STATOIL

ANNUAL REPORT ON FORM 20-F 2001

STATOIL

The picture on the front cover is from the Statoil collection of art and shows installations on Sleipner.
Frans Widerberg (1934).
The Pavilion in the Sea, 1999.
Oil on canvas, 80x100 cm.

Photo: Thomas Widerberg

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, 2001

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 2,164,585,600

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

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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
- 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 equivalents equals 1 barrel of crude oil
- 1 barrel of oil equivalents equals159 standard cubic meters of natural gas
- 1 barrel of oil equivalents equals 5,612 cubic feet of natural gas
- 1 barrel of oil equivalents equals 0.122 tonnes of NGLs
- 1 billion standard cubic meters of natural gas equals 1 million standard cubic meters of oil equivalents
- 1 cubic meter equals 35.3 cubic feet
- 1 km equals 0.62 miles
- 1 square kilometer equals 0.39 square miles
- 1,000 standard cubic meters of natural gas equals 6.29 boe
- 1 standard cubic foot equals 0.0283 standard cubic meter
- 1 tonne of NGLs equals 1.3 standard cubic meters of oil equivalents
- 1 degree Celsius equals -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
- 1 tonne of LNG equals 1,360 standard cubic meters of natural gas at minus 163 degrees Celsius

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 - i.e., 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
  - 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
- Petroleum is a collective term for hydrocarbons, whether solid, liquid or gaseous. Hydrocarbons are compounds formed from 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 called 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, 2001 have been translated into US dollars at the rate of NOK 8.9724 to US$ 1.00, the noon buying rate on December 31, 2001. The financial data has been derived from our financial statements, which have been prepared in accordance with the 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 State's direct financial interest (SDFI) assets 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 for the year ended December 31, 2001.

	YEAR ENDED DECEMBER 31,					
(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)	*1997 NOK*	*1998 NOK*	*1999 NOK*	*2000 NOK*	*2001 NOK*	*2001 US$*
Income Statement						
Revenues:						
Sales	134,890	114,034	149,598	229,832	231,087	25,755
Equity in net income (loss) of affiliates	925	614	(745)	523	439	49
Other income	221	-	1,279	70	4,810	536
Total revenues	136,036	114,648	150,132	230,425	236,336	26,340
Expenses:						
Cost of goods sold	(64,400)	(53,449)	(79,508)	(119,469)	(126,153)	(14,060)
Operating expenses	(24,707)	(25,776)	(25,657)	(28,883)	(29,547)	(3,293)
Selling, general and administrative expenses	(6,262)	(6,528)	(6,688)	(3,891)	(3,547)	(395)
Depreciation, depletion and amortization	(13,149)	(14,471)	(17,579)	(15,739)	(18,058)	(2,013)
Exploration expenses	(2,863)	(4,137)	(3,122)	(2,452)	(2,877)	(321)
Total expenses before financial items	(111,381)	(104,361)	(132,554)	(170,434)	(180,182)	(20,082)
Income before financial items, income taxes and minority interest	24,655	10,287	17,578	59,991	56,154	6,258
Net financial items	(2,926)	(1,862)	1,431	(2,898)	65	7
Income before income taxes and minority interest	21,729	8,425	19,009	57,093	56,219	6,265
Income taxes	(15,228)	(6,809)	(12,856)	(40,456)	(38,486)	(4,289)
Minority interest	(12)	24	256	(484)	(488)	(54)
Net income	6,489	1,640	6,409	16,153	17,245	1,922
Net income per ordinary share(1)(2)	3.28	0.83	3.24	8.18	8.31	0.93
Dividends paid per ordinary share(2)(3)	4.94	2.43	3.47	10.81	26.69	2.97

(1) On May 10, 2001 an extraordinary general meeting approved a common stock split by which the existing stock – 49,397,140 ordinary shares with nominal value of NOK 100 per ordinary share – was replaced by 1,975,885,600 ordinary shares with nominal value of NOK 2.50 per ordinary share. All references to the number of ordinary shares and per ordinary share amounts have been restated to give retroactive effect to the stock split for all periods presented.

(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, 1997 NOK	1998 NOK	1999 NOK	2000 NOK	2001 NOK	2001 US$
Balance Sheet						
Assets:						
Cash and cash equivalents	1,400	602	4,061	9,745	4,395	490
Short-term investments	5,538	6,123	3,604	3,857	2,063	230
Accounts receivable	21,254	19,257	28,421	29,871	26,208	2,921
Accounts receivable - related parties	-	-	1,972	2,177	1,531	171
Inventories	3,722	4,172	4,294	4,226	5,276	588
Prepaid expenses and other current assets	4,628	4,316	11,235	5,447	9,184	1,023
Total current assets	36,542	34,470	53,587	55,323	48,657	5,423
Investments in affiliates	6,115	8,652	9,852	10,214	9,951	1,109
Long-term receivables	3,831	4,516	4,789	8,165	7,166	799
Net properties, plants and equipments	110,780	120,117	128,967	132,278	126,500	14,099
Other assets	3,080	4,283	7,287	7,669	7,421	827
TOTAL ASSETS	160,348	172,038	204,482	213,649	199,695	22,257
Liabilities and Shareholders' Equity:						
Short-term debt	5,275	9,682	9,190	2,785	6,613	737
Accounts payable	10,739	12,393	19,324	15,266	10,970	1,222
Accounts payable – related party	6,889	4,173	10,083	11,454	10,164	1,133
Accrued liabilities	8,012	8,836	8,666	11,228	13,831	1,542
Income taxes payable	6,084	2,477	6,366	14,877	16,618	1,852
Total current liabilities	36,999	37,561	53,629	55,610	58,196	6,486
Long-term debt	24,259	34,579	41,307	34,197	35,182	3,921
Deferred income taxes	37,864	38,198	43,020	43,331	42,354	4,720
Other liabilities	6,307	7,455	8,831	10,205	10,693	1,192
Total liabilities	105,429	117,793	146,787	143,343	146,425	16,319
Minority interest	2,205	1,838	1,590	2,480	1,496	167
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	4,940	5,474	610
Treasury shares (25,000,000 shares)	–	–	–	–	(63)	(7)
Additional paid-in capital	23,014	25,111	29,759	45,628	37,728	4,205
Retained earnings	23,582	20,422	19,978	14,768	6,682	745
Accumulated other comprehensive income	1,178	1,934	1,428	2,490	1,953	218
Total shareholders' equity	52,714	52,407	56,105	67,826	51,774	5,771
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	160,348	172,038	204,482	213,649	199,695	22,257

	YEAR ENDED DECEMBER 31, 1997	1998	1999	2000	2001
Other financial information					
Net debt to capital employed(1)	33.6%	44.1%	42.6%	25.0%	39.0%
After-tax return on average capital employed(2)	9.6%	3.2%	6.4%	18.7%	19.9%

(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.

(2) After-tax return on average capital employed is equal to net income before minority interest plus after tax net interest costs, divided by the average of opening and closing balances of net debt, shareholders' equity and minority interest. We base our targets for normalized return on average capital employed, or ROACE, assuming a long-term oil price of US$ 16 per barrel (calculated using year 2000 US dollars) and a similar assumption for the long-term gas price.

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 and 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.

	YEAR ENDED DECEMBER 31,		
PRODUCTION	*1999*	*2000*	*2001*
Norway:			
Crude oil (mmbbls)[1]	240	254	252
Natural gas (bcf)	452	495	511
Natural gas (bcm)	12.8	14.0	14.5
Combined oil and gas (mmboe)	321	342	343
International:			
Crude oil (mmbbls)	21	21	22
Natural gas (bcf)	60	19	16
Natural gas (bcm)	1.7	0.5	0.4
Combined oil and gas (mmboe)	32	24	25
Total:			
Crude oil (mmbbls)	262	275	274
Natural gas (bcf)	512	514	527
Natural gas (bcm)	14.5	14.6	14.9
Combined oil and gas (mmboe)	353	367	368

(1) Crude oil includes LPG and condensate production.

Sales Volume Information

We have historically marketed and sold 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. The Norwegian State has elected to continue this arrangement. For additional information see Item 7–Major Shareholders and Related Party Transactions–Major Shareholders. 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.

	YEAR ENDED DECEMBER 31,		
SALES VOLUMES	*1999*	*2000*	*2001*
Statoil:			
Crude oil (mmbbls)[1]	413	425	466
Natural gas (bcf)	523	519	533
Natural gas (bcm)	14.8	14.7	15.1
Combined oil and gas (mmboe)	506	517	561
SDFI assets retained by the Norwegian State:			
Crude oil (mmbbls)	371	384	395
Natural gas (bcf)	573	602	667
Natural gas (bcm)	16.2	17.0	18.9
Combined oil and gas (mmboe)	473	491	514
Total:			
Crude oil (mmbbls)	784	809	861
Natural gas (bcf)	1,096	1,121	1,200
Natural gas (bcm)	31.0	31.7	34.0
Combined oil and gas (mmboe)	979	1,008	1,075

(1) Sales volumes of crude oil include LPG 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 US$ 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
1997	6.3420	7.7564	7.0953	7.3740
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

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 2001	LOW	HIGH
October	8.7350	8.9525
November	8.8230	9.0350
December	8.8660	9.1120

YEAR 2002	LOW	HIGH
January	8.8775	9.1110
February	8.8710	9.1050
March	8.7200	8.8875

On March 29, 2002 the noon buying rate for Norwegian kroner was US$ 1.00 = NOK 8.8530.

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 that such reserves be calculated under Norwegian GAAP and consist of:

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

after deduction for uncovered losses, the 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 26,579 million (before provisions for dividend for the year ended December 31, 2001 of NOK 6,169 million) at December 31, 2001.

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 the impact of 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, for each of the past five fiscal years.

	PER ORDINARY SHARE(1)		*TOTAL (IN MILLIONS)*	
YEAR	*NOK*	*US$(2)*	*NOK*	*US$(2)*
1997	4.94	0.55	9,751	1,087
1998	2.43	0.27	4,802	535
1999	3.47	0.39	6,853	764
2000	10.81	1.20	21,363	2,381
2001(3)	26.69	2.97	55,415	6,176

(1) Based on 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 such years.

(2) The US$ amounts are based on the noon buying rate for Norwegian kroner on December 31, 2001, which was NOK 8.9724 to US$ 1.00.

(3) Total dividends paid in 2001 include a cash settlement for the SDFI assets amounting to NOK 19.65 (US$ 2.19) per share.

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 the past reflected our status as wholly owned by the Norwegian State and should not be considered indicative of our future dividend policy.

Because 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.

Our European long-term gas sales contracts are with approximately 20 to 25 customers. Approximately two-thirds of the volumes covered by our existing long-term gas sales contracts were eligible for potential price review in October 2001. Given the increasing demand for gas in the European market combined with the measures to create a single European gas market, it is difficult to predict the outcome of any price reviews that take place or the evolution of gas prices in European markets. See Item 4–Information on the Company–Operations–Natural Gas–Gas Sales Agreements.

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 improved efforts and 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. For example, we expect that Norway's 17th licensing round, particularly in the Halten/Nordland area, one of our core areas, will be very competitive with many of the largest oil companies seeking to be awarded licenses for exploration.

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, especially those created by recent mergers, 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 mutual 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.

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.

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 reserves discovered 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 pipeline and 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. In addition, we are currently exploring in the remote Barents Sea where there is no pipeline access. 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. Other countries, such as Venezuela, Nigeria and Angola, where we also have operations, have experienced expropriation or nationalization of property, civil strife, acts of war, guerilla activities and insurrections.

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 which 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 Legal Proceedings by the European Commission

The European Commission has commenced proceedings against us under EU/EEA competition laws, which, if determined against us, could have a material adverse impact on our natural gas business and our financial results.

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 has also adopted a statement of objections against 22 other producers of natural gas on the NCS. The European Commission has been investigating since 1996 the arrangements for the sale of gas from the NCS including the activities of the Gas Negotiation Committee, known as the Gassforhandligsutvalget or GFU under EU/European Economic Area, or EEA, competition laws. The Commission alleges these arrangements involve the joint sale of gas by producers on the NCS in contravention of EU/EEA competition laws. Working closely with the Norwegian State, we had been in discussions with the Commission to attempt to reach a mutually acceptable solution on these issues, but the settlement negotiations ended with no agreed solution reached. A hearing was held in December 2001, and we are awaiting their decision on the proceedings. If finally determined against Statoil, the Commission's proceedings could result in the imposition of a fine. Under the relevant EU regulation, the maximum fine that could be levied would be 10% of our worldwide revenues in the preceding financial year (e.g., up to NOK 23.6 billion based on year 2001 revenues). We may also be required to offer customers with existing gas sales agreements the opportunity to renegotiate or terminate those agreements. In addition, any finding of an infringement by us of the EU/EEA competition laws by the Commission or in other proceedings might also result in counterparties to our gas sales agreements challenging the validity of those agreements and possibly claiming substantial damages. See Item 8–Financial Information–Legal Proceedings and Item 4–Information on the Company–Regulation.

The outcome of any proceedings by the Commission, or the extent to which we may be required to terminate or renegotiate our existing gas sales agreements, could have a material adverse impact on our natural gas business and our financial results.

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 requires EU member states to take certain minimum steps to open their gas markets to greater competition. Each member 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.

These designated customers 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. Although not an EU member state, Norway and other European Free Trade Association, or EFTA, states may be bound to EU legislation if the EEA Joint Committee formally decides to include such legislation as a part of the EEA Agreement. No decision has yet been taken by the EEA Joint Committee to include the EU Gas Directive into the EEA Agreement. The Norwegian State has, however, stated its intention to accept the inclusion of the Directive into the EEA Agreement as soon as practicable.

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.

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 will be reduced by 150,000 barrels per day from January 1, 2002 until June 30, 2002. This amounts to roughly a 5% reduction in output. The reductions will in principle be applied equally and in a non-discriminatory manner to all companies operating on the NCS. All oil producing fields will be subject to a proportional reduction in production, except all major gas producing fields, two fields that Norway shares with the United Kingdom in the North Sea (Statfjord and Murchison) and one field that is soon to terminate production (Varg). 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.

Following our initial public offering, the Norwegian State still holds more than a two-thirds majority of our shares. Accordingly, the Norwegian State continues to have 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 with up to one third of the members of the board of directors as well as the corporate assembly. The corporate assembly has the power to elect 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 will 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 and 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 stability and economic growth in relevant areas of the world; development and use of new technology; geological or technical difficulties; the actions of competitors; the actions of field partners; natural disasters and other changes to business conditions.

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 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, 2001 consisted of 1,963 million barrels of oil, or mmbbls, and 368 billion standard cubic meters, or bcm (13 trillion standard cubic feet, or tcf) of natural gas, which represents an aggregate of 4,277 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 16,686 employees as of December 31, 2001 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, 2001 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 sets 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.

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 that we make on behalf of 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,			
	1999	*2000*	*2001*	
(IN MILLIONS)	*NOK*	*NOK*	*NOK*	*US$*
Income before financial items, income taxes and minority interest of:				
E&P Norway	16,841	46,715	40,697	4,536
International E&P	(1,995)	773	1,291	144
Natural Gas	5,052	7,893	9,629	1,073
Manufacturing and Marketing	(1,754)	4,559	4,480	499
Other	(566)	51	57	6
Total	**17,578**	**59,991**	**56,154**	**6,258**

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 curently producing hydrocarbons: Troll/Sleipner, Halten/Nordland, Tampen, and one, Tromsøflaket, is expected to begin production in 2006. We operate 16 developed fields in our three producing core areas. These fields produced a total of 2.06 mmboe per day in 2001, 47% of total NCS daily production. Throughout 2001, our daily equity oil production was 691,000 barrels of oil, and daily equity gas production was 39.7 mmcm (1,401 mmcf) compared to 695,000 barrels of oil and our daily equity gas production of 38 mmcm (1,341 mmcf) in 2000. 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, 2001, E&P Norway had proved reserves of 1,398 million barrels of crude oil and 360 bcm (12.7 tcf) of natural gas, which represents an aggregate of 3,664 mmboe. Our experience over the last 30 years in the challenging NCS environment has helped us to 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, will 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 of Norway. We have established positions in four core areas: Caspian, Western Africa (Angola and Nigeria), Western Europe and Venezuela. As of

December 31, 2001, International E&P had net proved reserves of 565 million barrels of crude oil and 7.6 bcm (267 bcf) of natural gas, which represents an aggregate of a 612 mmboe. We have participated in six of the largest finds in the world over the last five years, and in 2001 we discovered hydrocarbons in three out of nine exploration wells in which we participated internationally. In 2001 we produced 59,700 barrels of oil and 1.2 mmcm (41 mmcf) of gas per day from our international operations compared to 57,100 barrels of oil and 1.5 mmcm (53 mmcf) of gas for 2000. We believe that this business segment is important in providing long-term profitable growth for our business.

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 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 25% interest in the Statpipe joint venture which owns 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 2001 we sold approximately 33.6 bcm (1.2 tcf) of natural gas, which includes the Norwegian State's natural gas sold by us, compared to 31.1 bcm (1.1 tcf) in 2000.

Manufacturing and Marketing. The Manufacturing and Marketing segment comprises downstream activities including trading and sales of crude oil, NGL and petroleum products, refining, industrial marketing, retail marketing of oil products, methanol production and sales, petrochemical operations through our 50%-owned joint venture Borealis, and shipping operations through our now wholly-owned subsidiary Navion ASA. 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.

Norwegian State's Restructuring of its Oil and Gas Assets

The Norwegian State owns directly 39% (prior to the recent sale of 6.5% of SDFI assets) of the proved oil and gas reserves on the NCS, known as the State's direct financial interest or 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 15% of its SDFI assets to us and recently sold 6.5% of its SDFI assets to other oil and gas companies. In a single transaction with the Norwegian State, we purchased 84 license interests and ownership interests in five pipeline joint ventures from the Norwegian State on June 1, 2001. The Norwegian State has, on a sole basis, identified and selected the assets transferred to and from Statoil. In this process the Norwegian State sought to promote operational efficiencies by increasing our holdings in our core areas on the NCS by increasing our holdings in smaller fields where we are the operator and by increasing our gas holdings on the NCS in order to give further insentives to our gas marketing operations (which involve marketing and sales of the Norwegian State's gas together with our own).

We believe that this transaction allowed us better opportunities for increasing recovery and reducing costs while enabling us to make more effective use of existing infrastructure through coordination and ownership alignment. As a result of this acquisition, our NCS reserves were increased from 2,453 mmboe (pre-acquisition) to 3,787 mmboe (post-acquisition) based on proved reserves as at December 31, 2000, and our own production on the NCS increased from 586,400 boe per day (pre-acquisition) to 935,600 boe (post-acquisition) based on average daily production for the year ended December 31, 2000.

The financial, production, reserve and other operating information in this Annual Report, except where otherwise noted, reflects our acquisition of these SDFI assets and has been prepared as if the SDFI assets had been part of Statoil throughout the financial periods prior to the acquisition.

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 25.00% interest in Norsea Gas AS (Norpipe), all of which had a valuation date of January 1, 2001 and a 35.00% interest in our crude oil terminal at Mongstad, which had a valuation date of June 1, 2001.

The financial, production, reserves and other operating information in this Annual Report, except where otherwise noted, does not reflect the transfer of assets from us to the Norwegian State. For accounting purposes, this transfer is treated as occurring on the date the agreements were entered into, which was May 7, 2001. See Item 5—Operating and Financial Review and Prospects.

The following table shows the transfer of assets as a result of this single transaction. Please note that each field may include more than one license interest.

(IN %)	*CHANGE IN OWNERSHIP*	*STATOIL'S INTEREST*
Troll/Sleipner		
Troll	6.93	20.80
Sleipner East	29.60	49.60
Sleipner West	32.37	49.50
Gungne	34.40	52.60
Glitne	30.00	58.90
Yme(1)	30.00	65.00
Halten/Nordland		
Åsgard	11.45	25.00
Norne	1.00	25.00
Kristin	20.45	46.60
Mikkel	33.26	56.52
Tyrihans(2)	30.00	54.71
Trestakk	30.00	55.00
Skarv	30.00	30.00
Tampen		
Gullfaks	43.00	61.00
Snorre	1.40	14.40
Statfjord East	10.50	25.05
Sygna	9.45	24.73
Visund	19.60	32.90
Vigdis	21.00	28.22
Tordis/Tordis East	21.00	28.22
Borg	21.00	28.22
Kvitebjørn	10.00	50.00
Other		
Tommeliten	42.38	42.38
Transportation		
Statpipe	(33.25)	25.00
Norsea Gas AS	(25.00)	25.00
Mongstad Terminal DA	(35.00)	65.00
Europipe II	14.99	15.00
Troll Oil pipelines I & II	6.93	20.85
Norne Gas T.S.	1.00	25.00
Haltenpipe	7.19	19.06
Kvitebjørn Oil pipeline	10.00	50.00

(1) Yme was decommissioned in May 2001.
(2) Based on a preliminary split between PL073: 87% and PL091: 13%.

The transaction between Statoil and the Norwegian State was completed on June 1, 2001 with a valuation date of January 1, 2001 (with the exception of the sale of the interest in the Mongstad terminal which has 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. See Item 5—Operating and Financial Review and Prospects–Operating Results–Company Restructuring. The historical financial information, prior to June 1, 2001, in this Annual Report assumes that our purchase of the SDFI assets was financed with equity and therefore does not reflect the impact of our payment of the purchase price on our results of operations or financial condition.

For more detailed information regarding the Norwegian State's restructuring of its oil and gas assets, see Item 7—Major Shareholders and Related Party Transactions.

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 will be return on average capital employed, or ROACE, of 12% by 2004, assuming a long-term oil price of US$ 16 per barrel, (calculated using year 2000 US dollars) and a similar assumption for the long-term gas price. We intend to deliver 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. We have increased the focus on our managers' performance-related pay by introducing 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 increase production and profitability in our three core producing areas, Troll/Sleipner, Halten/Nordland and Tampen, via accelerated field development, more effective use of improved recovery technology and the development of satellite fields close to existing infrastructure. Benefits of portfolio consolidation and enhanced ownership alignment, both resulting from the SDFI purchase, make each of the above more easily attainable. We have reduced the costs in E&P Norway and we have achieved in excess of NOK 1,400 million in cost savings since 1998, before giving effect to any cost savings achieved through our acquisition of certain license interests from the Norwegian State. We have started development of the Snøhvit field, in which we recently sold a 12% interest, and we expect to develop and operate new promising core areas, such as Tromsøflaket, and are carefully and selectively evaluating opportunities in the Møre/Vøring and Lofoten areas of the Norwegian Sea and 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 in the last five years, we are now focusing 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 outside our four core areas. We will continue to pursue attractive opportunities in these areas as they arise and as our rigorous capital allocation process permits. We will also continue to manage our portfolio of assets to seek to further increase profitability and secure operating influence and, where possible, operatorships.

Capitalize on our strong position in European gas markets to take advantage of expected demand growth. As a leading supplier of gas to Europe, we are well positioned to benefit from both growing demand for gas and the deregulation of gas markets. We intend to manage our upstream and transportation portfolio actively to maximize the income from existing long-term natural gas contracts. Furthermore, we intend to capitalize on expected demand growth by employing our scale in marketing gas. As demand grows and deregulation leads to new opportunities for us, we will leverage the extensive transportation infrastructure, which offers additional capacity and flexibility to create more value from the NCS natural gas. We will build on our experience in marketing natural gas to adapt as required to new commercial opportunities. In particular, we intend to capitalize on the anticipated increase in demand for imports of gas in the United Kingdom, a market we are well positioned to supply. We will also further increase our ability to realize additional margin and optimize synergies by extracting and commercializing NGL streams to meet internal and external demand for NGLs. Our natural gas marketing expertise will shape our natural gas operations in our core international areas.

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 and sold 50% of our retail subsidiary SDS to the ICA/Ahold supermarket group to strengthen our leading brand further and accelerate non-fuel sales growth. In refining, partially through our joint venture with Shell, 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 as low cost new plants, oriented towards serving growing Asian markets, come on stream and as we identify further synergies with our upstream segments. We will continue evaluating fuel cell technology opportunities as part of our methanol strategy. Finally, in shipping, our subsidiary Navion intends to concentrate on shuttle tankers and conventional shipping and divest its drillship activities. It is our intention to reduce our ownership in Navion to below 50%.

Operations

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 50 producing oil and gas fields on the NCS and serve as operator for 16 of these. In addition, subject to regulatory and partner approval, we will succeed Norsk Hydro as operator for four fields in 2003, thus making us the sole operator for all Norwegian development in the Tampen area of the northern North Sea, including the Gullfaks and Statfjord fields. We are also the operator of the Troll gas field in the Troll/Sleipner area. Other major 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 40,697 million, or 72% of our total income before financial items, income taxes and minority interest in 2001.

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

	YEAR ENDED DECEMBER 31,			
	1999	*2000*	*2001*	
(IN MILLIONS)	*NOK*	*NOK*	*NOK*	*US$*
Revenues	38,487	71,135	65,655	7,317
Depreciation, Depletion and Amortization	9,126	11,225	11,806	1,316
Exploration Expenditure	1,647	1,657	2,020	225
Income before financial items, income taxes and minority interest	16,841	46,715	40,697	4,536
Capital Expenditure	27,448	12,992	10,759	1,199
Long-Term Assets	77,881	79,864	77,550	8,643

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, where we hold approximately 3,664 mmboe of proved reserves as of December 31, 2001, compared to 3,787 mmboe as of December 31, 2000.

Commercial petroleum deposits were proven on the NCS in the late 1960s. 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 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 rates. We are working to extend production from our major fields through improved reservoir and technology management. The key emerging innovative technologies include:

- seabed and time lapse seismic studies with three-dimensional visualization of geological structures, in order more efficiently to identify additional resources and enhance recovery;
- the drilling of long-reach wells, horizontal wells and designer wells, which are wells drilled with a curve in the horizontal plane, which allows optimal drainage of reservoirs; and
- the use of gas injection and microbial recovery methods.

We monitor changes in the expected oil recovery factors for a fixed portfolio of oil fields on the NCS. The fixed portfolio includes every Statoil-operated field that was in production or had been sanctioned for development as of December 31, 1995. Proved reserves of the fields in this portfolio represent approximately 90% of our total proved reserves at Statoil-operated NCS oil fields as of December 31, 2001. Between 1995 and 2001 we have improved the expected oil recovery factor for this portfolio, and we believe we will be able to improve our operations so as to further improve our recovery factors. We believe that much of the improvement can be attributed to our effective reservoir and production management and use of enhanced recovery methods.

Potential Producing Areas

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

Southern North Sea. In addition to our two North Sea core areas, Tampen and Troll/Sleipner, we have interests in 1,800 square kilometers of licensed exploration acreage in the southern part of the North Sea. There has been no exploration drilling in 2001, but two wells operated by Phillips Petroleum and Amerada Hess are scheduled for drilling in 2002. A new North Sea licensing round is expected to be announced later in 2002.

Møre/Vøring. We have interests in 8,000 square kilometers of licensed acres in the Møre/Vøring area of the Norwegian Sea, which is a deepwater area with depths ranging from 400 meters to 2,000 meters, that lies 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. The area also contains several large unexplored structures, some of which have similar geology to Ormen Lange. There is strong industry interest in this area, and we expect increased competition at the 17th licensing round, for which the application deadline was March 18, 2002.

Lofoten. The Lofoten areas of the Norwegian Sea, located in the coastal region near Norway, are one of several major oil provinces left to explore on the NCS. We have interests in two licenses in this area, totaling 250 square kilometers. However, due to its proximity to shore and concerns relating to the effect of the exploration drilling activities on the fishing industry and the environment, the Ministry of Environment is now evaluating the need for new environmental restrictions in the exploration activities before new drilling permission is granted. We drilled a dry well in 2000, and drilling of the scheduled Norsk Hydro well in 2001 in the area has been postponed until the Norwegian Pollution Control Authority can issue a drilling discharge permit possibly based on new restrictions.

Barents Sea. Our new core area, Tromsøflaket, is located in the southwestern part of the Barents Sea. This area includes our gas discovery Snøhvit, for which a plan for development was recently approved by the Norwegian authorities. We have interests in further 8,000 square kilometers of licensed acres. We are also conducting seismic exploration activity in two large areas under a seismic option awarded by the Ministry of Petroleum and Energy. We also have a 35-45% interest in two of the other three large seismic option areas. Under the terms of the seismic option agreement, the license group is committed to do specified seismic evaluation of the area. At any time within the licensed period of 10 years, the license group has the right to obtain a production license with the obligation to drill exploration wells. An appraisal well has confirmed the oil discovery made by Norsk Agip in 2000 in the area south of Snøhvit. This discovery has been named Goliat, and Norsk Agip is currently planning development. We made an oil and gas discovery in January 2001 with the first well drilled in the most eastern part of the Norwegian sector of the Barents Sea. The reserves, appraised by a sidetrack well, are too small for a stand-alone development. However, several other promising structures with similar geology as the discovery are located within the licensed acreage.

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 under —Exploration and Development, could serve as a cornerstone for the area's future development.

Portfolio Management

We have been and intend to continue our efforts in managing our ownership interests in NCS assets to improve return on capital employed. Our position on the NCS has been enhanced recently both by our purchase of SDFI assets in 2001 and continued restructuring. As a result of the assets purchased from the Norwegian State, our NCS proved reserves increased from 2,453 mmboe (pre-acquisition) to 3,787 mmboe (post-acquisition) as of December 31, 2000, and our own production on the NCS increased from 586,400 boe per day (pre-acquisition) to 935,600 boe (post-acquisition) based on average daily production for the year ended December 31, 2000. Our licenses increased from 106 to 128, of which 26 are licenses in the production phase and 102 are in the exploration phase. This increased ownership and improved alignment of license interests should enable us to enhance the value of our assets through coordinated logistics, planning and organization across exploration, development and production operations.

In January 2001, we entered into agreements to sell interests in six production licenses, including four fields, for NOK 2.1 billion consisting of NOK 1.7 billion in cash and NOK 0.4 billion in tax depreciation assets. This, combined with earlier divestments, has enabled us to concentrate resources on our core areas. In 1999, we acquired approximately 25% of the assets of Saga Petroleum for NOK 8.1 billion following Norsk Hydro's acquisition of Saga Petroleum. Under the agreement with Norsk Hydro on the acquisition of Saga, we acquired approximately 300 mmboe proved reserves and are scheduled to take over the Snorre, Vigdis, Tordis and Visund operatorships in the Tampen area of the northern North Sea in 2003. This acquisition strengthened our reserve base, production and position on the NCS.

As of December 31, 2001 we were participating in 132 licenses of which 26 are in the production phase and 106 in the exploration phase.

To date in 2002, we have signed an agreement to sell our 28% share in the Varg field in the Troll/Sleipner area to PGS and 14.9% of our share in the Mikkel Unit in the Halten/Nordland area to Norsk Agip and Fortum Petroleum AS, reducing our share in Mikkel to 41.62%. These transactions are part of our strategy of focusing on core areas and aligning ownership interests for more effective resource management.

Exploration and Development

We have been engaged in exploration and drilling on the NCS since 1975 and have drilled a total of 266 exploration and appraisal wells as of December 31, 2001. Approximately 50% of all exploration and appraisal wells that we drilled in the last three years have yielded discoveries or positive appraisals that 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 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 2001, we participated in 21 exploration and appraisal wells and were the operator for 11 compared to 2000 where we participated in 14 exploration and appraisal wells of which we were the operator of four. Of the 11 Statoil-operated wells in 2001, seven were successful, and of the ten partner-operated wells, eight were successful. Our exploration expenditure on the NCS in 2001, including expenditure in respect of SDFI assets we acquired from the Norwegian State, totaled NOK 2,020 million, of which NOK 677 million was capitalized. The figures for 2000 were NOK 1,658 million and NOK 750 million respectively. Additionally, exploration expenditure of NOK 665 million, which was capitalized in earlier years, was expensed in 2001 compared to NOK 403 million in 2000. Our expenditure was somewhat lower in 2001 than we expect in the upcoming years primarily due to the cost savings program that has been carried out during the period 1999 to 2001.

Our expenditure on development on the NCS totaled NOK 11.5 billion in 2000 and NOK 9.7 billion in 2001. In 2000 we participated in 156 development wells, and in 2001 we participated in 138 development wells.

Of our 2001 NCS exploration expenditures, approximately 68% was spent in our three core producing areas (approximately 37% was spent in the Halten/Nordland area and another 31% in the Troll/Sleipner and Tampen areas) and substantially all of the balance in the Møre/Vøring and Lofoten areas of the Norwegian Sea and the Barents Sea. Of our 2001 NCS development budget, approximately 97% was spent in our three core producing areas (approximately 15% in the Halten/Nordland area, 44% in the Troll/Sleipner area and 38% 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 2002 NCS development budget, approximately 93% will be spent in our three core producing areas (approximately 19% in the Halten/Nordland area, 42% in the Troll/Sleipner area and 32% in the Tampen area) and the remainder in our new core area Tromsøflaket and potential producing areas in the Barent 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 1999, 2000 and 2001.

	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
Troll/Sleipner			
Statoil Operated Exploratory			
Successful	1	1	1
Dry	2	—	3
Total	3	1	4
Development	10	14	5
Partner Operated Exploratory			
Successful	1	1	2
Dry	1	2	1
Total	2	3	3
Development	53	59	52
Halten/Nordland			
Statoil Operated Exploratory			
Successful	2	2	3
Dry	—	—	—
Total	2	2	3
Development	28	25	23
Partner Operated Exploratory			
Successful	2	3	3
Dry	2	—	—
Total	4	3	3
Development	—	—	—
Tampen			
Statoil Operated Exploratory			
Successful	—	—	2
Dry	2	—	—
Total	2	—	2
Development	32	38	28
Partner Operated Exploratory			
Successful	1	1	2
Dry	1	—	1
Total	2	1	3
Development	12	20	14
Other Areas			
Statoil Operated Exploratory			
Successful	—	—	1
Dry	—	1	1
Total	—	1	2
Development	—	—	—
Partner Operated Exploratory			
Successful	—	2	1
Dry	1	1	—
Total	1	3	1
Development	—	—	16
Totals			
Exploratory			
Successful	**7**	**10**	**15**
Dry	**9**	**4**	**6**
Total	**16**	**14**	**21**
Development	**135**	**156**	**138**

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. Neither exploration expenditure nor reserve changes include those costs or changes due to acquisitions or disposals. 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 1999, 2000 and 2001, our finding costs were US$ 2.13, US$ 1.68 and US$ 1.50 per boe respectively.

Three Statoil-operated and one partner-operated field development projects were completed in the second half of 2001, Glitne, Gullfaks Satellites Phase II, Huldra and Snorre Phase II, described below under —Production.

We are currently the operator of four ongoing field development projects on the NCS, which in order of scheduled production are: Mikkel, Kvitebjørn, Kristin and Snøhvit. We are also involved in the development of Sigyn, for which ExxonMobil is the license operator, and have a share in the Fram West development operated by Norsk Hydro.

