2010

Annual Report on Form 20-F

Statoil

Annual Report on Form 20-F

Annual Report on Form 20-F

Cover Page

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 20-F

(Mark One)

☐ **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, 2010

OR

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

For the transition period from _________ to _________

OR

☐ **SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Date of event requiring this shell company report _________

Commission file number 1-15200

Statoil ASA

(Exact Name of Registrant as Specified in Its Charter)

N/A
(Translation of Registrant's Name Into English)

Norway
(Jurisdiction of Incorporation or Organization)

Forusbeen 50, N-4035, Stavanger, Norway
(Address of Principal Executive Offices)

Torgrim Reitan
Chief Financial Officer
Statoil ASA
Forusbeen 50, N-4035
Stavanger, Norway
Telephone No.: 011-47-5199-0000
Fax No.: 011-47-5199-0050
(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

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

Title of Each Class	Name of Each Exchange On Which Registered
American Depositary Shares	**New York Stock Exchange**
Ordinary shares, nominal value of NOK 2.50 each	**New York Stock Exchange***

*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

Securities registered or to be registered pursuant to Section 12(g) of the Act: **None**

Securities for which there is a reporting obligation pursuant to Section 15(d) of the 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	**3,188,647,103**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

☒ Yes ☐ No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

☐ Yes ☒ No

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the registrant: (1) has filed all reports required 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 ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).**

☒ Yes ☐ No

**This requirement does not apply to the registrant until its fiscal year ending December 31, 2011.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP ☐ International Financial Reporting Standards as issued by the International Accounting Standards Board ☒ Other ☐

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ☐

Item 18 ☐

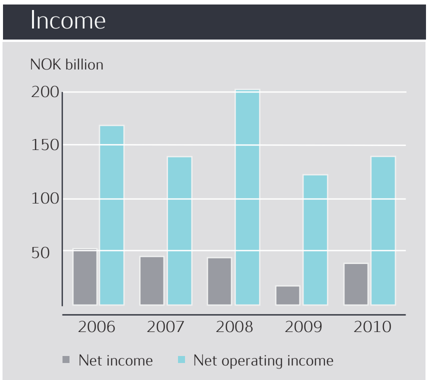
If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

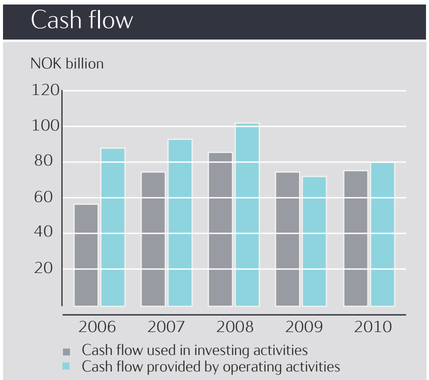
☐ Yes ☒ No

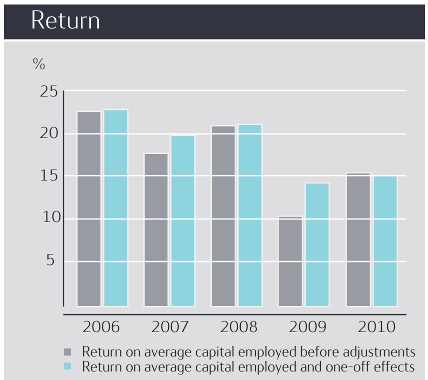
1 Introduction

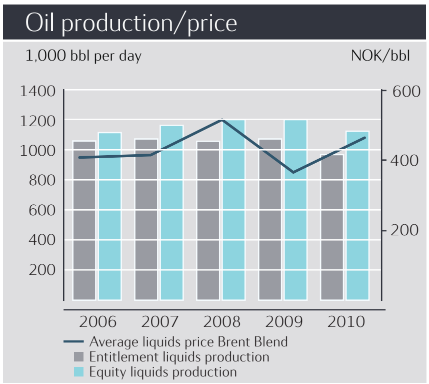
1.1 Key figures

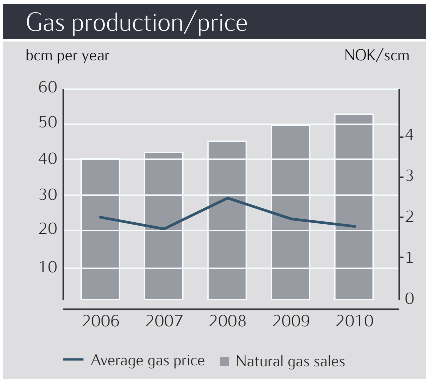
This section is a presentation of our performance in important areas: income, cash flow, return, proved reserves, oil production and price, gas production and price, serious incidents, total recordable injuries and carbon dioxide emissions.

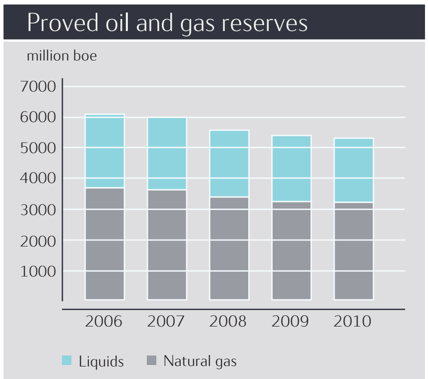


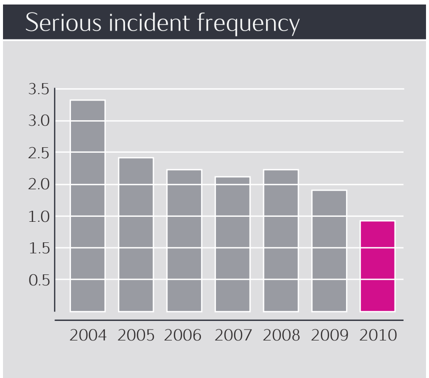


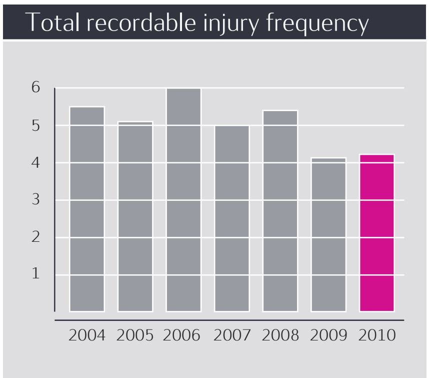


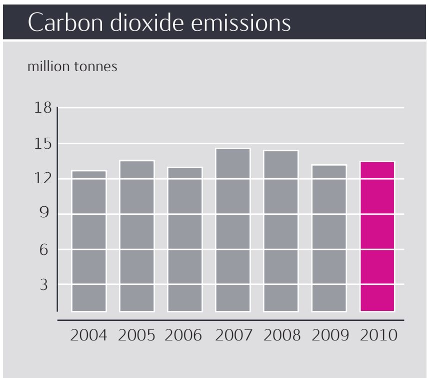












1.2 About the report

Statoil's Annual Report on Form 20-F for the year ended 31 December 2010 ("Annual Report on Form 20-F") is available online at www.statoil.com.

Statoil is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, Statoil files its Annual Report on Form 20-F and other related documents with the Securities and Exchange Commission, the SEC. It is also possible to read and copy documents that have been filed with the SEC at the SEC's public reference room located at 100 F Street, N.E., Washington, D.C. 20549, USA. You may also call the SEC at 1-800-SEC-0330 for further information about the public reference rooms and their copy charges, or you may log on to www.sec.gov. The report can also be downloaded from the SEC website at www.sec.gov.

Statoil discloses on its website at http://www.statoil.com/en/about/corporategovernance/statementofcorporategovernance/pages/default.aspx, and in its Annual Report on Form 20-F (Item 16G) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under the New York Stock Exchange (the "NYSE") listing standards.

1.3 Financial highlights

2010 was an important year strategically for Statoil. We demonstrated value creation by executing agreements for the partial sale of our operated assets in Brazil and Canada, sanctioned nine projects and executed a successful IPO of our retail activities.

Whilst production volumes were below our expectations in the second part of the year due to high maintenance, specific operational issues and reduced production permits, we continued to deliver strong financial results and cash flows.

Statoil publishes financial data in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and IFRS as adopted by the European Union (EU).

	For the year ended 31 December				
(in NOK billion, unless stated otherwise)	2010	2009	2008	2007	2006
Financial information					
Total revenues and other income	529.6	465.4	656.0	522.8	521.5
Net operating income	137.2	121.6	198.8	137.2	166.2
Net income	37.6	17.7	43.3	44.6	51.8
Cash flow provided by operating activities	80.8	73.0	102.5	93.9	88.6
Cash flow used in investing activities	76.2	75.4	85.8	75.1	57.2
Interest-bearing debt	111.5	104.1	75.3	50.5	54.8
Net interest-bearing debt	69.7	75.3	46.0	25.5	43.8
Total assets	643.0	562.8	579.2	483.1	458.8
Share Capital	8.0	8.0	8.0	8.0	8.0
Non-controlling interest (Minority Interest)	6.9	1.8	2.0	1.8	1.6
Total equity and minority interest	226.4	200.1	216.1	179.1	169.4
Net debt to capital employed	24.6 %	27.3 %	17.5 %	12.4 %	20.5 %
Return on average capital employed after tax	15.4 %	10.5 %	21.0 %	17.7 %	22.6 %
Operational information					
Equity oil and gas production (mboe/day)	1,888	1,962	1,925	1,839	1,780
Proved oil and gas reserves (mmboe)	5,325	5,408	5,584	6,010	6,101
Reserve replacement ratio (three-year average)	64%	64%	60%	81%	76%
Production cost (NOK / boe equity volumes)	38.6	35.3	34.6	41.4	27.3
Share information					
Earnings per share for income attributable to equity holders of company basic and diluted	11.94	5.75	13.58	13.80	15.82
Share price at Oslo Stock Exchange on 31 December	138.60	144.80	113.90	169.00	165.25
Dividend paid per share NOK (1)	6.25	6.00	7.25	8.50	9.12
Dividend paid per share USD (2)	1.07	1.04	1.26	1.47	1.58
Weighted average number of ordinary shares outstanding	3,182,574,787	3,183,873,643	3,185,953,538	3,195,866,843	3,230,849,707

(1) See Shareholder information section for a description of how dividends are determined and information on share repurchases. The board of directors will propose the 2010 dividend for approval at the Annual General Meeting scheduled for 19 May 2011.

(2) USD figure presented using the Central Bank of Norway 2010 year-end rate for Norwegian kroner, which was USD 1.00 = 5.86 NOK. The board of directors will propose the 2010 dividend for approval at the Annual General Meeting scheduled for 19 May 2011.

1.4 A glance at 2010

Production volumes fell below expectations in the second half of the year due to high maintenance, specific operational issues and reduced production permits. Nevertheless, Statoil continued to deliver strong financial results and cash flows in 2010.

January
We signed an agreement with ConocoPhillips to take over a 25% interest in 50 licences in the Chukchi Sea near Alaska.

Statoil was awarded shares in eight production licences on the Norwegian Continental Shelf (NCS), comprising six North Sea licences and two Norwegian Sea licences. We will be operator of six of the licences.

In the third licence round for offshore wind parks in the UK, the Forewind consortium, of which Statoil is a member, was awarded the rights to develop Dogger Bank, which was the largest zone in the round.

Lukoil and Statoil signed a contract relating to the West Qurna 2 field in Iraq. First oil is scheduled for the end of 2012 and full production is expected for a period of 13 years from 2017.

February
The Tyrihans field was awarded the prestigious Five Star Award at the Deep Offshore Technology conference in Houston, for being one of the five best offshore developments in the world during 2009.

March
We enhanced our shale gas position in the USA by signing a contract with Chesapeake that extended our net share of 2,400 square kilometres by a further 236 square kilometres in the Marcellus formation.

Our two Peregrino oil platforms were towed into position off the coast of Brazil. First oil is expected towards the end of the first quarter 2011.

We extended our portfolio in the US sector of the Gulf of Mexico. Statoil was the highest bidder on 21 licences.

We signed an investment contract worth USD 6 billion with ACG partners relating to the development of the Chirag oil project in the Azeri sector of the Caspian Sea.

Low-pressure production methods have increased oil recovery from the Oseberg field in the North Sea.

We increased our share in the St. Malo development in the Gulf of Mexico to 21.5% by exercising our first option in connection with the sale of Devon's share of the development.

We entered transport contracts with New Jersey and New York City for the transport and delivery of natural gas produced in the northern part of the Marcellus shale gas region in Pennsylvania (PA).

April
Norway and Russia reached agreement regarding the Barents Sea delimitation line, dividing the 175,000 square kilometre area into two more or less equal parts. It is believed that there could be considerable deposits of oil and gas in the area.

Statoil launched a new technology plan designed to reduce CO2 emissions from oil sand production, with the intention of achieving reductions of more than 40% by 2025.

Njord licence partners approved the development of the Njord North West flank, a development that will increase the total recoverable reserves and extend Njord's lifetime by up to two years.

We announced that we had found oil and gas at the Fossekall prospect north of the Norne field in the Norwegian Sea.

The Macondo accident in the Gulf of Mexico caused the loss of 11 lives and an extensive oil spill. US authorities imposed restrictions following the accident, leading to the temporary closure of two of our drilling operations in the area.

May
We signed a partnership agreement in which we sell a 40% stake in the Peregrino field in Brazil to the Sinochem Group. We will retain a 60% share and remain as operator on the field. The divestment is a natural step in our ongoing efforts to optimise our portfolio.

Statoil and EGL announced the transfer of a combined share of 15% in the Trans Adriatic Pipeline Project to E.ON Ruhrgas. The Trans Adriatic Pipeline will provide a link between the existing and planned pipeline systems for natural gas in South West Europe and the pipeline systems in West Europe.

We signed an agreement for the transport of gas through a pipeline from the northern part of the Marcellus shale gas region in Pennsylvania to Niagara on the US-Canadian border. The agreement secures us access to a central, inter-state pipeline system.

On 19 May a situation arose involving a change in pressure and the loss of drilling fluid in well C-06 on the Gullfaks C platform in the North Sea. We demobilised 89 employees to the Gullfaks A platform by helicopter. Our investigation and the report of the Petroleum Safety Authority Norway concluded that the planning of the drilling and completion operations in the well had been carried out with deficiencies in planning and risk assessment. Following this incident, we implemented a number of measures.

June
We signed a letter of intent with Sinochem Group of China to promote collaboration and the long-term share of experience between the two companies. The letter was signed after the Peregrino partnership agreement in which Sinochem signed an agreement to acquire a 40% share in Statoil's oilfield off the coast of Brazil.

The first floating platform to be supplied with electricity from the mainland, Gjøa, was towed to its location on the west coast of Norway. The solution will reduce CO2 emissions by 210,000 tonnes of carbon dioxide per year.

The plan for the development and operation of the Gudrun field in the North Sea was approved by the Norwegian parliament in June. We expect that the traditional steel jacket will be completed and installed in the summer of 2011 before well drilling commences in October 2011. Production start-up is planned for the first quarter of 2014.

Work commenced on the Sheringham Shoal offshore wind farm in the UK, jointly owned by Statoil and Statkraft. The wind farm, scheduled to come on stream in 2011, will supply an estimated 200,000 UK households with electricity.

Statoil and Poweo of France signed a 20-year agreement relating to the supply of natural gas to Poweo's planned 400 MW combined cycle gas turbine (CCGT) power station in Toul, France. The plan is for deliveries to commence on 1 October 2012.

July
We signed frame agreements for insulation, scaffolding and surface treatment on platforms, production ships and land facilities in Norway and Denmark. The contracts were worth a total of NOK 12 billion, including options.

August
We published details of our fast track developments that are aimed to make small fields more profitable and help maximise the potential of the NCS. The first projects are PanPandora, Katla, Vigdis Nordøst and Gygrid.

We announced the discovery of oil and gas east of the Gudrun field.

We announced a new organisational structure effective from 1 January 2011. The rationale behind the new organisation is to simplify our way of working by having fewer internal interfaces and better defined responsibilities, an increased global perspective and improved local presence close to important investments.

Oil production commenced from the subsea field Morvin, tied back to Åsgard, in the North Sea. The field has a strategic significance for the further development and operation of our North Sea activity.

September
We signed an agreement with Nautical Petroleum, enhancing our offshore heavy oil portfolio. The deal involved the acquisition of 20.67% of Nautical Petroleum's share of the UK offshore licence P335 that includes the Mariner field.

October
The company's energy and retail business became a standalone company Statoil Fuel & Retail ASA (SFR), which was listed on the Oslo stock exchange on 22 October. Private and institutional investors showed considerable interest in shares in the new company. Statoil ASA retains a 54% ownership stake in SFR.

The state-run Mexican oil company Petróleos Mexicanos (Pemex) and Statoil are collaborating to reduce gas flaring on the Tres Hermanos oil field in Mexico. It was announced in October that the project is registered under the UN's Clean Development Mechanism (CDM).

We carried out an extensive oil spill protection exercise on Sørøya in West Finnmark, in northern Norway, together with Eni and Lundin, NOFO (Norsk oljevernforening for operatørselskap) and a local task force. The exercise confirmed that the emergency response preparations function as planned.

We submitted our development plan for the Valemon field to the Ministry of Petroleum and Energy. The plan involves a new, unmanned platform in the North Sea planned to come on stream in 2014.

We approved development of the major Jack/St. Malo fields in the deepwater Gulf of Mexico together with operator Chevron and our other partners. Start-up is expected in 2014.

The seventh oil discovery in block 15/06 off the coast of Angola was announced, completing our minimum commitment to this area 18 months ahead of schedule. The well was tested for a rate of more than 6,000 barrels of light oil per day.

We announced that we were boosting our land-based projects in the USA by acquiring a 67,000 net acre share of the Eagle Ford shale gas formation. Statoil and Talisman have formed a 50/50 joint venture with the aim of developing the resources in Eagle Ford.

November
We announced the formation of a partnership including the sale of a 40% stake in the company's oil sands project in Alberta, Canada, to Thai company PTT Exploration and Production. The contract, reducing our 100% stake to 60%, follows on from other transactions completed in 2010 designed to optimise the risk and strategy profile of our global portfolio.

We submitted our application for new exploration licences in the Barents Sea and the Norwegian Sea in the 21st licensing round on the Norwegian continental shelf. It is expected that Norwegian authorities will allocate acreage here during the spring of 2011.

Production on the Gjøa oil and gas field came on stream on 7 November. This development opens up for more activity in the far north of the North Sea.

We announced that we would further concentrate our efforts to develop offshore wind turbines as part of our renewable energy strategy in the light of the rapid international developments within the offshore wind sector.

December
We signed a technology development agreement with Siemens with whom we will collaborate on wind power, subsea technology, electro technology and boosting energy efficiency.

The Gas Advocacy Forum, a group of major gas players in Europe of which Statoil is a member, submitted a report to the EU Commission stating that Europe can achieve its target of an 80% reduction in carbon emissions by 2050 if natural gas is allowed to play a substantial role in the energy mix.

Production started up on the Vega gas and condensate field south west of the Sogne coast in Norway.

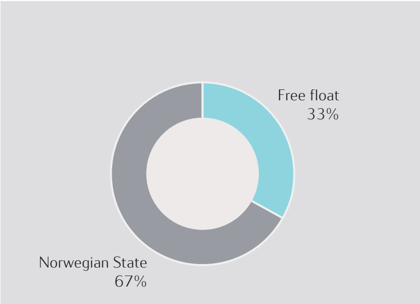
2 Business overview and strategy

2.1 Our business

Statoil is an integrated energy company that is primarily engaged in oil and gas exploration and production activities. Statoil's headquarters are in Norway, and the company is present in 42 countries worldwide.

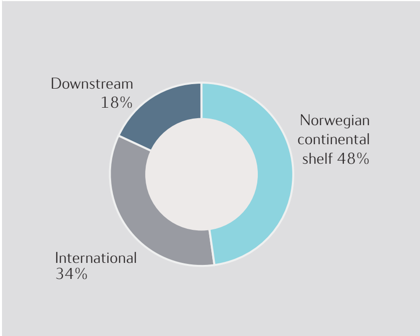
Statoil ASA is a public limited liability company organised under the laws of Norway and subject to the provisions of the Norwegian act relating to public limited liability companies (the Norwegian Public Limited Companies Act). Statoil is the leading operator on the Norwegian continental shelf (NCS). It is also expanding its international activities.

Ownership structure *

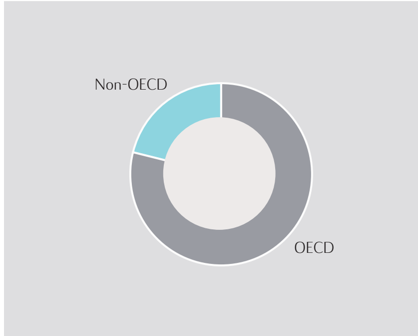


*As per 31 December 2010

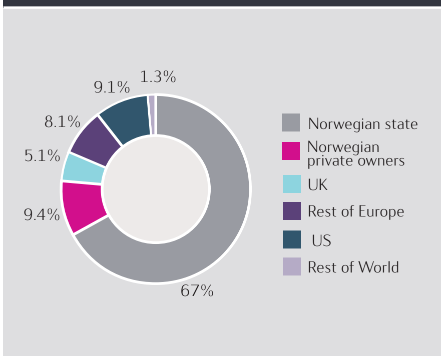
Fixed assets



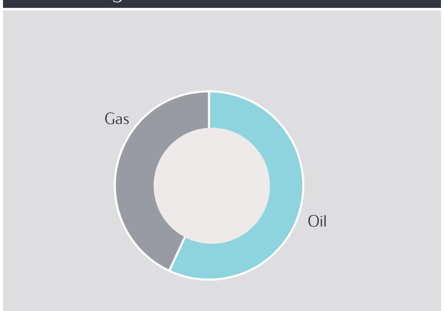
Upstream assets



Distribution of shareholders



Oil and gas*



*Entitlement production

Entitlement oil and gas production outside Norway accounted for 19.5% of our total production, which averaged 1,705 mmboe per day in 2010.

As of 31 December 2010, we had proved reserves of 2,124 mmbbl of oil and 509 bcm (equivalent to 18.0 tcf) of natural gas, corresponding to aggregate proved reserves of 5,325 mmboe.

We are present in 42 countries. As of 31 December 2010, there were approximately 30,400 employees in the Statoil group. Of this total, 10,400 were employees of the Statoil Fuel & Retail group, in which we held a 54% majority ownership interest as of 31 December 2010.

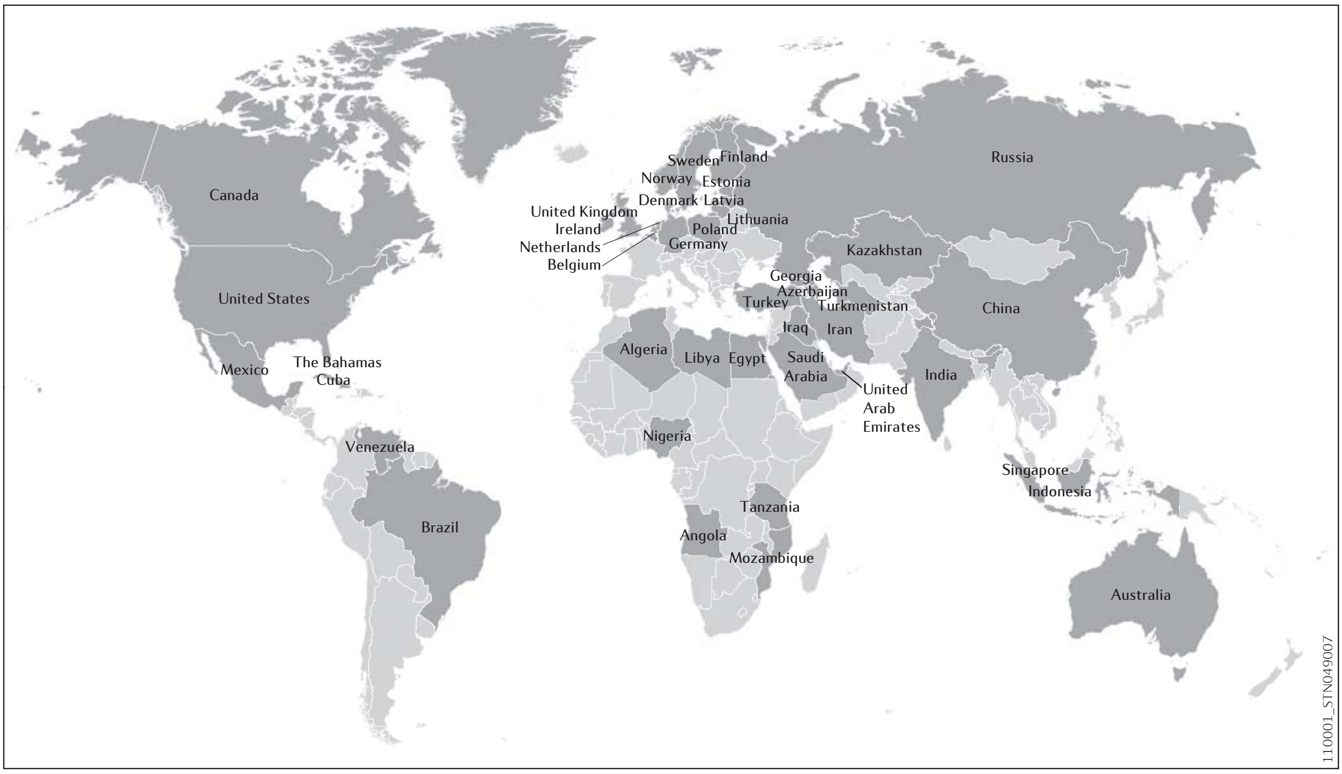
We are among the world's largest net sellers of crude oil and condensate, and we are the second largest supplier of natural gas to the European market. We also have substantial processing and refining activities. We are contributing to the development of new energy resources, have ongoing activities in the fields of wind power and biofuels and are at the forefront in relation to the implementation of technologies for carbon capture and storage (CCS).

In further developing our international business, we intend to utilise our core expertise in areas such as deep water, heavy oil, harsh environments and gas value chains in order to exploit new opportunities and develop high quality projects.

Business address
Our business address is Forusbeen 50, N-4035 Stavanger, Norway. Our telephone number is +47 51 99 00 00. Our largest locations in terms of the number of employees are in Stavanger, Bergen and Oslo, Norway.

The Statoil group, the main business areas and staff functions are presented in the following sections of this report.

The figure below provides an overview of the geographical reach of Statoil's business.



See the section Business overview and strategy - New organisational structure as from January 2011, for the organisational structure of our business areas and staff functions up to and including 31 December 2010 and as from 1 January 2011.

2.2 Our history

Statoil was formed in 1972 by a decision of the Norwegian Storting (parliament). It was listed on the stock exchanges in Oslo and New York in 2001.

Statoil was incorporated as a limited liability company under the name Den norske stats oljeselskap a.s on 18 September 1972. As a company wholly owned by the Norwegian State, Statoil's role was to be the government's commercial instrument in the development of the oil and gas industry in Norway.

In 2001, the company became a public limited company listed on the Oslo and New York stock exchanges, and it changed its name to Statoil ASA. On 1 October 2007, the oil and gas division of Norsk Hydro ASA was merged with Statoil, and the company was given the temporary name of StatoilHydro. On 1 November 2009, the company changed its name back to Statoil.

We have grown in parallel with the Norwegian oil and gas industry, which dates back to the late 1960s. The commencement of our operations focused primarily on exploration for and the production and development of oil and gas on the Norwegian continental shelf (NCS) as a partner.

In the 1970s, we commenced our own operations, made important discoveries and began oil refining operations, which have been of great importance to the further development of the NCS.

In the 1980s, we saw substantial growth through the development of major fields on the NCS (Statfjord, Gullfaks, Oseberg, Troll and others). We also became a major player in the European gas market by securing large sales contracts for the development and operation of gas transport systems and terminals. During the same decade, we were involved in manufacturing and marketing in Scandinavia, and we established a comprehensive network of service stations.

The 1990s were characterised by substantial improvements in the production performance of our large fields. This was the result of intense technological development on the NCS. We laid the foundation for future improvements by becoming a leading company in the fields of floating production facilities and subsea development. The company grew strongly, expanded in new product markets and increased its commitment to international exploration and production.

Since 2000, our business has grown as a result of substantial investments on the NCS and internationally. Our ability to fully realise the potential of the NCS was strengthened through the merger with Hydro's oil and gas division, which also bolstered our global competitiveness.

In recent years, we have utilised our expertise to design and manage operations in various environments, in order to grow our upstream activities outside our traditional area of offshore production, for example through the development of heavy oil and shale gas projects.

In October 2010, we successfully carried out an initial public offering (IPO) of Statoil Fuel & Retail ASA on the Oslo stock exchange, partially divesting and reducing our interest in the business relating to service stations.

Although petroleum-related activities on the NCS and internationally have been the main part of our business, we increasingly participate in projects focusing on other forms of energy, such as wind power and CCS (carbon capture and storage), in anticipation of the need to expand energy production, strengthen energy security and combat adverse climate change.

2.3 Statements on competitive position

Information about Statoil's competitive position relies on a range of sources, including analysts' reports, independent market studies and our internal assessments of our market share.

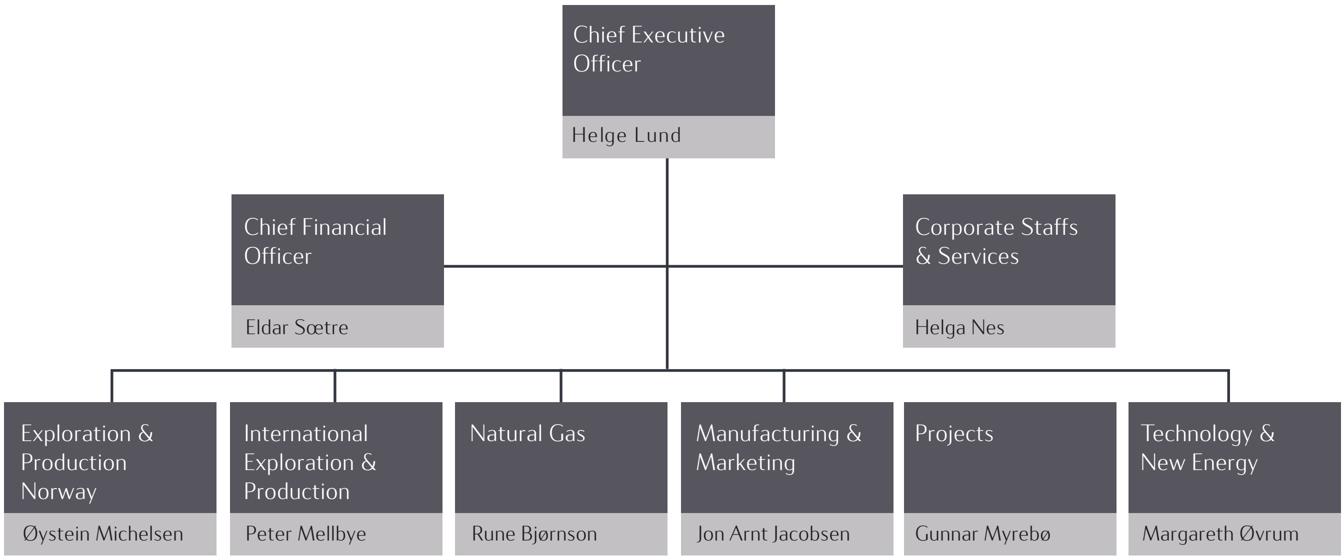
The information about Statoil's competitive position in the Business overview and strategy and Operational review sections is based on a number of sources, including investment analysts' reports, independent market studies and our internal assessments of our market share based on publicly available information about the financial results and performance of market players.

We have endeavoured to present information based on other sources accurately, but we have not independently verified such information.

2.4 New organisational structure as from January 2011

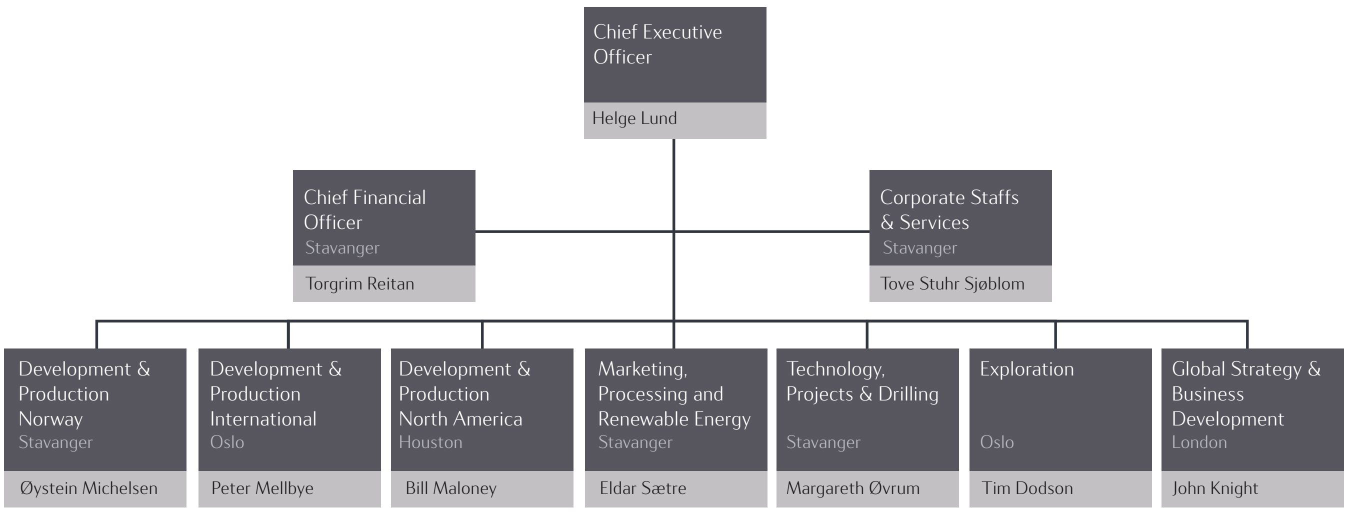
A new corporate structure was implemented with effect from 1 January 2011.

The figure below provides an overview of the organisational structure of our business areas and staff functions up to and including 31 December 2010.



A new corporate structure was implemented with effect from 1 January 2011 (see the figure and descriptions below). The changes were made in order to simplify the organisation and clarify internal accountability. The following Strategy section reflects the organisation as from 1 January 2011. However, the rest of the presentation in this annual report on Form 20-F 2010 is based on the organisation as of 31 December 2010.

Statoil's Corporate Executive Committee and the respective business areas and staff functions



Development and Production business areas

Our Development and Production business areas encompass our worldwide upstream activities. Development and Production Norway (DPN) comprises our upstream activities on the Norwegian continental shelf (NCS), Development and Production North America (DPNA) comprises our upstream activities in North America, and Development and Production International (DPI) comprises our worldwide upstream activities that are not included in the DPN and DPNA business areas.

Our upstream activities were previously included in the Exploration & Production Norway and International Exploration & Production business areas. Over the past few years, we have made large investments in North America. Establishing DPNA as a separate business area reflects the importance of the region to our business.

Marketing, Processing and Renewable Energy
The activities previously included in Natural Gas, Manufacturing & Marketing and the New Energy unit of Technology & New Energy comprise Marketing, Processing and Renewable Energy (MPR). We expect that combining these activities will create synergies in operating our onshore plants and marketing and trading activities.

Technology, Projects and Drilling
The new business area Technology, Projects and Drilling (TPD) combines the activities previously included in the Technology unit of Technology & New Energy, the Projects & Procurement business area and the Drilling and Well unit of Exploration & Production Norway. Combining these activities simplifies work processes and significantly reduces the numbers of internal interfaces.

Exploration
Exploration is a new business area. Our exploration activities were previously part of Exploration & Production Norway and International Exploration & Production. We expect that a single global exploration business area will strengthen the deployment of resources to priority activities across the portfolio.

Global Strategy and Business Development
Global Strategy and Business Development (GSB) is also a new business area. GSB is responsible for setting the corporate strategy, business development, and merger and acquisition activities (M&A).

2.5 Strategy

Statoil's long-term strategy builds on the company's vision: "Crossing Energy Frontiers". It continues the current strategic direction of creating shareholder value as an upstream-oriented and technology-based energy company.

Our strategy of long-term value creation starts with our short-term deliveries in relation to operations and HSE. As we work towards our ambition of realising the full value potential of the Norwegian continental shelf (NCS), we are simultaneously developing international platforms for long-term growth and gradually building a position in renewable energy production.

We operate in an industry that is becoming more complex. Access to resources is also becoming more challenging. In future, the pace of change will increase and the importance of quality in execution will be even higher - making safe and efficient operations more important than ever.

2.5.1 Business environment

The recovery of the world economy continued through 2010, mainly driven by strong growth in the emerging economies. This led to a robust recovery in energy demand in most regions.

