for 2000, 2001 and 2002.

	YEARS ENDED DECEMBER 31,		
PRODUCT	*2000*	*2001*	*2002*
Ethylene	1,099	1,233	1,242
Propylene	655	620	673
Polyethylene	1,828	1,889	1,851
Polypropylene	1,386	1,566	1,561

Borealis's production capacity for 2002 was 1.5 million tonnes of ethylene, 0.7 million tonnes of propylene, 2.2 million tonnes of polyethylene and 1.4 million tonnes of polypropylene. In addition Borealis has 0.2 million tonnes of production capacity of compounded products, which is a further processing of polyolefins. Borealis has six main production areas in Norway, Sweden, Finland, Belgium, Austria and Portugal, and additional production facilities in Germany, Italy, Brazil and the US.

An ethylene plant and two polyethylene facilities have been constructed in Abu Dhabi by Borealis and the Abu Dhabi National Oil Company, ADNOC. The polyethylene plants are based on Borealis' proprietary Borstar technology and will benefit from locally-sourced, lower cost feedstock. All three facilities started production at the end of 2001. In 2000, Borealis established a new joint venture for polyolefin special products with OPP Petroquimica S.A., at two plants in Brazil and sold its first Borstar license to an external customer for a polyethylene plant completed in Shanghai, China.

Statoil and Borealis collaborate to exploit feedstock synergies, currently achieved in two major projects. At Kårstø, ethane is extracted from the natural gas stream, allowing Statoil both to produce higher volumes of gas and to realize the higher value of ethane as a petrochemical feedstock. For Borealis these ethane volumes are a cost-efficient and secure supply of feedstock that has allowed Borealis to expand its olefin plant in Sweden and guarantee it a long-term supply of ethane at its 50%-owned olefin plant in Norway. At Mongstad, a long-term contract between Statoil and Borealis for liquefied petroleum gases contributed to Statoil's establishment of a plant for fractionating natural gas liquids. For Borealis this contract is designed to provide the necessary feedstock at the 50%-owned plant in Norway as other feedstock agreements have expired.

Navion

In December 2002 Statoil entered into an agreement to sell our shipping subsidiary Navion to Norsk Teekay AS, which is a wholly owned subsidiary of Teekay Shipping Corporation (NYSE: TK). The net sales price is approximately USD 800 million in cash. The effective date for the transaction will be January 1, 2003 and the closing is expected to occur in the second quarter of 2003, pending satisfactory assignment of certain contractual arrangements. Navion's present board of directors and president will continue until the closing. Teekay is a leading provider of international crude and petroleum product transportation services through the world's largest fleet of medium-sized oil tankers. With its operational headquarters in Vancouver, Canada and offices in 11 other countries, Teekay employs more than 4,100 seagoing and shore based staff around the world.

Navion transferred the ownership of the multipurpose vessel *Navion Odin* in December 2002 to Statoil. The vessel, recently renamed *Odin,* has been employed as a terminal tanker for Statoil since January 2002, and the possibility of selling this vessel is being explored by Statoil.

Navion's 50% interest in the *West Navion* drill ship was transferred to Statoil in December 2002. Smedvig ASA is co-owner and operator of this vessel. West Navion finished a drilling contract for Amerada Hess and a short-term assignment for BP in early December 2002, and was thereafter moved to the south of Spain for an expected lay up until late March 2003. The next assignment for the drillship is a deepwater exploration well for ChevronTexaco, in the UK west of Shetland, followed by a contract with Esso Norge AS in the Norwegian Sea. This will keep the unit continuously employed for an estimated period from late March to October 2003. The possibility of divesting this holding is being explored by Statoil.

HEALTH, SAFETY AND ENVIRONMENT

Our operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which we operate, governing, among other things, air emissions, wastewater discharges and discharges to the sea, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety. As with our competitors, liability risks are inherent in our operations. Requirements under environmental laws and regulations can be expected to increase in the future. We also have long-term obligations concerning the decommissioning of operational facilities and the remediation of soil or groundwater at certain of our facilities and liability for waste disposal or contamination on properties owned by others. We have established financial reserves for estimated environmental liabilities based on our current information with respect to those liabilities. We have also made significant expenditures to comply with environmental regulations. However, significant additional financial reserves or compliance expenditures could be required in the future due to changes in law, new information on environmental conditions or other events, and those expenditures could have a material adverse effect on our financial condition or results of operations.

Health, safety and the environment, or HSE, comprises health and working environment, safety and emergency preparedness, the environment and security. Statoil's management system for health, safety and the environment (HSE) forms an integrated part of the group's total management system. In 2002, Statoil's management system relating to corporate governance was certified to the international ISO 9001 standard. In 2002, Statoil was listed in the Dow Jones sustainability index (DJSI).

Our approach to HSE is risk-based, which means that risks are identified, appropriate criteria are established and measures are implemented in order to meet these criteria. We aim to carry out our operations without harm to the environment and according to the principles for sustainable development.

Our corporate indicators for environmental performance include:

- number of unintentional oil spills;
- volume of unintentional oil spills (cubic meters);
- CO_2 emissions, total (tonnes);
- NO_x emissions, total (tonnes); and
- waste recovery ratio.

The EU Directive on Low Sulphur Diesel is intended to reduce emissions of sulphur dioxide resulting from the combustion of certain types of liquid fuels (heavy fuel oil and gas oil). The EU member states must ensure that the use of heavy fuel and gas oil falls below specific levels of sulphur content within their territory. Lower levels of sulphur content than stipulated in the Directive for heavy fuel and gas oil may be imposed by the EU member states separately. Although Norway is not an EU member, as a result of Norway's participation in the EEA and our sales of products to EU member states, our business activities are subject to this Directive. For more information, see—Regulation—EU Regulation below. We have invested more than NOK 1 billion at our two refineries during the last years to meet the new EU-regulations on product quality specifications.

Our CO_2 emissions (from Statoil operations) totaled 8.9 million tonnes in 2002, down from the 9.2 million tonnes emitted in 2001. Our NO_x emissions were 26,300 tonnes in 2002, against 29,500 tonnes in 2001. One important reason for these reductions is good production regularity for operations on the NCS where carbon and nitrogen dioxide emissions as a whole have been reduced even though the amount of produced hydrocarbons has increased. Historically, our NCS emissions of CO_2 and NO_x, measured in tonnes per produced quantity, have been below the NCS average. Compared to other oil regions in the world, however, the NCS is the area with the lowest relative emissions, with an average of 6.4 kg/boe compared to an industry average of 16.4 kg/boe. Changes in laws regulating greenhouse gas emissions could cause us to incur additional expenditures for pollution control equipment.

Our industry is working closely with the Norwegian authorities to eliminate harmful discharges to the sea caused by operations by 2005. The number of unintentional oil spills to the external environment in 2002 was 431 against 414 in 2001. In volume terms, unintentional oil spills in 2002 totaled 200 cubic meters against 246 cubic meters in 2001.

Our corporate indicators within safety are currently:

- fatal accidents;
- frequency of total recordable injuries;
- frequency of lost-time injuries; and
- frequency of serious incidents.

Six fatalities were suffered by Statoil employees and contractors working for Statoil in 2002. The number of serious incidents in 2002 was 297, up from 287 in 2001. The total recordable injury frequency (the number of injuries per million working hours) declined from 6.7 in 2001 to 6.0 in 2002. The lost-time injury frequency (the number of total recordable injuries causing loss of time at work per million working hours) was 2.8 in 2002 against 3.1 in 2001. The frequency of serious incidents, calculated as the number of undesirable events of a very serious nature per million working hours, is 3.8, down from 4.1 in 2001. Our safety indicators include both Statoil and contractors working for Statoil.

During 2001, we completed a technical safety review project, reviewing all major Statoil-operated plants and facilities. The project has brought Statoil to the forefront in developing a systematic approach to reviewing and monitoring the condition of technical safety barriers. The developed methodology is in compliance with the latest regulatory development in the Norwegian Petroleum Directorate. We are now closing the identified gaps so that we comply with the minimum requirements. This will reduce the risk of major incidents and be the basis for improved regularity.

Within the health and working environment area, our principal objective is to secure a sound, challenging and rewarding working environment for the benefit of both the employee and Statoil. The corporate indicator within the health and working environment is the percentage of sickness absences, which came to 3.4% in 2002, the same as in 2001. The general level in Norwegian industry is 7.1% according to an official study (NHO 2001). We also carry out regular health and working environment and organization surveys to track our working environment.

We have in the past incurred penalties for certain environmental violations, but such amounts have not been material to us. In 2002 we incurred no penalty for environmental violations, but we incurred a penalty of NOK 10 million related to a fatality in 1999 at the Statoil-operated Heidrun-platform on the NCS where one contractor lost his life. We may continue to incur additional expenditures for environmental, health and safety compliance in the future and these increases could have an adverse material effect on our operations or financial condition.

TECHNOLOGY, RESEARCH AND DEVELOPMENT

Background

The success of our business is closely connected to our access to and application of advanced technological competence. Operating under the harsh weather and environmentally sensitive conditions in the Norwegian Sea, transporting oil and gas across the deep Norwegian trench and draining complex petroleum reservoirs with high pressures and high temperatures all represent challenges on the NCS that we have overcome. The necessary technological capabilities have to a large extent been developed through our experience as an operator within exploration, project development and operations.

In addition to the technology developed through field development projects, a substantial amount 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 universities, research institutions, other operators and the supplier industry. As of the end of 2002, we had more than 500 employees engaged in our research and development sector, of which approximately 400 hold advanced degrees. Group research development expenditures through our research center in 2000, 2001 and 2002 amounted to NOK 740 million, NOK 620 million and NOK 780 million, respectively. In addition, we have a technical staff that functions within our operating units where we also conduct research and development. Our patent portfolio reflects our range of technological developments, and we actively manage our portfolio to ensure that we protect any proprietary technology we may have.

Technologies and competencies

We invest in technology and competence development as part of our overall short and long-term business development plans. A brief description of some of these developments is given below.

Health, Safety and the Environment. Our overarching ambition within our technology development is to contribute to our HSE goals, which are zero accidents or losses and no harm to people or the environment. Our innovations include:

- minimum flaring through high regularity gas compression; extinguished flare and recovery of vent gas during operation on the Gullfaks field and subsequently on several other fields;
- a method to map and monitor the technical safety level on offshore and land-based facilities. The method is based on the status of safety critical elements, safety barriers, and their intended function in major accident prevention. The technical safety level of all company operated plants and facilities has been reviewed during 2001-2002, and a continuous monitoring program has been implemented;
- a CO_2 removal and underground storage system on the Sleipner field;
- crane simulators to improve lifting operations and minimize probability of accidents in crane operations; and
- use of hydrocarbons as blanket gas in the storage tanks on the Åsgard A FPSO and a liquefication system for volatile organic compounds on shuttle tankers. These technologies virtually eliminate VOC emissions from loading and storage of crude oil.

Improved recovery. Over the past 15 years, new methods and technologies have led to considerable increases in estimated recovery factors. The key technologies include:

- seabed 4-component seismic and time lapse 4-dimensional seismic, which help us identify remaining oil pockets;
- injection of water and/or gas into the reservoirs to increase recovery; and
- drilling long-reach, horizontal and designer wells to allow optimal drainage of reservoirs. We have also used long-reach drilling technology to bring satellite fields on stream.

We are also using microbial recovery methods to improve hydrocarbon recovery. This method is implemented at the Norne field. The long-reach drilling technology has given us the ability to optimize the number of platforms we use in field developments. For example, in the Sleipner West development, we were able to reduce the number of wellhead platforms from three in the planning stage to only one being installed.

Subsea systems and floating production. During the past few years, floating production vessels with extensive subsea facilities have dominated new developments, such as the Norne and Åsgard fields. Floating facilities are less expensive to construct and maintain than traditional platforms for medium water depths. We are one of the world's largest subsea field operators with approximately 220 subsea wells and are a recognized technology-developer within subsea and floating production. We believe that our competence in this area positions us to become a leading deepwater operator.

In order to make subsea projects viable, we have had to address technological hurdles, such as the following:

- use of dynamic risers, or vertical pipelines, to bring the hydrocarbons from the well-head on the sea floor to the floating production vessel;

- use of turret/swivel capabilities on the floating production facilities in different sizes and pressure ratings to enable the risers to connect with the production facility;
- subsea transportation of well streams over long distances; and
- development of complex subsea systems.

Multiphase technology. From the early 1980s, Statoil developed competence within multiphase technology which enables us to transfer different well-stream products simultaneously in single pipelines over gradually longer distances. This competence was crucial in increasing the profitability and reliability of the Troll gas supply by enabling the processing facilities to be moved from the offshore platform to an onshore processing and compression plant. We have since used these technologies in developing the Statfjord satellites, Gullfaks satellites and Åsgard field. Today, our experience from Troll and subsequent developments pave the way for the Snøhvit development and our support for the subsea-to-land concept selection for Ormen Lange. The Snøhvit field is being developed with a 160-kilometer long well stream transfer pipeline from the subsea field installations to the onshore processing plant. Multiphase technologies are central in the economic development of subsea satellite developments on the Norwegian Continental Shelf, a mature oil and gas province, with primarily smaller oil and gas discoveries.

Pipeline materials. When transporting multiphase well stream in pipelines from subsea installations to the processing units, corrosion is a significant challenge. One straightforward solution is to inject chemicals into the well stream at the wellhead and then transport the well stream to the processing facilities through normal carbon steel quality pipelines. Another solution is to transport the multiphase flow through more costly stainless steel pipelines. Neither of these options were feasible due to volume constraints using the chemical injection method and both costs and lead time constraints for stainless steel pipe supply. As a result, and in collaboration with the steel mills and pipeline-laying companies, we developed a 13% chrome steel quality that lowered production costs and enabled quicker development. This development permitted the parallel development of the Gullfaks satellite fields and the Åsgard field.

Production technologies. As an operator of mature fields, we have developed technologies for increasing production capacities of installed infrastructure. The technologies remove bottlenecks experienced through increased fluid loads and gas loads allowing us to maintain high and stable oil production. The technologies can be divided into the following groups:

- enhanced separation (degassing) technologies by compact, high-efficiency inline pre-separation;
- enhanced scrubbing technologies; and
- water separation, handling and disposal technologies.

Through our developments of technologies and competence within these areas we are developing compact technologies that will further improve our competitive edge on production facilities and enhanced oil production. Several of these technologies are now being tested on our offshore facilities and shows promising performance figures.

Gas chain development. We occupy a leading position in offshore construction and operation of oil and gas transportation facilities. We have been laying large diameter subsea pipelines since 1982 and have reduced per meter costs significantly over our 20 years of pipe laying activity. The pipelines can carry increased volume capacity through our concept of stepped pressure rating design, the use of flow improvers for oil pipelines and special coatings designed to reduce drag. In addition, we have developed cost effective multi-diameter pipeline concepts including inspection pigging tools and tie-in solutions. We use remote-controlled subsea vehicles to map and position our pipelines. In case of damage to any pipeline system, we operate the most comprehensive Pipeline Repair System tool pool, ensuring minimum down time in the transportation facility.

We are currently developing a remote operated hot-tap tooling system in order to allow cost effective extension of our subsea pipeline infrastructure. Improved techniques to process high-pressure gas and focusing on gas-to-liquid technology, which is the transformation of natural gas to synthesized gas, such as methanol, are other ongoing developments. Such products are important feedstock for further upgrading to synthetic fuels. Our focus on the commercialization of gas will enable us to upgrade our products and produce fuels such as naphtha and diesel more efficiently.

LNG production. The Snøhvit field will be developed based upon our strong competence and know-how in subsea systems and multiphase transport. Together with Linde, we have developed a new Mixed Fluid Cascade Process (pre cooling, liquefaction and sub cooling using mixed refrigerants). The Snøhvit LNG development will be based upon this technology. Unlike previous LNG plants, the Snøhvit plant will be built on a barge and transported to the site in northern Norway (Melkøya).

Future Technology. In 2001 we benchmarked our technology capabilities and revised our technology strategy. A benchmarking study by Arthur D. Little concluded that we were strong in reservoir management, subsea systems and floating production and pipeline technologies. In all other relevant technologies we were rated comparable to most of our competitors.

In addition to the benchmark study, Statoil also identified its technology needs based upon our ambitions and the business units plans. Building on our leading technology position on the Norwegian continental shelf, the following future technology needs will be prioritized:

- reservoir management (both sandstone and carbonate reservoirs);
- subsea and floating production in harsh environments and on medium water depth; and
- gas chain management (design and operation of large diameter/high pressure offshore pipelines, GTL plants and floating LNG plants).

We are well positioned for future technology developments and implementation of innovative solutions. We are working with enhanced reservoir developments, subsea and floating production, total gas solutions, improved field operations, refining and HSE challenges. Our priorities are:

- Predicting fluid content and reservoir quality before drilling the first exploration well. We have extensive research projects on 3-dimensional prospect analysis, integrated lithology and fluid prediction, 4-component seismic, 3-dimensional seismic data improvement, seismic reservoir monitoring (4-dimensional seismic), reservoir description and modeling of complex reservoirs, advanced recovery methods to improve recovery, including water alternating gas injection, simultaneous water and gas injection, and microbiological enhanced oil recovery methods. We also use real-time drilling analysis with update of reservoir and geology information, based on observations while drilling, to optimize well placement; and

- Subsea processing facilities. We are concentrating our efforts on implementing the subsea processing and multiphase technology in our core area Halten/Nordland off mid-Norway. The Norne field is being evaluated for subsea processing while the Svale and Stær discoveries are evaluated for raw seawater injection. We are also considering the Tyrihans discovery, located near the Åsgard and Kristin fields, as a possible pilot for integration of subsea processing and multiphase technology.

REGULATION

Introduction

The principal Norwegian legislation applying to petroleum activities in Norway and on the NCS is currently the Norwegian Petroleum Act of November 29, 1996, and a number of regulations promulgated thereunder, as well as the Petroleum Taxation Act of June 13, 1975. The Petroleum Act states the principle that the Norwegian State is the owner of all subsea petroleum on the NCS, that the exclusive right to resource management is vested in the Norwegian State and that the Norwegian State alone is authorized to award licenses concerning the petroleum activities.

Under the Petroleum Act, the Norwegian Ministry of Petroleum and Energy is responsible for resource management and for administering petroleum activities on the NCS. The main task of the Ministry of Petroleum and Energy is to ensure that petroleum activities are conducted in accordance with the applicable legislation, the policies adopted by the Storting, and relevant decisions of the Norwegian State. The Ministry of Petroleum and Energy primarily implements petroleum policy through its power to administer the award of licenses, approve operators' field and pipeline development plans, as well as petroleum transport and gas sales contracts. Only those plans that conform to the policies and regulations set by the Storting are approved. As set forth in the Petroleum Act, if a plan involves an important principle or will have a significant economic or social impact, it must also be submitted to the Storting for acceptance before being approved by the Ministry of Petroleum and Energy.

We are not required to submit any decisions relating to our operations to the Storting. However, the Storting's role with respect to major policy issues in the petroleum sector may affect us in two ways: first, when the Norwegian State acts in the capacity as the majority owner of our shares and second, when the Norwegian State acts in its capacity as regulator:

- The Norwegian State's shareholding in us is managed by the Ministry of Petroleum and Energy. The Ministry of Petroleum and Energy will normally determine how the Norwegian State will vote its shares on proposals submitted to general meetings of the shareholders. However, in certain exceptional cases, it may be necessary for the Norwegian State to seek approval from the Storting before voting on a certain proposal. This will normally be the case if we issue additional shares and such issuance would significantly dilute the Norwegian State's holding in us, or if such issuance would require a capital contribution from the Norwegian State in excess of government mandates.
- The Norwegian State exercises important regulatory powers over us, as well as over other companies and corporations. As part of our business, we, or the partnerships to which we are a party, frequently need to apply for licenses and other approvals of various types from the Norwegian State. In respect of certain important applications, such as approvals of major plans for operation and development of fields, the Ministry of Petroleum and Energy must obtain the consent of the Storting before it can approve our or the relevant partnership's application. This may take additional time and affect the content of the decision.

Although Norway is not a member of the European Union, or EU, it is a member of the European Free Trade Association (EFTA). The EU and its member states have entered into the Agreement on the European Economic Area, referred to as the EEA Agreement, with the members of EFTA (except Switzerland).

The EEA Agreement makes certain provisions of EU law binding as between the states of the EU and the EFTA states, and also as between the EFTA states themselves. An increasing volume of regulation affecting us is adopted within the EU and is then applied to Norway under the EEA Agreement. As a Norwegian company operating both within EFTA and the EU, our business activities are regulated by both EU law and EEA law to the extent that EU law has been accepted into EEA law under the EEA Agreement.

The Norwegian Licensing System

The most important type of license awarded under the Petroleum Act is the production license. The Ministry of Petroleum and Energy holds executive discretionary power to award a production license and to determine the terms of that license. In exercising this power, the Ministry of Petroleum and Energy is obliged to implement the policy and objectives of the relevant Storting reports. The Government is not entitled to award a license in an area until the Storting has decided to open the area in question for exploration. A company refusing to abide by the terms of the Ministry of Petroleum and Energy's decision, the Petroleum Act or the license conditions may face severe consequences, including a refusal by the Ministry of Petroleum and Energy to grant a production license or the revocation of a license already granted.

A production license grants the holders an exclusive right to explore for and produce petroleum within a specified geographical area. The licensees become the owners of the petroleum produced from the field covered by the license. Notwithstanding the exclusive rights granted under a production license, the Ministry of Petroleum and Energy has the power to, in exceptional cases, permit third parties to carry out exploration in the area covered by a production license. For a list of our shares in production licenses, see –Business Overview–Operations–Exploration and Production Norway above.

Production licenses are normally awarded through licensing rounds. The first licensing round for NCS production licenses was announced in 1965. Licenses under the 17th licensing round were awarded in May 2002. In recent years, the principal licensing rounds have mainly included licenses in the Norwegian Sea. Licenses in the North Sea area have been awarded in separate yearly rounds. The Ministry of Petroleum and Energy has in a recent report to the Storting announced that this policy will continue.

Traditionally, the Norwegian State only accepted license applications from individual companies, and, therefore, companies were not able to choose their partners in an individual block. In recent years, however, the Norwegian State has, to a larger degree, permitted group applications, enabling us to choose our exploration and development partners.

Production licenses are awarded to joint ventures consisting of several companies. The members of the joint venture are jointly and severally responsible to the Norwegian State for obligations arising from petroleum operations carried out under the license. Once a production license is awarded, the licensees are required to enter into a joint operating agreement and an accounting agreement. The Ministry of Petroleum and Energy decides the form of the joint operating agreements and accounting agreements.

The accounting agreements set out the principles for the accounts of the joint venture and regulate certain economic aspects of the relationship between the partners. The joint operating agreements regulate the relationship between the licensees and are in many ways similar to partnership agreements, although they are expressly exempted from the provisions of the Norwegian Partnerships Act of June 21, 1985.

The governing body of the joint venture is the management committee. Each member is entitled to one seat on the management committee. The management committee's tasks are set out in the joint operating agreement and include setting guidelines for the operator of the field, exercising control over the activities of the operator, and making decisions on the activities of the joint venture. Votes in the management committee are counted by a combination of the number of members in the joint venture and their ownership interest. The number of votes required to make a decision varies from license to license, but a decision is normally reached when a certain number of the members and a percentage of the ownership interests, specified individually in each license, have voted in favor of a proposal. The voting rules are structured so that a licensee holding more than 50% of a license normally cannot vote through a proposal on its own, but will need the support of one or more of the other licensees. In licenses awarded since 1996 where the SDFI holds an interest, the Norwegian State, acting through the SDFI management company, may veto decisions made by the joint venture management committee, which, in the opinion of the Norwegian State, would not be in compliance with the obligations of the license as to the Norwegian State's exploitation policies or financial interests. This veto right has never been used.