Mikkel. Mikkel, a gas and condensate development which was discovered in 1987, lies in 220 meters of water on Halten Bank East in the Halten/Nordland core area, about 40 kilometers away from both Åsgard's Midgard accumulation and Draugen. Our interest in this field was, on December 31, 2001, 56.52%, and our partners are Norsk Hydro (10%) and ExxonMobil (33.48%). In the beginning of 2002, we sold 14.9% of our share to Norsk Agip and Fortum Petroleum AS, reducing our share to 41.62%. The plan for development and operation of Mikkel was approved by the Ministry of Petroleum and Energy in June 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. Production is planned to commence in 2003 and is expected to reach a capacity of 6 mmcm (212 mmcf) per day by 2004. The development is expected to cost NOK 2.4 billion, of which 0.4 billion has been invested as of December 31, 2001. An adjustment of the participating interests has been made in 2002 to align interests between the Mikkel and Åsgard Licensees.

Kvitebjørn. Discovered in 1994, Kvitebjørn lies south of Gullfaks in the Tampen area. Our interest is 50% in this gas and condensate development project, and our partners are the SDFI (30%), Norsk Hydro (15%) and TotalFinaElf (5%). The field will be developed with a manned wellhead platform with initial processing of gas and condensate for transport in separate pipelines to receiving facilities for final processing and export. In addition, the development plan includes a new oil pipeline connecting the Kvitebjørn development to the gas processing plant at Kollsnes and refinery facilities at Mongstad. An extension of the initial plan for development and operation (which was approved in June 2000), covering production from a larger part for the Kvitebjørn reservoirs, was approved by the Ministry of Petroleum and Energy in June 2001. Production is due to start in October 2004, and we expect it to reach an estimated 16 mmcm (565 mmcf) per day by 2006. The project has a total estimated investment of NOK 10 billion, of which NOK 2.9 billion has been invested as of December 31, 2001.

Kristin. Kristin, discovered in 1997, is a gas condensate field lying across two production licenses in the southwestern part of the Halten/Nordland area, about 20 kilometers southwest of Åsgard's Smørbukk field. The unitization agreement for this area was approved by the Ministry of Petroleum and Energy in December 2001. A unitization agreement is an agreement among owners of interests in production licenses to coordinate the management, development, production and conservation of oil and gas in the area. Our interest in the unitized area is 46.6%, and our partners are Norsk Hydro, Agip, TotalFinaElf, and ExxonMobil. The proposed plan for development and operation for the Kristin field was approved by the Storting in December 2001. The Kristin reservoir lies almost 5,000 meters beneath the seabed, and plans call for it to be drained with 12 subsea production wells, with the wellstream transported to a semi-submersible processing platform. At 900 bars and 170 degrees Celsius, pressure and temperature in this reservoir are higher than in any field developed on the NCS. To overcome this challenge, we plan to utilize subsea installations with four templates that will be used to choke down the wellstream to reduce the pressure before transportation through flexible risers to the floating processing platform. The stabilized condensate will be exported through the field storage unit and rich gas will be transported to shore via the Åsgard pipeline to the gas processing facility at Kårstø. Production is expected to start in 2005. The estimated total investment cost for this project is NOK 17 billion, of which NOK 0.6 billion has been invested as of December 31, 2001.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 – Ragnfrid, Lavrans, Erlend and Morvin – using the Kristin processing facilities as a field center.

Snøhvit. Snøhvit, discovered in 1984, is the largest gas field in the Barents Sea. After the sale of 12% to Gaz de France, our interest in Snøhvit is 22.29%, and our partners are the SDFI (30%) TotalFinaElf (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 licenses. A unitization agreement for the area was approved by the Ministry of Petroleum and Energy in July 2000.

We will use liquid natural gas technologies to develop Snøhvit. The development plan calls for an LNG plant to be located at Melkøya near Hammerfest, Norway to process gas piped from Snøhvit and its neighboring Askeladden and Albatross fields. Furthermore, the development will include subsea installations, a pipeline to shore, a treatment/liquefaction complex on land, and shipment to customers in purpose-built vessels. CO_2 separated from the gas will be piped back to the field and injected. In October 2000, Gaz de France was included as an alliance partner because of its strength in LNG treatment and transportation. Long-term sales contracts for the liquefied natural gas were entered into in October 2001. The Storting approved the plan for development and operation in March 2002. The development costs for the project, which reflects the difficult development conditions, are estimated to be NOK 46 billion, of which NOK 0.2 billion has been invested as of December 31, 2001. The field development plan calls for production to start in 2006. The production capacity is expected to reach 15 mmcm (530 mmcf) of LNG per day by 2007.

The partners in the Statoil-operated project have sought a clarification of the tax position for Snøhvit from the Norwegian authorities. The partners have requested a final clarification by April 15, 2002 to continue the development.

Sigyn. Sigyn was discovered in 1982 and lies in the Troll/Sleipner area. Our interest in this gas and condensate development is 50%, and our partners are ExxonMobil (40%) and Norsk Hydro (10%). ExxonMobil, the operator of the Sigyn field, has assigned to us responsibility for the subsea installations, the flowlines, the actual drilling and the processing of the output on the Sleipner A installations. ExxonMobil will manage the reservoirs and recommend drilling locations. Sigyn will cost an estimated NOK 2.2 billion, of which NOK 0.3 billion has been invested as of December 31, 2001. Production is due to start by year-end 2002 and is expected to reach a capacity of 4 mmcm (141 mmcf) per day by 2003.

We are also partner in the development project operated by Norsk Hydro on Fram West in the Troll/Sleipner area. Our interest in the Fram West project, which is an oil field, is 20%, and our partners are the SDFI (30%), Norsk Hydro (25%) and ExxonMobil (25%). In June 2000, the owners of the Fram field decided to base development of the reserves in the license on the use of subsea technology with a tie-in to existing infrastructure 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 485 million had been invested as of December 31, 2001. Production is expected to start in 2005. The field production capacity is expected to reach 50,000 barrels per day by 2007.

Troll Up-grading Project. In connection with the decision to land the rich gas from the Kvitebjørn field at the Troll license's 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 submitted to the Ministry of Petroleum and Energy in November 2001, and we expect approval in the spring of 2002. Total investment for the plant is estimated to be NOK 3 billion, of which NOK 0.1 billion has been invested as of December 31, 2001. 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 is 26.1 mmcm per day.

The Sleipner West Compression project is an ongoing project estimated to cost NOK 1 billion aiming to modify the Sleipner facilities to prepare for low-pressure production in the later stages of the field life.

A similar modification is described in the Troll Gas plan for development and operations. Preparation for installation of pre-compression facilities at Troll A is ongoing. We expect the Ministry of Petroleum and Energy to approve the project in May 2002 and expect to invest approximately NOK 3.2 billion.

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 2001, we had a total of 1,398 million barrels of proved oil reserves and 360 bcm (12.7 tcf) of proved natural gas reserves in Norway. Based on boe, our proved reserves consist of 38% oil and 62% natural gas.

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, ranging from 8% to 16%, for NCS oil produced from fields approved for development prior to January 1, 1986, including reserves attributable to our account based on our proportionate participation in fields with multiple participants. On January 1, 2001, we sold our interest in the Grane, Jotun and Njord fields. No major discovery or other favorable or adverse event has occurred since December 31, 2001 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
1998	**Proved reserves end of year**	**1,633**	**359.9**	**12,704**	**3,896**
	of which, proved developed reserves	*777*	*200.7*	*7,085*	*2,040*
1999	Revisions and improved recovery	82	(3.2)	(111)	62
	Extensions and discoveries	67	0.8	28	72
	Purchases of reserves-in-place	134	29.6	1,045	320
	Sales of reserves-in-place	(1)	0.0	(1)	(1)
	Production	(240)	(12.8)	(452)	(321)
	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*

Production

In Norway in 2001, our total equity oil production was 252 million barrels after deductions for royalty oil, and gas production for our own account was 14.5 bcm (512 bcf), which represents an aggregate 343 mmboe(1). Currently, our production is mainly in our three core producing areas of Troll/Sleipner, Halten/Nordland and Tampen. We participate in the majority of the 50 producing fields in the NCS and are the operator for 16 of them. In addition, we are scheduled to succeed Norsk Hydro as operator on the Snorre, Tordis, Vigdis and Visund fields in 2003. We are responsible as operator for approximately 35% of Norway's current oil output and approximately 80% 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.

The following table shows the NCS production fields and field areas in which Statoil currently participates, 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 2001. 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 2001 oil production from the Njård and Jotun fields is excluded in the reserve table, as their sale was effective on January 1, 2001, but included in the total equity production figure. Additionally, the NGL volumes that we buy from the other Troll owners are not included as reserves in the reserves table. The difference in gas volumes results from the inclusion of lifted volumes, as opposed to produced volumes, in the reserve table.

AREA	STATOIL'S EQUITY INTEREST	OPERATOR	ON STREAM	LICENSE EXPIRY DATE	PRODUCING WELLS OIL	PRODUCING WELLS GAS	AVERAGE DAILY PRODUCTION IN 2001 mboe/DAY
Troll/Sleipner							
Sleipner East	49.60%	Statoil	1993	2023	—	14	74.4
Sleipner West	49.50%	Statoil	1996	2026	—	13	77.3
Glitne	58.90%	Statoil	2001	2013	5	—	7.6
Gungne	52.60%	Statoil	1996	2026	—	2	4.5
Huldra	19.66%	Statoil	2001	2015	—	4	0.4
Troll Phase 1	20.80%	Statoil	1996	2030	—	39	84.8
Troll Phase 2	20.80%	Norsk Hydro	1995	2030	78	—	70.3
Veslefrikk	18.00%	Statoil	1989	2015	14	—	6.7
Varg	35.00%	Norsk Hydro	1998	2028	4	—	5.7
Oseberg	14.00%	Norsk Hydro	1988	2018	49	—	35.9
Oseberg South	18.22%	Norsk Hydro	2000	2018	10	—	13.8
Oseberg East	14.00%	Norsk Hydro	1999	2018	12	—	9.2
Heimdal	20.00%	Norsk Hydro	1985	2015	—	5	0.9
Ekofisk area	0.95%	Phillips Petroleum	1971	2028	111	—	4.4
Frigg	12.16%	TotalFinaElf	1977	2015	—	9	0.6
Togi	20.80%	Norsk Hydro	1991	2030	—	5	2.7
Brage	12.66%	Norsk Hydro	1993	2023	27	—	5.5
Jotun(1)	2.00%	ExxonMobil	1999	2021	12	—	1.4
Yme(2)	65.00%	Statoil	1996	2026	9	—	2.2
Total Troll/Sleipner					**331**	**91**	**408.3**
Halten/Nordland							
Heidrun	12.43%	Statoil	1995	2025	28	—	25.3
Åsgard	25.00%	Statoil	1999	2027	23	8	60.5
Norne	25.00%	Statoil	1997	2027	11	—	54.3
Njord(1)	20.00%	Norsk Hydro	1997	2027	9	—	4.6
Total Halten/Nordland					**71**	**8**	**144.7**
Tampen							
Statfjord Unit (Norwegian part)	51.88%	Statoil	1979	2009	76	—	101.9
Statfjord North	21.88%	Statoil	1995	2009	8	—	11.4
Statfjord East	25.05%	Statoil	1994	2024	7	—	11.5
Sygna	24.73%	Statoil	2000	2022	2	—	10.9
Gullfaks	61.00%	Statoil	1986	2016	89	—	111.4
Gullfaks South area	61.00%	Statoil	1998	2016	20	4	47.3
Snorre	14.40%	Norsk Hydro(3)	1992	2024	32	—	32.5
Tordis area	28.22%	Norsk Hydro(3)	1994	2024	9	—	25.8
Vigdis area	28.22%	Norsk Hydro(3)	1997	2024	8	—	18.8
Visund	32.90%	Norsk Hydro(3)	1999	2023	3	—	14.5
Murchison (Norwegian part)(4)	51.88%	Kerr-McGee	1980	2009	5	—	1.4
Total Tampen					**259**	**4**	**387.4**
Total NCS					**661**	**103**	**940.4**

(1) These interests were sold in 2000, but contributed to equity production until June 2001 awaiting approval of the sales by the Norwegian State.
(2) Yme was decommissioned in May 2001.
(3) Subject to regulatory and partner approval, we will succeed Norsk Hydro as operator on January 1, 2003.
(4) 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 1999, 2000 and 2001.

	YEAR ENDED DECEMBER 31,								
	1999			2000			2001		
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	203	30	389	212	33	416	219	30	408
Halten/Nordland	85	0	87	123	1	132	118	4	145
Tampen	370	5	403	360	4	387	354	5	387
Total	**659**	**35**	**879**	**695**	**38**	**936**	**692**	**39**	**940**

We reached our target of reducing basic operating costs for our main Statoil-operated fields by 20% from 1999 to 2001. These costs were reduced by NOK 1.4 billion in 2001, reaching the target of NOK 4 billion annual reduction for the period 1999 – 2001. We have been able to increase efficiency and contribute to group cost reductions over the last three years as a part of the corporate cost improvement program. This has been achieved through better focus on core areas, improved technology utilization and more efficient procurement and supply services as well as a more integrated and focused management and organizational structure.

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 2001 was 219,000 barrels of oil and 30.0 mmcm (1,059 mmcf) of gas per day, or 408 mboe. Our acquisition of SDFI assets from the Norwegian State has increased our daily production in Troll/Sleipner by 64% and strengthened our position in the area. We are working to optimize the use of infrastructure in the Sleipner area. The first result of these efforts is the decision in December 2001 to construct the NGL plant at Kollsnes and is expected to commence operations in October 2004. Our production target for these fields 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 these fields is 20.80%, and our partners are the SDFI (56%), Norsk Hydro (9.78%), Norske Shell (8.10%), TotalFinaElf (3.70%) and Norske Conoco (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 installation 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 and sold under the Troll gas sales agreements.

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 TotalFinaElf (10%). Our interest in Sleipner West is 49.50%, and our partners are ExxonMobil (32.24%), Norsk Hydro (9.41%) and TotalFinaElf (8.85%). We are the operator of both fields.

All Sleipner East and most of Sleipner West gas production is sold under the Troll gas sales contracts. Condensates from the 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 wellhead platform. Sleipner West is produced through two installations: the Sleipner B wellhead platform which includes a long reach flowline, and the Sleipner T gas treatment facility. Sleipner West is tied back to Sleipner East. Unprocessed wellstreams 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 CO_2 at the field and reinject it into a sand layer that lies underneath the seabed, thereby reducing the CO_2 emissions into the air, which has environmental benefits and, insofar as it reduces environmental taxes, it has financial benefits.

Oseberg. Oseberg, the third main field in Troll/Sleipner, is operated by Norsk Hydro. We have a 14% interest, and our partners are the SDFI (50.78%), Norsk Hydro (22.23%), TotalFinaElf (8.58%) and ExxonMobil (4.33%). 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 Oseberg East and Oseberg South Satellites are tied back to the main field installations for processing. Our interest in Oseberg East is 14%, and our partners are the SDFI (45.40%), Norsk Hydro (19.60%), TotalFinaElf (14%), and ExxonMobil (7.00%). Our interest in Oseberg South is 18.22%, and our partners are the SDFI (38.36%), Norsk Hydro (30.02%, and operator), Norske Conoco (7.70%) and ExxonMobil (3.70%).

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 TotalFinaElf (21.8%), Norsk Hydro (9.3%) and Det Norske Oljeselskap (10%). Glitne is the smallest field development on the NCS using a stand-alone floating production system. Total investment in the field is NOK 830 million. The field is being developed and produced with a production and storage ship. Development work on the field began in October 2000, and Glitne has been in production since August 29, 2001, with an average daily production rate in excess of 40,000 barrels of oil.

Huldra. Huldra, a high temperature and high pressure gas and condensate field in the Troll/Sleipner area, was discovered in 1982. Our interest in this project is 19.66%, and our partners are the SDFI (31.96%), TotalFinaElf (24.33%), Norske Conoco (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. Total cost for the development is an estimated NOK 5.9 billion, of which NOK 5.5 billion has been invested as of December 31, 2001. Production started in November 2001 and is expected to reach 8 mmcm (282 mmcf) per day by 2002.

<u>Halten/Nordland</u>

Our producing fields in the Halten/Nordland area are Åsgard, Heidrun and Norne, and the main participants, in addition to Statoil, are the SDFI, Norsk Hydro, Agip, Conoco and ExxonMobil. Our share of the area's production in 2001 was 118,400 barrels of oil and 4.2 mmcm (148 mmcf) of gas, or 144.7 mboe, per day. The acquisition of SDFI assets from the Norwegian State increased our daily production by 19%. Our production target for these fields 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 (35.50%), Norsk Agip (7.90%), TotalFinaElf (7.65%), ExxonMobil (7.35%), Fortum (7%) and Norsk Hydro (9.60%). 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 49 wells grouped in 16 seabed templates. Further, the Åsgard B platform is the largest floating gas processing center, and Åsgard A is the largest floating production ship, 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 line to the processing plant at Kårstø and on to receiving terminals in Emden and Dornum in Germany. Oil produced at the Åsgard A vessel is shipped from the field by shuttle tanker.

In February 2001, we discovered weaknesses in certain welds in the flowlines connecting the Midgard and Smørbukk reservoirs to the Åsgard B gas platform. In April 2001 we concluded that the problem related only to 24 welds on the Smørbukk system. We initiated a repair project, repairing the 24 welds by September 2001. During the repair period gas and condensate production from Midgard proceeded at planned production levels. In August, we experienced similar weaknesses in welds that had been cleared in April. The Åsgard B gas platform was shut down, and a new repair program for 48 subsea welds was initiated. This program will continue through the first half of 2002. During the period of gas export from Åsgard B, noise and vibrations were experienced above expected levels in the export system. A thorough design review of the platform was performed, and based on the findings of the review, it was decided to conduct a noise and stress monitoring project during the restart of the gas export from January 1, 2002 in order to find the root cause of the noise and vibration and to determine a safe operation window for the gas export system. This review is ongoing and the final decisions on further work on the platform systems are expected to be made in April 2002. The repairs will have no effect on contractual gas deliveries as agreements are in place for other fields to supply the required volumes. The liquid production from Åsgard in 2001 was reduced by 22% (4.1 mmbbls or 26 mmcm) due to the repair work. For 2002 the liquid production will be much less effected than in 2001.

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%), Norske Conoco (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 started on February 5, 2001 when this field was linked with the Åsgard Transport pipeline. The Heidrun field is in need of pressure support to keep up volumes from its production wells. In October 2001, we started the installation of a water reinjection module and a sulphate removal module as part of the Heidrun water injection project, planned to be completed by October 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 (8.10%), Norsk Agip (6.90%) and Enterprise Oil (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 has been connected to gas markets in continental Europe through a link with the Åsgard Transport system.

Tampen

Tampen 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 2001 was 354,000 barrels of oil and 5.4 mmcm (191 mmcf) of gas, or 387 mboe, per day. The acquisition of SDFI assets from the Norwegian State has increased our daily production by 75%. We are the major operator in the area and subject to regulatory and partner approval, we will be the sole operator after 2003. We believe that there will be substantial opportunities for synergy, such as better utilization of drilling completion units, common logistics and transportation and better coordination of development of satellite fields. Other major participants in the Tampen area are the SDFI, ExxonMobil, Norsk Hydro and Norske Conoco. 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.

To commercialize the Statfjord gas reserves, the Statpipe gas transportation system was commissioned in 1985 and opened up gas exports from the northern North Sea to continental Europe. The UK Statfjord participants export their equity gas to the UK via the FLAGS, a pipeline connecting the Statfjord field to the UK continental shelf.

Statfjord. Discovered in 1974, Statfjord has produced more than 3.8 billion barrels of oil as of the end of December 2001. 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. A unitization agreement is an agreement among owners of interests in production licenses to coordinate the management, development, production and conservation of oil and gas in the area. Our interest in the Statfjord Unit is 44.34%, and our partners are ExxonMobil (21.37%), Norske Conoco (10.33%), Norske Shell (8.55%), Enterprise Oil (0.89%), Conoco (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. Gullfaks, discovered in 1978, was developed with three large concrete production platforms. It was the first major offshore field which 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. Gullfaks produces 3.8 mmcm (134.1 mmcf) of gas and 251,700 barrels of oil per day.

Gullfaks Satellites, Phase II. The Gullfaks Satellites Phase II includes production and export of gas resources and associated liquids from the Gullfaks South and Rimfaks fields. Production started as scheduled on October 1, 2001. The development concept contains subsea installations tied back to the Gullfaks A and C platforms where oil and condensate will be stabilized, stored and loaded from existing facilities on the platforms. The gas is processed to rich gas, which is gas that includes a high proportion of NGLs, before being transported to Kårstø via a new rich gas line from Gullfaks that ties into Statpipe. Total investment in this development was approximately NOK 7.6 billion, of which NOK 6.5 billion has been invested as of December 31, 2001. This project will consolidate the Tampen area as a gas province in addition to being an oil province. Gas export is expected to reach 13 mmcm (458 mmcf) per day by 2005. Our interest in this gas development, which lies in the Tampen area, is 61%, and our partners are the SDFI (30%) and Norsk Hydro (9%).

Snorre. Snorre was discovered in 1979 and has been developed with a subsea production system. Our interest in the field is 14.4%, and our partners are the SDFI (30%), ExxonMobil (11.16%), RWE-DEA (8.88%), Idemitsu (9.60%), Norsk Hydro (17.65% and operator), TotalFinaElf (5.95%), Amerada Hess (1.18%) and Enterprise Oil (1.18%). Oil and gas are piped to Statfjord for final processing, storage and export. Snorre produced an average of 2.5 mmcm (88.3 mmcf) of gas and 213,000 barrels of oil per day in 2001.

Snorre Phase II. The Snorre Phase II development in the Tampen area involves the development of the Snorre field's northern flank by means of a new floating production platform. Our interest in the Snorre Phase II project is 14.4%, and our partners are the SDFI (30%), ExxonMobil (11.16%) and RWE-DEA Norge (8.88%), Idemitsu (9.60%), Norsk Hydro (17.65%), TotalFinaElf (5.95%), Amerada Hess (1.18%) and Enterprise Oil (1.18)%. The field is operated by Norsk Hydro until January 1, 2003 at which time, subject to regulatory and partner approval, we will take over. Oil and gas will be piped to Statfjord B for storage and transport. Total development costs are estimated to NOK 15.2 billion, of which NOK 11.7 billion has been invested as of December 31, 2001. Production started in June 2001 and the field is expected to have a capacity of producing 115,000 barrels per day by 2003.

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 flowlines and suction anchors. Total cost for the project is NOK 305 million, of which our share is 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 is 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 there is a provision of NOK 61 million in our books 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, 1999, 2000 and 2001.

	YEAR ENDED DECEMBER 31,		
	1999	*2000*	*2001*
Average cost per boe			
NOK	25.1	24.8	24.9
US$	3.22	2.82	2.77
Average sales price per barrel of oil			
NOK	140.4	250.2	216.7
US$	18.0	28.4	24.1
Average sales price per scm of gas			
NOK	0.58	0.99	1.22
US$	0.07	0.11	0.14
NOK/US$ (average daily exchange rate)	7.80	8.81	8.99

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 European continent. 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. Phillips 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 TotalFinaElf, carries 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. 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. Our focus internationally will be on a limited number of areas, and on developing commercial opportunities which could provide operatorships. We hold interests in nine major projects in four core areas: Caspian, Western Africa (Angola and Nigeria), Western Europe and Venezuela. 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 1,291 million in 2001 compared to NOK 773 million in 2000.

The following table presents key financial information about this business segment. The changes from 2000 to 2001 are primarily a result of the gain from divestment of the Kashagan and Vietnam assets in addition to lower operating costs, depreciation and exploration expenditure. This was partly offset by lower oil prices and the NOK 2.0 billion writedown of the LL 652 field in Venezuela. The changes from 1999 to 2000 largely reflect the divestment of our upstream activities within Statoil Energy Inc.

	YEAR ENDED DECEMBER 31,			
	1999	*2000*	*2001*	
(IN MILLIONS)	*NOK*	*NOK*	*NOK*	*US$*
Revenues	21,745	9,027	7,693	857
Depreciation, Depletion and Amortization	2,544	1,704	3,371	376
Exploration Expenditure	1,361	1,764	683	76
Income before financial items, income taxes and minority interest	(1,995)	773	1,291	144
Capital Expenditure	6,644	5,070	5,027	560
Long-Term Assets	14,821	19,465	21,530	2,400

Internationally, we have participated in six of the largest oil and gas discoveries over the last five years: Kashagan in Kazakhstan, Shah Deniz in Azerbaijan, Agbami (Ekoli) in Nigeria, and Dalia, Kizomba A and Kizomba B in Angola. We believe that discoveries in our core areas contain attractive investment opportunities. We plan to increase our investment in international upstream and midstream development projects from NOK 5.0 billion in 2001 to NOK 8.0 billion in 2002. In addition, we expect to invest NOK 0.5 billion in exploration in 2002. The investments in 2001 were lower than originally forecasted. The divestment of our Vietnam assets and lower activity on the LL 652 field resulted in lower investments. There was also deviation due to a temporary delay in some of our projects and lower capitalized exploration costs than expected.

Our International E&P effort has been assisted by our 1991-1999 alliance with BP, which focused on accessing undeveloped frontier areas. BP's experience combined with our strengths from the NCS were a major factor in our success in accessing licenses in several promising exploration and production areas, including Angola, Azerbaijan, Nigeria (where we have operatorships), Kazakhstan, and Vietnam. The alliance was terminated in 1999 as a result of the merger of BP and Amoco, but Statoil's positions and activities internationally have not changed significantly as a result.

We believe that we are well positioned to secure attractive investment projects, which will allow us greater opportunities to exploit the group's technology and expertise developed on the NCS. The technology and expertise include global exploration, maximum field recovery through improved oil recovery techniques, subsea solutions and conversion of gas-to-liquids. Our expertise 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 further on a limited number of core areas where we own quality assets and on developing commercial opportunities which could provide operatorships and reduce our capital employed.

In 1999, we sold the upstream parts of our US subsidiary, Statoil Energy Inc., we consolidated our interests in the UK, and as part of our acquisition of Saga assets, we increased our interest in the Corrib gas field in Ireland.

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 large 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 have relinquished our licenses in Greenland by the end of December 2001.

Reserves

In 2001, we increased our proved reserves by 15%. The change principally reflects increases in Angola, Azerbaijan and Ireland. The writedown of the Venezuelan field LL 652 had a negative impact on the proved reserves based on new geological assessments performed after slower than anticipated response to water and gas injection projects and development well results resulting in a reduction of the projected volumes of oil. Our international proved oil and NGL reserves were 565 mmbbls oil, and we had 7.6 bcm (267 bcf) of proved natural gas reserves at the end of 2001, together representing 14.3% of the group's total proved reserves in barrels of oil equivalents. Over the period 1999-2001, we had an international reserve replacement ratio, calculated based on a three year average, of (0.38), or 2.14 when adjusted for the disposal of Statoil Energy Inc. Our unit finding costs in our international operations were US$ 2.15 per boe in 2001, calculated as an average number over the last three years. This figure reflects that we are in a build-up phase internationally. Our aim is to reduce the unit finding cost level as we prove the reserves in those areas in which we have found hydrocarbons.

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

		OIL/NGL		*NATURAL GAS*	*TOTAL*
YEAR		*mmboe*	*bcm*	*bcf*	*mmboe*
1998	**Proved reserves at end of year**	**507**	**34.5**	**1,219**	**724**
	of which, proved developed reserves	*92*	*22.6*	*797*	*234*
1999	Revisions and improved recovery	(23)	0.6	21	(19)
	Extensions and discoveries	0	4.0	141	25
	Purchases of reserves-in-place	4	0.3	9	6
	Sales of reserves-in-place(1)	(6)	(34.4)	(1,215)	(223)
	Production	(21)	(1.7)	(60)	(32)
	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**
	of which, proved developed reserves	*187*	*1.8*	*65*	*198*
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(2)	(1)	(4.8)	(170)	(31)
	Production	(22)	(0.4)	(15)	(25)
	Proved reserves at end of year	**565**	**7.6**	**267**	**612**
	of which, proved developed reserves	*166*	*1.2*	*42*	*173*

(1) Due to the sale of Statoil Energy Inc.
(2) Due to sale of Vietnam assets.

Production

Our petroleum production outside Norway amounted to an average of 67,000 boe per day in 2001. 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 the Stine field in Denmark began test production in September 2001. For Sincor, OPEC restrictions imposed in 2001 resulted in a reduction of our share of initial field production of about 1 million boe in 2001.

	YEAR ENDED DECEMBER 31,		
	1999	*2000*	*2001*
Average daily oil (mbbls)	59	57	60
Average daily natural gas (mmcm/mmcf)	4.5 / 160	1.5 / 53	1.2 / 41
Average daily boe (mboe)	87	67	67

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, 2001.

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	8.8
Western Europe						
Denmark: Lulita Unit	18.82%	Maersk	1998	2026	1	0.3
Denmark: Siri(2)	40.00%	Statoil	1999	2027	6	12.4
UK: Alba	17.00%	ChevronTexaco	1994	2018	20	13.5
UK: Schiehallion	5.88%	BP	1998	2017	14	5.4
UK: Merlin	2.35%	Shell	1997	2017	3	0.6
UK: Dunlin	28.76%	Shell	1978	2017	18	3.8
UK: Jupiter	30.00%	Conoco	1995	2010	12	7.4
Western Africa						
Angola: Girassol	13.33%	TotalFinaElf	2001	2023	4	0.5
Venezuela						
LL 652 reactivation	27.00%	ChevronTexaco	1998	2018	189	2.6
Sincor(3)	15.00%	Sincor JV	2001	2037	106(4)	5.5
Other						
China: CA 17/22 Lufeng	75.00%	Statoil	1997	2013	5	6.2
Total International E&P					**390**	**67.0**

(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 57 wells that were ready for production as of December 31, 2001.

Our unit cost for international production averaged approximately US$ 5.2 per boe in 2001. The unit production cost declined by US$ 1.4 per boe compared to 2000. The main reason for the reduction in unit production cost is that a larger share of the international production is coming from fields with lower unit costs. We believe that our unit production cost is explained by the nature of our international portfolio. Most of our fields are in tail production (UK, Denmark and China) or are still at a very early stage of their production life (Venezuela). These types of assets will often have a higher unit cost of production than fields where production rates are in the plateau period.

Core Areas

We are 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 preliminary 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 Sea and giant oil fields such as Tengiz and Karachaganak – and later Kashagan – in Kazakhstan in the mid- and late-1980s showed that despite 150 years of oil production, the Caspian region still contains significant amounts of oil, NGL and gas.

There is still a potential 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. With both presidents now in their 70s, 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 2001, a permanent solution does not appear imminent. There are currently bilateral agreements in place between Russia and Azerbaijan and between Russia and Kazakhstan, although the details 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 field work 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 Western pipeline through Georgia to the Black Sea Port at Supsa. A Northern pipeline to Novorossiysk in Russia is also available, but is currently only used by the State Oil Company of the Azerbaijan Republic. As the production volumes increase from the next stages of development on Azeri-Chirag-Gunashli and other fields, the export capacity of the current infrastructure will be insufficient. Several different solutions have been proposed to address the additional capacity needed.

- a Southern route from Baku through Tbilisi, Georgia to the Mediterranean port of Ceyhan in Turkey;
- expansion of the capacity of the Northern route to Novorossiysk;
- expansion of the capacity of the Western route through Georgia to Supsa; and
- a swap arrangement with Iran.

We support the Baku-Tbilisi-Ceyhan transportation route and are a sponsoring company for the Baku-Tbilisi-Ceyhan pipeline with a 6.45% share. Development of the Baku-Tbilisi-Ceyhan pipeline would ensure export flexibility through multiple pipelines, and thereby diversify risk involved in commercializing the land-locked upstream resources. This option is described in greater detail below, in – Azerbaijan – Azeri-Chirag-Gunashli.

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 very 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: 8.56% in the Azeri-Chirag-Gunashli, or ACG, oil field, 25.50% in the Shah Deniz gas and condensate field and 15% in the Alov, Araz and Sharg prospects. In addition, as descibed above, we are one of the sponsors for the Baku-Tbilisi-Ceyhan major oil transportation pipeline with a current interest of 6.45%.

Azeri-Chirag-Gunashli. We are partner with an 8.56% share in the Azeri-Chirag-Gunashli PSA. Our partners are BP (34.14%), Unocal (10.28%), LUKoil (10%), State Oil Company of the Azerbaijan Republic, or SOCAR (10%), ExxonMobil (8%), Turkish Petroleum, or TPAO (6.75%), Pennzoil (5.63%), Itochu (3.92%) and Delta Hess Khazar (2.72%). BP has been the operator of the field since June 1999.

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. A dispute with SOCAR regarding cost recovery for the Western Route was resolved in 2001. Oil production from Chirag began in November 1997 and in 2001 averaged close to 120,000 barrels per day. During 2001, an expansion of the capacity of the Chirag 1 platform and increased pumping capacity in the Western Route to Supsa increased the ACG early oil production capacity up to 140,000 barrels per day. During 2002, we expect that the field will have a capacity to produce an annual average of 127,000 barrels per day. The ACG fields will be further developed in three phases.

The ACG Phase I development plans call 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 injection platform, as well as additional pipelines for oil and gas to Sangashal and oil terminal extensions, will be installed. ACG Phase I is estimated to cost US$3.5 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 partners sanctioned ACG Phase I in August 2001.

ACG Phase II development planning has also begun, with sanctioning planned during 2002. 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. Phase II 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 US$ 4.6 billion.

The partners will require a new export pipeline to transport the oil from these phases to the market. A number of regional oil pipeline routes have been considered. In 2000, the authorities in Turkey, Georgia and Azerbaijan approved agreements on laying a 1,750 kilometer oil export pipeline from Baku in Azerbaijan, via Tbilisi in Georgia to Ceyhan in Turkey. The pipeline will have a target throughput capacity of 1 million barrels per day and is expected to cost US$ 3 billion. We are one of the sponsoring companies of this project with a current interest of 6.45% and the possibility of acquiring up to 10%. The Baku-Tbilisi-Ceyhan pipeline detailed engineering work is currently ongoing and is scheduled to be sanctioned in 2002, followed by a land acquisition and construction phase. The Baku-Tbilisi-Ceyhan pipeline is expected to commence operations by year-end 2004 when ACG Phase I is ready to go on stream. However, in the event the Baku-Tbilisi-Ceyhan pipeline is not ready in time for Phase I start up, the ACG partners will have to pursue alternative options to secure transportation capacity for the Phase I oil volumes. Among the alternatives being considered are expansion of the western export route capacity to 300,000 barrels of oil per day and the northern export route to 200,000 barrels of oil per day. This last option would require additional agreements to be negotiated with Transneft for the Russian part of the pipeline.