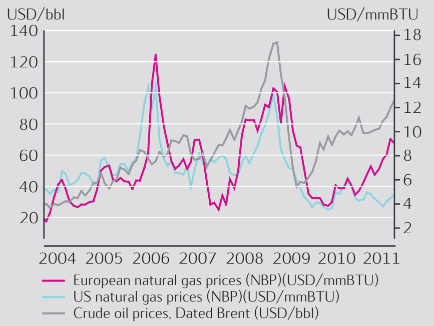
Energy prices, which fell sharply during the second half of 2008, consolidated and partly recovered in 2009. With the exception of US natural gas prices, energy prices strengthened further in 2010.

Macroeconomic outlook
In 2008-2009, the world economy experienced its most severe recession since the Great Depression of the 1930s. However, both emerging economies and the hard-hit advanced economies started to recover during the second half of 2009. The recovery strengthened further during the first half of 2010, driven by restocking, continued policy stimuli and a strong pick-up in private demand in most regions.

Growing by more than 10% in the first part of the year, the Chinese economy provided an important stimulus to the recovery of other regions. India, other emerging economies and Latin America have also witnessed strong economic growth. The pace of growth abated somewhat, however, during the second half of 2010, in both some advanced and emerging economies.

In China a deliberate policy tightening to avoid overheating of the economy has ultimately led to somewhat lower growth, whereas private sector demand in several advanced countries only grew moderately. This reflects the process of deleveraging that both indebted household and the banking sectors in the USA and Europe are still undergoing. The sovereign debt crises in Europe and the volatility of the financial markets have added to the restrictions on bank lending, especially in Europe. After contracting by 1.9% in 2009, world GDP grew by about 3.6% in 2010.

Historic oil and gas prices*



*As of 1 March 2010. Sources: Platts

The outlook for the world economy over the next few years will continue to be influenced by the adjustment processes within the various economies (internal rebalancing) and the re-adjustment of unbalanced trade and capital flows between debt-ridden advanced economies and fast-growing export-driven economies (external rebalancing). At the beginning of 2011, most advanced economies are still facing major internal adjustment challenges.

These economies need to strengthen households' balance sheets, stabilise public debt, and repair and reform their financial sectors. Governments' large budget deficits mean that fiscal policy will have to be significantly tightened over the medium-term, which will partially limit the pace of economic growth. By contrast, China and several other emerging economies face the challenge of restructuring their economies from being reliant on export-led growth to becoming more consumption-oriented.

However, China appears to be determined to move only cautiously in this direction, and the process of revaluation of the Chinese renminbi and other measures that could weaken its export machine will most likely be gradual. This cautiousness will slow the external rebalancing process and dampen the much needed stimulus to the advanced economies, and it could also spur rising protectionist sentiment in the USA and other regions.

Ultimately, the development of the world economy will be strongly dependent on the domestic policies of key countries and the degree of international policy cooperation. Consequently, the medium-term outlook is still characterised by moderate economic growth and major uncertainty, with considerable downside risk.

Energy markets and price developments

After falling by 1.1% in 2009, global energy consumption recovered strongly in 2010 and, based on preliminary statistics, it has grown by more than 4-5%. Demand for oil, natural gas and coal increased, primarily in Asia and other emerging economies. Despite the robust demand, ready and available supplies prevented prices in most markets from rising significantly through 2010.

Crude oil prices, which plunged during the recession, started to recover in the spring of 2009 and ended the year in the USD 75-80/bbl price range. Given ample oil stocks and spare Opec production capacity of more than 5 mbd, the market was mainly driven by expectations of a sustained macroeconomic recovery and a gradual tightening of the oil market over the medium-term.

Costs of developing new oil production in high-cost areas were seen as a key benchmark in price determination. These underlying market dynamics prevailed throughout 2010. Crude oil prices fluctuated significantly during the year driven by changing perceptions about the sustainability of the world economic recovery. Prices strengthened considerably during the fourth quarter, partly supported by cold weather in the Northern hemisphere and ended the year in the USD 90-95/bbl range. US monetary policy, financial players' perceptions, portfolio optimisation and market positions continue to be important drivers for price determination. The average price of dated Brent in 2010 was USD 79.5/bbl, up from USD 61.6/bbl in 2009.

Global oil demand, which fell by 1.1 mbd in 2009, recovered sharply during 2010, with a gain of about 2.7 mbd relative to 2009 - the second strongest annual growth in demand in the last 30 years. China accounted for almost 0.9 mbd of the total, but other emerging economies also contributed to the growth in global oil demand. North American oil demand increased for the first time since 2005. At the same time, non-Opec production and Opec NGL/condensate production continued to expand strongly, by 1.1mbd and 0.5 mbd, respectively, while Opec crude oil production edged up modestly.

The Atlantic Basin product markets, which were severely hit by the economic recession, also partly recovered during 2010. Total products demand increased by 0.45 mbd in the USA, with the strongest growth in demand being for distillates/diesel and various products for broad industrial and household use. In the European markets, product demand, which fell by 0.9 mbd in 2009, consolidated in 2010, with transportation fuels seeing modest growth. However, these gains were offset by further contraction in demand for fuel oil.

Global distillate and naphtha demand, driven by the Asian markets, accounted for the largest proportion of the growth in total products demand. With product stocks in the Atlantic Basin markets still at comfortable levels and with a high level of spare refining capacity, product price differentials (margins) generally remained relatively low, especially gasoline margins. In the US market, a large part of the growth in demand was met by non-refinery liquids and ethanol. European distillate margins improved moderately during 2010 from depressed levels in 2009.

The 2008-2009 recession and the sharp increase in both US unconventional gas production and global LNG production all contributed to a significant over-supply of natural gas and sharply falling prices in all the main regional markets. However, prices consolidated around USD 5/MMBtu on the prospect of more balanced markets during autumn 2009. Despite a strong demand recovery, the Atlantic natural gas markets remained well supplied during 2010. In the first half of 2010, natural gas prices in Europe and North America fluctuated around the levels seen in 2009.

The two markets moved in different directions throughout the year, however, reflecting differences in their competitive nature and supply pressures. In North America, natural gas demand, driven by the recovery of the economy and a strong weather effect, increased by more than 3.0%. However, resilient domestic gas production kept the market over-supplied throughout the year, pushing stock levels to record highs and putting downward pressure on natural gas prices. During most of the year, prices have fluctuated in the USD 3.50-5.00/MMBtu range. The expansion of unconventional gas, especially shale gas, continued at a fast pace. The trends suggest that North America will remain self-sufficient and basically disconnected from the other regional gas markets.

In Europe, by contrast, the combination of strong but volatile demand growth and restrained gas supplies gradually restored the balance in the market and put spot prices on a rising trend during 2010. After fluctuating around USD 4.50/MMBtu during spring, spot prices rose through the rest of the year, reaching USD 9.00/MMBtu by the end of the year. Demand growth, which was very strong during the first half of the year, softened during the summer months, but, driven by extremely cold weather, recovered in the last quarter. Rising coal prices, mainly driven by strong demand from Asia and especially China, have sustained natural gas's competitiveness.

In the last part of the year, however, natural gas faced stronger competition from nuclear power and renewable energy in Germany and several other markets. Total European gas demand increased by about 6% from 2009. LNG imports from the Middle East and Africa continued to grow during 2010, but the moderation and flexibility of Russian exports served to balance the market and ensured a moderate tightening during the year. The strong demand from the Asian LNG markets has also played an important part in the rebalancing of the European gas market.

European electricity prices fluctuated around EUR 50-60/MWh during 2005-08, reached a peak of almost EUR 100/MWh immediately after the start of the economic crisis, but fell to a low of EUR 30-40/MWh in the middle of the recession. After falling by 6% in 2009, European power demand is estimated to have grown by about 4% in the first half of 2010. This drove electricity prices gradually upwards to around EUR 50/MWh.

Prices in the European carbon dioxide market, the EU Emissions Trading Scheme, are basically driven by the supply of allowances derived from the member countries' emission targets, and the demand for emission allowances, which is strongly influenced by activity levels in the industry and power sectors. Carbon prices tend to follow the same pattern as European energy prices. After recovering in the first half quarter of 2009, carbon prices fluctuated around EUR 13-15/tonne over the following 12 months. Since spring 2010, prices have fluctuated around the EUR 15/tonne level. The UN climate change negotiations had limited effect on the short to medium-term emissions trading market last year.

Energy outlook

The outlook for all energy markets over the next few years is fundamentally linked to the uncertain prospects for the world economy. The pace of growth in China and other fast-growing emerging economies is especially important in this context. Global growth in oil demand, which was very strong in 2010, is expected to be moderate over the next few years. On the supply side growth in non-Opec production and Opec NGL/condensate production is also expected to slow. In sum, these prospects mean that Opec's spare production capacity will gradually be reduced. Opec's crude production and marketing policies over the medium term will be affected by a potentially strong expansion of Iraqi oil production.

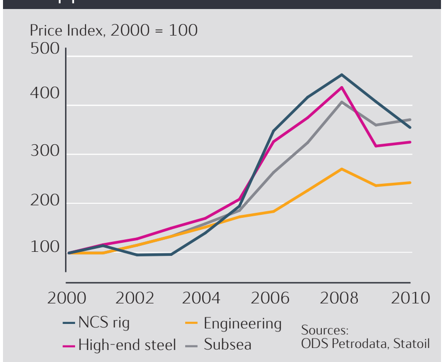
However, a challenging political environment and infrastructure bottlenecks in Iraq indicate that the build-up of new production capacity will proceed relatively slowly. Since oil price formation is also influenced by financial players, the uncertain outlook for financial markets, geopolitical developments and the US dollar will also play a role. The short-term outlook for the Atlantic Basin products markets is driven by modest demand growth and the potential for product imports from several export refineries in the Middle East and Far East. The outlook for sustained overcapacity in refining in the Atlantic Basin may well lead to capacity closures in the mature OECD markets over the next few years.

2.5.2 Industry context

General market conditions for the oil and gas industry improved throughout 2010. However, the industry is still challenged by limited access to new resources and increased international competition.

In 2009, the oil and gas industry's margins were hit as a result of the financial turmoil. The lower oil and gas prices were accompanied by a moderate fall in supplier market costs. Companies reacted to the margin squeeze by adjusting capital expenditure plans, re-evaluating dividend policies and focusing strongly on cost control. This resulted in reduced demand in the supplier market and a further fall in supplier costs. Margins improved throughout 2010, as energy prices rebounded and the supplier markets in general experienced overcapacity and continued restrained prices (see chart). Several companies are following through with their announced portfolio restructuring programmes, however.

Supplier market cost indicies



Looking at longer-term trends, certain strategic challenges have affected the direction of the industry. A large part of the world's remaining conventional resources are held by countries with limited access for international oil companies (IOCs), thus restricting IOCs access to new resources. In addition, the competition for international resources is intensifying, particularly with national oil companies becoming more active in the international hunt for resources. To replace produced reserves and grow, IOCs have therefore gradually been pushed into looking for hydrocarbon resources in more remote areas, in deeper waters and in more technologically challenging environments. As a result, unconventional and deepwater hydrocarbons play an increasingly important part in the global production mix. This trend is likely to continue.

Unconventional gas in general, and shale gas in particular, has attracted much interest from different players over the last few years. As US shale gas represents a relatively accessible resource with low break-even prices, it is an attractive proposition for the IOCs. All the major IOCs have therefore endeavoured to position themselves in this business area. These resources have become a game changer for the US hydrocarbon supply structure; due to the increase in unconventional gas production. The USA is currently almost self-sufficient as regards gas and the expected volume of natural gas imports has dropped significantly. This has contributed to the depressed US gas prices, particularly compared with oil, and there has recently been increased interest in the industry in more liquid rich shale plays.

In April 2010, the oil industry was impacted by one of the most serious accidents in its history, when the Deepwater Horizon rig exploded and caught fire in the US Gulf of Mexico, killing 11 people and causing a massive oil spill. The accident is expected to redefine important parts of the US offshore industry's technical requirements and industry practices, and similar repercussions are expected for global deepwater players. The US Department of the Interior's Bureau of Ocean Energy Management Regulation and Enforcement has already implemented significant new measures to address safety and operational issues, and companies and operators will face stricter operational requirements.

Refining margins have improved somewhat over the last year, but there is still some overcapacity in the refining market.

In October, Statoil formed a stand-alone company, Statoil Fuel & Retail ASA, comprising its energy and retail business, which successfully completed an initial public offering. This transaction is in line with the trend seen in recent years of large IOCs reducing their downstream positions.

Increased concern about energy security and climate change has continued to fortify policy and long-term market drivers for commercial growth in renewables. While most renewable energy sources are currently more costly than fossil fuels, the competitive landscape is expected to shift over time as production costs for renewable energy decline and the cost of carbon emissions is increasingly reflected in power and fuel prices. Significant amounts of public and private funding are currently going into research, development and expansion of new technologies in order to make renewables and carbon capture and storage (CCS) more competitive. Wind power is one of the largest areas in renewable energy, with prospects of increasing production over time. Offshore wind, where Statoil has taken on several projects, is expected to take a significant share of the total wind market if several large countries are to achieve their renewable energy goals.

2.5.3 A strategy for value creation and growth

Statoil's strategy is to profitably grow its long-term oil and gas production while gradually building a position in renewable energy production.

Overall strategic direction
Our overall long-term strategy as an upstream-oriented, technology-driven company is based on the following key components:

- Deliver on operations and HSE.
- Utilise our technology and management capabilities to capture the full potential of our positions on the Norwegian continental shelf (NCS).
- Deliver profitable international growth in the short and medium-term from existing positions, while creating new opportunities for long-term value creation.
- Use exploration as an important growth tool to secure long-term production capacity.
- Develop profitable midstream and downstream positions in support of our upstream activities.
- Minimise carbon emissions from, and the general environmental impact of, our upstream and midstream activities.
- Pursue selected business opportunities for renewable energy production and carbon capture and storage (CCS).
- Apply technology and innovate in order to create value and accelerate asset developments.
- Utilise organisational capabilities as a global energy company.

Our growth strategy
We are addressing the challenges of growing our production, reserves and resource base through efficiency improvements resulting from simplification and renewal of our organisation, and by continually reviewing our portfolio in light of global business opportunities.

The Global Strategy and Business Development (GSB) business area has been created to bring together corporate strategy, business development and merger and acquisition activities in order to actively drive Statoil's corporate development. GSB will set a strong strategic direction and identify, develop and deliver opportunities for global growth for Statoil. This will be achieved through close collaboration within the group across geographical regions and business areas. As noted at the February 2011 Capital Market Update, Statoil is currently undertaking a strategy review with the aim of securing continued growth and value creation.

Our growth strategy is based on exploration, focused business development, strategic acquisitions and divestments, and building long-term partnerships. Our aim is to increase the scale of our operations in terms of production, reserves and technological and geographical breadth, and to bring our resource base closer to production. We will continue to deliver profitable projects in a range of complex technical and stakeholder environments.

Our short-term priorities are to conduct safe operations and to deliver production growth in line with our guidelines.

Safe and efficient operations are essential to our business. In order to prevent harm to people and the environment, all activities in Statoil are carried out with a strong focus on HSE. We seek to achieve this through long-term and systematic application of best practices across our activities. We are improving efficiency, for example on the NCS through the "fast-track" and "integrated operations" (IO) initiatives, as we continue to maximise the full value potential of our positions.

By implementing the Statoil 2011 organisation, we aim to put ourselves in an even better position to become a global energy player. Combining company-wide activities in exploration (EXP), marketing, processing and renewables (MPR), technology, projects and drilling (TPD), and global strategy and business development (GSB) into individual business areas, and focusing development and production activity in three geographical business areas (DPN, DPNA, DPI), will allow us to systematically support the globalisation of Statoil, to better support business priorities, and to reinforce leadership and clarify accountability.

Utilising our capabilities

Gaining access to sufficient petroleum resources is increasingly challenging. We are seeking new opportunities in demanding areas that require the full use of our legacy of expertise in technology and management. We have experience and expertise that could give us a competitive advantage in the following four growth platforms:

- Deep water: we are active in six of the most interesting deepwater basins in the world - the Gulf of Mexico, Brazil, Angola, Nigeria, Norway and Indonesia.
- Harsh environments: we see the resource potential of the Arctic as particularly interesting, although it is a region that is not expected to deliver substantial results until the medium to longer term due to technical and environmental challenges.
- Heavy oil: we have positions in Norway, Canada, Brazil, Venezuela and the United Kingdom.
- Gas value chain: we are active in finding and delivering gas in many countries and have an extensive portfolio that includes conventional European gas, unconventional gas, e.g. US shale gas, and liquefied natural gas (LNG)

Responding to the climate challenge

Our ambition is to be an industry leader in carbon efficiency by having a low climate impact in all of the activities in which we are engaged. We aim to create value by seeking competitive low-carbon and energy-efficient solutions in all areas of our business. Responding effectively to the climate challenge as it impacts our activities will give us a competitive advantage in future. We are a leading industry player in CCS.

Maximising value creation from upstream access opportunities

We will use exploration as an important growth tool to secure long-term growth of reserves, production and value. This is consistent with maximising the long-term value of the NCS and with utilising our core expertise to build, mature and deliver profitable growth outside Norway. We will continue to optimise our exploration portfolio, balancing frontier, growth and infrastructure-led exploration.

We will continue selective business development activities to optimise the portfolio.

Maximising long-term value creation on the NCS

We are maintaining our position as the main industry player on the NCS. We are working continuously to improve our HSE performance as well as our cost-efficiency and operational efficiency, and we are implementing measures for improved hydrocarbon recovery (IHR). We see a structural shift in our non-sanctioned project portfolio from a few large, complex projects to a high number of mainly smaller projects or sub-sea tie-backs. This requires a high level of standardised technical concepts as well as simplified development processes.

Building and delivering profitable international growth

Our strategy is to deliver profitable international growth in the short and medium term from existing positions, while creating new opportunities for long-term value creation. We will utilise our core expertise in areas such as deep water, harsh environments, heavy oil and the gas value chain to pursue attractive business opportunities around the world.

In the longer term, we anticipate that Statoil's future growth will mainly take place outside the NCS and that our international asset base will enable us to grow and become more diversified, both in geographical terms and in terms of types of production. Our short to medium-term focus is on delivering and maturing a high-quality project portfolio on time and within budget.

Developing profitable midstream and downstream positions

Statoil's strategy is to develop projects and to produce oil and gas where we see a potential for attractive returns and added value. We have a strong upstream focus in terms of our total value and asset base, complemented by a midstream and downstream portfolio related to marketing, trading, refining and storage of oil and gas products. We endeavour to achieve synergies between upstream and midstream positions.

Creating a platform for renewable energy production and CCS

Our strategy for renewable energy production and carbon management is to utilise existing core capabilities and current business positions to create profitable positions in renewable energy, prioritising offshore wind projects while keeping track of opportunities in other areas through technology and selective investments.

We are building a portfolio of wind farms, with the focus on offshore sites, and we are developing technology for large-scale deepwater offshore wind power generation. In this context, our participation in the Sheringham Shoal UK wind farm and the Forewind consortium on the Dogger Bank development are important projects for us. Off the south-west coast of Norway, we are piloting a prototype of the world's first full-scale floating wind turbine, Hywind, which is designed to be placed at water depths of between 120 and 700 metres.

In addition, we are reducing emissions of greenhouse gases from fossil energy production through CCS.

Using technological innovation and implementation as a key business enabler
Technology is a key enabler in terms of Statoil realising its goals as an internationally competitive energy company. Our ambition is to attain distinctiveness and industrial leadership by aligning our technology and R&D efforts with our portfolio of activities, and vice versa.

Based on our history of technological achievements, we actively endeavour to master demanding and critical developments within our priority activity areas. We prioritise technology efforts that add value to resources and that enable us to develop smarter solutions for energy exploration and production that are cost-efficient and environmentally benign. We are refining and standardising our technical requirements and work processes.

Technology innovation and implementation is critical to success in many of our activities, such as enabling field development in frontier deepwater and Arctic areas, the production of heavy oil, exploration for hydrocarbons trapped below salt, and managing environmental and climate-related issues. In addition, in order to enable sustainable energy provision in the long term, we aim to remain competitive in a broad range of core and emerging technologies, such as floating offshore wind.

2.5.4 DPN strategy

DPN's strategy is to realise the full potential of the Norwegian continental shelf (NCS).

We aim to achieve this through safe and efficient operations, improving operational and drilling cost-efficiency, increasing recovery from existing fields, new developments, optimising use of existing infrastructure, and access to new acreage.

Safe and efficient operations are essential to our business strategy
Statoil aims to carry out all activities with strong focus on HSE in order to prevent harm to people and the environment and to ensure the quality of the work. The implementation of integrated operations (IO) is expected to increase economic value through higher production, higher regularity and cost reductions. Through our ongoing focus on integrated operations and common work processes on all our installations on the NCS, we aim to utilise best practices and optimise the use of our total resources to ensure safe and efficient operation. Upgrading and modification programmes for offshore installations are also planned with a view to maintaining safe and efficient operations.

Maintaining a high production level
Statoil aims to maintain a stable production level on the NCS during the period up until 2020. Due to the decline in the mature part of our portfolio, substantial new production is required. We aim to achieve this through several measures:

- Several fields on the NCS are maturing and production is declining. High priority will therefore be given to more efficient drilling operations, improved regularity and increased hydrocarbon recovery (IHR). High regularity is expected to be achieved through efficient well work, better reservoir management, the de-bottlenecking of export infrastructure and efficient turnarounds.

- Optimal development and exploitation of our producing fields is necessary in order to secure a solid foundation for future activities through exploration and continued maturation of the project portfolio. New field developments are generally more challenging than before, in terms of their complexity, smaller size and/or profitability.

- Due to their size and location, the majority of our discoveries will be developed as subsea tie-backs in order to utilise existing infrastructure. This requires a higher degree of standardisation and simplification of technical solutions. Active near-field exploration is a key factor in extending fields' lifetimes and initiating cost-effective tail-end production on fields that are in decline and/or have reached a critical point with respect to profitability.

Access to new, high-quality exploration acreage is necessary in order to maintain a high production level in the longer term. Considering the long lead times for field developments, it is a prerequisite in the near term to open new acreage.

Energy efficiency and carbon emissions
Development and Production Norway (DPN) aims to maintain and strengthen the NCS's position as the most energy-efficient petroleum region in the world. We intend to push for energy efficiency in our day-to-day operations and evaluate new field developments in a long-term perspective with regard to energy and the environment. DPN also plans to put more effort into developing a more energy-efficient supply chain from a life-cycle perspective.

Industry leader on the NCS
We aim to maintain our position as a preferred operator on the NCS. The NCS is an arena for world-class innovation and technological development. Statoil is a leader in the deployment of new technology, such as drilling and subsea technology, new solutions for reducing costs and the use of new technology to develop discoveries. As the largest operator on the NCS, we are in the forefront of the development of optimal area solutions and the overall development of the shelf.

2.5.5 DPI strategy

DPI's strategy is to build a large and profitable international E&P portfolio by delivering on existing projects and accessing new opportunities.

Development and Production International (DPI) is responsible for the safe and efficient development and production of oil and gas resources worldwide (apart from Norway and North America). DPI will focus on four strategic growth areas - deep water, gas value chains, harsh environments and heavy oil - and access projects where Statoil can apply its core technological and organisational expertise to create value. Going forward, particular attention will be devoted to:

- We expect that delivering on operated projects - such as starting production from the Peregrino field in Brazil in 2011 and significantly progressing the development of the Mariner and Bressay fields in the UK - will mature DPI's resource base and further develop an organisational skill set and international operator experience.

- Driving production from key partner-operated positions, such as projects in Angola, Algeria and Azerbaijan, and continuing to be a value-adding partner in these projects by actively promoting effective technological improvements and sound operational practices.

- Maturing other large projects such as the Shtokman gas development in Russia and the West Qurna II field in Iraq, thereby actively utilising Statoil's experience.

- Optimising the portfolio to maximise value, and actively seeking new growth opportunities, striving for technical innovation, financial robustness and HSE excellence in all projects.

In line with the corporate growth strategy, our growth strategy is based on exploration, focused business development, strategic acquisitions and divestments, and the building of long-term partnerships in order to increase the scale of our operations in terms of production, reserves and technological and geographical breadth and bring our resource base closer to production. DPI will continue to deliver profitable projects in a range of complex technical and stakeholder environments.

2.5.6 DPNA strategy

DPNA's strategy is to build a balanced portfolio of profitable assets by delivering existing projects and accessing new growth opportunities.

Development and Production North America (DPNA) is responsible for planning for the safe, efficient and profitable development and production of oil and gas resources in North America.

DPNA's growth ambition is focused on Statoil's four strategic growth areas: deep water, gas value chains, heavy oil and harsh environments.

Deep water
Statoil is the third largest licence holder in the deepwater regions of the US Gulf of Mexico. Our ambition is to profitably grow Statoil's equity production, while being a leading company in relation to HSE, by moving existing discoveries to first oil. In the short term, the priority is to become fully compliant with any new offshore regulations and to secure new drilling permits to allow de-risking and value creation through exploration. DPNA is also focusing on the large yet-to-find potential of the deepwater regions of Mexico.

Gas value chains
Statoil's onshore shale gas positions in Marcellus and Eagle Ford offer competitive costs compared with other US gas supply sources. Our strategy is to continue to improve the joint ventures' operational performance, to maximise the value creation from existing acreage and to secure production growth together with our JV partners. Statoil plans to operate in these unconventional shale plays within 2-3 years.

Heavy oil
By entering the Canadian oil sands in 2007, Statoil positioned itself as a long-term player in the Canadian oil sands. With the Leismer Demonstration Project on stream, the plan is to add additional phases and to implement a technology plan aimed at increasing energy efficiency and bitumen recovery, driving down costs and carbon dioxide emissions.

Harsh environments
Our ambition in the East Coast Canada semi-arctic Jeanne D'Arc basin is to profitably grow Statoil's equity production through IOR in existing fields and through new field developments. East Coast Canada will have a special role as an Arctic Competence Centre.

2.5.7 MPR strategy

MPR's strategy is to maximise corporate value through safe, reliable and efficient operations, and through the development of profitable midstream, downstream and renewable energy business opportunities.

Marketing, Processing and Renewable Energy (MPR) is responsible for the transportation, processing, storage and marketing of all hydrocarbons in Statoil's upstream portfolio, including refined products. Following the initial public offering of Statoil's energy and retail business in October 2010, the remaining parts of Statoil's midstream and downstream oil and gas value chains now have a more industrial end-user focus.

Dynamic gas markets and the increasing complexity of Statoil's crude qualities call for close cooperation between Statoil's upstream business areas and MPR. An integrated value chain approach has already added significant value to key projects, such as Peregrino in Brazil (oil) and Marcellus in the USA (gas). For example, Statoil's upstream business areas and MPR had to work closely to find the most efficient solutions for the marketing of Peregrino crude oil.

We have a flexible gas transportation system, with six different landing points on the European Continent/UK and flexibility in terms of gas deliveries from large gas-producing fields such as Troll and Oseberg. We plan to leverage our competitive position as a low cost supplier with significant flexibility, proximity to attractive markets and our LNG capabilities to capture opportunities and maximise shareholder value.

Marketing
MPR will continue to strengthen its global trading and marketing activities. We will increase our presence in strategic regions such as the Americas, while maintaining established market position in Europe. We will continue to develop business and infrastructure positions in order to secure reliable market access and competitive pricing for Statoil's products. Access to attractive infrastructure and efficient logistical solutions give our business a competitive edge both with respect to our own equity volumes, as well as third party volumes sourced globally.

Processing
The market outlook for the European refining industry is challenging and is expected to remain so in the mid-term. We aim to enhance the refineries competitive position by improving product yields, operational reliability and energy efficiency and by reducing costs while maintaining a high HSE performance. A strong focus on operations and performance is of the essence.

MPR's ambition is to strengthen the interface between manufacturing and trading units and to add value through more pro-active integration of the operation of the Mongstad and Kalundborg refineries. The objective is to exploit synergies through crude feedstock optimisation, greater flexibility and exchange of products between the refineries. In the gas processing facilities, a high reliability and cost-efficient performance is fundamental for reliable and competitive deliveries of gas to Statoil's customers.

Renewable Energy
MPR's strategy for developing its business in renewable energy is founded on Statoil's overall expertise within oil and gas exploration, development and operations and, in particular, the extensive experience from offshore operations.

This strategy has been employed in the growing offshore wind industry, where the company is engaged in a development project in the UK (Sheringham Shoal) and also has been awarded an additional large offshore development acreage in the UK (as part of a consortium).

Statoil believes that technologies for CCS will provide attractive contributions in curbing greenhouse gas emissions to the atmosphere. MPR is engaged in ongoing efforts to develop a commercial CO2 storage concept, leveraging the unique and extensive experience Statoil has acquired from Sleipner and other fields that have been separating and injecting CO2 for years.

2.5.8 TPD strategy

TPD's strategy is to create value by providing Statoil with safe and cost efficient drilling and project deliveries. Competitive solutions are key success factors in developing our global activities.

Statoil's upstream development portfolio is substantial. In addition our portfolio is technically as well as geographically diverse. We have demonstrated excellent project execution skills, for example within the Peregrino project off the coast of Brazil. Furthermore, we have gained valuable experience from oil sands in Canada, where the Leismer project started production late 2010. We have also expanded our portfolio of unconventional gas projects in the US.

Within renewable energy, a wind park with more than 80 windmills is being built off the east coast of England for the Sheringham Shoal project, thus gaining expertise in the execution of offshore wind projects.

TPD has made a significant effort associated with CO2 storage and carbon management to complete the construction of the Test Centre plant at Mongstad (TCM). Experience gained from TCM will be used to enhance new business opportunities with the potential of adding value to certain oil and gas activities across the company. (Future projects that will fall under strict CO2 regime or exposed for high CO2 costs will benefit from effective solutions for CO2 treatment and TCM experience will be valuable for project evaluation.)

On the NCS many of our projects are related to redeveloping and upgrading existing fields and installations to prolong lifetime and increase recovery rates. A number of small satellite fields are being tied into existing hubs as this will significantly shorten the time from discovery to production.

We are actively working to simplify development concepts and to standardise use of equipment and services. A key focus area is to enhance recovery from wells already drilled. Finally we are developing and implementing new technology with the aim of ensuring future growth both on the NCS and elsewhere.

Our corporate technology strategy is driven by business challenges and aims to further strengthen our industry position. The technology strategy addresses which technologies to develop and implement to support the corporate strategic ambitions. The technology strategy promotes technologies that will increase competitiveness and enable the company to grow and to deliver world class development projects.

We put emphasis on developing enabling- and new- technologies for frontier areas. An example of this is the choice of a subsea compression solution for the Åsgard field on the NCS. At the same time we put emphasis on standardising selected technologies, fast resource maturation and cost-efficient development solutions.

Much of our technology development and deployment is carried out in close cooperation with national and international universities, research institutes and suppliers. Our performance is strongly dependent on our supplier's performance. We work closely with our suppliers in order to optimise our joint performance.

2.5.9 EXP strategy

Statoil is committed to delivering value through exploration in several of the most important oil and gas provinces in the world.

Exploration is an important growth tool for Statoil in order to secure long term growth of reserves, production and value. We are present in several of the most important oil and gas provinces in the world and will continue to optimise our portfolio, balancing infrastructure-led exploration, growth opportunities in mature areas and frontier exploration in new areas.

Our exploration strategy remains focused on accessing more new quality acreage, including unconventional hydrocarbons and technologically challenging exploration resources.

As of January 2011, Statoil merged all exploration activities into one business unit (EXP) in order to utilize competence, resources and technology more effectively across all exploration areas.

Statoil will focus on managing the risks associated with exploration activities. We will influence our partners and contractors over the implementation of safe practices in all phases of our activities and strive for a continuous improvement in our operational performance.

On the NCS further exploration is necessary for maximising the long term value of our portfolio beyond 2020, and we will collaborate across our producing areas to maximise value for the longer term by extending field lifetimes through near-field exploration. We participate in 213 licences in all licensed parts of the NCS and operate 157 of them.

Access to new, prospective acreage is necessary in order to maintain a high production level in the longer term.

Outside Norway we will expand our exploration portfolio managing risk and reward to deliver profitable growth.

We are the third largest licence holder in the deepwater regions of the US Gulf of Mexico. In addition we currently have exploration licences in Canada, USA (Alaska), Africa (Angola, Algeria, Egypt, Libya, Mozambique, Nigeria and Tanzania), Asia (India, Indonesia and Iran*), Europe and the Caspian region (Azerbaijan, the Faroes, Greenland, Ireland, Norway and the UK), South America (Brazil, Cuba and Venezuela).

*Statoil will not make any future investments in Iran under the present circumstances. For more information, see section Operational review - International E&P - International fields in development and production - The Middle East and Asia - Iran.

3 Operational review

Statoil's operational review follows the organisation of its operations, although certain disclosures about oil and gas reserves are based on geographical areas, as required by the SEC.

Statoil prepared this operational review in accordance with the segment (business area) structure it used prior to 1 January 2011 (for more information, see section Business overview and strategy - New organisational structure as from January 2011). Each business area is presented individually, and underlying business clusters are included according to how the business area organises its operations.

For further information on extractive activities, see the sections E&P Norway and International E&P, respectively.

As required by the SEC, Statoil prepares its disclosures about oil and gas reserves and certain other supplementary oil and gas disclosures based upon geographical areas. The geographical areas are defined by country and continent. They consist of Norway, Eurasia excluding Norway, Africa and the Americas.

For further information on disclosures about oil and gas reserves and certain other supplementary disclosures based upon geographical areas as required by the SEC, see the sections Operational review - Production volumes and price information and Proved oil and gas reserves.

3.1 E&P Norway

3.1.1 Introduction to E&P Norway

Exploration & Production Norway consists of our exploration, field development and operations activities on the Norwegian continental shelf (NCS).

Exploration & Production Norway (EPN) is the operator of 44 developed fields on the NCS. Statoil's equity and entitlement production on the NCS was 1,374 mmboe per day in 2010, which was about 73% of Statoil's total production. Acting as operator, EPN is responsible for approximately 75% of all oil and gas production on the NCS. In 2010, our average daily production of oil and natural gas liquids (NGL) on the NCS was 705 mboe, while our average daily gas production on the NCS was 106.4 mmcm (3.8 bcf).

We have ownership interests in exploration acreage throughout the licensed parts of the NCS, both within and outside our core production areas. We participate in 213 licences on the NCS and are operator for 157 of them.

As of 31 December 2010, EPN had proved reserves of 1,241 mmbbl of crude oil and 463 bcm (16.3 tcf) of natural gas, an aggregate total of 4,153 mmboe.

3.1.2 E&P Norway key events in 2010

Activity levels in Exploration & Production Norway were high in 2010 with several new projects sanctioned including three fast track projects.

- Total entitlement liquids and gas prodution in 2010 amounted to 1,374 mboe per day.
- An extensive turnaround programme was completed in 2010.
- High discovery rate in 2010: 12 discoveries out of 17 exploration wells.
- Final investment decisions were made for the following projects:
  - Gudrun
  - Ekofisk Hotel
  - Njord North West Flank
  - Marulk
  - Valemon
  - Kristin LPP
  - PanPandora
  - Smørbukk North East
  - Ekofisk South
  - Eldfisk
- Production from four new fields added total capacity of approximately 70 mboe per day:
  - Morvin
  - Gjøa
  - Vega
  - Vega South

3.1.3 The NCS portfolio

Our NCS portfolio consists of licences in the North Sea, the Norwegian Sea and the Barents Sea.

We are extending production from existing fields through improved reservoir management and IOR projects. We also operate a significant number of exploration licences.

3.1.3.1 Core production areas

Statoil's NCS portfolio consists of licences in the North Sea, the Norwegian Sea and the Barents Sea.

We have organised our production operations into four business clusters - Operations West, Operations North Sea, Operations North and Partner Operated Fields. The Operations West and Operations North Sea clusters cover our licences in the North Sea. Operations North covers our licences in the Norwegian Sea and in the Barents Sea, while Partner Operated Fields cover the whole NCS.

The fields in each cluster use common infrastructure, such as production installations and oil and gas transport facilities where possible. This reduces the investments required to develop new fields. Our efforts in these core areas will also focus on finding and developing smaller fields through the use of the existing infrastructure and on increasing production by improving the recovery factor.

We are making active efforts to extend production from our existing fields through improved reservoir management and the application of new technology.

3.1.3.2 Potential producing areas

In addition to the producing areas, we operate a significant number of exploration licences. The exploration acreage is located both in undeveloped frontier areas as well as close to infrastructure and producing fields.

NCS
By the end of 2010, the total licensed acreage on the NCS covered an area of 115,331 square kilometres divided between 401 licences. Statoil has interests in 213 licences, covering an acreage of 51,313 square kilometres and is operator for 157 of them. As a consequence of the continuous high-grading and alignment of the former Statoil and Hydro licence portfolios, the number of Statoil licences has been reduced by twelve and the total licenced acreage reduced by 9,086 square kilometres compared with 2009. Statoil has applied for acreage in the 21st licensing round. Awards are expected in the first half of 2011. Statoil also applied for acreage in The Awards in Predefined Areas 2010 (APA), awarded in January 2011.