Under the joint operating agreements covering licenses awarded prior to 1996, the management company that supervises the Norwegian State's SDFI interest (Petoro AS) has the power, with certain exceptions, to make decisions unilaterally in matters which are assumed to be of political or principal importance, or which may have significant social or socio-economic consequences, if Petoro AS is acting under the direction of its shareholder. Prior to the establishment of the SDFI management company, Statoil held this right, which was exercised three times, most recently in 1988. In autumn 2002, the Storting approved that the individual license groups may substitute this special voting rule for SDFI with a veto rule similar to the veto rules which have applied in licenses awarded since 1996. Such a substitution is subject to approval from the Ministry of Petroleum and Energy.

The day-to-day management of a field is the responsibility of an operator appointed by the Ministry of Petroleum and Energy. The operator is in practice always a member of the joint venture holding the production license, although this is not legally required. The terms of engagement of the operator are set out in the joint operating agreement. Under the joint operating agreement, an operator normally may terminate its engagement upon six months' notice. The management committee may, however, with the consent of the Ministry of Petroleum and Energy, instruct the operator to continue performing its duties until a new operator has been appointed. The management committee can terminate the operator's engagement upon six months' notice on an affirmative vote by all members of the management committee other than the operator. A change of operator requires the consent of the Ministry of Petroleum and Energy. In special cases the Ministry of Petroleum and Energy can order a change of operator.

Licensees are required to submit a plan for development and operation, or PDO, to the Ministry of Petroleum and Energy for approval. In respect of fields of a certain size, the Storting has to accept the PDO before it is formally approved by the Ministry of Petroleum and Energy. Until the PDO has been approved by the Ministry of Petroleum and Energy, the licensees cannot, without the prior consent of the Ministry of Petroleum and Energy, undertake material contractual obligations or commence construction work.

Production licenses are normally awarded for an initial exploration period which is typically six years, but which can be for a shorter period or for a period of a maximum of ten years. During this exploration period the licensees must meet a specified work obligation set out in the license. The work obligation will typically include seismic surveying and/or exploration drilling. If the licensees fulfill the obligations set out in the production license, they are entitled to require that the license be prolonged for a period specified at the time when the license is awarded, typically 30 years. The right to prolong the license does not apply as a main rule to the whole of the geographical area covered by the initial license, but only to a percentage, typically 50%. The size of the area which must be relinquished is determined at the time the license is awarded. In special cases, the Ministry of Petroleum and Energy may extend the duration of a production license.

If natural resources other than petroleum are discovered in the area covered by a production license, the Norwegian State may decide to delay petroleum production in the area. If such a delay is imposed, the licensees are, with certain exceptions, entitled to a corresponding extension of the period of the license. To date, such a delay has never been imposed.

The Norwegian State may, if important public interests are at stake, direct us and other licensees on the NCS to reduce production of petroleum. From July 15, 1987 until the end of 1989, licensees were directed to curtail oil production by 7.5%. Between January 1, 1990 and June 30, 1990, licensees were directed to curtail oil production by 5%. In 1998, the Norwegian State resolved to reduce Norwegian oil production by about 3%, or 100,000 barrels per day. In March 1999, the Norwegian State decided to increase the reduction to 200,000 barrels per day. In the second quarter of

2000, the reduction was brought back to 100,000 barrels per day. On July 1, 2000, this restriction was removed. By a royal decree of December 19, 2001, the Norwegian government decided that Norwegian oil production should be reduced by 150,000 barrels per day from January 1, 2002 until June 30, 2002. This amounted to roughly a 5% reduction in output.

Licensees may buy or sell interests in production licenses subject to the consent of the Ministry of Petroleum and Energy and the approval of the Ministry of Finance of a corresponding tax treatment position. The Ministry of Petroleum and Energy must also approve direct or indirect transfers of interest in a license, including changes in the ownership of a licensee, if they result in someone's obtaining a decisive influence over the licensee. There are in most licenses no pre-emption rights in favor of the other licensees. The SDFI, or the Norwegian State, as appropriate, however, still holds pre-emption rights in all licenses.

A license from the Ministry of Petroleum and Energy is also required in order to establish facilities for transport and utilization of petroleum. When applying for such licenses, the owners, which are in practice licensees under a production license, must prepare a plan for installation and operation. Licenses to establish facilities for transport and utilization of petroleum will normally be awarded subject to certain conditions. Typically, these conditions require the facility owners to enter into a participants' agreement. The ownership of most facilities for transport and utilization of petroleum in Norway and on the NCS are organized as a joint venture of a group of license holders, and the participants' agreements are similar to the joint operating agreements entered into among the members of joint ventures holding production licenses.

Licensees are required to prepare a decommissioning plan before a production license or a license to establish and use facilities for transportation and utilization of petroleum expires or is relinquished, or the use of a facility ceases. The decommissioning plan must be submitted to the Ministry of Petroleum and Energy no sooner than five and no later than two years prior to the expiry of the license or the cessation of the use of the facility, and must include a proposal for the disposal of facilities on the field. On the basis of the decommissioning plan, the Ministry of Petroleum and Energy makes a decision as to the disposal of the facilities. If the Ministry of Petroleum and Energy requires the removal of the facility, the Norwegian State will pay its share of the expenses based on a formula set out in the Act relating to Contributions to the Removal of Facilities on the Continental Shelf of 1986. The contribution formula is designed to reimburse licensees for their inability under Norwegian tax law to deduct removal costs from taxable income.

The Norwegian State is entitled to take over the fixed facilities of the licensees when a production license expires, is relinquished or revoked. In respect of facilities on the NCS, the Norwegian State decides whether any compensation will be payable for facilities thus taken over. If the Norwegian State should choose to take over onshore facilities, the ordinary rules of compensation in connection with expropriation of private property apply.

Licenses for the establishment of facilities for transport and utilization of petroleum typically include a clause whereby the Norwegian State can require that the facilities be transferred to it free of charge at the expiration of the license period.

The Norwegian Gas Sales Organization

Until recently, gas sales contracts with buyers for the supply of Norwegian gas were required by Norwegian authorities to be concluded with the Gas Negotiation Committee, known as the Gassforhandlingsutvalget or GFU.

The structural changes taking place in the European gas market prompted the Norwegian State to consider whether changes to the gas resource management system on the NCS could contribute to further enhancing the efficiency for Norwegian gas producers. Accordingly, the Norwegian State has, by royal decree dated June 1, 2001, decided to abandon the GFU system and put in place a system whereby the individual licensees can manage the disposal of their own gas. Necessary adjustments in legislation, license agreements and other existing contracts in order to implement the new system were finalized during 2002. For more information, see above under —Business Overview—Operations—Natural Gas—Recent Changes to the Norwegian Gas Resource Management System.

From January 1, 2003 the ownership of the Zeepipe, Franpipe, Europipe II, Åsgard Transport, Statpipe, Oseberg Gas Transport and Vesterled joint ventures and Norpipe AS was transferred to a new joint venture called Gassled.

Together with the approval of Gassled, Norwegian authorities have by a royal decree of December 20, 2002 issued regulations for access to and tariffs for capacity in the upstream gas transportation system. There are three main considerations behind the regulations. Firstly it shall, together with the law adopted by the Storting in June 2002, implement the Gas Directive of the European Union. Further it shall establish a system for access to the upstream gas transportation system that is compatible with company based gas sales from the Norwegian Continental Shelf. Thirdly, it shall provide for the new ownership structure of the upstream gas transportation system (Gassled).

Parts of the regulations have a general application and parts – including the tariffs – are applicable only to the upstream gas transportation system owned by the Gassled joint venture.

The new regulations set the main principles for access to the upstream gas transportation system. The access regime consists of a regulated primary market where the right to book free capacity, in accordance with regulations, is allocated to users with a duly substantiated reasonable need for transportation of natural gas. Further the access regime consists of a secondary market where the capacity can be transferred between the users after the allocation in the primary market if the need for transportation changes.

The capacity in the primary market will be released and booked through Gassco AS on the web. Spare capacity will be released for pre-defined time periods at announced points in time and with specific time limits for reservations. If the reservations exceed the spare capacity the spare capacity, will be allocated based on a distribution formula. However, consideration shall in case of spare capacity first be given to the owners' duly substantiated needs for capacity, limited to twice the owner's equity interest in the upstream pipeline network in question.

Based upon an authorization given under the new regulation, tariffs for use of capacity in Gassled are to be determined by the Ministry of Petroleum and Energy. The Ministry's policy for determining the tariffs is to avoid excessive returns being created on the capital invested in the transportation system, allowing the return on the Norwegian petroleum activity to be taken out on the fields instead of in the transportation systems. The tariffs are to be paid for booked capacity and not in respect of the actually transported volume.

HSE Regulation

Petroleum operations in Norway are subject to extensive regulation with regard to health, safety and the environment, or HSE. Under the Petroleum Act, which is in this respect administered by the Ministry of Labor and Government Administration, all petroleum operations must be conducted in compliance with a reasonable standard of care, taking into consideration the safety of employees, the environment and the economic values represented by installations and vessels. The Petroleum Act specifically requires that petroleum operations be carried out in such a manner that a high level of safety is maintained and developed in accordance with technological developments.

Licensees and other persons engaged in petroleum operations are required to maintain at all times a plan to deal with emergency situations. During an emergency, the Ministry of Labor and Government Administration may decide that other parties should provide the necessary resources, or otherwise adopt measures to obtain the necessary resources, to deal with the emergency for the account of the licensees.

The Norwegian Petroleum Directorate has adopted a wide range of regulations that set forth detailed requirements as to the HSE aspects of petroleum operations. In addition, a number of regulations adopted under other acts, such as the Working Environment Act of 1977 and the Pollution Act of 1981, apply to our operations. Violations of such regulations can lead to fines.

In our capacity as a holder of licenses under the Petroleum Act, we are subject to strict statutory liability in respect of losses or damages suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of our licenses. This means that anyone who suffers losses or damages as a result of pollution caused by any of our NCS license areas can claim compensation from us without needing to *demonstrate that the damage is due to any fault on our part. If the pollution is caused by a force majeure event, a Norwegian court may reduce the* level of damages to the extent it considers reasonable.

Taxation of Statoil

We are subject to ordinary Norwegian corporate income tax as well as to a special petroleum tax relating to our offshore activities. We are also subject to a special carbon dioxide emissions tax. Under our production licenses we are obligated to pay royalties and an area fee to the Norwegian State. Set forth below is a summary of certain key aspects of the Norwegian tax rules that apply to our operations.

Corporate income tax. Our profits, both from offshore oil and natural gas activities and from onshore activities, are subject to Norwegian corporate income tax. The corporate income tax rate is currently 28%. Our profits are computed in accordance with ordinary Norwegian corporate income tax rules, subject to certain modifications that apply to companies engaged in petroleum operations. Gross revenue from oil production and the value of lifted stocks of oil are determined on the basis of norm prices which are decided on a monthly basis by the Petroleum Price Board, a body whose members are appointed by the Ministry of Petroleum and Energy, and published quarterly. The Petroleum Taxation Act provides that the norm prices shall correspond to the prices that could have been obtained in case of a sale of petroleum between independent parties in a free market. When adopting norm prices, the Petroleum Price Board takes into consideration a number of factors, including spot market prices and contract prices within the industry.

The maximum rate for depreciation of development costs related to offshore production installations and pipelines is 16 2/3% per year. The depreciation starts when the expense is incurred. Exploration costs may be deducted in the year in which they are incurred. Most financial items are allocated to onshore and offshore activities in proportion to the remaining tax balances of assets related to onshore and offshore activities, respectively. There is an adjustment factor allowing companies with an equity ratio of more than 0.2 to allocate a higher share of net financial items to the offshore tax regime.

Any NCS losses may be carried forward indefinitely against subsequent income earned. Any onshore losses may be carried forward for 10 years. Fifty percent of losses relating to activity conducted onshore in Norway may be deducted from NCS income subject to the 28% tax rate. Losses from foreign activities may not be deducted against NCS income. Losses from offshore activities are fully deductible against onshore income.

By use of group contributions between Norwegian companies in which we hold more than 90% of the shares and the votes, tax losses and taxable income can, to a great extent, be offset. Group distributions are not deductible in our offshore income.

As a result of tax credits granted against tax levied on dividends received from Norwegian companies, we are effectively not subject to tax on dividends from Norwegian companies. Dividends from foreign companies are normally subject to income tax in both Norway and the foreign company's state of residence. If Norway has entered into a tax treaty with the foreign company's state of residence, the tax of the foreign company's state of residence is normally limited to a withholding tax at a specified rate. We are entitled to credit such withholding taxes against Norwegian income tax payable on the dividends.

Furthermore, if we own more than 10% of the capital of a foreign company, we are also entitled to a tax credit for a proportionate part of the foreign company's income tax. This tax credit is only available against Norwegian taxes payable on the dividends received from the company. To obtain credit for taxes paid in the foreign company's state of residence, we must provide documentation proving that income taxes actually have been paid in the foreign state, and that the foreign taxes are creditable against Norwegian taxes.

Special petroleum tax. A special petroleum tax is levied on profits derived from petroleum production and pipeline transportation on the NCS. The special petroleum tax is currently levied at a rate of 50%. The special tax is applied to relevant income in addition to the standard 28% income tax, resulting in a 78% marginal tax rate on income subject to petroleum tax. The basis for computing the special petroleum tax is the same as for income subject to ordinary corporate income tax, except that onshore losses are not deductible against the special petroleum tax, and a tax-free allowance, or uplift, is granted at a rate of 5% per year. The uplift is computed on the basis of the original capitalized cost, including capitalized interest, of offshore production installations. The uplift may be deducted from taxable income for a period of six years starting the year in which the capital expenditures are incurred. Unused uplift may be carried forward indefinitely. Special provisions apply to investments made prior to 1992.

Carbon dioxide emissions tax. A special carbon dioxide emissions tax applies to petroleum activities on the NCS. The tax is currently NOK 0.75 per standard cubic meter of gas burned or directly released, and per liter of oil burned.

Area fee. After the expiration of the initial exploration period, the holders of production licenses are required to pay an area fee. The amount of the area fee is set out in regulations promulgated under the Petroleum Act. In respect of most of the production licenses, the initial annual area fee is currently NOK 7,000 per square kilometer. The annual area fee is increased yearly by NOK 7,000 until it reaches NOK 70,000 per square kilometer.

Royalty. We and other oil companies have an obligation to pay a royalty to the Norwegian State for oil produced on fields for which a plan for development and operation was approved prior to January 1, 1986. The royalty varies from 8% to 16% of the gross production value, and increases with the level of production. The Ministry of Petroleum and Energy may on six months' notice require that the royalty be paid in kind by delivery of petroleum. The Ministry of Petroleum and Energy has exercised this right so that we are currently required to pay royalty by delivering oil. Such royalty oil is repurchased by us at a calculated market price. No royalty is charged on natural gas or NGL production.

In a 1999 Government proposal, the Norwegian State announced that the remaining royalty obligations would be gradually abolished. The obligation to pay royalty currently only remains for the Gullfaks and Oseberg fields and will be abolished completely by the end of 2005.

EU Regulation

EU Gas Directive

Fundamental changes are now taking place in the organization and operation of the European gas market, with the objective of opening up national markets to competition and integrating them into a single internal market for natural gas. It is difficult to predict the effect of liberalization measures on the evolution of gas prices, but the main objective of the single gas market is to bring greater choice and reduced prices for customers through increased competition.

The EU Gas Directive, Directive 98/30/EC, was to be implemented in the national legislation of the EU member states by August 10, 2000. The Directive was included in the EEA Agreement in June 2002 and was incorporated into Norwegian legislation in 2002.

Main Provisions of the Gas Directive. The Directive establishes common rules for the transmission, distribution, supply and storage of natural gas. It lays down the rules relating to the organization and functioning of the natural gas sector, access to the market, the operation of systems, and the criteria and procedures applicable to the granting of authorizations for transmission, distribution, supply and storage of natural gas. To these ends, it imposes a series of obligations on EU member states and other states implementing the Directive.

The main purpose of the Directive is to require owners of gas pipelines to open up their transport systems, including systems within domestic markets, to eligible customers, such as distribution companies and large industrial customers in order to bring greater competition into the European gas market. Eligible customers are to be specified by EU member states but must include at least all gas-fired power generators (subject to optional thresholds for combined heat and power producers) and all other final customers consuming more than a specified annual volume of gas. From August 10, 2000, the specified annual volume of gas was 25 mmcm. This will decrease to 15 mmcm on August 10, 2003 and to 5 mmcm on August 10, 2008. This decrease in volumes required to qualify as an eligible customer is intended to open national gas markets. The Directive requires that from August 10, 2000, the definition of eligible customers must result in an opening of the market equal to at least 20% of the total national gas consumption. This will increase to 28% on August 10, 2003 and to 33% on August 10, 2008.

In addition, the Directive contains provisions relating to upstream pipeline networks. EU member states are required to take the necessary measures to ensure that natural gas undertakings and eligible customers, wherever they are located, are able to obtain access to upstream pipeline networks, including facilities supplying technical services incidental to such access in accordance with the Directive, except for the parts of such networks and facilities which are used for local production operations at the site of a field where the gas is produced. Access shall be provided in a manner determined by the EU member state in accordance with the relevant legal instruments. EU member states shall apply the objectives of fair and open access, achieving a competitive market in natural gas and avoiding any abuse of a dominant position, taking into account security and regularity of supplies, capacity which is or can reasonably be made available and environmental protection. Ownership in the Norwegian pipeline network has been consolidated into a common ownership structure, the joint venture Gassled. See above under —The Norwegian Gas Sales Organization.

If a natural gas undertaking encounters, or expects that it would encounter, serious economic and financial difficulties because of its take-or-pay commitments accepted in one or more gas purchase contracts, an application for a temporary derogation from the access to the system may be sent to the member state or its designated authority. Applications must be presented on a case-by-case basis either before or after refusal of access to the system and must be accompanied by all relevant information on the nature and extent of the problem and on the efforts taken to solve the problem. Derogations granted by a member state or its competent authority must be notified to the EC Commission, which may request that the decision to grant the derogation be amended or withdrawn. If this request is not complied with, a final decision is taken by the Commission assisted by a committee of the Member States and/or the Council.

New Proposals. On February 3, 2002, the Council adopted a common position to amend the Directive and to extend its provision. Common positions will be sent to the European Parliament for a second reading in accordance with the decision procedure. Final adoption of the amended Directive is expected to take place during the first half of 2003.

The main points covered by the Council's compromise are as follows:

- *The timetable for liberalization of the gas market follows a two-step approach, with deadlines for the full opening of the market on* July 1, 2004 for non-household users and July 1, 2007 for household users.

- Provisions on unbundling of transmission and distribution system operators are included essentially in order to prevent cross-subsidies that would be detrimental to competition in the future liberalized environment. The amendment proposal provides that transmission and distribution system operators should be independent, in terms of their legal form as well as organization and decision-making, from activities not relating to transmission and distribution. Legal and management unbundling of transmission undertakings will take place upon entry into force of the amended Directive and legal unbundling at distribution level as from the date of full market opening.

No specific amendments are proposed to Article 23 of the Directive, which regulates access to upstream pipeline networks.

COMPETITION

The integrated oil and gas industry is characterized by intense competition for customers, production licenses, operatorships, capital and experienced human resources. The industry is currently subject to several important influences, which we must deal with effectively if we are to remain competitive and achieve our goals.

Consolidation. In the past few years, the strategic and competitive landscape of the oil and gas industry has been transformed by a wave of mergers and acquisitions. This activity has been driven mainly by the need to enhance shareholder returns, to respond to the growing competitive threat of national oil companies, and to achieve greater operational scale to capture new, attractive business opportunities. In 1998, the following mergers took place: BP/Amoco, Exxon/Mobil and Total/Fina. In 1999, further merger activity involved BPAmoco/ARCO, Repsol/YPF and TotalFina/Elf. In addition, Norsk Hydro acquired all the outstanding shares in Saga Petroleum after which we acquired certain Saga assets. In 2000, Chevron and Texaco announced a merger, while ENI acquired British Borneo and Lasmo. In 2001, Phillips announced the acquisition of Tosco and a merger with Conoco.

Deregulation. The establishment of free, competitive and integrated markets has become an important governmental objective in many countries. Initiatives such as the Directive aim to alter the framework of laws and institutions that govern the European gas industry. This includes, among others, the obligation on owners or operators of gas transportation facilities to offer non-discriminatory access to third parties wishing to use the infrastructure, and the opening of the industry to new participants. The relationship between customers and suppliers of gas is expected to change as a result of greater competition, with the emphasis on bringing down costs for energy purchasers.

International Opportunities. Significant shifts in the global political climate have provided oil and gas companies with access to previously inaccessible hydrocarbon resources in regions such as the former Soviet Union and the Middle East. New licensing rounds such as in the deepwater offshore sector of Western Africa have also created new exploration and development opportunities. Most recoverable oil and gas resources are believed to be located in such areas, where the political risk mostly remains high. Long-term growth in our reserves and production will require us to capture international opportunities in the face of significant competition.

Technological Advances. Technological innovations in the oil and gas industry have improved the industry's performance in finding and developing hydrocarbon resources. Exploration success rates have improved, field life and recovery rates from existing and marginal fields have been increased, and full project cycle costs have generally been reduced. These have been achieved by applying advanced technology more effectively. In addition, the exploitation of hydrocarbon reserves in remote deepwater and harsh environment offshore regions has been made possible by improvements in subsea development capabilities and sophisticated floating production and storage units. In general, there is comparable access to technology across the industry, and, in order to achieve our strategic and financial goals, we will need to compete on the basis of applying available technology to complex projects in the most skillful manner.

Environmental and Social Concerns. Oil and gas companies are facing increasing demand to conduct their operations in the context of and consistent with environmental and social goals. Investors, customers and governments are more actively following companies' performance on environmental responsibility and human rights, including performance with respect to the development of alternative and renewable sources of energy.

Organizational Structure

The following table sets forth our significant subsidiaries, equity interest and the subsidiaries' country of incorporation. In all cases our voting interest is equivalent to our equity interest.

SUBSIDIARY	*EQUITY INTEREST%*	*COUNTRY OF INCORPORATION*
Statoil Norge AS	100	Norway
Statoil Danmark A/S	100	Denmark
Statoil AB	100	Sweden
Statoil (U.K.) Limited	100	Great Britain
Statoil North America Inc	100	United States of America
Statoil Apsheron AS	100	Norway
Statoil Nigeria AS	100	Norway
Navion ASA (sold, effective January 1, 2003)	100	Norway
Statoil Coordination Center N.V.	100	Belgium
Statoil Venezuela AS	100	Norway
Statoil Sincor AS	100	Norway
Statoil Investments Ireland Ltd.	100	Ireland
Statoil Forsikring AS	100	Norway
Statoil Exploration (Ireland) Ltd.	100	Ireland
Statoil (Orient) Inc.	100	Switzerland
Statoil Pernis Invest AS	100	Norway
Mongstad Refining DA	79	Norway
Statoil Metanol ANS	82	Norway
Statoil Angola Block 17 AS	100	Norway
Statoil Dublin Bay AS	100	Norway

Property, Plants and Equipment

Our principal executive offices are located at Forusbeen 50, N-4035, Stavanger, Norway, and comprise 103,000 square meters of office space, and are owned by Statoil.

We have interests in real estate in numerous countries throughout the world, but no one individual property is significant to us as a whole. We have no significant ongoing construction projects or plans to add new office space. See Item 4—Information on the Company for a description of our significant reserves and sources of oil and natural gas.