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 will be approximately 1 million barrels per day from seven installed platforms by 2012. We estimate overall investments for the ACG full field development to be approximately US$12 billion. These cost estimates cover all three phases and early oil production, but exclude pipeline transportation arrangements from land terminal to shipping harbor.

We received our first revenue from the ACG operation in 1998. The asset brought a net profit to our international operations in 2000 and 2001.

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 have a 25.50% interest in Shah Deniz, and our partners are BP (25.50% and operator), TotalFinaElf (10%), LUKAgip (10%), Naftiran Intertrade Co. Ltd (NICO) (10%), TPAO (9%) and SOCAR (10%).

The field will most likely be developed in stages. We plan to sanction Stage 1 development on the east flank of the reservoir as soon as the partners determine commercially viable solutions for the development. Turkey is expected to be the main market for gas from Shah Deniz. 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. This represents a major step towards a commercial solution for Shah Deniz. In order to secure further a long-term market for our Shah Deniz gas, we have established an alliance with the Turkish KOÇ group and opened a gas marketing office in Turkey. However, the rate of growth in Turkish demand remains uncertain.

We expect first production to commence within three to four years after we sanction the Stage 1 development. The plateau production level of Stage 1 is expected to be 8.4 bcm (297 bcf) gas to be sold per year and will be reached after three to four years of production. The planned transportation system will be prepared for expanded capacity to facilitate future development stages. The partners estimate that the total capital investment for the development is approximately US$ 2.7 billion, which includes offshore facilities, wells, pipelines to shore, gas processing plant and onshore pipeline for transportation to the Turkish border.

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. 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 800,000 boe per day, most of which comes from shallow water fields. Angola has been enmeshed in a civil war for over 30 years. Even during periods with fierce fighting, however, oil production has continued with limited problems. We believe that our activities in the deepwater area of Angola are not likely to be materially affected by fighting between government forces and the UNITA rebels. The country has to date provided a stable fiscal environment for the oil companies.

The Girassol discovery made by TotalFinaElf 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 have been used extensively to further field development.

Block 17. This block spans approximately 5,000 square kilometers and includes discoveries at Girassol, Dalia and the Rosa Lirio Cravo area. The water depth varies between 500 and 1,600 meters. Exploration started in 1994. A total of 14 exploration wells and eight appraisal wells have been drilled, and ten discoveries have been made. All commitments in the PSA have been met. One additional exploration well is planned before the exploration license expires in August 2002. We have a 13.33% interest, and our other partners are TotalFinaElf (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. This 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 offtake 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. Due to Angola's self-imposed OPEC restrictions, the daily production for March to June 2002 will be reduced by 2.2% compared to the target plateau. We expect that the necessary investments for the field will be US$ 3 billion, of which US$ 2.3 billion has been invested by the end of 2001.

Jasmim, a subsea tieback to the Girassol FPSO, was sanctioned for development in 2001 and is expected to come on stream during 2003. The production license expires in 2025. The development included minor tie-in modifications on the FPSO and subsea tieback wells for production and injection. Production from this field is expected to peak at 60,000 barrels of oil per day by 2004.

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

Dalia was expected to be approved during 2002. Sonangol, however, has proposed a leasing scheme for the FPSO that will have a very negative effect on the value of the project, so the partners have rejected the proposal. This issue is about to delay the project, and all main invitations to tender have been put on hold pending a resolution of the lease issue. We expect that the necessary investments for the field will be US$ 3 billion from 2002 to 2005. However, a delay due to the lease issue would affect the project schedule. The production license expires in 2024. The oil in this discovery is heavier than at Girassol, approximately 22 degrees API, which we believe will result in a lower selling price.

Block 15. This block is approximately 4,000 square kilometers and includes discoveries at Kizomba A, B and C. The water depth varies between 800 and 1,600 meters. The first discovery was made in 1998. A total of 14 exploration wells and six appraisal wells have been drilled to date, and 12 discoveries have been made. Remaining exploration drilling is currently planned for 2002 and 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 to be 250,000 barrels of oil per day by 2006. We expect that the necessary investments for the field will be approximately US$ 3 billion from 2001 to 2004.

Kizomba B, encompassing the Kissanje and Dikanza discoveries, is expected to 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. We expect that an FPSO and a wellhead platform identical to the ones planned for Kizomba A will be used. Production should start in 2006, and we expect peak production capacity to be 250,000 barrels per day by 2006. We expect that the necessary investments for the field will be US$ 3 billion from 2003 to 2006.

Mondo 1 was discovered in 2000 and could, with the addition of the Batuque, M'bulumbumba and Saxi discoveries, form the basis for a third development, tentatively named Kizomba C. The Marimba and Mavacola discoveries will most likely be tied back to either Kizomba A or B. Xikomba is a small isolated discovery which is planned to be produced by a leased FPSO. The project was sanctioned in March 2002 with first oil by year-end 2003.

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-well-commitment, was drilled in 2001 with disappointing results. Two further wells are planned for 2002. We have a 13.33% interest in Block 31, and our other partners are BP (26.66% and operator), ExxonMobil (25%), Sonangol (20%), Marathon (10%) and TotalFinaElf (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.

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 major oil discoveries: Bonga by Shell in Block 212, Agbami/Ekoli in Blocks 216 and 217 with ChevronTexaco and Statoil as operators respectively, Akpo in Block 246 by TotalFinaElf and Erha by ExxonMobil in Block 209. ExxonMobil and Shell are the two biggest participants in the deepwater areas. We, TotalFinaElf, 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 operations are in the deepwater areas of Nigeria, where to date there have been no major events of this kind.

We entered Nigeria in 1993 as part of our alliance with BP. 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. Upon confirmation of commercial discoveries 50% of the licensed area will be converted to a production license valid for 20 years. Both blocks have such discoveries and await conversion into production licenses.

A third block, OPL213, was part of the original holding. We sold the block in 1999 and ChevronTexaco currently has a 100% interest.

We have drilled a total of six exploration wells in the two license areas, resulting in one oil discovery, Ekoli, and one gas discovery, Nnwa. The last well, Bilah 1 was completed late in 2000, and is currently believed to be a non-commercial hydrocarbon discovery.

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. Sanction and contract awards are planned for mid 2002. The development will probably consist of a floating wellhead platform and a closely moored FPSO. We estimate that production will start in 2005 with expected peak production capacity of 200,000 barrels per day by 2006. Necessary investments for the project would be approximately US$ 3.9 billion in the period 2002 to 2005. Partner discussions are ongoing to determine the final unitization between license OPL 216 and license OPL217.

The Nnwa-1 well indicated a major gas discovery and small amounts of oil. The discovery was confirmed through Shell's Doro-1 well, drilled on an extension of the structure in an adjacent area. At present no gas market exists in Nigeria. Field development studies centered around different LNG options were undertaken in 2001, and following discussion with Nigerian authorities and the Nigerian National Petroleum Corporation, evaluations leading to a decision are expected to continue.

Western Europe

We have interests in Ireland, the Faroes, the UK and Denmark. We believe that the Atlantic Margin, the outer part of the continental shelf running from Norway's Lofoten Islands to west of Ireland, is a promising frontier exploration province. We expect the region to contain predominantly gas. We have an exploration portfolio of licenses on the Atlantic Margin with gross acreage of approximately 15,000 square kilometers. Our producing assets in UK and Denmark were the main contributors to International E&P's positive income before net financial items, income taxes and minority interest in 2001.

Ireland. In Ireland, we have interests in six exploration licenses, and of these we are the operator for two. We are partner in the Corrib field.

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 and has a 30-year duration. We have a 36.50% interest in Corrib gas field, and our partners are Enterprise (45% and operator) and Marathon (18.50%).

The development will involve seven subsea wells in 350 meters water depth with output flowing directly through a pipeline to an onshore terminal. This terminal and receiving facility will be constructed on the coast of County Mayo with production expected to start at the beginning of 2004. We expect to have a plateau production capacity of 8.9 mmcm (314 mmcf) per day by 2004.

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. Approximately 75% of the market is today supplied by an interconnector from the UK. 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 operation 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.

In 2001 a Statoil-operated exploration well was drilled in License 8/95, Porcupine Basin. The well was plugged and abandoned as a dry hole, and the license was relinquished in 2001.

We acquired and processed a large three-dimensional seismic survey in 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 final well commitment in 2003. Statoil's partners in this license are Enterprise Energy Ireland (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 into 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, as much of the area has been covered by thick layers of basalt, which are old lava flows, but we believe it has significant potential.

The Statoil-operated License 003 lies in the Foinaven sub-basin and was granted in 2000 for 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. We have a 35% interest, and our partners are Phillips (30%), Enterprise (20%) and Veba (15%). The Amerada Hess Group, however, made a significant gas and light oil discovery in License 001, and we are now evaluating the results of this discovery and its implications 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, was granted in 2000 for nine years, and only requires us to perform seismic surveys. We have a 27.50% interest, and our partners are Anadarko (27.50%), Phillips (20%), Enterprise (15%) and Veba (10%).

United Kingdom. We are one of the largest gross acreage holders on the UK part of the Atlantic Margin and a partner in the producing Schiehallion field. We are also a key partner in several producing licenses on the UK continental shelf, holding interests in the Alba, Dunlin, Merlin oil fields and the Jupiter gas field.

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 14 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 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 90,000 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, an additional four phases are planned to recover the reserve volumes fully. Phase IIa, which consisted of an additional producer/injector pair of wells together with a pilot appraisal well, was completed in early 2001. Phases IIb, Phase III and Phase IV will continue from 2001 onwards. The field development is being monitored by regular 3D/4D seismic evaluation, the most recent of which was acquired in 2000. We expect that the necessary investments for Phases IIb, III and IV will be approximately UK£220 million, UK£170 million and UK£310 million, respectively.

Oil is exported via a dedicated shuttle tanker to the Sullom Voe terminal. Associated gas is currently used for fuel with the residual being injected into a dedicated gas disposal well. From August 2002, however, Schiehallion gas will be exported via pipeline to Sullom Voe and onto the BP-operated Magnus field where it will be used for enhanced oil recovery.

Alba. The Alba reservoir is located at a depth of 1,850 meters and lies 215 kilometers northeast of Aberdeen Scotland, 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 expires in March 2018. We have a 17% interest in the Alba field, and our partners are ChevronTexaco (21.17% and operator), BP (15.5%), TotalFinaElf (12.65%), Conoco (23.43%), Energy Africa (8%) and Enterprise (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, will develop the extreme south area of the field. The development was sanctioned by the UK Department of Trade and Industry during the third quarter of 2001 and first oil is scheduled for October 2002, with continued drilling until March 2003. The development will be based on a subsea installation tied back to the Alba platform. The necessary investments for this phase are expected to be UK£138 million from 2001 to early 2003. Additional gas management and debottlenecking improvements are being undertaken during 2002.

Caledonia. The Caledonia field is a new development located immediately north of the Alba field and contained within the same license area. The small oil discovery was made during 1977 with the first well, and appraisal drilling followed during the 1990s. The single production well will be drilled during mid-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 is expected to commence at the end of third quarter 2002 at approximately 13,000 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%), TotalFinaElf (12.65%), Energy Africa (10.06%) and Enterprise (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 is expected to be approximately 10,000 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 commingled production stream is exported via the Brent System Pipeline to the Sullom Voe Terminal.

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 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 expected average production during 2002 of 5,800 barrels of oil per day. Current production is approximately 7,500 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 field is located 150 kilometers east of the Theddlethorpe gas terminal. It consists of six gas reservoirs: Ganymede, Callisto South, Callisto North, Europa, Sinope North and Bell. All gas is produced from reservoirs in a sandstone formation 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 32,000 boe per day. The Jupiter license will expire in 2010. We have a 30% interest in the Jupiter gas field, and our partners are Conoco (20% and operator) and ExxonMobil (50%).

Denmark. We discovered oil at Siri in 1995, the same year as the license award. We brought the Siri project in the Danish North Sea on stream in 1999 and have a 40% interest. Our partners are Paladin Resources (25.26%), Dong E&P (23.62%) and Denerco (11.12%). We were the first foreign operator to develop a field off Denmark. Siri is also the first producing Danish field outside the Central Graben area, where the country's offshore oil and gas production had previously been concentrated. Production from Siri imposes less of a burden on the environment than other platforms off Denmark, in part because produced water is reinjected to the reservoir as pressure support, and in part because there is no planned gas flaring. The nearby Stine Segment 2 was discovered in 2001 and was developed with a horizontal well from the Siri platform the same year. We have a 45.7% interest in Stine. The Siri field is on decline, and Siri and Stine currently produce a total of 35,000 barrels of oil per day.

We also have an 18.82% interest in the Lulita field, operated by Maersk, which has been producing since 1998. The field is currently producing 550 boe per day from one well at Maersk's Harald Platform.

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 the region can be considered 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. Since then, a wide range of reforms have been introduced, some of which are not popular and are being contested. A 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. Some uncertainty regarding the application of the law remains for other oil projects.

LL 652. We have a 27% interest in the LL 652 oil field located in Venezuela's Lake Maracaibo. Our partners in LL 652 are ChevronTexaco (27%), BP (36%) and P&GI (10%). The field has been on 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. Further plans include drilling of new wells for injection and production purposes.

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. Current estimates show that the project will cost US$ 1.4 billion, of which US$ 1.1 billion had been invested as of December 31, 2001, including a bid bonus. In December 2001, we decided to writedown the book value of our interests in LL 652 based on a new geologic assessment performed after slower than anticipated response to water and gas injection projects and development well. Through the writedown we recognized a pre-tax loss of NOK 2.0 billion (NOK 1.4 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 15% by us, PDVSA (38%) and TotalFinaElf (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 requires 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 is produced has already commenced and first shipment of diluted crude oil took place in January 2001. The initial production 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 late in 2006 at a production level of 180,000 boe per stream day of 30-32 degree API, low sulphur Syncrude, which Sincor will market under the name of Zuata Sweet. In addition, Sincor will produce sulphur and petroleum coke, known as petcoke, for sale on the international market. The estimated total investment in the project up to commercial production is US$ 4.2 billion, of which US$ 4.0 billion had been invested at the end of 2001.

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 Caspian Region, Latin America and the Middle East.

Iran. We consider Iran to be a promising country for business opportunities given the improving business and political environment and the potential for improved recovery in existing fields, 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. 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.

We have also been invited to bid on several of the South Pars phases, and we expect the result of these bids during the second quarter of 2002.

We opened a small office in Tehran in 2001 to facilitate and support business development activities. However, we are not yet committed to any investments. Depending on the outcome of the bids submitted on South Pars, and the outcome of exploration and enhanced oil recovery studies, which we expect may be completed by 2003, we may decide to make significant investments in Iran as early as 2002. In August 1996, the United States adopted the Iran and Libya Sanctions Act which requires the President of the United States to impose two or more 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 of US$ 20 million or more that directly and significantly contribute to the enhancement of Iran's ability to develop its petroleum resources. We cannot predict interpretations of, or the implementation policy of the US Government under, the Iran and Libya Sanctions Act with respect to our current or future activities in Iran. This act, which was due to expire on August 5, 2001, was extended for a further five years.

Caspian Region. We sold our interest in the giant 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 being pursued. Statoil also made significant progress towards a future agreement on exploration and field development studies in the Caspian region with another major company in the region.

Brazil. In June 2001, we bid for a number of blocks in the third Brazilian licensing round. We were successful in two bids and now have 25% equity in Blocks BM-S 17 and BM-S 19 in the Santos Basin. BM-S 17 is operated by Petrobras (50%) with Enterprise as partner (25%). BM-S 19 is operated by Repsol/YPF (50%), also with Enterprise as a 25% equity partner. A three-dimensional seismic acquisition program is planned in both blocks during 2002.

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 2001 levels, the field could stay in production until mid-2003.

Natural Gas

Introduction

Our Natural Gas business segment transports, processes and sells natural gas from production fields to purchasers. In 2001, we sold on our own behalf 14.7 bcm (500 bcf) of natural gas as well as approximately 18.9 bcm (600 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 pursuant to long-term contracts with third-party downstream customers represent approximately two-thirds of the entire NCS contract portfolio.

For the year ended December 31, 2000 (the most recent year for which official figures are available), natural gas represented approximately 20.5% of the overall Norwegian petroleum production by all producers from the NCS. 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, which 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 for the time being by the Norwegian State. The technical operation of the natural gas transport system and the Kårstø Gas Treatment Plant, such as system maintenance, will be carried out by us on a cost-recovery basis after the operatorships are transferred. This change in operator has, in itself, no effect on ownership, tariffs or access.

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,			
	1999	*2000*	*2001*	
(IN MILLIONS)	*NOK*	*NOK*	*NOK*	*US$*
Revenues	13,799	20,624	23,468	2,615
Depreciation, Depletion and Amortization	725	730	664	74
Income before financial items, income taxes and minority interest	5,052	7,893	9,629	1,073
Capital Expenditure	1,810	810	671	75
Long-Term Assets	13,557	13,030	10,500	1,170

European Gas Market

According to the International Energy Agency (IEA) annual natural gas consumption in OECD-Europe rose from 356 bcm (12.6 tcf) in 1995 to 469 bcm (16.6 tcf) in 2000 (the most recent year for which official figures are available). They estimate that annual consumption in OECD-Europe will rise to approximately 513 bcm (18.1 tcf) by 2005 and to 600 bcm (21.2 tcf) in 2010. 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 subsectors of the OECD-Europe natural gas market over the next nine years. They expect more than 60% of the total growth in gas demand in the period 1997 to 2010 to come from power generation.

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 2001, an industry consultant, and Transco Plc, a 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. Transco warns that UK supply may not meet demand in winter. 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.

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 below under —Regulation.

Gas Sales and Marketing

Our current export markets for NCS gas are Germany, France, Italy, Spain, the Netherlands, Belgium, Austria, Poland, the Czech Republic and the United Kingdom. Our customers are mainly large national or regional gas companies, such as Ruhrgas, Gaz de France, Snam, Gasunie and Gas Natural. 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 approximately one-third will be for our own account. In 2000, 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 —Major Shareholders—The Norwegian State as a Shareholder—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 have completed the restructuring of our natural gas business and are focusing our natural gas marketing efforts towards larger industrial customers, power generators and wholesalers, and participating in the UK spot market. In 2001, we delivered close to 0.9 bcm (32.4 bcf) to the industrial and commercial sector in the United Kingdom. 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 natural gas activities are connected to our continental natural gas activities through our capacity rights in the UK-Continent Interconnector gas transportation pipeline which links Bacton on the south eastern coast of England to Zeebrugge in Belgium. To enhance access to the UK market, we have an interest in the Vesterled pipeline that connects the Heimdal riser platform and the Frigg field and other contiguous fields to St. Fergus in the UK. Vesterled, operational since October 1, 2001, uses the existing Frigg Norwegian pipeline and has a design capacity of 33 mmcm (1.2 bcf) per day, or approximately 10 to 12 bcm (353 to 423 bcf) per year.

In July 2001 we signed a new long-term gas contract with BP Gas Marketing. The 15-year contract covers deliveries of 1.6 bcm (56.5 bcf) natural gas per year into the UK through Vesterled. Deliveries of gas started on October 1, 2001. The volume represents approximately 1.5% of total current UK demand. The Ministry of Petroleum and Energy approved the contract on July 11, 2001.

In Ireland, Statoil will supply natural gas to the Dublin Bay Power Plant, owned by the Synergen Partnership between Statoil Dublin Bay a.s (30%) and Dublin Bay Power Limited (70%), and we will undertake activities relating to transportation and sourcing of the natural gas. The commissioning period started with an initial firing on January 11, 2002. Electricity was exported to the grid on January 21, 2002 (after synchronization). The power plant is expected to begin commercial operations by the third quarter of 2002 and has a capacity of 400 megawatts which represents 10% of the total Irish power demand. Synergen has entered into a long-term agreement with ESB Independent Energy Limited, a wholly owned subsidiary of the Electricity Supply Board, the state-owned, national electricity utility in Ireland, to market and sell electricity generated by the Dublin Bay Power Plant.

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.

We entered into a new major gas sales agreement on September 3, 2001 with the Polish Oil and Gas Company, which involves cumulative sale of 73.5 bcm from Norway to Poland over 16 years starting in 2008. The Statoil/SDFI share of the deliveries is 72.8% (53.5 bcm). There are conditions to be fulfilled by both parties before the gas sales agreement enters into force, to be fulfilled by October 1, 2005.

On October 18, 2001 we, together with four other licensees in the Snøhvit field in the Barents Sea, signed separate contracts for the sale of liquefied natural gas with two international energy companies. We have a 22.29% share in the Snøhvit license and in addition are the marketer for SDFI's 30% share. El Paso Global LNG Company will purchase 2.4 bcm of gas per year, and Iberdrola S.A will purchase 1.6 bcm per year. Delivery startup is scheduled for autumn 2006, and the sales agreements apply for a period of 17 to 20 years. One of the conditions for the agreements was that the Storting approve the Snøhvit project on conditions consistent with the Snøhvit group's development applications, which was done on March 7, 2002, and that other approvals from relevant authorities are obtained. See also —Exploration and Production Norway—Exploration and Development—Snøhvit.

Potential New Markets

Turkey. Based on our ownership interest in the significant natural gas discovery in the Shah Deniz field in Azerbaijan, we have taken steps towards entering the Turkish gas and power markets. The viability of the Shah Deniz project increased significantly in March 2001 when SOCAR and the Turkish company Botas signed a Gas Sales and Purchase Agreement covering 6.6 bcm (233 bcf) of gas annually. We expect Turkey to be the most attractive market for this natural gas as it is a quickly growing market driven mainly by a strong need for new gas-fired power generation capacity. The deregulation of the Turkish market will provide opportunities for private investors in gas marketing, distribution, and power generation. However, due to the recent

economic crisis in the country, the current investment climate has deteriorated. We expect it to improve during 2002 and the subsequent years.
Our cooperation in Turkey with KOÇ Holding, one of Turkey's largest enterprises expanding into energy as a result of the ongoing deregulation, began in 2000 and is progressing well. On the basis of the regulatory framework now under development, we are working on a joint gas marketing company and we are evaluating investment opportunities in gas-fired power generation and local distribution of gas in order to secure outlets for our natural gas from Azerbaijan.

We believe that a position in Turkey could also facilitate our transport of additional Caspian natural gas volumes towards Europe.

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. Most of the technical aspects of operating the transportation system are being carried out by us on a cost recovery basis. We are the largest corporate owner of these operated facilities. In 2001, the system transported 51.9 bcm (1.8 tcf) of Norwegian gas, although at this export level, the system has an additional 26 to 30 bcm (917 to 1.1 tcf) per year capacity. This existing infrastructure, operating with spare capacity and combined with new pipelines such as Vesterled (described above), permits us to bring new fields on stream without having to make substantial new investments in infrastructure. This puts us in a strong position to exploit anticipated growth in the natural gas markets and to continue to increase our supplies to the European market.

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 yearly 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 must approve the tariff. The pipelines are maintained under a yearly maintenance plan approved by the Norwegian Petroleum Directorate.

As part of the SDFI asset restructuring, we transferred a 33.25% interest in Statpipe to the Norwegian State, leaving us with 25%, and a 25% interest in Norsea Gas AS, leaving us with 25%. We received an additional 14.99% interest in Europipe II increasing our interest to 15%.

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 terminal that are operated by Phillips Petroleum Norge.

PIPELINES

JOINT VENTURE	*STARTUP DATE*	*PRODUCT*	*START POINT*	*END POINT*	*TRANSPORT CAPACITY MMSm3/d*	*STATOIL SHARE*
Zeepipe						
Zeepipe 1	1993	Dry gas	Sleipner riser Platform	Zeebrugge	41.7	15.00%
Zeepipe 2A	1996	Dry gas	Kollsnes	Sleipner riser Platform	55.4	15.00%
Zeepipe 2B	1997	Dry gas	Kollsnes	Draupner E	59.5	15.00%
Europipe 1	1995	Dry gas	Draupner E	Dornum/Emden	53.6	15.00%
Franpipe	1998	Dry gas	Draupner E	Dunkerque	52.2	9.71%
Europipe II	1999	Dry gas	Kårstø	Dornum	68.1	15.00%
Norpipe AS	1977	Dry gas	Norpipe Y (Ekofisk Area)	Emden	43.0	25.00%
Haltenpipe	1996	Rich gas	Heidrun Field	Tjeldbergodden/ Åsgard Transport	7.1	19.06%
Åsgard Transport	2000	Rich gas	Åsgard	Kårstø	66.0	13.55%
Statpipe						
Zone 1	1985	Rich gas	Statfjord	Kårstø	29.0	25.00%
Zone 4A	1985	Dry gas	Heimdal	Draupner S	29.0	25.00%
			Kårstø	Draupner S	23.0	25.00%
Zone 4B	1985	Dry gas	Draupner S	Norpipe Y (Ekofisk Area)	43.0	25.00%
Oseberg Gas Transport(1)	2000	Dry gas	Oseberg	Heimdal	41.0	12.04%
Norne Gas Export	2001	Rich gas	Norne	Åsgard Transport	11.0	25.00%
Vesterled						
(Frigg Transport)	2001	Dry gas	Heimdal	St. Fergus	33.0	12.28%

(1) Owned by E&P Norway.

TERMINALS

JOINT VENTURE	*STARTUP DATE*	*PRODUCT*	*LOCATION*	*STATOIL SHARE*
Zeepipe				
Europipe Receiving Facilities	1995	Dry gas	Receiving Terminal, Dornum	15.0%
Europipe Metering Station	1995	Dry gas	Metering Station, Emden	15.0%
Zeepipe Terminal J/V	1993	Dry gas	Gas Terminal, Zeebrugge	7.35%
Dunkerque Terminal DA	1998	Dry gas	Gas Terminal, Dunkerque	6.31%
Norsea Gas AS	1977	Dry gas	Gas Terminal, Emden	25.0%
Statpipe	1985	Dry gas/NGL	Kårstø terminal	25.0%
Etanor DA	2000	Ethane	Ethane plant at Kårstø	16.42%
Vesterled (Frigg Terminal)	1978	Dry gas	St. Fergus	12.28%

Kårstø Processing Plant

We have a 25% interest in the Statpipe joint venture, owner of the Kårstø processing plant, which commenced operations in 1985. 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 teatment plant. Our partners include the SDFI (33.25%), TotalFinaElf (12%), Norsk Hydro (10%), ExxonMobil (12%), Shell (5%) and Conoco (2.75%). Kårstø processes rich gas and condensate, or light oil, from the NCS received via the Statpipe, Sleipner and Åsgard pipelines. 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 2001, Kårstø produced 3.3 million tonnes of LPG and 3.3 million tonnes of condensate exported to customers worldwide.

We have entered into a 15-year contract 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 Haltenbanken area in October 2000 and completed a new export pipeline, Europipe II, to connect Kårstø to the receiving terminal in Dornum, Germany in 1999. In addition, we decided to expand the plant to accommodate gas from the Mikkel field. We are currently evaluating plans to expand the processing capacity of the Kårstø plant to accommodate additional gas when production commences from the Kristin field. We expect a decision on this expansion to be made later in the third quarter of 2002. 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 required Kårstø to reduce its NOx emissions. The final permit was received June 2001 and requires a reduction of 187 tonnes of NOx per year starting in 2005. We are currently investigating how to fulfill this requirement, but we estimate the costs to be between NOK 100 million and NOK 200 million. The cost will depend on the steps we choose to meet the requirement. 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 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, commonly known as take-or-pay, 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, commonly known as take-or-pay contracts. Since these contracts are based on volume and not depletion, the contracts are field neutral, meaning they do not specify which fields are to supply the gas. 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. The Ministry of Petroleum and Energy would only approve, and allocate to field(s) on the NCS, gas sales contracts negotiated in accordance with the Norwegian legal framework and Storting reports and are consistent with the Norwegian State's resource management objectives. The Ministry of Petroleum and Energy also determined the sellers' volume obligations under specific sales contracts. This approval and allocation system has been changed. For more information, see —Recent Changes to the Norwegian Gas Resource Management System below.

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 gas sales entered into by Norwegian producers and allow for delivery from NCS sources other than the Troll reservoirs. The Ministry of Petroleum and Energy decides which fields will be granted the right to deliver gas under the Troll gas sales agreements. For this purpose, the Ministry of Petroleum and Energy established a set of principles in 1990, reflected in the Troll Commercial Model, or TCM, to distribute rights and obligations under these agreements. The TCM distributes, on an average basis, income, costs and risks between all fields approved by the Ministry of Petroleum and Energy to deliver gas under the Troll gas sales agreements. The TCM also includes a mechanism to secure an outlet of associated gas from oil and condensate fields, whereby the Troll licensees buy the gas on an as-produced basis and modulate these deliveries along with its own production to accord with the deliveries contracted under the Troll gas sales agreements. Modulation is a reliable back-up service, ensuring continuity of supply, thereby making deliveries less dependent on a specific field's actual production.

Our long-term contracts generally run for 20 years or more. Under a significant portion of our current long-term sales contracts, the volumes are scheduled to increase rapidly toward the plateau level to be reached between 2005 and 2008. Our currently contracted for volumes, together with volumes contracted for on behalf of the SDFI, will increase by approximately 40% in the period 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 six to nine months prior to the date of adjustment as published in reference indices. The price formula, however, is not able to capture all trends in the marketplace in either the gas or competing fuel markets, and, 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 update the price formula.

Under our long-term sales contracts either party may elect to enter into a price review process under certain circumstances as set forth in the contracts. This review process can be elected at regular intervals. Approximately two-thirds of the volumes represented in our existing long-term sales contracts were eligible for potential price review in October 2001. Given the increasing demand for natural gas in the European market combined with a deregulating European gas market, it is difficult to predict the outcome of any price review that takes place or the evolution of gas prices in European markets. 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. To date, price reviews have been requested under two contracts, and we are still in negotiations with these parties. Under the remaining contracts, representing the bulk of the gas volume, the parties agreed to defer the date for requesting a review until later in 2002. Any resulting change in pricing will be applied retroactively from October 1, 2001. We are in discussions with such parties in order to investigate whether it is possible to find mutually acceptable solutions without invoking the formal price review procedures.

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. The implementation of this decision to change the system requires significant changes to the institutional, legal and commercial arrangements, including existing license, supply and transportation agreements. In addition, new lifting arrangements in the individual licenses will have to be established by the licensees. At the request of the Ministry of Petroleum and Energy, Statoil and other NCS license holders are examining the aspects of implementing such a system.

The main immediate effect of this Royal Decree has been 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, license agreements and other existing contracts are still ongoing and are expected to be finalized during 2002. We are currently pursuing opportunities on an individual basis.

We do not expect the change to the existing system to affect the volume escalation or price review provisions in the contracts for gas volumes already allocated, except that future price reviews will be carried out on an individual company basis.

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

We are the largest marketer of Norwegian natural gas. The volumes that we sell, together with those of the Norwegian State, pursuant to long-term contracts with third party downstream customers represent approximately two-thirds of the entire NCS contract portfolio. The bulk of the remainder of the volumes sold under the contract portfolio is shared by approximately 10 other license holders. Even with the dismantling of the GFU, we remain by far the largest NCS player. We would also continue to seek to secure new customers as opportunities arise and to increase our marketing resources to meet the challenges of the new environment. Consequently, we support the process initiated by the Ministry of Petroleum and Energy to change its gas resource management system from the GFU system to a system based on individual company marketing and sales of gas. For more information, see Item 8—Legal Proceedings.

Manufacturing and Marketing

Introduction

The Manufacturing and Marketing business segment comprises our downstream activities, including trading and sales of crude oil and refined products, refining, retail and industrial marketing of oil products, methanol production and sales, petrochemical operations through our 50% interest in Borealis and shipping operations through our wholly owned subsidiary Navion.

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

	YEAR ENDED DECEMBER 31,			
	1999	*2000*	*2001*	
(IN MILLIONS)	*NOK*	*NOK*	*NOK*	*US$*
Revenues	112,535	201,585	203,387	22,668
Depreciation, Depletion and Amortization	4,646	1,734	1,855	207
Income Before net financial items, income taxes and minority interest	(1,754)	4,559	4,480	499
Capital Expenditure	4,085	2,860	811	90
Long-Term Assets	31,197	32,925	30,432	3,392

Oil Trading and Supply

We are one of the largest net sellers of crude oil in the world, operating out of trading offices in Stavanger, London, Singapore and Stamford, Connecticut, trading crude oil, NGLs and refined products. We market and sell the Norwegian State's crude oil together with our own. In 2001, we sold 795 million barrels of crude, or almost 2.2 million barrels per day, including sales to our own refineries and other internal divisions. Oil sales in 2001 were 6% higher than sales in 2000. Our main crude oil market is in northwest Europe, and we also sell large volumes into North America. Most of our oil volumes are sold on spot market terms, based on worldwide prices and quotations. Of the volumes we sold in 2001, 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—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.

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, an increasing number of condensate cargoes are sold in the US market. In 2001, we sold approximately 21.7 million tonnes of refined oil products, the majority of which was refined at our refineries at Mongstad and Kalundborg, and approximately 6.6 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. In 2001 we sold our 15% interest in the Melaka refinery in Malaysia to the other two owners of the refinery – Conoco and Petronas.

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 Mongstad and Kalundborg.

	YEAR ENDED DECEMBER 31, 1999			2000			2001		
	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	8.0	8.2	92.0%	10.0	8.7	94.2%	9.5	8.7	91.9%
Kalundborg	5.1	5.5	88.5%	5.3	5.5	88.8%	5.0	5.5	88.2%

(1) Actual throughput of crude oils, condensates, feed and blendstock
(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 of hydrocarbons and 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 entered into 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.

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 manufactured by Mongstad for the periods indicated. In addition to crude, as shown below, the Mongstad refinery upgrades large volumes of fuel feedstock (approximately 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, 1999		2000		2001	
LPG	221	3%	307	3%	289	3%
Gasoline/naphtha	2,914	36%	3,941	40%	3,755	40%
Jet/kero	493	6%	702	7%	543	6%
Gasoil	3,240	40%	3,881	39%	3,696	40%
Fuel oil	442	6%	311	3%	262	3%
Coke/sulphur	219	3%	218	2%	223	2%
Fuel, flare and loss	511	6%	596	6%	584	6%
Total throughput	**8,039**	**100%**	**9,956**	**100%**	**9,352**	**100%**
North Sea Crude Oils:						
Troll, Yme (FOB Crude Oils)	3,597	45%	3,426	34%	2,382	25%
Other North Sea Crude Oils (CIF Crude Oil)	3,175	39%	4,802	48%	5,213	56%
Residue	1,007	13%	983	10%	768	8%
Other fuel and blendstock	260	3%	745	7%	989	11%

Note: Changes in throughput and yields are partly due to maintenance shutdowns and expansions. There were no maintenance shutdowns in 2000, but there were two extraordinary shutdowns in 2001 due to cracker breakdowns. The shutdowns lasted 23 days and 7 days.