North Sea
The total licensed acreage in the North Sea covers 56,831 square kilometres divided among 241 licences. Statoil has interests in 114 licences covering 19,516 square kilometres and is operator for 85 of them. One new licence has been awarded to Statoil as operator and three Statoil-operated licences and one partner-operated licence have been relinquished. In order to further minimise area fee costs, the licensed acreages in six more licences were reduced. Total relinquished acreage is 4,282 square kilometres.

Norwegian Sea
The total licensed acreage in the Norwegian Sea covers 41,282 square kilometres divided among 123 licences. Statoil has interests in 19,987 square kilometres divided between 73 licences and is operator for 52 of them, covering an area of 9,389 square kilometres. Eleven of the Statoil-operated licences and five of the partner-operated licences covering 6,300 and 6,968 square kilometres, respectively, are located in areas with a water depth greater than 500m. Five Statoil-operated and three partner-operated licences have been relinquished, and the licensed acreage in three licences was reduced. Total relinquished acreage is 3,807 square kilometres.

Barents Sea
The total licensed acreage in the Barents Sea covers 17,218 square kilometres divided among 40 licences. Statoil has interests in 11,809 square kilometres divided between 26 licences and is operator for 20 of them. One new licence was awarded and two licences were relinquished last year, all of them operated by Statoil. To further minimise area fee costs, the licensed acreages in six more licences were reduced. Total relinquished acreage is 997 square kilometres.

3.1.3.3 Portfolio management

Statoil takes an active approach to portfolio management on the NCS. By continuously managing our portfolio, we create value by optimising our positions in core areas and new growth areas in accordance with our strategies and targets.

Statoil signed several sales and purchase agreements (SPA) in 2010. Two SPAs were signed with Marathon Petroleum AS. In the first SPA, Statoil acquired an 8.2% participation interest in PL025, which contains the Gudrun development, for a consideration of 10% of PL187 and 12.5% of PL048E. A new SPA was therefore signed in which Statoil acquired all of Marathon Petroleum AS's participation interests in PL025 and PL 187 (the Gudrun development and the Sigrun and Brynhild discoveries) and in PL048E (the Eirin discovery) for cash consideration.

An SPA was signed with PGNiG Norway AS in which it farms in 10% to PL326, the Gro discovery. We signed further SPAs with Concedo to acquire its 5% share of PL 348 containing the Gygrid discovery; with Petoro AS, a company owned by the Norwegian State that was formed to manage SDFI assets, to divest our 30% share in PL158 containing the Hasselmus discovery; and with TOTAL E&P Norge AS to divest our 21% share in PL043CS and PL043DS containing the Islay discovery. SPAs were also signed with TOTAL E&P Norge AS and ExxonMobil Exploration and Production Norway AS to carve out the Theta NE prospect from PL046, PL303 and PL078B, thus aligning the participation interests.

Several transactions have also been carried out that involve the farming-in and farming-out of exploration licences.

3.1.4 Exploration on the NCS

Statoil's 2010 exploration drilling activity on the NCS was reduced compared with the extensive exploration drilling campaigns carried out in 2008 and 2009.

17 exploration wells and four exploration extensions wells were completed in 2010 compared with the completion of 39 exploration wells in 2009 and also in 2008. In 2010, the focus has been on evaluating and maturing all the 2009 and 2008 well results.

12 of the 17 wells drilled for exploration purposes were wildcat wells drilled to test new prospects, and six of them were operated by Statoil. Five of the six Statoil-operated wildcat wells and three of the six partner-operated wildcat wells confirmed the presence of hydrocarbons.

A major oil discovery was made in the central part of the North Sea in the Avaldsnes prospect, which is located on the Utsira High, a structural element separating the two Statoil-operated fields, Sleipner and Grane. Lundin is operator for the Avaldsnes licence, and Statoil has a 40% ownership share. The prospect evaluation prior to the drilling was based on a new geological play model for the area. The positive result, which proves the validity of this model, has increased the probability of success for similar prospects in a neighbouring Statoil-operated licence scheduled for drilling in 2011.

Another discovery is Fossekall, located near the Norne field in the Norwegian Sea. Fossekall, which is operated by Statoil, will be developed as a tie-in to Norne together with Dompap, a discovery made in late 2008. Fossekall is now considered to be a fast track candidate with estimated production start-up in 2013. For further information about fast track projects, see section Operational review - Projects & Procurement - Project development.

The Snadd North discovery was made in 2010 in the BP-operated Skarv-Idun area, where Statoil is a major partner (36.165%). Test production of the low carbon dioxide gas will start during the third quarter 2011 and last for 12-18 months. Afterwards, the partnership will evaluate the further development of both Snadd North and South.

The drilling results from the two Shell-operated exploration wells in the Vøring basin are disappointing. The wildcat well located on the Dalsnuten prospect never penetrated any potential reservoir rock, and the appraisal well on the Gro structure proved the same marginal reservoir condition in this new segment as in the previous one. A re-evaluation of the prospects in this part of the Norwegian Sea is necessary before the next exploration well is drilled.

In the Barents Sea, ENI, as operator for the first of four scheduled drilling operations, started the joint 2010/2011 drilling campaign for the Arctic-equipped "Polar Pioneer" rig. Operatorship will be transferred from ENI to Statoil in early 2011, and the second well will be drilled in the southern part of the Hammerfest basin.

The Norwegian Minister of Petroleum and Energy has announced that there will be no drilling in any deepwater licenses granted from the NCS's 21st licensing round, scheduled to be completed in the first half of 2011, until the Norwegian Ministry of Petroleum and Energy has deeper knowledge about the accident that occurred on the BP-operated Macondo well in the deepwater Gulf of Mexico in April 2010, including possible implications for the Ministry's regulations. Although drilling on the NCS occurs mainly at a shallower depth and at lower pressure conditions than in the deepwater Gulf of Mexico, both Statoil and the Norwegian authorities are examining operations on the NCS in light of the accident in the Gulf of Mexico. The Norwegian Petroleum Safety Authority (PSA) is putting more focus on the ability of companies to effectively handle a potential blow-out event. This means, for example, that companies will have to demonstrate their ability to handle a potential blow-out and inform the PSA about how they plan to shut down a well in case of a blow-out before receiving permission to start drilling a new well. The PSA has also established a project team to systematise and assess experience gained and investigatory findings from the Macondo incident in order to secure lessons and improvements for the NCS.

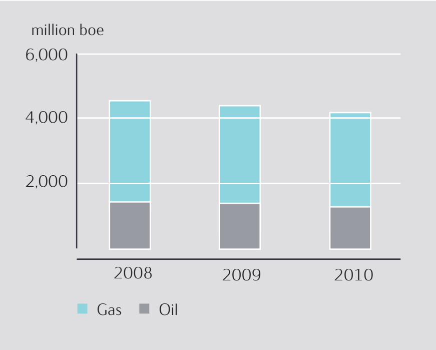
The table below shows Statoil's exploratory and development wells drilled on the NCS over the last three years.

	2010	2009	2008
North Sea			
Statoil operated exploratory	10	23	13
Successful	7	18	8
Dry	3	5	5
Statoil operated development	59	72	75
Partner operated exploratory	6	1	4
Successful	4	1	2
Dry	2	0	2
Partner operated development	11	17	13
Norwegian Sea			
Statoil operated exploratory	2	10	15
Successful	2	8	12
Dry	0	2	3
Statoil operated development	14	19	13
Partner operated exploratory	3	4	0
Successful	2	3	0
Dry	1	1	0
Partner operated development	6	1	3
Barents Sea			
Statoil operated exploratory	0	1	7
Successful	0	1	5
Dry	0	0	2
Statoil operated development	0	0	0
Partner operated exploratory	0	0	0
Successful	0	0	0
Dry	0	0	0
Partner operated development	0	0	0
Totals			
Exploratory	21	39	39
Successful	15	31	27
Dry	6	8	12
Development	90	109	104

3.1.5 Oil and gas reserves on the NCS

At the end of 2010, Statoil had a total of 1,241 mmbbl of proved oil reserves and 463 bcm (16.3 tcf) of proved natural gas reserves on the NCS.

EPN, oil and gas reserves



Measured in barrels of oil equivalents (boe), our NCS proved reserves consist of 30% oil and 70% natural gas, based on total NCS proved reserves of 4,153 mmboe.

In 2010, final investment decisions were made for Valemon, Gudrun, Visund South and Marulk on the NCS, and contributed positively to the proved reserves balance. In addition, revision of proved reserves for several of our producing fields contributed positively.

Proved developed reserves at year end were 3,394 mmboe, which is 82% of the proved reserves. Of the 2010 proved developed reserves, 950 mmboe are oil and 389 bcm (13.7 tcf) are natural gas.

The following table shows our total NCS proved reserves as of 31 December for each of the last three years. Further information on reserves can be found in section Operational review - Proved oil and gas reserves and in note 35 - Supplementary oil and gas information - to our Consolidated Financial Statements.

		Oil/NGL	Natural gas		Total
Year		mmbbls	bcm	bcf	mmboe
2010	Proved reserves end of year	1,241	463	16,343	4,153
	of which, proved developed reserves	950	389	13,721	3,394
2009	Proved reserves end of year	1,351	480	16,938	4,369
	of which, proved developed reserves	1,028	401	14,138	3,548
2008	Proved reserves end of year	1,396	498	17,581	4,529
	of which, proved developed reserves	1,113	410	14,482	3,693

3.1.6 Production on the NCS

In 2010, our total entitlement oil and NGL production in Norway was 257 mmbbl, and gas production was 38.8 bcm (1,372 bcf), which represents an aggregate of 1.374 mmboe per day.

The following table shows the NCS production fields and field areas in which we are currently participating. Field areas are groups of fields operated as a single entity.

Business cluster	Georgraphical area	Statoil's equity interest in %[1]	Operator	On stream	Licence expiry date	Producing wells Oil	Producing wells Gas	Average daily production in 2010 mboe/day
Operations North Sea								
Sleipner Øst	The North Sea	59.60	Statoil	1993	2028	0	10	**20.5**
Sleipner Vest	The North Sea	58.35	Statoil	1996	2028	0	20	**76.8**
Gungne	The North Sea	62.00	Statoil	1996	2028	0	4	**11.8**
Troll Phase 1 (Gas)	The North Sea	30.58	Statoil	1996	2030	0	39	**162.8**
Troll Phase 2 (Oil)	The North Sea	30.58	Statoil	1995	2030[2]	117	0	**36.7**
Fram	The North Sea	45.00	Statoil	2003	2024	9	0	**29.2**
Kvitebjørn	The North Sea	58.55	Statoil	2004	2031	0	10	**96.2**
Visund	The North Sea	53.20	Statoil	1999	2023	6	1	**24.2**
Vega	The North Sea	60.00	Statoil	2010	2035	0	2	**0.3**
Vega Sør	The North Sea	45.00	Statoil	2010	2024	2	0	**0.1**
Gjøa	The North Sea	20.00	GDFSuez	2010	2028	3[17]	2	**1.3**
Grane	The North Sea	36.66	Statoil	2003	2030[3]	25	0	**54.7**
Veslefrikk	The North Sea	18.00	Statoil	1989	2015	17	0	**2.5**
Huldra	The North Sea	19.88	Statoil	2001	2015	0	5	**3.6**
Glitne	The North Sea	58.90	Statoil	2001	2013	6[4]	0	**2.6**
Heimdal	The North Sea	29.87	Statoil	1985	2021[5]	0	3	**1.2**
Brage	The North Sea	32.70	Statoil	1993	2015[6]	21	0	**9.9**
Vale	The North Sea	28.85	Statoil	2002	2021	0	1[7]	**0.1**
Vilje	The North Sea	28.85	Statoil	2008	2021	2	0	**8.8**
Volve	The North Sea	59.60	Statoil	2008	2028	3	0	19.8
Total Operation North Sea						211	97	**562.9**
Operations West								
Statfjord Unit	The North Sea	44.34	Statoil	1979	2026	68[8]	8	**48.7**
Statfjord Nord	The North Sea	21.88	Statoil	1995	2026	7	0	**1.7**
Statfjord Øst	The North Sea	31.69	Statoil	1994	2026[9]	7	0	**5.5**
Sygna	The North Sea	30.71	Statoil	2000	2026[10]	3	0	**0.3**
Gullfaks	The North Sea	70.00	Statoil	1986	2016	95	9	**109.8**
Snorre	The North Sea	33.32	Statoil	1992	2015[11]	27	0	**34.6**
Tordis area	The North Sea	41.50	Statoil	1994	2024	6	0	**5.2**
Vigdis area	The North Sea	41.50	Statoil	1997	2024	14	0	**15.1**
Gimle	The North Sea	65.13	Statoil	2006	2016	2	0	**2.5**
Oseberg	The North Sea	49.30	Statoil	1988	2031	62	0	**101.7**
Tune	The North Sea	50.00	Statoil	2002	2032	0	4	**6.0**
Total Operations West						291	21	331.3
Operations North								
Alve	The Norwegian Sea	85.00	Statoil	2009	2029	0	1	**19.2**
Kristin	The Norwegian Sea	55.30	Statoil	2005	2033[12]	12	0	**41.9**
Norne	The Norwegian Sea	39.10	Statoil	1997	2026	9	0	**14.2**
Urd	The Norwegian Sea	63.95	Statoil	2005	2026	3	0	**4.6**
Heidrun	The Norwegian Sea	12.41	Statoil	1995	2024	29[13]	0	**8.8**
Åsgard	The Norwegian Sea	34.57	Statoil	1999	2027	0	37	**123.4**
Mikkel	The Norwegian Sea	43.97	Statoil	2003	2022[14]	0	3	**22.6**
Morvin	The Norwegian Sea		Statoil	2010	2027	1	0	**4.6**
Njord	The Norwegian Sea	20.00	Statoil	1997	2021 & 2023[15]	6[16]	0	**10.4**
Tyrihans	The Norwegian Sea	58.84	Statoil	2009	2029	4	0	**42.1**
Snøhvit	The Barents Sea	33.53	Statoil	2007	2035	0	9	**37.0**
Yttergryta	The Norwegian Sea	45.75	Statoil	2009	2027	0	1	**4.5**
Total Operations North						64	51	333.4
Partner Operated Fields								
Ormen Lange	The Norwegian Sea	28.92	Shell	2007	2041	0	12	**21.0**
Ekofisk area	The North Sea	7.60	ConocoPhillips	1971	2028	153	0	**108.6**
Ringhorne Øst	The North Sea	14.82	ExxonMobil	2006	2030	3	0	**2.9**
Sigyn	The North Sea	60.00	ExxonMobil	2002	2018	1	2	**10.8**
Enoch	The North Sea	11.78	Talisman	2007	2018	1	0	**2.1**
Skirne	The North Sea	10.00	Total	2004	2025	0	2	**0.5**
Total Partner Operated Fields						158	16	**146.0**
Total						724.0	185.0	1,373.7

(1) Equity interest as of December 31, 2010.
(2) Troll Phase 2 (Oil) has 64 multi branched wells
(3) Grane has 9 multi branched wells
(4) Glitne 1 multi branched well
(5) PL036 expires in 2021 and PL102 expires in 2025. The owner share of the topside facilities is 39,44%, however the owner share of the reservoir and production is 29,87%.
(6) PL185 expires in 2015 and PL053B and PL055 both expire in 2017
(7) Vale 1 multi branched well
(8) 89 single completed wells, 4 multiple completed wells
(9) PL037 expires in 2026 and PL089 expires in 2024
(10) PL037 expires in 2026 and PL089 expires in 2024
(11) PL089 expires in 2024 and PL057 expires in 2015
(12) PL134B expires in 2027 and PL199 expires in 2033
(13) 1 multi branched well
(14) PL092 expires in 2020 and PL121 expires in 2022
(15) PL107 expires in 2021 and PL132 expires in 2024
(16) 1 multi branched well
(17) From 2011 Gjøa will be reported as a partner operated field

The following table shows our average daily entitlement production of oil, including NGL and condensates, and natural gas for each of the years ending 31 December 2010, 2009 and 2008.

Area production	2010 Oil and NGL mbbl	2010 Natural gas mmcm	2010 mboe	2009 Oil and NGL mbbl	2009 Natural gas mmcm	2009 mboe	2008 Oil and NGL mbbl	2008 Natural gas mmcm	2008 mboe
	For the year ended December 31,								
Operations North	183	24	333	175	25	332	175	22	314
Operations North Sea	240	51	563	269	49	574	250	49	558
Operations West	246	14	331	297	14	385	355	19	477
Partner Operated Fields	36	18	146	43	18	158	43	11	112
Total	704	106	1,374	784	106	1,450	824	101	1,461

3.1.7 Development on the NCS

The NCS is the backbone of our operations and the centre of innovation. We continue to explore and develop the NCS as operator and partner using the best available technology and increasingly standardised development solutions.

3.1.7.1 Fields under development on the NCS

The following fields are currently under development on the NCS.

The **Gudrun** Field is located in the North Sea. The field will be developed with a separate steel jacket-based process platform for separation of the oil and gas. Gas and partly stabilised oil will be transported in separate pipelines from Gudrun to Sleipner. Gas will be further transported through the Gassled system, while oil will be transported together with Sleipner condensate by pipeline to the Gassco-operated Kårstø plant near Haugesund. (Gassco AS is a company owned by the Norwegian state that operates the Norwegian natural gas transportation system, Gassled. Statoil's ownership interest in Gassco was 32.1% by year end 2010, and 22.5% from 1 January 2011). The plan for development and operation (PDO) was submitted to the Norwegian authorities in February 2010, and approved by the Norwegian authorities in June 2010. Production is estimated to start in 2014. The total investments are estimated to be NOK 19.6 billion. Statoil holds a 46.8% interest in Gudrun.

Skarv is an oil and gas field located in the Norwegian Sea in which we have an interest of 36.165% and for which BP is the operator. The field is being developed with a floating production storage and offloading (FPSO) vessel and five subsea installations. Oil will be exported by offshore loading, and gas will be exported via the Åsgard export system. Production is expected to start in August 2011. The total development cost is estimated by the operator, BP, to be NOK 36.8 billion.

The PDO for **Goliat** was submitted in February 2009 and approved by the Norwegian authorities in June the same year. Goliat is the first oilfield to be developed in the Barents Sea. The field is being developed with subsea wells tied back to a circular FPSO. The oil will be offloaded to shuttle tankers. Associated gas will initially be reinjected and later exported together with the gas cap. Statoil is the only partner in Goliat, with an interest of 35%. Eni is the operator. Production start-up is expected in late 2010. The operator has estimated the development costs for the field to be NOK 30.5 billion.

Valemon, which is located in the North Sea, will be developed with a steel jacket platform with gas, condensate and water separation. Drilling will be performed using a jack-up rig. Rich gas will be transported via Huldrapipe to Heimdal for processing. Sales gas will be transported in Vesterled to St Fergus, or, alternatively, in Statpipe to Draupner. There will be a condensate tie-in to Kvitebjørn for stabilisation and further export in pipelines to Mongstad. Statoil holds an interest of 64.275% in the field. The PDO was submitted to the Norwegian authorities at the end of October 2010 and PDO approval is expected during the second quarter of 2011. The development cost of Valemon is currently estimated to be NOK 19.6 billion, and production start-up is estimated to take place during the fourth quarter 2014.

Marulk, in which Statoil holds an interest of 50%, is a gas and condensate field located in the Norwegian Sea 25 kilometres southwest of Norne. The field was discovered in 1992. The final investment decision was taken early 2010 and the PDO was approved by the Norwegian authorities in July 2011.The field is a subsea development with two wells tied back to Norne. Rich gas will be transported through the Norne pipeline and Åsgard Transport System for processing to sales gas at Kårstø. Condensate will be stored and off-loaded commingled with the Norne crude. Production is estimated to start in the second quarter 2012. The operator estimates the total investments to be NOK 4 billion. The operator is Eni, but Statoil is carrying out the project work.

The table below shows some key figures as at 31 December 2010 for our major development projects.

Project	Statoil's share as at 31 December 2010	Statoil's investment as at 31 December 2010 (1)	Production start	Plateau production Statoil's share (3)	Lifetime in years
Goliat (2)	35.000 %	10.7	2013	30,000	18
Gudrun	46.800 %	9.2	2014	40,000	12
Skarv (2)	36.165 %	13.7	2011	53,000	12
Marulk	50.000 %	1.9	2012	10,400	14
Valemon	64.275 %	12.6	2014	50,000	14

(1) Estimated in NOK billion
(2) Partner operated project
(3) Boe/day

3.1.7.2 Redevelopments on the NCS

The following projects are being developed on the NCS to extend the life of existing installations or to exploit new opportunities.

The **Snorre redevelopment** project, which is defined as an increased oil recovery (IOR) project, will contribute to achieving the overall oil recovery ambition for the Snorre Unit and Vigdis. The project includes a water injection pipeline from Statfjord C to the Vigdis field.

The **Statfjord late life** project converted Statfjord into a mainly gas-producing field by changing the drainage strategy. Gas exports to the UK through a new pipeline connected to the existing pipelines to Flags and St Fergus commenced in late 2007. Investments in the project are estimated to total NOK 21.5 billion.

Troll Field projects include the Troll B gas injection project and the Troll A P12 pipeline project. The main goals of these projects are IOR from Troll B and enabling the Troll field to maintain an average gas export capacity of 120 million standard cubic metres per day and a long-term gas export capacity of 30 billion standard cubic metres per year.

The **Troll B Gas Injection** project includes two gas injectors in the Troll West Gas Province south. Start-up is planned in 2011.

The **Troll A P12 project** includes a new 62.5-kilometre 36-inch pipeline between Troll A and Kollsnes, modifications on Troll A and an interface with the Kollsnes plant. Start-up of the pipeline is planned in late 2011.

The **Troll C - O2 template**, which will be located north-west of the Troll C platform, is defined as an IOR project. The O2 template will be tied back to the existing O1 template, which is tied back to Troll C. Drilling started in December 2009 and the first two wells started production in 2010.

The **Norne M template** will be located in the southern area of the Norne field. The template will have four production well slots and will be connected to the existing infrastructure at the K template. Drilling started in March 2010 and production start-up is scheduled for April 2011.

The **Gullfaks B water injection upgrade** project includes replacement of the pipeline from Gullfaks A to Gullfaks B, upgrading of the existing water injection system and increased water injection capacity on Gullfaks B. The project is expected to be completed in early 2014.

The main purpose of **Kvitebjørn Precompression** project is to increase and accelerate gas and condensate recovery by facilitating low pressure production. The project includes installation of a turbine-driven compressor in a new module on the platform. Start-up is scheduled for December 2013.

The **Njord North-West Flank** project will enable Njord A to drill and produce from the NWF reservoir. Drilling is scheduled to start in May 2011 and production is planned to start in April 2012.

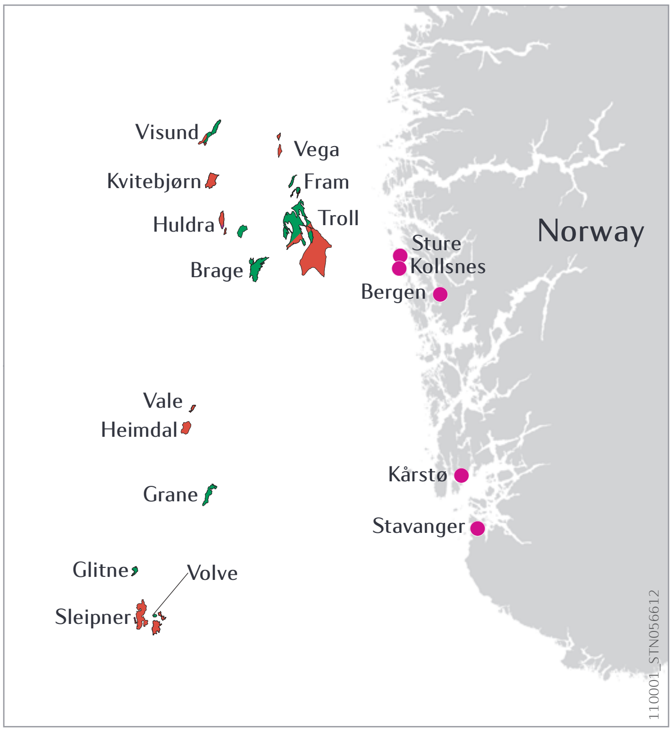
3.1.8 Fields in production on the NCS

We continue to develop the NCS, delivering good results in a year that saw extensive turnarounds and several operational challenges.

3.1.8.1 Operations North Sea

Operations North Sea include a large part of Statoil's production activity on the NCS. Our focus is on increasing and prolonging production in the area, and we give priority to IOR and exploration and development of new fields.

The main producing fields in the Operations North Sea area are Troll, Sleipner, Kvitebjørn, Visund, Grane, Brage, Veslefrikk, Huldra, Glitne, Volve and Heimdal. In addition, our new Vega field started production in December 2010.



The area is dominated by natural gas production, with 57.5 of the equity production in 2010. The petroleum reserves are located below water depths of between 80 and 330 metres. In 2010, Statoil's share of the area's production was 240 mbbl of oil, condensate and NGL per day and 323 mboe of gas per day, or 563 mboe per day in total.

Brage is an oilfield east of Oseberg in the northern part of the North Sea. The oil is piped to Oseberg and then through the pipeline in the Oseberg Transport System to the Sture terminal. A gas pipeline is tied back to Statpipe.

Fram is connected to the Troll C platform for processing. Oil production started in 2003, while gas exports started in October 2007.

Glitne is an oilfield located about 40 kilometres north-west of Sleipner East. Glitne is the smallest field development on the NCS to use a stand-alone production system.

Grane is the first field on the NCS to produce heavy crude oil. It is Statoil's largest heavy oil field. The field is located to the east of the Balder field in the northern part of the North Sea. Oil from Grane is piped to the Sture terminal, where it is stored and shipped. Injection gas is imported to Grane by pipeline from the Heimdal facility. As a result, after around 25 years of oil production, Grane is producing injected gas as well.

Heimdal is a gas field located in the northern part of the North Sea. Heimdal mainly operates as a processing centre for other fields. Huldra, Skirne and Vale deliver gas to Heimdal, and gas from Oseberg is also transported via Heimdal. The PDO for Valemon was submitted in October 2010. Gas from this field will be carried via the existing pipeline from Huldra to Heimdal. The PDO approval is expected during the first quarter of 2011. Then the lifetime of the processing facility at the Heimdal Gas Centre will be extended, thereby enabling us to maintain important processing capacity in the area.

Pre-compression plans for the **Kvitebjørn** field are expected to increase the production of gas and condensate from the Kvitebjørn field by approximately 35 million standard cubic metres (mscm) of oil equivalent and thus increase the recovery rate from 55% to 70%. Work on production of the compressor has already started. The offshore installation is expected to take place from 2012 until completion in early 2014.

Sleipner consists of the Sleipner East, Gungne and Sleipner West gas and condensate fields. Condensate from the Sleipner field is transported to the gas processing plant at Kårstø. The gas from Sleipner has a high level of carbon dioxide. It is extracted on the field and re-injected into a sand layer beneath the seabed to reduce carbon dioxide emissions to the air. We are currently exploring several prospects and discoveries in the Sleipner area that can potentially be tied in to Sleipner. The PDO for Gudrun was approved by the Norwegian authorities in June 2010, and the hydrocarbons will be piped to the Sleipner field. On Sleipner, the oil and gas from Gudrun will be further processed before the oil is transported to Kårstø together with the Sleipner condensate.

The **Troll** Area comprises Troll, Fram and Vega. Troll is the largest gas field on the NCS and a major oilfield. The Troll Field Project submitted a new PDO in June 2008 for IOR in the area. The PDO was approved by Norwegian authorities in June 2009 and the project is well under way.

The **Vega** field came on stream in December 2010. It consists of two licences, Vega South and Vega Central; Statoil has substantial ownership interests in both licences. Vega is a new production area for Statoil. The Vega field has been developed with three seabed templates, and gas and condensate are sent to the new Gjøa platform. For further information about the Gjøa platform, see Operational review - E&P Norway - Fields in production on the NCS - Partner operated fields on the NCS.

Veslefrikk is an oilfield located north of Oseberg in the northern part of the North Sea. **Huldra** is located in the Viking Graben and developed by a (normally unmanned) platform remotely controlled from the Veslefrikk field. Oil from Veslefrikk is exported through the Oseberg Transportation System, while gas is exported to Kårstø. Veslefrikk also processes condensate from Huldra.

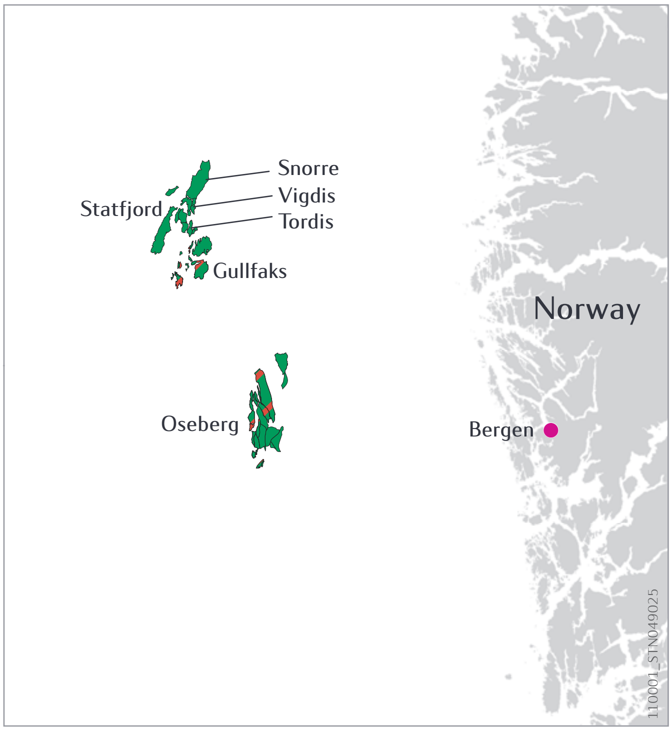
The first oil flowed from the **Vilje** field to the Alvheim FPSO on 1 August 2008. The Vilje field, which is linked to the Alvheim field, is located in the northern part of the North Sea, north of the Heimdal field.

The **Visund** oilfield is located to the east of the Snorre field in the northern part of the North Sea. The field contains oil and gas in several tilted fault blocks with separate pressure and liquid systems. The oil is piped to Gullfaks A for storage and export. Gas is exported to the Kvitebjørn gas pipeline and on to Kollsnes.

Volve is an oilfield located in the southern part of the North Sea approximately eight kilometres north of Sleipner East. The development is based on production from the Mærsk Inspirer jack-up rig, with *Navion Saga* used as a storage ship for crude oil before export. Gas is piped to the Sleipner A platform for final processing and export.

3.1.8.2 Operations West

The Operations West area contains light oil petroleum resources in a compact geographic area in which Statoil is the sole operator. The main producing fields in the Operations West area are Statfjord, Gullfaks, Snorre, Oseberg, Tordis and Vigdis.



Statoil's share of the area's production in 2010 was 246 mbbl per day of oil, condensate and NGL, and 85 mboe per day of gas, or 331 mboe per day in total. Operations West is the leading oil-producing area on the NCS and, even after over 20 years of production, we believe there are still substantial opportunities for increased value creation.

Statoil has taken several initiatives to identify and implement measures to increase and prolong production from the Operations West area. These initiatives involve IOR, and they have resulted in a prolongation of planned production beyond the current licence periods for several of the fields.

In 2010, Operation West performed two turnarounds without serious HSE incidents.

Gullfaks has been developed with three large concrete production platforms. Oil is loaded directly into custom-built shuttle tankers on the field. Associated gas is piped to the Kårstø gas processing plant and then on to continental Europe. Five satellite fields, Gullfaks South, Rimfaks, Gullveig, Gulltopp and Skinfaks, have been developed with subsea wells remotely controlled from the Guilfaks A and C platforms.

On 19 May, a well control incident occurred at well C-06A on Gullfaks C. The direct cause of the incident was leakage in a well casing. A thorough procedure to reinstall the second well barrier kept the platform shut down for two months. Statoil's internal investigation into the incident found that there were deficiencies in risk management and compliance with internal requirements for drill operation, planning and execution. The most important remedial measures identified by the internal investigation relate to risk analyses and acceptance criteria when complexity increases; supporting documentation, quality assurance and formal procedures in planning and decisionmaking; and greater involvement of technical expertise. A copy of Statoil's internal investigation report can be found at
http://www.statoil.com/enlNewsAndMedialNews/2010/Downloads/5Nov_201 0_%20Rapport_broennhendelse_Gullfaks%20C .pdf.

The Norwegian PSA also audited the planning of the well, and issued a report that concluded that overall serious deficiencies were identified in Statoil's planning of the well. Following its investigation, the Norwegian PSA issued an order requiring Statoil to review and assess compliance with the work processes established to safeguard the well construction process on Gullfaks, conduct an independent assessment of why measures adopted after prior similar incidents did not have the desired effect on Gullfaks and implement measures throughout Statoil based on the Norwegian PSA ordered review and assessments. Statoil is complying in all respects with the Norwegian PSA's order. A copy of the Norwegian PSA's report and related documentation can be found at http://www.ptil.no/news/notification-of-order-to-statoil-gullfaks-c-article7409-79.html?lang=enUS.

Gullfaks C resumed drilling in July, but following our internal investigation, we shut down drilling operations for three wells in November to ensure that the drilling and well operations were being conducted in accordance with our procedures and the findings in our internal investigation.

In late 2010, Statoil decided to shut in the Gullfaks South Brent reservoir for six months in order to maintain drillability for future wells.

The **Gimle** field is a Gullfaks satellite field that is operated as a separate unit. Permanent production started in May 2006, converting the Gimle exploration well drilled from the Gullfaks C platform into a production well. By the end of 2010, Gimle consisted of two producers and one injector, all drilled as long-reach wells from the Gullfaks C platform.

The **Oseberg** area includes the main Oseberg field developed with field centre installations and the Oseberg C production platform, and two satellite fields - Oseberg East and Oseberg South - developed with production platforms. In addition, the Tune field and Oseberg West Flank have been developed with subsea installations and tied back to the Oseberg field centre. Oil and gas from the satellites are piped to the Oseberg field centre for processing and transportation. Oil is exported to shore through the Oseberg transportation system, and gas is exported through the Oseberg gas transportation system to Heimdal and on to market.

The **PL 089** licence includes the Vigdis, Borg and Tordis fields. The Tordis field and the southern part of the Borg field have been developed with seven subsea satellites and two templates that are tied back to Gullfaks C, where the oil and gas are processed and stored for offshore loading and export.

The **Vigdis** field was developed in 1997 with three subsea templates with a well stream through pipelines connected to Snorre A, where the oil is stabilised and exported to Gullfaks for storage and loading. The northern part of Borg is also produced via the Vigdis templates.

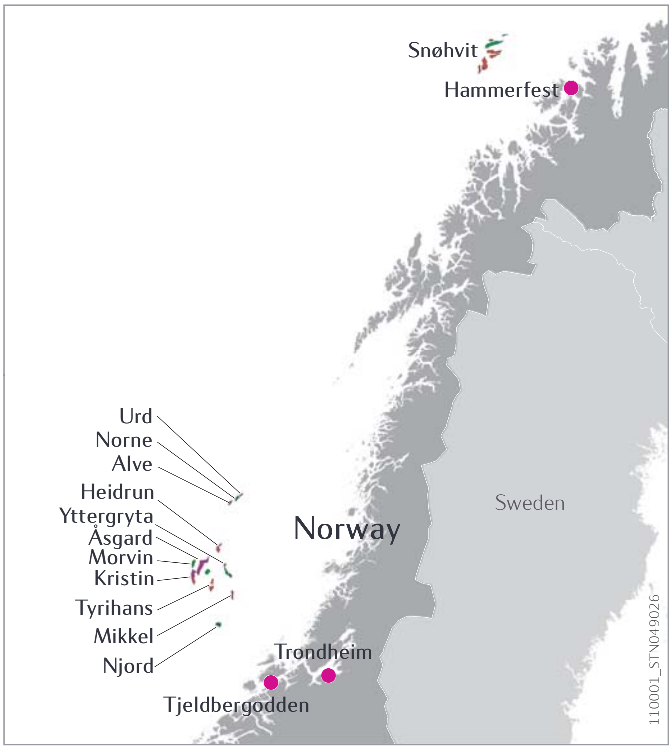
The **Snorre** field has been developed with two platforms and one subsea production system connected to one of the platforms (Snorre A). Oil and gas is exported to Statfjord for final processing, storage and loading. One satellite field, Vigdis, has been developed with a subsea tie-back to Snorre A

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. Associated gas is piped through the Tampen link to the UK or, alternatively, to the Kårstø gas processing plant and then on to continental Europe. Three satellite fields (Statfjord North, Statfjord East and Sygna) have been developed, each of them tied back to the Statfjord C platform. In 2005, an amended PDO was approved by the Norwegian authorities for the late life production period for Statfjord. The Norwegian authorities granted a licence extension for the Statfjord area from 2009 to 2026.

According to plan, Statfjord A will be shut down for production in 2016.

3.1.8.3 Operations North

Our producing fields in the Operations North area are Åsgard, Mikkel, Yttergryta, Heidrun, Kristin, Tyrihans, Norne, Urd, Alve, Njord and Snøhvit. The Morvin field started production on 1 August 2010.