Item 5 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 on Form 20-F.

Operating Results

Overview of Our Results of Operations

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

We divide our operations into the following four business segments:

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

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

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

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

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

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

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

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

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

In 2000, we divested our exploration interests in the Gulf of Mexico. We recorded a provision of NOK 500 million against this sale in 1999, the year in which we decided to divest these interests. In 2000 we recorded a loss of NOK 200 million as we sold our marketing activities in Statoil Energy in the US.

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

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

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

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

Factors Affecting Our Results of Operations

Our results of operations substantially depend on:

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

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

- recent volatility in oil prices, possible or continued actions by the Norwegian Government, or possible or continued actions by members of the Organization of Petroleum Exporting Countries affecting price levels;
- increasing competition for exploration opportunities and operatorships; and
- the deregulation of the natural gas markets, which may cause substantial changes to the existing market structures and to the overall level and volatility of prices.

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

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

	2000	*2001*	*2002*
Crude oil (USD per barrel Brent blend)	28.5	24.4	25.0
Natural gas(1) (NOK per scm)	0.99	1.22	0.95
Norwegian kroner/US dollar average daily exchange rate	8.81	8.99	7.97

(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, income taxes and minority interest and our net income assuming activity at levels achieved in 2002.

Sensitivities on 2002 results

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

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

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

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

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

Fluctuating foreign exchange rates can have a significant impact on our operating results. Our revenues are mainly denominated in US dollars, while our operating expenses and income taxes payable accrue to a large extent in NOK. We seek to manage this currency mismatch by issuing or swapping long-term debt into US dollars and engaging in foreign currency hedging. We manage the risk arising from our interest rate exposures through the use of interest rate derivatives, primarily interest rate swaps, based on a benchmark for the interest reset profile of our total loan portfolio. See —Liquidity and Capital Resources—Risk Management and Item 11—Quantitative and Qualitative Disclosures about Market Risk. In general, an increase in the value of the US dollar against the NOK can be expected to increase our reported earnings. However, because our currently debt outstanding is in US dollars, the benefit to Statoil would be offset in the near term by an increase in the value of our debt, which would be recorded as a financial expense and, accordingly, would adversely affect our net income. See —Liquidity and Capital Resources—Risk Management and Item 11—Quantitative and Qualitative Disclosures about Market Risk.

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

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

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

Total purchases of oil and NGL from the Norwegian State by Statoil amounted to NOK 72,298 million (374 mmboe), NOK 53,291 million (265 mmboe) and NOK 42,290 million (173 mmboe) in 2002, 2001 and 2000, respectively. See Item 7—Major Shareholders and Related Party Transactions—Major Shareholders—The Norwegian State as Shareholder—Marketing and Sale of the SDFI's Oil and Gas.

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

Historically, our revenues have largely been generated from the production of oil and natural gas from the NCS. Norway imposes a 78% marginal tax rate on income from offshore oil and gas activities. See Item 4—Information on the Company—Regulation—Norwegian Regulation—Taxation of Statoil—Corporate income tax. Our earnings volatility is moderated as a result of the significant amount of our Norwegian offshore income that is subject to a 78% tax rate in profitable periods and the significant tax assets generated by our Norwegian offshore operations in any loss-making periods. A significant part of the taxes we pay are paid to the Norwegian State. In June 2001, the Storting enacted certain changes in the taxation of petroleum operations. For details, see Item 4—Information on the Company Regulation—Norwegian Regulation—Taxation of Statoil.

Combined Results of Operations

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

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

Years ended December 31, 2002, 2001 and 2000

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

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

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

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

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

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

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

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

We record revenues from sales of production based on lifted volumes. The term "production" as used in this section means lifted volumes. The term "production" used in Item 4 —Information on the Company, means produced volumes, which include lifted volumes adjusted for under- and overlifting. Overlifting and underlifting positions are a result of Statoil lifting either a higher or a lower volume of oil than that represented by our total equity interest in that field.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Business Segments

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

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

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

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

E&P Norway

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

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

(1) Reserve replacement rate, finding cost and finding and development costs are calculated as a rolling three-year average based on our proved reserves estimated in accordance with the SEC definitions.

(2) The reserve replacement rate is defined as the total additions to proved reserves, including acquisitions and disposals, divided by produced reserves.

(3) Our unit production (lifting) cost is calculated by dividing operating costs relating to the production of oil and natural gas by total production (lifting) of petroleum in a given year.

Years ended December 31, 2002, 2001 and 2000

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

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

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

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

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

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

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

Exploration expense in 2002 was NOK 1.4 billion, compared to NOK 2.0 billion in 2001 and NOK 1.3 billion in 2000. The 30% decrease in expensed exploration from 2001 to 2002 and the 53% increase from 2000 to 2001 are consistent with changes in expenditure levels due to variations in exploration activity. Fifteen exploration and appraisal wells were completed in 2002, of which ten resulted in discoveries. In addition, five extensions on production wells were completed, of which four resulted in discoveries. In comparison, 18 exploration and appraisal wells and two extensions on production wells were completed in 2001, of which 15 resulted in discoveries, and 14 exploration and appraisal wells were completed in 2000, of which 10 resulted in discoveries. Furthermore, exploration expense in 2002 included NOK 0.5 billion of expenditure capitalized in previous years, but written off in 2002, compared to NOK 0.7 billion of expenditure written off in 2001. In 2000, exploration expense included NOK 0.4 billion of exploration expenditure capitalized in previous years, but written off in 2000.

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

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

International E&P

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

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

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

Years ended December 31, 2002, 2001 and 2000

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

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

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

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

Depreciation, depletion and amortization expenses were NOK 2.4 billion in 2002, compared to NOK 3.4 billion in 2001 and NOK 1.7 billion in 2000. The 30% decrease in 2002 as compared to 2001 is primarily related to the NOK 2.0 billion impairment of the LL652 oil field in Venezuela in 2001, partly offset by a NOK 0.8 billion impairment charge for writing down the LL652 field in 2002. The 98% increase in 2001 as compared to 2000 is primarily related to the NOK 2.0 billion writedown of the LL652 oil field in Venezuela in 2001. The 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 0.9 billion in 2002, compared to NOK 0.7 billion in 2001 and NOK 1.8 billion in 2000. The 40% increase in exploration expenditure from 2001 to 2002 was mostly related to increased exploration activity in 2002, and the 61% decrease in exploration expenditure from 2000 to 2001 was primarily due to lower exploration activity in 2001. We expect the exploration expenditure to increase significantly in 2003.

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

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

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

Natural Gas

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

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

Years ended December 31, 2002, 2001 and 2000

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

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

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

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

Manufacturing and Marketing

Years ended December 31, 2002, 2001 and 2000

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

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

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

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

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

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

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

Other operations

Years ended December 31, 2002, 2001 and 2000

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

Liquidity and Capital Resources

Cash Flows Provided by Operating Activities

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

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

Cash Flows used in Investing Activities

Net cash flows used in investing activities amounted to NOK 16.8 billion in 2002, as compared to NOK 12.8 billion for 2001 and NOK 16.0 billion for 2000. Gross investments, defined as additions to property, plant and equipment and capitalized exploration expenditures, declined from NOK 18.7 billion in 2000 to NOK 17.4 billion in 2001 and increased to NOK 20.1 billion in 2002. Gross investments also include investments in intangible assets and long-term share investments.

The 31% increase in net cash flows used in investment activities from 2001 to 2002 is primarily related to higher investment levels in E&P Norway, International E&P and Manufacturing and Marketing, as well as reduced cash flow from sale of assets compared to 2001.

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

Cash Flows used in/provided by Financing Activities

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

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

Working Capital

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

Liquidity

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Impact of Inflation

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

Critical Accounting Policies

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

Proved oil and gas reserves. Statoil's oil and gas reserves have been estimated by its experts in accordance with industry standards under the requirements of the US Securities and Exchange Commission (SEC). An independent third party has in all material aspects verified Statoil's estimates. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements but not on escalations based upon future conditions.

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

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

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

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

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

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

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

New Accounting Standards

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

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

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

RISK MANAGEMENT

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

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

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

Strategic Market Risks

We are exposed to strategic risks, which we define as long-term risks fundamental to the operation of our business. Strategic market risks are reviewed by our Corporate Risk Committee with the objective of avoiding 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. Currency options, purchased in the OTC market for a premium, provide us with the right to buy or sell an agreed amount of currency at a specified exchange rate at the end of a specified period.

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

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

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

Set forth below are our capital expenditures in our four principal business segments for 1999-2001. We have also set forth these capital expenditures for each segment as a percentage of our total capital expenditure for the relevant period.

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

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

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

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

For further information, see Item 11–Quantitative and Qualitative Disclosures about Market Risk.

Derivatives and Credit risk

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

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

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

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

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

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

Operational Risks

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

Research and Development

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

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

Trend Information

Return on Capital Employed and Capital Expenditure Targets

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

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

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

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

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

Reconciliation of normalized ROACE calculation 2002

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

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

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

We are also committed to pursuing the following objectives to enhance operational efficiencies from 2002 to 2004:

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

All targets are based on a continued organic development of Statoil and exclude possible effects related to acquisitions, which may affect our targets materially and cause us to revise our targets as a result of the impact of such acquisitions. We are seeking to expand our international portfolio and are actively pursuing potential opportunities, including possible acquisitions of properties or businesses. If we are successful in making such acquisitions, and no assurances can be given that we will be, the new projects we acquire will require additional capital expenditure and will increase our finding and development expenditure. It is likely that such acquisitions will be in the exploratory or development phase and not in the production phase, and thus could materially affect our net return in proportion to our average capital employed over the next few years. These projects may also have different risk profiles than our existing portfolio. In addition, although we have no current intension to issue additional equity, we may require additional debt or equity financing to undertake or consummate future acquisitions or projects, which would affect our average capital employed and other key components of our targets. These and other effects of such acquisitions could result in our having to revise some or all of our targets with respect to ROACE, capital expenditure amounts and allocations, unit production costs, finding and development costs, reserves replacement rate and production. For more information about the risks related to acquisitions and other growth, see Item 3—Key Information—Risk Factors.

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

Our ROACE in any financial period and our ability to meet our target ROACE will be affected by our ability to generate net income. Our level of net income, including our targets to reduce production costs and finding and development costs, and our expected organic production growth are subject *to numerous risks and uncertainties as described in Item 3—Key Information—Risk Factors and —Operating Results—Factors Affecting Our Results of* Operations. These risks include, among others, fluctuation in demand, retail margin, changes in our oil and gas production volumes and trends in the *international* oil industry.

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

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

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

Years 2003 – 2004

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

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

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

E&P Norway. Based on our current business plan, we estimate that E&P Norway's investments will require about NOK 28.8 billion over the period 2003-2004. A substantial portion of our 2003-2004 capital expenditure is allocated to the ongoing development projects in Kvitebjørn, Kristin and Snøhvit. For more information on these projects, see Item 4–Information on the Company–Business Overview–Operations–Exploration and Production Norway.

International E&P. We estimate that International E&P's investments will require approximately NOK 23 billion over the period 2003-2004. We currently estimate that the substantial portion of our 2003-2004 capital expenditure will be allocated to the ongoing and planned development projects: Azeri-Chirag-Gunashli including the Baku-Tbilisi-Ceyhan pipeline, Shah Deniz including the South Caucasus pipeline, Dalia, Kizomba A, B and C, South Pars phase 6-8 and Corrib. For more information on these projects, see Item 4–Information on the Company–Business Overview–Operations–International Exploration and Production.

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

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

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

- exploration and appraisal results, such as favorable or disappointing seismic data or appraisal wells;
- cost escalation, such as higher exploration, production, plant, pipeline or vessel construction costs;
- government approvals of projects;
- government awards of new production licenses;
- partner approvals;
- development and availability of satisfactory transport infrastructure;
- development of markets for our petroleum and other products including price trends;
- political, regulatory or tax regime risk;
- accidents 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.

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

Item 6 Directors, Senior Management and Employees

Directors and Senior Management

Management

Our management is vested in our board of directors and our Chief Executive Officer. The Chief Executive Officer is responsible for the day-to-day management of our company in accordance with the instructions, policies and operating guidelines set out by our board of directors.

The business address of the directors, executive officers and corporate assembly members is c/o Statoil at the corporate headquarters in Stavanger, Norway.

Board of Directors

Our articles of association require that our board of directors consist of a minimum of five and a maximum of 11 members. Currently, we have 9 directors. The members of the board have extensive and relevant experience from Norwegian and international business activities. Members of the board of directors serve two-year terms. The members of the board are primarily recruited from the Norwegian business community, and our executive management is not represented on the board. As required by Norwegian companies law, our employees are entitled to be represented by three board members. The corporate assembly has elected the current board of directors. The current term of office for the directors expires in May 2004, other than Kaci Kullmann Five whose term of office expires in August 2004. There are no directors' service contracts that provide for benefits upon termination of employment.

Our directors, their place of residence, age and their position are identified below.

NAME	*PLACE OF RESIDENCE*	*AGE*	*POSITION*
Leif Terje Løddesøl	Oslo, Norway	67	Chairman
Kaci Kullmann Five	Oslo, Norway	51	Director
Finn A Hvistendahl	Oslo, Norway	61	Director
Grace Skaugen	Oslo, Norway	49	Director
Eli Sætersmoen	Oslo, Norway	38	Director
Knut Åm	Stavanger, Norway	59	Director
Marit Bakke (1)	Bergen, Norway	37	Director
Stein Bredal (1)	Stavanger, Norway	53	Director
Bjørn Erik Egeland (1)	Bergen, Norway	59	Director

(1) Elected by the employees.

Leif Terje Løddesøl was elected to the board of directors in May 2002. Mr. Løddesøl was in the period from 1996 to 2002 Chairman of Statoil's Corporate Assembly. He was in the periods 1973 to 1980 and 1988 to 2000 president and Chief Executive Officer of Wilh. Wilhelmsen ASA. In the period 1980 to 1988 Mr. Løddesøl was President and Chief Executive Officer of Den norske Creditbank. Currently, Mr. Løddesøl is Chairman of the Committee of Gard (mutual protection and indemnity insurance), and a member of the Executive Committee of International Chamber of Shipping. Mr. Løddesøl was involved in developing the Norwegian oil legislation as a legal advisor in the Foreign Office. He has previously held positions as President of the Norwegian Bankers Association and the Norwegian Ship-owners Association.

Kaci Kullmann Five was elected to the board of directors in August 2002. Ms. Five is a public affairs consultant. In the period 1981 to 1997 she was a member of the Norwegian Parliament and in the period 1989 to 1990 she was minister for Trade and Shipping in the Norwegian Government. Ms. Five was in the period 1991 – 1994 leader of the Norwegian Conservative Party. Currently, Ms. Five is a director of the boards of Norsk Medisinaldepot ASA and Asker og Bærum Budstikke ASA and a member of the control committee of Carnegie Fondsforsikring ASA and the Norwegian Nobel Committee appointed by the Norwegian Parliament.

Finn A Hvistendahl was elected to the board of directors in April 1999 and re-elected in May 2002. Mr. Hvistendahl is a business development *consultant in Oslo. Previously, he held senior positions in Norsk Hydro and was Chief Executive Officer of Den norske Bank ASA. Currently, he is* Chairman of the board of directors of KreditTilsynet (The Banking, Insurance and Securities Commission of Norway) and director of Dyno Nobel AS.

Grace Skaugen was elected to the board of directors in May 2002. Ms. Skaugen is Director, Corporate Finance – Orkla Enskilda Securities, Oslo, a position held since 1994. Previously, she was a Special Project Advisor to AS Aircontactgruppen, Oslo, a Venture Capital Consultant to Fearnley Finance Ltd., London and a Microelectronics Research Officer – Columbia University, New York. Ms. Skaugen has previously also been director to the boards of Hilmar Rekstens Almennyttige Fond (Art Foundation), Geelmuyden-Kiese and member of the WWF Council and Fundraising Committee. Currently, Ms. Skaugen is Chairman of the board of AS Netkubator, Oslo.

Eli Sætersmoen was elected to the board of directors in May 2002. Eli Sætersmoen holds a "Master of Science in Petroleum Engineering" from the Norwegian Institute of Technology, Trondheim, Norway, and a "Master of Business Administration" from Amos Tuck School of Business Administration, Dartmouth College New Hampshire, USA. Eli Sætersmoen is Chief Financial Officers and Executive Vice President in Selvaag Gruppen (Selvaag Group of Companies) in Oslo. Previously, she held positions in Cell Network ASA, Orkla Securities, GE-Capital, London, McKinsey & Company and in Norsk Hydro ASA. In McKinsey & Company she was responsible for strategic developments for the oil industry. Eli Sætersmoen has been a board member and Deputy Chairman of the board of SND (Government Organization for Regional Development). She is a board member of several boards including A/S Selvaagbygg and Selvaag Invest.

Knut Åm was elected to the board of directors in April 1999 and re-elected in May 2002. Mr. Åm is a former Vice President of Phillips Petroleum. Previously he was the Chairman of the board of the Norwegian Oil Industry Association and Hitec ASA and President of the Norwegian Petroleum Society and the Norwegian Geological Council.

Marit Bakke was elected to the board of directors in April 2000 and re-elected in May 2002 and serves as an employee-elected representative to the board. Ms. Bakke is a Staff Engineer within petroleum technology. Ms. Bakke represents the joint list presented by the Norwegian Association for Supervisors, the Norwegian Society of Chartered Engineers and the Norwegian Society of Engineers. She was formerly a full-time union official for her union and has worked with Statoil since 1992.

Stein Bredal was elected to the board of directors in April 2000 and re-elected in May 2002 and serves as an employee-elected representative to the board. He is Materials Coordinator on the Gullfaks field and has worked with Statoil since 1985. Mr. Bredal represents the Confederation of Vocational Unions where he is a full-time union official.

Bjørn Erik Egeland was elected to the board of directors in April 2002 and serves as an employee-elected representative. Mr. Egeland was also a director in our board in the period 1996 to 2000. He is a Logistics Manager on the Gullfaks field and has worked with Statoil since 1985. Previously, he worked as manager on the Statfjord field, which Statoil later took over, since 1981. Mr. Egeland represents the Norwegian Association for Supervisors.

Executive Committee

An executive committee is not required under Norwegian corporate law, but we established the committee as part of the overall organization of our company. Each member of the executive committee supervises separate business areas or staff units. Although the CEO is responsible for making decisions on important matters not requiring the decision of the board of directors, as well as all matters referred to him by the board, the executive committee has an advisory role. The board of directors has granted three members of the executive committee, Olav Fjell, Inge K Hansen and Erling Øverland, the power of procuration, which under Norwegian law essentially empowers each member to act on behalf of our company in all matters relating to our normal operations.

The members of our executive committee, their place of residence, age and position are identified below.

NAME	*PLACE OF RESIDENCE*	*AGE*	*POSITION*
Olav Fjell	Asker, Norway	51	President and Chief Executive Officer
Inge K Hansen	Oslo, Norway	57	Chief Financial Officer and Executive Vice President, Corporate Center and Services
Henrik Carlsen	Stavanger, Norway	56	Executive Vice President, Exploration and Production Norway
Richard John Hubbard	Sevenoaks, England	52	Executive Vice President, International Exploration and Production
Peter Mellbye	Stavanger, Norway	53	Executive Vice President, Natural Gas
Erling Øverland	Stavanger, Norway	50	Executive Vice President, Manufacturing and Marketing
Elisabeth Berge	Stavanger, Norway	48	Executive Vice President, Communications & Public Affairs
Terje Overvik	Stavanger, Norway	51	Executive Vice President, Technology

Olav Fjell has served as President and Chief Executive Officer since 1999. Mr. Fjell previously worked as the Managing Director of Postbanken from 1995 to 1999 and as Executive Vice President of Den norske Bank from 1991 to 1995 after having served in various positions in the bank since 1987. He is also currently the chairman of the board of NSB, the Norwegian railway system. Mr. Fjell received a MS in Business from the Norwegian School of Economics and Business Administration in 1975.

Inge K Hansen has served since 2000 as Chief Financial Officer and as Executive Vice President of Corporate Center and Services. Mr. Hansen has previously worked as the Managing Director of Orkla Finans from 1994 to 2000 and as General Manager of Bergen Bank/Den norske Bank from 1985 to 1994. He is also currently a member of the board of The Norwegian School of Management BI. Mr. Hansen received his MS in Business from the Norwegian School of Economics and Business Administration in 1970.

Henrik Carlsen has served as Executive Vice President of E&P – Norway since 1999. Employed at Statoil since 1974, Mr. Carlsen has held numerous positions. Most recently, Mr. Carlsen served as Senior Vice President of Natural Gas Production and Transport from 1995 to 1999, as Vice President of Statfjord from 1992 to 1995 and as Vice President of Technology E&P from 1990 to 1992. He graduated from the Norwegian University of Technology in 1970 and the University of Bergen in 1974.

Richard John Hubbard has served as Executive Vice President of International E&P since November 1, 2000. Mr. Hubbard has 25 years of international experience in the oil and gas industry. Prior to joining Statoil, Mr. Hubbard was President of BP Amoco Brazil. Previously, he held positions as Head of Exploration in Monument Oil and Gas and Planning Manager in British Petroleum. He received a Ph.D. in geology from Stanford University in California, United States in 1985.

Peter Mellbye has served as Executive Vice President of Natural Gas since 1992. Employed at Statoil since 1982, Mr. Mellbye has held numerous positions. Most recently, Mr. Mellbye served as President of the Natural Gas business segment from 1990 to 1992 and as Vice President of Natural Gas Marketing from 1982 to 1990. Currently, Mr. Mellbye is a member of the board of Siemens AS and of Verbundnetz Gas AG in Germany. Mr. Mellbye graduated from the Universities of Oslo and Bergen with a degree in political science in 1977.

Erling Øverland has served as Executive Vice President of Manufacturing and Marketing since 2000. Employed at Statoil since 1976, Mr. Øverland has previously served as Chief Financial Officer from 1995 to 2000, and as President of Refining and Marketing from 1994 to 1995 and as President of Statoil Norge AS from 1992 to 1994. He was also a member of the board of directors of Hafslund ASA and the Foundation for Scientific and Industrial Research of the Norwegian University of Science and Technology. Currently, Mr. Øverland is Chairman of the board Navion and Vice Chairman of the board of Borealis. He also is Chairman of the Norwegian Federation of Process Industry and member of the executive committee in the Employers' Organization (NHO). He graduated in 1976 with a MS in Business from the Norwegian School of Economics and Business Administration.

Elisabeth Berge has served as Executive Vice President of Communications & Public Affairs since July 1, 2001 and she was also responsible for the State's direct financial interest since 1999 until this function was transferred to Petoro in 2001. Employed at Statoil since 1990, Ms. Berge has previously served as Senior Vice President of our Natural Gas business segment from 1996 to 1999, as Executive Assistant to the Executive Board from 1993 to 1996 and as Marketing Manager of Natural Gas Marketing from 1990 to 1993. Currently, Ms. Berge is a member of the board of Kavli Holding. Ms. Berge received her MBA from the Norwegian School of Economics and Business Administration in 1978 and an MA in Economics from the University of California in 1979.

Terje Overvik has served as Executive Vice President for Technology since August 19, 2002. He holds a PhD from the former Norwegian Institute of Technology (NTH) in Trondheim, he also worked there as an associate professor and researcher before joining Statoil in 1983. Mr. Overvik has held a number of different posts in Statoil, including platform manager for the Statfjord A platform in the North Sea from 1992-2000, and vice president for Statfjord operations from 2000-2002.

Corporate Assembly

Our corporate assembly consists of 12 members. The general meeting elects 8 members, and our employees elect an additional four members.