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 will also explore other options to meet these new specifications.

From 1998 to 2000, we significantly decreased our unit costs in Norwegian kroner terms as a result of increased throughput and cost improvements. In addition, we have a two-year 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 was somewhat behind our original plan in 2001, partly due to the unplanned cracker unit stops. The program goals remain unchanged. The two cracker breakdowns in 2001 lasted 23 and 7 days, respectively. A defect fuse caused the first breakdown of 23 days, and the second breakdown of 7 days was caused by coke blocking catalyst circulation. Further modifications to improve the situation are planned for the 2002 turnaround.

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 manufactured by Kalundborg for the periods indicated.

	YEARS ENDED DECEMBER 31,					
KALUNDBORG PRODUCT YIELDS AND FEEDSTOCK	*1999*		*2000*		*2001*	
LPG	105	2%	117	2%	103	2%
Gasoline/naphtha	1,685	32%	1,708	32%	1,683	34%
Jet/kero	247	4%	281	5%	268	5%
Gasoil	2,001	39%	1,902	36%	1,843	37%
Fuel oil	910	19%	1,083	21%	923	18%
Coke/sulphur	4	0%	4	0%	4	0%
Fuel, flare and loss	163	3%	176	3%	177	4%
Total throughput	**5,115**	**100%**	**5,271**	**100%**	**5,001**	**100%**
North Sea Crude Oils						
Sleipner, Åsgard condensates	1,052	21%	1,188	23%	1,146	23%
Other North Sea Crude Oils	3,598	70%	3,638	69%	3,511	70%
Other fuel and blendstock	465	9%	445	8%	344	7%

Note: Changes in throughput and yields are partly due to maintenance shutdowns and expansions. There were no maintenance shutdowns in 2000 or 2001.

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.

We will invest NOK 460 million in 2001–2002 to upgrade the refinery in order to increase our flexibility in converting feedstock supplies and to enable us to produce refined products which meet the expected 2005 EU requirements for low sulphur gasoline and diesel. As of December 31, 2001, investments of NOK 260 million had been made.

Nordic Energy

Our Nordic Energy unit, with approximately 1,800 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 market share and control of the necessary infrastructure to supply customers within the Scandinavian market. Our portfolio also includes ownership interests in gas distribution companies and planned gas-fired power generation sites in several locations.

Due mainly to reduced 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 compared with 2000. In the longer term, we are evaluating opportunities to expand our energy product offerings. Through our position on the NCS, landing points for natural gas, and our position in gas distribution, we have identified options to further develop the Nordic gas market. Nordic Energy's competence and customer portfolio in the LPG market will provide additional leverage as we evaluate these options relating to the future marketing of gas.

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 2001, these stations sold approximately 4.4 billion liters of gasoline and diesel.

The following table lists these retail outlets by region or country as of December 31, 2001, and our volume of automotive fuel sales for the year ended December 31, 2001.

	SCANDINAVIA	*IRELAND*	*POLAND*	*BALTICS*	*RUSSIA*	*TOTAL*
Retail Outlets						
Statoil or SDS-owned and operated	332	59	123	98	5	617
Statoil or SDS-owned and dealer-operated	555	29				584
Dealer owned and operated	494	194				688
Total	**1,381**	**282**	**123**	**98**	**5**	**1,889**
Volume of Petrol Sold						
Gasoline (millions of liters)	2,194	473	303	231	21	3,222
Diesel (millions of liters)	451	450	115	135	1	1,152
Total	**2,645**	**923**	**418**	**366**	**22**	**4,374**

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, and to give SDS an increased share of the retail margin.

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 99 ICA Express convenience stores as of December 31, 2001 compared with 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, with approximately 23% of the retail gasoline market in 2001, according to the Irish Petroleum Industry Association. As of December 31, 2001, 51 of the Irish stations included our Fareplay-branded convenience stores, which we expect to further increase to 64 by the end of 2002. We have introduced automated, unmanned stations under the name 1-2-3 in the Baltics and Scandinavia. To date we have eight automated stations in the Baltics and 13 in Scandinavia. In Poland we have a small market share but we believe that Poland has significant growth potential and that we are well positioned for future growth.

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 tones per year and actual output during 2001 of 867,000 tonnes. Actual output in 2001 equaled approximately 14% of Western European consumption. Conoco owns 18.3% of the facility. We have the sole marketing rights for the plant, however, for historical reasons, Conoco is presently selling 12% of the output to DuPont.

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 petrol to enhance octane and improve air quality. We are working with other companies in order to develop new markets for methanol. In 2001 a pilot plant at Tjeldbergodden was built with the German company Lurgi AG, which has developed a technology that allows methanol to be converted into propylene. The plant is intended to demonstrate 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, which has an air fractionation and 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 plant 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 owned and operated by our Technology and Development unit rather than the Manufacturing and Marketing segment. 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.

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 5,300 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 2001, Borealis's gross sales were EUR 3.7 billion (NOK 30 billion) and EUR 3.7 billion (NOK 31 billion) in 2000.

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 for major products for 1999, 2000 and 2001.

	YEARS ENDED DECEMBER 31,		
PRODUCT	*1999*	*2000*	*2001*
Ethylene	991	1,099	1,233
Propylene	624	655	620
Polyethylene	1,922	1,828	1,889
Polypropylene	1,341	1,386	1,566

Borealis's production capacity for 2001 was 1.4 million tonnes of ethylene, 0.7 million tonnes of propylene, 2.1 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, France, Italy, Brazil and the US. Borealis's newest plant at Schwechat, Austria began production of polypropylene in May 2000. It was the first plant to use the Borealis-developed patented Borstar technology to produce polypropylene.

Borealis regards establishing production capacity outside Europe as important for its long-term success, as it believes that there is new consumer growth for petrochemical products in Asia following the recent period of slower expansion. An ethylene plant and two polyethylene facilities have been constructed in Abu Dhabi by Borealis and the local state-owned oil company ADNOC. The polyethylene plants are based on 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 now being built 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 have 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 guarantees the necessary feedstock at the 50%-owned plant in Norway as other feedstock agreements have expired.

Shipping

On October 1, 1997, our shipping and maritime technology operations were launched as a separate company, Navion ASA. This company, previously owned 80% by Statoil and 20% by Rasmussengruppen AS was set up to continue pursuing commercial opportunities in ship-based transport of crude oil and refined products, offshore loading and floating storage and production. In 2001 we bought Rasmussengruppen's shares, and became Navion's sole owner. It is our intention to reduce our ownership in Navion to below 50%. The company is headquartered in Stavanger, Norway and employs 117 people. Navion operates a modern fleet of 60 ships with a total capacity of approximately 5.4 million deadweight tonnes. Its revenue in 1999 was NOK 6.3 billion, in 2000 NOK 9.8 billion and in 2001 NOK 9 billion.

Navion provides a wide range of vessel-based services to the oil industry, covering the oil storage and transportation process. Navion is the world's leading operator of shuttle tankers and a major transporter of crude oil in northwest Europe. The Navion fleet consists of specially designed offshore shuttle tankers, storage vessels, conventional crude oil tankers, product tankers and gas tankers. The average age of the fleet is 7.2 years, considerably below the average age of the world's tanker fleet.

Navion is a leading, experienced, technologically-advanced company in offshore loading. Navion operates a fleet of 25 shuttle tankers, of which nine are owned. The other 16 are chartered on both long-term contracts of up to 10 years and shorter-term contracts with an option to extend.

Navion holds offshore loading contracts for a total of 24 fields in the Norwegian, British and Danish sectors of the North Sea. Some of the contracts are for the life of the field, while others are medium-term with optional extension periods. Navion also holds frame agreements with Amerada Hess, Enterprise Oil and Statoil. A frame agreement governs crude oil transportation from an oil company's existing and new fields within a specific geographic area. We expect petroleum production in Northwest Europe to expand over the next few years and then to decline, so in addition to new developments in the North Sea, Navion will pursue international market opportunities on the east coast of Canada, the Gulf of Mexico, the Caspian Sea and other areas. An office has been opened in Houston, Texas to monitor North American markets and regulatory authorities.

Navion's strategy within conventional shipping, the transport of crude oil, refined products, natural gas liquids, and methanol, is to provide customers with "total shipping services", including chartering, shipping consultancy, business development/advice as well as tonnage supply/freight service. While Statoil is Navion's primary customer, Navion also transports significant volumes for other oil companies, such as BP, ExxonMobil and TotalFinaElf. The total conventional shipping fleet consists of 33 double-hulled ships, which are mainly chartered for periods of one to three years. Navion owns the ethane tanker, Navion Dania, which is used under a long-term contract with Borealis.

Navion sold its interests in two floating production vessels in 2001. Navion took delivery of a multipurpose vessel, the Navion Odin, in September 2001, and it has been employed as terminal tanker for Statoil since January 2002.

Navion holds a 50% interest in the West Navion drill ship, with Smedvig ASA, as co-owner and operator of this vessel. After significant delays and cost overruns, the West Navion was finally delivered in early 2000. The drill ship demonstrated during 2001 that it can operate efficiently in deep water and under difficult weather conditions. Operated by Smedvig of Stavanger, this vessel had a high level of utilization until an accident in November 2001, involving a helicopter overturning on the helideck, forcing it to seek repairs. In a subsequent drilling contract off Canada, damage to the derrick and recently discovered cracks in risers put the ship out of commission in early January 2002 until March 2002 when it became operational again. We took a writedown of NOK 1.2 billion in the book value of the vessel in 1999. The possibility of divesting this holding is being explored.

Other

Our other operations includes the activities of Corporate Services, Corporate Center, Group Finance, as well as Technology and Development. Corporate Services provides general administrative and business services to the rest of Statoil. The unit delivers services in four major areas: information technology, property management and administration, financial and accounting services, and consulting services in areas such as communications and training.

Group Finance is responsible for management of financial assets and risks as well as financing and insurance. Group Finance includes the wholly owned Statoil Coordination Center N.V., in Belgium, which engages in certain financial coordination activities for Statoil, and Statoil Forsikring AS, our wholly owned insurance subsidiary. Statoil Forsikring AS carries principally captive risk associated with our offshore and onshore activities and related pollution liability. As of December 31, 2001, approximately 27% of the sum insured, which totals approximately NOK 104 billion, was retained for its own account. The balance was reinsured.

Group Finance is also responsible for Statoil Kapitalforvaltning ASA, a wholly-owned subsidiary that manages the financial assets of Statoil Pensjonskasse (the pension fund), Statoil Forsikring AS and the portion of our liquidity reserves held in cash and cash equivalents. Statoil Kapitalforvaltning ASA manages total assets of approximately NOK 20 billion.

Industrial Development develops and maintains our intellectual property rights and makes cost efficient technology commercially available to our other business units in cooperation with the supplier industry. Development takes place in close cooperation with the respective operational units.

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.

In Statoil, health, safety and the environment, or HSE, comprises health and working environment, safety and emergency preparedness, the environment and security. 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 (accidental) oil spills;
- volume of (accidental) oil spills (cubic meters);
- CO_2 emissions, total (tonnes);
- NOx 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 decided in 2001 to invest more than NOK 1 billion at our two refineries during the next two years to meet the new EU-regulations.

Currently, the total emission of greenhouse gases from our operations is increasing and will continue to increase in line with production growth and due to a greater amount of tail production on the NCS. Our CO_2 emissions totaled 9.2 million tonnes in 2001, up from the 8.3 million tonnes emitted in 2000. Our NOx emissions were reduced to 29,500 tonnes in 2001, down from 30,300 tonnes in 2000. Historically, our NCS emissions of CO_2 and NOx, measured in tonnes per produced quantity, have been below the NCS average. During 2001 we were on par with the NCS average due to the increased amount of tail production. Compared to other oil regions in the world, however, the NCS is the area with the lowest relative emissions. Changes in laws regulating greenhouse gas emissions could require 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 accidental oil spills to the external environment in 2001 was 414 as against 431 in 2000. The number of such spills has been declining steadily since 1997. In volume terms, accidental oil spills in 2001 totaled 246 cubic meters as against 120 cubic meters in 2000.

Our corporate indicators within safety are currently:

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

Two fatalities were suffered by contractors working for Statoil and Navion in 2001. Our performance by other corporate indicators are on par or better than average for the NCS. The number of serious incidents in 2001 was 287, down from 310 in 2000, and the frequency, calculated as the number of incidents with a high loss potential per million working hours, is 4.1, down from 4.3 in 2000. This indicator includes 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 review and monitor the condition of technical safety barriers. The developed methodology is in compliance with the latest regulatory development in the Norwegian Petroleum Directorate. We have developed plans to close the identified gaps up to a minimum requirement. This will reduce the risk of major incidents and be the basis for improved regularity.

Within the health and working environment sector, our principal objective is to secure a sound, challenging and rewarding working environment to 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 2001, down from 3.5% in 2000. The general level in Norwegian industry is 9.0%. 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 2001 we were fined NOK 2 million for an incident where process water did not go through the purification plant. The incident took place in 1998 at the Kårstø gas processing plant. We may in the future incur penalties for environmental violations. We may continue to incur additional expenditures for environmental, health and safety compliance in the future and these increases could have an adverse material affect on our operations or financial condition.

Technology, Research and Development

Background

The success of our business is closely connected to our access to 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 of 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 2001, we have 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 1999 to 2001 were NOK 850 million, NOK 740 million and NOK 620 million, respectively. In addition, we have technical staff, however, who function 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:

- extinguished flare and recycling of flare gas during normal operation on the Gullfaks field;
- 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
- a liquefication system for volatile organic compounds, or VOCs, which can capture virtually all of the NMVOCs (non-methaneous VOCs) given off as vapor by crude oil during loading into transport shuttles. The liquid is stored in a tank on the vessel and piped to the engines as fuel, replacing conventional fuel oil. With this process, we will reduce expenditures on fuel, and the recovered VOCs are considerably less polluting than the heavy fuel oil burned in marine diesels today. The surplus VOCs recovered can alternatively be reabsorbed by the crude oil. Following rulings from the Norwegian pollution authorities, VOC emissions on the NCS must be reduced gradually so that 95% of all loading facilities must be equipped to recover NMVOCs by 2005.

Increased 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 which can be used in both tidal and deep-sea deposit reservoirs. We expect to use this method on 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 well-head platforms from three in the planning stage to only one being installed.

Subsea and floating production. During the past few years, floating production vessels with extensive subsea facilities dominate new developments, such as the Norne and Åsgard fields, because floating facilities are less expensive to construct and maintain than traditional platforms for the water depths in which they have been placed. We are one of the world's largest subsea field operators with approximately 155 subsea wells, and we 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.

A small selection of our solutions includes multiphase flow and 13% chromium pipelines, explained below.

Multiphase flow. From the early 1980s, we developed competence within multiphase flow, which means the use of pipelines to carry different well-stream products simultaneously. 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. Multiphase technologies are also central to the development of subsea production facilities and satellite developments. Examples of critical technologies are multiphase pumps and multiphase metering. The development of the Åsgard field relied strongly on the use of multiphase pipelines. The Snøhvit LNG project, sanctioned autumn 2001, has plans for a 160-kilometer gas and condensate pipeline tieback to the onshore processing plant. Multiphase flow knowledge is also vital for the many satellite developments with tie-ins to existing processing facilities, like the Statfjord satellites developed in 1994.

Pipeline materials. When transporting multiphase wellstream in pipelines from subsea installations to the processing units, corrosion is a significant challenge. One straightforward solution is to inject chemicals into the wellstream at the well-head 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 high carbon-quality and therefore costly pipelines. These options were not feasible because we wanted to transport greater volumes of wellstream than possible using the chemical injection method and because there was insufficient production of the high-carbon quality pipelines. As a result, working together with the steel mills and pipeline-laying companies, we developed a new alloy with 13% chrome steel quality which lowered production costs and enabled quicker development. This development permitted the parallel development of the Gullfaks satellite fields and the Åsgard field.

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 pipe since 1982 and have reduced per meter costs significantly over our nearly 20 years of pipe laying activity. The pipelines can also carry increased volume capacity through our utilization of multi-design pressure pipelines, the use of flow improvers for oil pipelines and special coatings designed to reduce drag. In addition, we have created more effective tie-in solutions, which connect pipelines to the on shore terminals, thereby reducing potential waste and environmental damage. We use remote-controlled subsea vehicles to map and position our pipelines. We efficiently and quickly laid the Vestprosess, Troll Oljerør and Haltenpipe lines with this advanced technology.

Integrated with our pipelines, we are developing 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. Such products are important feedstock to upgrade further 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.

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

In addition to the benchmark study, Statoil also identified its technology needs based upon our ambitions and the business units plans. The results of this exercise resulted in the following technology strategy:

Building on our leading technology position on the Norwegian continental shelf, we are prioritizing the following future technology developments:

- 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 of 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 which is a transfer of downhole data with updating of reservoir and geology information to optimize well placement. We also use real-time drilling analysis with update of reservoir and geology information, based on observations while drilling, to optimize well placement.
- subsea processing facilities. We are concentration our efforts to implement the subsea processing and multiphase technology in our core area Halten Nordland. We are looking at the Tyrihans discovery, located near the Åsgard and Kristin fields, as a possible trial for integration of subsea processing and multiphase technology to evaluate its effectiveness and efficiency. As operator for the Norne license, we are investigating the possibility of subsea processing to increase the water handling capabilities through a three-stage implementation of raw seawater subsea injection pumping, subsea separation and subsea multiphase pumping.

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, Statoil has developed a new Mixed Fluid Cascade Process. The Snøhvit LNG development will be based upon this technology. The Mixed Fluid Cascade Process is an efficient and flexible process, based on the classical cascade process, with three refrigerant circuits (precooling, liquefaction and subcooling). Different from the classical cascade, each of the cooling circuits consists of a mixed refrigerant. Different from LNG plants built previously, the Snøhvit plant will be built on a barge and transported to the site (Melkøya), which we expect will result in efficient construction and project execution.

REGULATION

Norwegian Regulation

Introduction

The Norwegian State proclaimed its jurisdiction over the NCS on May 1, 1963 and is responsible for managing NCS petroleum assets for the benefit of Norwegian society. The proclamation established the principle that ownership of the petroleum resources on the NCS is vested in the Norwegian State. 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 reiterates 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 State makes resource management decisions. Due to the specific importance of the petroleum sector to Norway, the Norwegian parliament, the Storting, is informed of all main government policy issues in the petroleum sector, and initiatives must be submitted to the Storting for discussion and adoption before they are implemented.

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.

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.

The Licensing System

The Petroleum Act empowers the Norwegian State to award two types of oil and gas licenses on the NCS: reconnaissance licenses and production licenses. A reconnaissance license grants the holder the right to carry out geological, petrophysical, geophysical, geochemical and geotechnical surveys in a specified geographical area of the NCS. Being granted a reconnaissance license does not give the grantee exclusive rights in the area covered by the license nor does it entail any preferred right to a production license in that area. Reconnaissance licenses are normally granted for periods of three years.

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. An area will only be opened for exploration after an assessment of the industrial and environmental impact of the petroleum operations as well as of the risk of pollution and the economic and social consequences that the petroleum operations may have. Furthermore, plans for opening a new area for exploration are subject to a public consultation process before the Storting can approve the opening of such area.

The most important type of licenses 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. A company refusing to abide by the terms of the Ministry of Petroleum and Energy's decision 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.

In accordance with the requirements of the EU's Licensing Directive, an invitation to apply for production licenses must normally be published in the Norwegian Gazette and the Official Journal of the European Communities at least 90 days before the closing date for submitting applications. The notice inviting applications must set out the objective and non-discriminatory criteria on which licenses will be granted. In some cases, the State can decide to award licenses without such announcement, but is then required to inform holders of licenses on adjacent fields in advance so as to permit them to submit applications for the new license.

Production licenses are normally awarded through licensing rounds. The first licensing round for NCS production licenses was announced in 1965. Licenses under the 16th licensing round were awarded in April 2000. The 17th licensing round is covering acreage in the Norwegian Sea, and was announced in late 2001. The deadline for application is in April 2002, and we expect final awards to be announced later in 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 rounds in 1999, 2000 and 2001, referred to as the 1999, 2000 and 2001 North Sea Awards.

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. This approach was used in connection with the Barents Sea project in 1997 and the North Sea round of 1999. In a Storting report published in 2000, the Norwegian State stated that it intends to allow group applications in all parts of the NCS in future licensing rounds.

Production licenses are awarded to joint ventures consisting of several companies. The members of the joint venture are jointly and severally responsible towards 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 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 has been exercised three times, most recently in 1988.

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 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 will be reduced by 150,000 barrels per day from January 1, 2002 until June 30, 2002. This amounts to roughly a 5% reduction in output. The reductions will in principle be applied equally and in a non-discriminatory fashion to all companies operating on the NCS. All oil producing fields will be subject to a proportional reduction in production, except all major gas producing fields, two fields that Norway shares with the United Kingdom in the North Sea (Statfjord and Murchison), and one field that is soon to terminate production (Varg).

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. Until the 14th licensing round, the partners in most licenses had a right of preemption in relation to purchase/sale transactions. Following requests from the Ministry of Petroleum and Energy to surrender these rights so as to create a more effective market, preemption rights have been surrendered by a number of licensees. The SDFI, or the Norwegian State, as appropriate, however, still holds preemption rights in all licenses.

During the initial exploration period of a production license, the licensees may relinquish the production license or part of the area covered by the license upon three months' notice. After the expiration of the exploration period, the licensees may relinquish the license or part of the area of the license at the end of each calendar year, provided that notice is given at least three months before the end of the year.

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.

In case of serious or repeated violations of the Petroleum Act, the regulations promulgated thereunder, conditions set out in licenses or orders from public authorities, or if the information in a license application is incorrect or incomplete, the Government may revoke a license.

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

Introduction. The first Norwegian gas sales agreements were structured as depletion contracts. Under these contracts the purchaser would agree to purchase the total quantity of gas produced at a specified field. The buyers were thus carrying the risk of the depletion of gas reserves. Following the landmark Troll agreements in 1986, gas sales agreements have generally been structured as field-neutral supply agreements. Under these agreements the sellers undertake to deliver a specified quantity of gas, without specifying from which field the gas will be delivered. The sellers, therefore, carry the risk that they have or can contract for sufficient gas reserves to fulfill their delivery obligations.

Until recently, gas sales contracts with buyers for the supply of Norwegian gas were required to be concluded with the Gas Negotiation Committee, known as the Gassforhandlingsutvalget or GFU, whether the buyer is within or outside the EU or the EEA. For more information, see –Recent Changes to the Norwegian Gas Resource Management System below.

The GFU and the Gas Supply Committee, known as the Forsyningsutvalget or FU, together formed integrated instruments for the management of gas resources on the NCS. The GFU evaluated the market and negotiated new gas sales contracts on a field neutral basis in order to establish optimal off take conditions for Norwegian gas. The FU prepared the necessary supply plans that can meet the supply obligations under the new contracts. All gas sales contracts for Norwegian gas had and still have to be approved by the Ministry of Petroleum and Energy. The Ministry of Petroleum and Energy would only approve gas sales contracts which have been negotiated in compliance with the Norwegian legal framework and policies established by the Storting and are consistent with the Norwegian State's resource management objectives.

The Ministry of Petroleum and Energy allocated approved gas contracts to fields where the licensees concerned take on the contractual and/or delivery obligations. The Ministry of Petroleum and Energy thus determined the identity of the seller(s) who will be obliged to deliver under the contract and of the licensees who will physically deliver under the contract.

Recent Changes to the Norwegian Gas Resource Management System. 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, announced that King-in-Counsel 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. The implementation of this decision to change the system requires significant changes to the institutional, legal and commercial arrangements, including existing license, supply, and transportation agreements. In addition, new lifting arrangements in the individual licenses will have to be established by the licensees. To that end the Ministry of Petroleum and Energy has requested Statoil and nine other NCS license holders examine aspects of implementing such a system.

The principal effect of this Royal Decree has been 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 at the end of 2001. Furthermore, the system of gas sales within the EEA through the GFU was suspended as of the date of the Royal decree, June 1, 2001. 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, license agreements and other existing contracts are still ongoing and expected to be finalized during 2002. For more information, see above under –Business Overview–Operations–Natural Gas–Recent Changes to the Norwegian Gas Resource Management System.

Participation of the Norwegian State — SDFI

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 State's direct financial interest, or 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.

While the SDFI's participating interests in licenses formally have been registered in our name, the Norwegian State has had full ownership of these participating interests and has paid the costs and received the income arising from them. The SDFI's holdings have not been refected in our accounts. Since 1985 and until the recent restructuring of the SDFI, we have acted as a manager for the SDFI's shares in licenses, whether or not we have had our own economic interest in such licenses. 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. In order to comply with the requirements of EU's Licensing Directive, we established a separate unit in 1996 to manage the SDFI's shares in production licenses in which we did not have any economic interest. Although the Licensing Directive was implemented only with effect from the 15th licensing round, this unit also managed the SDFI's interests in licenses allocated in earlier rounds, but in which we later disposed of our economic interests. Our other units have not had access to information obtained by us in our capacity as manager for the SDFI in these production licenses. We have not received any remuneration for acting as manager of the SDFI's interests. We have also been responsible for marketing the petroleum of which the Norwegian State becomes the owner through the SDFI shares in production licenses.

The Norwegian State has recently restructured its interests on the NCS. As part of the restructuring, the Norwegian State decided to transfer the role of manager of the SDFI from us to a newly established management company. We will continue, however, to market petroleum owned by the Norwegian State through the SDFI share in production licenses. See Item 7–Major Shareholders and Related Party Transactions–Major Shareholders–Norwegian State as Shareholder.

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 to 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 0.73 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. Royalty will be abolished for the Statfjord and Ula fields by the end of 2002 and for the Gullfaks and Oseberg fields by the end of 2005.

EU Regulation

The EU and the EEA

Although Norway is not a member of the European Union (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 (the EEA Agreement) with the members of EFTA (except Switzerland).

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 EEA Agreement

The EEA Agreement is an agreement made under public international law between the European Union and its 15 member states for the one part, and the three EFTA States (Norway, Liechtenstein and Iceland) on the other. 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.

EEA rules that correspond to EU rules found in the Treaty on the European Union, such as those relating to the free movement of goods, services, people and capital, and to competition and state aid, are contained in the main text of the EEA Agreement. Rules of a secondary nature, such as those found in EU directives and regulations, are integrated into the EEA Agreement by way of a reference technique. This means that although EFTA States, such as Norway, do not have a role in the legislative process of the EU, they are nonetheless bound, subject to the provisions and procedures of the EEA Agreement, to implement new secondary legislation of the EU. The obligation to implement such secondary legislation only arises when a formal decision to include the legislation in the EEA Agreement is taken by the EEA Joint Committee.

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.

Directive 98/30/EC was to be implemented in the national legislation of the EU member states by August 10, 2000. The Norwegian government has stated its intention to accept the inclusion of the Directive into the EEA Agreement as soon as practicable.

The 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 this end, it imposes a series of obligations on EU member states.

The following paragraphs contain a non-exhaustive summary of the main provisions of the Gas Directive.

General Rules. EU member states are required to ensure that natural gas undertakings are operated in accordance with the principles of the directive with a view to achieving a competitive market in natural gas and not to discriminate between such undertakings as regards either rights or obligations.

EU Member States may impose on natural gas undertakings, in the general economic interest, public-service obligations which may relate to security, including security of supply, regularity, quality and price of supplies and to environmental protection. Such obligations shall be clearly defined, transparent, non-discriminatory and verifiable and shall be published and notified to the EC Commission. Where an authorization is required for the construction or operation of natural gas facilities or to supply natural gas, the criteria to be met must be objective, non-discriminatory and public. Reasons for refusal must be given, and there must be an appeal procedure.

Technical rules establishing the minimum technical design and operational requirements for connection to the systems, facilities and pipelines must be developed and made available and must ensure that systems are interoperable and be objective and non-discriminatory.

Transmission, Storage and LNG; Distribution and Supply. EU member states are required to ensure that transmission, storage and LNG undertakings and distribution undertakings operate, maintain and develop under economic conditions secure, reliable and efficient facilities and systems. They must not discriminate between users, and must provide other similar undertakings with sufficient information to ensure that their relevant activities can take place in a manner compatible with the secure and efficient operation of the system. They must also preserve the confidentiality of commercially sensitive information and transmission and distribution undertakings must not abuse commercially sensitive information, obtained from third parties in the context of providing or negotiating access to the system.

Unbundling and Transparency of Accounts. EU member states are required to ensure that they and designated competent authorities have right of access to natural gas undertakings' accounts. Such accounts must be drawn up, submitted to audit and published in accordance with national law adopted pursuant to relevant EU directives. Integrated natural gas undertakings must keep separate internal accounts (including a balance sheet and a profit and loss account) for their natural gas transmission, distribution and storage activities, and consolidated accounts for non-gas activities, with a view to avoiding discrimination, cross-subsidization and distortion of competition. The rules for the allocation of assets and liabilities, expenditure and income and depreciation which they follow must be specified and may be amended only in exceptional cases, duly mentioned and substantiated. Transactions of a certain size conducted with related undertakings shall be indicated.

Access to the System. EU member states may choose either or both of two procedures for access to the system: negotiated access or regulated access. Each procedure must operate in accordance with objective, transparent and non-discriminatory criteria.

Under the negotiated access procedure, EU member states must take the necessary measures for natural gas undertakings and eligible customers either inside or outside the territory covered by the interconnected system to be able to negotiate access to the system so as to conclude supply contracts with each other on the basis of voluntary commercial agreements and the parties shall be obliged to negotiate in good faith. EU member states are required to ensure that natural gas undertakings publish their main commercial conditions for the use of the system on an annual basis.

Under the regulated access procedure, EU member states must take the necessary measures to give natural gas undertakings and eligible customers either inside or outside the territory covered by the interconnected system a right of access to the system on the basis of published tariffs and/or other terms and obligations for use of that system. The right of access for eligible customers may be given by enabling them to enter into supply contracts with competing natural gas undertakings other than the owner and/or operator of the system.

Natural gas undertakings may refuse access to the system on the basis of lack of capacity or where access would prevent them carrying out public service obligations which are assigned to them or where on the basis of serious economic and financial difficulties with take-or-pay contracts having regard to the criteria and procedures set out in the directive and described further below.

Member states may take the measures necessary to ensure that a natural gas undertaking refusing access to the system on the basis of lack of capacity or a lack of connection shall make the necessary enhancements as far as is economically possible or when a potential customer is willing to pay for them.

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. As 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. As from August 10, 2000, the definition of eligible customers must also 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.

EU member states are required to take the necessary measures to enable natural gas undertakings to supply eligible customers through a direct pipeline and where an authorization is required for the construction or operation of such pipelines, the criteria for the grant of authorizations shall be laid down and shall be objective, transparent and non-discriminatory.

EU member states are further required:

- to ensure that parties negotiate access to the system in good faith and that none of them abuses its negotiating position to prevent the successful outcome of such negotiations. A competent authority is to be designated which must be independent of the parties to settle expeditiously disputes relating to negotiations. Provision is made for dealing with cross-border disputes; and
- to create appropriate and efficient mechanisms for regulation, control and transparency so as to avoid any abuse of a dominant position, in particular to the detriment of consumers, and any predatory behavior, taking into account the provisions of the EU Treaty.

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 customers required to be eligible, 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. The following may be taken into account:

- the need to refuse access where there is an incompatibility of technical specifications which cannot reasonably be overcome;
- the need to avoid difficulties which cannot be reasonably overcome and could prejudice the efficient, current and planned future production of hydrocarbons, including that from fields of marginal economic viability;
- the need to respect the duly substantiated reasonable needs of the owner or operator of the upstream pipeline network for the transport and processing of gas and the interests of all other users of the upstream pipeline network or relevant handling or processing facilities who may be affected; and
- the need to apply their laws and administrative procedures, in conformity with Community law, for the grant of authorization for production or upstream development.

Member states are required to have in place a mechanism to settle disputes, including an authority independent of the parties with access to all relevant information, to enable disputes relating to access to upstream pipeline networks to be settled expeditiously. Provision is made for dealing with cross-border disputes.

Safeguard Measures. Provision is made for a member state temporarily to take the necessary safeguard measures in the event of a sudden crisis in the energy market or where the physical safety or security of persons, apparatus or installations or system integrity is threatened.

Take-or-Pay Contracts. If a natural gas undertaking encounters, or considers 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.
In deciding on derogations, members states, designated authorities and the Commission shall take into account, in particular, the following criteria:

- the objective to achieve a competitive gas market;
- the need to fulfill public-service obligations and to ensure security of supply;
- the position of the natural gas undertaking in the gas market and the actual state of competition in this market;
- the seriousness of the economic and financial difficulties encountered by natural gas undertakings and transmission undertakings or eligible customers;
- the dates of signature and terms of the contract in question, including the extent to which they allow for market changes;
- the efforts made to find a solution to the problem;
- the extent to which, when accepting the take-or-pay commitments in question, the undertaking could reasonably have foreseen, having regard to the provisions of this Directive, that serious difficulties were likely to arise;
- the level of connection of the system with other systems and the degree of interoperability of these systems; and
- the effects the granting of a derogation would have on the correct application of this Directive as regards the smooth functioning of the internal natural gas market.

A decision on a request for a derogation concerning take-or-pay contracts concluded before the entry into force of the directive should not lead to a situation in which it is impossible to find economically viable alternative outlets. Serious difficulties shall in any case be deemed not to exist when the sales of natural gas do not fall below the level of minimum off-take guarantees contained in take-or-pay contracts or in so far as the relevant take-or-pay contract can be adapted or the natural gas undertaking is able to find alternative outlets.

The Commission is required by August 10, 2003 to submit a report on the experience gained from the application of the provisions concerning take-or-pay contracts so as to allow the need to adjust them to be considered.

Transitional Regimes. The Gas Directive provides for transitional regimes in emerging markets and regions in which initial commercial gas supply started less than 10 years before August 10, 1998 where derogation from key parts of the Gas Directive may be applied for. Derogations have been granted to Greece and Portugal. Derogation may also be granted to EU member states which are not directly connected to the interconnected system of any other EU member state and which have only one main external supplier with a market share of more than 75%. Derogations have been granted to Greece and Finland.

New Proposals

On March 14, 2001, the Commission presented a proposal to amend the Gas Directive and to extend its provision. This proposal was considered by the European Council of Ministers at a summit meeting that took place in Stockholm on March 23-24, 2001. The proposal was noted in the summit's concluding statement, and the Council of Ministers was invited to examine it as soon as possible. The Commission was asked to evaluate the extent of market opening in the gas sector and to report to the Council of Ministers at their summit meeting in the spring of 2002. The European Council duly considered the proposal to amend the Gas Directive at its meeting in Barcelona on March 15-16, 2002. The Council then agreed that strong efforts should be made to agree the amendment of the Directive as soon as possible in 2002. The Council also agreed that an amended Directive should contain the following general provisions:

- freedom of choice of supplier for all European non-household consumers as of 2004;
- separation of transmission and distribution from supply;
- non-discriminatory access for consumers and producers to the network, based on transparent and published tariffs; and
- establishment in every Member State of a regulatory function, within the appropriate regulatory framework, with a view to ensuring in particular effective control of the tariff-setting conditions.