Our share of the area's production in 2010 was 183 mbbl per day of oil, condensate and NGL, and 151 mboe per day of gas, or 334 mboe per day in total.

The region is characterised by petroleum reserves located at water depths between 250 and 500 metres. The reserves are partly under high pressure and at high temperatures. These conditions have made development and production more difficult, challenging the participants to develop new types 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 decline in production from the mature fields through increased seismic activity and well maintenance. In addition, we intend to expand our activities by utilising our installed production and transportation capacity before building new infrastructure.

The **Heidrun** platform is the largest concrete tension leg platform ever built. Heidrun was the first production platform in Operations North, with production start-up in 1995. Most of the oil from Heidrun is shipped by shuttle tankers to our Mongstad crude oil terminal for onward transportation to customers. Gas from Heidrun provides the feedstock for the methanol plant at Tjeldbergodden in Norway. Additional gas volumes are exported through the Åsgard Transport System (ÅTS) to gas markets in continental Europe.

Kristin is a gas and condensate field in the south-western section of the Operations North area. The Kristin development is the first high-temperature/high-pressure (HTHP) field developed with subsea installations. The pressure and temperature in the reservoir - 900 bar and 170 degrees Celsius, respectively - are higher than on any other developed field on the NCS. The stabilised condensate is exported to a joint Åsgard and Kristin storage vessel, and the rich gas is transported to shore via the ÅTS to the gas processing facility at Kårstø.

Tyrihans started producing oil and gas in July 2009, and the field was producing from five wells by the end of 2010. In addition, gas is injected into two injection wells via Åsgard B. Tyrihans is expected to be completed in 2011 with another three wells. All production volumes are processed on the Kristin platform.

Njord consists of two installations. Njord A is a platform with drilling facilities and a production plant for oil and gas. Njord B is a storage vessel for oil. The Njord field has produced oil since 1997, and gas export started in late 2007 via ÅTS and Kårstø.

The **Norne** field has been developed with a production and storage ship tied to subsea templates. This ship has processing facilities on deck and storage tanks for oil. Processed crude oil can be transferred over the stern to shuttle tankers. Norne is connected to gas markets in continental Europe through a link with ÅTS.

The **Urd** fields, Svale and Stær, are located ten and five kilometres north of the Norne field, respectively. The fields are produced through subsea facilities, with the well stream tied back to the Norne FPSO.

The **Alve** field, which consists of one producing well and a subsea template, was started up in March 2009. A second producing well is scheduled to start in 2011. The field is produced through subsea facilities, with the well stream tied back to the Norne FPSO.

Snøhvit is the first field developed in the Barents Sea. Twenty wells are expected to produce natural gas from three gas reservoirs: Snøhvit, Askeladd and Albatross. By the end of 2010, Snøhvit was producing from nine wells. All the offshore installations are subsea, which makes Snøhvit one of the first major developments without production facilities offshore. Snøhvit re-injects carbon dioxide from the liquefied natural gas (LNG) plant into a separate well/reservoir.

The natural gas, which is transported to shore through a 143-kilometre-long pipeline, is landed on Melkøya, where it is processed at our LNG plant. This plant is Europe's largest export factory for LNG, which is shipped to customers in Europe and the USA in tankers. The first shipment took place in late 2007. The LNG plant has suffered from operational challenges, particulary in relation to problems with the heat exchangers, which are located in the heart of the

Snøhvit LNG Plant (Cold box). Their function is to bring the temperature down on the methane gas so that it liquidizes at -164 C. The heat exchangers use ethane and prophane as cooling medium as they condense at higher temperatures than methane. The cooling medium is sprayed over the spiral wounds which contains the methane gas.

Hammerfest LNG has improved regularity and capacity in 2010. There has been one planned inspection shutdown lasting ten days and two unplanned production stops due to unforeseen process challenges.

The **Åsgard** field contains three fields: Smørbukk, Smørbukk South and Midgard. 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 are among the most extensive in the world, with a total of 58 wells grouped in 17 seabed templates. The Åsgard B platform is the largest floating gas processing centre in the world, and Åsgard A is one of the largest floating production ships ever built.

The Åsgard development links the Haltenbanken area to Norway's gas transport system in the North Sea. Gas from the field is piped through the ÅTS to the processing plant at Kårstø and on to receiving terminals in Emden and Dornum in Germany. Oil produced at the Åsgard A vessel and condensate from the Åsgard C storage vessel are shipped from the field in shuttle tankers.

Mikkel is a gas and condensate field. Production from two seabed templates is tied to the subsea installation at Midgard for onward transportation to the Åsgard B gas processing platform.

Yttergryta produces from a single well, and the well stream is tied back to Åsgard B for processing.

Morvin started production on 1 August 2010. The field consists of two seabed templates with planned production from four wells. The first three wells have been completed and were put into production by year end. The last well is expected to be completed during spring 2011. The well stream with oil and gas is tied back to Åsgard B for processing. Morvin is an important contributor to utilising the production capacity at Åsgard B.

3.1.8.4 Partner-operated fields on the NCS

Partner-operated fields account for a significant proportion of Statoil's oil and gas portfolio. With expected production start-up on Skarv in 2011, and on Marulk and Goliat in 2012, the importance of partner-operated fields in Statoil is increasing.

The portfolio ranges from development projects to mature fields, and their complexity requires detailed knowledge of the areas involved.

Ormen Lange, a deepwater gas field in the Norwegian Sea, is the second largest gas field on the NCS. Statoil has a 28.92% interest in the field. Statoil was operator for the development phase and Norske Shell became the operator for the production phase that began at the end of 2007. Statoil continues to execute the approved, but not yet completed subsea compression pilot. The selected development is an extensive subsea development at depths ranging from 850 to 1,100 metres. The well stream is transported to an onshore processing and export plant at Nyhamna. The gas is then transported through a dry gas pipeline, Langeled, via Sleipner to Easington in the UK.

Ekofisk was the first developed field complex to come into operation on the NCS. ConocoPhillips is the operator. It consists of the Ekofisk, Eldfisk and Embla fields (Statoil's interest 7.604%), plus Tor (Statoil's interest 6.639%). Ekofisk has been upgraded with several new platforms over the years, the latest being the 2/4-M, which was installed in 2005. In early 2010 a final investment decision was made to construct a new Ekofisk accomodation and field centre platform. Several new projects are being studied: a new Ekofisk South drilling platform and redevelopments of Eldfisk and Tor. Final investment decisions were made in 2010 for Ekofisk South and Eldfisk. The new platforms are expected to extend the field life beyond the current licence period, which ends in 2028.

Sigyn, operated by ExxonMobil and in which Statoil has a 60% interest, is a gas and condensate field located 12 kilometres south-east of the Sleipner A installation. The gas is exported from Sleipner A and the condensate is delivered to Kårstø. The development consists of three production wells on one subsea template, with two pipelines and one umbilical connecting it to the Sleipner A platform.

Statoil has a 14.82% interest in the ExxonMobil-operated **Ringhorne East** field. The unitised field started production in March 2006. Three production wells have been drilled from the Ringhorne facility. Oil is transported via Ringhorne to Balder for offshore loading. Gas is exported via Jotun into Statpipe. A final decision has been made to drill a fourth production well in late 2011, and a fifth production well is planned.

Statoil has a 10% interest in the **Skirne** gas and condensate field, which is operated by Total. The field has two subsea templates with one well each. The well stream is transported to Heimdal for processing. From there, gas is transported in Vesterled or Statpipe. The condensate is transported from Brae to St Fergus in the UK.

Statoil has an 11.78% interest in the **Enoch** field operated by Talisman. The field is a subsea development tied back to Brae A in the British sector. Production started in May 2007.

Gjøa is located in the North Sea and has been developed with a subsea production system and a semi-submersible production platform. Statoil was the operator in the development phase, while GDF SUEZ took over as operator from production start-up in November 2010. Statoil will provide support and services to GDF SUEZ through a post-transfer agreement, and we continue to execute the drilling and completion of the production wells. Gas is exported via the FLAGS pipeline to St Fergus, and oil is exported via the Troll 2 pipeline to the Statoil-operated Mongstad refinery near Bergen. The Gjøa platform processes and exports volumes from both the Gjøa field and the neighbouring Vega fields. The platform is supplied with land-based electricity from Mongstad. Statoil holds a 20% interest in Gjøa.

3.1.9 Decommissioning on the NCS

No Statoil-operated fields have been decommissioned during the last three years.

The Norwegian government has laid down strict procedures for the removal and disposal of offshore oil and gas installations under the Convention for the Protection of the Marine Environment of the Northeast Atlantic (the OSPAR Convention). During the last three years, however, no Statoil-operated fields have been decommissioned. On partner-operated fields, there has been removal activity on Frigg and Ekofisk.

For further information about decommissioning, see the note 25 to the Consolidated Financial Statements, Asset retirement obligations, other provisions and other liabilities.

3.2 International E&P

3.2.1 Introduction to International E&P

Statoil is present in several of the most important oil and gas provinces in the world and International Exploration & Production will account for most of Statoil's future production growth.

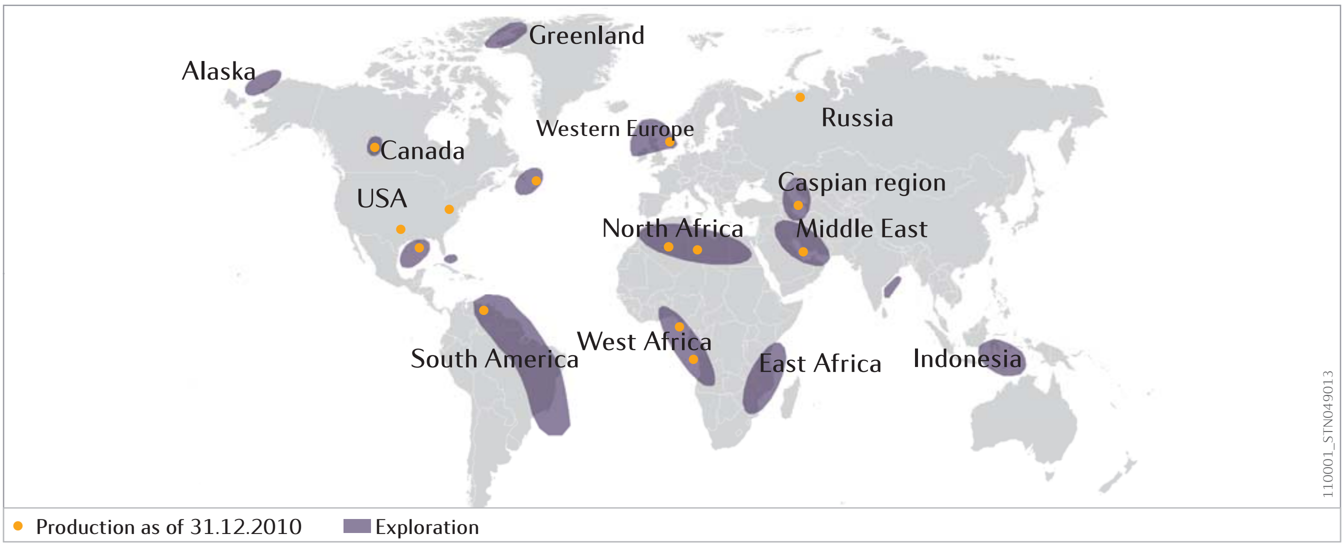
International Exploration & Production (INT) is responsible for exploration, development and production of oil and gas outside the Norwegian continental shelf.

In 2010, the business area was engaged in production in 11 countries: Canada, the USA, Venezuela, Algeria, Angola, Libya, Nigeria, the UK, Azerbaijan, Russia and Iran. In 2010, INT produced 27 % of Statoil's total equity production of oil and gas, and INT's share is expected to increase significantly in the future.

We have exploration licences in North America (Canada and the USA), South America (Brazil, Cuba and Venezuela), Africa (Algeria, Angola, Egypt, Libya, Mozambique, Nigeria and Tanzania), the European and Caspian area (the Faroes, Greenland, Ireland, the UK and Azerbaijan), and the Middle East and Asia (India, Iran and Indonesia).

The main sanctioned development projects in which we are involved are in the USA and Angola. We believe we are well positioned for further growth through a substantial pre-sanctioned project portfolio, including a strengthened onshore USA position following the Eagle Ford acquisition.

The map shows our exploration and production areas.



3.2.2 International E&P key events in 2010

International E&P's future growth ambitions have been further confirmed during 2010 through the sanctioning of a number of important projects.

- Equity production increased by 0.3% from 2009, to 514 mboe/day.
- Exploration activity has been significantly affected by the suspension of drilling activity in the US Gulf of Mexico (GoM). 18 exploration wells were completed during the year, with seven announcements of discoveries. Five wells were under evaluation at year end.
- Final investment decision has been made for a number of important projects during the year:
  - Chirag Oil Project in Azerbaijan, which is a new phase in the Azeri-Chirag-Gunashli (ACG) development.

    - CLOV in Block 17 in Angola
    - BigFoot, Jack and St. Malo in the GoM
    - In Salah Southern Fields in Algeria
- On 3 September, the Leismer Demonstration plant in Northern Alberta in Canada achieved its first steam. The first shipments by truck took place on 15 November.

3.2.3 Our International E&P portfolio

To optimise our portfolio, we signed Joint Venture agreements with partners in Canada and in Peregrino off the coast of Brazil in 2010, while increasing our interest in several projects and broadening our US onshore gas portfolio with Eagle Ford.

Statoil brought a partner into the Peregrino development in Brazil by agreeing to sell a 40% share to the Sinochem Group from China. The transaction is subject to governmental approvals in Brazil. We also brought a partner into our Canadian oil sands project by selling 40% share to PTT Exploration & Production PCL (PTTEP) from Thailand. The transaction was closed on January 2011. Major additions to our international portfolio in recent years include entry into the Marcellus shale gas play in the USA in 2008 and entry into the West Qurna 2 field in Iraq in late 2009. Statoil's main merger and acquistion (M&A) activities in 2010 and early 2011 are presented below.

Acquisitions and licence rounds:
In December 2009, Statoil and Lukoil submitted the winning bid for developing the **West Qurna 2** field in Iraq's second licensing round. On 31 January 2010, Statoil and Lukoil signed a development and production contract for West Qurna 2 with the Iraqi authorities. The consortium of contractors consists of the Iraqi state's North Oil Company (25%), Lukoil (56.25%) and Statoil (18.75%). Lukoil is the operator for the project. The Preliminary Development Plan for West Qurna 2 was approved by Iraqi authorities in November 2010.

In January 2010, we entered a deal with ConocoPhillips whereby we acquired a 25% interest in 50 leases in the **Chukchi Sea in Alaska**. The addition of these leases to the 16 previously acquired in Chukchi means we now have a sizable acreage portfolio to explore in the coming years.

In January 2010, we increased our share in **St. Malo** in the US GoM from 6.25% to 21.5% by exercising our preemption rights.

Statoil was awarded 21 deepwater leases in Central Lease Sale 213 in the **US GoM** in March 2010.

Statoil increased its share in the **Agbami** field in Nigeria from 18.8%. to 20.2% with effect from 1 July 2010 as a result of an equity determination process.

In September 2010, Statoil acquired 20.67% of Nautical Petroleum's interest in UK offshore licence P335, which contains the **Mariner** field. Statoil's share in Mariner after the transaction is 65.1%. The increased ownership interest in Mariner strengthens Statoil's position in offshore heavy oil, a core area in Statoil's international growth strategy.

In October 2010, Statoil acquired 67,000 net acres in the **Eagle Ford** shale gas formation in Southwest Texas through agreements with Enduring Resources, LLC and Talisman Energy Inc.. This Eagle Ford position complements Statoil's existing US onshore portfolio, and entails supplying a different range of hydrocarbons to different markets. Statoil and Talisman have formed a 50/50 joint venture for the purpose of developing assets in the Eagle Ford shale. Talisman will operate the asset initially. Statoil will operate 50% of the acreage within three years of acquisition. The effective date of the transaction was 1 August 2010.

In November 2010, Statoil was awarded operatorship of three new exploration licences on the **UK continental shelf**. Statoil was awarded 44.4% interest in one licence close to the Statoil-operated Mariner heavy oil discovery and 50% interest in two licences near the Faroe border. The commitments for the licence close to Mariner are a seismic survey and evaluation, while, for the two other licences, the commitment consists of reprocessing existing seismic surveys.

In November 2010, Statoil was awarded interests in two large exploration blocks in the Baffin Bay bid round in **Greenland,** a 20.125% interest in block 5 and a 14.875% interest in block 8. Shell will be the operator for both blocks.These new frontier opportunities enhance our exploration portfolio. The commitment in the licences consists of acquiring seismic and carrying out a shallow core programme.

In December 2010, Statoil was awarded interests in four new offshore licences in **Canada:** a majority share and operatorship in three licenses in the Flemish Pass Basin, and a 50% share in one licence in the Jeanne d'Arc Basin. The new acreage underlines Statoil's ambitions in the area.

In January 2011 Sonangol announced that Statoil will be the operator of the **Angolan pre-salt** blocks 38 and 39 and be a participant in blocks 22, 25 and 40. Statoil will have 40% interest in blocks 38 and 39 and 20% interest in the other blocks. All blocks are in the Kwanza Basin offshore Angola. Formal granting of licences for all blocks is subject to the Angolan Ministry of Petroleum's decision of any appeal of the bid round jury's decision, and the successful negotiation of contractual terms including the terms of Production Sharing Agreements (PSAs).

Divestments and other reductions of Statoil's portfolio:
With effect from 1 January 2010, the Russian state oil company Zarubezhneft became a partner in the **Kharyaga** production sharing agreement (PSA) with a 20% interest, thus reducing Statoil's share from 40% to 30%.

Libyan State Oil Company (NOC) in Libya has renegotiated the PSA for Mabruk, and in January 2010, our equity share of production in **Mabruk** was reduced from 25.0% to 5.0% effective as of 1 January 2008.

In May 2010, Statoil annouced entering a joint venture and the sale of 40% of the **Peregrino** field off the coast of Brazil to Sinochem Group. Statoil retains 60% ownership and operatorship of the field. Sinochem Group will pay a total of USD 3,070 million in cash. The divestment demonstrates substantial value creation on Statoil's part in the development phase and is a natural step in our continuous efforts to optimise our portfolio. Brazil will continue to be a key part of Statoil's international strategy. The transaction is subject to government approval in Brazil.

In November 2010, Statoil announced the sale of a 40% interest in its **Kai Kos Dehseh oil sands project in Alberta, Canada** to PTTEP of Thailand. Statoil will retain 60% ownership and operatorship of the project. PTTEP paid a total of USD 2,280 million for the 40% interest. This transaction underlines the quality of our Canadian resources and demonstrates our ability to create value as an oil sands operator. The effective date of the transaction was 1 January 2011, pending governmental approvals which resulted in a closing date of 21 January 2011.

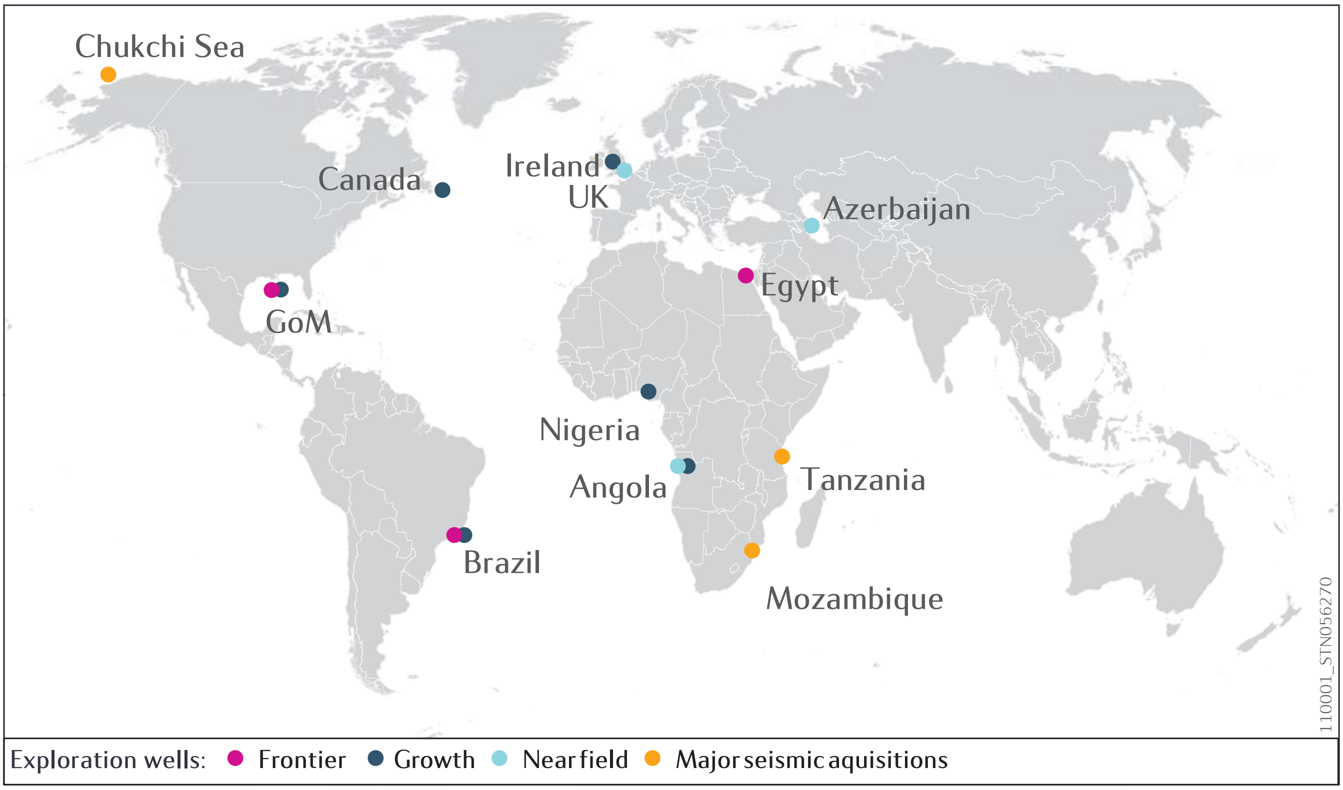
3.2.4 International exploration activity

Statoil's strategy is to continuously access new exploration acreage with high resource potential and to maximise the number of high impact wells.

We have exploration licences in North America (Canada and the USA), South America (Brazil, Cuba and Venezuela), Africa (Algeria, Angola, Egypt, Libya, Mozambique, Nigeria and Tanzania), Europe and the Caspian region (the Faroes, Greenland, Ireland, the UK and Azerbaijan), and the Middle East and Asia (Iran, India and Indonesia).

We have completed 18 wells in 2010, and six were ongoing at year end. Of the 18 wells, seven were announced as discoveries and five are currently under evaluation. We plan to drill about 20 wells in 2011.

Areas with drilling or significant Statoil operated seismic activity in 2010:



The areas where we entered or had significant activity in 2010 are presented below.

3.2.4.1 North America

3.2.4.1.1 Canada

Statoil is operator and partner in licences off the coast of Newfoundland, and we hold 1,129 square kilometres (279,053 acres) of oil sands leases in Alberta.

Offshore

Planning activities for the drilling of two Statoil-operated wells were initiated in 2010. As operator, we are planning to drill a well on our Mizzen discovery located in the Flemish Pass Basin and another on our Fiddlehead licence in the Jeanne d'Arc Basin in 2011/ 2012. In November 2010, re-entry drilling operations started on the Ballicatters M-96Z well. This well is operated by Suncor and Statoil has a 50% interest.

In December 2010, Statoil was awarded interests in four new licences off the coast of Canada. The new acreage underlines the company's ambitions in the area. The licences include a significant discovery licence (SDL) and three exploration licences off the coast of Newfoundland. The licences were awarded through a land sale issue by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB). These licences provide further growth opportunities near our Mizzen discovery in the Flemish Pass Basin and near existing infrastructure in the Jeanne d'Arc Basin, as well as more frontier opportunities. Statoil is operator and has a 65% interest in the SDL, which is an extension of Statoil's current Mizzen licence, and in the exploration licence located in the vicinity of the Mizzen SDL. Statoil is operator with a 75% interest in the exploration licence situated in the northern part of the Flemish Pass Basin and a partner with a 50% interest in the exploration licence located in the Jeanne d'Arc Basin.

Oil sands

We currently have an interest in 1,129 square kilometres (279,053 net acres) of oil sands leases located in the Athabasca region of Alberta.

In order to determine the extent of the exploitable oil sands deposits in Alberta, a total of more than 650 wells were drilled in the region from 2003 to 2010. Extensive seismic surveys were also carried out during the same period.

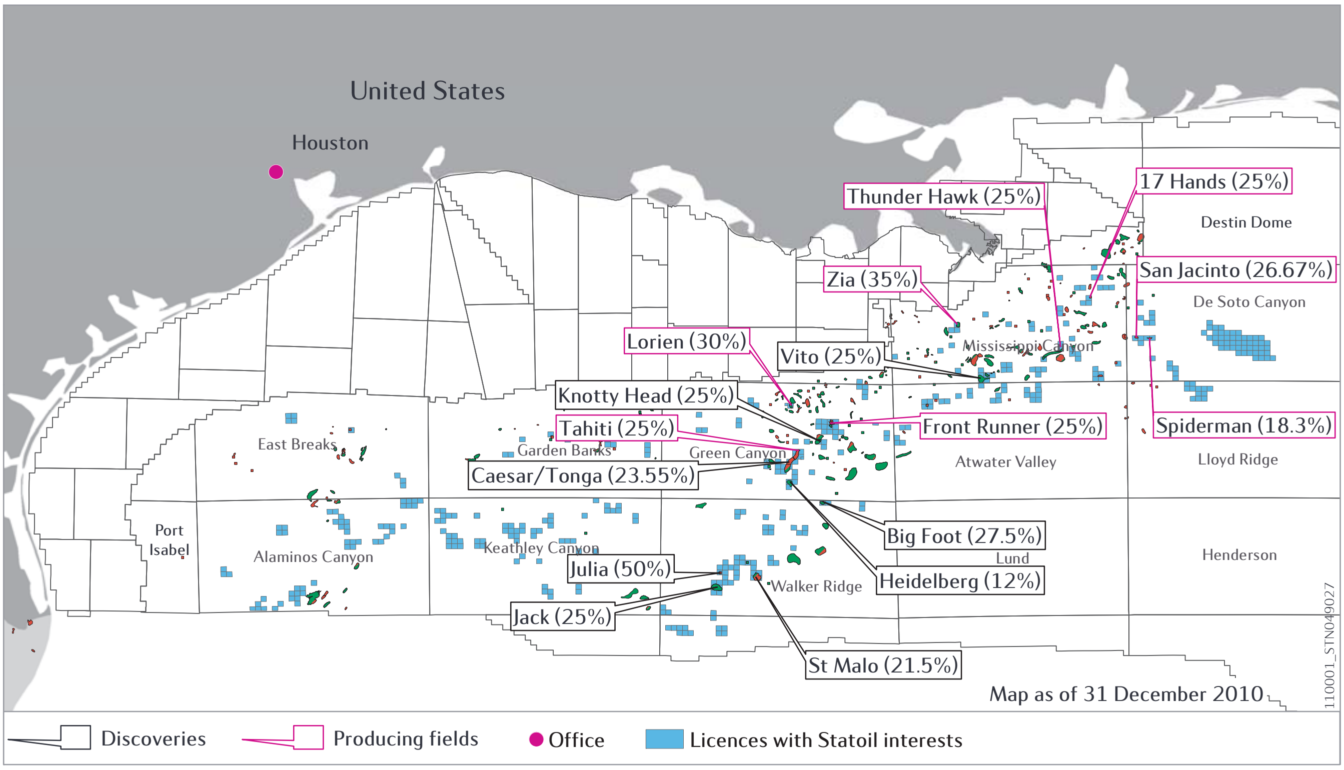
In the 2009-2010 winter drilling programme, wells were drilled that are required for delineation, observation and water source or disposal purposes for near-term development phases.

Additional drilling for delineation, observation, and water source or disposal purposes and further seismic surveys are under way at year end 2010 as part of the 2010-2011 winter drilling programme.

Our oil sand activities are described in more detail in section Operational review - International E&P fields in development and production-North America-Canada.

3.2.4.1.2 The USA

We have significant activities in the USA, with more than 400 leases in the Gulf of Mexico and 66 in Alaska. Drilling activity was reduced in 2010 as a result of the Gulf of Mexico drilling moratorium.



US Gulf of Mexico

During 2010, we participated in seven exploration and appraisal wells, four of which had reached reservoir depth prior to the imposition of the drilling moratorium resulting from the Macondo incident. Appraisal and delineation activity on the Vito and Heidelberg discoveries has been suspended but is scheduled to resume in 2011. Statoil's operated drilling programme, consisting of the Tucker appraisal and Krakatoa exploration wells, was also suspended due to the drilling moratorium. We have endeavoured to reduce financial losses by using the Discoverer Americas, a drillship used in the Gulf of Mexico prior to the drilling moratorium, to drill an exploration well on our Egypt acreage and by sub-letting the Maersk Developer, a semi-submersible used in the Gulf of Mexico prior to the drilling moratorium, in the Gulf of Mexico. Meanwhile we continue to high grade our exploration portfolio and we expect to resume drilling in the Gulf of Mexico towards the end of the first half of 2011.

As a result of the accident on the BP-operated Macondo well in the Gulf of Mexico in April 2010, a four-and-a-half-month moratorium on certain deepwater drilling in the Gulf of Mexico region was imposed, new regulatory initiatives were implemented and further changes and additions to laws and regulations are currently under review in the US. The future effects of this accident, including any new or additional regulations that may be adopted in response, are not fully known at this time.

Although the drilling moratorium was lifted on 12 October 2010, operators may not re-commence drilling activity until they certify compliance with all rules and requirements, including availability of adequate blow-out response resources. The US Bureau of Ocean Energy Management, Regulation & Enforcement has stated that Statoil is one of thirteen operators that may not need to submit revised exploration plans or development operations coordination documentation in order to re-commence its drilling activity. Statoil has worked in recent months to comply with all rules and requirements, and we are in the process of completing the work necessary so that our two rigs that were drilling in the Gulf of Mexico prior to the drilling moratorium can resume drilling. We expect the drilling for Statoil in the Gulf of Mexico to resume towards the end of the first half of 2011. The first new permit for the drilling of a deepwater well (apart from water injection and side track wells) was issued at the end of February 2011. There remains industry-wide uncertainty around the pace at which new drilling activity will be restored.

Statoil remains committed to deepwater exploration and development in the Gulf of Mexico and other deepwater basins around the world.

See the section Risk review - Risk factors - Risks related to increased regulation and regulatory compliance and section Operational review - Regulation - HSE regulation.

We were awarded 21 deepwater leases in Central Lease Sale 213 held in March 2010, including 14 with partner BHP Billiton.

Alaska

Statoil carried out a successful 3D seismic survey over our operated leases and the surrounding acreage in the Chukchi Sea, Alaska. More than 2,600 square kilometers of high quality seismic data were acquired during the ice-free season in August and September. There was extensive stakeholder engagement with local communities. There were no safety or environmental incidents. The data are now being interpreted. Statoil also participated in gathering extensive baseline science data in the Chukchi Sea this summer.

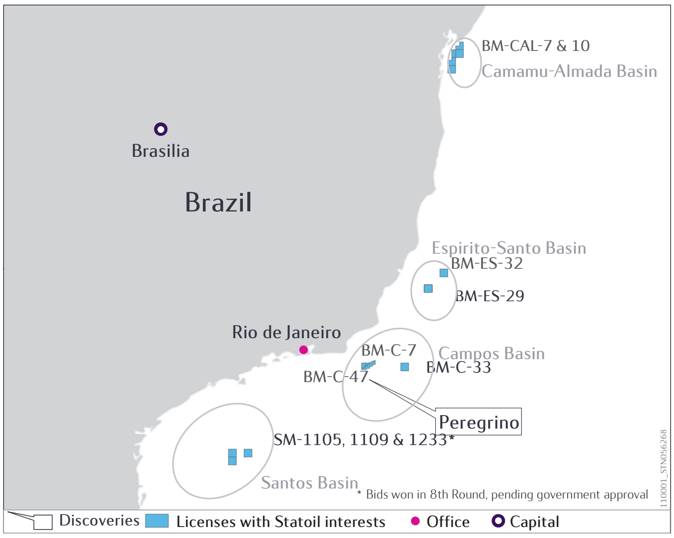
Shale Gas

Exploration activity related to onshore shale gas in the USA is presented in section Operational review-International E&P-International fields in development and production.

3.2.4.2 Latin America

3.2.4.2.1 Brazil

We have interests in nine exploration licences in four different basins in waters off the coast of Brazil. We are the operator for four of the licences.



We have completed one well in BM-C-33 and one in BM-ES-29. This fulfilled our commitments in these licences. The second exploration period in BM-C-33 has begun, and drilling of the commitment well started in November. In addition, we have one commitment well in Statoil-operated BM-CAL-10 and BM-C-47 and one in the partner-operated BM-CAL-7. Rig capacity that will enable us to complete our commitment wells in BM-CAL-10 and BM-C-47, has been secured. Indra, in BM-ES-32, was announced as an oil discovery in December 2010.

Statoil will operate a total of three exploration wells in 2011. Two of them will be drilled in the Peregrino area. The objective of these wells is to prove some of the upsides we believe are present in the Peregrino area.

The interests in three blocks that we won in the eighth round in the Santos basin are pending award.

3.2.4.3 Africa

3.2.4.3.1 Angola

Statoil holds interests in blocks 4/05, 15, 15/06, 17, 31 and 34 in Angola.

We are engaged in extensive exploration activity in Angola. A number of wells were drilled in 2010, and more are expected to be drilled in 2011 and the coming years. We have interests varying from 5% to 50% in six blocks.

In January 2011, Sonangol announced that the Angolan jury of the bid rounds has elected Statoil for operatorship and participation in several pre-salt blocks offshore Angola.
As the operating company, Statoil was elected by the jury of the bid rounds to participate in the following blocks:

- Block 38, 6298 square kilometres. Statoil operator with a 40% share.
- Block 39, 7800 square kilometres. Statoil operator with a 40% share.

As a non-operating partner, Statoil was elected by the jury of the bid rounds to participate in the following blocks:

- Block 22, 5180 square kilometres. Statoil with 20 % partnership.
- Block 25, 4825 square kilometres. Statoil with 20 % partnership.
- Block 40, 7588 square kilometres. Statoil with 20 % partnership.

Formal granting of licenses for all blocks is subject to the Angolan Ministry of Petroleum's decision of any appeal of the jury's decision, and the successful negotiation of contractual terms including Production Sharing Agreements (PSAs).

The exploration acreage in parts of Blocks 15, 17 and 31 has been relinquished. Areas with proved oil have been converted into development areas (DA) and provisional development areas (PDA).

In Block 4/05, operated by Sonangol and assisted by Statoil, we completed the remaining commitment exploration well in January 2011.

In Block 31, operated by BP, certain of the exploration acreage was relinquished in May 2010. A total of 31 exploration wells have been drilled in that block. We are working to mature existing discoveries into future developments on the remaining acreage.

In Block 15/06, which is operated by ENI, four discoveries were announced this year.

In Block 15, work is being initiated to mature existing discoveries as tie- ins to existing infrastructure. Thirty-eight exploration and appraisal wells have been drilled in block 15 so far.

In Block 17, appraisal drilling was carried out in 2010 and will continue into 2011. Thirty-five exploration and appraisal wells have been drilled in block 17.

Block 34, which is operated by Sonangol, is the only area with a remaining commitment well.

3.2.4.3.2 East Africa

Statoil is the operator for two large frontier offshore blocks in the East Africa region - Block 2 in Tanzania and Area 2&5 in Mozambique, both with water depths in the 1,000 to 3,000 metres range.

Sesmic

Block 2 (11,099 square kilometres), **Tanzania**: We have fulfilled the seismic commitment in the current exploration phase in this block. In order to mature the block further, a 1,600 square kilometre 3D survey was carried out between December 2009 and March 2010. In March 2010, we farmed down 35% of our equity to ExxonMobil. We are the operator of the block and have a 65% interest. A well is planned to be drilled in late 2011 or early 2012.

Area 2&5 (8,041 square kilometres), **Mozambique**: Statoil is the operator with a 90% interest in the licence, which consists of two blocks under one licence agreement. The state oil company Empresa Nacional de Hidrocarbonetos (ENH) is the partner with a 10% interest. We are currently in the second exploration period and have fulfilled our 3D seismic commitment. A 1,300 square kilometer 3D survey was carried out between March and June 2010, and interpretation is ongoing. In accordance with the production sharing contract (PSC), we relinquished some of the area on 1 December, 2010. The decision to extend the licence and commit to drilling a well will be made by 1 June 2011.

3.2.4.3.3 Egypt

We are the operator, with an 80% interest, in two offshore exploration licences located west of the Nile Delta in the Mediterranean, in water depths ranging from sea level to 3,000 metres.