Our corporate assembly has a duty to control the board of directors and our Chief Executive Officer in their management of our company. Norwegian companies law imposes a fiduciary duty on the corporate assembly to our shareholders. The corporate assembly communicates its recommendations concerning the board of directors' proposals about the annual accounts, balance sheets, allocation of profits and coverage of losses of our company to the general meeting. The corporate assembly renders decisions, based on the board's proposals, in matters related to substantial investments, measured in terms of the total resources of our company, and matters regarding rationalizations or restructurings of the operations of the company which will result in a major change or reorganization of the workforce. The corporate assembly is also responsible for electing and removing our board of directors. The term of office of the corporate assembly members is two years and the current term of office expires in May 2004.

Set forth below is a list of the current members of our corporate assembly, their place of residence, age and occupation.

NAME	*PLACE OF RESIDENCE*	*AGE*	*POSITION*
Anne Kathrine Slungård	Trondheim, Norway	39	Mayor, Municipality of Trondheim, Norway
Kjell Bjørndalen	Skotselv, Norway	56	Chairman of the Norwegian Trade Union; Fellesforbundet
Kirsti Høegh Bjørneset	Ålesund, Norway	40	Attorney, Tømmerdal & Co, Ålesund, Norway
Erlend Grimstad	Oslo, Norway	45	Executive Vice President, Umoe AS, Oslo, Norway
Gunnar Mathiesen	Oslo, Norway	52	Senior Advisor, Geelmuyden-Kiese, Oslo, Norway
Wenche Meldahl	Stavanger, Norway	57	Chief Executive Officer, Øglænd Pioner A/S, Sandnes, Norway
Anita Roarsen	Oslo, Norway	45	Finance Director, Aon Grieg AS, Oslo, Norway
Asbjørn Rolstadås	Trondheim, Norway	59	Professor at NTNU (Technical and Scientific University of Norway, Trondheim), Norway
Arvid Færaas	Vormedal, Norway	40	Union official, NOPEF (Statoil)
Einar Arne Iversen	Stavanger, Norway	40	Union official, NITO (Statoil)
Hans M Saltveit	Stavanger, Norway	31	Union official, YS (Statoil)
Åse Karin Staupe	Stavanger, Norway	36	Project Manager, NIF (Statoil)

Compensation

Compensation to the Board of Directors, Executive Committee and Corporate Assembly

In 2002, total remuneration of NOK 381,000 was paid to the members of the corporate assembly, NOK 1,625,000 to the board of directors and NOK 19,905,704 to the members of the executive committee, excluding Olav Fjell's compensation.

Olav Fjell, our Chief Executive Officer, received a salary and other remuneration of NOK 3,770,000 in 2002. Starting from 2002, Mr. Fjell is eligible to a bonus limited to 30% of base salary. Payment of the bonus depends on a total evaluation of achieved results, based on added value for shareholders, profitability, achievements in the area of Health, Environment and Safety (HES) and other relevant conditions for the development of Statoil. The board of directors and the Chief Executive Officer have jointly agreed that the Chief Executive Officer will not receive a bonus for 2002.

If Mr. Fjell resigns at the request of the Board, he is entitled to severance pay equaling two annual salaries. This severance arrangement also applies to Erling Øverland, Inge K Hansen and Peter Mellbye. The chief executive and these three executive vice presidents are also entitled, under specific terms, to a pension after reaching the age of 60. The pension paid will amount to 66% of their pensionable salaries.

A performance pay system has been established for the other members of the executive committee, vice presidents and other key managers and professionals. This entails a variable remuneration based on pre-set goals. The scheme allows for a bonus of up to 20% of base salary for results that clearly exceed these goals.

Pension Benefits

We provide pension benefits to the majority of the group's employees entitling them to defined future pension benefits. The amount of benefits provided are dependent on the number of years of their pensionable service, their final salary level, and the size of public insurance benefits.

Employees in the parent company, and the majority of Norwegian subsidiaries, are insured mainly through Statoil's pension funds. These funds are organized as independent trusts. The major part of their assets are invested in Norwegian and foreign bonds and shares, as well as in real estate in Norway. Employees in subsidiaries are insured through their own pension funds or through collective pension schemes in various insurance companies.

The projected benefit obligation at the end of the year is NOK 13,025 million whereas the estimated fair value of plan assets at the end of the year amounts to NOK 12,480 million.

Employee Incentive Plan

Statoil ASA has a common bonus scheme for its employees. This bonus scheme will have a maximum payment of 5%, calculated on each employee's base salary.

Board Practices

In keeping with business practice in Norway, the board of directors of Statoil does not act through committees, with the effect that Statoil does not have an audit committee or a remuneration committee.

Employees

As of December 31, 2002, we had 17,115 employees, of whom we employed 11,214 in Norway. The remaining 5,901 people were employed outside of Norway, with more than 100 employees in each of Poland, Ireland, Denmark, Sweden, Lithuania, Latvia, Estonia and the UK.

The tables below set forth the number of employees in each of our business areas at the end of 2000, 2001 and 2002, and the numbers of employees inside and outside of Norway. The table does not include employees of affiliated companies.

	NUMBER OF EMPLOYEES								
	DECEMBER 31, 2000			DECEMBER 31, 2001			DECEMBER 31, 2002		
	NORWAY	OUTSIDE NORWAY	TOTAL	NORWAY	OUTSIDE NORWAY	TOTAL	NORWAY	OUTSIDE NORWAY	TOTAL
E&P-Norway	5,452	0	5,452	5,603	0	5,603	5,774	0	5,744
International E&P	247	234	481	276	245	521	355	243	598
Natural Gas	807	163	970	844	130	974	805	132	937
Manufacturing and Marketing	1,780	5,099	6,879	1,744	5,262	7,006	1,632	5,461	7,093
SDFI	20	0	20	5	0	5	0	0	0
Other Operations	2,547	59	2,606	2,522	55	2,577	2,648	65	2,713
Total	**10,853**	**5,555**	**16,408**	**10,994**	**5,692**	**16,686**	**11,214**	**5,901**	**17,115**

We intend to limit our recruitment to growth areas and focus on young professionals and specific key competencies. We have a set of union/employer agreements at national, industry and local levels, which is the typical way of organizing union agreements in Norwegian industry. We take part in agreements at the national level as a member of the Norwegian Employers Association and at the industry level as a member of Norwegian Oil Industry Association and the Federation of Norwegian Process Industry, both of which are branches of the Norwegian Employers Association.

At the local level, we have agreements with the trade unions. Our employees are represented by five trade unions: the Norwegian Oil and Petrochemical Workers Union, Confederation of Vocational Unions, Norwegian Association for Supervisors, Norwegian Society of Chartered Engineers and Norwegian Society of Engineers. Approximately 77% of our employees are union members. The unions are entitled to appoint three members to our board of directors. Labor contracts with the unions were renewed in 2002 for a period of two years. Overall, we consider our relations with our employees as well as the unions to be good, and there are currently no major labor disputes.

We continually seek to improve the skills and development of our employees in each of our business units. Employees participate in various training programs. Our training organization provides different development programs, and we cooperate with selected colleges and universities as well as other educational and research institutions in Norway and abroad.

Share Ownership

The number of shares owned by the members of the board of directors, the executive committee, and the corporate assembly is shown below. Board members and members of the executive committee, including closely related parties, who own shares are set forth below. Each owns less than 1% of the Statoil shares outstanding.

BOARD OF DIRECTORS	*NO. OF SHARES OWNED AS OF MARCH 14, 2003*
Knut Åm	14,594
Leif Terje Løddesøl	242
Kaci Kullmann Five	1,242
Finn A Hvistendahl	2,947
Bjørn Erik Egeland	1,243
Stein Bredal	165
Marit Bakke	165

EXECUTIVE COMMITTEE	*NO. OF SHARES OWNED AS OF MARCH 14, 2003*
Olav Fjell	11,003
Inge K Hansen	12,403
Henrik Carlsen	1,243
Richard John Hubbard	1,243
Peter Mellbye	1,243
Erling Øverland	2,464
Elisabeth Berge	1,603
Terje Overvik	825

Members of the corporate assembly owned as of March 14, 2003 a total of 1,738 shares.

Item 7 Major Shareholders and Related Party Transactions

Major Shareholders

The Norwegian State as a Shareholder

The following table shows the number of Statoil shares owned by the Norwegian State as of December 31, 2002. The State did not buy or sell any shares in the period from December 31, 2002 to March 14, 2003. We have not been notified of any other beneficial owner of 5% or more of our ordinary shares as of March 14, 2003.

	NUMBER OF SHARES	% OF SHARES
Kingdom of Norway	1,770,168,598	80.84(1)

(1) Based upon 2,166,143,626 ordinary shares outstanding and 23,441,974 ordinary shares held in treasury.

In June 2001, in connection with the initial public offering of our ordinary shares, we established a sponsored American Depositary Receipt facility with The Bank of New York as depositary pursuant to which American Depositary Receipts (ADRs) representing American Depositary Shares (ADSs) are issued. We have been informed by The Bank of New York that in the United States, as of March 14, 2003, there were 10,924,912 ADRs outstanding (representing approximately 0.50% of the ordinary shares outstanding). As of March 14, 2003 there were 45 registered holders resident in the United States.

On April 26, 2001 the Storting (the Norwegian parliament) authorized the Ministry of Petroleum and Energy to reduce its shareholding in us by up to one-third of our value through the sale of its existing shares or the issuance by us of new shares to new investors. Following the initial public offering, the Norwegian State owned 80.84% of the shares of Statoil. This percentage was calculated based on shares authorized and issued.

The Norwegian State does not have any different voting rights from the rights of other ordinary shareholders as described in Item 10–Additional Information–Memorandum and Articles of Association. However, as the Norwegian State, acting through the Minister of Petroleum and Energy, continues to own in excess of two-thirds of the shares in us following completion of the initial public offering, it has the sole power to amend our articles of association. As long as the Norwegian State owns more than one-third of our shares, it will be able to prevent any amendments to our articles of association. In addition, as a majority shareholder, the Norwegian State has the power to control any decision at general meetings of our shareholders that requires a majority vote, including the election of the majority of the corporate assembly, which has the power to elect our board of directors and approve the dividend proposal by the board of directors.

The Norwegian State has stated that as one of our several shareholders, it will concentrate on issues relating to return on capital and dividend policy, emphasizing long-term profitable business development and the creation of value for all shareholders. The Norwegian State will exercise its ownership position based on a coordinated ownership strategy to maximize the value of the Norwegian State's aggregate holdings in Statoil and the SDFI.

The Norwegian State as a Regulatory Authority

As a corporation based in Norway, we are subject to the laws and regulations of the Kingdom of Norway. Changes to relevant laws and regulations could have a significant impact on our operations. Various agencies and departments of the Kingdom of Norway exercise regulatory functions over our activities. The Ministry of Petroleum and Energy also exercises important regulatory powers over all petroleum operations of the companies of the NCS, including those of Statoil. For additional information about the Ministry of Petroleum and Energy's role, see the section entitled Item 4–Information on the Company–Regulation–Norwegian Regulation. A number of other agencies and departments, such as the Norwegian Petroleum Directorate, the Ministry of Finance, the Ministry of Labor and Government Administration, the Ministry of the Environment and the Norwegian Pollution Control Authority, exercise regulatory powers which affect important parts of our operations.

A significant part of the taxes we pay are paid to the Norwegian State, see Item 4–Information on the Company–Business Review–Regulation–Norwegian Regulation–Taxation of Statoil.

The Norwegian State's Direct Participation in Petroleum Operations on the NCS

The Norwegian State's policy as an owner has been, and continues to be, to ensure that petroleum activities create the highest possible value for the Norwegian State. Initially, the Norwegian State's participation in petroleum operations was organized mainly through us. In 1985, the Norwegian State established the State's direct financial interest, or SDFI, through which the Norwegian State has taken direct participating interests in licenses and petroleum facilities on the NCS. As a result, the Norwegian State holds interests in a number of licenses and petroleum facilities in which we also hold interests. Until June 17, 2001, we acted as manager of the SDFI's interests in licenses and petroleum facilities.

As a result of changes in global markets and competitive conditions in the petroleum industry, the Norwegian State implemented a strategic review of its oil and gas policy in 2000. Based on the results of this strategic review, the Norwegian State prepared a plan to restructure its petroleum holdings on the NCS that was approved by the Storting on April 26, 2001. The key elements of the restructuring plan include:

- the partial privatization of Statoil;
- a restructuring of the Norwegian State's SDFI assets, including the sale of SDFI assets to us and to other oil and gas companies and an exchange of interests in certain oil and gas infrastructure between the SDFI and us;
- the establishment of procedures to ensure that, as long as the Norwegian State instructs us to do so, we will continue to market and sell the State's oil and gas, together with our oil and gas, following the partial privatization;
- the transfer of responsibility over and management of the SDFI's assets from us to a new company which will be wholly-owned by the Norwegian State; and
- the transfer of operational responsibility over certain pipelines on the NCS from us to a new company which, for the time being, is wholly owned by the Norwegian State.

Sale of Petroleum Assets between the Norwegian State and us

The Norwegian State owns directly a substantial portion of the total oil and gas reserves on the NCS, through the SDFI. As a part of the Norwegian State's decision in 2001 to restructure its oil and gas assets on the NCS, the Norwegian State sold a portion of its SDFI assets to us and other oil and gas companies. In a single transaction with the Norwegian State, we purchased a significant number of production license interests and certain pipeline ownership interests from the Norwegian State.

As a part of the single transaction with the Norwegian State we transferred to the Norwegian State a 33.25% interest in Statpipe (including a 33.25% interest in Statpipe's processing plant at Kårstø), a 25% interest in Norsea Gas A/S (Norpipe) and a 35% interest in the crude oil terminal at Mongstad.

The transaction between Statoil and the SDFI was completed on 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 and, as a result, we made a net balancing cash payment to the Norwegian State of NOK 25.0 billion and incurred NOK 13.6 billion in subordinated debt to the Norwegian State, calculated as of January 1, 2001. The agreement relating to the purchase and sale of SDFI assets is incorporated by reference hereto as Exhibit 4(a)(ii).

Marketing and Sale of the SDFI's Oil and Gas

Introduction. We have historically marketed and sold the Norwegian State's oil and gas as a part of our 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 our articles of association by adding a new article which requires us to continue to market and sell the Norwegian State's oil and gas together with our 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.

The Norwegian State has a coordinated ownership strategy to maximize the aggregate value of its ownership interests in Statoil and the Norwegian State's oil and gas. This is reflected in the owner's instruction, which contains a general requirement that, in our activities on the NCS we are required to take account of these ownership interests in decisions that may affect the execution of this marketing arrangement.

The owner's instruction sets forth specific terms for the marketing and sale of the Norwegian State's oil and gas. The principal provisions of the owner's instruction are as set forth below.

Objectives. The overall objective of the marketing arrangement is to obtain the highest possible total value for our oil and gas and the Norwegian State's oil and gas and ensure an equitable distribution of the total value creation between the Norwegian State and us. In addition, the following considerations are important:

- create the basis for making long-term and predictable decisions concerning the marketing and sale of the Norwegian State's oil and gas;
- ensure that results, including costs and revenues related to our oil and gas and the Norwegian State's oil and gas, are transparent and possible to measure; and
- ensure an efficient and simple administration and execution.

Our tasks. Our tasks under the owner's instruction are to market and sell the Norwegian State's oil and gas and to carry out all necessary tasks, other than those carried out jointly with other licensees under the production license, in relation to the marketing and sale of the Norwegian State's oil and gas, including, but not limited to, the responsibility for processing, transport and marketing. In the event that the owner's instruction is terminated, in whole or in part, by the Norwegian State, the owner's instruction provides a mechanism under which contracts for the marketing and sale of the Norwegian State's oil and gas to which we are a party may be assigned to the Norwegian State or its nominee. Alternatively, the Norwegian State may require that the contracts be continued in our name, but to the effect that in the underlying relationship between the Norwegian State and us, the Norwegian State receives all rights and obligations related to the Norwegian State's oil and gas.

Costs. The Norwegian State does not pay us specific consideration for executing these tasks, but the Norwegian State reimburses us for its proportionate share of certain costs, which under the owner's instruction may be our actual costs or an amount specifically agreed.

Price mechanisms. For sales of the Norwegian State's natural gas, both to us and to third parties, the 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.

Lifting mechanism. As part of the coordinated ownership strategy, a lifting mechanism for the Norwegian State's and our oil and gas is established in accordance with rules set out in the owner's instruction.

To ensure a neutral weighting between the Norwegian State's and our natural gas volumes, a list has been established for deciding the priority between each individual field. To decide the ranking, a mathematical optimization model is used which describes existing and planned production facilities, infrastructure and processing terminals where the Norwegian State and we have ownership interests. The list yields a result giving the highest total net present value for the Norwegian State's and our oil and gas. In the evaluation, the following objective criteria shall, among other things, apply:

- the effect of the draw on the depletion rate;
- identification of time critical fields;
- influence on oil/liquid fields with associated gas needing gas disposal; and
- free capacity and flexibility in transportation systems and onshore facilities.

The different fields are ranked in accordance with the assumed total value creation of the Norwegian State and us, assuming all of the fields meet our profitability requirements if we participate as a licensee, and the Norwegian State's profitability requirements if the State is a licensee. The list is updated annually or more frequently if incidents occur that may significantly influence the ranking. Within each individual field where both the Norwegian State and we are licensees, the Norwegian State and we will deliver volumes and share income in accordance with our respective participating interests.

The Norwegian State's oil and NGL are lifted together with our oil and NGL in accordance with applicable lifting procedures for each individual field and terminal.

Withdrawal or Amendment. The Norwegian State may utilize its position as majority shareholder of Statoil, at any time, to withdraw or amend the instruction requiring us to market and sell the SDFI oil and natural gas together with our own.

Petoro - The New SDFI Management Company

Since the establishment of Statoil in 1972, the participation of the Norwegian State in production licenses and facilities for transport and utilization of petroleum took place entirely through us. As of January 1, 1985, the Norwegian State's participation was reorganized through the establishment of the SDFI. Through this reorganization the Norwegian State began taking a direct financial interest in production licenses. The establishment of the SDFI entailed a transfer of a substantial part of our participation in most of our then-existing licenses to the SDFI, although formally such licenses continued to be held wholly in our name. Since its establishment in 1985, the SDFI has taken shares in most licenses awarded. The SDFI also holds shares in a number of oil and gas pipelines and land-based terminal facilities.

We were, until June 17, 2001, registered as licensee for all SDFI shares in licenses. In accordance with a decision made in an extraordinary general meeting on May 10, 2001, we were until this time also the manager of the SDFI shares in these licenses on behalf of the Norwegian State. Where both the SDFI and we had an interest in the same license, the department managing our interest also managed the SDFI interest. In fields with SDFI interests only, the interests were managed by a separate unit that we established for this purpose. Our tasks as the manager of the SDFI's interests have included attending management committee meetings for both the SDFI's and our own share in licenses, and votes cast by us in management committee meetings have represented both the SDFI's and our own interests in the licenses. We have also been responsible for marketing the petroleum of which the Norwegian State becomes the owner through the SDFI shares in production licenses.

In connection with the restructuring, the Norwegian State on May 9, 2001 established a new State-owned company, Petoro AS, which took over responsibility for and the management of the SDFI assets as licensee, in accordance with a new chapter of the Petroleum Act. The Norwegian State continues to be the beneficial owner of these assets. We continue to market and sell the Norwegian State's oil and gas together with our own oil and gas, pursuant to the owner's instruction described under –Marketing and Sale of the SDFI's Oil and Gas above. One of the tasks of Petoro AS is to supervise our compliance with the owner's instruction.

Petoro AS does not own any of the oil and gas produced under the license interests it holds, does not receive any revenues from sales of the State's oil and gas, and is not be permitted to obtain an operator role. However, Petoro AS may become a participant in new licenses awarded by the Norwegian State.

At an extraordinary general meeting of shareholders held on May 10, 2001, the Norwegian State, as our sole shareholder, approved a resolution instructing us to continue managing the SDFI's interest until June 17, 2001. We entered into a contract with Petoro AS pursuant to which we agreed to assist Petoro AS in managing the SDFI's interests for a transition period that lasted until July 1, 2002. During this transition period, Petoro AS gradually assumed all management functions related to the SDFI. Pursuant to the terms of the contract, Petoro AS reimbursed us for our expenses associated with our management role activities during the transition period, including employee and overhead costs.

Gassco – The New Gas Transportation Operating Company

In connection with the restructuring of the Norwegian State's oil and gas interests, on May 14, 2001 the Norwegian State established a separate company, Gassco AS, which on January 1, 2002 took over as operator of the natural gas transportation system previously operated by us. Gassco AS is wholly owned by the Norwegian State. The owners of the infrastructure systems appointed Gassco AS as the new operator.

The transfer of the operatorship to Gassco AS was made without consideration and does not affect existing arrangements with respect to ownership or access to the natural gas transportation system or tariffs for transport. However, in accordance with the joint venture agreements relating to each of the gas transportation assets, the operator is entitled to be reimbursed for its costs as operator. Accordingly, since Gassco AS was appointed as operator,

we no longer receive such reimbursement, and we will, as other users of the infrastructure, be required to pay our portion of Gassco AS's expenses associated with the operation of the natural gas pipelines in which we hold interests.
Gassco AS has entered into contracts with us for each infrastructure joint venture, pursuant to which we will carry out technical operating activities on behalf of Gassco AS, such as system maintenance, for which we will receive reimbursement of costs. Either Gassco or we may terminate without cause each of these contracts, except the contract for the Statpipe joint venture, after five years. Either Gassco or we may also terminate the part of the Statpipe contract, which refers to the offshore pipelines, after five years. Currently, Gassco may terminate the part of the Statpipe contract that refers to the Kårstø plant, at any time, provided that 2/3 of the owners, representing more than 2/3 of the ownership interests, have supported such termination. The Technical Services Agreement, dated February 27, 2002, is incorporated by reference hereto as Exhibit 4(a)(i).

As from January 1, 2003 the ownership of the Zeepipe, Franpipe, Europipe II, Åsgard Transport, Statpipe, Oseberg Gas Transport and Vesterled joint ventures and Norpipe AS were transferred to a new joint venture called Gassled. This also includes the terminals in Statpipe and Vesterled, the Europipe Receiving Facilities and the Europipe Metering Station. The ownership interest in Zeepipe Terminal JV and Dunkerque Terminal DA will also be adjusted. Gassco AS is the operator of the Gassled joint venture.

Our initial direct ownership interest will be 20.379% in Gassled (21.133% including our indirect interest through our 25% holding in Norsea Gas AS), 9.98571% in Zeepipe Terminal JV and 13.24635% in Dunkerque Terminal DA. From January 1, 2011, our ownership interest in Gassled will be reduced to 17.179% due to an increased ownership interest for SDFI. In addition, our ownership interest in Gassled may also change as a result of inclusion of existing or new infrastructure or if Gassled undertakes further investments without participation from its owners in the same ratio as their ownership interests in Gassled. For more information on the Gassled joint venture, see Item 4–Information on the Company–Business Overview–Operations–Natural Gas.

Related Party Transactions

Transactions with the Norwegian State

For a description of transactions with the Norwegian State, see –Major Shareholders–The Norwegian State as a Shareholder above.