The question of freedom of choice of supplier for household customers will be considered separately, with a decision on this being made before the Council's spring summit in 2003.

The outcome of the Barcelona Council represents a political heads of agreement on the main framework elements an amended Gas Directive should contain. The detailed incorporation of these elements in the text of an amended Directive has yet, however, to be agreed.

Since being presented originally and prior to Barcelona, the details of the proposal had already been amended several times. Negotiations on detailed drafting between the EU and the member states and the Commission will continue. Given the Council's position at Barcelona, there is an expectation that both the Council and the European Parliament will agree an amended Directive during this year. On that basis, the amended Directive is likely to enter into force in 2003. While it is unclear what the final detailed content of amendments to the Gas Directive will be if the proposal is adopted in its present form, it will implement several important changes to the present Gas Directive.

Customer choice. It is proposed that the EU member states should ensure all that non-domestic customers (those who purchase natural gas which is not for household use) should be free to purchase gas from the supplier of their choice within the EU and should have the rights of eligible customers for third party access in order to execute such supplies in accordance with the directive, no later than January 1, 2004. As noted above, the Council will be separately considering the details of the proposed freedom of choice of supplier for household customers.

Consumer protection and other measures. It is proposed that member states would have to implement appropriate measures to achieve the objectives of social and economic cohesion, environmental protection and security of supply. Member states would further be obliged to take appropriate measures to ensure high levels of customer and consumer protection. The Commission would have to publish, every two years, a report analyzing the different measures taken in the member states to meet high public service standards. Where appropriate, the Commission would have to make recommendations as to measures to be taken at a national level to achieve those standards.

Transmission, storage and LNG; distribution and supply. It is proposed that member states should designate or should require undertakings which own transmission, storage or LNG facilities to designate, for a period of time to be determined by member states (having regard to considerations of efficiency and economic balance) one or more system operators to be responsible for operating, ensuring the maintenance of, and developing the transmission, storage and LNG facilities in a given area and their interconnection with other systems in order to guarantee security of supply.

Member states may require transmission system operators to meet minimum levels of investment for the maintenance and development of the transmission system, including interconnection capacity. The transmission system operator and, from January 1, 2004, the distribution system operator, should be independent, at least in terms of their legal form, organization and decision-making, from other activities not relating to respectively transmission or distribution. A number of criteria would be applied in order to ensure the independence of the system operators.

Transmission system operators must procure the energy they use for the carrying out of their functions according to transparent, non-discriminatory and market based procedures.

It is proposed that rules for balancing the gas system adopted by system operators shall be transparent and non-discriminatory. Tariffs and terms and conditions for the provision of such services by system operators shall be established in a non-discriminatory way reflecting prevailing market prices and shall be fixed or approved by the national regulatory authority prior to their entry into force.

Unbundling and transparency of accounts. It is proposed that the integrated natural gas undertakings must keep separate internal accounts (including a balance sheet and a profit and loss account) not only for their natural gas transmission, distribution and storage activities but also for their natural gas supply activities and their LNG activities.

Access to the system. It is proposed that, except for access to storage, equivalent flexibility instruments and other ancillary services, member states must give regulated access to the system. Member states should ensure the implementation of a system of third party access to the transmission and distribution system and LNG facilities based on published tariffs, applicable to all eligible customers and applied objectively and without discrimination between system users. These tariffs must be approved prior to their entry into force by a national regulatory authority.

For the organization of access to storage and for certain other matters, member states may choose either the negotiated access procedure or the regulated access procedure described above.

New national regulatory authorities. It is proposed that member states must establish national regulatory authorities. These authorities must be wholly independent of the interests of the gas industry and must, among other things, have the sole responsibility for fixing or approving terms and conditions for connection and access to national networks including transmission and distribution tariffs. They must have sole responsibility for defining the rules on the management and allocation of interconnection capacity, in conjunction with the national regulatory authority or authorities of those member states with which interconnection exists, and for fixing or approving any mechanisms to deal with congested capacity within the national gas system. They must also ensure respect for the consumer protection and other measures set out in the proposal.

It is further proposed that member states designate a body, which may be the independent regulatory authority, to monitor security of supply issues and publish an annual report of their findings.

We have not determined what impact the foregoing proposals, if adopted, could have on our business.

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 production licenses, operatorships, capital, experienced human resources and customers. 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 EU's Gas 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 markets, 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	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, comprise 103,000 square meters of office space, and 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, 2001, we had total revenues of NOK 236.3 billion and net income of NOK 17.2 billion. In the year ended December 31, 2001, we produced 276 million barrels of crude oil and sold approximately 14.7 bcm (519 bcf) of natural gas, resulting in total production of 368 million boe. Our proved reserves as of December 31, 2001 consisted of approximately 2.0 billion barrels of crude oil and NGLs and 368 bcm (13 tcf) of natural gas, resulting in a total of approximately 4.3 billion boe.

We divide our operations into the four following business segments:

- Exploration and Production Norway, which includes our exploration, development and production operations relating to crude oil and natural gas on the NCS which have been significantly increased during 2001 by our acquisition of part of the Norwegian State's oil and gas assets on the NCS, as described below under —Company Restructuring—Acquisition of SDFI assets and transfer of certain pipeline and other assets;
- International Exploration and Production, which includes all of our exploration, development and production operations relating to crude oil and natural gas outside of Norway;
- Natural Gas, which is responsible for the processing, transport and sale of gas from our upstream operations on the NCS and elsewhere; and
- Manufacturing and Marketing, which comprises downstream activities including trading and sales 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 through our now wholly-owned subsidiary, Navion ASA. See —Company Restructuring.

Company Restructuring

Improvement Program. In 1999, we initiated a group-wide improvement program in response to low crude oil prices and our high level of development projects. This program had as its objectives a restructuring of our asset portfolio, a reduction in our level of capital expenditure by focusing on our core areas, an improvement in the cost-efficiency of our operations and a reduction in the level of our capital employed.

Accordingly, since 1999, we have been pursuing a restructuring of our asset portfolio in order to improve our focus on core areas and improve our returns on capital employed. This restructuring has been achieved through asset swaps, sales and acquisitions of assets on the NCS and internationally, and by the disposition of interests in some of our downstream businesses.

Acquisition of SDFI assets and transfer of certain pipeline and other assets. As part of the Norwegian State's restructuring of its oil and gas assets on the NCS, the Norwegian State determined that it would sell approximately 15% of its SDFI assets to us and approximately 6.5% to other oil and gas companies. In a single transaction with the Norwegian State, we purchased 84 license interests and ownership interests in five pipeline joint ventures from the Norwegian State, including an additional interest in the Troll oil and gas field. As part of the transfer of the Troll interest, we agreed not to sell or transfer any of our interest in the Troll field without the prior written consent of the Norwegian State.

As a result of this transaction, our NCS proved reserves increased from 2,453 mmboe (pre-acquisition) to 3,787 mmboe (post-acquisition) based on proved reserves as at December 31, 2000 and our own production on the NCS increased from approximately 582,200 boe per day (pre-acquisition) to approximately 919,200 boe per day (post-acquisition) based on average daily production for the year ended December 31, 2000. In addition, our license areas have increased from 106 to 132, of which 26 are licenses in the production phase and 106 are in the exploration phase. The numbers of licenses include all of our transactions as of December 2001. Our commitments for capital expenditures increased from NOK 3.6 billion (pre-acquisition) to NOK 6.7 billion (post-acquisition). This transaction has strengthened our interests in fields in our core areas on the NCS. We believe that this allows us better opportunities for increasing recovery of oil and gas and reducing costs while enabling us to make more effective use of existing infrastructure through coordination and ownership alignment.

As part of the single transaction with the Norwegian State, we transfered to the Norwegian State a 33.25% interest in Statpipe, including the processing plant at Kårstø (reducing our interest to 25%), a 25% interest in Norsea Gas AS (Norpipe) (reducing our interest to 25%) and a 35% interest in the crude oil terminal at Mongstad (reducing our interest to 65%). See Item 4—Information on the Company.

This single transaction between Statoil and the Norwegian State was completed on June 1, 2001 with an effective date of January 1, 2001 (with the exception of the sale of the interest in the Mongstad terminal which had an effective date of June 1, 2001). To ensure that the sales and the exchange of the SDFI assets and our pipeline and terminal interests were made at fair market value, we and the Norwegian State obtained separate valuation reports on such assets from independent, internationally recognized experts. These valuations resulted in a net balancing cash payment paid by us to the Norwegian State of NOK 38.6 billion plus a payment of interest and currency fluctuation from the effective date of NOK 2.2 billion (NOK 0.7 billion after tax). The total amount paid to the Norwegian State was financed through an initial 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.

Because the acquisition of the SDFI assets was a transaction between entities under common control, the transaction has been accounted for in a manner similar to a pooling of interests. As a result, our financial statements include the SDFI assets as if the SDFI assets had been part of Statoil in all financial periods presented. The sale of assets to the Norwegian State and the payment of the net purchase price to the Norwegian State are not included in our historic financial statements but were recorded upon closing when they occurred June 1, 2001.

Equity Issue. In June 2001, we completed an initial public offering and listing of our American Depositary Shares on the New York Stock Exchange and our ordinary shares on the Oslo Stock Exchange. Of the 394,417,002 ordinary shares sold in the global offering, we offered 188,700,000 and 205,717,002 were offered by the Norwegian State.

Cost Savings. In 1999, we initiated a group cost reduction program to be implemented during the period 1999 through 2001. The amounts are calculated based on our asset portfolio in 1999 without giving effect to our acquisition of SDFI assets from the Norwegian State. The cost savings were initially driven by a focused reduction in our exploration expenditure in 1999, while the implementation of common group-wide administrative processes and other measures to reduce costs did not have a full effect until 2000. This program resulted in cost savings in our annual operating costs, selling, general and administrative expenses and exploration expenditures of NOK 4.4 billion, of which NOK 1.7 billion was achieved in 1999, NOK 1.3 billion in 2000 and NOK 1.4 billion in 2001. In 1999 NOK 1.1 billion of the NOK 1.7 billion annual savings were attributable to savings in exploration expenditures, in 2000 NOK 0.2 billion of the NOK 1.3 billion annual savings were savings in exploration expenditures, whereas in 2001 NOK 0.9 billion of the NOK 1.4 billion annual savings were savings in exploration expenditures.

Portfolio Restructuring. From 1998 to 1999, we carried out an overall review of our strategy and asset portfolio. This resulted in the restructuring of our asset portfolio both on the NCS and internationally and included significant provisions and writedowns against some of our upstream and downstream assets. See —Combined Results of Operations—Years ended December 31, 2001, 2000 and 1999—Income before financial items, income taxes and minority interest. We reduced our capital employed by NOK 4.7 billion in 2001. Total reduction in capital employed from 1998 to 2001 is NOK 17.8 billion, corresponding to a 20.5% reduction.

On the NCS we restructured our portfolio as follows:
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.

In 1999, in connection with the acquisition by Norsk Hydro ASA of all the outstanding ordinary shares in Saga Petroleum, an independent oil and gas exploration and production company, we acquired some of Saga Petroleum's interests in certain oil and gas producing licenses in exchange for a total purchase price of NOK 8.1 billion which we paid partly with cash (NOK 4.2 billion) and partly with our existing shareholding in Saga Petroleum which we transferred to Norsk Hydro. The production from the acquired Saga Petroleum assets represented approximately an additional 63,000 boe per day in 2000. Under our agreement with Norsk Hydro, we acquired interests in several exploration licenses and 320 mmboe of proved reserves and are scheduled to take over the Snorre, Vigdis, Tordis and Visund operatorships in the Tampen area of the northern North Sea in 2003. By increasing our oil production, the acquisition of the Saga Petroleum assets also contributed to a 2.1% increase in our revenue from 1999 to 2000, as discussed below under —Combined Results of Operations.

We restructured our E&P International portfolio as follows:
In May 2001, we sold our 4.76% interest in the large 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. This included the development of the Lan Tay and Lan Do gas and condensate fields (Statoil share 13.33%), a gas pipeline and a gas receiving station (Statoil share 16.33%) and interests in two exploration licenses, Block 05.2 (Statoil share 33.33%) and Block 05.3 (Statoil share 50%). We realized a pre-tax profit of NOK 1.3 billion (NOK 0.9 billion after tax).

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, which was partially reversed in 2000.

In 1999, we sold the exploration and production activities of our US subsidiary, Statoil Energy Inc., and in 2000 we sold Statoil Energy's marketing arm. In connection with this disposal we recorded a loss of NOK 1.1 billion, of which NOK 900 million was recorded in 1999 and NOK 200 million was recorded in 2000. In 1999, Statoil Energy accounted for revenues of NOK 18.5 billion (which accounted for approximately 85% of our International E&P business segment's total revenues for that year) and proved reserves of 217 million boe. As a result of these sales, the revenue of International E&P decreased by 58% from 1999 to 2000.

In December 2001, we decided to write down the book value of our interests in the LL 652 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 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 end user sales focus towards sales to larger, industrial customers.

In Manufacturing and Marketing, we restructured our portfolio as follows:
In May 2001, we sold our 15% interest in the Malaysian Refining Company, which operates the refinery in Melaka, Malaysia to the two other shareholders in that refinery, Petronas and Conoco Asia.

In October 2001, we acquired, as part of the restructuring of our ownership in Navion, the Rasmussengruppen's 20% equity interest in the company, so that we now own 100% of Navion. The agreement was effective from October 1, 2001. In addition, as part of the restructuring, we sold our interests in the production ships Navion Munin and Berge Hugin to Bluewater in the second half of 2001.

In 1999, we sold 50% of our shares in SDS to ICA/Ahold and recorded a NOK 1.2 billion gain on the sale. We account for the results of this business using the equity method of accounting. Accordingly, we include our 50% share of the net income of SDS in our revenues.

Factors Affecting Our Results of Operations

Our results of operations substantially depend on:

- crude oil trading prices, which increased significantly in 1999 and 2000, but decreased in 2001;
- natural gas contract prices, which declined in 1999, but strengthened considerably in 2000 and 2001;
- trends in the exchange rate between the US dollar, in which the trading price of crude oil is generally stated, and the Norwegian kroner, in which our accounts are held 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;
- recent consolidation in the industry, including mergers creating so-called "super majors", which is sharpening competition for exploration opportunities and operatorships; and
- the deregulation of the natural gas markets, which may cause substantial changes to the existing market structures and to the overall level and volatility of prices.

The following table shows the yearly average crude oil trading prices, natural gas contract prices and Norwegian kroner/US dollar exchange rates for 1999, 2000 and 2001.

	1999	*2000*	*2001*
Crude oil (US$ per barrel Brent blend)	18.0	28.5	24.4
Natural gas(1) (NOK per scm)	0.58	0.99	1.22
Norwegian kroner/US dollar average daily exchange rate	7.80	8.81	8.99

(1) From the Norwegian Continental Shelf.

The following table illustrates how certain changes in the crude oil trading price, natural gas contract prices, refining margins and the Norwegian kroner/US dollar exchange rate may impact our income before financial items, income taxes and minority interest and our net income assuming activity at levels achieved in 2001.

Sensitivities on 2001 results

(IN NOK BILLION)	*CHANGE IN EBIT(1)*	*CHANGE IN NET INCOME*
Oil price (+/- US$ 1/bbl)	2.5	0.6
Gas price (+/- 10%)	1.8	0.4
Refining margins (+/- US$ 0.50/bbl)	0.5	0.3
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)	-	0.7

(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 actually would appear in our consolidated financial statements. Our consolidated financial statements would also reflect the effect on 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 program 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 put on a downside protection structure for some of our production, reducing price risk below US$ 17 per barrel in 2001 and below US$ 18 per barrel for 2002. Natural gas is typically sold under price formulas that establish time lags for the change of the gas price.

Approximately 25% of the refining margin for 2001 was locked in late 2000. Also, 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 mainly in US dollars.

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 general assembly on May 25, 2001 and became effective on June 17, 2001. Pursuant to the owner's instruction, we agreed to purchase all of the SDFI oil and NGL produced and, therefore, include the proceeds from the sale of the SDFI production as revenue and the price that we pay to the Norwegian State as cost of goods sold. The treatment of our sales of SDFI natural gas 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 gas from the Norwegian State by Statoil amounted to NOK 50,987 million, NOK 39,185 million and NOK 22,293 million in 2001, 2000 and 1999, 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 currently paying royalty are Statfjord, Gullfaks and Oseberg, which together represented 37%, 30% and 27% of our total petroleum production in 1999, 2000 and 2001 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 January 1, 1986 or later. Remaining royalty obligations will gradually be abolished in such a manner that royalty payments from Statfjord will be abolished over a three-year period and royalty payments from Gullfaks and Oseberg will be abolished over a six-year period, in each case beginning in 2000.

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 Norwegian kroner. 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 duration 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 Norwegian kroner can be expected to increase our reported earnings. As a result, such an increase would favor Statoil if maintained in the longer term. However, because our currently outstanding debt is principally 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.

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. See Item 4—Information on the Company—Regulation—Norwegian Regulation—Taxation of Statoil. In June 2001, the Storting enacted certain changes in the taxation of petroleum operations. For details, see Item 4—Information on the CompanyRegulation—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, 1999	2000	2001
CONSOLIDATED STATEMENTS OF INCOME			
Revenues:			
Sales	99.6%	99.8%	97.8%
Equity in net income (loss) of affiliates	(0.5%)	0.2%	0.2%
Other income	0.9%	0.0 %	2.0%
Total revenues	100.0%	100.0 %	100%
Expenses:			
Cost of goods sold	53.0%	51.9%	53.4%
Operating expenses	17.1%	12.5%	12.5%
Selling, general and administrative expenses	4.4%	1.7%	1.5%
Depreciation, depletion and amortization	11.7%	6.8%	7.6%
Exploration expenses	2.1%	1.1%	1.2%
Total expenses before financial items	88.3%	74.0%	76.2%
Income before financial items, income taxes and minority interest	11.7%	26.0%	23.8%

Years ended December 31, 2001, 2000 and 1999

Sales. Our sales revenue includes sales of our own oil and gas production and sales of oil and gas production that we purchase from others, including oil and gas that we purchase from the SDFI to take into our own inventory and royalty oil, as well as, prior to June 17, 2001, the net result of our marketing and selling of SDFI oil and gas production that we sold directly on to external customers. Sales revenues also include our share of tariffs paid by third parties for transport through pipelines in which we have interests and revenues from our majority-owned downstream businesses.

Beginning on June 17, 2001, our sales revenue and cost of goods sold include sales of 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 (and not just the net result). See —Factors Affecting Our Results of Operations above for more information.

Our sales revenue totaled NOK 231.1 billion in 2001, compared to NOK 229.8 billion in 2000 and NOK 149.6 billion in 1999. The 0.5% increase in sales revenues from 2000 to 2001 was mainly due to a 29% increase in crude oil volumes bought from third parties and SDFI, primarily resulting from the new owner's instruction, and a 23% increase in our realized price of natural gas. This was to a large extent offset by a 15% reduction in realized oil prices, a 29% reduction in the refining margin (FCC-margin), our sale in 2000 of the marketing arm of our subsidiary Statoil Energy Inc. and the reduction in the contribution from Statpipe, 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 decrease in oil price and refining margins were partly offset by a 2% strengthening of the US dollar against the Norwegian kroner.

Comprising the NOK 1.3 billion increase in sales revenues in 2001 was approximately NOK 35 billion due to increased SDFI and third party volumes and approximately NOK 4 billion due to an increase in the price and volumes sold of natural gas. 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 start of production 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 Nord and Troll C fields coming on stream in Norway and increases in production from the Åsgard, Norne, Sygna, Oseberg Satellites and Snorre Sør fields. There was, however, a lower than expected production increase at Åsgard due a shutdown of production on the Åsgard B platform due to leakages in the welded joints on the subsea flowlines 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 that 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. See below for a description of the difference between produced volumes and lifted volumes. 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 and reduced production from the Heidrun and Sleipner fields and the decommissioning of the Yme field.

Our gas volumes sold of own produced gas were 14.7 bcm (518.8 bcf) in 2001, approximately the same as the volumes sold in 2000.

The 54% increase in sales revenue from 1999 to 2000 was principally due to an approximately 58% increase in our realized crude oil prices, an approximately 71% increase in our realized natural gas prices and an increase in our own oil production following the acquisition of the Saga Petroleum assets in July 1999, offset in part by a 58% decrease in sales revenue in our International E&P segment due to the sale of Statoil Energy Inc. In addition, the increase in our sales revenue from 1999 to 2000 reflected a strengthening of the US dollar against the Norwegian kroner, which contributed to the increase in crude oil prices measured in Norwegian kroner. Of the NOK 80.2 billion increase in sales revenue in 2000, approximately NOK 60 billion was due to the increase in oil prices expressed in NOK, approximately NOK 6 billion was due to an increase in the price and volumes sold of natural gas and approximately NOK 4 billion was due to the increase in oil production. Our average daily oil production increased from 709,900 barrels in 1999 to 733,300 barrels in 2000, primarily as a result of the acquisition of the Saga Petroleum assets in July 1999, which was reflected in our financial statements for a full year beginning in 2000 and which increased our average daily oil production in 2000 as compared to 1999 by approximately 30,000 barrels per day. Although our gas volumes sold decreased from 14.8 bcm (522.7 bcf) in 1999 to 14.7 bcm (519.2 bcf) in 2000 due primarily to our sale of Statoil Energy Inc., we generated higher revenues from gas sales as a result of an increase in our realized price of natural gas on the NCS of approximately 71% over the same period.

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, witch 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 SDS, our wholly-owned subsidiary Navion's 50% equity interest in the West Navion drill ship and our former 15% interest in the Melaka refinery which was sold in 2001. Our share of equity in net income of affiliates was NOK 439 million in 2001, NOK 523 million in 2000 and a loss of NOK 745 million in 1999. The decrease from 2000 to 2001 was primarily due to reduced income of Borealis as a result of reduced petrochemical margins. The increase from 1999 to 2000 was primarily due to an increase in the income of SDS, whereas the 1999 result was affected by the NOK 1.2 billion writedown in the value of our interest in the West Navion drill ship and the NOK 500 million writedown in the value of our 15% interest in the Melaka refinery.

Other income. Other income was NOK 4.8 billion in 2001, NOK 70 million in 2000 and NOK 1.3 billion in 1999. 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. The NOK 1.3 billion income in 1999 primarily comprises the gain realized on the sale of 50% of SDS to ICA/Ahold.

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 126.2 billion in 2001 from NOK 119.5 billion in 2000 and NOK 79.5 billion in 1999. The 5.6% increase in 2001 is mainly 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.

The increase of 50% from 1999 to 2000 was primarily due to an increase in crude oil prices and also, to a lesser extent, increased purchases of royalty oil, increased purchases of SDFI oil and a net increase in oil purchased from others for trading or for use in our operations. The increase occurred despite the 2000 divestment of the marketing arm of Statoil Energy Inc., which accounted for approximately 20% of our total cost of goods sold in 1999.

Operating expenses. Our operating expenses include production costs in fields and transport systems related to our share of oil and gas production. Operating expenses increased to NOK 29.5 billion in 2001 compared to 28.9 billion in 2000 and NOK 25.7 billion in 1999. 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.

The 13% increase from 1999 to 2000 was principally due to new fields coming on stream in 2000, and the effect of including the acquired Saga assets in our financial statements for a full fiscal year, partially offset by a reduction in operating expenses following the implementation of our cost reduction program.

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 decreased to NOK 3.5 billion in 2001 compared to NOK 3.9 billion in 2000 and NOK 6.7 billion in 1999. The decrease from 2000 to 2001 was mainly a result of our sale of the marketing arm of our subsidiary, Statoil Energy Inc. in 2000.

The 42% decrease from 1999 to 2000 primarily reflected the sale of 50% of SDS to ICA/Ahold in 1999, following the transfer of our retail network of service stations in Scandinavia to SDS, and the accompanying deconsolidation of the expenses associated with these service stations. This resulted in expense reduction of approximately NOK 1.4 billion in 2000. This decrease was also due in part to the cost savings program initiated in 1999, which reduced our selling, general and administrative costs from 2000.

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 goodwill and other intangible assets and depreciation of capitalized exploration costs as well as writedowns of impaired long-lived assets. Depreciation, depletion and amortization expenses were NOK 18.1 billion in 2001, NOK 15.7 billion in 2000 and NOK 17.6 billion in 1999. The increase of 15% from 2000 to 2001 was due principally to the writedown of NOK 2.0 billion (NOK 1.4 billion after tax) on the LL 652 oil field in Venezuela and increased depreciation due to higher production.

Depreciation, depletion and amortization expenses decrease by 10% from 1999 to 2000, due principally to several major writedowns and provisions taken in 1999 regarding the value of some of our refineries and other assets. This decrease was partially offset by an increase in depreciation as a result of the acquisition of the Saga assets being reflected in our financial statements for a full year. In addition, the increase in depreciation was also due to a full year effect of production at Åsgard and other new fields with higher depreciation rates compared to more mature fields.

Exploration expenses. Our exploration expenditure is capitalized to the extent our exploration efforts are successful and is otherwise charged to expense 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 2.9 billion in 2001, NOK 2.5 billion in 2000 and NOK 3.1 billion in 1999. 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 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.

Exploration expenses decreased to NOK 2.5 billion in 2000 from NOK 3.1 billion in 1999, a reduction of 21%, due to a higher success rate in 2000, which resulted in a lower level of costs being expensed, partly offset by the effect of the strengthening of the US dollar against the Norwegian kroner. In addition, exploration expenses in 1999 include NOK 0.8 billion relating to write-offs of expenditures capitalized in prior periods following a review of our NCS exploration portfolio, while exploration expense in 2000 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. Income before financial items, income taxes and minority interest totaled NOK 56.2 billion in 2001, NOK 60.0 billion in 2000, and NOK 17.6 billion in 1999. 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 the LL 652 oil field in Venezuela. 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.

From 1999 to 2000, income before financial items, income taxes and minority interest increased 241%, due primarily to a substantial increase in our revenues as discussed above, and benefits from our cost reduction program, as well as the absence in 2000 of NOK 7.2 billion in writedowns and provisions discussed below.

The writedowns in 1999 principally consisted of a NOK 1.8 billion writedown in the value of our refinery at Kalundborg, a NOK 1.2 billion writedown in the value of our interest in the West Navion drill ship and two NOK 500 million writedowns in respect of our 15% interest in the refinery in Melaka and our methanol plant at Tjeldbergodden. The provisions in 1999 principally consisted of a NOK 1.4 billion provision with respect to our operations in the United States and a significant provision related to estimated losses on rig rental contracts. Over the 1998-2000 period we provided approximately NOK 1.6 billion for the anticipated reduction in market value of fixed-price drilling service contracts. At December 31, 2001, the remaining reserve for these losses was NOK 734 million, which we believe will be sufficient to cover the remaining exposure. This judgment is based on assumptions regarding our own utilization of the rigs and the rate and duration at which we can sublet these rigs to third parties. Should our assumptions prove to be incorrect, changes in the provision may be required.

In 2001, 2000 and 1999, our income before financial items, income taxes and minority interest margins, measured as a percentage of income before financial items, income taxes and minority interest to revenue, was 24%, 26% and 12%, respectively.

Net financial items. In 2001 we reported a net income from financial items of NOK 0.1 billion, compared to a net expense of NOK 2.9 billion in 2000, and a net income of NOK 1.4 billion in 1999. The changes from year to year resulted principally from change in unrealized currency losses on the US dollar portions of our outstanding indebtedness due to changes in the US dollar rate against the Norwegian kroner. The currency mix of the debt portfolio changed during 2001, from 80% to nearly 100% US dollar, which due to the timing resulted in additional unrealized currency gains. However, in the same period we realized higher interest costs due to an increase in net debt resulting from the acquisition of SDFI assets. The net income in 1999 resulted from the gain of approximately NOK 1.5 billion from the sale of shares in Saga Petroleum to Norsk Hydro, which more than offset the effect of the reduction in of the Norwegian kroner rate.

Income taxes. Our effective tax rates were 68.5%, 70.9% and 67.6% in 2001, 2000 and 1999, respectively. Our effective tax rate is our income taxes divided by our income before income taxes and minority interest. Fluctuations in these 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, taxed at 28%, and income in other countries taxed at the applicable income tax rate. Tax benefits of net losses in foreign subsidiaries have in some cases been offset or reduced by a valuation allowance.

Minority interest. Minority interest in net profit in 2001 was NOK 488 million compared to 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 include 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.

Minority interest in net losses was NOK 256 million in 1999. The increase from 1999 to 2000 primarily reflected increased net income at Mongstad and in Navion.

Net income. Net income in 2001 was NOK 17.2 billion compared to NOK 16.2 billion in 2000 and NOK 6.4 billion in 1999 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 segment sell oil and natural gas to the Manufacturing and Marketing and to the Natural Gas business areas. 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. 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 US$ 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 three- to nine-month period.

	YEAR ENDED DECEMBER 31,			
(IN MILLIONS)	*1999 NOK*	*2000 NOK*	*2001 NOK*	*2001 US$*
E&P Norway				
Revenue	38,487	71,135	65,655	7,317
Income before financial items, income taxes and minority interest	16,841	46,715	40,697	4,536
Long-Term Assets	77,881	79,864	77,550	8,643
International E&P				
Revenue	21,745	9,027	7,693	857
Income before financial items, income taxes and minority interest	(1,995)	773	1,291	144
Long-Term Assets	14,821	19,465	21,530	2,400
Natural Gas				
Revenue	13,799	20,624	23,468	2,616
Income before financial items, income taxes and minority interest	5,052	7,893	9,629	1,073
Long-Term Assets	13,557	13,030	10,500	1,170
Manufacturing and Marketing				
Revenue	112,535	201,585	203,387	22,668
Income before financial items, income taxes and minority interest	(1,754)	4,559	4,480	499
Long-Term Assets	31,197	32,925	30,432	3,392
Other and Eliminations				
Revenue	(36,434)	(71,946)	(63,867)	(7,118)
Income before financial items, income taxes and minority interest	(566)	51	57	6
Long-Term Assets	13,438	13,042	11,026	1,229
Total income before financial items, income taxes and minority interest	17,578	59,991	56,154	6,258

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, 2001.

	YEAR ENDED DECEMBER 31, 1999	2000	% CHANGE	2001	% CHANGE
Revenues (in NOK million)	38,487	71,135	85%	65,655	(8%)
Depreciation, Depletion and Amortization (in NOK million)	9,126	11,225	23%	11,806	5%
Exploration Expense (in NOK million)	2,016	1,310	(35%)	2,008	53%
Income before financial items, income taxes and minority interest (in NOK million)	16,841	46,715	177%	40,697	(13%)
Production:					
Oil (mboe/day)	651.4	676.2	4%	697.1	3%
Natural gas (mmcf/day)	1,272	1,365	7%	1,380	1%
Total Production (mboe/day)	877.8	919.2	5%	942.7	3%
Reserve replacement ratio(1)(2)	0.80	0.85	6%	0.77	(9%)
Finding cost (US$ per boe)(1)	2.13	1.68	(21%)	1.53	(11%)
Finding and Development Costs (US$ per boe)(1)	10.98	10.65	(3%)	9.35	(12%)
Unit Production (lifting) Cost (US$ per boe)(3)	3.22	2.82	(12%)	2.77	(2%)

(1) Reserve replacement ratio, 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 ratio is defined as the total additions to proved reserves, including acquisitions and disposals, divided by volumes produced.
(3) Our unit production (lifting) cost is calculated as operating costs relating to the production of oil and gas divided by the total production (lifting) of petroleum in a given year.

Years ended December 31, 2001, 2000 and 1999

E&P Norway generated revenues of NOK 65.7 billion in 2001, compared to NOK 71.1 billion in 2000 and NOK 38.5 billion in 1999. The 8% decrease in revenue 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 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 Norwegian kroner. In addition, revenues in 2001 included approximately NOK 1.4 billion in non-taxable gains related to the sale of our interest in the Grane, Jotun and Njord fields and 12% interest in the Snøhvit field (reducing our interest to 22.29%). The 85% increase from 1999 to 2000 resulted primarily from an approximately 58% increase in our weighted average realized crude oil prices, an 82% increase in the transfer price of natural gas sold from E&P Norway to Natural Gas primarily as a result of a 71% increase in our realized price of natural gas, a higher exchange rate for translating US dollars into Norwegian kroner, increasing crude oil and natural gas sales measured in Norwegian kroner, and a 4% increase in our own oil production following the acquisition of the Saga assets in July 1999.

Average daily oil production in E&P Norway increased to 697,100 barrels in 2001 from 676,200 barrels in 2000 and from 651,400 barrels in 1999. The 3.1% increase in average daily oil production from 2000 to 2001 resulted primarily from the start up of the Gullfaks Satellites Phase II, Glitne, Snorre Nord and Troll C fields and from increased production from the Åsgard, Norne, Sygna, Oseberg Satellites and Snorre Sør 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 flowlines from the production wells to the platform. 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. The 4% increase in average daily oil production from 1999 to 2000 resulted primarily from the acquisition of the Saga assets which had the effect of increasing our average daily oil production by approximately 30,000 barrels per day in 2000, as compared to 1999, as well as a full year of production from the Åsgard and Varg fields, together with an increase in production from our Troll oil field.

Average daily gas production was 39.1 mmcm (1,380 mmcf) in 2001, as compared to 38.6 mmcm (1,365 mmcf) in 2000 and 36.0 mmcm (1,272 mmcf) in 1999. Gas production increased by 1% between 2000 and 2001 and 7.3% between 1999 and 2000, due primarily to an increase in contracted gas volumes to continental Europe. Reduced sales in the first and second quarters of 2001 due to high realized price of natural gas, were offset by higher contractual offtakes at the end of 2001.

Depreciation, depletion and amortization expenses were NOK 11.8 billion in 2001, NOK 11.2 billion in 2000 and NOK 9.1 billion in 1999. The 5% increase from 2000 to 2001 resulted primarily from the start of production from our new fields Glitne, Huldra, Gullfaks Satellites Phase II and Snorre North. The 23% increase in depreciation, depletion and amortization expenses from 1999 to 2000 resulted primarily from the effect of the Saga acquisition being included in our operating results for a full year, as well as a full year of production at Åsgard and other new fields with higher scheduled depreciation rates.

Exploration expenditure increased from 1999 to 2001. Exploration expenditure was NOK 2.0 billion in 2001, compared to NOK 1.7 billion in 2000 and NOK 1.6 billion in 1999. The 25% increase from 1999 to 2001 resulted primarily from an increase in the exploration activity, which is a consequence of our growth targets and reflects our confidence in the possibilities for new discoveries on the NCS.