The El Dabaa Offshore Licence (Block 9) covers an area of 8,368 square kilometers. We have fulfilled our seismic commitment. During the past year, we have been processing the 3D seismic survey and have also started reprocessing of our 2D seismic survey. During 2010, we have been planning the Kc37-1 (Kiwi-A1X) well. This well commenced drilling in October 2010 and operations continues into 2011. Completion of the well will fulfill our work commitment under the licence.

The Ras el Hekma Offshore Licence (Block 10) covers an area of 9,802 square kilometers. We have fulfilled our work commitment under this licence. We have been processing the 3D seismic survey and have also started reprocessing of our 2D seismic survey.

3.2.4.4 Middle East and Asia

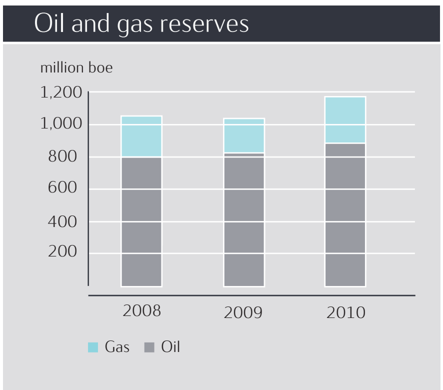
3.2.4.4.1 Indonesia

Statoil is operator of the Karama PSC with a 51% interest, and we also have a 40% interest in the Kuma PSC. Both licences are located off Indonesia in water depths ranging from 1,000 to 2,000 metres.

During 2010, detailed seismic mapping and special studies were carried out to define drillable prospects in both the Karama and Kuma PSCs. Drilling locations were defined for both PSCs and drilling programmes are currently being finalised. Several studies were carried out to support the definition of optimal drilling locations and in preparation for safe and efficient drilling operations. All drilling-related contracts have now been entered into and signed together with the other operators in the Makassar Strait Explorers Consortium (MSEC), which will use the drillship Global Santa Fe Explorer. The first MSEC well using the Global Santa Fe explorer was spudded in August. The Kuma well and at least two of the Karama wells are expected to be drilled during 2011.

3.2.5 International oil and gas reserves

At the end of 2010, the international business area had a total of 883 mmbbl of proved oil reserves and 45.9 bcm (1,621 bcf) of proved natural gas reserves.



Measured in barrels of oil equivalents (boe), our international proved reserves consist of 75% oil and 25% natural gas, based on total international proved reserves of 1,172 mmboe.

Several of our international fields contributed positively to the reserves balance in 2010:

- Final investment decisions were made for the Jack and St. Malo fields in the Gulf of Mexico, USA, the CLOV field development offshore Angola and the In Salah Southern fields development project in Algeria in 2010.
- The West Qurna 2 Preliminary Development Plan in Iraq was approved by Iraqi authorities in November 2010.
- Final investment decisions were made for the Chirag Oil Project in Azerbaijan in 2010, a new phase of the Azeri-Chirag-Gunashli (ACG) project.
- Acreage and production in the Eagle Ford shale formation in the USA was acquired in 2010.
- Further drilling in the Marcellus Shale Gas play in the USA has increased the proved reserves in 2010.

Statoil announced during 2010 the establishment of joint ventures and the sale of a 40% interest in the Peregrino field in Brazil and sale of a 40% interest in the oil sand leases in Alberta, Canada. These sales were not finally approved by the relevant authorities by year end 2010, and are therefore not reflected in the 2010 proved reserves statement. The expected effect on 2011 proved reserves statement is approximately 66 million boe sales of reserves-in-place.

The increased oil price during 2010 has had a negative effect on our proved reserves' estimates for international projects with a Production Sharing Agreement or a Buy Back Agreement.

Proved developed reserves at year end were 581 mmboe, up 3% from 2010. Of the 2010 proved developed reserves, 407 mmboe are oil and 27.7 bcm (977 bcf) are natural gas.

The following table shows our total international proved reserves as of 31 December for each of the last three years. Further information on reserves can be found in section Operational review - Proved oil and gas reserves and in note 35 - Supplementary oil and gas information - to our Consolidated Financial Statements.

Year		Oil/NGL mmbbls	Natural gas bcm	Natural gas bcf	Total mmboe
2010	Proved reserves end of year	883	45.9	1,621	1,172
	of which, proved developed reserves	407	27.7	977	581
2009	Proved reserves end of year	824	34.3	1,210	1,039
	of which, proved developed reserves	413	24.1	852	565
2008	Proved reserves end of year	805	39.7	1,403	1,055
	of which, proved developed reserves	406	20.6	727	536

3.2.6 International production

Statoil's petroleum production outside Norway in 2010 amounted to an average of 332 mboe per day of entitlement production and 514 mboe per day of equity production.

Our total annual entitlement production in 2010 was approximately 121 mmboe, compared with 130 mmboe in 2009.

The first table shows our average daily entitlement production of liquids and natural gas for the years ending 31 December 2010, 2009 and 2008.

Entitlement production	For the year ended 31 December 2010	2009	2008
Oil and NGL (mboe per day)	263	283	232
Natural gas (mmcm per day)	11	12	9
Total (mboe per day)	332	357	290

The next table provides information about the fields which contributed to 2010 production.

Field	Statoil's equity interest in per cent	Operator	On stream	License expiry	Producing wells	Average daily entitlement production [1] mboe/day	Average daily equity production mboe/day
Canada					65	18.2	18.2
Canada: Hibernia	5.00%	HMDC	1997	2027	35	7.7	7.7
Canada: Terra Nova	15.00%	Suncor	2002	2022	15	10.2	10.3
Canada: Leismer Demo [1]	60.00%	Statoil	2010	HBP [2]	15	0.2	0.2
USA					244	62.3	62.3
USA: Lorien	30.00%	Noble	2006	HBP	2	0.6	0.6
USA: Front Runner	25.00%	Murphy Oil	2004	HBP	6	1.7	1.7
USA: Spiderman Gas	18.33%	Anadarko	2007	HBP	3	3.9	3.9
USA: Q Gas	50.00%	Statoil	2007	HBP	1	4.6	4.6
USA: San Jacinto Gas	26.67%	ENI	2007	HBP	2	1.1	1.1
USA: Zia	35.00%	Devon	2003	HBP	1	0.2	0.2
USA: Seventeen Hands	25.00%	ENI	2006	HBP	1	0.0	0.0
USA: Marcellus shale gas	32.50%	Chesapeake	2008	HBP	162	11.0	11.0
USA: Eagleford shale	43.00%	Talisman	2010	HBP	47	0.2	0.2
USA: Eagleford shale	4.00%	Laredo	2010	HBP	9	0.0	0.0
USA: Tahiti	25.00%	Chevron	2009	HBP	7	31.1	31.1
USA: Thunderhawk	25.00%	Murphy Oil	2009	HBP	3	8.0	8.0
Latin America					497	13.1	13.1
Venezuela: PetroCedeño [3]	9.68%	PetroCedeño	2008	2032	497	13.1	13.1
North Africa					241	36.2	69.5
Algeria: In Salah	31.85%	Sonatrach/BP/Statoil	2004	2027	36	20.0	42.7
Algeria: In Amenas	50.00%	Sonatrach/BP/Statoil	2006	2022	21	12.2	22.4
Libya: Mabruk [4]	5.00%	Total	1995	2028	63	1.4	1.6
Libya: Murzuq	2.40%	Repsol	2003	2032	121	2.6	2.8
Sub Saharan Africa					155	128.2	219.6
Angola: Kizomba A	13.33%	ExxonMobil	2004	2026	27	5.1	17.4
Angola: Kizomba B	13.33%	ExxonMobil	2005	2027	25	7.5	23.4
Angola: Xikomba	13.33%	ExxonMobil	2003	2027	4	0.9	1.7
Angola: Marimba North	13.33%	ExxonMobil	2007	2027	3	2.4	4.5
Angola: Mondo	13.33%	ExxonMobil	2008	2029	9	5.9	10.4
Angola: Saxi-Batuque	13.33%	ExxonMobil	2008	2029	7	9.9	11.9
Angola: Girassol/Jasmim	23.33%	Total	2001	2022	25	8.2	24.8
Angola: Dalia	23.33%	Total	2006	2024	27	29.4	56.1
Angola: Rosa	23.33%	Total	2007	2022	12	15.5	19.5
Angola: Block 4/05	20.00%	Sonangol P&P	2009	2026	3	3.0	3.2
Nigeria: Agbami [5]	20.21%	Chevron	2008	2024	13	40.3	46.6

Field	Statoil's equity interest in per cent	Operator	On stream	License expiry	Producing wells	Average daily entitlement production[1] mboe/day	Average daily equity production mboe/day
Caspian					71	55.6	110.5
Azerbaijan: ACG	8.56%	BP	1997	2024	67	23.0	70.4
Azerbaijan: Shah Deniz	25.50%	BP	2006	2031	4	32.5	40.1
Western Europe					75	7.1	7.1
UK: Alba	17.00%	Chevron	1994	2018	39	4.8	4.8
UK: Jupiter	30.00%	ConocoPhillips	1995	2010	15	1.0	1.0
UK: Schiehallion	5.88%	BP	1998	2017	21	1.3	1.3
Other areas					19	11.0	13.6
Russia: Kharyaga [6]	30.00%	Total	1999	2032	19	6.1	8.7
Iran: South Pars	37.00%	POGC	2008	2012		4.9	4.9
Total International E&P					1,367	332	514

1) Statoil has sold a 40% interest in the oil sands project to PTTEP of Thailand with a valuation date of 1 January 2011. The transaction was closed in January 2011. We will act as Managing Partner and retain 60% ownership of the partnership holding the oil sands project, and will continue to be operator of the project.

2) Held by Production (HBP): A company's right to own and operate an oil and gas lease is perpetuated beyond its original primary term, as long thereafter as oil and gas is produced in paying quantities. In the case of Canada, besides continue being in production status, other regulatory requirements must be met.

3) Petrocedeño is a non-consolidated company.

4) Renegotiation of the PSA by the Libyan State Oil Company (NOC) for the Mabruk field was completed in January 2010. Statoil's equity share in Mabruk was reduced from 25.0% to 5.0% effective as of 1 January 2008.

5) Following a technical re-assessment of the resource inventory, our interest in the unitised field has been increased from 18.85% to 20.21% effective from 1 July 2010.

6) With effect from 1 January 2010, the Russian state oil company Zarubezhneft became a partner in the Kharyaga PSA with a 20% interest, thus reducing Statoil's share from 40% to 30%.

The table below presents equity and entitlement production per country in 2010.

Country	Average daily equity production (1) mboe/day	Average daily entitlement production (2) mboe/day
North America		
Canada	18.2	18.2
USA	62.3	62.3
Sub Saharan Africa		
Angola	173.0	87.9
Nigeria	46.6	40.3
North Africa, Europe, Caspian and Russia		
Algeria	65.1	32.2
Libya (3)	4.4	4.0
Azerbaijan	110.5	55.6
Russia	8.7	6.1
UK	7.1	7.1
The Middle East and Asia		
Iran	4.9	4.9
Subtotal International E&P production	500.8	318.6
Equity accounted production		
Venezuela: PetroCedeño (4)	13.1	13.1
Total International E&P including share of equity accounted production	514	332

(1) In PSA countries our share of capital expenditures and operational expenses are computed on the basis of equity production.
(2) Production figures are after deductions for royalties, production sharing and profit sharing.
(3) Renegotiation of PSA by the Libyan State oil Company (NOC) for the Mabruk field was completed in January 2010.
(4) Petrocedeño is accounted for pursuant to the equity accounting method.

3.2.7 International fields in development and production

Major efforts are under way to make the transition from a mainly Norwegian offshore player to a world-class international operator.

We are working continuously to develop our inventory of projects into producing assets by looking at innovative technical and commercial solutions.

This section covers projects under development and fields in production. Significant pre-sanctioned projects, including some discoveries in the early evaluation phase, are also presented. This section often refers to a field's plateau production, which means the yearly average equity production at plateau for a field for a 100% ownership share. Capacities also refer to the total field or facility.

Exploration activities are described in the report section Operational review - International E&P - International exploration activity.

Sanctioned projects coming on stream 2011-2013 *	Statoil's share	Operator	Time of sanctioning	Production start
Brazil: Peregrino	60%**	Statoil	2007	2011
Angola: Pazflor	23.33%	Total	2007	2011
Angola: PSVM	13.33%	BP	2008	2011
The USA: Caesar Tonga phase 1	23.55%	Anadarko	2009	2012
Angola: Kizomba satellites phase 1	13.33%	Exxon	2009	2012
Ireland: Corrib	36.50%	Shell	2003	2013

* Not exhaustive

** Statoil currently owns 100% of Peregrino; however, in May 2010, Statoil agreed to sell a 40% stake to Sinochem Group, which would leave Statoil with a 60% stake in Peregrino. This transaction is subject to governmental approvals in Brazil.

3.2.7.1 North America

Statoil's development and production activities in North America comprise interests and operations in the US Gulf of Mexico, in the Appalachian region and in southwest Texas, off the eastern coast of Canada and in the oil sands of Alberta, Canada.

We also have a representative office in Mexico City.

3.2.7.1.1 Canada

Oil sands are an important long-term investment for the company, and our Leismer Demonstration Project is on schedule. Offshore, we have production from Hibernia and Terra Nova, and two development projects.

Oil sands

In 2007, we acquired 100% of the shares in North American Oil Sands Corporation (NAOSC) and operatorship of the **Kai Kos Dehseh (KKD)** leases in the Athabasca region of Alberta. In November 2010, we agreed to sell a 40% interest in the oil sands project to PTTEP of Thailand with a valuation date of 1 January 2011. The transaction was closed on 21 January 2011. We will act as Managing Partner and retain 60% ownership of the partnership holding the oil sands project, and will continue to be operator of the project. As of 31 December, we owned a 100% interest in 1,129 square kilometres (279,053 net acres) of oil sands leases located in the Athabasca region of Alberta. On closing, Statoil will hold a 60% interest, amounting to 167,432 net acres of oil sands leases.


Leismer

Statoil Oil Sands project's first phase is the **Leismer Demonstration Project**, whose construction and commissioning is substantially complete, having achieved delivery of all key components on or ahead of schedule. In fact, the first steam milestone was completed a full month ahead of schedule. All of the production wells have been drilled and completed. Three of the four well pads were put on circulation, which resulted in early pre-commercial production of approximately 84,000 bbls of bitumen in 2010. Conversion to SAGD production mode will continue to progress at the remaining well pairs through the first quarter 2011. The Cheecham terminal is undergoing commissioning in accordance with plan. The Leismer Demonstration Project is connected to the existing pipeline infrastructure at Cheecham that runs to the Edmonton area. After producing pre-commercial production volumes in late 2010, we announced first commercial oil on 27 January 2011. The project was in full operation by the end of the first quarter of 2011.

Offshore

Statoil has interests in two crude oil producing fields, Hibernia (Statoil share: 5%) and Terra Nova (Statoil share: 15%), and in two development projects, Hebron (Statoil share: 9.7%) and Hibernia Southern Extension Unit (Statoil share: 10.5%)

Fields in production

Hibernia, which was developed with a gravity-based structure (GBS), is operated by Hibernia Management and Development Company Ltd (HMDC). The Hibernia field is in the initial stages of decline, with 2010 gross production rates averaging 155,000 barrels of oil per day.

Terra Nova produces from an FPSO and is operated by Suncor Energy. The Terra Nova field is also in decline, with 2010 gross production rates averaging 70,000 barrels of oil per day. Development drilling of the field is planned to continue in 2011.

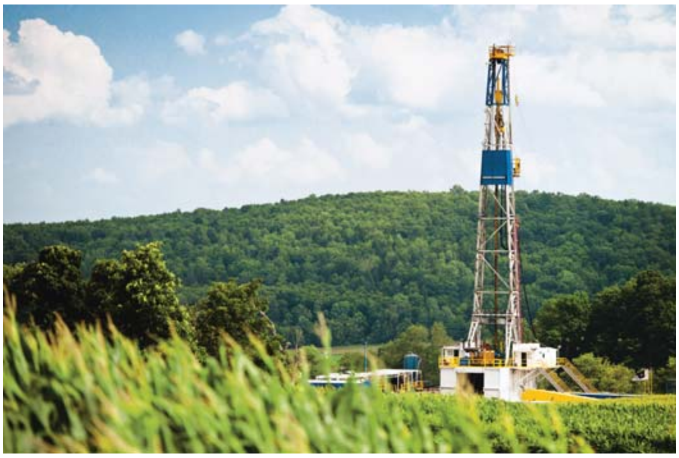
Development projects

The **Hebron** field, which is operated by ExxonMobil, will be developed with a gravity-based structure (GBS). The project has entered the front end engineering design (FEED) phase with the award of two large contracts for the GBS and the platform topside facilities.

The **Hibernia Southern Extension Unit,** which is operated by ExxonMobil, comprises the development of resources in several fault blocks to the south of the existing Hibernia field. The field is planned for development as a satellite to the Hibernia field. The Hibernia South Extension Unit is located across three licence areas. Statoil holds working interests of 22.5% in PL1005, 4.5% in EL1093 and 4.5% of the unit portion of PL1001. Statoil's unitised interest is currently 10.5%. The development plan application (DPA) was approved in October 2010.

3.2.7.1.2 USA

Tahiti and several other properties continued production in 2010. Statoil sanctioned the Tahiti Phase II, Jack, St. Malo and Big Foot projects. Onshore, Marcellus shale gas production is increasing, and we acquired acreage in the Eagle Ford play in Texas.



Marcellus well pad

Onshore

The **Marcellus Shale Gas** play is located in the Appalachian region in north-eastern USA. In November 2008, we entered into a strategic alliance with Chesapeake Energy, acquiring 32.5% of Chesapeake's 1.8 million acres in Marcellus. Statoil has continued to acquire acreage within the play, with a net acreage position of over 665,000 acres at the end of 2010. Marcellus provides Statoil with a long-life gas asset with considerable optionality in relation to the timing of drilling and producing from these leases. Marcellus production started in 2008, and Statoil's daily equity production was approximately 18,700 boe by year-end 2010. Statoil and Chesapeake will continue to acquire and high-grade acreage around the most prospective areas of the play and will build up production from both dry gas and natural gas liquid producing areas.

Water is used in our fracing operation in the Marcellus and our partners maintain the required permits to access necessary water supplies. Modern filtration methods and settling ponds are used to recycle produced frac fluid resulting in disposal of a minimal amount of waste water. Water processing facilities are under construction to process and re-use produced frac fluids, which will further reduce water consumption. We expect that additional water conservation improvements will further reduce usage and allow for efficient development of these unconventional resources.

Through agreements with Enduring Resources, LLC and Talisman Energy Inc. in 2010, Statoil acquired 67,000 net acres in the **Eagle Ford** shale formation in south-west Texas. Statoil and Talisman formed a 50/50 joint venture for the purpose of developing assets in the Eagle Ford shale formation. As part of the joint venture, Statoil and Talisman jointly acquired the Eagle Ford assets of Enduring, comprising 97,000 acres (48,500 net to Statoil), in a USD 1.325 billion transaction. The purchase price corresponds to about USD 10,900 per acre. Statoil also acquired 50% of Talisman's existing Eagle Ford acreage and production for USD 180 million (18,500 acres net to Statoil). As a result, Statoil and Talisman together hold 134,000 net Eagle Ford acres and associated assets and production in the joint venture. Statoil paid a total of USD 861 million (approximately NOK 5.2 billion), including closing adjustments, in the two transactions.

Offshore, Gulf of Mexico

Fields in production

Production started in May 2009 from the Chevron-operated **Tahiti** oilfield in which we have a 25% interest. The field is located in Green Canyon Blocks 640/596 and consists of seven wells in two subsea drill centres connected to a floating facility with processing capacity of approximately 155,000 barrels of oil per day. Gross average daily production in 2010 was approximately 124,400 boe. The second phase of the Tahiti development was sanctioned in 2010 and is now in the execution phase. Tahiti Phase 2 will add two producing and three water injection wells to the existing architecture.

Production started in July 2009 from the **Thunder Hawk** oilfield located in Mississippi Canyon Block 734. We have a 25% interest in this Murphy Oil-operated development, which consists of a semi-submersible floating production facility located in Mississippi Canyon Block 736. The processing capacity is approximately 45,000 barrels of oil per day, and gross average daily production in 2010 was approximately 32,000 boe.

Our three deepwater natural gas fields - **Q, San Jacinto and Spiderman** - are part of the Anadarko-operated Independence Hub. The Q field is Statoil-operated, while San Jacinto and Spiderman are partner-operated. The fields are subsea tie-backs to the Independence Hub platform, a floating production facility located in Mississippi Canyon Block 920. They are at varying stages of their life cycle. Spiderman continues to produce, while efforts are being made to extend the life of San Jacinto. Q was depleted in June 2010, and Statoil is planning for the abandonment of the well and related infrastructure. The Independence Hub is owned by third parties and has processing capacity of approximately one billion cubic feet of natural gas per day. We have contractual rights to 12.7% of the total capacity.

The Murphy-operated **Front Runner** oilfield is located in Green Canyon Blocks 338/339/382. We have a 25% interest in Front Runner, which started production in 2004. The field produces while carrying out simultaneous drilling activities from a rig situated on a spar floating production facility.

We have a 30% interest in the Noble Energy-operated **Lorien** oilfield, located in Green Canyon 199. Lorien produces through a subsea tie-back to Shell's Bullwinkle platform.

Zia, an oilfield located in Mississippi Canyon Block 496, and **Seventeen Hands,** a gas field located in Mississippi Canyon Block 299, continue to produce small volumes. Both fields tie back to platforms owned by others.

Fields under development
Statoil has a 23.55% working interest in the Anadarko Petroleum-operated **Caesar Tonga** Unit in Green Canyon Block 683. Development of the four block unit was sanctioned in 2009 as a four-well subsea tie-back to Anadarko's Constitution platform.

Statoil has a 25% working interest in the **Jack** oilfield, located in Walker Ridge Blocks 758/759 and a 21.5% working interest in **St. Malo** located in Walker Ridge Block 678. In early 2010, we increased our interest in St. Malo from 6.25% to 21.5%. St. Malo and Jack are located at a water depth of approximately 2,000 metres and are approximately 40 kilometres apart. The two fields are operated by Chevron and will be developed jointly with subsea wells connected to a centrally-located production platform. The Jack and St. Malo projects were sanctioned in September 2010. The first oil is planned in late 2014.

Statoil has a 27.5% interest in **Big Foot** located in Walker Ridge Block 29. Big Foot is operated by Chevron and will be developed with a dry tree tension leg platform with a drilling rig. The Big Foot project was sanctioned in December 2010. The first oil is planned in late 2014.

3.2.7.2 Latin America

Our current asset portfolio in Latin America comprises the Peregrino offshore heavy oil project in Brazil and the onshore extra heavy oil producing asset, Petrocedeño, in Venezuela.

In May 2010, Statoil agreed to sell 40% of the Peregrino Field to Sinochem Group. The transaction is subject to government approval in Brazil.

3.2.7.2.1 Brazil

Statoil is operator for the Peregrino offshore oilfield in Brazil, and by 2012, we expect to become the largest foreign offshore operator in Brazil in terms of production.

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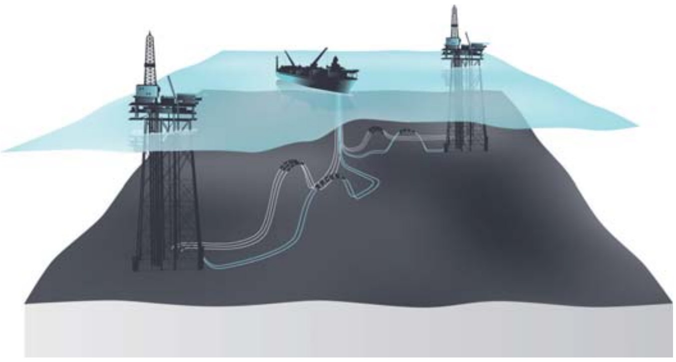


The Peregrino field is a heavy oil field located in approximately 120 metres of water in the prolific Campos Basin, about 85 kilometres off the coast of Rio de Janeiro.

The field is being developed with a FPSO vessel and two wellhead platforms with drilling capability. First oil is expected towards the end of the first quarter 2011. We expect to reach plateau production in the first year of production. Design capacity is 100 mboe per day.

In May 2010 we agreed to sell 40% of the Peregrino Field to Sinochem Group. Statoil retains 60% ownership and operatorship of the field. The transaction is subject to government approval in Brazil.

Peregrino

3.2.7.2.2 Venezuela

Statoil has a 9.677% interest in Petrocedeño, one of the largest extra heavy crude projects in Venezuela.

The Petrocedeño project involves the extraction of extra heavy crude oil from reservoirs in the Orinoco Belt. A diluting component is added in order to enable the extra heavy oil to be transported by pipeline to the coast, where it is upgraded to a light, low-sulphur syncrude destined for the international market. Petrocedeño, S.A., owned by the project partners - PDVSA, Total, and Statoil - operates the field and markets the products.

Petrocedeño experienced operational challenges also in 2010 and produced below design capacity. A recovery programme has been initiated to improve the situation.

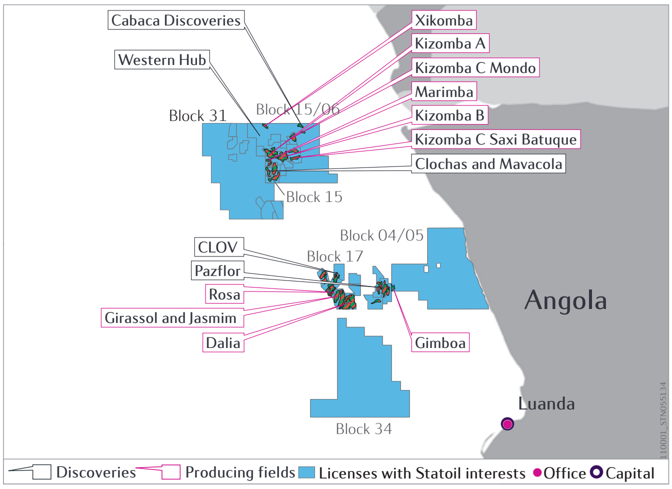
We have been present in Venezuela since 1994, and our activities in the country are based on a long-term perspective.

3.2.7.3 Sub-Saharan Africa

Our development and production portfolio in sub-Saharan Africa comprises blocks 4/05, 15, 15/06, 17 and 31 off the coast of Angola, and the OML 127 and OML 128 production licences off the coast of Nigeria.

3.2.7.3.1 Angola

The Angolan continental shelf is the largest contributor to Statoil's production outside Norway. It yielded 173 mboe per day in equity production in 2010, 34 % of our total international oil and gas output.




Kizomba A

Block 17 is operated by Total, and our interest is 23.33%. Production from the block currently comprises four development areas produced over two FPSOs. The **Girassol**, **Jasmim** and **Rosa** development areas are produced over the Girassol FPSO and the **Dalia** development area over the Dalia FPSO. The combined equity production from Block 17 in 2010 was 100 mboe per day.

The **Pazflor** project, which comprises the *Perpetua, Acacia, Zinia and Hortensia* discoveries, will be produced over a new FPSO, with expected production capacity of 220 mboe per day. Start-up is scheduled for the second half of 2011.

The **CLOV** project consists of the *Cravo, Lirio, Orchidea and Violeta* discoveries. The project was sanctioned in mid-2010 and major engineering, procurement and construction (EPC) contracts have been awarded. CLOV will be produced over a new FPSO, with expected production capacity of 160 mboe per day. The first oil is expected in 2014.

IOR projects to fill excess capacity on the Girassol FPSO and to increase oil recovery from Block 17 are under evaluation. The IOR projects include subsea tie-backs, infill wells, and the use of multi-phase pumps.

Block 15 is operated by Esso Angola, a subsidiary of ExxonMobil. Our interest is 13.33%. Statoil's equity production from Block 15 in 2010 was 69 mboe per day. Production comes from the **Kizomba A**, **Kizomba B**, **Kizomba C-Mondo, Kizomba C-Saxi Batuque,** and **Xikomba** FPSOs. In addition, one satellite, **Marimba**, is producing through a tie-back to the Kizomba A FPSO.The **Xikomba** FPSO is expected to cease production in the first part of 2011.

Kizomba satellites phase 1, which consists of two discoveries, *Clochas* and *Mavacola,* was sanctioned by the partnership in 2009 and is currently under development. The first oil is scheduled for 2012.

Evaluation of a possible development of the **Kizomba Satellites phase 2** is ongoing. The project includes the *Bavuca*, *Kakocha* and *Mondo South* discoveries.

Block 31 is an ultra-deepwater licence operated by BP. Our interest is 13.33%. The development of the first four discoveries in the northern part of the block - *Plutao, Saturno, Venus* and *Marte* (**PSVM**) - was approved by the concessionaire in July 2008 and is now under execution. PSVM will be developed via a new FPSO with a production capacity of 150 mboe per day. According to the operator, production start-up is expected in late 2011.

Work is also ongoing to pursue a second development around the *Palas*, *Astraea*, *Juno* and *Dione* discoveries in the southern part of the block. Other discoveries will either be tied back to one of these developments or be developed through additional FPSOs.

Block 4/05 is operated by Sonangol P&P, and our interest is 20%. This block includes the **Gimboa** field. The equity production in 2010 was 3.2 mboe per day.

Block 15/06 is operated by Eni. Our interest is 5%. Work is currently being done to progress a development solution for the discoveries on the block.

Gas Gathering Projects: Pursuant to the production sharing agreement (PSA), all surplus gas from the fields in Angola is to be delivered to Sonangol, which owns the gas. No income will be generated for the transfer of gas, and costs and investments related to the projects will be recovered through the PSA.

The first delivery of commissioning gas from block 15 to the Angola LNG Terminal is expected to start in the second quarter of 2011. Normal deliveries of gas are expected to start in the first quarter 2012.

Export of gas from Block 17 with injection into Block 2 started December 2010. Completion of a pipeline from Block 2 to the Angola LNG Terminal is scheduled for completion April 2011.

3.2.7.3.2 Nigeria

In Nigeria, we have an interest in the largest deepwater producing field, Agbami.

The Agbami field, located in deep waters off Nigeria, is produced from subsea wells connected to an FPSO. Production started in 2008. Agbami, which is operated by Chevron, is located in licences OML 127 and OML 128, approximately 110 kilometres off the Nigerian coast. Following a technical re-assessment of the resource inventory, our interest in the unitised field has been increased from 18.85% to 20.21% effective from 1 July 2010.

The Agbami field is currently producing at the nominal plateau rate of 250 mboe per day and is expected to continue to do so for several years to come.

The Nigerian government continues to work for the restructuring of the oil and gas sector through the passage of the Petroleum Industry Bill (PIB). The Bill is currently with the National Assembly and in its final stage. The law is likely to increase the government take.

The security and political situation is largely unchanged. The overall security situation is being monitored closely and appropriate security measures are being assessed for our personnel and assets.

3.2.7.4 North Africa, Europe, Russia and Caspian

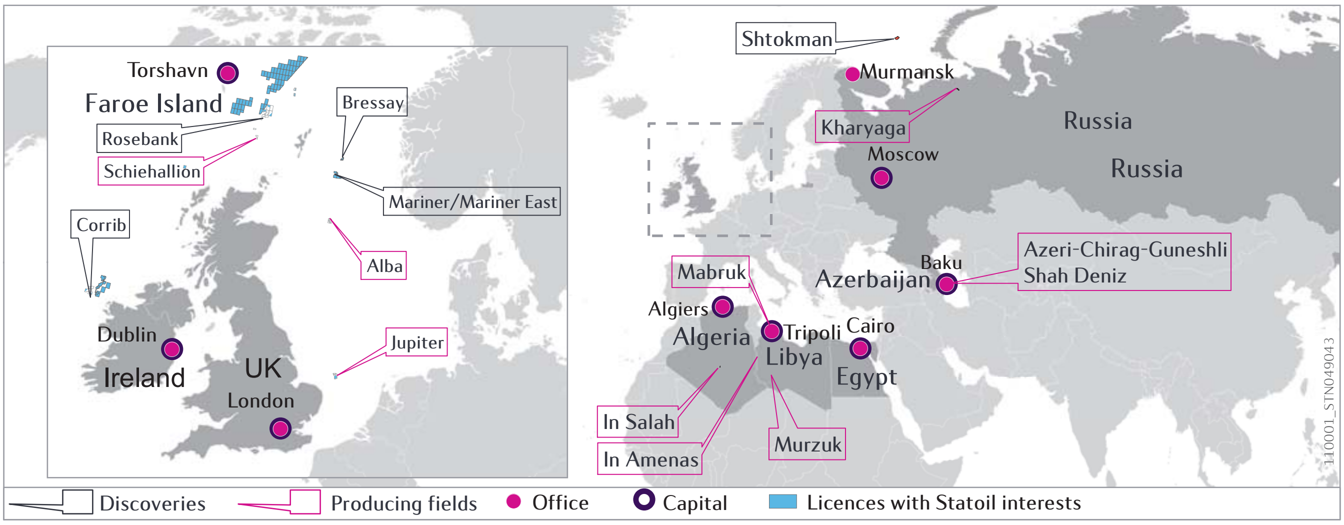
Statoil has built a unique position as supplier to the European gas market. In addition to our heritage position on the Norwegian continental shelf, we have upstream assets that supply this market from Algeria and from Azerbaijan.

The Shtokman field is a long-term resource that can enhance our upstream gas position while making us a supplier from the north-east.

The Chirag Oil Project was sanctioned in March 2010 and is expected to start production in 2013. The project will comprise one new platform with capacity to produce 185,000 barrels of oil per day. This will further strengthen our position in Azerbaijan.

We have interests in production and development assets in Algeria, Libya, Ireland, the United Kingdom, Azerbaijan, Iraq and Russia, in addition to early-phase evaluation assets in the United Kingdom and Algeria.

We also have representative offices in Kazakhstan and Turkmenistan.



3.2.7.4.1 Algeria

Our main assets, In Salah and In Amenas, are the third and fourth largest gas developments in Algeria. The developments of the In Salah Southern Fields and In Amenas Gas Compression Project were sanctioned in 2010.

Fields in production

The **In Salah** onshore gas development, in which we have a 31.85% interest, is Algeria's third largest gas development. The field is currently producing at plateau level of around 130 mboe per day. Facilities have been installed for carbon dioxide capture and reinjection through dedicated wells.

A Contract of Association, including mechanisms for revenue sharing, governs the rights and obligations of the joint operatorship between Sonatrach, BP and Statoil. A joint marketing company sells the gas produced in the development. All gas that will be produced up until 2017 has been sold under long-term contracts.

In the In Salah Gas Compression Project, gas compression facilities were installed at the three existing northern fields in 2010. Compression has started at all three fields.

The **In Amenas** onshore development is the fourth largest gas development in Algeria, containing significant liquid volumes. Production efficiency is high, although occasional capacity restrictions due to priorities in the export pipeline system remain an issue.

The facilities are operated through a joint operatorship between Sonatrach, BP and Statoil, and we have a 50% share of the development costs. Production has reached its plateau level. The rights and obligations are governed by a production sharing contract that gives BP and Statoil access to a share of the liquid volumes. A continuous production drilling campaign is ongoing.

The In Amenas Gas Compression Project, which is led by BP, was sanctioned in late 2010. The compressors are expected to come on stream in 2013. This will make it possible to reduce wellhead pressure and maintain the contractual production commitment.

Fields in development

The **In Salah Southern Field Development Project** was sanctioned in late 2010. This project will mature the remaining four discoveries into production. It is planned to come on stream in 2013. The southern fields will tie in to existing facilities at the northern fields.

The **Hassi Mouina** exploration phase has been extended until September 2011. Statoil is currently assessing the technical solutions for and commercial attractiveness of a potential development.

3.2.7.4.2 Libya

In 2010, we had two producing assets in Libya.

The **Mabruk** oilfield (operated by Repsol) is located in licence C-17 in the Sirte basin. Mabruk Oil Operations is the operating company for Mabruk C-17 license with Total as the lead partner for the International Oil Companies. The field has been producing since 1995. The Dahra south-east project was sanctioned in 2009.

The NC 186 licence in the **Murzuq** area consists of seven fields (A, B, D, H, I/R, J and K). Akakus Oil Operations is the operating company for Murzuq NC 186 license with Repsol as the lead partner for the International Oil Companies. The K field came on stream in 2010, and the average production was 218 mboe per day in 2010. The oil from the Murzuq fields was transported by pipeline to the Az Zawia terminal west of Tripoli for lifting by ship.

Due to the outbreak of political unrest in Libya, Statoil's Libyan operations were suspended in February 2011, the fields stopped production on 21 February (Murzuq) and 26 February (Mabruk). Statoil's office in Libya was closed on 20 February 2011. All Statoil expatriate staff and their families have been evacuated from Libya. The future impact of the ongoing unrest, potential political changes and international sanctions on Statoil's current Libyan operations is uncertain.

3.2.7.4.3 United Kingdom

We have several oilfields under appraisal in the United Kingdom (UK) and hold interests in three producing fields.

Fields in production
The Alba oilfield, located in the central part of the UK North Sea, is operated by Chevron. We have a 17% interest in this field.