Transactions with other entities controlled by the Norwegian State

Norsk Hydro. On May 27, 1999, we entered into an agreement with Norsk Hydro ASA for the purchase of certain assets of Saga Petroleum for NOK 8.1 billion and 24.66% of the aggregate cash portion of the joint offer made by Norsk Hydro and Statoil for the shares in Saga Petroleum. This consideration was paid in the form of 28,977,320 Saga shares that we held, with the remaining portion in cash. In return for this purchase price, we received the following assets: 6% in Production Licenses 050 and 050B (Gullfaks); 3% in Production License 085 and 085B (Troll); 2.04% in the Troll Oil pipeline joint venture; 13% in Production License 199; 5% in Production License 091; 2.82% in Production License 089 (outside) (corresponding to a 3% interest in the Snorre Unit, based on current participating interest); 1.875% in Production License 037 (Statfjord); 15% in Production License 128 (Norne) (corresponding to a 9% interest in the Norne field); 9% in Production License 128B (Norne); 15% in Production License 215; 5% in Production License 213; and debt in the amount of the difference between the purchase price and the value of the transferred shares. Prior to Norsk Hydro's acquisition of Saga Petroleum, the Norwegian State owned 51% of Norsk Hydro's share capital. Following the acquisition, the Norwegian State owns 43.8% of Norsk Hydro's share capital.

We hold interests in a number of the licenses and petroleum facilities in which Norsk Hydro also holds interests, and for many of these licenses and petroleum facilities Norsk Hydro or we serve as operator. Norsk Hydro has an indirect participating interest in the Gassled joint venture. Further, we from time to time engage in common drilling campaigns, exploration and development projects with Norsk Hydro. In addition, Norsk Hydro is a party to the 15-year agreement for the sale of ethane described below in —Transactions with associated companies.

Den norske Bank ASA. In addition to Den norske Bank ASA's participation as joint global coordinator for our initial public offering, it also participates as a member of the bank group for our USD1 billion Multicurrency Revolving Credit and Swingline Facility. This facility, entered into on November 24, 2000, is coordinated by Barclays Capital and Barclays Bank Plc acts as Facility and Swingline Agent. Den norske Bank ASA's total commitment under the program is USD 58,750,000, of which USD 29,375,000 is part of the swingline facility. There are 16 other banks in the group. The terms of the facility allow us to have outstanding up to six advances at any time. The interest rate is linked to the London Inter-Bank Offer Rate (LIBOR) and our Standard and Poor's credit rating at the time of the drawdown. This facility has a change of control provision that provides that in the case of the Norwegian State not owning at least 51% of our voting share capital, then we must notify the Facility Agent who will in turn notify the other banks. If the banks representing 33.33% of the aggregate total commitments under the facility so require, the Facility Agent will cancel the facility and declare all outstanding advances, together with accrued interest, and all other accrued amounts due immediately.

Others. As a result of the substantial percentage of industry in Norway controlled by the Norwegian State, there are many state-controlled entities with which we do business. The financial value of most such transactions is relatively small, and the ownership interest of the Norwegian State of such counter parties has not had any effect on the arm's-length nature of the transactions. In particular, in respect of the goods and services that we purchase, we purchase telephone services from Telenor ASA, a telecommunications company in which the Norwegian State holds a 77.63% interest. Such purchases are made pursuant to standard tariff rates applicable to public and private companies in Norway.

Transactions with associated companies

Borealis. On November 28, 2000, we entered into a long-term Sales and Purchase Agreement with Borealis for the sale of LPG derived from our entire share of crude oil from the Oseberg field in which we have a 64.78% participating interest. The LPG is made available after the crude oil from Oseberg has gone through the transportation, separation and storage processes in the Vestprosess facility at Mongstad, our refinery in Norway. The agreement provides for regular deliveries of LPG to Borealis's nominated plant. The price is based on the content of isobutene in the delivered LPG and is set in relation to the market price for naphtha. Certain quality specifications regulate the methanol, butane and isobutene content in the delivered product. The initial period for the contract is 15 years. In 2002, we sold 119,091 tonnes of LPG under this contract for an approximate consideration of NOK 224 million.

On June 2, 1997, we entered into a 15-year agreement for the sale of ethane between the participants in the Troll field, including us, as sellers and Borealis, Noretyl ANS and Norsk Hydro Produksjon AS as buyers. This contract provides for the purchase and sale of ethane feedstock for the Borealis plant in Stenungsund, Sweden, the Noretyl plant in Rafnes, Norway, and the Hydro Agri Ammonia plant at Herøya in Porsgrunn, Norway from the Statpipe owned Kårstø plant. Currently, 50% of production is delivered to Stenungsund and 50% to Rafnes. It is a take-or-pay contract whereby the buyers are obligated to pay for all ethane made available by the sellers under the contract. The price for the ethane is based on the market price of naphtha and is adjusted to reflect changes in the Norwegian consumer price index and the market price of marine fuel. Deliveries under the contract began in October 2000, and the initial term of the agreement lasts until October 1, 2015. In 2002, the seller group sold 519,418 tonnes of ethane under this contract for an approximate consideration of NOK 651 million. This arrangement is also described under Item 4–Information on the Company–Business Overview–Operations–Natural Gas–Kårstø Processing Plant.

Statoil Detaljhandel Skandinavia. On June 1, 1999, we entered into a Fuel Supply Agreement with SDS whereby we became the sole supplier of refined petroleum products to SDS for its retail petroleum activities in Scandinavia. The three-year agreement was renewed in 2002 with an effective date of January 1, 2002. The agreement encompasses bulk products sold at SDS's service stations such as gasoline and automotive diesel oil, burning kerosene and LPG, as well as marginal bulk products such as RME, biogas and bioethanol and the volume of products contracted for shall be enough to cover the sales of SDS's service stations. We deliver the products to the individual service stations. Prices paid by SDS are based on market prices for the different products, adjusted for changes that occur to the products during transportation, storage and distribution, and are negotiated annually with the intention that SDS shall enjoy competitive market prices and conditions in respect of the products. In addition to the product prices, SDS pays to us an amount to cover the cost of distribution per service station location, which is also negotiated annually. In 2002, we received NOK 16.0 billion, of which NOK 11.3 billion were excise taxes, pursuant to this Fuel Supply Agreement.

Other Transactions with the Norwegian State

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

On May 24, 1996, we agreed with the Ministry of Petroleum and Energy on guidelines for setting the price of the SDFI gas used in the production of methanol at Tjeldbergodden. The guidelines entitle Statoil to acquire all SDFI gas produced at the unitized Heidrun field to be used in the production of methanol. The guidelines also set out a formula to be used in setting the gas price to the SDFI. In 2000, Statoil paid the Ministry of Petroleum and Energy NOK 189 million for SDFI gas transferred to the methanol production plant.

Employee Loans

Some of our employees are eligible for an interest-free car loan. The loan is limited to the price of the car purchased, and is capped at NOK 250,000, NOK 375,000 or NOK 475,000, depending on the seniority of the employee.

Executive vice presidents Henrik Carlsen, Elisabeth Berge and Terje Overvik have interest-free car loans of NOK 299,000, NOK 71,000 and NOK 386,000, respectively. These loans were entered into prior to July 30, 2002 and have a repayment period of ten years.

We have an arrangement with Den norske Bank whereby Den norske Bank makes available to each of our employees personal loans of up to NOK 100,000. The employees pay the "norm interest rate", which is set by the Norwegian State, and we pay the difference between the norm interest rate and the then-current market interest rate. We also guarantee these loans up to an aggregate maximum amount of NOK 5 million. The repayment period is up to eight years. Our obligations for paying the interest rate difference will be dependent on the loan volume, but based on current interest rates would not exceed NOK 20 million per year.

The three employee elected members of the board of directors each entered into loan agreements under this facility prior to July 30, 2002, and had as of December 31, 2002 an aggregate total balance outstanding payable to DnB under this loan facility of NOK 224,566. Executive Vice President Terje Overvik entered into a loan under this facility prior to becoming a member of the executive committee, and as at the end of the year 2002, the balance outstanding payable to DnB under this loan facility was NOK 96,000. The loan will be repaid in full in the near future.

Members of the executive committee, the board of directors and the corporate assembly may not renew existing loans or enter into new loans under the foregoing programs.

Item 8 Financial Information

Consolidated Statements and Other Financial Information

See Item 18–Financial Statements.

Legal Proceedings

We are involved in a number of judicial, regulatory and arbitration proceedings concerning matters arising in connection with the conduct of our business. Except as set forth below, we are currently not aware of any legal proceedings or claims that we believe could have, individually or in the aggregate, significant effects on our financial position or profitability or our results of operations or liquidity.

European Commission Proceedings.
On June 12, 2001 we received a statement of objections from the European Commission, Directorate-General Competition, commencing proceedings against us in relation to the arrangements for sale of natural gas from the NCS. The Commission also adopted a statement of objections against 22 other producers of natural gas on the NCS. A statement of objections is the first step in a formal proceeding in which the Commission has set out its preliminary assessment of the facts and legal issues upon which it alleges that the sale of natural gas from the NCS has been conducted in contravention of EU/EEA competition laws. We disputed the allegations made in the statement of objections. The Norwegian Government also publicly announced that it opposed the statement of objections issued by the European Commission. During spring 2002, the European Commission approached us about opening discussions regarding a settlement of the case. These discussions resulted in an amicable settlement of the case being reached between the EU Commission and us on July 17, 2002. Thus, the European Commission decided in July 2002 to withdraw the statement of objections issued against us and the other companies on the NCS regarding alleged breach of EU/EEA competition rules for marketing of Norwegian gas by the Gas Negotiation Committee.

The settlement entails that the European Commission will withdraw the case and that we undertake, from June 1, 2001 to September 30, 2005, to offer for sale on commercially competitive terms and conditions a total of 13 billion cubic meters of natural gas to new customers during that period. As our undertaking is retroactive from June 1, 2001, a portion of this gross volume has already been sold to such new customers. We will endeavor to distribute the volume evenly over the period. The definition of a new customer comprises all creditworthy undertakings within the EEA that were not among our long-term customers prior to 2001.

We have undertaken the above commitments without any admission that our and GFU's marketing activities constituted an infringement of the competition rules of the EU/EEA. We are satisfied with the settlement as the commitments are in accordance with our current business strategy.

Dividend Policy

We currently intend to pay an annual, aggregate dividend to shareholders of an amount in the range of 45% to 50% of our net income as determined in accordance with USGAAP. In any one year, however, the aggregate dividends paid to shareholders may be lower or higher than 45% to 50% of USGAAP net income, reflecting our view of the cyclical outlook for energy product prices as well as our operating cash flows, financing requirements and capital expenditure plans to ensure we maintain appropriate financial flexibility. Further, our ability to pay dividends is restricted by law to amounts calculated under Norwegian GAAP. See Item 3—Key Information–Dividends.

Significant Changes

None.

Item 9 The Offer and Listing

Markets and Market Prices

The principal trading market for Statoil's ordinary shares is the Oslo Stock Exchange on which they have been listed since the initial public offering of Statoil on June 18, 2001. The ordinary shares are also listed on the New York Stock Exchange trading in the form of American Depositary Shares, or ADSs, evidenced by American Depositary Receipts, or ADRs. Each ADS represents one ordinary share. Statoil has a sponsored ADR facility with the Bank of New York as Depositary.

The following table gives, for the periods indicated, the reported high and low market quotations for the ordinary shares on the Oslo Stock Exchange, as derived from its Daily Official List, and the highest and lowest sales prices of the ADSs as reported on the New York Stock Exchange composite tape..

	NOK PER ORDINARY SHARE		*USD PER ADS*	
MONTH OF	*HIGH*	*LOW*	*HIGH*	*LOW*
June 2001 (from June 18)	71.00	67.00	7.64	7.12
July 2001	68.00	61.00	7.27	6.55
August 2001	66.50	61.00	7.30	6.75
September 2001	69.00	55.00	7.00	6.23
October 2001	62.00	54.50	6.85	6.15
November 2001	64.50	56.50	7.10	6.26
December 2001	61.50	58.00	6.80	6.44
January 2002	62.50	56.50	6.99	6.35
February 2002	64.50	58.00	7.19	6.31
March 2002	70.00	65.00	7.90	7.26
April 2002	73.50	69.50	8.66	7.80
May 2002	72.50	67.50	8.90	7.94
June 2002	68.50	64.00	8.92	8.21
July 2002	69.00	54.00	9.35	6.80
August 2002	66.50	60.00	8.84	7.75
September 2002	64.00	55.50	8.55	7.32
October 2002	59.00	52.00	7.85	6.80
November 2002	54.50	50.00	7.52	6.80
December 2002	59.00	53.00	8.39	7.20
January 2003	59.50	52.00	8.70	7.50
February 2003	55.00	51.50	7.89	7.33
March 2003 (up to and including March 14)	57.00	55.00	7.92	7.65

Item 10 Additional Information

Memorandum and Articles of Association

Summary of our Articles of Association

Name of the Company
Our registered name is Statoil ASA. We are a Norwegian public limited company.

Registered office
Our registered office is in Stavanger, Norway, registered with the Norwegian Register of Business Enterprises under number 913 609 016.

Object of the company
The object of our company is, either by us 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 businesses.

Share capital
Our share capital is NOK 5,473,964,000 divided into 2,189,585,600 ordinary shares.

Nominal value of shares
The nominal value of each ordinary share is NOK 2.50.

Board of directors
Our articles of association provide that our board of directors shall be composed of a minimum of five and a maximum of 11 directors.

Corporate Assembly
We have a corporate assembly of 12 members who are elected for two-year terms. Eight members with three alternates are elected by the general meeting and four members with four alternates are elected by and among the employees.

Annual general meeting
Our annual general meeting is held no later than June 30 each year upon at least two weeks' written notice.

The meeting will deal with the Annual Report and accounts, including distribution of dividends, and any other matters as required by law or our articles of association.

Marketing of petroleum on behalf of the Norwegian State
Our articles of association provide that we are responsible for marketing and selling petroleum produced under the SDFI's shares in production licenses on the NCS as well as petroleum received by the Norwegian State as royalty together with our own production. Our general meeting adopted an instruction in respect of such marketing on May 25, 2001.

Election Committee
The general meeting decided to amend our articles of association on May 7, 2002 in order to establish an election committee. The tasks of the election committee are to make recommendations to the 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 election committee shall consist of four members who shall be shareholders or representatives of shareholders. The chairman of the corporate assembly shall be a permanent member and chairman of the election committee. The general meeting shall elect two members, and one member shall be elected by and among the corporate assembly's shareholder-elected members.

General Meetings
In accordance with Norwegian law, our annual general meeting of shareholders is required to be held each year on or prior to June 30. Norwegian law requires that written notice of general meetings be sent to all shareholders whose addresses are known at least two weeks prior to the date of the meeting. A shareholder may vote at the general meeting either in person or by proxy.

Although Norwegian law does not require us to send proxy forms to our shareholders for general meetings, we plan to include a proxy form with future notices of general meetings.

In addition to the annual general meeting, extraordinary general meetings of shareholders may be held if deemed necessary by the board of directors, the corporate assembly or the chairman of the corporate assembly. An extraordinary general meeting must also be convened for the consideration of specific matters at the written request of our auditors or of shareholders representing a total of at least 5% of the outstanding share capital.

Voting Rights

All of our ordinary shares carry equal right to vote at general meetings. Except as otherwise provided, decisions which shareholders are entitled to make pursuant to Norwegian law or our articles of association may be made by a simple majority of the votes cast. In the case of elections, the persons who obtain the most votes cast are deemed elected. However, certain decisions, including resolutions to waive preferential rights in connection with any share issue, to approve a merger or demerger, to amend our articles of association or to authorize an increase or reduction in our share capital, must receive the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at a shareholders' meeting. The Norwegian State continues to hold more than two-thirds of our share capital. See Item 7–Major Shareholders and Related Party Transactions–Major Shareholders–The Norwegian State as a Shareholder.

In general, in order to be entitled to vote, a shareholder must be registered as the owner of shares in the share register kept by the Norwegian Central Securities Depository, referred to as the VPS System (described below), or, alternatively, report and show evidence of its share acquisition to us prior to the general meeting.

Beneficial owners of shares that are registered in the name of a nominee are generally not entitled to vote under Norwegian law, nor are any persons who are designated in the register as holding such shares as nominees. The beneficial owners of ADSs are therefore only able to vote at meetings by surrendering their ADSs, withdrawing their ordinary shares from the ADS depositary and registering their ownership of such ordinary shares directly in our share register in the VPS System. Alternatively, the ADS holder may instruct the ADR depositary to vote the ordinary shares underlying the ADSs on behalf of the holder, provided that the ADS holder instructs the ADR depositary to execute a temporary transfer of the underlying ordinary shares in the VPS System to the beneficial owner. Similarly, beneficial owners of ordinary shares registered through other VPS-registered nominees may not be able to vote their shares unless their ownership is reregistered in the name of the beneficial owner prior to the relevant shareholders' meeting.

The VPS System and Transfer of Shares

The VPS System is Norway's paperless centralized securities registry. It is a computerized bookkeeping system that is operated by an independent body in which the ownership of, and all transactions relating to, Norwegian listed shares must be recorded. Our share register is operated through the VPS System.

All transactions relating to securities registered with the VPS are made through computerized book entries. No physical share certificates are or can be issued. The VPS System confirms each entry by sending a transcript to the registered shareholder regardless of beneficial ownership. To effect these entries, the individual shareholder must establish a securities' account with a Norwegian account agent. Norwegian banks, the Central Bank of Norway, authorized investment firms in Norway, bond issuing mortgage companies, management companies for securities funds (insofar as units in securities funds they manage are concerned), and Norwegian branches of credit institutions established within the EEA are allowed to act as account agents.

The entry of a transaction in the VPS System is prima facie evidence in determining the legal rights of parties as against the issuing company or a third party claiming an interest in the subject security. The VPS System is strictly liable for any loss resulting from an error in connection with registering, altering or canceling a right, except in the event of contributory negligence, in which event compensation owed by the VPS System may be reduced or withdrawn. A transferee or assignee of shares may not exercise the rights of a shareholder with respect to his or her shares unless that transferee or assignee has registered his or her shareholding or has reported and shown evidence of such share acquisition and the acquisition of such shares is not prevented by law, our articles of association or otherwise.

Amendments to our Articles of Association, including Variation of Rights

The affirmative vote of two-thirds of the votes cast as well as two-thirds of the aggregate share capital represented at the general meeting is required to amend our articles of association. Any amendment which would reduce any shareholder's right in respect of dividends payments or other rights to our assets or restrict the transferability of shares requires a majority vote of at least 90% of the aggregate share capital represented in a general meeting. Certain types of changes in the rights of our shareholders require the consent of all affected shareholders as well as the percentage threshold otherwise required to amend our articles of association.

Additional Issuances and Preferential Rights

If we issue any new shares, including bonus share issues, our articles of association must be amended, which requires the same vote as other amendments to our articles of association. In addition, under Norwegian law, our shareholders have a preferential right to subscribe to issues of new shares by us. The preferential rights to subscribe to an issue may be waived by a resolution in a general meeting passed by the same percentage threshold required to approve amendments to our articles of association.

The general meeting may, with a vote as described above, authorize the board of directors to issue new shares, and to waive the preferential rights of shareholders in connection with such issuances. Such authorization may be effective for a maximum of two years, and the par value of the shares to be issued may not exceed 50% of the nominal share capital when the authorization was granted.

The issuance of shares to holders who are citizens or residents of the United States upon the exercise of preferential rights may require us to file a registration statement in the United States under United States securities laws. If we decide not to file a registration statement, these holders may not be able to exercise their preferential rights.

Under Norwegian law, bonus share issues may be distributed, subject to shareholder approval, by transfer from Statoil's distributable equity or from our share premium reserve. Any bonus issues may be affected either by issuing shares or by increasing the par value of the shares outstanding.

Minority Rights

Norwegian law contains a number of protections for minority shareholders against oppression by the majority including but not limited to those described in this paragraph. Any shareholder may petition the courts to have a decision of the board of directors or general meeting declared invalid on the grounds that it unreasonably favors certain shareholders or third parties to the detriment of other shareholders or the company itself. In certain grave circumstances shareholders may require the courts to dissolve the company as a result of such decisions. Minority shareholders holding 5% or more of our share capital have a right to demand that we hold an extraordinary general meeting to discuss or resolve specific matters. In addition, any shareholder may demand that we place an item on the agenda for any shareholders' meeting if we are notified in time for such item to be included in the notice of the meeting.

Mandatory Bid Requirement

Norwegian law requires any person, entity or group acting in concert that acquires more than 40% of the voting rights of a Norwegian company listed on the Oslo Stock Exchange, or OSE, to make an unconditional general offer to acquire the whole of the outstanding share capital of that company. The offer is subject to approval by the OSE before submission of the offer to the shareholders. The offer must be in cash or contain a cash alternative at least equivalent to any other consideration offered. The offering price per share must be at least as high as the highest price paid by the offeror in the six-month period prior to the date the 40% threshold was exceeded, but equal to the market price if it is clear that the market price was higher when the 40% threshold was exceeded. A shareholder who fails to make the required offer must within four weeks dispose of sufficient shares so that the obligation ceases to apply. Otherwise, the OSE may cause the shares exceeding the 40% limit to be sold by public auction. A shareholder who fails to make such bid cannot, as long as the mandatory bid requirement remains in force, vote the portion of his shares which exceed the 40% limit or exercise any rights of share ownership in respect of such shares, unless a majority of the remaining shareholders approve, other than the right to receive dividends and preferential rights in the event of a share capital increase. In addition, the OSE may impose a daily fine upon a shareholder who fails to make the required offer.

Compulsory Acquisition

A shareholder who, directly or via subsidiaries, acquires shares representing more than 90% of the total number of issued shares as well as more than 90% of the total voting rights has the right (and each remaining minority shareholder of that company would have the right to require the majority shareholder) to effect a compulsory acquisition for cash of any shares not already owned by the majority shareholder. A compulsory acquisition has the effect that the majority shareholder becomes the owner of the shares of the minority shareholders with immediate effect.

A majority shareholder who effects a compulsory acquisition is required to offer the minority shareholders a specific price per share. The determination of the offer price is at the discretion of the majority shareholder. Should any minority shareholder not accept the offered price, such minority shareholder may, within a specified period of not less than two months, request that the price be set by the Norwegian courts. The cost of such court procedure would normally be charged to the account of the majority shareholder, and the courts would have full discretion in determining the consideration due to the minority shareholder as a result of the compulsory acquisition.

Election and Removal of Directors and Corporate Assembly

At the general meeting of shareholders, two-thirds of the members of the corporate assembly are elected, together with alternate members, while the remaining one-third, together with alternate members, are elected by and from among our employees. There is no quorum requirement, and nominees who receive the most votes are elected. Any shareholder at the meeting may place nominations before the meeting.

We have an election committee that makes recommendations to the general meeting regarding the election of shareholder-elected members of the corporate assembly and their alternates. The committee consists of four members who are shareholders or representatives of shareholders. The chairman of the corporate assembly is a permanent member of the committee and acts as its chairman. Two members are elected by the general meeting and one member is elected by and from among the corporate assembly's shareholder-elected members. Each member is elected for a two-year term. A member of the corporate assembly (other than a member elected by employees) may be removed by the shareholders at any time without cause.

Our directors are elected to the Board and may be removed from office by our corporate assembly. If requested by at least one third of the members of the corporate assembly, up to one-third of the directors must be employee representatives. Our election committee makes recommendations to the corporate assembly regarding the election of shareholder-elected directors of the board and their alternates. Half of the corporate assembly members elected by the employees may demand that the members of the board of directors be elected by the shareholder-elected members of the corporate assembly and the employee-elected members of the corporate assembly, each voting as a separate group. A director (other than a director elected directly by the employees) may be removed at any time by the corporate assembly without cause.

The corporate assembly makes decisions by majority vote, and more than half of its members must be present for a quorum. If votes are tied, the chairman of the meeting casts the deciding vote. The members of the corporate assembly and the board of directors have fiduciary duties to the shareholders, see –Liability of Directors and–Corporate Assembly.

Payment of Dividends

For a discussion of the declaration and payment of dividends on our ordinary shares, see Item 3–Key Information–Dividends and Item 8–Financial Information–Dividend Policy.