Exploration expense in 2001 was NOK 2.0 billion, compared to NOK 1.3 billion in 2000 and NOK 2.0 billion in 1999. The 54% increase in exploration expense from 2000 to 2001 resulted primarily from increased exploration activity. Eighteen exploration wells were completed in 2001, of which 12 resulted in discoveries, as compared to 14 exploration wells in 2000, of which 10 resulted in discoveries. In addition, exploration expense in 2001 included NOK 0.7 billion of expenditure, which had been capitalized in previous years but was written off in 2001 following an overall review of our NCS exploration activity. The 35% decrease in exploration expense from 1999 to 2000 was primarily the result of a higher success rate for wells drilled. In addition, exploration expense in 1999 included NOK 0.8 billion of expenditure which had been capitalized in previous years, but was written off in 1999 following an overall review of our NCS exploration activity, while exploration expense in 2000 included NOK 0.4 billion of exploration expenditure capitalized in previous years but written off in 2000. Excluding these amounts, exploration expense increased by 45% from 2000 to 2001 and decreased by 25% from 1999 to 2000.

Income before financial items, income taxes, and minority interest for E&P Norway was NOK 40.7 billion compared to NOK 46.7 billion in 2000 and NOK 16.8 billion in 1999. 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. Excluding the gains on sale of the Njord, Grane and Jotun fields and a 12% interest in the Snøhvit field, the income before financial items, income taxes and minority interest was NOK 39.3 billion, compared to NOK 46.7 billion in 2000. 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 has been partly offset by a higher transfer price for gas paid by Natural Gas, increased production of crude oil, increased sale of natural gas and reduced operating costs. The reduction in operating costs was mainly due to reduced costs of goods sold due to inventory adjustments and reduced provisions for future removal costs of field installations as a consequence of updated removal cost estimates. This was partly offset by an increase in operating costs due to new fields coming on stream and an increase in preparation for operational activities for new fields.

The increase in income before financial items, income taxes and minority interest from 1999 to 2000 of 177% was primarily the result of the substantial increase in sales revenues. In 1999, we also took a provision of NOK 900 million related to anticipated losses on contracts for rental of rigs entered into in 1997 and 1998.

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, 2001.

	YEAR ENDED DECEMBER 31,				
	1999	*2000*	*% CHANGE*	*2001*	*% CHANGE*
Revenues (in NOK million)	21,745	9,027	(58%)	7,693	(15%)
Depreciation, Depletion and Amortization (in NOK million)	2,544	1,704	(33%)	3,371	98%
Exploration Expense (in NOK million)	1,107	1,141	3%	866	(24%)
Income before financial items, income taxes and minority interest (in NOK million)	(1,995)	773	N/A	1,291	67%
Production (lifting):					
Oil (mboe/day)	58.6	57.1	(2%)	57.8	1%
Natural Gas (mmcf/day)	160	53	(67%)	41	(23%)
Total Production (lifting) (mboe/day)	87.1	66.6	(24%)	65.2	(2%)
Reserve replacement ratio(1)(2)(3)	5.17	3.62	(30%)	2.14	(32%)
Finding Cost (US$ per boe)(1)	1.93	1.73	(10%)	2.15	27%
Finding and Development Costs (US$ per boe)(1)(3)	5.80	5.09	(12%)	8.58	69%
Unit Production (lifting) Cost (US$ per boe)(4)	5.04	6.61	31%	5.16	(22%)

(1) Reserve replacement ratio, 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 ratio is defined as the total additions to proved reserves, including acquisitions and disposals, divided by volumes produced.
(3) Adjusted for the sale of Statoil Energy Inc.
(4) Our unit production (lifting) cost is calculated by taking operating costs relating to the production of oil and gas and dividing them by the total production (lifting) of petroleum in a given year.

Years ended December 31, 2001, 2000 and 1999

International E&P generated revenues of NOK 7.7 billion in 2001, compared to NOK 9.0 billion in 2000 and NOK 21.7 billion in 1999. The 15% decrease in revenue 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. The 58% decrease in revenue from 1999 to 2000 was primarily the result of the sale of the upstream business of Statoil Energy Inc. in late 1999 and the sale of the marketing, power generation and energy trading business in early 2000. This was partially offset by an approximately 58% increase in crude oil prices and a higher exchange rate for translating US dollars into Norwegian kroner.

Average daily oil production was 57,800 barrels per day in 2001 compared to 57,100 barrels per day in 2000 and 58,600 barrels per day in 1999. 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 mainly offset by declining production for the Siri field in Denmark and Lufeng field in China. The 3% decrease in average daily production of oil from 1999 to 2000 resulted primarily from a decline in production from the Lufeng field in China.

Average daily gas production in 2001 was 1.2 mmcm (41 mmcf) compared to 1.5 mmcm (53 mmcf) in 2000 and 4.5 mmcm (160 mmcf) in 1999. The 23% decrease from 2000 to 2001 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. Production from one well resumed in the fourth quarter of 2001, and one additional well came back on stream in early 2002. We will decide what steps to take with the third well depending on the development of the production capacity from the existing wells. The 67% decrease from 1999 to 2000 primarily resulted from the sale of the upstream activities of Statoil Energy Inc.

Depreciation, depletion and amortization expenses were NOK 3.4 billion in 2001 compared to NOK 1.7 billion in 2000 and NOK 2.5 billion in 1999. The 98% increase in 2001 as compared to 2000 is primarily related to the NOK 2.0 billion writedown of the LL 652 oil field in Venezuela. The 33% decrease from 1999 to 2000 primarily related to the sale of the upstream business of Statoil Energy Inc. in 1999 and the corresponding absence of a NOK 900 million financial provision taken in 1999 with respect to Statoil Energy Inc.

Exploration expenditure was NOK 0.7 billion in 2001, compared to NOK 1.8 billion in 2000 and NOK 1.4 billion in 1999. The 61% decrease in exploration expenditure from 2000 to 2001 was primarily due to lower exploration activity in 2001. The 30% increase in exploration expenditure from 1999 to 2000 was due primarily to the strengthening of the US dollar, increasing the expenditure measured in Norwegian kroner. Increased drilling activities inside our core assets in 2000 were partially offset by the implementation of our cost reduction program.

Exploration expense in 2001 was NOK 0.9 billion, compared to NOK 1.1 billion in 2000 and NOK 1.1 billion in 1999. 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. The 3% increase in exploration expense from 1999 to 2000 was primarily due to the currency effect of translating the US dollar costs into Norwegian kroner.

Income before financial items, income taxes and minority interest for International E&P in 2001 was NOK 1,291 million compared to NOK 773 million in 2000 and a loss before financial items, income taxes and minority interest of NOK 1,995 million in 1999. 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 LL 652 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. Significant improvement in our income before financial items, income taxes and minority interest occurred from 1999 to 2000 primarily due to increased underlying revenue excluding the effect of the sale of Statoil Energy Inc., and decreased operating expenses as a result of our cost reduction program, as well as the absence in 2000 of the NOK 1.4 provision taken in connection with the disposals of our US operations, of which NOK 900 million was taken in respect of Statoil Energy Inc. and NOK 500 million related to our upstream interests in the Gulf of Mexico.

Natural Gas

The following table sets forth certain financial and operating data for our Natural Gas business segment and percentage change in each of the three years ended December 31, 2001.

	YEAR ENDED DECEMBER 31,				
	1999	2000	% CHANGE	2001	% CHANGE
Revenues (in NOK million)	13,799	20,624	49%	23,468	14%
Natural gas sales (in NOK million)	9,454	16,060	70%	18,984	18%
Processing and transportation (in NOK million)	4,345	4,564	5%	4,484	(2%)
Income before financial items, income taxes and minority interest (in NOK million)	5,052	7,893	56%	9,629	22%
Volumes marketed:					
For our own account (bcf)	464.3	499.7	8%	517.8	4%
For the account of the SDFI (bcf)	573.2	601.5	5%	666.9	11%
For our own account (bcm)	13.1	14.1	8%	14.7	4%
For the account of the SDFI (bcm)	16.2	17.0	5%	18.9	11%

Years ended December 31, 2001, 2000 and 1999

Revenues in the Natural Gas business mainly consist 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 23.5 billion in 2001, compared to NOK 20.6 billion in 2000 and NOK 13.8 billion in 1999. The 14% increase in 2001 over 2000 resulted mainly from a 23% average increase in NCS natural gas prices. Revenues also increased due to new gas deliveries to the Kårstø processing plant from the Åsgard, Draugen, Heidrun and Norne fields, but was offset by a decline in the contribution from Statpipe as a consequence of our interest being reduced from 58.25% to 25% as of June 1, 2001, as a result of the SDFI transaction. The 49% increase in 2000 over 1999 resulted principally from a 71% increase in NCS natural gas prices.

Gas sales were 14.7 bcm (517.8 bcf) in 2001, 14.1 bcm (499.7 bcf) in 2000 and 13.1 bcm (464.3 bcf) in 1999. The 4% increase in gas sales from 2000 to 2001 was primarily due to deliveries under our long-term supply contracts combined with increased short-term gas sales. 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 whitn in 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. We expect our currently contracted gas volumes to increase until 2005 because our gas sales contracts contain scheduled annual volume delivery increases. As customers may 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 year.

Income before financial items, income taxes and minority interest for Natural Gas in 2001 was NOK 9.6 billion, compared to NOK 7.9 billion in 2000 and NOK 5.1 billion in 1999. 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 which 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, partially offset by reduced transport tariffs. In addition, the contribution from Statpipe declined as a consequence of our interest being reduced from 58.25% to 25%, as discussed under Item 4—Information on the Company—Business Overview—Operations—Natural Gas—Norwegian Gas Transportation System and Other Facilities.

In 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 our end user sales focus towards larger, industrial customers. Starting in October 2001, the new Vesterled pipeline opened further opportunities to sell gas to the UK. In July we entered into a 15-year contract with BP for the sale of 1.6 bcm per year of natural gas to BP for deliveries into the UK market which started on October 1, 2001.

Income before financial items, income taxes and minority interest for Natural Gas in 2000 was NOK 7.9 billion, compared to NOK 5.1 billion in 1999. The 56% increase in income before financial items, income taxes and minority interest from 1999 to 2000 was primarily the result of increased revenues from gas sales, as well as a reduction in fixed costs, partially offset by operating loss incurred by our Alliance Gas subsidiary in the UK.

Manufacturing and Marketing

Years ended December 31, 2001, 2000 and 1999

Manufacturing and Marketing generated revenue of NOK 203.4 billion in 2001, compared to NOK 201.6 billion in 2000 and NOK 112.5 billion in 1999. 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. The 79% increase in 2000 over 1999 resulted principally from the effect of the approximately 58% increase in crude oil prices on our operating and trading activities, a higher exchange rate for translating US dollars into Norwegian kroner, an increase in prices for refined products and higher shuttle tanker rates.

Depreciation, depletion and amortization totaled NOK 1.9 billion in 2001, as compared to NOK 1.7 billion in 2000 and NOK 4.6 billion in 1999. The 7% increase in depreciation, depletion and amortization expenses from 2000 to 2001 was primarily due to a NOK 0.1 billion writedown of the Navion Clipper shuttle tanker. The 63% decrease in depreciation, depletion and amortization expenses from 1999 to 2000 was primarily due to the NOK 2.3 billion writedowns in the value of our refinery at Kalundborg and our methanol plant at Tjeldbergodden in 1999 and the restructuring of our retail network of service stations in Scandinavia (SDS).

Income before financial items, income taxes and minority interest for Manufacturing and Marketing was NOK 4.5 billion in 2001, as compared with NOK 4.6 billion in 2000 and a loss of NOK 1.8 billion in 1999. Lower refining margins were the main reason for the reduction in income from the refining activity. Average refining margin (FCC-margin) was 30% lower, equaling US$ 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 performance 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, cost reductions as well as a small gain from the sale of an office building in Denmark. Methanol results for 2001 increased by NOK 0.2 billion from 2000. Average realized price on methanol was about 8% 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.

This business segment delivered record income before financial items, income taxes and minority interest in 2000, as compared to a loss before financial items, income taxes and minority interest in 1999, due to the substantial improvement in refining margins and better results from shipping due to higher rates and better utilization, as well as the absence of NOK 4 billion in writedowns taken in 1999 and the implementation in 1999 of our cost reduction program. This improvement was partially offset by a loss in Nordic Energy which resulted from lower marketing margins due to increased competition. Manufacturing and Marketing had a loss before financial items, income taxes and minority interest in 1999 due to total writedowns of NOK 4 billion taken in 1999 in the value of our refinery at Kalundborg (NOK 1.8 billion), our 15% holding in the refinery in Melaka (NOK 0.5 billion), our methanol plant at Tjeldbergodden (NOK 0.5 billion) and in the value of our interest in the West Navion drill ship (NOK 1.2 billion). Income before financial items, income taxes and minority interest in 1999 was also affected by low refining margins due to over-capacity in the European refining industry. In addition, the marketing business was affected by sharp competition resulting in reduced volumes and narrower margins. These factors were partly offset by the NOK 1.2 billion gain on the sale of 50% of SDS to ICA/Ahold and good results from trading of crude oil and refined products.

Navion contributed NOK 1.5 billion to the income before financial items, income taxes and minority interest of the Manufacturing and Marketing business segment in 2001, as compared to an income before financial items, income taxes and minority interest of NOK 2.1 billion in 2000 and a loss before financial items, income taxes and minority interest of NOK 0.6 billion in 1999. 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. The net result for Navion for 1999 as compared to 2000 was adversely affected by our writedown of NOK 1.2 billion in the value of our interest in the West Navion drill ship, which we intend to sell.

The contribution from our affiliate SDS to Manufacturing and Marketing's income before financial items, income taxes and minority interest was NOK 222 million in 2001, compared with NOK 194 million in 2000 and NOK 105 million in 1999. The increase of NOK 28 million from 2000 to 2001 and the increase of NOK 89 million from 1999 to 2000 were both 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 a loss of NOK 146 million in 2001, an income of NOK 244 million in 2000 and an income of NOK 656 million in 1999. The contribution from Borealis fell from 2000 to 2001 mainly due to reductions in margins in the range of 30 euro/ton, approximately 18%, as a consequence of weaker market conditions for polyolefin and olefin products. The contribution from Borealis fell from 1999 to 2000 as a result of manufacturing disturbances at several plants leading to lower production volumes and higher feedstock prices resulting in reduced margins for polyolefins, which constitute a significant portion of Borealis's total production.

Other operations

Years ended December 31, 2001, 2000 and 1999

Our other operations consist of the activities of Corporate Services, Corporate Center, Group Finance and Technology. In connection with our other operations, we recorded income before financial items, income taxes and minority interest of NOK 57 million in 2001, NOK 51 million in 2000 and a loss before financial items, income taxes and minority interest of NOK 566 million in 1999. The loss before financial items, income taxes and minority interest in 1999 was primarily due to a NOK 500 million provision made on the Group level for employee termination benefits in connection with a company-wide staff reduction program.

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 2001 amounted to NOK 39.2 billion, as compared to NOK 56.8 billion for 2000 and 29.6 billion in 1999. 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. The 92% increase from 1999 to 2000 was primarily attributable to the approximate 58% increase in crude oil prices from 1999 to 2000.

Cash Flows used in Investing Activities

Net cash flows used in investing activities amounted to NOK 12.8 billion for 2001, as compared to NOK 16.0 billion for 2000 and NOK 25.0 billion in 1999. Gross investments, defined as additions to property, plant and equipment and capitalized exploration expenditures, declined from NOK 28.6 billion in 1999 to NOK 18.7 billion in 2000 and to NOK 17.4 billion in 2001. This decline in net cash flows used in investing activities 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. The 36% decrease in net cash flows used in investing activities from 1999 to 2000 was primarily due to the absence in 2000 of the cash investment of NOK 4.2 billion used in connection with our acquisition of the Saga assets in 1999 and the decrease in investment in accordance with our improvement program.

Cash Flows used in/provided by Financing Activities

Net cash flows used in financing activities amounted to NOK 31.5 billion for 2001, as compared to NOK 35.2 billion for 2000 and NOK 1.1 billion in 1999. New long-term borrowing increased by NOK 8.4 billion compared to 2000, while repayment of long-term debt decreased by NOK 8.7 billion. 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 1999 to 2000 was due primarily to a NOK 12.2 billion decrease in new long-term borrowings and a NOK 7.9 billion increase in repayments of long-term borrowings and a NOK 14.5 billion increase in dividends paid.

For the fiscal year ended December 31, 2001, we paid a dividend of NOK 55.4 billion. The dividend for the year ended December 31, 2000 was NOK 21.4 billion, and for the year ended December 31, 1999 NOK 6.9 billion. The increase in 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 9.5 billion as of December 31, 2001, NOK 0.3 billion as of December 31, 2000 and NOK 0.4 billion as of December 31, 1999. 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, 2001, we had liquid assets of NOK 6.5 billion, including approximately NOK 2.1 billion of domestic and international capital market investments, primarily government bonds, but also other short- and long-term debt securities, 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 Norwegian kroner and 15% 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 Norwegian kroner, and the majority of the remaining cash is held in US dollars. Capital market investments decreased by NOK 1.8 billion during 2001, as compared to year-end 2000. Cash and cash equivalents decreased by approximately NOK 5.3 billion during 2001, as compared to year-end 2000. The reason for both these decreases is that cash was accumulated prior to and used for the SDFI transaction in June 2001.

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 Norwegian kroner 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.

The financing of the SDFI assets acquired in 2001 was done through the application of accumulated cash and cash equivalent instruments, existing note programs, some new long-term loans and the proceeds from the initial public equity offering. The proceeds from the offering were used to repay a temporary, subordinated loan from the Norwegian State.

As of December 31, 2001, gross debt amounted to NOK 41.8 billion, comprising NOK 26.3 billion of US dollar borrowings, NOK 4.6 billion of euro borrowings and the remainder denominated in a variety of other currencies (before the effect of currency swaps), as compared to NOK 37.0 billion, comprising NOK 20.7 billion of US dollar and NOK 5.9 billion of euro borrowings, respectively, with the remainder denominated in a variety of other currencies as of December 31, 2000.

As of December 31, 2001, our available committed credit facilities totaled US$ 1.5 billion, equivalent to NOK 13.2 billion, under which US$ 0.3 billion, equivalent to approximately NOK 2.5 billion, had been drawn. These facilities were a syndicated revolving credit facility entered into by our Navion subsidiary in 1997 and available for drawdowns until December 2002, originally amounting to US$ 0.9 billion, but reduced to US$ 0.46 billion during 2001 and a US$ 1.0 billion syndicated revolving credit facility entered into by us in 2000 and available for drawdowns until November 2005. In addition, two lines of credit totaling EUR 242 million have been established in our favor on a bilateral basis by an international financial institution. Of this amount, EUR 200 million was established for our benefit in the name of our Belgian subsidiary and guaranteed by us. The other EUR 42 million is in our own name. These lines of credit, under which we may only draw down with at least 15 days notice, allow us to draw down amounts in tranches and repay them in time periods ranging from 4 to 15 years. Requests for drawdowns under the EUR 200 million line of credit may be delivered until December 1, 2002, and for the EUR 42 million line of credit, until December 1, 2002. As of December 31, 2001, no amounts had been drawn under either of these lines of credit.

Our borrowing needs are met through short-term and long-term capital market debt issues, including a US dollar commercial paper program and a euro medium-term note program and through drawdowns under committed credit facilities and credit lines. In 2001, US$ 250 million of two-year floating rate notes were issued under our euro medium-term note program. US$ 100 million with a five-year term were borrowed under a bilateral agreement with a European bank. Two loans amounting to JPY 5 billion each and with final maturities of five and seven years, respectively, were borrowed from Japanese life insurance companies. After the effect of currency swaps, our borrowings are almost exclusively in US dollars. 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. As of December 31, 2000, our long-term debt portfolio totaled NOK 34.2 billion with a weighted average maturity of approximately 13.3 years and a weighted average interest rate of approximately 6.2% per annum. These amounts primarily consisted of NOK 30.5 billion for 2000 and NOK 33.3 billion for 2001 of capital market debt, with maturities from 2002 and 2003 respectively to 2029. Our debt strategy considers funding sources, maturity profile, currency mix, interest rate risk management instruments and the liquidity reserve, and we use a multi-currency liability model (MLM) to identify 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 manage our foreign currency exposures with the objective of optimizing our debt portfolio based on underlying cash flow. In accordance with a revision of our debt strategy during 2001, our borrowings are mainly denominated in or have been swapped into US dollars because the most significant part of our net cash flow before tax is in US dollars. In addition, we manage our interest rate exposures through the use of interest rate derivatives, primarily interest rate swaps, based on an agreed range for the interest reset profile of our total loan portfolio.

New borrowings totaled NOK 9.6 billion in 2001 and NOK 1.2 billion in 2000. We repaid approximately NOK 4.5 billion in 2001 and NOK 13.3 billion in 2000. At December 31, 2001, NOK 5.4 billion of our borrowings was due for repayment within one year, NOK 2.3 billion was due for repayment between one and two years, NOK 6.3 billion was due for repayment between two and five years and NOK 26.6 billion was due for repayment after five years, as compared to NOK 2.8 billion, NOK 2.8 billion, NOK 5.3 billion and NOK 26.2 billion, respectively, as of December 31, 2000.

The following table summarizes our principal contractual obligations at December 31, 2001. The table below only includes the contractual obligations, which are described in the consolidated financial statements. All other contractual obligations such as derivatives and other hedging instruments are excluded. 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	40,546	5,364	6,691	2,085	26,406
Finance lease obligations	71	23	20	20	8
Operating leases	16,647	4,174	5,048	3,486	3,939

Contractual obligations in respect of capital expenditure amount to NOK 14,116 of which payments of NOK 8,475 are due within one year.

The following table summarizes our principal commercial commitments at December 31, 2001.

		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	80.5	14.4	66.1	-	-

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 (with a view toward portfolio optimization) in cooperation with our corporate risk management department, and we use a number of derivative instruments, which are transacted by specialist treasury personnel. The internal control is reviewed regularly for risk assessment by 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, 2001, 2000, and 1999 was 3.0%, 3.1% and 2.3% 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). Statoil's estimates have in all materiality been verified by an independent third party. 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 Statements 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 have found 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 it is decided not to perform any further exploration work in the near future.

Leasehold acquisition costs are periodically assessed to determine whether they have been impaired. This assessment is made 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.

New Accounting Pronouncements

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement No. 133 (FAS 133), "Accounting for Derivative Instruments and Hedging Activities". The Statement requires us to recognize all derivatives on the balance sheet at fair value. Derivatives that are not hedges must be adjusted to fair value through income. As a result of the adoption of FAS 133 on January 1, 2001, we recorded during the first quarter ended March 31, 2001 a NOK 2 million net expense in net financial items in the Consolidated Statement of Income due to the immateriality of the transition adjustment. No transition adjustment was required to be recorded in other comprehensive income related to cash flow hedges.

New Accounting Standards issued, not yet adopted

In June 2001, the FASB issued FAS 141, Business Combinations, and FAS 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. We adopted FAS 141 and FAS 142 as of January 1, 2002 and do not expect that the adoption of the Statements will have a significant impact on our financial position and results of operations.

In June 2001, the FASB issued FAS 143, Accounting for Asset Retirement Obligation, effective for fiscal years beginning after June 15, 2002. Under the new rules, asset retirement obligations have to be recorded at fair value at the time of acquisition/construction. A corresponding amount has to be included in the cost of the related asset, and depreciated over the useful life of the asset. We will apply the new rules on accounting for asset retirement obligations beginning in January 2003, and a cumulative adjustment will be recorded as a transition effect in the Income Statement in the first quarter of 2003. The Company has not yet estimated the impact of the new standard.

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 Company adopted FAS 144 as of January 1, 2002 and does not expect that the adoption of the Statement will have a significant 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.

Internal auditors are responsible for monitoring compliance with the strategic market risk policy which the Corporate Risk Committee develops and implements, as well as for monitoring compliance with indicators adopted for measuring the tolerable risk level, the consistency in trading methodologies and the portfolio of financial instruments and market conditions.

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 managed 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 Risks

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

Tactical Risks

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 and market swaps related to crude oil and petroleum products. Futures contracts have little credit risk because organized exchanges are the counter-parties. The credit risk from Statoil's OTC derivative contracts derives from the counter-party to the transaction. Brent forwards, other forwards, swaps and other OTC instruments are traded subject to internal assessment of creditworthiness of counter-parties, which are primarily oil and gas companies and well known trading companies. Credit risk related to commodity-based instruments is managed by maintaining, reviewing and updating lists of authorized counter-parties by assessing the financial position, by frequent monitoring of credit exposure for counter-parties, and by requiring collateral, guarantees or cash deposits when appropriate under contracts and internal policies. Derivatives associated with crude oil and oil products are traded mainly on the International Petroleum Exchange in London, the New York Mercantile Exchange, in the OTC Brent market, and in crude and refined products swaps markets. Derivatives associated with natural gas are mainly OTC physical forwards and options.

We are also subject to interest rate risk and foreign exchange risk. Interest rate risk and currency risk are assessed against mandates which are developed and issued by our Chief Financial Officer and passed on to our Finance Director and 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 operating results. Our cash flows are largely in currencies other than Norwegian kroner, while cash receipts in connection with oil and gas sales are mainly in foreign currencies and cash disbursements are to a great extent in Norwegian kroner. Accordingly, our exposure to foreign currency rates exists primarily with US dollars versus Norwegian kroner, Danish kroner, Swedish kroner and euro. 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.

All tactical risk management activities occur within established internal mandates and stop-loss programs. All trading in connection with tactical risk management is transacted by specialist personnel, with additional support from our internal accounting and other departments.

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

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, 2001, approximately 73% of the approximately NOK 104 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 through various insurance products, financial products or combinations of such products.

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 633 million, NOK 656 million and NOK 718 million in 2001, 2000 and 1999, 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 involve as much as NOK 5 billion. 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:

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

Average capital employed reflects a simple average of capital employed at the beginning and end of the financial period. Our historic ROACE for 1999, 2000 and 2001 was 6.4%, 18.7% and 19.9%, respectively.

For purposes of measuring our performance against our ROACE targets, we are assuming an average realized oil price of US$ 16 per barrel and an equivalent natural gas price (calculated using year 2000 US dollars). Under the same price assumptions, we are targeting a 12% ROACE by 2004. In 2000, using an oil price assumption of US$ 16 and an equivalent natural gas price assumption, the ROACE was 9.9%, or 9.2% adjusted on a pro forma basis for our transfer of assets to the Norwegian State. For the year ended December 31, 2001, our ROACE was 10.3% based on an oil price of US$ 16 and an equivalent natural gas price. In order to achieve our target ROACE by 2004, we will need to allocate capital only to those projects that meet our strict financial return criteria of having a positive net present value 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.

While continuing to focus on our overall objective of strict capital discipline, we believe that the completion of our 2001 improvement program, our organic production growth and enhanced operating efficiencies will help us reach our 12% ROACE target. First, through the effects of our 2001 improvement program we have achieved cost savings in 2001 as part of our overall improvement program, which amounted to NOK 1.4 billion compared with year 2000. In addition, our planned portfolio restructuring was carried out, including the sales of our interests in the Kashagan oil field in Kazakhstan, the sale of our activities in Vietnam, the sale of the FPSO subdivision in Navion, the sale of our interest in the refinery in Melaka, Malaysia, as well as sale of certain licences on the NCS. We anticipate that these divestments will further reduce our costs and capital employed as the divestments made in 2001 will fully affect our average capital employed from 2002 going forward. On the other hand, the full effect of the transfer of certain assets to the Norwegian State will have a negative impact on our ROACE from 2002 and onwards.

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

- improving unit production costs; our target is to reduce unit production costs from 2.9 US$/boe in 2001 to lower than 2.8 US$/boe in 2004;
- reducing finding and development costs; our target is to reduce finding and development costs (3 years average) from 9.1 US$/boe in 2001 to below 6.0 US$/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 and our Nordic Energy operations.

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

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, for purposes of measuring our target ROACE, 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, refinery and retail margin, polyolefin margins, fluctuations in the US dollar/Norwegian kroner exchange rate, 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 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.

SEGMENT	YEAR ENDED DECEMBER 31, 1999		2000		2001	
(AMOUNTS IN MILLION, EXCEPT PERCENTAGE DATA)	NOK	%	NOK	%	NOK	%
E&P Norway	27,448	68.0	12,992	59.0	10,759	60.0
International E&P	6,644	16.4	5,070	23.0	5,027	28.0
Natural Gas	1,810	4.5	810	3.7	671	3.7
Manufacturing and Marketing	4,085	10.1	2,860	13.0	811	4.5
Other	413	1.0	300	1.3	685	3.8
Total	40,400	100	22,032	100	17.953(1)	100

(1) Gross investments, which represent cash flow spent on property, plant and equipment and capitalized exploration expenditures, amount to NOK 17,414 million.

The table below sets out for our four principal business segments (i) our approximate expected capital expenditures for 2002 and (ii) our current aggregate estimates 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. We have set forth these expenditure plans and estimates for each segment as a percentage of our total capital expenditure for the relevant period.

Our opportunities and projects under consideration could be sold, delayed or postponed in implementation, reduced in scope or rejected, especially in light of the restructuring and asset trading opportunities available to us as a result of the SDFI asset purchase from the Norwegian State. Accordingly, the figures for 2002-2004 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.

SEGMENT	APPROXIMATE EXPECTED CAPITAL EXPENDITURE FOR 2002		ESTIMATES OF POTENTIAL CAPITAL EXPENDITURE FOR OPPORTUNITIES AND PROJECTS IN 2003-2004	
(AMOUNTS IN MILLION, EXCEPT PERCENTAGE DATA))	NOK	%	NOK	%
E&P Norway	12,800	51.2	21,300	41.0
International E&P	8,000	32.0	23,600	45.4
Natural Gas	600	2.4	2,400	4.6
Manufacturing and Marketing	3,100	12.4	3,500	6.7
Other	500	2.0	1,200	2.3
Total	25,000	100	52.000	100

Year 2002

E&P Norway. We expect that we will have capital expenditures totaling NOK 12.8 billion in 2002. We expect the capital expenditure to be concentrated on the Kvitebjørn, Mikkel, Sigyn, Snøhvit and Kristin development projects and on drilling of production wells in the producing fields in our core areas Tampen, Halten/Nordland,Troll/Sleipner and Tromsøflaket. For a discussion of our various development projects, see Item 4—Information on the Company —Business Overview—Operations—Exploration and Production Norway.

International E&P. We expect that we will have capital expenditures totaling NOK 8.0 billion in 2002. We expect the capital expenditure to be concentrated in Venezuela, Azerbaijan, Angola and Ireland for our ongoing projects, Kizomba A, Sincor, Azeri-Chirag-Gunashli and Corrib respectivelyFor a discussion of our various projects in these areas, see Item 4—Information on the Company—Business Overview—Operations—International Exploration and Production.

***Natural Gas**.* We expect that we will have capital expenditures totaling NOK 0.6 billion in 2002. We are focusing our capital expenditure on the construction of the Dublin Bay Power Plant in Ireland.

Manufacturing and Marketing. We expect that we will have capital expenditures totaling NOK 3.1 billion in 2002. We are focusing our capital expenditure on maintaining our assets, expanding our retail network in Poland and upgrading the Mongstad refinery to increase flexibility and meet expected EU and US refined product environmental requirements and environmental investment regarding the shuttle-tankers operated by Navion.

Years 2003 - 2004

E&P Norway. Based on our current business plan, we estimate that E&P Norway's investment opportunities and other capital projects could require NOK 21.3 billion over the period 2003-2004. We currently estimate that the substantial portion of our 2003-2004 capital expenditure may be allocated to the 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 investment opportunities and other capital projects could require NOK 23.6 billion over the period 2003-2004. We currently estimate that the substantial portion of our 2003-2004 capital expenditure may be allocated to the ongoing and planned development projects: Azeri-Chirag-Gunashli including the Baku-Tbilisi-Ceyhan pipeline, Shah Deniz including the Shah Deniz pipeline, Dalia, Kizomba A and B, Agbami/Ekoli 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's investment opportunities and other capital projects could require NOK 2.4 billion over the period 2003-2004. We expect to focus our capital expenditure on increasing the capacity and flexibility of our gas transportation and processing infrastructure through several projects under consideration such as an expansion of the Kårstø processing plant, the Baltic pipeline and the Netra pipeline.

Manufacturing and Marketing. We estimate that Manufacturing and Marketing's investment opportunities and other capital projects could require NOK 3.5 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 Mongstad refinery to increase flexibility and meet expected EU and US refined product environmental requirements.

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

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

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 consists of a minimum of five and a maximum of 11 members. Currently, we have 10 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 current board of directors (excluding employee representatives) has been elected by the general meeting. In the future, the board of directors will be elected by the corporate assembly. The current term of office for the directors appointed by the general meeting expires in April 2003, other than Jerome Contamine, whose term of office expires in August 2002. The current term of office for the directors elected by the employees expires in April 2002. However, regardless of the individual board members´ original term of office, it is planned to arrange an election of board members after the corporate assembly has been elected in the spring of 2002.

There are no directors' service contracts which 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*
Ole Lund	Oslo, Norway	67	Chairman
Knut Åm	Edinburgh, Scotland	58	Director
Kirsti Koch Christensen	Bergen, Norway	61	Director
Finn A Hvistendahl	Oslo, Norway	60	Director
Ingvar M Sviggum	Cologne, Germany	57	Director
Jerome Contamine	Paris, France	44	Director
Ellen Stensrud	Lørenskog, Norway	48	Director
Lill-Heidi Bakkerud(1)	Porsgrunn, Norway	39	Director
Stein Bredal(1)	Stavanger, Norway	52	Director
Marit Bakke(1)	Bergen, Norway	36	Director

(1) Elected by the employees.

Ole Lund has served as the chairman of the board of directors since April 1999. Mr. Lund is currently a partner in BAHR law firm in Oslo. Previously, he was chairman of Den norske Bank ASA and the Oslo Stock Exchange. He has also been the managing director of Nordisk Skibsrederforening from 1978 to 1986. Currently, Mr. Lund is also chairman of the board of directors of Norsk Medisinaldepot, Nordisk Språkteknologi AS and Eckbos legater and deputy chairman in Schibsted ASA. Ole Lund has announced that he will retire from his position as Chairman of the board at the annual general meeting in May 2002.

Knut Åm was elected to the board of directors in April 1999. Mr. Åm is a former Vice President of Phillips Petroleum and lives in Edinburgh, Scotland. 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.

Kirsti Koch Christensen was elected to the board of directors in April 1999. Ms. Christensen is currently a professor and the University Vice Chancellor at the University of Bergen, Norway and was recently elected Chairman of the Norwegian Council of Higher Education. From 1992 to 2000, Ms. Christensen was a member of the board of the Norwegian Research Counsel.