The Schiehallion oilfield is located west of the Shetland Islands. BP is the operator, and we have a 5.88% interest. In April 2010, the Schiehallion partnership approved the concept selection for the acquisition of a new FPSO vessel.

Jupiter is a gas field located in the southern part of the UK North Sea. We have a 30% interest and the operator is ConocoPhillips.

All these fields are in the mature to late-life stage of production.

Discoveries under appraisal
We are operator for Bressay (in which we have a 81.63% interest) and Mariner East (in which we have a 62% interest). In September 2010, we acquired an additional 20.67% in the Mariner Field, of which we are also operator, taking our total interest to 65.1%. They are all heavy oil discoveries for which studies and concept selection will continue.

Rosebank, a discovery made by Chevron in 2004, is located west of the Shetland Islands. We have a 30% interest in this field. The partnership is currently working on concept selection for field development.

3.2.7.4.4 Ireland

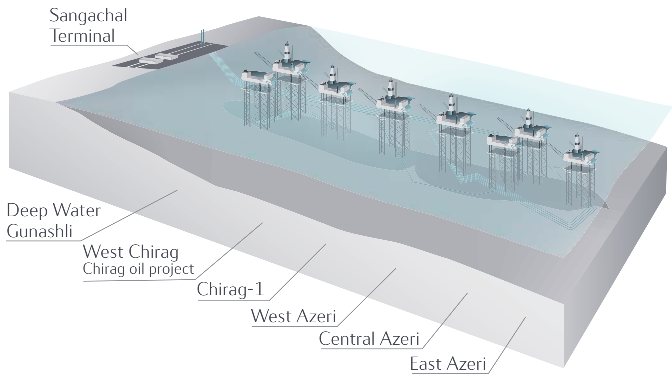
We have a 36.5% interest in the Corrib gas field, which lies on the Atlantic Margin north-west of Ireland. The Shell-operated Corrib field development was sanctioned in 2001, and work towards the first gas is progressing.

Planning permission for the gas terminal was granted in 2004 but project execution was suspended in 2005 due to protests by local landowners. Alternative onshore pipeline routes were identified as part of a community consultation process and a modified application to tunnel under the estuary was submitted in May 2010. Approval for this was granted by the Irish planning authority, An Bord Pleanála (ABP), on 20 January 2011. Further approval was given by the Department of Communications, Energy and Natural Resources on 28 February 2011. Additional approvals are required from the Department of Environment, Heritage and Local Government and Mayo County Council before construction can begin.

Six subsea wells have been drilled and the pipeline from field-to-shore is in-place. However the control umbilical has yet to be installed. A link-line connecting the terminal to the Irish gas grid will be used to import gas to commission the terminal which will then be preserved in a state of readiness for first gas. The final schedule to first gas will be determined once all approvals are in-place.

3.2.7.4.5 Azerbaijan

We have been present in Azerbaijan since 1992 and are now the second largest foreign oil company in the country in terms of proven reserves and production.



Azeri Chirag Gunashli (ACG) platforms

At present, we hold interests in three production sharing agreements (PSAs) offshore in the Azeri sector of the Caspian Sea: the Azeri-Chirag-Gunashli (ACG) oilfield, the Shah Deniz gas and condensate field, and the Alov, Araz and Sharg prospects.

We have an 8.5633% interest in the BP-operated ACG PSA. Crude oil production from the field commenced in 1997. The field has subsequently been developed through ACG Phases one to three, and put on stream from 2005 through 2008. The Chirag Oil Project, which was sanctioned in March 2010, is expected to start production in late 2013. The project will comprise one new platform with capacity to produce 185,000 barrels of oil per day. Crude production from ACG currently exceeds 800,000 barrels of oil per day.

Central Azeri Platforms

Statoil has a 25.5% interest in the Shah Deniz PSA, where BP is the field operator. The production of gas from stage one started in December 2006 and reached nearly seven billion cubic metres in 2010. We are the operator of the Azerbaijan Gas Supply Company (AGSC), which manages gas sales, contract administration and business development for Shah Deniz stage one gas. We are also the commercial operator of the South Caucasus Pipeline system (SCP) for gas transport from Shah Deniz to markets in Azerbaijan, Georgia and Turkey. See also section Risk review - Risk factors - Risks related to our business.

The crude oil from ACG is transported to the Mediterranean Sea through the 1,760-kilometre Baku-Tbilisi-Ceyhan (BTC) Pipeline, in which we participate with an 8.71% interest.

The Shah Deniz partnership has ambitions to start production of stage two. The project is in the concept selection phase, and commercial negotiations are ongoing to secure sales contracts and transportation rights to the markets.

3.2.7.4.6 Russia

Statoil has been present in Russia since the late 1980s. We have a 24% ownership interest in Shtokman Development AG, which is responsible for the Shtokman development phase one, and a 30% ownership interest in one producing field, the Kharyaga oilfield.

Field under planning

The Shtokman gas and condensate field is located in the Russian Barents Sea. The agreement with Gazprom gives Statoil a 24% equity interest in the Shtokman Development AG (SDAG) in which Gazprom (51%) and Total (25%) are the other two partners. The owners have seconded personnel to SDAG, which is responsible for planning, financing, constructing and operating the infrastructure that is necessary for the first phase of the development. SDAG will own and operate the infrastructure for 25 years from the start of commercial production. SDAG is currently maturing the technical concept for the first phase of the Shtokman development in accordance with the framework agreements signed in 2007. Implementation of the project is subject to a final investment decision (FID) pursuant to SDAG's plans. In February 2010, SDAG's board of directors decided to split the FID into two stages. The first FID will be for pipeline gas and the second for LNG.

Field in production
The Kharyaga field is located onshore in the Timan Pechora basin in north-west Russia. The field is being developed under a production sharing agreement (PSA). Total is the operator. With effect from 1 January 2010, Zarubezhneft, a Russian national oil company, became a partner in the Kharyaga PSA with a 20% interest, thus reducing Statoil's share from 40% to 30%.

During 2010, production has been maintained at plant capacity level. Phase three development is ongoing, and eight new wells have been drilled.

3.2.7.5 The Middle East and Asia

Statoil and Lukoil signed a development and production contract with the Iraqi authorities in January 2010 for the development of the West Qurna 2 field.

We have a representative office in China and the United Arab Emirates.

3.2.7.5.1 Iraq

In January 2010, Statoil and Lukoil signed a development and production service contract with the Iraqi authorities for the development of the West Qurna 2 field.

Iraq signing

The parties to the contract are the Iraqi state's South Oil Company and a consortium of contractors. South Oil Company is the contractual counterparty to the consortium of contractors, and it has signed the contract on behalf of the Republic of Iraq. Under the contract South Oil Company is also the highest authority with regard to both governance and procurement. The consortium consists of the Iraqi state's North Oil Company (25%), Lukoil (56.25%) and Statoil (18.75%). The development and production service contract for the West Qurna 2 field was offered as a service contract under which the contractors receive cost recovery plus a remuneration fee. Lukoil and Statoil's bid for West Qurna 2 included a production plateau level of 1,800,000 barrels per day.

With support from Statoil, Lukoil has built up the organisation required to develop the field. Statoil has taken positions in the operating organisation in administrative and technical roles. Statoil is also in the process of setting up a representative office in Baghdad.

Work on the field has started in the form of preparations for the start-up of development activities, which is expected in 2011. The first milestone under the service contract, the Preliminary Development Plan, was approved on 27 November 2010. Invitations to tender have been issued for the first contracts for the field development.

The security of personnel and implementation of necessary security measures are the main priorities. The security situation in Iraq is still demanding, but it has improved over the last two years.

By entering Iraq, Statoil has gained an important position in the Middle East, taking part in developing one of the world's largest oilfields.

3.2.7.5.2 Iran

Statoil was offshore operator for the development of phases 6, 7 and 8 of the South Pars gas and condensate field in the Persian Gulf until its completion in 2009, after which the National Iranian Oil Company (NIOC) took over as formal operator.

Statoil is assisting the NIOC for a limited transitional period in accordance with the contractual framework for the development phase.

Statoil has previously taken part in exploration and drilling activities in the country on the Anaran block. Work on this project has been stopped. Statoil also holds a licence for exploration of the Khorramabad block. No activity is planned for this licence.

The company will not make any future investments in Iran under the present circumstances, but it is committed to fulfilling its contract obligations in relation to South Pars.

In a letter from the US Department of State dated 1 November 2010, Statoil was informed that the company is no longer considered to be a company of concern with regard to its previous Iran-related activities, since the Secretary of State chose to apply the "Special Rule" in the Comprehensive Iran Sanctions, Accountability and Divestment Act of 2010.

See section Risk review - Risk factors - Risks related to our business, for additional information about the risk of sanctions relating to activities in Iran.

3.3 Natural Gas

3.3.1 Introduction to Natural Gas

The Natural Gas business area is responsible for Statoil's transportation, processing and marketing of natural gas worldwide, including the development of additional processing, transportation and storage capacity.

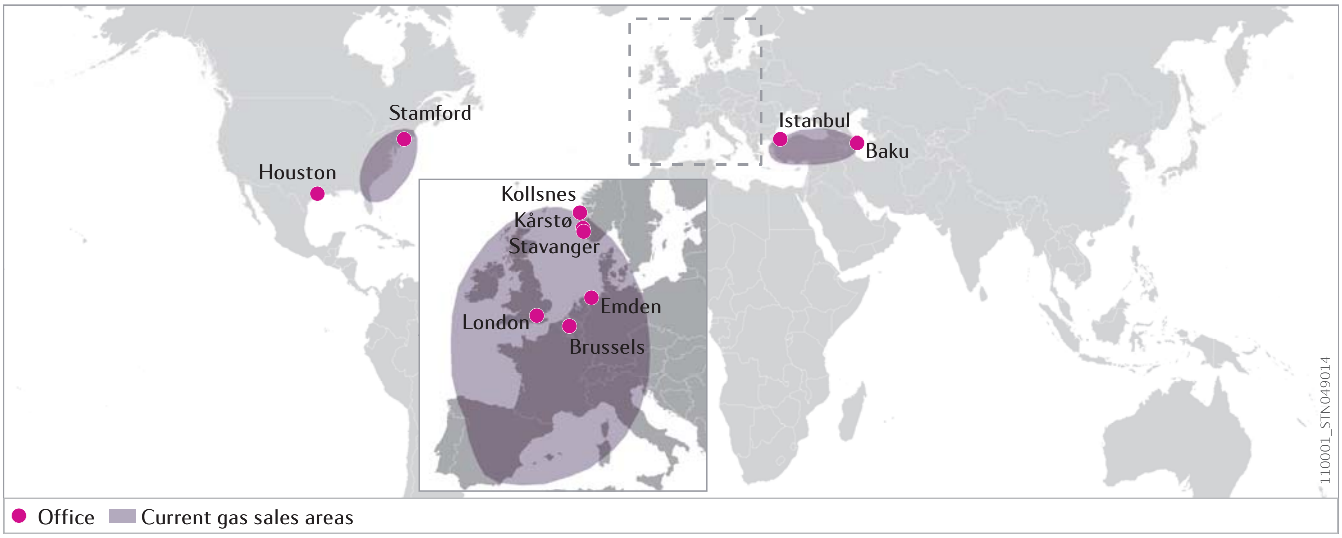
Natural Gas (NG) is also responsible for marketing gas supplies originating from the Norwegian state's direct financial interest (SDFI). In total, we account for approximately 80% of all Norwegian gas exports and are responsible for technical operation of the majority of the export pipelines and onshore plants in the processing and transportation system for Norwegian gas (Gassled*).

NG's business is conducted from three locations in Norway (Stavanger, Kårstø and Kollsnes) and from offices in Belgium, the UK, Germany, Turkey, Azerbaijan and the USA (Houston and Stamford).

In 2010, we sold 38.7 bcm (1.37 tcf) of natural gas from the Norwegian Continental Shelf (NCS) on our own behalf, in addition to approximately 35.3 bcm (1.25 tcf) of NCS gas on behalf of the Norwegian state. Statoil's total European gas sales, including third party gas, amounted to 85.9 bcm (3.04 tcf) in 2010. That makes us the second largest gas supplier to Europe.

In addition, we sold 5.5 bcm (0.19 tcf) of gas originating from our international positions, mainly in Azerbaijan and the USA, 3.0 bcm (0.11 tcf) of which was entitlement gas.

We have a significant interest in the NCS pipeline system owned by Gassled, which is the world's largest offshore gas pipeline transportation system, totalling approximately 8,100 kilometres. This network links gas fields on the NCS with processing plants on the Norwegian mainland and with terminals at six landing points located in France, Germany, Belgium and the United Kingdom. It thus gives us access to customers throughout Europe.



*This system is owned by Gassled in which Statoil has a 32.1% ownership interest at year end 2010. From 1 January 2011, Statoil's ownership is 28.5%.

3.3.2 Natural Gas key events in 2010

In 2010, the gas market was characterised by gradually increasing gas prices and volatile customer off-take. Major maintenance projects at Kårstø and Kollsnes led to significantly reduced equity gas production in the third quarter.

- **Entitlement gas.** Total sales of entitlement gas was at 41.7 bcm, which is an increase of 0.3 bcm compared with 2009.
- **Major maintenance projects.** In the third quarter, Kårstø processing plant was shut down for maintenance, modification and installation work in connection with the Kårstø expansion project (KEP). The maintenance shutdown at Kårstø, was the biggest ever at the plant. A turnaround was also carried out at Kollsnes processing complex in the third quarter. The turnarounds contributed to a decrease in equity production during the shutdowns.
- **Shale gas from Marcellus.** Sales of equity gas from Marcellus started in April. The initial volumes are relatively modest but will increase in the years ahead in step with the increased production of shale gas from Marcellus.
- **Transportation of Marcellus gas.** A transportation agreement was concluded with National Fuel Gas Supply Corporation. This agreement will enable Statoil to transport gas from the Northern Marcellus production area to the US/Canadian border at Niagara Falls, thereby providing access to the attractive urban areas of Eastern Canada.
- **Eagle Ford acquisition.** Statoil and Talisman formed a 50/50 joint venture for the purpose of developing acquired assets in the Eagle Ford shale in Texas. See Operational review - International E&P - International fields in development and production - North America - USA for further details.

3.3.3 The gas market

In 2010, the European natural gas market was dominated by increasing supplies of LNG and only gradual recovery in demand.

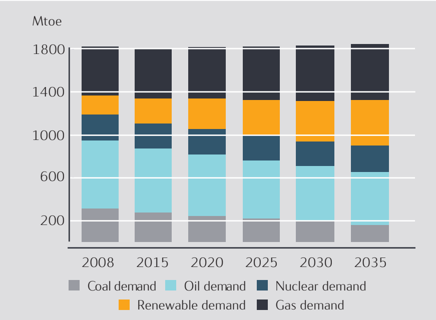
We still expect short-term challenges resulting from increasing global supplies of LNG and slow recovery in European economies but expect growth in the gas markets in the long term. We expect demand for gas to continue to pick up along with a gradual industrial recovery and increased demand for gas in power generation. The new supply of LNG has also connected new emerging markets in Asia and Latin America to the global marketplace.

In the longer term, we believe natural gas will be an increasingly attractive commodity. According to the IEA World Energy Outlook 2010, estimated global gas consumption in 2030 will be 50% higher than the current level, reaching 4,500 bcm per year.

Europe

The gas market in OECD Europe is expected to grow to approximately 650 bcm by 2030, which is up from the current level of around 550 bcm. The competitiveness of gas is driving its share of total energy consumption from 25% in the OECD countries in Europe to an expected 28% in 2030. Most of this growth is expected to take place in the electricity sector.

European energy demand

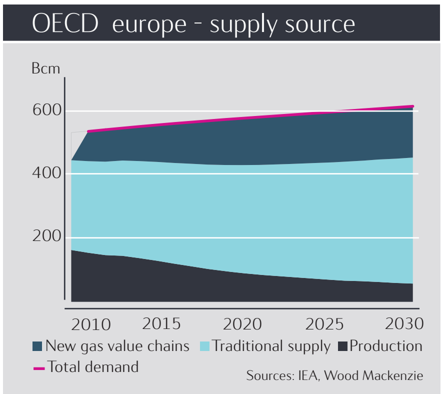


Source: IEA WEO 2009 Reference Scenario

We market and sell our own gas as well as the Norwegian state's natural gas volumes, and we are the second largest gas supplier to Europe. We also market gas sourced from producing areas other than the NCS. Other major gas suppliers in Europe are Gazprom in Russia, Sonatrach in Algeria and GasTerra in the Netherlands. During 2010, Qatari LNG has also become a major European supplier. However, we believe that Norwegian natural gas exports will remain highly competitive due to reliability to Europe, access to a flexible and integrated transportation infrastructure and proximity to key European markets such as the UK, Germany and France. In addition, natural gas is an attractive source of energy from an environmental perspective since it emits far less carbon dioxide than coal and oil. During 2010, we increased our efforts to develop new marketing channels, targeting both end-user segments and power producers, resulting in new short-term and longer-term contracts.

The EU is set to import some 80% of its natural gas by 2020 due to declining domestic gas production. In order to diversify supplies, European countries and companies are actively seeking alternative supply solutions. Moreover, Europe will need additional new sources of natural gas since the global LNG market is expected to divert more gas to the growing Asian economies. Based on our infrastructure, we believe we are well positioned to supply part of this additional demand for imported natural gas.

Statoil participates in increasing gas production in Azerbaijan, and the Shah Deniz field in the Caspian Sea is a key asset. Gas is already exported from Azerbaijan to Georgia and Turkey via the South Caucasus Pipeline (SCP). We are working with our partners in Shah Deniz to commercialise the field's stage two development, including export solutions to Europe.



Statoil participates in the Trans Adriatic Pipeline (TAP), the aim of which is to connect the Italian market with gas flowing westwards from Turkey, through Greece and Albania. TAP is one of several pipeline projects competing for gas volumes from the Caspian region.

As the European energy markets are continuously facing changes in regulation and structures, we believe that natural gas will play an increasingly important role. This trend will be reinforced by further steps in Europe to curb climate gas emissions, in particular by the use of carbon pricing mechanisms such as the EU Emissions Trading Scheme. We expect continued growth in the use of natural gas as a source of electricity generation, as it is necessary to replace even more coal-based generation capacity with natural gas. Liberalisation creates new opportunities and new business models in the gas sector, both with regard to added value as a result of efficiency gains and with regard to building a more substantial portfolio of sales directly aimed at large industrial customers and local distribution companies. Access to downstream markets has traditionally presented challenges since capacity has been booked by incumbent companies. The Third Package (a raft of legislation from the EU) will introduce measures that should address capacity congestion and result in gradual improvements in market access and liquidity as the legislation is implemented across Europe. The integration of the gas and electricity markets also presents us with new business opportunities.

North America

In North America, natural gas demand increased by more than 3.0% in 2010. However, strong domestic gas production kept the market over-supplied throughout the year, pushing storage levels to record high levels and causing downward pressure on natural gas prices. During most of the year, prices fluctuated in the USD 3.50-5.00 per million BTU range. The growth in unconventional gas production, especially shale gas, continued at a fast pace. This trend suggests that North America will remain basically self-sufficient.

For information about the EU Gas Directive, please see report section Operational review - Regulation - The EU Gas Directives.

3.3.4 Gas sales and marketing

Statoil is a long-term, reliable natural gas supplier with a strong position in some of the world's most attractive markets. We are the second largest gas supplier to Europe.

Europe

The major export markets for NCS gas are Germany, France, the United Kingdom, Belgium, Italy, the Netherlands and Spain. The gas is mostly sold through long-term take-or-pay contracts. Our main customers are large national or regional gas companies such as E.ON Ruhrgas, GdF Suez, ENI Gas & Power, British Gas Trading (a subsidiary of Centrica), Distrigaz and GasTerra. We also market our gas to large industrial customers, power generators and wholesalers, in addition to participating in the spot market.

Statoil has end user sales business based in Belgium and the United Kingdom, serving major customers in Belgium, the UK, the Netherlands and France. Our group-wide gas trading activity is mainly focused on the UK gas market (National Balancing Point), which is a significant market in terms of size and the most liberalised market in Europe. We are also increasingly taking part in other liquid trading points, such as the TTF (Title Transfer Facility) in the Netherlands, the Zeebrugge Hub in Belgium and Gaspool /NCG in Germany.

In 2004, Statoil (UK) Limited and SSE Hornsea Limited (subsidiaries of Statoil and Scottish and Southern Energy Plc, respectively) entered into a joint venture for the development, operation and maintenance of a salt cavern gas storage facility near Aldbrough on the east coast of Yorkshire, near the Easington terminal. On completion, the storage facility will comprise nine underground caverns. Statoil (UK) Limited owns one-third of the storage capacity being developed, of which the SDFI will have access to 48.3%. The facility has been developed and is operated by SSE Hornsea Limited. The limited commercial operation that started in 2009 continued in 2010. Full commercial operation of the nine-cavern facility is scheduled for 2012. The design capacity of the storage facility is expected to be 420 mmcm. Statoil's share of the total development cost is estimated to be NOK 0.7 billion.

In Germany, we hold a 30.8% stake in the Norddeutsche Erdgas-Transversale (Netra) overland gas transmission pipeline, and a 23.7% stake in Etzel Gas Storage through our subsidiary Statoil Deutschland. Etzel Gas Storage is currently increasing its working gas capacity by 10 additional caverns, one of which was completed in 2009. Eight caverns were handed over to commercial operation in 2010, and the last one will be handed over in 2011. All partners in Etzel Gas Storage are participating in this project.

USA

The USA is the world's largest and most liquid gas market. Statoil Natural Gas LLC (SNG) has a gas marketing and trading organisation in Stamford, Connecticut that markets natural gas to local distribution companies, industrial customers and power generators. SNG has two long-term capacity contracts with Dominion Resources Inc., which owns the Cove Point LNG re-gasification terminal in Maryland. The first is for a one-third share of Cove Point capacity (LTD1), which is equivalent to approximately 3.2 bcm per year. The second is for 100% of the Cove Point Expansion (CPX) capacity of approximately 7.7 bcm per year. This is equivalent to a total re-gasification capacity of 10.9 bcm per year. This long-term capacity agreement was renegotiated in December

2010 and approved by the Board of Statoil ASA and Dominion Resources Inc. in January 2011. As a consequence, Statoil's commitments related to the re-gasification capacity at CPX have been significantly reduced. The agreement is still pending approval from the government in the US.

The CPX capacity also includess downstream pipeline capacity from the Cove Point terminal to Leidy in Pennsylvania and gas storage capacity at Leidy.

Through Statoil, SDFI pays for a share of the capacity at the Cove Point re-gasification terminal, downstream pipeline capacity and storage capacity. LNG is sourced from the Snøhvit LNG facility in Norway and from third-party suppliers.

SNG also markets the equity production from Statoil's assets in the US Gulf of Mexico.

In 2008, Statoil entered into a strategic agreement with Chesapeake Energy Corporation relating to Marcellus Shale gas. The agreement added a major building block to Statoil's gas value chain in the USA by providing access to large gas reserves geographically near the North East which, historically, is the highest paying gas market. This will thereby strengthen Statoil's USA gas position. Over time, Statoil expects this to result in a significant increase in the volume of gas marketed and traded by Statoil in the USA.

In 2009, SNG concluded transportation agreements with Tennessee Gas Pipeline (a subsidiary of El Paso Corp), and Texas Eastern Transmission (a subsidiary of Spectra Energy Corp), ensuring Statoil the right to transport up to two billion cubic metres (bcm) per year/200,000 mcf/day directly from the Northern Marcellus production area to New York City and surrounding areas. In 2010, SNG concluded a transportation agreement with National Fuel Gas Supply Corporation for up to 3.2 billion cubic metres (bcm) per year/320,000 mcf/day. This agreement will enable Statoil to transport gas on a direct path from the Northern Marcellus production area to the US/Canadian border at Niagara Falls, thereby providing access to the attractive urban areas of Eastern Canada.

In December 2010, Statoil and Talisman formed a 50/50 joint venture for the purpose of developing assets in the Eagle Ford shale. As part of the joint venture, Statoil and Talisman have jointly acquired Enduring's Eagle Ford assets. At the same time, Statoil will buy into Talisman's existing Eagle Ford acreage and production. Together, in a 50/50 partnership Statoil and Talisman will hold 134,000 net Eagle Ford acres and associated assets and production in the joint venture. Initially, Talisman will take the lead as operator for the total acreage, with Statoil taking over the operatorship of 50% of the acreage within three years. Statoil expects that a significant proportion of the revenue from Statoil's Eagle Ford acreage will come from gas liquids and condensate. The Eagle Ford equity production will be a valuable addition to Statoil's oil and gas market portfolio in North America and it will contribute to bolstering value realisation.

Azerbaijan

Statoil has a 25.5% share in the Shah Deniz gas/condensate field in Azerbaijan and is the commercial operator for gas transportation and sales activities for Shah Deniz stage 1 gas volumes. In addition, Statoil chairs the partners' gas sales committee for the planned Shah Deniz stage 2 full field development. Azerbaijan, Georgia and Turkey are part of the gas sales portfolio for stage 1 in which Turkey is the main market. Gas is purchased and sold through the Statoil-operated Azerbaijan Gas Supply Company (AGSC), and the gas is shipped to customers through the South Caucasus Pipeline (SCP), which runs from the Sangachal terminal in Azerbaijan via Georgia to the Georgian/Turkish border. Shah Deniz stage 1 gas transportation and sales reached 6.8 bcm in 2010, 4.36 bcm of which reached Turkey.

The stage 2 development of Shah Deniz is currently in the concept selection phase of operator BP's capital value process. Field reserves support stage 2 production. In June 2010, the governments of Turkey and Azerbaijan signed a Memorandum of Understanding relating to the sale of gas to Turkey and transportation through Turkey to the European markets. Together with key partners in Shah Deniz, Statoil is currently negotiating sales contracts with several marketing companies in Europe and full sales and transit agreements with Botas in Turkey.

Algeria

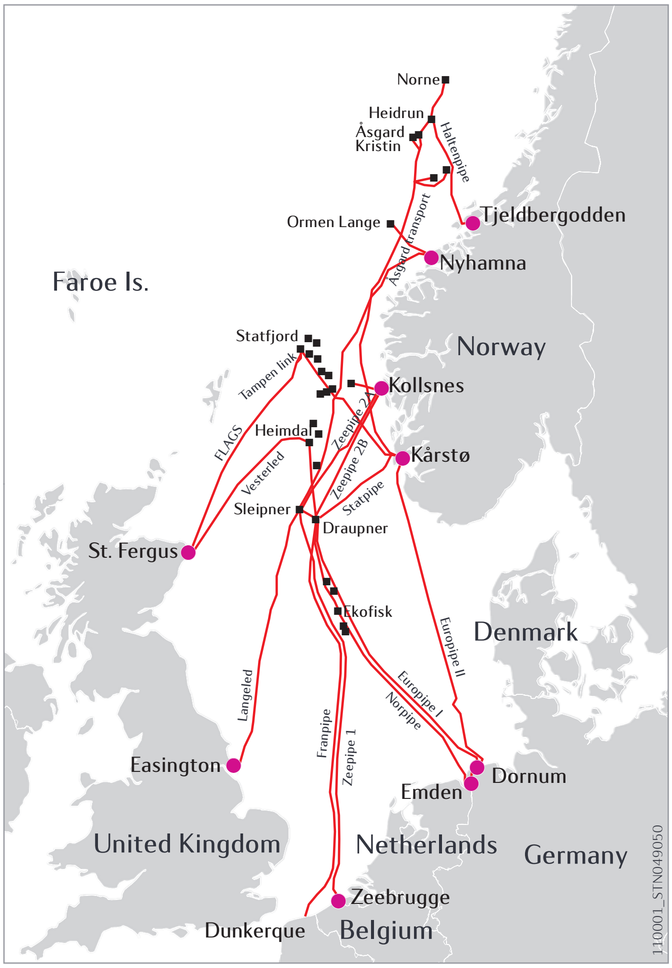
Statoil has a 31.85% share in In Salah and a 50% share in In Amenas, Algeria's third and fourth-largest gas developments, respectively. We are operator of the fields in a joint venture together with BP and Sonatrach. All the gas produced from In Salah is sold under long-term contracts. As regards In Amenas, Statoil receives its production share in kind in the form of condensate and LPG. Statoil has a 75% share in and is operator of the Hassi Mouina exploration licence. Field exploration work has been completed and field development studies are being conducted. The partner is Sonatrach.

LNG

The LNG production plant at Melkøya, the first and only large-scale LNG production facility in Europe, underwent technical maintenance in the third quarter 2010. LNG production has been more regular since the maintenance, and the facility is currently producing stably at design capacity. All contractual obligations have been met during 2010 despite operational issues at Melkøya earlier in 2010. Global LNG prices were under severe pressure from lower demand and increased global production during the first six months of the year. The largest drop in LNG imports was seen in the US market. Increased demand for natural gas, combined with technical production problems on the Norwegian continental shelf and unseasonal cold weather towards the end of the year have helped double prices from April lows. Of the Snøhvit production, a total of 14 cargoes were diverted away from the US market into higher priced markets in Europe and Asia. Statoil will continue to pursue its ambition to grow a global LNG portfolio, including non-equity LNG supply and commitments.

3.3.5 Norway's gas transport system

Over the last 30 years, the Norwegian gas pipeline system has been developed into an integrated system connecting gas-producing fields to receiving terminals in Europe via processing plants on the Norwegian mainland.



The total length of Norway's gas pipelines is currently 8,100 kilometres. All gas pipelines on the NCS with third party customers are owned by a single joint venture, Gassled, with regulated third party access. The Gassled system is operated by the independent system operator, Gassco AS, a company wholly owned by the Norwegian State. In 2010, the Gassled system transported 97.3 bcm (3.4 tcf) of gas to Europe.

In 2010, the Gassled system was again expanded through the merger with the Gjøa Gas Pipeline. When new gas infrastructure facilities are merged into Gassled, the ownership interests are adjusted in relation to the relative value of the assets and each owner's relative interest.

The Gassled ownership interests were adjusted with effect from 1 January 2011. Petoro's interests increased by approximately 7% and all other parties reduced their interests proportionally. Statoil's direct ownership is 28.5% from 2011. Similar adjustments will be made to the ownership interest in Zeepipe Terminal JV and Dunkerque Terminal DA. In addition, Statoil's future ownership interest in Gassled may change as a result of the inclusion of new infrastructure.

Statoil is technical service provider (TSP) for Gassco with respect to the Kårstø and Kollsnes processing terminals, as well as for most of the gas pipeline and platform infrastructure system.

As an integrated pipeline network with high flexibility and regularity, we believe that the Norwegian gas pipeline system is an essential facility in terms of ensuring reliable supplies of natural gas to Europe.

The tables below present facts about the NCS gas pipelines, including transportation routes and daily capacities, and about our ownership in Gassled and receiving terminals.

Norways gas transport system tables

Gas pipelines included in Gassled	Start up date	Product	Start point	End point	Transport capacity[1] mmcm/day	Statoil share in %
Zeepipe						
Zeepipe 1	1993	Dry gas	Sleipner riser platform	Zeebrugge	40.9	See Ownership structure Gassled
Zeepipe 2A	1996	Dry gas	Kollsnes	Sleipner riser platform	72.0	
Zeepipe 2B	1997	Dry gas	Kollsnes	Draupner E	71.0	
Europipe 1	1995	Dry gas	Draupner E	Dornum/Emden	44.5	
Franpipe	1998	Dry gas	Draupner E	Dunkerque	52.4	
Europipe II	1999	Dry gas	Kårstø	Dornum	64.6	
Norpipe AS	1977	Dry gas	Norpipe Y (Ekofisk Area)	Emden	43.1	
Åsgard Transport	2000	Rich gas	Åsgard	Kårstø	70.4	
Statpipe						
Zone 1	1985	Rich gas	Statfjord	Kårstø	26.8	
Zone 4A	1985	Dry gas	Heimdal	Draupner S	33.3	
			Kårstø	Draupner S	20.1	
Zone 4B	1985	Dry gas	Draupner S	Norpipe Y (Ekofisk Area)	30.0	
Oseberg Gas Transport	2000	Dry gas	Oseberg	Heimdal	39.9	
Vesterled (Frigg transport)	2001	Dry gas	Heimdal	St. Fergus	36.0	
Langeled North	2007	Dry gas	Nyhamna	Sleipner Riser	Approx. 70.0	
Langeled South	2006	Dry gas	Sleipner	Easington	68.0	
Tampen Link	2007	Rich gas	Statfjord	FLAGS	26.5 [2]	
Norne Gas Transportation System	2001	Rich gas	Norne field	Åsgard Transport	11.0	
Kvitebjørn gas pipeline	2004	Rich gas	Kvitebjørn	Kollsnes	25.4	
Gjøa Gas Pipe	2010	Rich gas	Gjøa Field	FLAGS	17.0	

(1) We use committable capacity as a measurement for transport capacity. Committable capacity is defined as the capacity available for stable deliveries.

(2) 26.5 mmcm/d is the maximal committable capacity.

Norways gas transport system tables

Gas pipelines not included in Gassled	Start-up date	Product	Start point	End point	Transport capacity mmcm/day	Statoil share in %
Haltenpipe	1996	Rich gas	Heidrun field	Tjeldbergodden/ Åsgard Transport	7.1	19.06
Heidrun gas export	2001	Rich gas	Heidrun	Åsgard Transport	10.9	12.41

Terminal facilities included in Gassled	Startup date	Product	Location
Europipe Receiving Facilities	1995	Dry gas	Dornum, Germany
Europipe Metering Station	1995	Dry gas	Emden, Germany
Norsea Gas Terminal	1977	Dry gas	Emden, Germany
Kårstø Gas Processing Plant	1985	Dry gas/NGL	Kårstø, Norway
Easington Receiving Facilities	2006	Dry gas	Easington, UK
St.Fergus Terminal	1978	Dry gas	St. Fergus, Scotland
Kollsnes Gas Processing Plant	1996	Dry gas/NGL	Kollsnes, Øygarden Norway

Terminals not included in Gassled	Startup date	Product	Location
Zeepipe terminal JV (1)	1993	Dry gas	Zeebrugge, Belgium
Dunkerque terminal DA (2)	1998	Dry gas	Dunkerque, France

(1) Gassled owners hold 49 per cent interest in the terminal.
(2) Gassled owners hold 65 per cent interest in the terminal.

Ownership structure Gassled	Period 2009-2010	Period 2011-2028
Petoro AS(1)	38.43%	45.79%
Statoil ASA	32.07%	28.48%
ExxonMobil	9.40%	8.04%
Total	7.76%	6.10%
Shell	5.34%	5.01%
Norsea Gas AS	2.72%	2.26%
ConocoPhillips	1.99%	1.68%
Eni	1.52%	1.28%
Dong	0.66%	0.98%
GDF SUEZ	0.09%	0.30%
RWE Dea	0.02%	0.08%
Statoil interest including 28.58% of Norsea Gas AS	32.84%	29.13%

(1) Petoro holds the participating interest on behalf of the SDFI.

3.3.6 Kårstø gas processing plant

As technical service provider (TSP), Statoil is responsible for the operation, maintenance and further development of the Kårstø gas processing plant on behalf of the operator Gassco.

Kårstø. Kårstø is currently preparing for the future with the ongoing KEP.

Kårstø processes rich gas and condensate, or light oil, from the NCS received via the Statfjord pipeline, the Åsgard pipeline and the Sleipner condensate pipeline. The processing plant currently has a rich gas capacity of 88 mmcm per day. Products produced at Kårstø include ethane, propane, iso-butane, normal butane, naphtha and stabilised condensate. When all these elements have been separated from the gas, the remaining gas (dry gas) is sent to customers via the Statpipe, Europipe II and Rogass pipelines. The processing plant currently has a dry gas export capacity of 77 mmcm per day.

Over the last four years, the Kårstø processing plant has been undergoing comprehensive upgrading in order to meet safety and technical requirements and future needs. KEP is the project name for several projects aimed at making the Kårstø facilities more robust and ensuring safe and efficient operation. The investment is estimated to be around NOK 7.5 billion. The plan is that the remaining sub-projects will be completed between 2011 and 2012. In 2010, Kårstø produced 22.0 bcm of dry gas, 0.8 million tonnes of ethane, 3.6 million tonnes of LPG and 1.9 million tonnes of condensate/naphtha for export to customers worldwide. Capacity utilisation was 89.9% in 2010.

3.3.7 Kollsnes gas processing plant

As technical service provider, Statoil is responsible for the operation, maintenance and further development of the Kollsnes gas processing plant on behalf of the operator Gassco.

Kollsnes. At Kollsnes gas comes ashore for further processing before it is transported in pipelines to customers in Europe

The plant was initially built to receive gas from the Troll field in two 36-inch pipelines. In 2010, the Kollsnes projects (KOP) started with the aim of increasing the robustness of the plant and maintaining gas capacity, with a new 36-inch pipeline from the Troll Field to Kollsnes. In addition Kollsnes receives gas from the offshore fields Visund, Kvitebjørn and Fram. These volumes are processed through the NGL plant. The Kollsnes gas processing plant currently has a design capacity of 143 MSm3/day. The dry gas is sent to customers in France, Great Britain, Belgium, Netherlands, and Germany through the Zeepipe, Franpipe, Langeled and Norpipe pipelines.