Rights of Redemption and Repurchase of Shares

Our articles of association do not authorize the redemption of shares. In the absence of authorization, the redemption of shares may still be decided by a general meeting of shareholders by a two-thirds majority under certain conditions. However, the share redemption would, for all practical purposes, depend on the consent of all shareholders whose shares are redeemed.

A Norwegian company may purchase its own shares if an authorization to do so has been given by a general meeting with the approval of at least two-thirds of the aggregate number of votes cast as well as two thirds of the share capital represented at the general meeting. The aggregate par value of treasury shares held by the company must not exceed 10% of the company's share capital and treasury shares may only be acquired if the company's distributable equity, according to the latest adopted balance sheet, exceeds the consideration to be paid for the shares. The authorization by the general meeting cannot be given for a period exceeding 18 months.

Shareholders' Votes on Certain Reorganizations

A decision to merge with another company or to demerge requires a resolution of our shareholders at a general meeting passed by a two-thirds majority of the aggregate votes cast as well as two-thirds of the aggregate share capital represented at the general meeting. A merger plan or demerger plan signed by the board of directors along with certain other required documentation would have to be sent to all shareholders at least one month prior to the shareholders' meeting.

Any agreement by which we acquire assets or services from a shareholder or a shareholder's related party against a consideration exceeding the equivalent of 5% of our share capital must be approved by the general meeting. This does not apply to acquisition of listed securities at market price or to agreements in the ordinary course of business entered into on normal commercial terms.

Liability of Directors

Our directors, the chief executive officer and the corporate assembly owe a fiduciary duty to the company and its shareholders. Their fiduciary duty requires that they act in our best interests when exercising their functions and to exercise a general duty of loyalty and care toward us. Their principal task is to safeguard the interests of the company.

Our directors, the chief executive officer and the members of the corporate assembly can each be held liable for any damage they negligently or willfully cause us. Norwegian law permits the general meeting to exempt any such person from liability, but the exemption is not binding if substantially correct and complete information was not provided at the general meeting when the decision was taken. If a resolution to grant such exemption from liability or to not pursue claims against such a person has been passed by a general meeting with a smaller majority than that required to amend our articles of association, shareholders representing more than 10% of the share capital or (if there are more than 100 shareholders) more than 10% of the number of shareholders may pursue the claim on our behalf and in our name. The cost of any such action is not our responsibility, but can be recovered by any proceeds we receive as a result of the action. If the decision to grant exemption from liability or not to pursue claims is made by the majority necessary to amend the articles of association, the minority shareholders cannot pursue the claim in our name.

Indemnification of Directors and Officers

Neither Norwegian law nor our articles of association contain any provision concerning indemnification by us of our board of directors.

Distribution of Assets on Liquidation

Under Norwegian law, a company may be wound-up by a resolution of the company's shareholders in a general meeting passed by both a two-thirds majority of the aggregate votes cast and two-thirds of the aggregate share capital represented at the general meeting. The shares rank equal in the event of a return on capital by the company upon a winding-up or otherwise.

Material Contracts

See Item 7–Major Shareholders and Related Party Transactions.

Exchange Controls and Other Limitations Affecting Shareholders

Under Norwegian foreign exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior government approval except for the physical transfer of payments in currency, which is restricted to licensed banks. This means that non-Norwegian resident shareholders may receive dividend payments without a Norwegian exchange control consent as long as the payment is made through a licensed bank.

There are presently no restrictions affecting the rights of non-residents or foreign owners to hold or vote our shares.

Taxation

Norwegian Tax Matters

This section describes the material Norwegian tax consequences that apply to shareholders resident in Norway as well as non-resident shareholders in connection with the acquisition, ownership, and disposition of the shares and ADSs. This section does not provide a complete description of all tax regulations, which might be relevant (i.e., for investors for whom special regulations may be applicable). This section is based on current law and practice. Shareholders should consult their professional tax advisors for advice concerning individual tax consequences.

Last year, the Norwegian government appointed last year a commission to evaluate the Norwegian tax system. The commission delivered its report on February 6, 2003. The commission did not propose any changes in the tax system that will have a significant impact on Statoil. The most important changes proposed are improved credit rules for tax paid abroad and introduction of Norwegian rules similar to EU directive 90/434 regarding cross border mergers, demergers and asset and share swaps. These proposed changes will be positive for Statoil's international activity if enacted. The report will now be out on a three months hearing before the Government prepares a white paper for the Storting in the autumn of 2003.

Taxation of Dividends

Dividends distributed are subject to taxation in Norway as general income at a flat rate, currently 28%. Shareholders that are residents of Norway for tax purposes are entitled to a tax credit ("godtgjørelse") against the Norwegian tax levied on dividends distributed from Norwegian companies equal to the tax to be levied on the dividends received, and will effectively not be subject to tax on dividend distributions from Norwegian companies.

Non-resident shareholders are subject to a withholding tax at a rate of 25% on dividends distributed by Norwegian companies. The withholding rate of 25% is often reduced in tax treaties between Norway and the country in which the shareholder is resident. Generally, the treaty rate does not exceed 15%, and in cases where a corporate shareholder holds a qualifying percentage of the shares of the distributing company, the withholding tax rate on dividends may be further reduced. The treaty rate in the treaty between the United States and Norway is 15% in all cases. The withholding tax does not apply to shareholders that carry on business activities in Norway and whose shares are effectively connected to such activities. In that case, the rules described in the foregoing paragraph apply. We are obliged by law to deduct any applicable withholding tax when paying dividends to non-resident shareholders.

The 15% withholding rate under the tax treaty between Norway and the United States will apply to dividends paid on shares held directly by holders properly demonstrating to the company that they are entitled to the benefits of the tax treaty.

Dividends paid to the depositary for redistribution to shareholders holding ADSs will at the outset be subject to a withholding tax of 25%. The beneficial owners will in this case have to apply with the Norwegian Directorate of Taxes for refund of the excess amount of tax withheld. As yet there is no standardized application form to obtain a refund of Norwegian withholding tax. An application must contain the following information:

1. the company from which dividends were received and the date and amount of payment, the exact number of shares, the amount of tax withheld by Norway and the amount claimed for refund from Norway. All amounts are to be stated in Norwegian kroner;

2. confirmation from a central tax authority stating that, in the year the dividends were declared or received, the refund claimant was resident for tax purposes in the country with respect to which such claimant claims the benefits of a tax treaty with Norway, and original documentation that the claimant was the beneficial owner of the shares when the dividends were declared; and

3. evidence that the dividends were actually received by the applicant and the rate at which Norwegian withholding tax was withheld on the dividends.

The application must be signed by the applicant. If the application is signed by proxy, a copy of the letter of authorization must be enclosed.

However, pursuant to agreements with the Norwegian Banking, Insurance and Securities Commission and the Norwegian Directorate of Taxes, The Bank of New York, acting as depositary, is entitled to receive dividends from us for redistribution to a beneficial owner of shares or ADSs at the applicable treaty withholding rate, provided the beneficial holder has furnished The Bank of New York appropriate certification to establish such holder's eligibility for the benefits under an applicable tax treaty with Norway.

Wealth Tax

The shares are included when computing the wealth tax imposed on individuals who for tax purposes are considered resident in Norway. Norwegian joint stock companies and certain other similar entities are not subject to wealth tax. Currently, the marginal wealth tax rate is 1.1% of the value assessed. The value for assessment purposes for shares listed on the Oslo Stock Exchange is 100% of the listed value of such shares as of January 1 in the year of assessment. Non-resident shareholders are not subject to wealth tax in Norway for shares in Norwegian joint stock companies unless the shareholder is an individual and the shareholding is effectively connected with his business activities in Norway.

Inheritance Tax and Gift Tax

When shares or ADSs are transferred, either through inheritance or as a gift, such transfer may give rise to inheritance tax in Norway if the deceased, at the time of death, or the donor, at the time of the gift, is a resident or citizen of Norway. If a Norwegian citizen at the time of death, however, is not a resident of Norway, Norwegian inheritance tax will not be levied if an inheritance tax or a similar tax is levied by the country of residence. Irrespective of citizenship, Norwegian inheritance tax may be levied if the shares or ADSs are effectively connected with the conduct of a trade or business through a permanent establishment in Norway.

Taxation upon Disposition of Shares

A shareholder who is resident for tax purposes in Norway will realize a taxable gain or loss upon a sale, redemption or other disposition of shares. Such capital gain or loss is included in or deducted upon computation of general income in the year of disposal. General income is taxed at a flat tax rate of 28%. The gain is subject to tax and the loss is deductible irrespective of the length of the ownership and the number of shares disposed of.

The taxable gain or loss is computed as the sales price adjusted for transactional expenses less the taxable basis. A shareholder's tax basis is normally equal to the acquisition costs of the shares. The tax basis is adjusted according to the so-called RISK-rules (RISK is the Norwegian abbreviation for the variation in the company's retained earnings after tax during the ownership of the shareholder). The RISK amount is computed at the end of each fiscal year. If the shareholder owns shares acquired at different times, the shares that were acquired first will be regarded as the first to be sold for the purpose of calculating capital gains or losses.

Shareholders not resident in Norway are generally not subject to tax in Norway on capital gains, and losses are not deductible upon sale, redemption or other disposition of shares or ADSs in Norwegian companies, unless the shareholder has been resident for tax purposes in Norway and the disposal takes place within five years after the end of the calendar year in which the shareholder ceased to be a resident of Norway for tax purposes, or, alternatively, the shareholder is carrying on business activities in Norway and such shares or ADSs are or have been effectively connected with such activities.

Transfer Tax

There is no transfer tax imposed in Norway in connection with the sale or purchase of shares.

United States Tax Matters; *General*

This section describes the material United States federal income tax consequences of owning shares or ADSs. It applies to you only if you hold your shares or ADSs as capital assets for tax purposes. This section does not apply to you if you are a member of a special class of holders subject to special rules, including:

- dealers in securities;
- traders in securities that elect to use a mark-to-market method of accounting for their securities holdings;
- tax-exempt organizations;
- life insurance companies;
- persons liable for alternative minimum tax;
- persons that actually or constructively own 10% or more of the voting stock of Statoil;
- persons that hold shares or ADSs as part of a straddle or a hedging or conversion transaction; or
- persons whose functional currency is not the US dollar.

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations, published rulings and court decisions, and the Convention between the United States of America and the Kingdom of Norway for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income and Property (the "Treaty"). These laws are subject to change, possibly on a retroactive basis. In addition, this section is based in part upon the representations of the depositary and the assumption that each obligation in the deposit agreement and any related agreement will be performed in accordance with its terms. For United States federal income tax purposes, if you hold ADRs evidencing ADSs, you generally will be treated as the owner of the ordinary shares represented by those ADSs. Exchanges of shares for ADSs, and ADSs for shares generally will not be subject to United States federal income tax.

You are a "US holder" if you are a beneficial owner of shares or ADSs and you are:

- an individual who is a citizen or resident of the United States;
- a corporation created or organized in or under the laws of the United States or any political subdivision thereof;
- an estate whose income is subject to United States federal income tax regardless of its source; or
- a trust if a United States court can exercise primary supervision over the trust's administration and one or more United States persons are authorized to control all substantial decisions of the trust.

You should consult your own tax advisor regarding the United States federal, state and local and other tax consequences of owning and disposing of shares and ADSs in your particular circumstances.

Taxation of Dividends

If you are a US holder, you must include in your gross income the gross amount of any dividend paid by Statoil out of its current or accumulated earnings and profits (as determined for United States federal income tax purposes). You must include any Norwegian tax withheld from the dividend payment in this gross amount even though you do not in fact receive the amount withheld as tax. The dividend is ordinary income that you must include in income when you, in the case of shares, or the depositary, in the case of ADSs, receive the dividend, actually or constructively. The dividend will not be eligible for the dividends-received deduction generally allowed to United States corporations in respect of dividends received from other United States corporations.

The amount of the dividend distribution that you must include in your income as a US holder will be the US dollar value of the Norwegian kroner payments made, determined at the spot Norwegian kroner/US dollar rate on the date the dividend distribution is included in your income, regardless of whether the payment is in fact converted into US dollars. Distributions in excess of current and accumulated earnings and profits, as determined for United States federal income tax purposes, will be treated as a non-taxable return of capital to the extent of your tax basis in the shares or ADSs and, to the extent in excess of your tax basis, will be treated as capital gain.

Subject to certain limitations, the 15% Norwegian tax withheld in accordance with the Treaty and paid over to Norway will be creditable against your United States federal income tax liability. Dividends will be income from sources outside the United States, and generally will be "passive income" or "financial services income", which is treated separately from other types of income for purposes of computing the foreign tax credit allowable to you.

Any gain or loss resulting from currency exchange fluctuations during the period from the date you include the dividend payment in income to the date you convert the payment into US dollars generally will be treated as ordinary income or loss. Such gain or loss generally will be income or loss from sources within the United States for foreign tax credit limitation purposes.

Taxation of Capital Gains

If you are a US holder and you sell or otherwise dispose of your shares or ADSs, you generally will recognize capital gain or loss for United States federal income tax purposes equal to the difference between the US dollar value of the amount that you realize and your tax basis, determined in US dollars, in your shares or ADSs. Capital gain of a non-corporate US holder is generally taxed at a maximum rate of 20% where the property has been held for more than one year. The gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes.

If you receive any foreign currency on the sale of shares or ADSs, you may recognize ordinary income or loss from sources within the United States as a result of currency fluctuations between the date of the sale of the shares or ADSs and the date the sales proceeds are converted into US dollars.

Documents on Display

It is possible to read and copy documents referred to in this Annual Report on Form 20-F that have been filed with the SEC at the SEC's public reference room located at 450 Fifth Street, NW, Washington D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference rooms and their copy charges.

Item 11 Quantitative and Qualitative Disclosures about Market Risk

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. Our management has used and intends to use financial and commodity-based derivative contracts to reduce the risks in overall earnings and cash flows. Statoil also uses derivatives to establish certain limited speculative positions based on market movements.

Statoil has established an Enterprise-Wide Risk Management Program which establishes guidelines for entering into contractual arrangements (derivatives) to manage its commodity price, foreign currency rate, and interest rate risk. Our Corporate Risk Committee meets on a regular basis to review the existing policies and implementation of the guidelines. These procedures establish control over the use of derivatives, routine monitoring and reporting requirements, as well as counter-party credit approval processes.

Commodity Risk. The following table contains the fair market value and related price risk sensitivity of our commodity-based derivatives, as accounted for under FAS 133, all amounts in NOK million:

AT DECEMBER 31, 2001	*FAIR MARKET VALUE ASSET*	*FAIR MARKET VALUE LIABILITY*	*10% SENSITIVITY*
At December 31, 2002			
Crude oil and refined products	1,464	(1,691)	427
Natural gas and electricity	1,205	(941)	65
At December 31, 2001			
Crude oil and refined products	1,074	(684)	484
Natural gas and electricity	1,163	(862)	59

Substantially all these fair market value assets and liabilities are related to over-the-counter (OTC) derivatives. The term of crude oil and refined products derivatives is usually less than one year. The term of natural gas forwards is usually three years or less. The net fair market value of FAS 133 derivatives associated with long-term natural gas contracts (10 years or more) and included in the table above was NOK 91 million and negative NOK 145 million as of December 31, 2002 and 2001 respectively. Also included in the fair market values and basis for sensitivity figures are immaterial derivative positions held for speculative purposes.

Price risk sensitivities for 2002 and 2001 were calculated by assuming a hypothetical across-the-board 10% adverse change in all commodity prices regardless of the term or historical relationships between the contractual price of the instrument and the underlying commodity prices. In the event of an actual 10% change in all underlying prices, the change in the fair value of the derivative portfolio at the two respective year ends would typically be different from that shown above due to expected correlations between risk categories. In addition, there would be expected offsetting effects from changes in the fair value of our corresponding physical positions, contracts and anticipated transactions, which are not required to be recorded at market, and which are not reflected in the above table.

A 10% relative change of certain underlying commodity prices in relation to other prices would typically yield other sensitivities than those provided in the table above. Natural Gas sensitivities may for instance be adversely impacted by certain relative commodity price changes, due to pricing elements in long-term physical delivery contracts and assumptions used in arriving at the fair market value of FAS 133 derivatives related to long-term contracts.

Interest and Currency Risk. Interest and currency risks constitute significant financial risks for the Statoil group. Total exposure is managed at a portfolio level in accordance with approved strategies and mandates. Interest rate risk and currency risk are assessed against mandates on a regular basis. The fair market value of assets and liabilities, respectively, related to our fixed interest long-term debt, interest rate swaps and currency swaps were NOK 2,154 million and NOK 28,625 million as of December 31, 2002, and NOK 602 million and NOK 32,248 million as of December 31, 2001.

The estimated loss associated with a 10% adverse change in NOK currency rates would result in a loss of fair value of approximately NOK 4 billion and NOK 5 billion as of December 31, 2002 and 2001 respectively. A hypothetical one percentage point adverse change in interest rates would result in a loss of NOK 0.9 billion and NOK 1.2 billion related to interest bearing liabilities, investments in debt securities and related financial instruments as of December 31, 2002 and 2001, respectively. These estimated currency and interest rate sensitivities are based on an uncorrelated loss scenario and actual results could vary due to assumptions used and offsetting account correlations not reflected within this analysis.

Statoil's cash flows are largely in US dollars and euro but also significant amounts in NOK, Swedish kroner, Danish kroner and UK pounds sterling. The currencies in the debt portfolio are managed in connection with our expected future net cash flows per currency. Our debt, after considering currency swaps, is mainly in US dollars.

Equity Securities. Equity securities, mainly of the portfolio in Statoil Forsikring AS, are recorded at fair value and have exposure to price risk. The fair value of equity securities is based on quoted market prices. Risk is estimated as the potential loss in fair value resulting from a hypothetical 10% adverse change in quoted market prices. Actual results may vary due to assumptions utilized and risk correlations.

FAIR MARKET VALUE AT DECEMBER 31, (IN NOK MILLIONS)	*2002*	*2001*
Equity securities	1,270	1,598

MARKET RISK ON EQUITY SECURITIES, (IN NOK MILLIONS)	*2002*	*2001*
10% change in share prices	127	160

Item 12 Description of Securities Other Than Equity Securities

Not applicable.

PART II

Item 13 Defaults, Dividend Arrearages and Delinquencies

None.

Item 14 Material Modifications to the Rights of Security Holders and Use of Proceeds

None.

Item 15 Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures as defined in Exchange Act Rules 13a-14 and 15d-14 within 90 days of the filing date of this Annual Report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these disclosure controls and procedures are effective.

In designing and evaluating our disclosure controls and procedures, our management, including the Chief Executive Officer and Chief Financial Officer, recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected.

There were no significant changes in our internal controls or in other factors that could significantly affect internal controls subsequent to the date of their most recent evaluation.

PART III

Item 17 Financial Statements

Not applicable.

Item 18 Financial Statements

The consolidated financial statements beginning on page F-1 and the related notes, together with the report thereon of Ernst & Young, are filed as part of this Annual Report on Form 20-F.

Item 19 Exhibits

The following exhibits are filed as part of this Annual Report:

Exhibit 1	Articles of Association of Statoil ASA, as amended (English translation)
Exhibit 2(b)(i)	Instruments Defining the Rights of Holders of Long-Term Debt: The total amount of long-term securities of Statoil authorized under any instrument, does not exceed 10% of the total assets of Statoil on a consolidated basis. Statoil agrees to furnish copies of any or all such instruments to the Securities and Exchange Commission upon request.
Exhibit 4(a) (i)	Technical Service Agreement between Gassco AS and Statoil ASA, dated February 27, 2002 (Incorporated by reference to exhibit 4 to Statoil's Annual Report on Form 20-F for the fiscal year ended December 31, 2001)(File no 1-15200).
Exhibit 4(a) (ii)	Agreement relating to purchase and sale of SDFI assets (Incorporated by reference to Exhibit 10.1 to Statoil's Registration Statement on Form F-1, filed on May 14, 2001) (File no. 333-13502).
Exhibit 4(c)	Employment agreement with Olav Fjell (English translation) (Incorporated by reference to Exhibit 10.2 to Statoil's Registration Statement on Form F-1, filed on May 14, 2001) (File no. 333-13502).
Exhibit 8	Subsidiaries.

SIGNATURE

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this Annual Report on its behalf.

STATOIL ASA
(Registrant)

By: Inge K. Hansen

Inge K Hansen
Chief Financial Officer

Dated: March 26, 2003

CERTIFICATIONS

I, Olav Fjell, certify that:

1. I have reviewed this Annual Report on Form 20-F of Statoil ASA;

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this Annual Report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:
   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this Annual Report (the *"Evaluation Date"*); and
   c) presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this Annual Report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Dated: March 26, 2003

By: Olav Fjell

Olav Fjell
President and Chief Executive Officer

CERTIFICATIONS

I, Inge K Hansen, certify that:

1. I have reviewed this Annual Report on Form 20-F of Statoil ASA;

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this Annual Report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:
   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this Annual Report (the "Evaluation Date"); and
   c) presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this Annual Report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Dated: March 26, 2003

By: Inge K. Hansen

Inge K Hansen
Chief Financial Officer

Appendix A – Report of DeGolyer and MacNaughton

DEGOLYER AND MACNAUGHTON
4925 GREENVILLE AVENUE, SUITE 400
ONE ENERGY SQUARE
DALLAS, TEXAS 75206

February 14, 2003

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, 2002, 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, 2002 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, 2002, 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, 2002, 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)
1,867	13,470	4,267

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, 2002, 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)
1,807	13,663	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

Financial Statements

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To the Board of Directors and Shareholders of Statoil ASA

Report of independent auditors – USGAAP accounts

We have audited the accompanying consolidated balance sheets of Statoil ASA and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Statoil ASA and subsidiaries at December 31, 2002 and 2001, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

Stavanger, February 17, 2003
ERNST & YOUNG AS

Gustav Eriksen

Gustav Eriksen
State Authorised Public Accountant
(Norway)

Jostein Johannessen

Jostein Johannessen
State Authorised Public Accountant
(Norway)

CONSOLIDATED STATEMENTS OF INCOME – USGAAP

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

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

See notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS – USGAAP

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

See notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY – USGAAP

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

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

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

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

CONSOLIDATED STATEMENTS OF CASH FLOWS – USGAAP

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

See notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS – USGAAP

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

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

See notes to the consolidated financial statements

1. Organization and Basis of Presentation

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

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

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

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

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

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

2. Summary of Significant Accounting Policies

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

Consolidation

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

Foreign currency translation

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

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

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

Revenue recognition

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

Cash and cash equivalents

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

Short-term investments

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

Inventories

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

Use of estimates

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

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

Property, plant and equipment

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

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

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

Oil and gas accounting

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

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

Impairment of long-lived assets

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

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

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

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

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

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

Research and development
Research and development costs are expensed when incurred.

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

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

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

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

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

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

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

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

- Substantially all of Statoil's commodity-based derivatives (futures, forwards, options, swaps) are accounted for using the fair value method, whereby derivatives are carried on the balance sheet at fair value, including derivative positions utilized to manage price risk associated with corresponding physical positions, contracts, or anticipated transactions as a result of the instruments not meeting the criteria for deferral accounting. The gains and losses associated with the changes in the derivatives' fair value are recognized in Sales or Cost of goods sold in the period the change occurs.
- The deferral method of accounting, whereby gains and losses from the derivatives are deferred and recognized in earnings or as adjustments to the carrying amounts, when the hedged transaction occurs, is used for certain derivatives and related option premiums which are used to hedge anticipated transactions. At inception, these instruments are matched and designated to the underlying hedged commodity and changes in the market value of such instruments have a high correlation to the price changes of the hedged commodity. When an anticipated transaction is no longer likely to occur or is terminated before maturity, as appropriate, any deferred gain or loss that has arisen on the derivative is recognized in the income statement together with any gain or loss on the terminated item.
- Interest rate differentials to be paid or received as a result of interest rate swap agreements are accrued and recognized as an adjustment of interest expense related to the designated debt. Discounts or premiums from foreign currency forward contracts are accreted or amortized to interest expenses over the contract period of the agreements using the straight-line method while realized and unrealized gains and losses are offset against losses or gains on the items hedged.