Finn A Hvistendahl was elected to the board of directors in April 1999. Mr. Hvistendahl is a business development consultant in Oslo. Previously, he held senior positions in Norsk Hydro and was chief executive of Den norske Bank ASA. Currently, he is Chairman of the board of directors of Kredittilsymet (The Banking, Insurance and Securities Commission of Norway) and efinans.no, and a director of Alcatel STK ASA and Dyno Nobel AS.

Ingvar M Sviggum was elected to the board of directors in April 1999. Mr. Sviggum is Vice President of European Sales Operations at Ford of Europe Inc. in Germany. Since 1985, Mr. Sviggum has held prominent positions in the Ford Group. Currently, he is a member of the board of directors of THINK Nordic and Global Think Group.

Jerome Contamine was elected to the board of directors in August 2000. He is the Executive Vice President and Chief Financial Officer of Vivendi Environnement. Mr. Contamine is the former President of Elf Norway and has held other prominent positions with the Elf Group since 1988.

Ellen Stensrud was elected to the board of directors in August 2000. Mrs. Stensrud is the Head of Information at the Norwegian Confederation of Trade Unions.

Lill-Heidi Bakkerud was elected to the board of directors in March 1998, re-elected to the board in April 2000 and has served since that time as an employee-elected representative to the board. Ms. Bakkerud is the full-time union official for Statoil for the Norwegian Oil and Petrochemical Workers Union. She trained as a process technician and worked at the petrochemical complex in Rafnes and on the Gullfaks field.

Stein Bredal was elected to the board of directors in April 2000 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.

Marit Bakke was elected to the board of directors in April 2000 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.

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	50	President and Chief Executive Officer
Inge K Hansen	Oslo, Norway	56	Chief Financial Officer and Executive Vice President, Corporate Center and Services
Henrik Carlsen	Bergen, Norway	55	Executive Vice President, Exploration and Production–Norway
Richard John Hubbard	Sevenoaks, England	51	Executive Vice President, International Exploration and Production
Peter Mellbye	Stavanger, Norway	52	Executive Vice President, Natural Gas
Erling Øverland	Stavanger, Norway	49	Executive Vice President, Manufacturing and Marketing
Elisabeth Berge	Stavanger, Norway	47	Executive Vice President, Communications & Public Affairs
Morten Loktu	Trondheim, Norway	41	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 of Borealis and Navion. 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.

Morten Loktu has served as Executive Vice President of Technology since 1999. He was employed at Statoil in the period from 1985 to 1989. From 1990 to 1991 he was Vice President, Manufacturing at Servi Hydraulikk AS. Since 1992 Mr. Loktu has again been employed at Statoil, serving as Research and Development Director from 1998 to 1999, as Vice President in charge of implementation of SAP R/3 and common administrative processes from 1996 to 1998 and as R&D Director from 1992 to 1996. He received his MS from the University of Trondheim in 1984.

Corporate Assembly

Our corporate assembly consists of 12 members. The general meeting elects 8 members, and our employees elect an additional 4 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 yearly 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 2002.

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

NAME	*PLACE OF RESIDENCE*	*AGE*	*POSITION*
Leif T Løddesøl	Oslo, Norway	67	Chairman of the board Wilh Wilhelmsen ASA
Wenche Meldahl	Stavanger, Norway	57	Chief Executive Officer, Øglend A/S
Kjell Bjørndalen	Skotselv, Norway	55	Chairman of the Norwegian Trade Union, Fellesforbundet
Jorunn Strand Vestbø	Finnøy, Norway	56	Mayor, Municipality of Finnøy
Asbjørn Rolstadås	Trondheim, Norway	58	Professor at NTNU (Technical and Scientific Universityof Norway-Trondheim), Norway
Tove Bull	Tromsø, Norway	56	Professor at University in Tromsø
Margrethe Riple Ådland	Haus, Norway	54	Adviser
Jens A Brødsjømoen	Drangedal, Norway	44	Chief, Accounting Services, Norcem
Arvid Færaas	Vormedal, Norway	39	Union official
Hans M Saltveit	Stavanger, Norway	30	Union official
Per Helge Ødegård	Porsgrunn, Norway	39	Process technician, Statoil
Einar Arne Iversen	Stavanger, Norway	39	Union official

Compensation

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

In 2001, total remuneration of NOK 307,000 was paid to the members of the corporate assembly, NOK 1,700,000 to the board of directors and NOK 15,576,000 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 3,188,000 in 2001. Starting from 2002, Mr. Fjell will be entitled to a bonus limited to 30% of base salary. Payment of the bonus will depend 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 will evaluate the performance and results achieved by the CEO and decide the amount to be paid as a bonus.

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. The board intends to develop this scheme further, including a potential share incentive program.

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.

Employee Incentive Plan

Statoil ASA has implemented a common bonus scheme for its employees as of the year 2001. 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, 2001, we had 16,686 employees, of whom we employed 10,994 in Norway. The remaining 5,692 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 1999, 2000 and 2001, and the numbers of employees by country.

	NUMBER OF EMPLOYEES								
	DECEMBER 31, 1999			*DECEMBER 31, 2000*			*DECEMBER 31, 2001*		
	NORWAY	*OUTSIDE NORWAY*	*TOTAL*	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
E&P Norway	4,091	0	4,091	5,452	0	5,452	5,603	0	5,603
International E&P	224	929	1,153	247	234	481	276	245	521
Natural Gas	724	146	870	807	163	970	844	130	974
Manufacturing and Marketing	1,915	4,488	6,403	1,780	5,099	6,879	1,744	5,262	7,006
SDFI	21	0	21	20	0	20	5	0	5
Other Operations	4,579	67	4,646	2,547	59	2,606	2,522	55	2,577
Total	**11,554**	**5,630**	**17,184**	**10,853**	**5,555**	**16,408**	**10,994**	**5,692**	**16,686**

We launched a downsizing program in 1999 and again in 2000. The change in Other Operations between 1999 and 2000 was due to the fact that resources were moved out of the technology unit and into the business segments. 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 in 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 are scheduled to be renewed in 2002. 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 as of March 15, 2002 is shown below. Board members and members of the executive committee, including closely related parties, who own shares are set forth below.

BOARD OF DIRECTORS	*NO. OF SHARES OWNED AS OF MARCH 15, 2002*
Ole Lund	1,460
Knut Åm	14,520
Finn A Hvistendahl	2,910
Ingvar M Sviggum	2,000
Lill-Heidi Bakkerud	150
Stein Bredal	150
Marit Bakke	150

EXECUTIVE COMMITTEE	*NO. OF SHARES OWNED AS OF MARCH 15, 2002*
Olav Fjell	7,290
Inge K Hansen	7,290
Henrik Carlsen	1,130
Richard John Hubbard	1,130
Peter Mellbye	1,130
Erling Øverland	2,240
Elisabeth Berge	1,490
Morten Loktu	1,130

Members of the corporate assembly own a total of 1,650 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, 2001. The State did not buy or sell any shares in the period from December 31, 2001 to March 15, 2002. We have not been notified of any other beneficial owner of 5% or more of our ordinary shares as per March 15, 2002.

	NUMBER OF SHARES	*% OF SHARES*
Kingdom of Norway	1,770,168,598	80.84 (1)

(1) Based upon 2,164,585,600 ordinary shares outstanding and 25,000,000 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 15, 2002, there were 13,488,951 ADRs outstanding (representing approximately 0.62% of the outstanding ordinary shares). As of March 31, 2002 there were 105 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 owns 80.84% of the shares of Statoil. This percentage is 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 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, will be 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 State's Direct Financial Interest (SDFI). As a part of the Norwegian State's recent decision 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 has 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. See Item 5–Operating and Financial Review and Prospects–Liquidity and Capital Resources–Liquidity.

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.

New SDFI Management Company

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.

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 natural 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 which may last until July 1, 2002. During this transition period, Petoro AS will gradually assume all management functions related to the SDFI. Pursuant to the terms of the contract, Petoro AS reimburses us for our expenses associated with our management role activities during the transition period, including employee and overhead costs.

New Gas Transportation Operating Company

In connection with the restructuring of the Norwegian State's oil and gas interests, the Norwegian State established on May 14, 2001 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 have, with effect as of January 1, 2002, 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.

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.

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 US$1 billion Multicurrency Revolving Credit and Swingline Facility. This facility, entered into on November 24, 2000, is coordinated by Barclays Capital and Barclays Bank Plc acts as Facility and Swingline Agent. Den norske Bank ASA's total commitment under the program is US$ 58,750,000, of which US$ 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 77.68% interest. Such purchases are made pursuant to standard tariff rates applicable to public and private companies in Norway. Other than the relationships described above, we and our business segments do not, individually or in the aggregate make significant purchases of goods and services from this or other companies controlled by the Norwegian State. These sales are also negotiated on an arm's-length basis.

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 2001, we sold 211,066 tonnes of LPG under this contract for an approximate consideration of NOK 378 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 2001, we sold 490,022 tonnes of ethane under this contract for an approximate consideration of NOK 673 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 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. The products are delivered by us 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. The initial term of the agreement is three years. In 2001, we received NOK 16.6 billion, of which NOK 11. billion were excise taxes, pursuant to this Fuel Supply Agreement.

Other Transactions with the Norwegian State

Total purchases of oil from the Norwegian State amounted to NOK 50,987 million, NOK 39,185 million and NOK 22,293 million in 2001, 2000 and 1999, 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

Executive vice presidents, Henrik Carlsen, Elisabeth Berge and Morten Loktu have interest-free car loans of NOK 63,000, NOK 120,000 and NOK 256,000, respectively. These loans have a repayment period of 10 years.

No other members of the executive committee, the board of directors, or the corporate assembly have any private loans from Statoil.

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 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.

In addition, some of our employees are also eligible for an interest-free car loan. The loan is limited to the price of the car purchased, and is capped at NOK 200,000, NOK 325,000 or NOK 425,000, depending on the seniority of the employee.

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 has 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 dispute the allegations made in the statement of objections and are defending our position vigorously. We believe we have substantial defenses.

The Norwegian Government has publicly announced that it opposes the statement of objections issued by the European Commission and has been accepted as an interested third party in the case. The Norwegian government submitted its written intervention at the end of October 2002, where it pleaded that the system for sale of natural gas from the NCS was a compulsory system established by the Norwegian authorities in accordance with Norwegian law and that the EU/EEA competition laws thus were not applicable.

Statoil responded in writing to the statement of objections at the end of October 2001. In December 2001 an oral hearing was arranged by the Commission. In the oral hearing, representatives from the Norwegian government and all companies having received the statement of objections made oral pleadings in the case. The Commission has not yet rendered a decision.

If the Commission finds that a company has infringed EU/EEA competition laws it may adopt a decision requiring the companies concerned to bring the alleged infringement to an end and, in appropriate cases, requiring the company to take action to remedy any adverse effects of the alleged infringement. The Commission may also impose a fine upon each of the companies concerned up to a maximum of 10% of the worldwide revenues in the preceding financial year of the group to which the company belongs.

The timing and outcome of the proceedings, including any appeals, are uncertain at this time. The Commission's statement of objections states that it seeks to prohibit us and other companies producing natural gas on the NCS from selling gas from the NCS under the former arrangements for the sale of this gas (including the activities of the GFU) and to impose fines on us. The Commission's statement of objections also states that it seeks to require us to offer customers with existing gas sales agreements (including long-term take-or-pay agreements) the opportunity to remain committed to the existing agreements or to renegotiate or terminate those agreements. Any finding of an infringement by us of the EC/EEA competition laws by the Commission or in other proceedings might also result in counter-parties to our gas sales agreements challenging the validity of those agreements and possibly claiming substantial damages.

If the Commission adopts a decision against us, we have the right to appeal that decision to the European Court of First Instance and a further right of appeal from that court to the European Court of Justice. The Court of First Instance may also be asked to suspend the operation of the Commission's decision pending the outcome of the appeal process. These proceedings through the courts could take at least four years before a final judgment is rendered.

In 1996 the European Commission, acting under powers given to it regarding the enforcement of the EC/EEA competition laws, commenced an investigation of the members of the GFU, including Statoil, relating to the arrangements for the sale of gas from the NCS, including the activities of the GFU. The Commission originally indicated that it was interested in pursuing a mutually acceptable settlement of this matter. It suggested that settlement would involve commitments by Norwegian gas producers to market gas individually in the future and to take remedial measures. Marketing gas on an individual basis would require a decision by the Norwegian State. The remedial measures proposed would have committed us to make available very substantial new volumes of gas for a five year period, with priority being given for sales to new customers and with a significant proportion of sales being made under an auction mechanism. Such proposal would have required us to make substantial new investments and/or renegotiate our existing agreements.

We discussed the Commission's proposal with the Norwegian State. The Norwegian State instructed us not to enter into such commitments as proposed as they are outside our competence to negotiate, and so informed the Commission.

Working closely with the Norwegian State, we engaged in further discussions with the Commission. We put forward an alternative proposal to the Commission which would have made available certain quantities of gas to new customers for a period. However, the Commission informed us that this proposal was not acceptable in terms of the quantities and the period and due to the absence of an auction mechanism. These negotiations ended with no agreed solution reached. Recently the European Commission has approached us about reopening such discussions.

Åsgard/Kårstø Arbitration.
On June 20, 2000, Norsk Agip A/S, Fortum Petroleum AS and Total Norge AS filed a claim for arbitration against us in connection with the construction of new facilities at the Kårstø terminal as part of the Åsgard development. The plaintiffs alleged that they, as participants in the Åsgard license, were overcharged by us as operator for the license. The claim for compensatory damages was limited to NOK 530 million and was based on their joint participating interest of 22.55%. The arbitration hearings began in Norway on October 2, 2001. On that same day, Total Norge AS withdrew from the proceedings, and the arbitration continued with the remaining two parties. On January 24, 2002, both Fortum Petroleum AS and Norsk Agip A/S also withdrew from the proceedings, thereby ending the arbitration. We do not expect any additional claims from the other Åsgard partners.

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.

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		*US$ 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

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.

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.

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. After completion of the Offering the Norwegian State will continue 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 which 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 European Economic Area 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 majority normally 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 majority required to approve amendments to our articles of association.

The general meeting may, with a majority 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 offer or 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. In practice, we expect that nominations will be proposed by our management and directors and placed before the meeting by the chairman of the meeting. 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. 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 members) may be removed at any time by the corporate assembly without cause.

The corporate assembly makes decisions by majority vote, and more than half 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 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 members of 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 to not pursue claims is made by such a majority as is 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 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. However, in accordance with Norwegian law, the Norwegian Ministry of Trade and Industry must be notified upon the acquisition of shares or other ownership interests in companies in Norway, including us, which exceeds certain thresholds if a purchaser or group of purchasers acting in concert, regardless of nationality, becomes the owner of shares, other ownership interests or voting rights which, in the aggregate, meet or exceed the respective thresholds of one-third, one-half or two-thirds of the shares, other ownership interests or voting rights in such company. For acquisitions requiring this notification, the Norwegian Ministry of Trade and Industry may refuse to approve the acquisition or may approve it subject to certain conditions. These notification requirements apply to the acquisition of 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.

The Norwegian government appointed last year a commission to evaluate the Norwegian tax system. According to the commissions mandate a report shall be delivered during 2002. It is difficult to predict the substance of any new legislation that may be the result of the proposals of the commission.

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 acquiring, 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, but 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.

Alternatively, you may elect to claim a US tax deduction, instead of a foreign tax credit, for such Norwegian tax, but only for a year in which you elect to do so with respect to all foreign income taxes.

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, and 18% where the property has been held for more than five years. 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 has established an Enterprise-Wide Risk Management Program which establishes guidelines for entering into 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 well as Value at Risk (VaR). All amounts are in NOK million.

AT DECEMBER 31, 2001	*FAIR MARKET VALUE ASSET*	*FAIR MARKET VALUE LIABILITY*	*10% SENSITIVITY*	*VAR*
Crude Oil and Refined Products	1,074	(684)	484	84
Natural Gas and Electricity	1,163	(862)	59	3

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, which represent a significant part of the fair market values of Natural Gas and Electricity derivatives included in the table, is normally three years or less.

The following table contains the fair values and related price risk sensitivities for commodity based derivatives for the period prior to implementing Statement of Financial Accounting Standard 133. All amounts are in NOK million.

AT DECEMBER 31, 2000	*FAIR MARKET VALUE*	*10% SENSITIVITY*
Crude Oil and Refined Products	323	165
Natural Gas and Electricity	503	13

Price risk sensitivities for 2001 and 2000 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 fair value of our derivative portfolio would typically change less than that shown 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.

Value at Risk (VaR) was calculated using the "historical simulation method" with 95% confidence interval and one day horizon. The VaR figure indicates the least size of a negative change in fair market value that statistically should occur one out of 20 trading days. Included in these figures are commodity derivatives as well as physical positions. Options utilized to hedge certain crude production volumes and long-term physical delivery contracts for Natural Gas are not included in the VaR figure.

The increased sensitivity for Crude Oil and Refined Products from December 31, 2000 to December 31, 2001 is mainly related to derivatives used in price risk management of crude inventories and other crude price exposure and to the time value of options utilized to hedge certain crude production volumes.

The fair market value of certain closed-out positions that do not contribute to price risk sensitivity but remain exposed to credit risk have been included in the fair market value of Natural Gas and Electricity derivatives as at December 31, 2000. Such positions were excluded in the prior year's presentation, which only included the fair market value of derivative positions directly impacting the price risk sensitivity.

A 10% relative change of certain underlying commodity prices in relation to other prices would typically yield other sensitivities than those provided 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.

The fair market values of the futures and exchange-traded option contracts are based on quoted market prices obtained from the New York Mercantile Exchange or the International Petroleum Exchange of London. The fair values of swaps and other over-the-counter arrangements are estimated 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 on 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 where market prices are not available. 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 certain assumptions used.

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 the strategies and mandates issued by the Enterprise-Wide Risk Management Program. Interest rate risk and currency risk are assessed against mandates on a regular basis. The fair market value assets and liabilities, respectively, related to our fixed interest long-term debt, interest rate swaps and currency swaps were NOK 602 million and NOK 36,318 million as of December 31, 2001, and the net fair market value was NOK 32,769 million as of December 31, 2000. Fair market values are estimated based on quoted market prices, estimates obtained from brokers, prices of comparable instruments, and other appropriate valuation techniques.

Credit risk from interest rate swaps and currency swaps, which are over-the-counter transactions, derive from the counterparties to these transactions. Counterparties are highly rated financial institutions. The credit rating and counterparty exposure is monitored on a continuous basis. 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 estimated loss associated with a 10% adverse change in Norwegian kroner currency rates would result in a loss of fair value of approximately NOK 5 billion and NOK 4.5 billion as of December 31, 2001 and 2000 respectively. A hypothetical one percentage point adverse change in interest rates would result in a loss of NOK 1.2 billion and NOK 1.1 billion related to interest bearing liabilities, investments in debt securities and related financial instruments as of December 31, 2001 and 2000 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 Norwegian kroner, 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 for 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 other risk correlations.

FAIR MARKET VALUE AT DECEMBER 31, AMOUNTS IN NOK MILLION	*2001*	*2000*
Equity securities	1,598	1,816

MARKET RISK ON EQUITY SECURITIES, AMOUNTS IN NOK MILLION	*2001*	*2000*
10% change in share prices	160	182

The following related Value at Risk figure is based on 95% confidence interval and a 30-day horizon.

Value at Risk at December 31, 2001, amount in NOK million	128

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

Pursuant to Registration Statement No. 333-13502, effective June 18, 2001, we conducted an initial public offering of our ordinary shares of NOK 2.50 par value, with DnB Markets, Morgan Stanley Dean Witter and UBS Warburg as joint global coordinators. We sold 188,700,00 ordinary shares at an aggregate price of approximately NOK 13 billion (US$ 1.4 billion). We incurred underwriting expenses of NOK 202 million (US$ 21.9 million[1]) and total expenses of NOK 332 million (US$ 36 million) which were paid directly or indirectly to the joint global coordinators and other advisors in addition to expenses related to marketing and sale of the shares.

We received net proceeds, net after taxes, of approximately NOK 12.9 billion (US$ 1.4 billion) in the offering. The net proceeds were used towards repayment of the NOK 13.6 billion subordinated loan from the Norwegian State that was used partially to fund our acquisition of the SDFI assets.

(1) US dollar amounts have been translated for your convenience based on the noon buying rate on June 18, 2001 of NOK 9.2140 per US dollar.

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, (English translation) (Incorporated by reference to Statoil's Registration Statement on Form F-1, filed on May 14, 2001) (File no. 333-13502).
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 Services Agreement between Gassco AS and Statoil ASA, dated February 27, 2002.
Exhibit 4(a)(ii)-(iii)	Statoil hereby incorporates by reference Exhibits 10.1 and 10.3 of 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 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:/s/ INGE K HANSEN

Inge K Hansen
Chief Financial Officer

Date: April 5, 2002

Appendix A – Report of DeGolyer and MacNaughton

DeGolyer and MacNaughton
4925 Greenville Avenue, Suite 400
One Energy Square
Dallas, Texas 75206

March 11, 2002

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, 2001, of certain properties in Angola, Azerbaijan, China, Denmark, Norway, Ireland, the United Kingdom, and Venezuela owned by Statoil ASA (STATOIL). The estimates are discussed in our "Report as of December 31, 2001 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, 2001, 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, 2001, 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)
1,963	12,985	4,277

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, 2001, 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)
1,974	13,044	4,298

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

TABLE OF CONTENTS

To the Board of Directors and Shareholders of Statoil ASA

Report of independent auditors

We have audited the accompanying consolidated balance sheets of Statoil ASA and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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, 2001 and 2000, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

Stavanger, February 18, 2002
ERNST & YOUNG AS

/s/ Gustav Eriksen
Gustav Eriksen
State Authorised Public Accountant
(Norway)

/s/ Jostein Johannessen
Jostein Johannessen
State Authorized Public Accountant
(Norway)

CONSOLIDATED STATEMENTS OF INCOME

(IN NOK MILLION, EXCEPT SHARE DATA)	*YEAR ENDED DECEMBER 31,* 2001	2000	1999
Sales	**231,087**	229,832	149,598
Equity in net income/(loss) of affiliates	**439**	523	(745)
Other income	**4,810**	70	1,279
Total revenues	**236,336**	230,425	150,132
Cost of goods sold	**(126,153)**	(119,469)	(79,508)
Operating expenses	**(29,547)**	(28,883)	(25,657)
Selling, general and administrative expenses	**(3,547)**	(3,891)	(6,688)
Depreciation, depletion and amortization	**(18,058)**	(15,739)	(17,579)
Exploration expenses	**(2,877)**	(2,452)	(3,122)
Total expenses before financial items	**(180,182)**	(170,434)	(132,554)
Income before financial items, income taxes and minority interest	**56,154**	59,991	17,578
Net financial items	**65**	(2,898)	1,431
Income before income taxes and minority interest	**56,219**	57,093	19,009
Income taxes	**(38,486)**	(40,456)	(12,856)
Minority interest	**(488)**	(484)	256
Net income	**17,245**	16,153	6,409
Net income per ordinary share	8.31	8.18	3.24
Weighted average number of ordinary shares outstanding	2,076,180,942	1,975,885,600	1,975,885,600

See notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEET

(IN NOK MILLION, EXCEPT SHARE DATA)	*AT DECEMBER 31,* *2001*	*2000*
ASSETS		
Cash and cash equivalents	**4,395**	9,745
Short-term investments	**2,063**	3,857
Cash, cash equivalents and short-term investments	**6,458**	13,602
Accounts receivable	**26,208**	29,871
Accounts receivable - related parties	**1,531**	2,177
Inventories	**5,276**	4,226
Prepaid expenses and other current assets	**9,184**	5,447
Total current assets	**48,657**	55,323
Investments in affiliates	**9,951**	10,214
Long-term receivables	**7,166**	8,165
Net property, plant and equipment	**126,500**	132,278
Other assets	**7,421**	7,669
TOTAL ASSETS	**199,695**	213,649
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	**6,613**	2,785
Accounts payable	**10,970**	15,266
Accounts payable - related parties	**10,164**	11,454
Accrued liabilities	**13,831**	11,228
Income taxes payable	**16,618**	14,877
Total current liabilities	**58,196**	55,610
Long-term debt	**35,182**	34,197
Deferred income taxes	**42,354**	43,331
Other liabilities	**10,693**	10,205
Total liabilities	**146,425**	143,343
Minority interest	**1,496**	2,480
Common stock (NOK 2.50 nominal value), 2,189,585,600 and 1,975,885,600 shares authorized and issued	**5,474**	4,940
Treasury shares - 25,000,000 shares	**(63)**	0
Additional paid-in-capital	**37,728**	45,628
Retained earnings	**6,682**	14,768
Accumulated other comprehensive income	**1,953**	2,490
Total shareholders' equity	**51,774**	67,826
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**199,695**	213 649

See notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(IN NOK MILLION, EXCEPT SHARE DATA)	*NUMBERS OF SHARES ISSUED*	*SHARE CAPITAL*	*TREASURY SHARES*	*ADDITIONAL PAID-IN CAPITAL*	*RETAINED EARNINGS*	*ACC OTHER COMPREHENSIVE INCOME*	*TOTAL*
At January 1, 1999	1,975,885,600	4,940	0	25,111	20,422	1,934	52,407
Comprehensive income							
Net income					6,409		6,409
Cumulative translation adjustment						(908)	(908)
Unrealized gain on investments						402	402
Total comprehensive income							5,903
Contribution from shareholder				4,648			4,648
Dividends					(6,853)		(6,853)
At December 31, 1999	1,975,885,600	4,940	0	29,759	19,978	1,428	56,105
Comprehensive income							
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
Comprehensive income							
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

Other comprehensive income amounts are net of income tax (expense)/benefit of NOK 84, (199) and (249) million at 2001, 2000 and 1999, respectively.

Dividends per share were NOK 26.69, NOK 10.81, and NOK 3.47 in 2001, 2000 and 1999, respectively. The dividends prior to the public offering are strongly affected by cash flows relating to the SDFI transaction.

Unrealized gain on investment relates to shares of Saga Petroleum which were considered available for sale, and subsequently sold in 1999. See note 4 "Significant Aquisitions and Dispositions" for further details.

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

(IN NOK MILLION)	*2001*	*YEAR ENDED DECEMBER 31,* *2000*	*1999*
OPERATING ACTIVITIES			
Consolidated net income	**17,245**	16,153	6,409
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Minority interest in income	**488**	484	(256)
Depreciation, depletion and amortization	**18,058**	15,739	17,579
Exploration costs written off	**935**	410	982
(Gains)/Losses on foreign currency transactions	**180**	1,643	(319)
Deferred taxes	**848**	1,222	(1,480)
Income taxes of transferred SDFI properties	**5,952**	14,109	4,731
(Gains)/losses on sales of assets and other items	**(4,990)**	637	(1,080)
Changes in working capital (other than cash)			
• (Increase) decrease in inventories	**(1,050)**	132	(120)
• (Increase) decrease in accounts receivable	**4,522**	(1,199)	(5,737)
• Increase in other receivables	**(1,543)**	(291)	(12,765)
• (Increase) decrease in short-term investments	**1,794**	(254)	2,518
• Increase (decrease) in accounts payable	**(3,852)**	(3,146)	12,778
• Increase (decrease) in other payables	**(1,629)**	9,427	5,065
Increase in other non-current obligations	**2,215**	1,686	1,305
Cash flows provided by operating activities	**39,173**	56,752	29,610
INVESTING ACTIVITIES			
Additions to property, plant and equipment	**(16,649)**	(17,292)	(27,772)
Exploration expenditures capitalized	**(765)**	(1,379)	(867)
Investments and loans granted	**(2,828)**	(3,343)	(2,985)
Repayment of long-term loans granted and other long-term items	**2,289**	0	0
Proceeds from sales of assets	**5,115**	6,000	6,636
Cash flows used in investing activities	**(12,838)**	(16,014)	(24,988)

See notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

(IN NOK MILLION)	*2001*	*YEAR ENDED DECEMBER 31,* *2000*	*1999*
FINANCING ACTIVITIES			
New long-term borrowings	**9,609**	1,191	13,365
Repayment of long-term borrowings	**(4,548)**	(13,258)	(5,371)
Distribution to minority shareholders	**(1,878)**	0	0
Ordinary dividend paid	**(5,668)**	(1,702)	(135)
Amounts paid to shareholder, related to SDFI properties	**(49,747)**	(19,661)	(6,718)
Capital contribution related to SDFI properties	**8,460**	0	0
Net proceeds from issuance of new shares	**12,890**	0	0
Net short-term borrowings, bank overdrafts and other	**(588)**	(1,730)	(2,278)
Cash flows used in financing activities	**(31,470)**	(35,160)	(1,137)
Net increase (decrease) in cash and cash equivalents	**(5,135)**	5,578	3,485
Effect of exchange rate changes on cash and cash equivalents	**(215)**	106	(25)
Cash and cash equivalents at beginning of year	**9,745**	4,061	601
Cash and cash equivalents at end of year	**4,395**	9,745	4,061
Interest paid	**3,793**	3,204	2,906
Taxes paid	**33,320**	16,614	5,716

See notes to the consolidated financial statements

Imputed income taxes related to the 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.

1. Organization and Basis of Presentation

Statoil ASA was founded in 1972, as a 100 percent 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 percent 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 2002. 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 percent. 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 percent ownership), are accounted for by the equity method.

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 duties 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.

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 management 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 license 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. Straight-line depreciation 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 license 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 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 (FAS 133), "Accounting for Derivative Instruments and Hedging Activities". 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. As a result of the adoption of FAS 133 on January 1, 2001 Statoil recorded during the first quarter ended March 31, 2001 a NOK 2 million net expense in net financial items in the Consolidated Statement of Income due to the immateriality of the transition adjustment. No transition adjustment was required to be recorded in other comprehensive income related to cash flow hedges.

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 original period of interest exposure, provided the designated liability continues to exist or is probable of occurring.

New Accounting Standards issued, not yet adopted

In June 2001, the FASB issued FAS 141, Business Combinations, and FAS 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 Company adopted FAS 141 and FAS 142 as of January 1, 2002 and does not expect that the adoption of the Statements will have a significant impact on the Company's financial position and results of operations.

In June 2001, the FASB issued FAS 143, Accounting for Asset Retirement Obligation, effective for fiscal years beginning after June 15, 2002. Under the new rules, asset retirement obligations have to be recorded at fair value at the time of acquisition/construction. A corresponding amount has to be included in the cost of the related asset, and depreciated over the useful life of the asset. The Company will apply the new rules on accounting for asset retirement obligations beginning in January 2003 and a cumulative adjustment will be recorded as a transition effect in the Income Statement in the first quarter of 2003. The Company has not yet estimated the impact of the new standard.

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 Company adopted FAS 144 as of January 1, 2002 and does not expect that the adoption of the Statement will have a significant 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, 2001, 2000 and 1999 is presented below.

(IN NOK MILLION)	*REVENUES*	*INCOME (LOSS) FROM EQUITY INVESTMENTS*	*DEPRECIATION, DEPLETION AND AMORTIZATION*	*INCOME BEFORE FINANCIAL ITEMS, INCOME TAXES AND MINORITY INTEREST*	*SEGMENT INCOME TAXES*	*SEGMENT NET INCOME*
Year ended December 31, 2001						
Third party	3,622					
Inter-segment	61,913					
Exploration and Production Norway	65,535	120	11,806	40,697	29,589	11,108
Third party	5,926					
Inter-segment	1,767					
International Exploration and Production	7,693	0	3,371	1,291	387	904
Third party	23,297					
Inter-segment	36					
Natural Gas	23,333	135	664	9,629	6,919	2,710
Third party	202,264					
Inter-segment	936					
Manufacturing and Marketing	203,200	187	1,855	4,480	1,305	3,175
Third party	788					
Inter-segment elimination	(64,652)					
Other	(63,864)	(3)	362	57	18	39
Total	235,897	439	18,058	56,154	38,218	17,936

(IN NOK MILLION)	*REVENUES*	*INCOME (LOSS) FROM EQUITY INVESTMENTS*	*DEPRECIATION, DEPLETION AND AMORTIZATION*	*INCOME BEFORE FINANCIAL ITEMS, INCOME TAXES AND MINORITY INTEREST*	*SEGMENT INCOME TAXES*	*SEGMENT NET INCOME*
Year ended December 31, 2000						
Third party	1,419					
Inter-segment	69,610					
Exploration and Production Norway	71,029	106	11,225	46,715	35,054	11,661
Third party	6,308					
Inter-segment	2,752					
International Exploration and Production	9,060	(33)	1,704	773	242	531
Third party	20,539					
Inter-segment	8					
Natural Gas	20,547	77	730	7,893	5,584	2,309
Third party	200,851					
Inter-segment	413					
Manufacturing and Marketing	201,264	321	1,734	4,559	1,271	3,288
Third party	785					
Inter-segment elimination	(72,783)					
Other	(71,998)	52	346	51	0	51
Total	229,902	523	15,739	59,991	42,151	17,840
Year ended December 31, 1999						
Third party	2,525					
Inter-segment	35,847					
Exploration and Production Norway	38,372	115	9,126	16,841	11,462	5,379
Third party	20,666					
Inter-segment	1,060					
International Exploration and Production	21,726	19	2,544	(1,995)	0	(1,995)
Third party	13,727					
Inter-segment	6					
Natural Gas	13,733	66	725	5,052	3,224	1,828
Third party	113,398					
Inter-segment	117					
Manufacturing and Marketing	113,515	(980)	4,646	(1,754)	0	(1,754)
Third party	561					
Inter-segment elimination	(37,030)					
Other	(36,469)	35	538	(566)	0	(566)
Total	150,877	(745)	17,579	17,578	14,686	2,892

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)	2001	YEAR ENDED DECEMBER 31, 2000	1999
Segment net income	17,936	17,840	2,892
Net financial items	65	(2,898)	1,431
Tax on financial items and other tax adjustments	(268)	1,695	1,830
Minority interest	(488)	(484)	256
Net income	17,245	16,153	6,409
Segment income taxes	38,218	42,151	14,686
Tax on financial items and other tax adjustments	268	(1,695)	(1,830)
Income taxes	38,486	40,456	12,856

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 petroleum products except natural 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)	ADDITIONS TO LONG-LIVED ASSETS	INVESTMENTS IN AFFILIATES	OTHER LONG-TERM ASSETS
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
Year ended December 31, 1999			
Exploration and Production Norway	27,448	89	77,792
International Exploration and Production	6,644	426	14,395
Natural Gas	1,810	962	12,595
Manufacturing and Marketing	4,085	7,514	23,683
Other	413	861	12,577
Total	40,400	9,852	141,042

Revenues by geographic areas

(IN NOK MILLION)	2001	YEAR ENDED DECEMBER 31, 2000	1999
Norway	205,401	178,509	111,837
Europe (excluding Norway)	30,798	36,201	23,131
United States	27,163	38,243	33,607
Other areas	8,880	13,784	6,065
Eliminations	(36,345)	(36,835)	(23,763)
Total revenues (excluding equity in net income/(loss) of affiliates)	235,897	229,902	150,877

Long-lived assets by geographic areas

(IN NOK MILLION)	2001	AT DECEMBER 31, 2000	1999
Norway	114,303	126,429	127,448
Europe (excluding Norway)	29,772	25,538	25,114
United States	70	20	1,141
Other areas	18,016	15,315	8,094
Eliminations	(11,717)	(9,170)	(11,171)
Total long-lived assets (excludes long-term deferred tax assets)	150,444	158,132	150,626

4. Significant Acquisitions and Dispositions

Until July 1999, Statoil owned 19% of the outstanding shares of Saga Petroleum ASA (Saga), an independent oil and gas company. In July 1999, Norsk Hydro ASA, through an agreement with Statoil and a tender offer, acquired 100% of Saga. In accordance with the terms of the transaction, Statoil contributed its existing shares of Saga and NOK 4.2 billion, to Norsk Hydro, in exchange for certain oil and gas producing licenses of Saga. Additionally, Norsk Hydro issued certain of its own shares for the remaining shares of Saga. Immediately preceding this transaction, Saga was considered an available for sale security, and carried at fair value on the Consolidated Balance Sheets. Statoil realized a gain on the divestiture of its shares in Saga of NOK 1.5 billion.