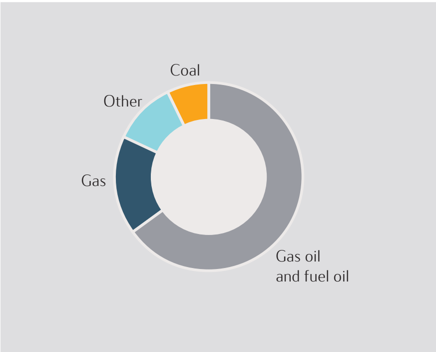
Kollsnes is a swing producer based on customer off-take. During the year, monthly off-take generally varies between 25% and 100%. To maintain high availability as a swing producer, Kollsnes has invested NOK 500 million in 2009 and 2010 to upgrade the facilities through various robustness projects, such as electricity supply, turbo expanders and preventive maintenance of the compressors. In 2010, Kollsnes produced 36.4 bcm of dry gas and 1.9 MSm3 of condensate.

3.3.8 Gas sales agreements

Statoil manages, transports and markets approximately 80% of all NCS gas.

Due to the relatively large size of the NCS gas fields and the extensive cost of developing new fields and gas transportation pipelines, a large proportion of Statoil's gas sales contracts are long-term contracts that typically run for 10 to 20 years or more. Under these contracts, the buyers agree to take a minimum daily volume and a minimum annual volume of gas. If this volume is not taken, the buyers are nevertheless obliged to pay for the contracted volume. The majority of Statoil's long-term sales contracts have reached plateau level.

Long term sales indexation split



Prices in traditional long-term contracts are generally tied to a formula based on the prices for substitute fuels for natural gas, typically heavy fuel oil and gasoil. In our gas portfolio, we also have gas sales contracts in the UK that are priced with reference to a gas spot market index. There can be significant price fluctuations during the life of the contract. Under the traditional long-term contracts, prices are typically adjusted quarterly and are calculated on the basis of the prevailing prices for substitute fuels in the three to nine months prior to the adjustment date. However, the price formula, which allows such quarterly adjustment, does not pick up on all trends in the marketplace, such as changes in the taxation of gas and competing fuels imposed by national governments. That is why most of the long-term gas contracts contain contractual price adjustment mechanisms that can be triggered by the buyer or seller at regular intervals, or under certain given circumstances. In 2010, Statoil was involved in such commercial discussions for significant volumes covered by long-term sales contracts. The outcome of these discussions has generally been the introduction of a smaller proportion of spot price indexation and/or limited reduction in the volume obligation for the buyer, and increased access to the continental spot markets for Statoil.

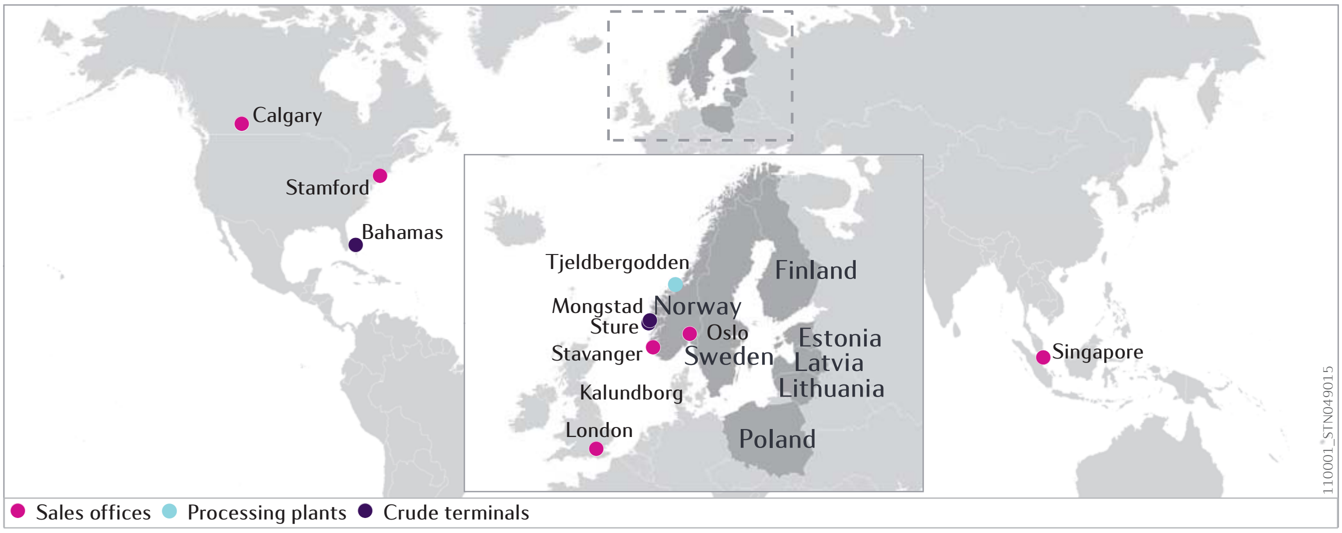
3.4 Manufacturing & Marketing

3.4.1 Introduction to Manufacturing & Marketing

Manufacturing & Marketing adds value through the processing and sale of the group's and the Norwegian state's production of crude oil and natural gas liquids.

Manufacturing & Marketing (M&M) is responsible for the group's transportation, processing, marketing and trading of crude oil, natural gas liquids and refined products. We run two refineries, one methanol plant and three crude oil terminals. Our international trading activities make us one of the world's largest crude oil traders.

In 2010, we traded 694 million barrels of crude oil and condensate, approximately 18 million tonnes of refined oil products and 13 million tonnes of natural gas liquids (NGL). The refinery throughput was 14.7 million tonnes. Tjeldbergodden produced approximately 10% of the European market's demand for methanol.



3.4.2 Manufacturing & Marketing key events 2010

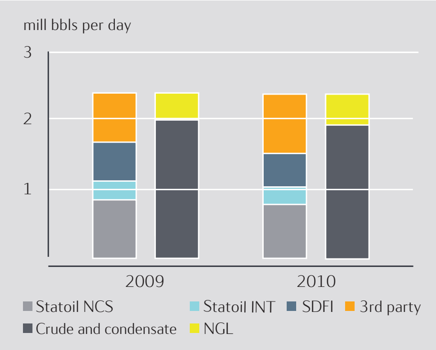
Refining margins improved in 2010, but were still low compared with 2008. In addition, trading results were lower than in 2009. Statoil Fuel & Retail was listed on Oslo Stock Exchange.

- The refining market was still challenging despite an increase in the FCC refining margin from USD 4.3 in 2009 to USD 5.4 per barrel in 2010.
- Turnarounds at Mongstad, Kalundborg and Tjeldbergodden.
- The combined heat and power (CHP) plant at Mongstad started commercial operation on 20 December.
- Statoil's board of directors decided to implement a new ownership structure for our Energy and retail business, which became a stand-alone entity, Statoil Fuel & Retail ASA (SFR). SFR was listed on Oslo stock exchange on 22 October.
- The new sulphur recovery unit at Mongstad was started up in October. It is the first major unit to be replaced since the refinery was built in 1975. The new unit will reduce sulphur dioxide emissions and improve feedstock flexibility.

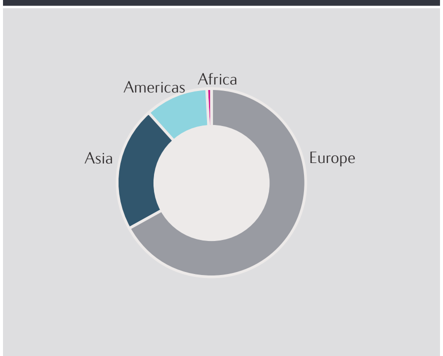
3.4.3 Oil Sales, Trading and Supply

Statoil is one of the world's major net sellers of crude oil, operating from sales offices in Stavanger, Oslo, London, Singapore, Stamford and Calgary and selling and trading crude oil, condensate, NGL and refined products.

Traded oil volumes per day



Crude and condensate sale



We market Statoil's own volumes and SDFI's equity production of crude oil and NGL, in addition to third party volumes. In 2010, our total sales of crude and condensate were equivalent to 694 million bbls, including supplies to our own refineries. The main crude oil market for Statoil is north-western Europe. In addition, we sell volumes to North America and Asia. Most of the crude oil volumes are sold in the spot market based on publicly quoted market prices. Of the total 694 million bbls sold in 2010, approximately 44% were Statoil's own equity volumes.

We operate the South Riding Point crude oil terminal in the Bahamas and are also responsible for optimising commercial utilisation of the crude terminal located at Mongstad. We are also responsible for Statoil's crude and LPG liftings at the Sture terminal.

Marketing activities are also optimised through lease contracts and long-term agreements for utilisation of third party assets.

In 2010, Statoil and its subsidiary, SFR, entered into fuel product supply agreements under which SFR is supplied exclusively by Statoil with respect to certain oil products sold by SFR in Scandinavia and the Baltic states until 31 December 2015, unless the agreements are terminated pursuant to the early termination provisions or extended. SFR's aviation business is also mainly supplied by Statoil, under one of these supply agreements, and under agreements with SFR subsidiaries.

3.4.3.1 South Riding Point

Statoil holds the lease for the South Riding Point crude oil terminal in the Bahamas until 2049. The lease includes oil storage as well as loading and unloading facilities.

The terminal, which is located on Grand Bahama Island, consists of two shipping berths and ten storage tanks with storage capacity for 6.75 million barrels of crude.

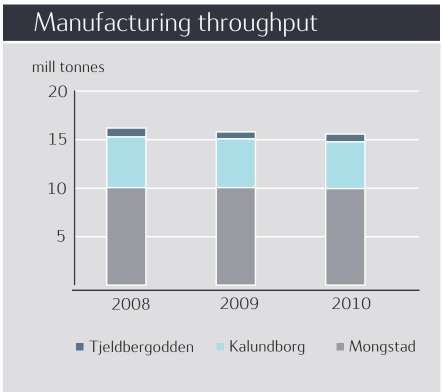
We have started a project to upgrade the terminal to enable the blending of crude oils, including heavy oils. Future blending operations will normally be carried out onshore, but facilities will also be installed that enable blending from ship to ship at the jetty.

This terminal will both support our global trading ambitions and improve our handling capacity for heavy oils. New blending facilities and full terminal capacity will strengthen both our marketing and trading positions in the North American market. The terminal will also be an important part of our plans to market our own volumes of heavy oil.

In addition to the existing lease period, we have an option to extend the agreement for an additional 30 years until 2079.

3.4.4 Manufacturing

Statoil is majority owner and operator of the Mongstad refinery and Tjeldbergodden methanol plant in Norway and sole owner and operator of the Kalundborg refinery in Denmark. We also operate the Oseberg Transportation System.



We are majority owner (79%) and operator of the Mongstad refinery in Norway, which has a crude oil distillation capacity of 180 mbbl per day. We are sole owner and operator of the Kalundborg refinery in Denmark, which has a crude oil and condensate distillation capacity of 118 mbbl per day. In addition, we have rights to 10% of production capacity at the Shell-operated refinery in Pernis, the Netherlands, which has a crude oil distillation capacity of 400 mbbl per day. Our methanol operations consist of an 81.7% stake in the gas-based methanol plant at Tjeldbergodden, Norway, which has a design capacity of 0.95 million tonnes per year.

We also operate the Oseberg Transportation System (36.2% stake) including the Sture crude oil terminal. The terminal was built to receive crude from the Oseberg field by pipeline. Since 2003, it has also received crude from the Grane field pipeline. Oseberg blend (after stabilisation), Grane blend and some LPG are exported, while some LPG and naphtha is piped to Mongstad combined with condensate from the Kollsnes gas processing plant.

The following table shows operating characteristics for the plants at Mongstad, Kalundborg and Tjeldbergodden.

All data for year ended December 31	Throughput [1]			Distillation capacity [2]			On stream factor % [3]			Utilization rate % [4]		
Refinery	2010	2009	2008	2010	2009	2008	2010	2009	2008	2010	2009	2008
Mongstad	**9.9**	10.0	10.0	**8.7**	8.7	8.7	**97.3**	92.3	92.2	**82.7**	86.8	88.2
Kalundborg	**4.8**	5.0	5.2	**5.5**	5.5	5.5	**97.2**	95.3	88.3	**86.6**	88.2	90.3
Tjeldbergodden	**0.8**	0.71	0.91	**0.95**	0.95	0.95	**95.0**	82.6	98.9	**96.9**	90.2	96.5

(1) Actual throughput of crude oils, condensates, NGL, feed and blendstock, measured in million tonnes.
Higher than distillation capacity for Mongstad due to high volumes of fuel oil and NGL not going through the crude distillation unit.
(2) Nominal crude oil and condensate distillation capacity, and methanol production capacity, measured in million tonnes.
(3) Composite reliability factor for all processing units, excluding turnarounds.
(4) Composite utilization rate for all processing units, stream day utilization.

The improvement programme for cost savings and increased value added reached its targets for 2010. The programme will be continued in coming years with the aim of further improving Kalundborg's competitive position.

3.4.4.1 Mongstad

The Mongstad refinery is a medium-sized, modern refinery. It is linked to offshore fields, the Sture crude oil terminal and the Kollsnes gas processing plant, making it an attractive site for landing and processing hydrocarbons.

Mongstad

The Mongstad refinery, which was built in 1975, was significantly expanded and upgraded in the late 1980s. It has been subject to considerable investment over the last 15 years in order to meet new product specifications and improved energy efficiency. A medium-sized, modern refinery, it is directly linked to offshore fields through two crude oil pipelines, through a natural gas liquids (NGL)/condensate pipeline to the crude oil terminal at Sture and the gas processing plant at Kollsnes, and by a gas pipeline to Kollsnes. This makes Mongstad an attractive site for landing and processing hydrocarbons and for the further development of our oil and gas reserves.

In addition to the refinery, the main facilities at Mongstad consist of a crude oil terminal, an NGL process unit and terminal, and a combined heat and power plant (CHP). Statoil owns 65% of the crude terminal. A large proportion of its crude oil comes via two direct pipelines from the Troll field. The storage capacity is 9.4 million barrels of crude.

Vestprosess, which is owned 34% by Statoil, transports and processes NGL and condensate. The Vestprosess pipeline connects the Kollsnes and Sture plants to Mongstad. The NGL is fractionated in the Vestprosess NGL unit to produce naphtha, propane and butane.

The CHP plant, which is 100% owned by Dong Generation Norge AS, receives gas from Troll and the refinery for the production of electric power and heat.

The refinery is owned 79% by Statoil and 21% by Shell.

Approximately 45% of Mongstad's total production is delivered to Scandinavian markets, and 55% is exported to north-western Europe and the United States. The following table shows the approximate quantities of refined products (in thousand tonnes) produced at Mongstad for the periods indicated. In addition to crude, the Mongstad refinery upgrades large volumes of heavy fuel oil, NGL from Oseberg and Tune, and condensate from Troll, Kvitebjørn, Visund and Fram.

Mongstad product yields and feedstock	2010		For the year ended 31 December 2009		2008	
LPG	360	4%	372	4%	311	3%
Gasoline / naphtha	4,258	43%	4,401	44%	3,902	39%
Jet / kerosene	681	7%	717	7%	820	8%
Gasoil	3,539	36%	3,473	34%	3,680	37%
Fuel oil	231	2%	374	4%	485	5%
Coke / sulphur	174	2%	164	2%	190	2%
Fuel, flare & loss	620	6%	532	5%	575	6%
Total throughput	9,863	100%	10,033	100%	9,963	100%
Troll, Heidrun (FOB crude oils)	4,516	46%	4,062	40%	4,676	47%
Other North Sea crude oils (CIF crude oil)	2,452	25%	3,679	37%	3,072	31%
Residue	1,523	15%	1,316	13%	1,132	11%
Other fuel and blendstock	1,372	14%	976	10%	1,083	11%
Total feedstock	9,863	100%	10,033	100%	9,963	100%

Note: Changes in throughput and yields are partly due to maintenance shutdowns (e.g. major turnarounds in 2008 and 2010).

The Mongstad refinery can manufacture products to meet different specifications through in-line blending during ship loading.

The refinery's reliability (i.e. its on-stream factor) was high in 2010, while we experienced some operational problems during 2008 and 2009. There were also shutdowns due to the market situation in 2009. In 2008, the largest turnaround in Mongstad's history was executed on schedule, and we also carried out a major turnaround in 2010. Capacity utilisation (the share of available plant capacity actually used) was reduced in 2009. This was also due to the market situation.

The new CHP plant started commercial operation on 20 December 2010, and was part of a strategically important project for Manufacturing & Marketing. The plant improves the Mongstad refinery's energy efficiency and has a capacity of approximately 280 megawatts of electric power and 350 megawatts of process heat. The plant will have a gradual start-up phase as the refinery needs less steam due to a changed feedstock pattern, lower throughput and the postponement of projects. The plant is operated by Dong Energy, with Statoil paying an annual tariff for its use. There is an agreement with the Troll licensees to supply power to the Troll A gas platform and the associated Kollsnes onshore processing plant. In addition to the CHP plant, the CHP investment project included a new gas pipeline from Kollsnes and necessary modifications at the refinery.

Together with the Norwegian Government, Statoil is involved in several projects that aim to develop solutions for carbon capture and storage (CCS) at Mongstad. See section Operational review - Technology & New Energy - New energy for further information.

3.4.4.2 Kalundborg

The Kalundborg refinery is a small but flexible oil refinery. This enables it to produce a variety of products, although its main products are low-sulphur petrol and diesel for markets in Denmark and Sweden.

Kalundborg

The refinery is connected via two pipelines (one gasoline and one gasoil) to our terminal at Hedehusene near Copenhagen, and most of our products are therefore sold locally.

Kalundborg's refined products are also supplied to other markets in north-western Europe, mainly Sweden and England.

The following table shows the approximate quantities of refined products (in thousand tonnes) produced by Kalundborg in the periods indicated.

Kalundborg product yields and feedstock	For the year ended 31 December 2010		2009		2008	
LPG	80	2%	71	1%	54	1%
Gasoline / naphtha	1,461	31%	1,620	32%	1,598	31%
Jet / kerosene	141	3%	130	2%	251	5%
Gasoil	2,124	44%	2,140	43%	2,105	40%
Fuel oil (2)	756	16%	886	18%	1,023	20%
Coke / sulphur	7	0%	0	0%	6	0%
Fuel, flare & loss	186	4%	189	4%	183	3%
Total throughput(1)	4,755	100%	5,036	100%	5,220	100%
Condensates: Ormen Lange, Snöhvit, Sleipner	754	16%	998	20%	659	12%
Other North Sea crude oils	3,492	73%	3,713	74%	4,314	83%
Other fuel and blendstocks	234	5%	202	4%	247	5%
Other crudes	275	6%	123	2%		
Total feedstocks	4,755	100%	5,036	100%	5,220	100%

Note: Changes in throughput and yields are partly due to maintenance shutdowns (e.g. major turnaround in 2010).

The refinery's reliability (i.e. its on-stream factor) was good in 2010 and on a par with the best years. The throughput in 2010 was lower than in 2009 due to a planned maintenance turnaround, while it was lower in 2009 than in 2008 due to the economic downturn. The product yield from the refinery is well positioned in relation to the expected future demand structure in the European market.

3.4.4.3 Tjeldbergodden

The methanol plant at Tjeldbergodden is the largest in Europe and one of the most energy efficient in the world. It is supplied with natural gas from the Heidrun field in the Norwegian Sea through Haltenpipe.

Tjeldbergodden

Statoil owns 81.7% of the plant, which has a maximum proven capacity of 0.92 million metric tonnes per year (mmtpa). The actual throughput in 2010 was reduced due to a planned maintenance turnaround. Methanol production in 2010 was 0.80 mmtpa.

We also own 50.9% of Tjeldbergodden Luftgassfabrikk DA, one of the largest air separation units (ASU) in Scandinavia.

3.4.4.4 Sture

The Sture terminal receives crude oil in two pipelines from the Oseberg area and the Grane field in the North Sea. The terminal is part of the Oseberg Transportation System in which Statoil has a 36.2% stake.

Sture terminal

The terminal has storage capacity for 6.3 million barrels of crude.

The processing facilities at Sture stabilise Oseberg crude oil and recover LPG mix (propane and butane) and naphtha. Oseberg Blend and Grane crude qualities and LPG mix are exported. LPG and naphtha are also transported through the Vestprosess pipeline to Mongstad.

The LPG processing capacity is max. 68 tonnes/hr. The import capacity is approx. 96,000 cm/d of Oseberg blend, and approx. 40,000 cm/d of Grane oil.

3.5 Technology & New Energy

3.5.1 Introduction to Technology & New Energy

Technology & New Energy is responsible for the development and implementation of technology and renewable energy, thereby contributing to solutions crossing energy frontiers.

Technology & New Energy (TNE) is responsible for ensuring capacity and expertise in the field of technology in addition to creating distinct technological solutions for global growth. This includes delivering innovative and competitive technological solutions for exploration, increased recovery, field development and safe, efficient and environmentally friendly operations. The research and development division, which has research centres in Trondheim, Bergen and Porsgrunn in Norway and in Calgary in Canada, is engaged in research and development as well as first use of new technology.

Climate change, supply security and growing demand for clean energy are opening up new business opportunities for Statoil, particularly in carbon capture and storage (CCS) and offshore wind power. Statoil is in a position to seize these opportunities by utilising core capabilities from the oil and gas industry. Statoil's New Energy business entity is responsible for the company's efforts in renewable energy. The activities are grouped under renewable energy production, new options and carbon management.

3.5.2 Technology & New Energy key events in 2010

This is an overview of key events relating to TNE in 2010.

Technology

- In 2010, we deployed a new formation-testing-while-tripping tool (FTWT) that enables safer and faster well testing without flaring of hydrocarbons. The technology has the potential to considerably reduce emissions to the environment compared with conventional well-testing methods. The application of FTWT technology also significantly reduces the time and cost of well-testing operations.
- Steerable drilling liner, which was developed by us, will improve our ability to drill in depleted reservoirs and unstable formations. Tests have been carried out sucessfully on Statfjord and Brage. We are currently working to develop it from a niche product to a new and efficient standard for well construction.
- Statoil's autonomous inflow control valve is a promising technology we have developed to achieve increased recovery from thin oil zones and heterogeneous reservoirs. The technology is being qualified for both conventional and heavier oil types.
- The production of bitumen using steam-assisted gravity drainage (SAGD) with some modifications is under testing at the Leismer field in Canada.

- We have been involved in establishing new technology and knowledge that can help prevent work-related hearing injuries as a result of noise exposure in the offshore industry. Quietpro, a new technology to make it easier to talk to colleagues in work and emergency situations offshore, is under qualification for use in all areas of offshore platforms.
- Statoil and its partners on Åsgard have opted for subsea gas compression to help recover the big remaining reserves in this Norwegian Sea field. Moving compression to the seabed results in both improved energy efficiency and lower costs compared with compression on a platform or on land.
- Statoil introduced a new diving and stand-by vessel, Scandi Arctic, which, because of its technical features and HSE standard, is a state-of-the-art vessel for diving operations. Statoil has been the driving force behind and sponsor of the development of the vessel, which is owned and operated by Technip.

New Energy

- Statoil and Statkraft have decided to develop the 315MW Sheringham Shoal Offshore Wind Farm in the UK, which is expected to provide energy for 220,000 British homes. Construction work has started with Statoil as operator for the development.
- Hywind, the world's first full-scale floating offshore wind turbine, started operation in autumn 2009. Its start-up enabled successful testing of the next generation of offshore wind technology.
- Construction of the European CO2 Technology Centre Mongstad (TCM) started in June 2009. Construction work is proceeding according to plan, and the project is about 65% complete.

3.5.3 Research and development initiatives

Our research and development (R&D) efforts focus on the technology areas identified as addressing our key business challenges. The aim is to secure future returns and strengthen our technology positions to give us a competitive advantage.

The R&D portfolio is organised in five programmes throughout the oil and gas value chain: Exploration, Increased Recovery, New development solutions, the Oil and gas value chain and New energy and HSE. R&D also addresses business challenges connected to the Gulf of Mexico and extra heavy oil in Canada. We also have an academia programme that addresses cooperation with universities and research institutes.

R&D expenditure has been stable for the last four years at approximately NOK 2.0 billion per year.

Cooperation with external partners such as academic institutions, R&D institutes and suppliers is crucial in relation to technology. Statoil aims for a 50/50 split between internal and external R&D spending.

Statoil has three research centres in Norway and a heavy oil technology centre in Canada. The R&D organisation is responsible for operating and further developing our world-class laboratories and experimental rigs.

Exploration

Our exploration research focuses on three key business challenges: (i) securing exploration growth and resource replacement, (ii) early access to frontier basins and plays, and (iii) exploration and exploitation of unconventional resources such as shale gas and oil and gas hydrates. Major technical developments that address these business challenges were made within seismic imaging and interpretation. New methods have been developed for evaluating basins and new concepts developed for understanding complex carbonate and deepwater clastic reservoir systems. Both these types of reservoir systems are present and are key targets in major exploration arenas for Statoil, such as the Norwegian Continental Shelf, the Gulf of Mexico and the South Atlantic basins.

Increased recovery

For proved reservoirs, the aim is to optimise hydrocarbon recovery by improving ways of identifying remaining resources and efficiently draining our reservoirs. The business potential of technologies that address increased recovery is significant. We focus specifically on the challenge of resource and reserve replacement. Moving the barrels faster from resources to production and maintaining current production levels requires a combination of innovative technologies and simple, but smart solutions. We are addressing resource and reserve replacement, contributing to next-generation reservoir exploitation and looking for ways in which we can implement fast-track processes for a broader range of projects. This includes developing fit-for-purpose modelling techniques for better and more efficient modelling of reservoir drainage, more efficient drilling and intervention solutions and more cost-effective well construction methods. The research portfolio maintains its clear relevance to the Norwegian Continental Shelf and our international activity. It has a strong focus on implementation together with our operating units and in close collaboration with service companies and suppliers.

New development solutions

Innovative cost-efficient offshore field development solutions are resulting in a transition from topside facilities to intelligent, remotely-operated, autonomous seabed facilities, coupled with ultra-long, subsea tie-backs and wellstream compression devices. However, we also see that compact processing technology developed for subsea application has a substantial potential to improve production efficiency on existing topside facilities. The aim is to improve the regularity and performance of both new and producing fields. It is also necessary to increase our knowledge about design and operations in ice-bound areas and in ultra-deepwater conditions. We are also developing technology for the processing and transportation of offshore heavy oil.

Oil and gas value chain
Statoil aims to develop competitive and sustainable technologies and expertise for use in the development of oil and gas value chains. The oil and gas industry is looking for solutions for the development of increasingly challenging hydrocarbon resources, and we are focusing on identifying and developing future unconventional hydrocarbon value chains. Challenging crude oils and acid gas removal are being addressed, and we continue to develop technologies to support Statoil's oil refineries, gas conversion and gas processing facilities. The aim is to contribute to maximising value through operational excellence.

New Energy and HSE
Our commitment to environmental stewardship is twofold: meeting our objective of zero harm to the environment by expanding our toolkit of environmental monitoring and integrated risk-modelling systems, and, secondly, creating business in new energy sources. Our research into new forms of energy is focused on offshore wind and second generation biofuels based on marine feedstock. Cost and energy-efficient carbon capture and storage (CCS) that does not harm the environment is an important technology being addressed by Statoil. We are committing resources to acquiring new ideas in this field, because we believe that technological innovation is the key to a profitable, sustainable, low-carbon energy future.

Extra heavy oil
Our extra heavy oil research is aimed at developing technologies that increase the reserve base and result in more cost-efficient and environmentally sustainable production of extra heavy oil. Extra heavy oil research has been a top priority this year. The Calgary Heavy Oil Technology Centre was established in 2008 to strengthen our efforts in heavy oil technologies. The centre has grown and now employs 20 people, which is one third of our R&D personnel in the field of extra heavy oil.

Gulf of Mexico
Statoil established a new R&D programme in 2010 to ensure focus on enabling technologies for realising business opportunities in the deepwater Gulf of Mexico. The aim is to improve our mapping and evaluation of low permeable reservoirs, deepwater drilling and future field development solutions to cut costs and improve recovery, with particular focus on deep Paleogene reservoirs. Cross-disciplinary groups have also initiated intensive research on the application of advanced geological interpretation, well technology and improved recovery methods.

Academia
As part of the research effort, we are engaged in an extensive collaboration programme with academic institutions in which we gain access to world-class research in strategic areas for Statoil. By stimulating the development of leading expertise in the energy segment, we also secure long-term recruitment to science and technology.

By supporting collaboration between universities, research institutions and industry, we also contribute to building a strong Norwegian petroleum cluster. Through the R&D programmes and our international offices, we also cooperate with international universities and organisations in Canada, the USA, China and Brazil, among other countries.

3.5.4 New energy

Our renewable energy business focuses in particular on developing profitable business in areas where we may have a competitive edge as a result of our offshore expertise. Key areas are offshore wind and carbon capture and storage.

Offshore wind projects
Statoil utilises its offshore competence in marine operations and offshore maintenance to give the company a competitive edge in offshore wind projects. We currently operate one large development, Sheringham Shoal, off the UK coast, and are involved in planning one of the world's largest offshore wind developments, Dogger bank, which is also off the UK coast. In addition, we have designed, built and successfully tested the world's first floating wind turbine, Hywind. As part of our strategy of focusing on offshore wind projects, we have decided to sell our onshore wind portfolio.

Sheringham Shoal
In partnership with the Norwegian utility Statkraft, we are building one of the largest offshore wind farms in the UK, Sheringham Shoal, off the Norfolk coast. The farm will cover more than 35 square kilometres and consist of 88 wind turbines, each of which will be 80 metres high. The site was chosen for its high wind speeds, shallow water depths, low level of fishing activity and location outside protected zones.

When Sheringham gradually starts operating in 2011, it is expected to generate an estimated 1.1 TWh annually, equivalent to the annual energy consumption of 220,000 British homes. It will also save an estimated half a million tonnes of carbon dioxide emissions per year compared with energy produced using conventional methods in the UK.

Hywind
Hywind is the world's first full-scale floating wind turbine prototype. During 2010, Statoil successfully tested Hywind off the coast of western Norway. Hywind's unique floating cylinder is based on a philosophy of utilising familiar technology from the wind power and offshore industries and combining it in a new way in a floating wind turbine structure.

Dogger Bank
On 8 January 2010, Forewind, a consortium consisting of Statoil, Statkraft, RWE and Scottish and Southern Energy, announced that it had been awarded development rights for an offshore wind farm in the Dogger Bank area in the UK sector of the North Sea. Surveys and planning are now being conducted, and the first investment decisions are expected some time after 2014.

Dogger Bank could be the world's largest wind power development, with a targeted capacity of 9GW, which is equivalent to nearly 10% of the total electricity needs in the UK. Due to the size of the area, the development will have to take place in phases. Dogger Bank covers nearly 9,000 square kilometres off the Yorkshire coastline, where depths range from 18 to 63 metres.

Carbon capture and storage (CCS)
CCS is seen as one of the main methods of combating climate change. Statoil has long been regarded as a pioneer of CCS in oil and gas production, and we currently operate some of the world's largest carbon capture and storage projects.

Statoil is also engaged in the development of potential medium and long-term breakthrough technologies for carbon capture. Together with Gassnova (which represents the Norwegian government in matters relating to CCS), the South African integrated energy and chemical company Sasol, and Shell, we are building a centre for carbon capture technologies at Mongstad, known as the CO_2 Technology Centre Mongstad (TCM).

The technology centre aims to help suppliers develop more cost-efficient, environmentally friendly and safe technologies for carbon capture to handle emissions from different flue gas sources, such as gas power, coal power and refineries. The centre is expected to have capacity to capture up to 100,000 tonnes of carbon dioxide annually. It represents an important step towards full, industrial-scale carbon capture. Construction work is progressing according to plan after starting in summer 2009, and start-up is scheduled for early 2012.

CCS business development
Based on our experience from Sleipner, In Salah and Snøhvit and our experience of handling geological risk and developing large projects, Statoil is now seeking CCS-related business opportunities. Provided that satisfactory commercial and legal conditions are in place, Statoil's ambition is to develop, own and operate profitable CCS projects, focusing on being a storage provider. However, to become an important tool in the fight against emissions of greenhouse gases and climate change, CCS must become commercially viable.

Potential storage sites are restricted to sedimentary basins that are spread around the world. These basins are found both onshore and offshore, mostly in the vicinity of land areas. Statoil has established a subsurface team dedicated to mapping and maturing future carbon storage. The ambition is to store our own carbon dioxide (for example from our own production of CO_2-rich natural gas streams like Sleipner), and third party carbon dioxide (for example from captured CO_2 from coal-fired power plants).

3.5.5 Technology implementation

We are among the front runners in terms of applying technology in the oil and gas industry.

We achieve this by providing best practice support, devising world-class concepts for our development projects, and by heading up corporate initiatives designed to improve performance.

Our technological expertise enhances our performance in areas such as exploration, improved oil recovery (IOR) and integrated operations (IO). Technology development is used to promote and achieve corporate targets for production growth, increased regularity, reduced costs and improved drilling efficiency.

We also support innovators and entrepreneurs with technology developments and commercialisation activities, thus helping to create robust suppliers and new technology products that are vital to our oil, gas and new energy activities. Statoil has ownership interests and is involved in all major Science Parks and Incubators in Norway, and benefits from venture activities aimed at accessing new technologies. Through a special purpose company, Energy Capital Management AS, Statoil uses venture capital as a tool for accessing new technologies.

Selected advances made in 2010 are summarised below:

Global Technical Requirements for Statoil facilities.

A complete set of technical requirement documents have been developed for onshore and offshore facilities engineering. These documents will be used in facilities engineering frame agreements and for all projects and purchases. International standards are used where relevant, but more important is that the best of Statoil's engineering experience has been documented as requirements for future work. The technical requirement documents are expected to contribute significantly both to our success internationally and to cost-efficiency in project execution in Norway. The technical requirement documents represent Statoil's legacy of professional experience from all projects executed and from all the facilities operated over the last 40 years.

Extra heavy oil and the Leismer field

Statoil is currently using the Leismer Demonstration Project as a learning platform. We are testing a number of technologies or processes aimed at improving energy efficiency, increasing the recovery factor, reducing costs and improving our environmental footprint. Important progress has been made this year, including the Sentinel project, which is a new and advanced multi-physics system for permanent geophysical reservoir monitoring of extra heavy oil production. Two vertical observation wells were drilled and instrumented at Leismer to monitor the heating of the reservoir and how steam replaces bitumen in the vicinity of these two wells. This increases our knowledge of how the bitumen is produced and how to best monitor this process. The autonomous inflow control device, which was developed in-house, is being further developed and adapted for use in a steam-assisted gravity drainage (SAGD) injection and production setting. We aim to be prepared for a pilot during 2011. A huge experimental effort has been made to provide data for optimising the solvent co-injection process in order to reduce energy consumption (steam-oil ratio) and improve bitumen recovery efficiency compared with SAGD. The experimental results provide valuable input to the solvent co-injection pilot planned at the Leismer field.

New system for open hole well-testing

A new system for open hole well-testing, formation-testing-while-tripping (FTWT), has been successfully piloted in exploration well 6407/2-6 S on the NCS. The technology was evolved by Statoil and developed in cooperation with Schlumberger. FTWT is expected to eliminate the requirement for topside production equipment, the flaring of hydrocarbons and exposure of personnel to pressurised equipment containing live hydrocarbons. We also expect that associated emissions to the environment would be considerably reduced compared with conventional well-testing methods. The time taken to execute well-testing operations is also significantly reduced.

Autonomous production valve

Our newly developed autonomous production valves have been installed in one well on the Grane field. These valves control the inflow to the well based on differences in fluid viscosity. They have a potential to increase oil production by reducing the gas inflow. After installation of the autonomous valves, the initial oil rate was significantly higher than before installation, resulting in payback of the valve installation costs in two months. A preliminary assessment indicates that the valves work as intended. They will be evaluated for use in a number of new wells.

3.6 Projects & Procurement

3.6.1 Introduction to Projects & Procurement

Projects & Procurement (PRO) is responsible for planning and executing all major development and modification projects, and for project and operational procurements, including securing rig capacity based on the corporate rig strategy.

PRO aims to be world-class in terms of project execution, to deliver on time and within budget and in accordance with high HSE standards and agreed quality standards. To become a truly global energy player, it is essential that Statoil is capable of executing projects at the very highest level, thereby strengthening the company's international competitiveness.

3.6.2 Projects & Procurement key events in 2010

Key events in Projects & Procurement in 2010 include the start up of production on Gjøa and Leismer, and Peregrino reaching the final project phase.

- The Gjøa field started production on 7 November 2010.
- Leismer started steam injection on 3 September 2010. The first oil production was transported from Leismer development project on 15 November 2010.
- Peregrino is currently in the final stage and production start-up is scheduled for the first quarter 2011.
- Morvin started production on 1 August 2010.
- Vega started production on 2 December 2010.