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

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

New Accounting Standards

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

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

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

3. Segment and geographic information

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

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

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

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

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

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

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

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

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

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

Revenues by geographic areas

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

Long-lived assets by geographic areas

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

4. Significant Acquisitions and Dispositions

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

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

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

5. Asset Impairments

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

6. Restructuring and Other Charges

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

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

At December 31, 2001 and December 31, 2002 the remaining provision for drilling service contracts was NOK 734 million and NOK 960 million, respectively. During 2000, 2001 and 2002, NOK 172 million, NOK 76 million and NOK 5 million, respectively, of contract payments were charged against the provision. These charges impact the Exploration and Production Norway segment.

7. Inventories

The lower of cost or market test is measured, and the results are recognized separately, on a country-by-country basis, and any resulting write-downs to market, if required, are recorded as permanent adjustments to the cost of inventories. There have been no liquidations of LIFO layers which resulted in a material impact to net income for the reported periods.

	AT DECEMBER 31,	
(IN NOK MILLION)	*2002*	*2001*
Crude oil	2,766	2,919
Petroleum products	2,647	2,567
Other	844	593
Total - inventories valued on a FIFO basis	6,257	6,079
Excess of current cost over LIFO value	(835)	(803)
Total	5,422	5,276

8. Summary Financial Information of Unconsolidated Equity Affiliates

Statoil's investments in affiliates include a 50% interest in Borealis, a petrochemical production company, and a 50% interest in Statoil Detaljhandel Skandinavia AS (SDS), a group of retail petroleum service stations.

Summary financial information for affiliated companies accounted for by the equity method is shown below. Statoil's investment in these companies is included in Investments in affiliates. Accounts receivable - related parties in the Consolidated Balance Sheets relate to amounts due from equity affiliates.

Equity method affiliates - gross amounts

	BOREALIS			SDS		
(IN NOK MILLION)	*2002*	*2001*	*2000*	*2002*	*2001*	*2000*
At December 31,						
Current assets	5,909	7,694	10,753	2,798	3,189	3,014
Non-current assets	17,432	19,710	18,121	6,029	6,105	6,333
Current liabilities	6,063	6,108	9,740	3,288	2,894	3,277
Long-term debt	5,787	8,787	5,870	2,488	3,382	3,242
Other liabilities	2,187	2,201	2,570	0	0	0
Net assets	9,304	10,310	10,694	3,051	3,018	2,828
Year ended December 31,						
Gross revenues	25,617	29,819	30,465	23,112	24,563	26,069
Income before taxes	215	(193)	686	423	411	328
Net income	43	(330)	488	302	290	233
Capital expenditures	978	1,182	2,117	721	552	592

Dividends received from Borealis amounted to NOK 0, 16 and 187 million for 2002, 2001 and 2000, respectively. No dividends have been received from SDS.

Equity method affiliates - detailed information

(AMOUNTS IN MILLIONS)	*CURRENCY*	*PAR VALUE*	*SHARE CAPITAL*	*OWNERSHIP*	*BOOK VALUE*	*PROFIT SHARE*
Statoil Detaljhandel Skandinavia AS	NOK	1,300	2,600	50%	1,152	221
Borealis A/S	DKK	2,000	4,000	50%	4,775	53
P/R West Navion DA	NOK	-	-	50%	1,115	(56)
Other companies	-	-	-	-	2,587	148
Total					9,629	366

Ownership corresponds to voting rights.

The difference between the book value and equity interest of the investment in SDS represents the difference between the book value and the fair value on the sale of Statoil's 50% interest in SDS in 1999 which is being amortized. P/R West Navion DA owns the drillship *West Navion*, and its only activity pertains to this drillship.

9. Investments

Short-term investments

(IN NOK MILLION)	*AT DECEMBER 31, 2002*	*2001*
Short-term deposits	51	189
Certificates	5,073	1,692
Bonds	50	180
Other	93	2
Total short-term investments	5,267	2,063

The cost price of short-term investments for the years ended December 31, 2002 and 2001 was NOK 5,261 and 2,053 million, respectively.

All short-term investments are considered to be trading securities and are recorded at fair value with unrealized gains and losses included in income.

Long-term investments included in Other assets

(IN NOK MILLION)	*AT DECEMBER 31, 2002*	*2001*
Shares in other companies	1,166	943
Certificates	1,031	680
Bonds	2,749	3,324
Marketable equity securities	1,270	1,596
Total long-term investments	6,216	6,543

10. Property, plant and equipment

(IN NOK MILLION)	MACHINERY, EQUIPMENT AND TRANSPORTATION EQUIPMENT	PRODUCTION PLANTS OIL AND GAS, INCL PIPELINES	PRODUCTION PLANTS ONSHORE	BUILDINGS AND LAND	VESSELS	CONSTRUCTION IN PROGRESS	CAPITALIZED EXPLORATION COST	TOTAL
Cost at January 1, 2002	10,891	205,862	26,651	6,521	8,221	11,941	4,281	274,368
Accumulated depreciation, depletion and amortization at January 1, 2002	(8,253)	(119,999)	(15,664)	(1,811)	(2,204)	64	0	(147,867)
Additions and transfers	1,131	11,275	5,094	292	0	673	98	18,563
Disposals at book value	(26)	(136)	(7)	(20)	0	(222)	(7)	(418)
Expensed expl cost capitalized prior years	0	0	0	0	0	0	(552)	(552)
Depreciation, depletion and amortization for the year	(584)	(14,476)	(1,234)	(200)	(286)	0	0	(16,780)
Foreign currency translation	(168)	(2,001)	(1,697)	(416)	(84)	(239)	(330)	(4,935)
Book value at December 31, 2002	2,991	80,525	13,143	4,366	5,647	12,217	3,490	122,379
Estimated useful life (years)	5-10	*	15-20	20-25	20-25			

*Unit of production, see note 1.

In 2002, 2001 and 2000, NOK 382, 723 and 1,494 millon, respectively, of interests were capitalized.
In addition to depreciation, depletion and amortization specified above intangible assets have been amortized by NOK 64 million in 2002.

11. Provisions

Provisions against assets (other than property, plant and equipment and intangible assets) recorded during the past three years are as follows:

(IN NOK MILLION)	AT JANUARY 1,	EXPENSE	RECOVERY	WRITE-OFF	OTHER	AT DECEMBER 31,
Year 2002						
Provisions for other long-term assets	16	0	(16)	0	0	0
Provisions for accounts receivables	212	47	(59)	(33)	(14)	153
Year 2001						
Provisions for other long-term assets	90	0	0	0	(74)	16
Provisions for accounts receivables	224	44	0	(12)	(44)	212
Year 2000						
Provisions for other long-term assets	90	0	0	0	0	90
Provisions for accounts receivables	174	33	43	(23)	(3)	224

12. Financial Items

(IN NOK MILLION)	YEAR ENDED DECEMBER 31, 2002	2001	2000
Interest and other financial income	1,311	2,107	2,426
Currency exchange adjustments, net	9,009	912	(3,389)
Interest and other financial expenses	(1,952)	(2,713)	(2,035)
Dividends received	457	18	82
Gain (loss) on sale of securities	(228)	(97)	371
Unrealized gain (loss) on securities	(364)	(162)	(353)
Net financial items	8,233	65	(2,898)

13. Income Taxes

Net income before taxes consist of

(IN NOK MILLION)	*YEAR ENDED DECEMBER 31,* 2002	2001	2000
Norway			
• Offshore	42,519	49,651	52,307
• Onshore	5,394	5,843	3,052
Other countries	3,422	725	1,734
Total	51,335	56,219	57,093

Significant components of income tax expense were as follows

(IN NOK MILLION)	*YEAR ENDED DECEMBER 31,* 2002	2001	2000
Norway			
• Offshore	34,253	37,942	39,542
• Onshore	885	1,169	979
Other countries 1)	352	253	529
Uplift benefit	(1,782)	(1,726)	(1,816)
Current income tax expense	33,708	37,638	39,234
Norway			
• Offshore	(707)	317	528
• Onshore	250	383	254
Other countries 1)	1,085	148	440
Deferred tax expense	628	848	1,222
Total income tax expense	34,336	38,486	40,456

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

Significant components of deferred tax assets and liabilities were as follows

(IN NOK MILLION)	*AT DECEMBER 31,* 2002	2001
Net operating loss carry-forwards	1,157	2,120
Impairment	1,058	1,365
Decommissioning	4,733	4,277
Other	3,665	4,911
Valuation allowance	(2,140)	(2,135)
Total deferred tax assets	8,473	10,538
Property, plant and equipment	35,518	35,144
Capitalized exploration expenditures and interest	8,914	8,668
Other	6,293	8,370
Total deferred tax liabilities	50,725	52,182

Deferred taxes are classified as followed

(IN NOK MILLION)	AT DECEMBER 31, 2002	2001
Short-term deferred tax asset	(415)	(113)
Long-term deferred tax asset	(486)	(597)
Long-term deferred tax liability	43,153	42,354

A valuation allowance has been provided as Statoil believes that available evidence creates sufficient uncertainty as to the realizability of certain deferred tax assets. Statoil will continue to assess the valuation allowance and to the extent it is determined that such allowance is no longer required, the tax benefit of the remaining net deferred tax assets will be recognized in the future.

Reconciliation of Norwegian nominal statutory tax rate of 28% to effective tax rate

(IN NOK MILLION)	2002	2001	2000
Calculated income taxes at statutory rate	14,374	15,741	15,969
Petroleum surtax	20,538	24,342	26,159
Uplift benefit	(1,782)	(1,726)	(1,816)
Other, net	1,206	129	144
Income tax expense	34,336	38,486	40,456

Revenue from oil and gas activities on the NCS is taxed according to the Petroleum tax law. This stipulates a surtax of 50% after deducting uplift, a special investment tax credit, in addition to normal corporate taxation. Uplift credits are deducted as they arise, 5% each year for six years, as from initial year of investment. Uplift credits not utilized of NOK 8.9 billion can be carried forward indefinitely.

At the end of 2002, Statoil had tax loss carry-forwards of NOK 3.3 billion, primarily in the US and in Ireland. Only a minor part of the carry-forward amounts expires before 2006.

14. Short-term Debt

(IN NOK MILLION)	AT DECEMBER 31, 2002	2001
Bank loans and overdraft facilities	2,258	948
Current portion of long-term debt	2,018	5,364
Other	47	301
Total	4,323	6,613
Weighted average interest rate (%)	5.28	4.62

15. Long-term Debt

	WEIGHTED AVERAGE INTEREST RATES IN %		*BALANCE IN NOK MILLION AT DECEMBER 31,*	
	2002	*2001*	*2002*	*2001*
Unsecured debentures bonds				
US dollar (US$)	5.74	5.79	16,590	19,006
Norwegian kroner (NOK)	7.50	5.67	20	255
Euro (EUR)	4.66	4.58	5,780	4,518
Swiss franc (CHF)	3.14	2.87	3,548	4,652
Japanese yen (JPY)	1.83	2.09	2,994	1,808
Great British pounds (GBP)	-	6.13	-	3,080
Total			28,932	33,319
Unsecured bank loans				
US dollar (US$)	1.77	6.00	2,193	3,510
Secured bank loans				
US dollar (US$)	3.82	6.43	2,902	2,879
Other debt			796	838
Grand total debt outstanding			34,823	40,546
Less current portion			(2,018)	(5,364)
Total long-term debt			32,805	35,182

Statoil has an unsecured debenture bond agreement for US$ 500 million with a fixed interest rate of 6.5%, maturing in 2028, callable at par upon change in tax law. At December 31, 2002 and 2001, NOK 3,435 million and NOK 4,441 million were outstanding, respectively. The interest rate of the bond has been swapped to a LIBOR-based floating interest rate.

Statoil has also an unsecured debenture bond agreement for EUR 500 million, with a fixed interest rate of 5.125%, maturing in 2011. At December 31, 2002 and 2001, NOK 3,601 million and NOK 3,933 million were outstanding, respectively. EUR 200 million of the bond has been swapped through an interest rate swap agreement to a LIBOR-based floating interest rate.

Statoil has also an unsecured debenture bond agreement for US$ 375 million, with a fixed interest rate of 5.75%, maturing in 2009. At December 31, 2002 and 2001, NOK 2,591 million and NOK 3,347 million were outstanding, respectively.

In addition to the unsecured debentures bond debt of NOK 16,590 million, denominated in US dollars, Statoil utilizes foreign currency swaps to manage foreign exchange risk on its long-term debt. As a result, an additional NOK 10,899 million of Statoil's unsecured debentures bond debt has been swapped to US dollars. The foreign currency swaps are not reflected in the table above as the swaps are separate legal agreements. The foreign currency swaps do not qualify as hedges according to FAS 133 as the swaps are not to functional currency, although they qualify as economic hedges. The stated interest rate on the majority of the long-term debt is fixed. Interest rate swaps are utilized to manage interest rate exposure.

Substantially all unsecured debenture bond and unsecured bank loan agreements contain provisions restricting the pledging of assets to secure future borrowings without granting a similar secured status to the existing bondholders and lenders.

Statoil has 21 debenture bond agreements outstanding, which contain provisions allowing Statoil to call the debt prior to its final redemption at par if there are changes to the Norwegian tax laws or at certain specified premiums. The agreements are, net after buyback, at the December 31, 2002 closing rate valued at NOK 24,315 million.

Reimbursements of long-term debt fall due as follows:

(IN NOK MILLION)	
2003	2,018
2004	3,235
2005	1,465
2006	1,801
2007	2,036
Thereafter	24,268
Total	34,823

Statoil has an agreement with an international bank syndicate for committed long-term revolving credit facility totalling US$ 1.0 billion, all undrawn. Commitment fee is 0.105% per annum.

As of December 31, 2002 and 2001 respectively, Statoil had no committed short-term credit facilities available or drawn.

16. Financial Instruments and Risk Management

Statoil uses derivative financial instruments to manage risks resulting from fluctuations in underlying interest rates, foreign currency exchange rates and commodity (such as oil, natural gas and refined petroleum products) prices. Because Statoil operates in the international oil and gas markets and has significant financing requirements, it has exposure to these risks, which can affect the cost of operating, investing and financing. Statoil has used and intends to use financial and commodity-based derivative contracts to reduce the risks in overall earnings and cash flows. Derivative instruments creating essentially equal and offsetting market exposures are used to help manage certain of these risks. Management also uses derivatives to establish certain positions based on market movements although this activity is immaterial to the consolidated financial statements.

Interest and currency risks constitute significant financial risks for the Statoil group. Total exposure is managed at portfolio level in accordance with the strategies and mandates issued by the Enterprise-Wide Risk Management Program and monitored by the Corporate Risk Committee. Statoil's interest rate exposure is mainly associated with the group's debt obligations and management of the assets in Statoil Forsikring AS. Statoil mainly employs interest rate swap and currency swap agreements to manage interest rate and currency exposure.

Statoil uses swaps, options, futures, and forwards to manage its exposure to changes in the value of future cash flows from future purchases and sales of crude oil and refined oil products. The term of the oil and refined oil products derivatives is usually less than one year. Natural gas and electricity swaps, options, forwards, and futures are likewise utilized to manage Statoil's exposure to changes in the value of future sales of natural gas and electricity. These derivatives usually have terms of approximately three years or less. Most of the derivative transactions are made in the over-the-counter (OTC) market.

Cash Flow Hedges

Statoil has designated certain derivative instruments as cash flow hedges to hedge against changes in the amount of future cash flows related to the sale of oil and refined petroleum products over a period not exceeding 12 months and cash flows related to interest payments over a period not exceeding 25 months. Hedge ineffectiveness related to Statoil's outstanding cash flow hedges was immaterial and recorded to earnings during the year ended December 31, 2002. The net change in Other comprehensive income associated with the current year hedging transactions was NOK 116 million (after tax), and the net amount reclassified into earnings during the year was immaterial. At December 31, 2002, the net deferred hedging loss in Accumulated other comprehensive income was NOK 118 million (after tax), the majority of which will affect earnings over the next 12 months. There were no cash flow hedges discontinued during the year because it was probable that the original forecasted transaction would not occur by the end of the originally specified time period.

Fair Value Hedges

Statoil has designated certain derivative instruments as fair value hedges to hedge against changes in the value of financial liabilities. There was no gain or loss component of a derivative instrument excluded from the assessment of hedge effectiveness related to fair value hedges during the year ended December 31, 2002. The net gain recognized in earnings in Net financial items during the year for ineffectiveness of fair value hedges was immaterial.

Fair Value of Financial Instruments

Except for the recorded amount of fixed interest long-term debt, the recorded amounts of cash and cash equivalents, receivables, bank loans, other interest bearing short-term debt, and other liabilities approximate their fair values. Marketable equity and debt securities are also recorded at their fair values.

The following table contains the carrying amounts and estimated fair values of financial instruments, and the carrying amounts and estimated fair value of long-term debts. Commodity contracts capable of being settled by delivery of commodities (oil & oil products, natural gas, electricity) are excluded from the summary.

The following table contains the carrying amounts and estimated fair values of financial derivative instruments, and the carrying amounts and estimated fair value of long-term debts. Commodity contracts capable of being settled by delivery of commodities (oil and oil products, natural gas, electricity) are excluded from the summary.

(IN NOK MILLION)	*FAIR MARKET VALUE OF ASSETS*	*FAIR MARKET VALUE OF LIABILITIES*	*NET CARRYING AMOUNT*
At December 31, 2002			
Debt-related instruments	2,153	(150)	2,003
Non-debt-related instruments	143	(5)	138
Long-term fixed interest debt	-	(28,475)	(25,465)
Crude oil and Refined products	568	(844)	(276)
Gas and Electricity	265	(212)	53
At December 31, 2001			
Debt-related instruments	602	(1,518)	(916)
Non-debt-related instruments	25	(32)	(7)
Long-term fixed interest debt	-	(30,730)	(29,246)
Crude oil and Refined products	701	(360)	341
Gas and Electricity	67	(46)	21

Fair values are estimated using quoted market prices, estimates obtained from brokers, prices of comparable instruments, and other appropriate valuation techniques. The fair value estimates approximate the gain or loss that would have been realized if the contracts had been closed out at year-end, although actual results could vary due to assumptions utilized.

Credit risk management

Statoil manages credit risk concentration with respect to financial instruments by holding only investment grade securities distributed among a variety of selected issuers. A list of authorized investment limits by commercial issuer is maintained and reviewed regularly along with guidelines which include an assessment of the financial position of counter-parties as well as requirements for collateral.

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

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

The credit risk concentration with respect to receivables is limited due to the large number of counter-parties spread worldwide in numerous industries.

The credit risk from Statoil's over-the-counter derivative contracts derives from the counter-party to the transaction, typically a major bank or financial institution, a major oil company or a trading company. Statoil does not anticipate non-performance by any of these counter-parties, and no material loss would be expected from any such unexpected non-performance. Futures contracts and exchange-traded options have a negligible credit risk as they are principally traded on the New York Mercantile Exchange or the International Petroleum Exchange of London.

Consequently, Statoil does not consider itself exposed to a significant concentration of credit risk.

17. Employee Retirement Plans

Pension benefits

Statoil and many of its subsidiaries have defined benefit retirement plans, which cover substantially all of their employees. Plan benefits are generally based on years of service and final salary levels. Some subsidiaries have defined contribution or multi-employer plans.

Net periodic pension cost

(IN NOK MILLION)	*YEAR ENDED DECEMBER 31,* 2002	2001	2000
Benefit earned during the year, net of participants' contributions	738	690	678
Interest cost on prior period benefit obligation	719	626	578
Expected return on plan assets	(856)	(793)	(761)
Amortization of loss	34	10	14
Amortization of prior service cost	44	44	44
Amortization of net transition assets	(16)	(16)	(16)
Defined benefit plans	663	561	537
Defined contribution plans	19	21	21
Multi-employer plans	4	4	4
Total net periodic pension cost	686	586	562

Change in projected benefit obligation (PBO)

(IN NOK MILLION)	*2002*	*2001*
Projected benefit obligation at beginning of year	12,000	10,632
Benefits earned during the year	738	690
Interest cost on prior period benefit obligation	719	626
Actuarial gain (loss)	(13)	471
Benefits paid	(401)	(391)
Foreign currency translation	(18)	(28)
Projected benefit obligation at end of year	13,025	12,000

Change in pension plan assets

(IN NOK MILLION)	*2002*	*2001*
Fair value of plan assets at beginning of year	13,068	12,310
Retained earnings in the pension trusts reclassified to plan assets	0	954
Actual return on plan assets	(770)	(15)
Company contributions	412	8
Benefits paid	(183)	(170)
Foreign currency translation	(47)	(19)
Fair value of plan assets at end of year	12,480	13,068

Status of pension plans reconciled to balance sheet

(IN NOK MILLION)	*AT DECEMBER 31, 2002*	*2001*
Funded status of the plans at end of year	(545)	1,068
Unrecognized net loss	1,868	769
Unrecognized prior service cost	363	462
Unrecognized net transition asset	(15)	(31)
Total net prepaid pension recognized	1,671	2,268
Amounts recognized in the balance sheet:		
Prepaid pension	3,861	4,046
Accrued pension liabilities	(2,190)	(1,778)
Net amount recognized	1,671	2,268

Weighted-average assumptions at end of year

Discount rate	6.0%	6.0%
Expected return on plan assets	6.5%	6.5%
Rate of compensation increase	3.0%	3.0%

The projected benefit obligation, accumulated benefit obligation, and fair value of plan assets for pension plans with accumulated benefit obligations in excess of plan assets were NOK 3,102 million, NOK 2,235 million and NOK 425 million, respectively, at December 31, 2002, and NOK 3,352 million, NOK 2,430 million and NOK 422 million, respectively, at December 31, 2001.

18. Decommissioning and Removal Liabilities

At December 31, 2002 and 2001, NOK 8,056 million and NOK 7,521 million, respectively, had been accrued for future well closure, decommissioning and removal of offshore installations and are included in Other liabilities. Statoil's share of the estimated total future well closure, decommissioning and removal costs is NOK 10,700 million and NOK 13,300 million at December 31, 2002 and 2001, respectively.

19. Research Expense

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

20. Leases

Statoil leases certain assets, notably shipping vessels.

In 2002, rental expense was NOK 5,595 million. In 2001 and 2000 rental expenses were NOK 7,687 and 6,455 million, respectively.

The information below shows future minimum lease payments under non-cancelable leases at December 31, 2002.

(IN NOK MILLION)	*OPERATING LEASES*	*CAPITAL LEASES*
2003	4,070	11
2004	3,087	12
2005	2,782	13
2006	2,350	14
2007	1,638	16
Thereafter	6,617	0
Total future rents	20,544	66
Interest component		(10)
Net present value		56

Property, plant and equipment include the following amounts for leases that have been capitalized at December 31, 2002 and 2001.

	AT DECEMBER 31,	
(IN NOK MILLION)	*2002*	*2001*
Vessels	107	217
Less accumulated depreciation	(80)	(177)
Net	27	40

21. Other Commitments and Contingencies

Contractual commitments

(IN NOK MILLION)	*IN 2003*	*THEREAFTER*	*TOTAL*
Contractual commitments made	8,633	10,665	19,298

These contractual commitments comprise acquisition and construction of tangible fixed assets.