In 1999, Statoil sold 50% of the shares in Statoil Detaljhandel Skandinavia AS, a group of service stations in Scandinavia, to a third party. The transaction amounted to NOK 3.1 billion and resulted in a gain of NOK 1.2 billion. As such, Statoil Detaljhandel Skandinavia AS is considered an equity method affiliate from 1999 because Statoil owns 50% of its shares.

On January 1, 2000, Statoil exchanged 21% of its Mongstad Refinery in Norway for a 10% participation in a refinery in the Netherlands. The transaction is considered an exchange of minority interests of similar productive assets which does not culminate in the earnings process and as such has been recorded at book value with no gain or loss recognized. The book value of the assets exchanged was NOK 0.9 billion.

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.

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. This write-down is mainly due to a slower-than-expected reservoir repressurization resulting in a reduction in the projected volumes of oil recoverable during the remaining contract period of operation.

In 1999, a charge of NOK 2.5 billion before tax (NOK 1,8 billion after tax) was recorded in depreciation, depletion and amortization to write down certain downstream properties (primarily in the Manufacturing and Marketing segment) to fair value. The long-lived assets concerned are located in Europe with the most significant impact related to the Kalundborg Refinery in Denmark of NOK 1.8 billion. This write-down was a result of a reduction in the refinery's estimated economic life caused by expected stricter petroleum refining regulations.

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. Of the NOK 1,400 million provided in 1999, NOK 130 million was reversed in 2000 related to contracted future lease payments for rig capacity which contract was assumed by a third party. Also, in 2000, Statoil realized additional losses of NOK 200 million related to the ultimate disposition of specific assets. The amounts remaining in the provision at December 31, 2000 and December 31, 2001 were NOK 224 million and NOK 144 million respectively. The balance at December 31, 2001 relates primarily to future lease costs, credit risk associated with assets sold, and legal costs expected to be settled in 2002. These charges are classified as "Operating expenses" and relate to the International Exploration and Production segment.

Also, during 1999, Statoil recorded NOK 500 million for employee termination benefits for a company-wide staff reduction program affecting approximately 800 employees. Statoil is reimbursed for a part of the total restructuring costs from other partners in applicable upstream operations. Based on actual charges incurred, Statoil reversed approximately NOK 150 million of the accrual in 2000. In 2000, Statoil recorded an additional NOK 150 million for similar employee termination benefits as for the 1999 program which reduced the size of the staff by approximately 250 employees. The staff reductions programs affected primarily Norwegian-based employees and was implemented in many of Statoil's operating segments across several business functions. For the twelve months ended December 31, 2000 and December 31, 2001, NOK 160 million and NOK 247 million were charged against the provision. As of December 31, 2001, all employees related to the 1999 and the 2000 plans had been terminated. These charges are classified mainly as either "Operating expenses" or "Selling, general and administrative expenses".

In 1998, included in "Operating expenses" is a special charge of NOK 700 million for an expected loss on purchased drilling rig service contracts. 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. The contract periods for the rigs last from 1-6 years. The decline in world-wide 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. The charge is Statoil's best estimate of the loss between fixed drilling rig contracts and the estimated sub-contract market rates. In 1999, Statoil accrued an additional NOK 900 million due to an increase in the estimated loss on the purchased long-term fixed price drilling service contracts as a result of a further decline in the estimated subcontract rate on several drilling rigs. 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 end of 2002. During 1999, 2000 and 2001, NOK 468 million, NOK 172 million and NOK 76 million, respectively, of contract payments were charged against the provision. In 2001 NOK 150 million of the provision was reversed due to a reduction in the estimated contract loss. At December 31, 2000 and December 31, 2001 the remaining provision for drilling service contracts was NOK 960 million and NOK 734 million, respectively. 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)	*2001*	*2000*
Inventories		
Crude oil	2,919	2,143
Petroleum products	2,567	2,928
Other	593	498
Total — inventories valued on a FIFO basis	6,079	5,569
Excess of current cost over LIFO value	(803)	(1,343)
Total	5,276	4,226

8. Summary Financial Information of Unconsolidated Equity Affiliates

Statoil's investments in affiliates include a 50 percent interest in Borealis, a petrochemical production company, and a 50 percent 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 relates to amounts due from equity affiliates.

Equity method affiliates - gross amounts

	BOREALIS			SDS		
(IN NOK MILLION)	*2001*	*2000*	*1999*	*2001*	*2000*	*1999*
At December 31,						
Current assets	7,694	10,753	8,513	3,189	3,014	3,333
Non current assets	19,710	18,121	16,720	6,105	6,333	6,240
Current liabilities	6,108	9,740	8,747	2,894	3,277	3,830
Long-term debt	8,787	5,870	3,118	3,382	3,242	3,157
Other liabilities	2,201	2,570	2,886	0	0	0
Net assets	10,310	10,694	10,482	3,018	2,828	2,586
Year ended December 31,						
Gross revenues	29,819	30,465	24,227	24,563	26,069	23,297
Income before taxes	(193)	686	1,649	411	328	66
Net income	(330)	488	1,312	290	233	41
Capital expenditures	1,182	2,117	3,520	552	592	6,909

Dividends received from Borealis amounted to NOK 16, 187 and 329 million for 2001, 2000 and 1999, respectively. No dividends are 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%	931	222
Borealis A/S	DKK	2,000	4,000	50%	5,081	(146)
P/R West Navion DA	NOK	-	-	50%	1,161	67
Other companies	-	-	-	-	2,778	296
Total					9,951	439

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 percent 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. Equity in net income/loss of affiliates in 1999 includes a writedown of NOK 1,200 million to estimated fair value of the investment in P/R West Navion DA.

9. Short-Term Investments

	AT DECEMBER 31,	
(IN NOK MILLION)	*2001*	*2000*
Short-term deposits	189	128
Certificates	1,692	3,376
Bonds	180	278
Marketable equity securities	2	75
Total short-term investments	2,063	3,857

The net change in unrealized gains on securities for the years ended December 31, 2001, 2000 and 1999 was a net gain of NOK 10 million, a net loss of NOK 45 million, and a net gain of NOK 58 million, respectively. The cost price for the short-term investments was NOK 2,053 and 3,857 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.

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, 2001	11,051	197,957	29,130	6,242	9,063	13,749	5,283	272,475
Additions and transfers	710	15,565	1,117	432	842	(1,232)	163	17,597
Disposal at cost	(871)	(7,660)	(3,596)	(153)	(1,684)	(576)	(230)	(14,770)
Expensed expl. cost capitalized prior years	-	-	-	-	-	-	(935)	(935)
Accumulated depreciation, depletion and amortization	(8,253)	(119,999)	(15,664)	(1,811)	(2,204)	64	0	(147,867)
Book value at December 31, 2001	2,637	85,863	10,987	4,710	6,017	12,005	4,281	126,500
Depreciation, depletion and amortization of property, plant and equipment for the year	607	15,654	1,034	206	492	0	0	17,993
Amortization of goodwill								65
Depreciation, depletion and amortization for the year								18,058
Estimated useful life (years)	5-10	*	15-20	20-25	20-25			

*Unit of production, see note 1.

Included in book value Vessels is NOK 40 million regarding financial lease.
In 2001, 2000 and 1999, NOK 723, 1,494 and 1,225 million, respectively, of interest were capitalized.

11. Provisions

Provisions against assets (other than property, plant and equipment and intangible assets) recorded during the past three years are as follows:

(IN NOK MILLION)	BALANCE AT JANUARY 1,	EXPENSE	RECOVERY	WRITE-OFF	OTHER	BALANCE AT DECEMBER 31,
Year 2001						
Provisions for other long-term assets	90	0	0	0	(74)	16
Provisions for accounts receivable	224	44	0	(12)	(44)	212
Year 2000						
Provisions for other long-term assets	90	0	0	0	0	90
Provisions for accounts receivable	174	33	43	(23)	(3)	224
Year 1999						
Provisions for other long-term assets	70	20	0	0	0	90
Provisions for accounts receivable	259	60	0	(147)	2	174

12. Financial Items

(IN NOK MILLION)	2001	YEAR ENDED DECEMBER 31, 2000	1999
Interest and other financial income	2,107	2,426	1,027
Currency exchange adjustments, net	912	(3,389)	(102)
Interest and other financial expenses	(2,713)	(2,035)	(1,850)
Dividends received	18	82	186
Realized gain and loss on sale of securities	(97)	371	1,717
Change in unrealized gain and loss on securities	(162)	(353)	453
Net financial items	65	(2,898)	1,431

13. Income Taxes

Net income before taxes consist of

(IN NOK MILLION)	2001	YEAR ENDED DECEMBER 31, 2000	1999
Norway			
• Offshore	49,651	52,307	22,254
• Onshore	5,843	3,052	(1,763)
Other countries	725	1,734	(1,482)
Total	56,219	57,093	19,009

Significant components of income tax expense were as follows

(IN NOK MILLION)	2001	YEAR ENDED DECEMBER 31, 2000	1999
Current taxes			
Norway			
• Offshore	37,942	39,542	15,471
• Onshore	1,169	979	69
Other countries	253	529	504
Uplift benefit	(1,726)	(1,816)	(1,708)
Current income tax expense	37,638	39,234	14,336
Deferred taxes			
Norway			
• Offshore	317	528	324
• Onshore	383	254	(1,323)
Other countries	148	440	(481)
Deferred tax expense (benefit)	848	1,222	(1,480)
Total income tax expense	38,486	40,456	12,856

Significant components of Statoil's deferred tax assets and liabilities were as follows

(IN NOK MILLION)	AT DECEMBER 31, 2001	2000
Deferred tax assets		
Net operating loss carry-forwards	2,120	2,317
Impairment	1,365	832
Decommissioning	4,277	3,992
Other	4,911	5,278
Valuation allowance	(2,135)	(2,309)
Total deferred tax assets	10,538	10,110
Deferred tax liabilities		
Property, plant and equipment	35,144	37,044
Capitalized exploration expenditures and interest	8,668	8,962
Other	8,370	6,924
Total deferred tax liabilities	52,182	52,930

Deferred taxes are classified as follows

(IN NOK MILLION)	AT DECEMBER 31, 2001	2000
Short-term deferred tax assets	(113)	(514)
Long-term deferred tax assets	(597)	(210)
Short-term deferred tax liabilities	0	213
Long-term deferred tax liabilities	42,354	43,331

Amounts presented in the prior year financial statments have been reclassified to reflect netting of deferred tax assets and liabilities within the same tax jurisdiction. The most significant impact of this reclassification results in a reduction of long-term deferred tax assets in 2000 from NOK 9,196 million to NOK 210 million and a reduction in long-term deferred tax liabilities from NOK 52,930 to NOK 43,331 million.

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 percent to effective tax rate

(IN NOK MILLION)	2001	YEAR ENDED DECEMBER 31, 2000	1999
Expected income taxes at statutory rate	15,741	15,969	5,312
Petroleum surtax	24,342	26,159	10,736
Uplift benefits	(1,726)	(1,816)	(1,708)
Other, net	129	144	(1,484)
Income tax expense	38,486	40,456	12,856

Revenue from oil and gas activities on the NCS is taxed according to the Petroleum tax law. This stipulates a surtax of 50 percent after deducting uplift, a special investment tax credit, in addition to normal corporate taxation. Uplift credit is deducted as the credits arises, 5 percent each year for 6 years, as from initial year of investment. Uplift credits not utilized of NOK 8.6 billion can be carried forward indefinitely.

At the end of 2001, Statoil had tax losses carry-forwards of NOK 7.0 billion, primarily in Norway, US and Ireland. Substantially all carry-forward amounts expire after 2006.

14. Short-Term Debt

(IN NOK MILLION)	AT DECEMBER 31, 2001	2000
Bank loans and overdraft facilities	948	194
Margin calls	0	1,172
Current portion of long-term debt	5,364	1,147
Other	301	272
Total	6,613	2,785
Weighted average interest rate	4.62	6.05

15. Long-Term Debt

	WEIGHTED AVERAGE INTEREST RATES		*BALANCE IN NOK MILLION AT DECEMBER 31,*	
	2001	*2000*	*2001*	*2000*
Unsecured debentures bonds				
US dollar (US$)	5.79	6.84	19,006	15,153
Norwegian kroner (NOK)	5.67	5.67	255	231
Euro (EUR)	4.58	4.59	4,518	4,957
Swiss franc (CHF)	2.87	3.12	4,652	5,714
French franc (FRF)	-	5.25	0	63
Japanese yen (JPY)	2.09	2.52	1,808	1,450
Great British pounds (GBP)	6.13	6.13	3,080	2,968
Total			33,319	30,536
Unsecured bank loans				
US dollar (US$)	6.00	6.00	3,510	1,053
Euro (EUR)	7.64	7.64	0	494
Total			3,510	1,547
Secured bank loans				
US dollar (US$)	6.43	6.30	2,879	2,827
Total			2,879	2,827
Other debt			838	434
Grand total outstanding debt			40,546	35,344
Less current portion			(5,364)	(1,147)
Total long-term debt			35,182	34,197

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, 2001 and 2000, NOK 4,441 million and NOK 4,424 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 agreement bond for EUR 500 million, with a fixed interest rate of 5.125%, maturing in 2011. At December 31, 2001 and 2000, NOK 3,933 million and NOK 4,117 million were outstanding, respectively. The interest rate of the bond has been swapped to a LIBOR-based floating interest rate through a EUR 200 million swap agreement.

Statoil has an unsecured debenture bond agreement for US$ 375 million, with a fixed interest rate of 5.75%, maturing in 2009. At December 31, 2001 and 2000, NOK 3,347 million and NOK 3,318 million were outstanding, respectively.

Statoil utilizes foreign currency swaps to manage foreign exchange risk on its long-term debt. The swaps are not reflected in the table above. The stated interest rate on the majority of its 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 outstanding six debenture bond agreements, 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, 2001 closing rate valued at NOK 12,029 million.

Reimbursements of long-term debt fall due as follows:

(IN NOK MILLION)	
2002	5,364
2003	2,251
2004	3,120
2005	1,320
2006	1,907
Thereafter	26,584
Total	40,546

Statoil has agreements with two bank syndicates for committed long-term revolving credit facilities totaling US$ 1,460 million (NOK 13,157 million), with US$ 275 million drawn. Commitment fees range from 0.0875% to 0.105% per annum. In addition, credits amounting to a total of EUR 242 million (NOK 1,929 million) are available to Statoil on a bilateral basis. There are no borrowings under these credits as at December 31, 2001.

As of December 31, 2001 Statoil had no committed short-term credit facilities.

At December 31, 2001 Statoil had no committed letter of credit available. Available and outstanding letters of credit as per December 31, 2000 amounted to US$ 28 million (NOK 246 million).

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 37 months. Hedge ineffectiveness related to Statoil's outstanding cash flow hedges was immaterial and recorded to earnings during the year ended December 31, 2001. The net change in Other comprehensive income associated with the current year hedging transactions was immaterial, and the net amount reclassified into earnings during the year was NOK 2 million (after tax). At December 31, 2001, the net deferred hedging loss in Accumulated other comprehensive income was NOK 2 million (after tax), none of which will affect earnings over the next 12 months. The gain component of a derivative instrument excluded from the assessment of hedge effectiveness related to cash flow hedges during the year was NOK 137 million (before tax). This item relates to time value of options utilized to hedge certain crude production volumes, and was recorded as sales in Exploration and Production Norway in the Consolidated Statement of Income. 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 and some inventories of crude oil. 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, 2001. The net gain recognized in earnings in Net financial items or Cost of sales during the year for ineffectiveness of fair value hedges was immaterial.

Fair Value of Financial Instruments

Except from 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.

(IN NOK MILLION)	*FAIR MARKET VALUE OF ASSETS*	*FAIR MARKET VALUE OF LIABILITIES*	*NET CARRYING AMOUNT*
At December 31, 2001			
Debt-related instruments	602	(1,518)	(916)
Non-debt-related instruments	25	(32)	(7)
Long-term fixed interest debt	0	(34,800)	(29,246)
Crude Oil and Refined Products	701	(360)	341
Gas and electricity	67	(46)	21

The following table contains the notional amounts, carrying amounts and estimated fair values of financial instruments, and the carrying amounts and estimated fair value of long-term debts for the period prior to implementing FAS 133. Commodity contracts capable of being settled by delivery of commodities (oil & oil products, natural gas, electricity) are excluded from the summary. The notional values of these and other derivative instruments do not represent assets or liabilities of Statoil but, rather, are the quantitative basis for settlement under the contract terms.

(IN NOK MILLION)	*NOTIONAL AMOUNT*	*FAIR MARKET VALUE*	*CARRYING AMOUNT*
At December 31, 2000			
Debt-related instruments	41,016	(346)	(277)
Non-debt-related instruments	(22,591)	191	191
Long-term fixed interest debt	0	(32,423)	(31,416)
Crude Oil and Refined Products	(2,988)	124	124
Gas and electricity	410	11	11

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 minimizes credit risk concentration with respect to financial instruments by holding only investment grade securities spread 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 likewise managed by maintaining, reviewing and updating lists of authorized counter-parties by assessing the financial position and requiring collateral when appropriate. The credit risk concentration with respect to receivables is limited due to the large number of customers 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 well known trading companies. 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,* 2001	2000	1999
Defined benefit plans			
Benefit earned during the year, net of participants' contributions	690	678	703
Interest cost on prior period benefit obligation	626	578	514
Expected return on plan assets	(793)	(761)	(645)
Amortization of loss	10	14	23
Amortization of prior service cost	44	44	44
Amortization of net transition assets	(16)	(16)	(16)
Net periodic pension cost	561	537	623
Defined contribution plans	21	21	19
Multi-employer plans	4	4	3
Total net periodic pension cost	586	562	645

Change in projected benefit obligation (PBO)

(IN NOK MILLION)	*2001*	*2000*
Projected benefit obligation at beginning of year	10,632	9,853
Benefits earned during the year	690	656
Interest cost on prior period benefit obligation	626	584
Actuarial gain (loss)	471	(256)
Benefits paid	(391)	(210)
Foreign currency translation	(28)	5
Projected benefit obligation at end of year	12,000	10,632

Change in pension plan assets

(IN NOK MILLION)	*2001*	*2000*
Fair value of plan assets at beginning of year	12,310	11,392
Retained earnings in the pension trusts reclassified to plan assets	954	0
Actual return on plan assets	(15)	457
Company contributions	8	549
Benefits paid	(170)	(86)
Foreign currency translation	(19)	(2)
Fair value of plan assets at end of year	13,068	12,310

Status of pension plans reconciled to balance sheet

(IN NOK MILLION)	AT DECEMBER 31, 2001	2000
Defined benefit plans:		
Funded status of the plans at end of year	1,068	1,678
Unrecognized net loss	769	389
Unrecognized prior service cost	462	512
Unrecognized net transition asset	(31)	(47)
Total net prepaid pension recognized	2,268	2,532
Amounts recognized in the Consolidated Balance Sheet:		
Prepaid pension	4,046	4,280
Accrued pension liabilities	(1,778)	(1,748)
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 3,352 million, NOK 2,430 million and NOK 422 million, respectively, at December 31, 2001, and NOK 2,945 million, NOK 2,071 million and NOK 418 million, respectively, at December 31, 2000.

18. Decommissioning and Removal Liabilities

At December 31, 2001 and 2000, NOK 7,521 million and NOK 7,063 million, respectively, had been accrued for future well closure, decommissioning and removal of offshore installations. Statoil's share of the estimated total future well closure, decommissioning and removal costs is NOK 13,300 million and NOK 12,800 million at December 31, 2001 and 2000, respectively.

19. Research Expense

Research expenses were NOK 633 million, NOK 656 million and NOK 718 million in 2001, 2000 and 1999, respectively.

20. Leases

Statoil leases certain assets, notably shipping vessels.

Rental expense is NOK 7,687 million, NOK 6,455 million and NOK 7,219 million in 2001, 2000 and 1999, respectively.

The information below shows future minimum lease payments under non-cancelable operating leases at December 31, 2001.

(IN NOK MILLION)	OPERATING LEASES	CAPITAL LEASES
2002	4,174	23
2003	2,818	10
2004	2,230	10
2005	1,883	10
2006	1,603	10
Thereafter	3,939	8
Total future rents	16,647	71
Interest component		(11)
Net present value		60

Property, plant and equipment include the following amounts for leases that have been capitalized at December 31, 2001 and 2000.

(IN NOK MILLION)	AT DECEMBER 31, 2001	2000
Vessels	238	769
Less allowance for depreciation	(198)	(688)
Net	40	81

In 1999, Statoil sold and leased back their interest in a production vessel for NOK 945 million. The gain of NOK 226 million on the sale is being deferred over the lease term of three years.

21. Other Commitments and Contingencies

Contractual commitments

(IN NOK MILLION)	IN 2002	THEREAFTER	TOTAL
Contractual commitments made	8,475	5,641	14,116

These contractual commitments comprise acquisition and construction of tangible fixed assets.

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 7.1 billion for each incident, including liability for claims arising from pollution damage. Most of the group's production installations are covered through the wholly-owned subsidiary Statoil Forsikring AS, which reinsures a major part of the risk in the international insurance market. About 46 percent is retained.

Guarantees

The group has provided guarantees of NOK 174 million.

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 2001, Statoil was committed to participating in 10 wells off Norway and 11 wells abroad, with an average ownership interest of approximately 23 percent. The expected costs to drill these wells amounts to approximately NOK 0.7 billion.

In 1996 the Directorate-General for Competition of the European Commission, according to EC/EEA competition rules, commenced an investigation of the members of the GFU, including Statoil, relating to the arrangements for the sale of gas from the NCS, including the activities of the GFU. Late in 2000 the European Commission indicated that it may bring proceedings under the EC/EEA competition rules against Statoil and others.

On June 12, 2001, Statoil received a "Statement of Objections" from the European Union's Competition authority. This is the first step in a formal process which can result in a legal proceeding against Statoil that could last for years. The statement from the EU Commission is mainly related to the gas sales organization imposed by the Norwegian authorities.

The Norwegian Government has publicly announced that it opposes to the Statement of Objections issued by the European Commission and has been accepted as an interested third party in the case. The Norwegian Government submitted its written intervention ultimo October 2001, where it pleaded that the system for sale of gas from the NCS was a compulsory system established by the Norwegian authorities in accordance with Norwegian law and that the EU/EEA competition laws thus were not applicable.

Statoil responded in writing to the Statement of Objections ultimo 2001. In December 2001 an oral hearing was arranged by the Commission. In the oral hearing, representatives from the Norwegian Government and all companies having received the Statements of Objections made oral pleadings in the case.

Statoil cannot predict the possible content or timing of any final Commission decision. However, if proceedings are commenced, the Commission may adopt a decision prohibiting the sale of gas from the NCS under the former arrangements for the sale of gas from the NCS (including the activities of the GFU), to impose fines, to require Statoil to offer customers with existing gas sales agreements (including long-term take-or-pay agreements) the opportunities to re-negotiate or terminate those agreements and/or to impose other obligations to remedy any adverse effects of the alleged infringement. Any finding of an infringement by Statoil of the EC/EEA competition laws might also result in counter parties to gas sales agreements challenging validity of those agreements and possibly claiming substantial damages. If any action were brought by the Commission, the Company would defend its positions vigorously, and the Company believes it has substantial defenses.

In addition, during the normal course of its business Statoil is involved in legal proceedings and a number of unresolved claims are currently outstanding. The ultimate liability in respect of litigation and claims cannot be determined at this time. Statoil has provided in its accounts for these items based on management's best judgment. Management does not believe that the resolution of these legal proceedings will have a material adverse effect on its financial position, results of operations or cash flows.

22. Related Parties

Total purchases of oil from the Norwegian State amounted to NOK 50,987 million (251 million barrels), NOK 39,185 million (155 million barrels) and NOK 22,293 million (161 million barrels) in 2001, 2000 and 1999, respectively. Amounts payable to the Norwegian State for these purchases are included as "Accounts payable — related parties" in the Consolidated Balance Sheets. The price paid by Statoil for the oil purchased from the Norwegian State are estimated market prices.

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. The treasury shares are intended to be used to grant bonus shares to retail investors. Investors are entitled to receive an additional ordinary share from Statoil for every 10 shares they purchased in the retail offering in Norway (up to an aggregate purchase amount of NOK 25,000, or in the case of Statoil employees up to an aggregate purchase amount of NOK 75,000), and continue to hold through June 17, 2002, for no additional consideration.

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.

The Board of directors has authority to issue up to 500,000 shares. The shares may only be used to issue shares under a possible share incentive program. The authority lasts to June 20, 2002.

The Board of directors is authorized to acquire treasury shares. The aggregate nominal value of treasury shares pursuant to this authority cannot exceed NOK 250,000,000. The minimum and maximum price is NOK 2.50 and NOK 300 per share respectively. The Board of directors may only use this authorization for the purpose of improving the capital structure (redemption).

There exists only one class of shares and all have voting rights.

Retained earnings available for distribution is based on Norwegian accounting principles, and legal regulations and amounts to NOK 26,579 million (before provisions for dividend for the year ended December 31, 2001 of NOK 6,169 million) at December 31, 2001. This differs from retained earnings in these financial statements of NOK 6,682 million due to differences between Norwegian legal and accounting regulations, which form the basis for retained earnings available for distribution, and USGAAP. The main difference is the impact of the transfer of the SDFI assets to Statoil, which is not reflected in the Norwegian GAAP accounts until the second quarter of 2001. Under Norwegian regulations the amount available for distribution is limited to the retained earnings of the parent company. Retained earnings in subsidiaries are not available for dividend distribution from the parent company. 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 2001 amounted to NOK 21.4 million for audit services and NOK 22.3 million for other services, including NOK 14.7 million for audit related services in connection with the initial public offering.

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 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.

The principles for booking of proved gas reserves in Norway are limited to contracted gas sales and gas with access to a market. New contracted sales are recorded as extensions and discoveries.

Statoil's delivery commitment related to supply type contracts is 12,800 bcf. Gas sales and delivery commitments for the contract years 2002, 2003 and 2004 are 685, 754 and 794 bcf respectively. These commitments may be met from proved developed reserves of 8,970 bcf as of December 31, 2001. In addition to the supply-type agreements, Statoil is party to depletion-type gas sales agreements. Here the natural gas supplied from certain fields is sold in its entirety to a customer or customergroup. Statoil has no obligation to deliver quantities beyond those produced from the fields in question.

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.

When Statoil enters into production sharing agreements, the reserves are estimated on the basis of the volumes to which it has access (cost oil and profit oil), limited to available market access.

In 1999, purchases and sales of petroleum in place are mainly related to the acquisition of Saga assets offshore Norway and the disposal of Statoil's gas producing activity in the US.

The totals in the following tables may not equal the sum of the amounts shown due to rounding differences.

	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 EQUIVALENT*		
	NORWAY	*OUTSIDE NORWAY*	*TOTAL*	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*	*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
At December 31, 1998	1,633	507	2,140	12,704	1,219	13,924	3,896	724	4,621
Proved developed reserves	777	92	869	7,085	797	7,882	2,040	234	2,274
Revisions and improved recovery	82	(23)	59	(111)	21	(90)	62	(19)	43
Extensions and discoveries	67	0	67	28	141	169	72	25	97
Purchase of reserves-in-place	134	4	138	1,045	9	1,054	320	6	326
Sales of reserves-in-place	(1)	(6)	(7)	(1)	(1,215)	(1,216)	(1)	(223)	(224)
Production	(240)	(21)	(262)	(452)	(60)	(512)	(321)	(32)	(353)
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	7505	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
Proved developed reserves	940	187	1,127	8,630	65	8,695	2,478	198	2,677
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
Proved developed reserves	948	166	1,113	9,069	42	9,112	2,564	173	2,737

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.

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, the Norwegian State's estimate of proved reserves not being available to Statoil and the fact that the State will sell an additional 6.5 percent of its interest in licenses on the NCS, 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.

For the year 2001, Statoil marketed and sold 406 million barrels of oil and NGL and 654 billion cubic feet of gas on behalf of the Norwegian State. For 2002, it is estimated that Statoil will market and sell 380 million barrels of oil and NGL and 750 billion cubic feet of gas.

Capitalized costs related to Oil and Gas Producing Activities

(IN NOK MILLION)	*AT DECEMBER 31, 2001*	*2000*
Unproved Properties	4,281	5,264
Proved Properties, wells, plants and other equipment	208,446	194,165
Total Capitalized Costs	212,727	199,429
Accumulated depreciation, depletion, amortization and valuation allowances	(117,450)	(102,636)
Net Capitalized Costs	95,277	96,793

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, 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
Year ended December 31, 1999			
Acquisition of properties			
• Unproved	1,186	180	1,366
• Proved	12,203	0	12,203
Exploration costs	1,647	1,361	3,008
Development costs	12,339	3,980	16,319
Total	27,375	5,521	32,896

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, 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
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
Year ended December 31, 1999			
Sales	2,673	4,207	6,880
Transfers	35,699	0	35,699
Total revenues	38,372	4,207	42,579
Exploration expenses	(2,016)	(1,107)	(3,123)
Production costs	(8,054)	(1,251)	(9,305)
Special items	0	(764)	(764)
DD&A(2)	(9,710)	(1,694)	(11,404)
Total costs	(19,780)	(4,816)	(24,596)
Results of operations before taxes	18,592	(609)	17,983
Tax expense	(12,918)	22	(12,896)
Results of producing operations	5,674	(587)	5,087

1) Impairment of LL652, 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 percent 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 percent 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, 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 percent 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 percent 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
At December 31, 1999			
Future net cash inflows	602,208	91,978	694,186
Future development costs	(35,829)	(13,216)	(49,045)
Future production costs	(189,956)	(18,359)	(208,315)
Future net cash flow pre-tax	376,423	60,403	436,826
Future income tax expenses	(270,466)	(17,429)	(287,895)
Future net cash flows	105,957	42,974	148,931
10 percent annual discount for estimated timing of cash flows	(41,283)	(24,696)	(65,979)
Standardized measure of discounted future net cash flows	64,674	18,278	82,952

Of a total of NOK 56,942 million of estimated future development costs as of December 31, 2001, an amount of NOK 37,595 million is expected to be spent within the next three years, as allocated in the table below.

Future development costs

(IN NOK MILLION)	*2002*	*2003*	*2004*	*SUM*
Norway	10,083	8,858	7,088	26,029
Outside Norway	4,907	3,877	2,782	11,566
Sum future development costs	14,990	12,735	9,870	37,595
Future development costs expected to be spent on proved undeveloped reserves	12,413	11,232	8,744	32,389

In 2001, Statoil incurred NOK 14,159 million in development costs, of which NOK 8,386 million related to proved undeveloped reserves. The comparable amounts for 2000 were 15,098 million and NOK 11,840 million, respectively.

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

(IN NOK MILLION)	*2001*	*2000*
Standardized measure at beginning of year	98,850	82,952
Net change in sales and transfer prices and in production (lifting) costs related to future production	(70,193)	206,251
Changes in estimated future development costs	(10,560)	(6,316)
Sales and transfers of oil and gas produced during the period, net of production costs	(62,283)	(70,246)
Net change due to extensions, discoveries, and improved recovery	2,064	10,292
Net change due to purchases and sales of minerals in place	(1,652)	(160)
Net change due to revisions in quantity estimates	11,604	(6,279)
Previously estimated development costs incurred during the period	14,159	15,098
Accretion of discount	57,721	(79,383)
Net change in income taxes	39,508	(53,359)
Total change in the standardized measure during the year	(19,632)	15,898
Standardized measure at end of year	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, 2001.

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

AT DECEMBER 31, 2001		*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Number of productive oil and gas wells				
Oil wells	— gross	661	508	1,169
	— net	172	104	276
Gas wells	— gross	103	13	116
	— net	31	4	35

AT DECEMBER 31, 2001 (IN THOUSANDS OF ACRES)		*NORWAY*	*OUTSIDE NORWAY*	*TOTAL*
Developed and undeveloped oil and gas acreage				
Acreage developed	— gross	484	186	670
	— net	113	33	146
Acreage undeveloped	— gross	9,993	13,760	23,753
	— net	3,482	3,949	7,431

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, 2001.

(NUMBER OF WELLS)		*NORWAY*	*AT DECEMBER 31, OUTSIDE NORWAY*	*TOTAL*
Number of wells in progress	— gross	34	11	45
	— net	9.3	1.4	10.7

Net productive and dry oil and gas wells

The following tables show the net productive and dry exploratory and development oil and gas wells completed or abandoned by Statoil in the past three years. Productive wells include wells in which hydrocarbons were found, and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing in sufficient quantities to justify completion.

	NORWAY	*AT DECEMBER 31, OUTSIDE NORWAY*	*TOTAL*
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	7.5
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
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
1999			
Net productive and dry exploratory wells drilled	6.4	4.9	11.3
– Net dry exploratory wells drilled	3.0	1.4	4.4
– Net productive exploratory wells drilled	3.4	3.5	6.9
Net productive and dry exploratory wells drilled	30.6	52.1	82.7
– Net dry development wells drilled	1.8	0.4	2.2
– Net productive development wells drilled	28.8	51.7	80.5

Average sales price and production cost per-unit

	NORWAY	*OUTSIDE NORWAY*
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	-	0.099
Average production costs, in NOK per boe	24.8	58.2
Year ended December 31, 1999		
Average sales price crude in US$ per bbl	18.0	16.4
Average sales price natural gas in NOK per Sm^3	0.58	-
Average sales price natural gas in US$ per Sm^3	-	0.083
Average production costs, in NOK per boe	25.1	39.3

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