Guarantees

The group has provided guarantees of NOK 0.7 billion for short-term commercial transactions and contractual commitments.

Contingent liabilities and insurance

Like any other licensee, Statoil has unlimited liability for possible compensation claims arising from its offshore operations, including transport systems. The Company has taken out insurance to cover this liability up to about NOK 5.6 billion for each incident, including liability for claims arising from pollution damage. Most of the group's production installations are covered through Statoil Forsikring AS, which reinsures a major part of the risk in the international insurance market. About 30% is retained.

Other commitments

As a condition for being awarded oil and gas exploration and production licenses, participants are committed to drill a certain number of wells. At the end of 2002, Statoil was committed to participating in 15 wells off Norway and 12 wells abroad, with an average ownership interest of approximately 32%. The cost to drill these wells is estimated to NOK 1.4 billion.

As owner in BTC Co Ltd Statoil is committed to, directly or indirectly, to finance, or to provide guarantees for financing of a development of the BTC pipeline system of approximately US$ 425 million in total. As a participant in the Transportation Agreement between BTC Co Ltd and the owners of the Azeri-Chirag-Gunashli oil field Statoil has entered into a ship and pay arrangement.

In addition, Statoil has entered into agreements for pipeline transportation for most of its prospective gas sale contracts. These agreements ensure the right to transport the production of gas through the pipelines, but also impose an obligation to cover Statoil's proportional share of the transportation costs. On the Norwegian continental shelf, Statoils ownership interest in the pipeline transportation systems exceeds its share of the transported volumes.

During the normal course of its business Statoil is involved in legal proceedings and a number of unresolved claims are currently outstanding. The ultimate liability in respect of litigation and claims cannot be determined at this time. Provisions in the accounts for these items are based on the Company's best judgment. Statoil is of the opinion that neither the financial position, results of operations nor cash flows will be material adverse affected by the resolution of these legal proceedings.

22. Related Parties

Total purchases of oil and natural gas liquid from the Norwegian State amounted to NOK 72,298 million (374 million barrels oil equivalents), NOK 53,291 million (265 million barrels oil equivalents) and NOK 42,290 million (173 million barrels oil equivalents), in 2002, 2001 and 2000, respectively. Amounts payable to the Norwegian State for these purchases are included as Accounts payable - related parties in the Consolidated Balance Sheets. The prices paid by Statoil for the oil purchased from the Norwegian State are estimated market prices. In addition Statoil sells the Norwegian State's natural gas, in its own name, but for the account and risk of the Norwegian State.

In addition to Accounts payable - related parties and Accounts receivable - related parties Statoil has a long term receivable of NOK 780 million against the Norwegian State included in Long-term receivables.

23. Shareholders' equity

Upon Statoil's inception in September 1972, 50,000 ordinary shares at NOK 100 nominal value were issued. There have been several subsequent issuances of ordinary shares, the last increase before the public offering of shares being in June 1989 for 19,962,140 ordinary shares issued at NOK 100 nominal value.

On May 10, 2001, an extraordinary general meeting approved a common stock split by which the existing 49,397,140 ordinary shares with nominal value of NOK 100 per share was replaced by 1,975,885,600 ordinary shares with nominal value of NOK 2.50 per share. All references to the number of ordinary shares and per share common amounts have been restated to give retroactive effect to the stock split for all periods presented.

At an extraordinary general meeting held on May 25, 2001, it was resolved to increase the share capital by NOK 62,500,000 through the issuance of 25 million ordinary shares through a transfer of capital from "Additional paid-in capital" to share capital (a bonus issue). Pursuant to this resolution, the Norwegian State waived its rights to receive the new shares, which was issued to the Company as treasury shares. In 2002 1,558,026 of the treasury shares were distributed as bonus shares in favor of retail investors in the initial public offering in 2001. Distribution of treasury shares requires approval by the general meeting.

At an extraordinary general meeting, held on June 17, 2001 it was further resolved to increase the share capital by NOK 471,750,000 from NOK 5,002,214,000 to NOK 5,473,964,000 through the issuance of 188,700,000 new ordinary shares of NOK 2.50 nominal value each. In June 2001, the Company completed a public offering of shares, which raised NOK 12,890 million, net of expenses, on the issuance of 188,700,000 shares of common stock.

There exists only one class of shares and all have voting rights.

Retained earnings available for distribution of dividends at December 31, 2002, is limited to the retained earnings of the parent company based on Norwegian accounting principles and legal regulations and amounts to NOK 39,482 million (before provisions for proposed dividend for the year ended December 31, 2002 of NOK 6,282 million). This differs from retained earnings in the financial statements of NOK 17,355 million mainly due to the impact of the transfer of the SDFI properties to Statoil, which is not reflected in the Norwegian GAAP accounts until the second quarter of 2001. Distribution of dividends is not allowed to reduce the shareholders' equity in the unconsolidated accounts of the parent company below 10 percent of total assets.

24. Auditors' remuneration

Total remuneration to the external auditors for the fiscal year 2002 amounted to NOK 22.8 million for audit services and NOK 13.7 million for other services, including NOK 5.2 million for audit related services.

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (unaudited)

In accordance with Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities and regulations of the US Securities and Exchange Commission (SEC), Statoil is making certain supplemental disclosures about oil and gas exploration and production operations. While this information was developed with reasonable care and disclosed in good faith, it is emphasized that some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgment involved in developing such information. Accordingly, this information may not necessarily represent the present financial condition of Statoil or its expected future results.

All the tables presented include the impact from the SDFI transaction. See note 1.

Oil and gas reserve quantities

Statoil's oil and gas reserves have been estimated by its experts in accordance with industry standards under the requirements of the SEC. Reserves are net of royalty oil paid in kind, and quantities consumed during production. Statements of reserves are forward-looking statements.

The determination of these reserves is part of an ongoing process subject to continual revision as additional information becomes available.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Statoil is selling its oil and gas together with the oil and gas of the Norwegian state (SDFI).

Under this arrangement, Statoil and SDFI will deliver gas to its customers in accordance with certain supply type sales contracts. The commitments will be met using a schedule that provides the highest possible total value for our oil and gas and the Norwegian State's oil and gas. Our gas reserves will be drawn on to supply this gas in the proportion that we own production from the fields that from time to time are chosen to deliver gas against these commitments. The commitments to be met by Statoil and SDFI under this arrangement were on December 31, 2002 to deliver a total of 36.9 tcf (41.7 trillion MJ @1.13 MJ/cf).

Statoil's and SDFI's delivery commitments for the contract years 2002, 2003, 2004 and 2005 are 1,568, 1,570, 1,592 and 1,911 bcf respectively (1,777, 1,779, 1,804 and 2,166 billion MJ). These commitments may be met by production from proved reserves of fields were both Statoil and the Norwegian State participates and by deliveries that the Norwegian State makes from fields where Statoil does not participate.

The principles for booking of proved gas reserves are limited to contracted gas sales and gas with access to a market. New contracted sales from the Norwegian continental shelf are recorded as Extensions and discoveries.

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (unaudited)

In 1997, Statoil entered into a service contract in Venezuela. The group's share of base production is not included in the reserves. Expected recovery of the field's proved reserves over and above quantities provided for in the service contract as base production is included in the International Exploration and Production oil reserves.

In 2002, Statoil entered into a buy-back contract in Iran. Statoil also participates in a number of production sharing agreements (PSA). Reserves from such agreements are based on the volumes to which Statoil has access (cost oil and profit oil), limited to available market access. Proved reserves at end of year associated with PSA and buy-back agreements are disclosed separately.

The totals in the following tables may not equal the sum of the amounts shown due to rounding.

	NET PROVED OIL AND NGL RESERVES IN MILLION BARRELS			*NET PROVED GAS RESERVES IN BILLION STANDARD CUBIC FEET*			*NET PROVED OIL, NGL AND GAS RESERVES IN MILLION BARRELS OIL EQUIVALENTS*		
	NORWAY	*OUTSIDE NORWAY*	*TOTAL*	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
At December 31, 1999	1,675	462	2,136	13,213	114	13,328	4,029	482	4,511
Proved developed reserves	934	85	1,019	7,505	68	7,574	2,271	97	2,368
Revisions and improved recovery	8	30	38	56	(11)	45	18	28	46
Extensions and discoveries	79	18	97	27	170	197	84	48	132
Sales of reserves-in-place	(2)	0	(2)	0	(19)	(19)	(2)	(3)	(5)
Production	(254)	(21)	(275)	(495)	(19)	(514)	(342)	(24)	(367)
At December 31, 2000	1,506	488	1,994	12,802	234	13,036	3,787	530	4,317
Of which:									
Proved developed reserves	940	187	1,127	8,630	65	8,695	2,478	198	2,677
Proved reserves under PSA and buy-back agreements	0	204	204	0	0	0	0	204	204
Production from PSA and buy-back agreements	0	3	3	0	0	0	0	3	3
Revisions and improved recovery	68	30	98	252	(7)	245	113	29	142
Extensions and discoveries	124	69	193	188	225	413	158	109	267
Sales of reserves-in-place	(54)	(1)	(55)	(1)	(170)	(171)	(54)	(31)	(85)
Production	(246)	(22)	(268)	(523)	(15)	(538)	(339)	(25)	(364)
At December 31, 2001	1,398	565	1,963	12,718	267	12,985	3,664	612	4,277
Of which:									
Proved developed reserves	948	166	1,113	9,069	42	9,112	2,564	173	2,737
Proved reserves under PSA and buy-back agreements	0	302	302	0	0	0	0	302	302
Production from PSA and buy-back agreements	0	3	3	0	0	0	0	3	3
Revisions and improved recovery	108	(25)	83	237	0	237	151	(25)	125
Extensions and discoveries	31	73	104	942	0	942	199	73	272
Purchase of reserves-in-place	4	0	4	35	0	35	10	0	10
Sales of reserves-in-place	(13)	(2)	(16)	(73)	0	(73)	(26)	(2)	(29)
Production	(242)	(29)	(271)	(645)	(12)	(657)	(357)	(31)	(388)
At December 31, 2002	1,286	580	1,867	13,215	255	13,470	3,641	626	4,267
Of which:									
Proved developed reserves	919	137	1,056	9,321	30	9,351	2,580	143	2,722
Proved reserves under PSA and buy-back agreements	0	349	349	0	0	0	0	349	349
Production from PSA and buy-back agreements	0	12	12	0	0	0	0	12	12

The conversion rates used are 1 standard cubic meter = 35.3 standard cubic feet, 1 standard cubic meter oil equivalent = 6.29 barrels of oil equivalent and 1,000 standard cubic meter gas = 1 standard cubic meter oil equivalent.

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (unaudited)

Statoil has historically marketed and sold the Norwegian State's oil and gas as a part of its own production. The Norwegian State has elected to continue this arrangement. Accordingly, at an extraordinary general meeting held on February 27, 2001, the Norwegian State, as sole shareholder, revised Statoil's articles of association by adding a new article which requires Statoil to continue to market and sell the Norwegian State's oil and gas together with Statoil's own oil and gas in accordance with an instruction established in shareholder resolutions in effect from time to time. At an extraordinary general meeting held on May 25, 2001, the Norwegian State, as sole shareholder, approved a resolution containing the instructions referred to in the new article. This resolution is referred to as the owner's instruction. For natural gas acquired by Statoil for its own use, its payment to the Norwegian State will be based on market value. For all other sales of natural gas to Statoil or to third parties the payment to the Norwegian State will be based on either achieved prices, a net back formula or market value. All of the Norwegian State's oil and NGL will be acquired by Statoil. Pricing of the crude oil will be based on market reflective prices; NGL prices will be either based on achieved prices, market value or market reflective prices.

The Norwegian State may at any time cancel the owner's instruction. Due to this uncertainty and the Norwegian State's estimate of proved reserves not being available to Statoil, it is not possible to determine the total quantities to be purchased by Statoil under the owner's instruction from properties in which it participates in the operations.

Capitalized costs related to Oil and Gas producing activities

(IN NOK MILLION)	*AT DECEMBER 31, 2002*	*2001*
Unproved Properties	3,490	4,281
Proved Properties, wells, plants and other equipment	222,494	208,446
Total Capitalized Costs	225,984	212,727
Accumulated depreciation, depletion, amortization and valuation allowances	(133,925)	(117,450)
Net Capitalized Costs	92,059	95,277

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

These costs include both amounts capitalized and expensed.

(IN NOK MILLION)	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Year ended December 31, 2002			
Exploration costs	1,350	942	2,292
Development costs	10,269	4,088	14,357
Total	11,619	5,030	16,649
Year ended December 31, 2001			
Exploration costs	2,020	683	2,703
Development costs	9,707	4,452	14,159
Total	11,727	5,135	16,862
Year ended December 31, 2000			
Exploration costs	1,657	1,764	3,421
Development costs	11,470	3,628	15,098
Total	13,127	5,392	18,519

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (unaudited)

Results of Operation for Oil and Gas Producing Activities

As required by Statement of Financial Accounting Standards No. 69, the revenues and expenses included in the following table reflect only those relating to the oil and gas producing operations of Statoil.

Activities included in Statoil's segment disclosures in note 3 to the financial statements but excluded from the table below relates to gas trading activities, transportation and business development as well as effects of disposals of oil and gas interests.

Income tax expense is calculated on the basis of statutory tax rates in addition to uplift and tax credits only. No deductions are made for interest or overhead.

Transfers are recorded approximating market prices.

(IN NOK MILLION)	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Year ended December 31, 2002			
Sales	1,199	4,744	5,943
Transfers	54,585	1,018	55,603
Total revenues	55,784	5,762	61,546
Exploration expenses	(1,420)	(775)	(2,195)
Production costs	(8,617)	(774)	(9,391)
Special items 1)	0	(766)	(766)
DD&A 2)	(12,402)	(1,738)	(14,140)
Total costs	(22,439)	(4,053)	(26,492)
Results of operations before taxes	33,345	1,709	35,054
Tax expense	(25,203)	(870)	(26,073)
Results of producing operations	8,142	839	8,981
Year ended December 31, 2001			
Sales	1,379	2,957	4,336
Transfers	61,913	1,767	63,680
Total revenues	63,292	4,724	68,016
Exploration expenses	(2,011)	(866)	(2,877)
Production costs	(8,557)	(1,102)	(9,659)
Special items 1)	0	(2,000)	(2,000)
DD&A 2)	(12,637)	(1,477)	(14,114)
Total costs	(23,205)	(5,445)	(28,650)
Results of operations before taxes	40,087	(721)	39,366
Tax expense	(30,958)	216	(30,742)
Results of producing operations	9,129	(505)	8,624

(IN NOK MILLION)	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Year ended December 31, 2000			
Sales	1,418	5,804	7,222
Transfers	69,610	1	69,611
Total revenues	71,028	5,805	76,833
Exploration expenses	(1,310)	(1,141)	(2,451)
Production costs	(8,338)	(1,414)	(9,752)
Special items	0	130	130
DD&A 2)	(12,468)	(1,815)	(14,283)
Total costs	(22,116)	(4,240)	(26,356)
Results of operations before taxes	48,912	1,565	50,477
Tax expense	(36,851)	(250)	(37,101)
Results of producing operations	12,061	1,315	13,376

1) Impairment of the oil field LL652 in Venezuela.

2) Include provisions made for future decommissioning and removal costs.

Standardized measure of discounted future net cash flows relating to proved oil and gas reserves

The table below shows the standardized measure of future net cash flows relating to proved reserves presented. The analysis is computed in accordance with FASB Statement No. 69, by applying year-end market prices, costs, and statutory tax rates, and a discount factor of 10% to year-end quantities of net proved reserves. The standardized measure is a forward-looking statement.

Future price changes are limited to those provided by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions. Future net cash flow pre-tax is net of decommissioning costs. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using 10% mid-period discount factors. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced. *The information provided does not represent management's estimate of Statoil's expected future cash flows or value of proved oil and gas reserves.* Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, identified reserves and contingent resources, that may become proved in the future, are excluded from the calculations. The standardized measure of valuation prescribed under FASB Statement No. 69 requires assumptions as to the timing and amount of future development and production costs and income from the production of proved reserves. This does not reflect management's judgment and should not be relied upon as an indication of Statoil's future cash flow or value of its proved reserves.

(IN NOK MILLION)	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
At December 31, 2002			
Future net cash inflows	644,327	127,460	771,787
Future development costs	(44,983)	(17,396)	(62,379)
Future production costs	(192,779)	(22,146)	(214,925)
Future net cash flows pre-tax	406,565	87,918	494,483
Future income tax expenses	(302,254)	(17,468)	(319,722)
Future net cash flows	104,311	70,450	174,761
10% annual discount for estimated timing of cash flows	(44,336)	(38,725)	(83,061)
Standardized measure of discounted future net cash flows	59,975	31,725	91,700

SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (unaudited)

(IN NOK MILLION)	NORWAY	OUTSIDE NORWAY	TOTAL
At December 31, 2001			
Future net cash inflows	660,247	107,074	767,321
Future development costs	(40,379)	(16,563)	(56,942)
Future production costs	(185,281)	(23,008)	(208,289)
Future net cash flow pre-tax	434,587	67,503	502,090
Future income tax expenses	(327,141)	(17,497)	(344,638)
Future net cash flows	107,446	50,006	157,452
10% annual discount for estimated timing of cash flows	(49,566)	(28,669)	(78,235)
Standardized measure of discounted future net cash flows	57,880	21,337	79,217
At December 31, 2000			
Future net cash inflows	757,634	103,859	861,493
Future development costs	(34,614)	(13,624)	(48,238)
Future production costs	(187,119)	(22,331)	(209,450)
Future net cash flow pre-tax	535,901	67,904	603,805
Future income tax expenses	(396,223)	(18,221)	(414,444)
Future net cash flows	139,678	49,683	189,361
10% annual discount for estimated timing of cash flows	(61,605)	(28,906)	(90,511)
Standardized measure of discounted future net cash flows	78,073	20,777	98,850

Of a total of NOK 62,379 million of estimated future development costs as of December 31, 2002, an amount of NOK 43,397 million is expected to be spent within the next three years, as allocated in the table below.

Future development costs

(IN NOK MILLION)	2003	2004	2005	TOTAL
Norway	13,118	10,620	6,183	29,921
Outside Norway	5,897	4,912	2,667	13,476
Sum future development costs	19,015	15,532	8,850	43,397
Future development costs expected to be spent on proved undeveloped reserves	15,996	13,156	7,293	36,445

In 2002, Statoil incurred NOK 14,357 million in development costs, of which NOK 9,964 million related to proved undeveloped reserves. The comparable amounts for 2001 were NOK 14,159 million and NOK 8,386 million, and for 2000 NOK 15,098 million and NOK 11,840 million, respectivily.

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

(IN NOK MILLION)	2002	2001	2000
Standardized measure at beginning of year	79,217	98,850	82,952
Net change in sales and transfer prices and in production (lifting) costs related to future production	(297)	(70,193)	206,251
Changes in estimated future development costs	(6,115)	(10,560)	(6,316)
Sales and transfers of oil and gas produced during the period, net of production costs	(56,994)	(62,283)	(70,246)
Net change due to extensions, discoveries, and improved recovery	9,790	2,064	10,292
Net change due to purchases and sales of minerals in place	(1,802)	(1,652)	(160)
Net change due to revisions in quantity estimates	9,791	11,604	(6,279)
Previously estimated development costs incurred during the period	14,357	14,159	15,098
Accretion of discount	33,342	57,721	(79,383)
Net change in income taxes	10,411	39,508	(53,359)
Total change in the standardized measure during the year	12,483	(19,632)	15,898
Standardized measure at end of year	91,700	79,217	98,850

Operational statistics

Productive oil and gas wells and developed and undeveloped acreage

The following tables show the number of gross and net productive oil and gas wells and total gross and net developed and undeveloped oil and gas acreage in which Statoil had interests at December 31, 2002.

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

AT DECEMBER 31, 2002		*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Number of productive oil and gas wells				
Oil wells	— gross	791	518	1,309
	— net	200	102	302
Gas wells	— gross	108	12	120
	— net	34	4	37

AT DECEMBER 31, 2002 (IN THOUSANDS OF ACRES)		*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Developed and undeveloped oil and gas acreage				
Acreage developed	— gross	560	313	873
	— net	134	76	210
Acreage undeveloped	— gross	9,536	9,813	19,349
	— net	3,240	2,632	5,872

Remaining terms of leases and concessions are between one and 30 years.

Exploratory and development drilling activities

The following table shows the number of exploratory and development oil and gas wells in the process of being drilled by Statoil at December 31, 2002.

(NUMBER OF WELLS)	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Number of wells in progress			
— gross	25	18	43
— net	6.5	1.9	8.4

Net productive and dry oil and gas wells

The following tables show the net productive and dry exploratory and development oil and gas wells completed or abandoned by Statoil in the past three years. Productive wells include wells in which hydrocarbons were found, and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing in sufficient quantities to justify completion.

	NORWAY	*OUTSIDE NORWAY*	*TOTAL*
Year 2002			
Net productive and dry exploratory wells drilled	9.6	1.5	11.0
— Net dry exploratory wells drilled	2.5	0.1	2.6
— Net productive exploratory wells drilled	7.1	1.3	8.4
Net productive and dry development wells drilled	27.3	13.5	40.8
— Net dry development wells drilled	0.0	0.3	0.3
— Net productive development wells drilled	27.3	13.2	40.5

	NORWAY	*OUTSIDE NORWAY*	*TOTAL*
Year 2001			
Net productive and dry exploratory wells drilled	9.7	2.2	11.9
— Net dry exploratory wells drilled	3.2	1.2	4.4
— Net productive exploratory wells drilled	6.5	1.0	7.6
Net productive and dry development wells drilled	32.8	27.4	60.2
— Net dry development wells drilled	0.7	0.3	1.0
— Net productive development wells drilled	32.1	27.1	59.2
Year 2000			
Net productive and dry exploratory wells drilled	4.7	4.8	9.5
— Net dry exploratory wells drilled	2.0	1.5	3.5
— Net productive exploratory wells drilled	2.7	3.3	6.0
Net productive and dry development wells drilled	30.6	71.4	102.0
— Net dry development wells drilled	0.8	0.0	0.8
— Net productive development wells drilled	29.8	71.4	101.2

Average sales price and production cost per-unit

	NORWAY	*OUTSIDE NORWAY*
Year ended December 31, 2002		
Average sales price crude in US$ per bbl	24.7	23.3
Average sales price natural gas in NOK per Sm^3	0.95	0.65
Average production costs, in NOK per boe	24.2	26.7
Year ended December 31, 2001		
Average sales price crude in US$ per bbl	24.1	22.3
Average sales price natural gas in NOK per Sm^3	1.22	0.97
Average production costs, in NOK per boe	24.9	46.4
Year ended December 31, 2000		
Average sales price crude in US$ per bbl	28.4	27.5
Average sales price natural gas in NOK per Sm^3	0.99	-
Average sales price natural gas in US$ per Sm^3	-	0.10
Average production costs, in NOK per boe	24.8	58.2

Investor relations in Statoil

Mari Thjømøe	Vice president	thjomoe@statoil.com	+47 51 99 77 90
Svein H Skår	IR officer	shs@statoil.com	+47 51 99 49 31
Lars Troen Sørensen	IR officer	dlts@statoil.com	+47 51 99 42 01

Investor relations in the USA:

Thore E Kristiansen	Vice president	tekri@statoil.com	+1 203 978 6950

For more information: www.statoil.com/IR

Design: Statoil

Trykk: Bryne Offset

STATOIL ASA
N-4035 STAVANGER
NORWAY
TELEPHONE: + 47 51 99 00 00
www.statoil.com