3.6.3 Project development

Our project portfolio is diverse. It ranges from major new field developments to both small and large redevelopment projects on the Norwegian continental shelf (NCS) and internationally. We have also started on cessation projects on the NCS.

In 2010, we finalised 17 projects. Two mega-projects were ongoing in 2010: Gjøa and Peregrino. The Gjøa platform started production on 7 November. Peregrino is currently in the final development stage and production start-up is scheduled for the first quarter 2011.

Expected project completions 2011 - 2012	Type
NCS	Oseberg C mud module, Oseberg D HRSG, Visund South, Gygrid, Vilje South Snorre A produced water upgrade, Snorre A Re-development, Snorre B produced water upgrade, Snorre A SAS, Snorre A Living Quarter Upgrade, Snorre A Fire and Gas systems upgrade, Statfjord Late Life, Statfjord C/ Vigdis Riser replacement, Tordis/Vigdis Control systems, Vigdis North East, Troll A Living Quarter Extension, Troll P12 Pipeline, TOGI Removal, Katla, Ormen Lange Subsea Compression, Åsgard Gas Transfer, Marulk, Njord North West Flank
Onshore	Kårstø Double Inlet X-over (DIXO), Kårstø NGL Metering station, Kollsnes projects, CO2 Technology Centre Mongstad, Snøhvit Improvement, Delayed Coker revamp Mongstad, Kårstø Expansion, Kårstø/Kollsnes Booster Compressor Expansion
International	In Salah Gas Compression, Peregrino, South Riding Point Terminal Upgrade, Sheringham Shoal Offshore Wind

Gudrun, an important Greenfield project on the NCS, was approved by the Norwegian authorities in 2010. The Gudrun field is scheduled to start production in the first quarter 2014.

The first four fast track subsea satellite tie-in projects are on schedule. All fast track developments consist of a single subsea template, a few wells and tie-back to existing systems. Statoil's portfolio is being expanded by a new wave of projects that are planned to be developed at reduced costs and on shorter schedules by industrialising execution and using standard equipment.

Executing projects internationally - an essential part of fulfilling the group's ambitions to become a truly global energy player - adds a further element of complexity to our business. Examples of our contributions in this respect are:

- The plant for the Leismer Demonstration Project in the oil sands in Canada. The first steam injection took place on 3 September and the first bitumen from the field was produced on 15 November 2010. Oil production started in January 2011.
- The In Salah Gas Compression project consists of three compression stations, two of which were completed in 2010.
- The upgrading project at the South Riding point terminal in the Bahamas was sanctioned in June 2010. The terminal upgrading aims to improve the market value of the Peregrino oil.

In building Statoil's international reputation as a world-class executor of projects, the way in which Statoil delivers results is of great importance. This means delivering on time and cost without compromising our high HSE and ethical standards.

3.7 Statoil Fuel & Retail

On 17 March 2010, Statoil ASA's board of directors approved the creation of a stand-alone energy and retail business by means of an initial public offering (IPO) on the Oslo Stock Exchange.

In October 2010, Statoil's Energy & Retail business became a stand-alone entity, Statoil Fuel & Retail ASA, through an initial public offering and listing on the Oslo Stock Exchange. Statoil continues to own 54% of the shares in Statoil Fuel & Retail and consolidates the results of Statoil Fuel & Retail in its financial statements.

Statoil Fuel & Retail is a leading Scandinavian road transportation fuel retailer with over 100 years of operations in the region. Statoil Fuel & Retail also has established with a strong presence in Poland, Latvia, Lithuania and Estonia. In Russia, Statoil Fuel & Retail has a presence in the fuel retail market in the Murmansk, St. Petersburg/Leningrad and Pskov regions.

As at 31 December 2010, Statoil Fuel & Retail had a network of 2,283 fuel stations across its eight countries of operations, comprising a combination of full-service stations, which have integrated convenience stores, and automated fuel stations and truck stops. Of these, 1,765 fuel stations are located in Scandinavia, and 518 are located in Poland, Latvia, Lithuania, Estonia and Russia.

In addition, Statoil Fuel & Retail is involved in the sale of stationary energy (mainly heating oil, kerosene, LPG and heavy fuel for industrial purposes) and marine fuel (marine gasoil and heavy fuel) as well as aviation fuel, lubricants and chemicals.

3.8 People and the group

Statoil's overall strategic objective is to build a globally competitive company and an exceptional place to perform and develop.

During the last few years, Statoil has expanded into new business activities, both geographically and into emerging technologies, such as deepwaters, heavy oil and shale gas. In order to succeed in these activities, we must have the right organisational and people capabilities, as well as the ability to attract new talents globally.

Through global people policies, Statoil aims to ensure consistent common standards across the organisation. Together with our values and ethics code of conduct, our people policies are the most important guidelines for the people processes. We endeavour to ensure a good match between the professional interests and goals of every employee and the needs of the business. Through our global development and deployment process, we endeavour to offer challenging and meaningful job opportunities. Statoil remains committed to providing financial and non-financial rewards that attract and motivate the right people, and it continues to focus on equal opportunities for all employees.

Through the Statoil 2011 reorganisation, effective from 1 January 2011, Statoil has accelerated the development of new leaders, and significantly expanded the proportion of female and international leaders.

3.8.1 Employees in Statoil

The Statoil group employs approximately 30,300 permanent employees. Of these were 10,400 employees within the Statoil Fuel & Retail group, of which we held a 54% majority ownership interest as of 31 December 2010. Approximately 19,000 of Statoil group's employees are employed in Norway and approximately 11,300 outside Norway.

In 2010, the Statoil group recruited almost 3,400 new employees. The table below provides an overview of the number of permanent employees and percentage of women in the Statoil group from 2008 to 2010.

Numbers of permanent employees* and percentage of women in the Statoil group from 2008 to 2010

	Number of employees			Women		
Geographical Region	2010	2009	2008	2010	2009	2008
Norway	**18,838**	18,100	17,891	**31%**	31%	30%
Rest of Europe	**10,335**	9,593	10,475	**49%**	50%	47%
Africa	**140**	165	144	**30%**	28%	32%
Asia	**145**	150	169	**58%**	55%	54%
North America	**713**	584	448	**33%**	34%	39%
South America	**173**	147	102	**46%**	48%	53%
TOTAL	**30,344**	28,739	29,229	**37%**	37%	35%
Non - OECD	**2,732**	2,703	3,009	**63%**	64%	65%

*** Service station personnel are included**

Geographical Region	Permanent employees 2010	Consultants	Total Workforce*	% Consultants**	% Part - Time	New Hires
Norway	18,838	4,907	23,745	21%	4%	1,209
Rest of Europe	10,335	2,475	12,810	20%	6%	1,999
Africa	140	27	167	16%	NA	6
Asia	145	29	174	17%	NA	12
North America	713	51	764	7%	NA	123
South America	173	264	437	60%	NA	30
TOT	30,344	7,753	38,097	20%	11%	3,379
Non - OECD	2,732	374	3,106	12%	NA	172

*Total workforce consists of number of permanent employees and consultants

** Consultants do not include enterprise personnel

Turnover by gender and age

We believe Statoil's low turnover rates reflect a high level of satisfaction and engagement among its employees, which is also supported by the results of the annual organisational and working environment survey. In Statoil ASA, the total turnover rate for 2010 was 0.9%. The figure opposite provides an overview of the total turnover rate by gender and age in Statoil ASA.

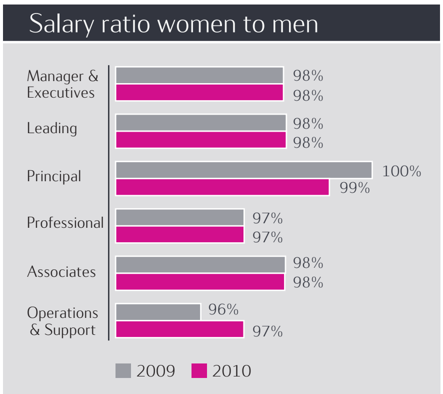
3.8.2 Equal opportunities

We are committed to building a workplace that promotes diversity and inclusion through its people processes and practices.

At 31 December 2010, the overall percentage of women in the company was 37%, and 40% of the board of directors were women, and 20% of the corporate executive team were women. The focus on diversity issues is also reflected in the company's people strategy. One of the key priorities in 2010 has been to strengthen diversity in the leadership pipeline. At the end of December 2010, the total proportion of female managers in Statoil ASA was 25%, and, among managers under the age of 45, the proportion was 34%.

We also devote close attention to male-dominated positions and discipline areas. In 2010, 26 % of staff engineers were women, and among staff engineers with up to 20 years' experience, the proportion of women was 31 %. The proportion of female skilled workers in 2010 was 16%.

The reward system in Statoil is non-discriminatory and supports equal opportunities, which means that, given the same position, experience and performance, men and women will be at the same salary level. However, due to differences between women and men in types of positions and number of years' experience, there are some differences in compensation when comparing the general pay levels of men and women.



Cultural diversity

We believe that being a global and sustainable company requires people with a global mindset. One way to build a global company is to ensure that recruitment processes both within and outside Norway contribute to a culturally diverse workforce. Outside Norway, we need to continue to focus on increasing the number of people and managers that are locally recruited, and to reduce long-term, extensive use of expats in our business operations.

3.8.3 Unions and representatives

Statoil's cooperation with employee representatives and trade unions is based on confidence, trust and continuous dialogue between management and the people in various cooperative bodies.

In Statoil, 68% of the employees in the parent company are members of a trade union. Work councils and working environment committees are established where required by law or agreement.

In 2010 the collaboration model for the Norwegian part of our business, agreed on by the unions and Statoil, played an important role in cooperation in the Statoil 2011 reorganisation. The collaboration model was established in 2009 with the finalisation of the merger between Statoil and Hydro's oil and gas division and is founded on the principles of simplification and decentralisation.

In 2010 the European Work Council (EWC) served as a central arena for dialogue between the Company management and the employees in the demerging of Statoil Fuel & Retail. The EWC is an arena where Statoil's employees in Europe receive relevant information on a regular basis, and engage in direct dialogue with management on matters concerning the group as a whole. Two conferences were held in 2010 where the main topic was the demerger.

In 2010, the ICEM agreement with the International Federation of Chemical, Energy, Mine and General Workers Union was renewed for another two-year period.

3.8.4 Organisational structure

The following table shows significant subsidiaries owned directly by the parent company, as well as the parent company's equity interest and the subsidiaries' country of incorporation as at 31 December 2010.

Our voting interest is in each case equivalent to our equity interest.

Ownership in certain subsidiaries (in %)

Name	%	Country of incorporation"	Name	%	Country of incorporation
Statholding AS	100	Norway	Statoil Norsk LNG AS	100	Norway
Statoil Angola Block 15 AS	100	Norway	Statoil North Africa Gas AS	100	Norway
Statoil Angola Block 15/06 Award AS	100	Norway	Statoil North Africa Oil AS	100	Norway
Statoil Angola Block 17 AS	100	Norway	Statoil North America Inc.	100	United States
Statoil Angola Block 31 AS	100	Norway	Statoil Orient AG	100	Switzerland
Statoil Apsheron AS	100	Norway	Statoil Petroleum AS	100	Norway
Statoil Azerbaijan AS	100	Norway	Statoil Sincor AS	100	Norway
Statoil BTC Finance AS	100	Norway	Statoil SP Gas AS	100	Norway
Statoil Coordination Centre NV	100	Belgium	Statoil UK Ltd	100	United Kingdom
Statoil Danmark AS	100	Denmark	Statoil Venezuela AS	100	Norway
Statoil Deutschland GmbH	100	Germany	Statoil Venture AS	100	Norway
Statoil Exploration Ireland Ltd.	100	Ireland	Statpet Invest AS	100	Norway
Statoil Forsikring AS	100	Norway			
Statoil Hassi Mouina AS	100	Norway	Statoil Methanol ANS	82	Norway
Statoil New Energy AS	100	Norway	Mongstad Refining DA	79	Norway
Statoil Nigeria AS	100	Norway	Mongstad Terminal DA	65	Norway
Statoil Nigeria Deep Water AS	100	Norway	Statoil Fuel & Retail ASA	54	Norway
Statoil Nigeria Outer Shelf AS	100	Norway	Tjeldbergodden Luftgassfabrikk DA	51	Norway

3.9 Production volumes and price information

Statoil's operational review accords with the organisation of its operations as at 31 December 2010, whereas certain disclosures about oil and gas reserves are based on geographical areas as required by the Securities and Exchange Commission (SEC).

Statoil prepared its operational review in accordance with its segment (business area) structure as at 31 December 2010. Each business area is presented individually, and includes underlying business clusters according to how the business area organises its operations. For information regarding Statoil's new segment structure, effective 1 January 2011, see section Business overview and strategy - New organisational structure as from January 2011.

For further information on extractive activities, refer to sections Operational review - E&P Norway and Operational review - International E&P, respectively.

Statoil prepares its disclosures for oil and gas reserves and certain other supplemental oil and gas disclosures based upon geographical areas as required by the SEC. The geographical areas are defined by continent, and consist of Norway, Eurasia excluding Norway, Africa and the Americas.

For further information on disclosures for oil and gas reserves and certain other supplemental disclosures based upon geographical areas as required by the SEC, refer to the section Operational review - Proved oil and gas reserves.

3.9.1 Entitlement production

This section describes our oil and gas production and sales volumes.

The following table shows our Norwegian and international entitlement production of crude oil and natural gas for the periods indicated. The stated production volumes are the volumes that Statoil is entitled to pursuant to conditions laid down in licence agreements and production sharing agreements. The production volumes are net of royalty oil paid in kind and of gas used for fuel and flaring. Our production is based on our proportionate participation in fields with multiple owners and does not include production of the Norwegian state's oil and natural gas. Production of an immaterial quantity of bitumen is included in crude oil production. Disclosures for the years end 31 December 2010 and 2009 are based on the SEC's revised requirements for geographical areas applicable starting in 2009 which were applied prospectively. The information for 2008 was not restated.

Entitlement production	2010	For the year ended 31 December 2009	2008
Norway			
Crude oil (mmbbls)[1]	256	279	302
Natural gas (bcf)	1,370	1,367	1,348
Natural gas (bcm)	38.8	38.7	38.2
Combined oil and gas (mmboe)	500	523	542
Eurasia excluding Norway			
Crude oil (mmbbls)[1]	18	19	n/a
Natural gas (bcf)	51	49	n/a
Natural gas (bcm)	1.4	1.4	n/a
Combined oil and gas (mmboe)	27	28	n/a
Africa			
Crude oil (mmbbls)[1]	53	63	n/a
Natural gas (bcf)	41	54	n/a
Natural gas (bcm)	1.2	1.5	n/a
Combined oil and gas (mmboe)	60	73	n/a
America			
Crude oil (mmbbls)[1]	26	20	n/a
Natural gas (bcf)	47	48	n/a
Natural gas (bcm)	1.3	1.4	n/a
Combined oil and gas (mmboe)	34	29	n/a
Outside Norway			
Crude oil (mmbbls)[1]	n/a	n/a	85
Natural gas (bcf)	n/a	n/a	121
Natural gas (bcm)	n/a	n/a	3.4
Combined oil and gas (mmboe)	n/a	n/a	106
Total			
Crude oil (mmbbls)[1]	352	381	386
Natural gas (bcf)	1,509	1,519	1,469
Natural gas (bcm)	42.8	43.0	41.6
Combined oil and gas (mmboe)	621	652	648

'1) Crude oil includes natural gas liquids (NGL), condensate and bitumen. NGL includes both LPG and naphta.

3.9.2 Average production cost and sales prices

The following tables present the average unit of production cost based on entitlement volumes and realised sales prices. The information has been split by continent for 2010 and 2009, while this split was not required for 2008.

	Norway	Eurasia excluding Norway	Africa	America
Year ended 31 December 2010				
Average sales price liquids in USD per bbl	76.3	79.1	76.8	75.1
Average sales price natural gas in NOK per Sm3	1.8	0.6	1.6	1.0
Average production cost in NOK per boe	40.6	42.0	49.3	66.2
Year ended 31 December 2009				
Average sales price liquids in USD per bbl	57.8	58.2	57.8	61.7
Average sales price natural gas in NOK per Sm3	1.9	0.6	1.4	0.9
Average production cost in NOK per boe	36.9	55.2	40.9	45.3

	Norway	Outside Norway
Year ended 31 December 2008		
Average sales price liquids in USD per bbl	91.5	88.7
Average sales price natural gas in NOK per Sm3	2.4	1.3
Average production cost in NOK per boe	37.3	42.2

3.10 Proved oil and gas reserves

Proved oil and gas reserves were estimated to be 5,325 mmboe at year end 2010, compared with 5,408 mmboe at the end of 2009.

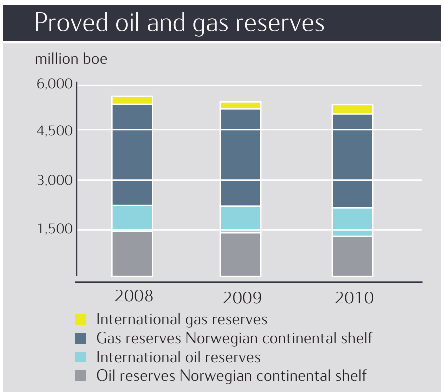
Statoil's proved reserves are estimated and presented in accordance with Securities and Exchange Commission (SEC) Rule 4-10 (a) of Regulation S-X and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins, as issued by the SEC staff. In January 2009, the SEC published a revision of Rule 4-10 (a) of Regulation S-X for the estimation of reserves. These revised rules form the basis for the 2009 and 2010 estimations of proved reserves. For additional information, see "Critical accounting judgements and key sources of estimation uncertainty; Key sources of estimation uncertainty; Proved oil and gas reserves" in note 2 Significant accounting policies to the Consolidated Financial Statements. For prior period figures, see note 35 Supplementary oil and gas information to the Consolidated Financial Statements.

Summary of oil and gas reserves as of 31 December 2010 based on average fiscal year prices.

Reserves category	Oil and NGL (mmbbls)	Proved reserves Natural Gas (bcf)	Total oil and gas (mmboe)
Developed			
Norway	950	13,721	3,394
Eurasia excluding Norway	99	421	174
Eurasia	1,048	14,142	3,568
Africa	192	221	231
America	116	336	176
Undeveloped			
Norway	291	2,622	758
Eurasia excluding Norway	71	214	109
Eurasia	362	2,836	868
Africa	121	300	175
America	284	130	307
Total proved reserves	2,124	17,965	5,325

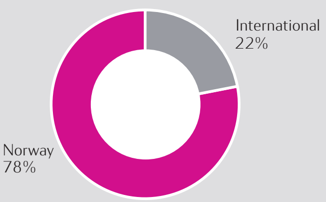
Statoil's proved reserves of bitumen in America is included as oil in the table above as they represent less than 3% of our proved reserves which is regarded as immaterial.

Basis for equivalents as given in section Terms and definitions.



Changes in proved reserves estimates are most commonly the result of revisions of estimates due to observed production performance, extensions of proved areas through drilling activities, or the inclusion of proved reserves in new discoveries through the sanctioning of development projects. These are sources of additions to proved reserves that are the result of continuous business processes and can be expected to continue to add reserves at some level in the future. Proved reserves can also be added or subtracted through the acquisition or disposal of assets.

Distribution of proved reserves



Changes in proved reserves can also be due to factors outside management control, such as changes in oil and gas prices. Proved reserves as of 31 December 2010 and 2009 have been determined on the basis of a 12-month average price, whereas proved reserves for 2008 are based on year-end prices. While higher oil and gas prices normally allow more oil and gas to be recovered from the accumulations, Statoil will generally receive smaller quantities of oil and gas under production sharing agreements (PSAs) and similar contracts. These changes are included in the revisions category in the table below.

In Norway, reserves are recorded as proved when a development plan is submitted, since there is reasonable certainty that such a plan will be approved by the regulatory authorities. Outside Norway, reserves are booked as proved when regulatory approval is received, or when such approval is imminent. Reserves from new discoveries, upward revisions of reserves and purchases of proved reserves are expected to contribute to maintaining proved reserves in future years.

Additions that have contributed to our proved reserves in 2010 are:

- The development plans for the Gudrun field in the North Sea and the Marulk field in the Barents Sea in Norway were approved by the Norwegian authorities in 2010.
- The Valemon and Visund South fields in the North Sea in Norway were sanctioned by the licencees in 2010.
- Investment decisions to develop the Smørbukk North East segment on the Åsgard field and the North West Flank on the Njord field, both in Norway, were taken by the partners in the licences in 2010.
- The Jack and St. Malo fields in the Gulf of Mexico, USA, were sanctioned in 2010.
- The CLOV field development off the coast of Angola was sanctioned in 2010.
- The West Qurna 2 Preliminary Development Plan in Iraq was approved by the Iraqi authorities in December 2010.
- The In Salah Southern fields development project in Algeria was sanctioned in 2010.
- The Chirag Oil Project in Azerbaijan, a new phase of the Azeri-Chirag-Gunashli (ACG) project, was sanctioned in 2010.
- Acreage in the Eagle Ford shale formation in the USA was acquired in 2010.
- Further drilling in the Marcellus Shale Gas play in the USA has increased the proved reserves in 2010.
- Production experience and further drilling have contributed positively to revision of proved reserves in 2010.

New discoveries with reserves booked in 2010 all start production in the period from 2010 to 2014.

In 2010, Statoil announced the sale of a 40% interest in the Peregrino field in Brazil and the sale of a 40% interest in the oil sands leases in Alberta, Canada. As of 31 December 2010, these sales had not been approved by the relevant authorities and therefore the reduction in reserves is not reflected in the 2010 proved reserves statement. The sale of the interest in Canada, was approved by the relevant authorities on 21 January 2011. The expected effect on the 2011 proved reserves statement is approximately 66 million boe sales of reserves-in-place.

Sanction of development plans for several new fields and projects have contributed to more reserves in the extensions and discoveries category in 2010 compared to 2009. In 2009 approval of further development plans for several of our producing fields on the NCS contributed positively to revisions of proved reserves. The same number of development plans have not been approved in 2010 giving less contribution to the revisions and improved recovery category in 2010 compared to 2009. The table below shows the additions to reserves in each category relating to the reserve replacement ratio for the years 2010, 2009 and 2008. The reserves replacement ratio is defined as the sum of additions and revisions of proved reserves, divided by produced volumes in any given period.

	For the year ended 31 December		
(million boe)	2010	2009	2008
Revisions and improved recovery	183	326	213
Extensions and discoveries	343	155	17
Purchase of petroleum-in-place	12	0	69
Sales of petroleum-in-place	0	(4)	(10)
Change in interest *	0	0	(68)
Total reserve additions	538	476	222
Production	(621)	(652)	(648)
Net change in proved reserves	(84)	(176)	(426)

* Reduction of interest in Petrocedeño

The reserves replacement ratio was 87% in 2010, compared with 73% in 2009. The increase in the reserves replacement ratio in 2010 compared with 2009 is mainly due to 2010 being a year with more additions to reserves from new fields, sanctioned future development plans for producing fields, revisions due to production experience and further drilling of wells and reduced production. The average replacement ratio for the last three years was 64%, including purchases, sales and the reduction of interest in Petrocedeño in 2008.

	For the year ended 31 December		
Reserves replacement ratio (three-year average)	2010	2009	2008
The group	**0.64**	0.64	0.60

The usefulness of the reserves replacement ratio is limited by the volatility of oil prices, the influence of oil and gas prices on PSA reserve booking, the sensitivity related to the timing of project sanctions, and the time lag between exploration expenditure and the booking of reserves.

Preparation of reserves estimates

Statoil's annual reporting process for proved reserves is coordinated by a central team of experts. This team, which is called Corporate Exploration and Production Forecasting (CEPF), consists of experts in geosciences, reservoir and production technology and financial evaluation. The team has an average of more than 20 years' experience from the oil and gas industry. CEPF reports to the vice president of finance and control in the Technology & New Energy business area and is thus independent of both the Exploration & Production Norway and International Exploration & Production business areas.

Although this team reviews the information centrally, each asset team is responsible for ensuring that it is in compliance with the requirements of the SEC and our corporate standards. Information about proved oil and gas reserves, standardised measures of discounted net cash flows related to proved oil and gas reserves and other information related to proved oil and gas reserves, is collected from the assets and checked for consistency and conformity with applicable standards by CEPF. The final numbers for each asset are quality controlled and signed off by the responsible asset manager, before aggregation to the required reporting level by CEPF.

The aggregated results are submitted for approval to the relevant business area management teams and the corporate executive committee and finally presented to the board of directors.

The person with primary responsibility for overseeing the preparation of the reserves estimates is the chair of the CEPF team. The person who presently holds this position has a Bachelor's degree in Earth Sciences from the University of Gothenburg, and a Master's degree in Petroleum Exploration and Exploitation from Chalmers University of Technology in Gothenburg, Sweden. She has 25 years' experience of the oil and gas industry, 24 of which are with Statoil. She is a member of the Norwegian Petroleum Society and vice-chair of the UNECE Expert Group on Resource Classification (EGRC).

Development of reserves

In 2010, Statoil converted approximately 300 million boe from undeveloped to developed reserves. Start-up of production from the Morvin, Gjøa and Vega fields in Norway and the Leismer SAGD Project in Canada increased our developed reserves by 116 million boe during the year. The rest of the converted volume is related to development activities on producing fields. Of the latter, the completion of a significant number of wells in the Marcellus shale gas play was the most important.

Sanctioning of new projects, such as Gudrun, Marulk, Valemon and Visund South in Norway, Jack and St. Malo in the Gulf of Mexico, CLOV in Angola and West Qurna 2 in Iraq, added a total of 233 million boe of proved undeveloped reserves in 2010.

As of 31 December 2010, the total proved undeveloped oil and gas reserves amounted to 1,350 million boe, 56% of which is related to fields in Norway. The Peregrino field in Brazil represents the largest undeveloped asset and, together with other fields not in production, such as Skarv, Valemon, Gudrun and Goliat in Norway, CaesarTonga, Jack and St. Malo in GoM USA, Corrib in Ireland and the Kizomba satellites Pazflor and CLOV in Angola, these fields represent approximately 28% of the total proved undeveloped reserves at year end 2010. Significant undeveloped reserves are also related to large gas fields on the NCS with continuous development activities, such as Snøhvit and Troll, and the Petrocedeño field in Venezuela.

In 2010, Statoil incurred NOK 54 billion in development costs relating to assets carrying proved reserves, NOK 29 billion of which was related to moving proved undeveloped reserves to developed reserves.

Due to the nature of large fields with continuous development activity, such as Troll and Snøhvit in Norway, Azeri-Chirag-Gunashli in Azerbaijan and Petrocedeño in Venezuela, these fields contain reserves that are expected to remain undeveloped for five years or more. All these projects are large field developments, three of them offshore, with several billion dollar investments having been made in complex infrastructure. The development of these fields will require extensive, sustained drilling of wells for a long period of time. A large proportion of the central facilities are already in place, and a significant part of the total investments have been made. It is highly unlikely that either of these field development projects would be prematurely terminated, since this would result in a significant loss of capital.

Additional information about proved oil and gas reserves is provided in note 35 - Supplementary oil and gas information - to our consolidated financial statements.

Delivery commitments
On behalf of the Norwegian State's direct financial interest (SDFI), Statoil is required to manage, transport and sell the Norwegian State's oil and gas from the Norwegian continental shelf (NCS). These reserves are sold in conjunction with our own reserves. As part of this arrangement, Statoil will deliver gas to customers under various types of sales contracts. In order to fulfil the commitments, Statoil will utilise a field supply schedule that ensures the highest possible total value for Statoil and SDFI's joint portfolio of oil and gas.

As of 31 December 2010, the Statoil/SDFI arrangement amounted to a total of 26.3 tcf (745 bcm) in total gas commitments from the NCS. The principles for the booking of proved reserves are limited to contracted gas sales or gas with access to a robust gas market.

The majority of Statoil's gas volumes are sold under long-term contracts with take-or-pay clauses. For each individual year, Statoil and SDFI express their delivery commitments as the sum of the annual contract quantity (ACQ). In the contract years 2010 to 2013, the total ACQ for the respective years are: 2.48, 2.48, 2.41, and 2.41 tcf. The majority of the delivery commitments will be met by production from our existing proved reserves from fields where Statoil and/or SDFI participates, while any shortfalls will be covered by use of storage or sourcing in the market.

3.10.1 Operational statistics

Operational statistics include information about acreage and the number of wells drilled.

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 31 December 2010.

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

At 31 December 2010		Norway	Eurasia excluding Norway	Africa	America	Total
Number of productive oil and gas wells						
Oil wells	— gross	814	146	339	581	1,880
	— net	291.3	19.3	34.2	72.0	416.9
Gas wells	— gross	164	49	57	224	494
	— net	71.0	16.6	21.1	63.1	171.8

The total gross number of productive wells as of end 2010 includes 370 oil wells and 16 gas wells with multiple completions or wells with more than one branch.

At 31 December 2010 (in thousands of acres)		Norway	Eurasia excluding Norway	Africa	America	Total
Developed and undeveloped oil and gas acreage						
Acreage developed	— gross	787	196	815	173	1,970
	— net	287	52	258	24	621
Acreage undeveloped	— gross	11,947	13,835	23,475	10,315	59,571
	— net	5,174	4,928	13,684	4,951	28,738

The largest concentrations of developed acreage in Norway are in Troll, Ormen Lange, Snøhvit and Oseberg. In Africa, the Algerian gas development projects In Amenas and In Salah represent the largest concentrations of developed acreage (gross and net).

Undeveloped acreage concentration in Eurasia excluding Norway is in the Faroes with six exploration licences representing some 40% of the total net acreage in this geographical area. Our largest acreage concentration in Africa is the Hassi Mouina blocks in Algeria representing about one-third of the total net acreage in Africa. Most of the undeveloped acreage in America is located in the Gulf of Mexico. We also have large acreage concentrations in America in the Marcellus shale play located in the Appalachian region in north-eastern USA, in the Camamu-Almada Basin in off-shore Brazil, in oil sands located in the Athabasca region of Alberta, Canada, and off the coast of Newfoundland, Canada.

Net productive and dry oil and gas wells drilled

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. The 2009 and 2010 information is split by continent, whereas this split is not required for 2008. Productive wells include wells in which hydrocarbons were discovered, 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 sufficient quantities to justify completion as an oil or gas well.

	Norway	Eurasia excluding Norway	Africa	America	Total
Year 2010					
Net productive and dry exploratory wells drilled	10.0	0.4	1.4	3.3	15.0
— Net dry exploratory wells drilled	3.1	0.4	0.7	1.9	6.0
— Net productive exploratory wells drilled	6.9	0.0	0.8	1.4	9.0
Net productive and dry development wells drilled	26.0	3.3	8.4	54.2	91.9
— Net dry development wells drilled	2.0	0.0	0.2	0.0	2.2
— Net productive development wells drilled	24.0	3.3	8.2	54.2	89.7
Year 2009					
Net productive and dry exploratory wells drilled	21.3	0.9	4.4	2.8	29.3
— Net dry exploratory wells drilled	9.6	0.3	2.1	1.0	13.0
— Net productive exploratory wells drilled	11.7	0.6	2.2	1.8	16.3
Net productive and dry development wells drilled	25.7	4.6	8.1	13.9	52.3
— Net dry development wells drilled	1.2	0.4	0.7	0.0	2.3
— Net productive development wells drilled	24.5	4.2	7.3	13.9	50.0

Year 2008	Norway	Outside Norway	Total
Net productive and dry exploratory wells drilled	26.1	12.1	38.2
— Net dry exploratory wells drilled	7.2	5.8	13.0
— Net productive exploratory wells drilled	18.9	6.3	25.2
Net productive and dry development wells drilled	27.9	23.7	51.6
— Net dry development wells drilled	0.5	0.0	0.5
— Net productive development wells drilled	27.4	23.7	51.1

Related to our oil sand development in the Athabasca region of Alberta we also drilled 156 wells in 2010 to map and delineate the bitumen pay. All of these wells were logged and almost 100% were cored. We also drilled 11 wells in which we were searching for suitable water source or disposal water zones. Some of these were abandoned and some completed for water needs.

Exploratory and development drilling in process

The following table shows the number of exploratory and development oil and gas wells in the process of being drilled by Statoil at 31 December 2010

At 31 December 2010		Norway	Eurasia excluding Norway	Africa	America	Total
Number of wells in progress						
Development Wells	— gross	52	10	18	230	310
	— net	21.3	1.5	4.0	63.1	90.0
Exploratory Wells	— gross	7	1	2	4	14
	— net	3.8	0.3	1.0	1.3	6.3

3.10.2 Report of DeGolyer and MacNaughton

Statoil's estimates of proved reserves are not materially different from those prepared by independent petroleum engineering consultants.

Petroleum engineering consultants DeGolyer and MacNaughton have carried out an independent evaluation of Statoil's proved reserves as of 31 December 2010. The evaluation accounts for 100% of Statoil's proved reserves. The aggregated net proved reserves estimates prepared by DeGolyer and MacNaughton do not differ materially from those prepared by Statoil when compared on the basis of net equivalent barrels.

Net proved reserves at 31 December 2010	Oil, Condensate and LPG (mmbbls)	Sales Gas (bcf)	Oil Equivalent (mmboe)
Estimated by Statoil	2,124	17,965	5,325
Estimated by DeGolyer and MacNaughton	2,082	18,550	5,387

A reserves audit report summarising this evaluation is included as Exhibit 15 (a)(iii).

3.11 Regulation

The principal Norwegian legislation governing our petroleum activities in Norway comprises the Norwegian Petroleum Act and the Norwegian Petroleum Taxation Act.

The principal Norwegian legislation governing our petroleum activities in Norway and on the NCS is currently the Norwegian Petroleum Act of 29 November 1996 (the "Petroleum Act"), and the regulations issued thereunder, and the Norwegian Petroleum Taxation Act of 13 June 1975 (the "Petroleum Taxation Act"). The Petroleum Act sets out the principle that the Norwegian state is the owner of all subsea petroleum on the NCS, that exclusive right to resource management is vested in the Norwegian state and that the Norwegian state alone is authorised to award licences for petroleum activities. We are dependent on the Norwegian state for approval of our NCS exploration and development projects and our applications for production rates for individual fields.

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

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

- The Norwegian State held 67% of our ordinary shares directly as of 12 March 2011. The Norwegian State's shareholding in Statoil is managed by the Ministry of Petroleum and Energy. The Ministry of Petroleum and Energy will normally decide how the Norwegian State will vote 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, or if such issuance would require a capital contribution from the Norwegian State in excess of government mandates. It is not possible to predict what stance the Norwegian Storting will take on a proposal to issue additional shares that would either significantly dilute its holding of Statoil shares or require a capital contribution from it in excess of government mandates. A decision by the Norwegian State to vote against a proposal on our part to issue additional shares would prevent us from raising additional capital in this manner and could adversely affect our ability to pursue business opportunities and to further develop the company. For more information about the Norwegian State's ownership, see section Risk review - Risk factors - Risks related to ownership by the principal shareholder and its involvement in the SDFI and Shareholder information - Major shareholders.
- 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 licences and other approval of various kinds from the Norwegian State. In respect of certain important applications, such as for the approval of major plans for the operation and development of fields, the Ministry of Petroleum and Energy must obtain the consent of the Storting before it can approve our or the relevant partnership's application. This may take additional time and affect the content of the decision. Although Statoil is majority-owned by the Norwegian State, it does not receive preferential treatment with respect to licences granted by or under any other regulatory rules enforced by the Norwegian State.

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

The EEA Agreement makes certain provisions of EU law binding between the states of the EU and the EFTA states, and also between the EFTA states themselves. An increasing volume of regulation affecting us is adopted within the EU and 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 EEA law and EU law to the extent that EU law has been incorporated into EEA law under the EEA Agreement.

3.11.1 The Norwegian licensing system

Production licences are the most important type of licence awarded under the Petroleum Act, and the Ministry of Petroleum and Energy holds executive discretionary power to and award a production licences and to decide the terms of that licence.

By the end of 2010, we participated in 213 licences on the NCS. As a participant in licences, we are subject to the regulations of the Norwegian licensing system.

Production licences are the most important type of licence awarded under the Petroleum Act, and the Ministry of Petroleum and Energy holds executive discretionary powers to award a production licence and to decide the terms of that licence. The Government is not entitled to award us a licence in an area until the Storting has decided to open the area in question for exploration. The terms of our production licences are decided by the Ministry of Petroleum and Energy.

A production licence grants the holder 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 licence. Notwithstanding the exclusive rights granted under a production licence, the Ministry of Petroleum and Energy has the power, in exceptional cases, to permit third parties to carry out exploration in the area covered by a production licence. For a list of our shares in production licences, see section Operational review - E&P Norway - Production on the NCS.

Production licences are normally awarded in licensing rounds. The first licensing round for NCS production licences was announced in 1965. The award of the first licences covered areas in the North Sea. Over the years, the awarding of licences has moved northward to cover areas in both the Norwegian Sea and the Barents Sea. In recent years, the principal licensing rounds have largely concerned licences in the Norwegian Sea.

The Norwegian State accepts licence applications from individual companies and group applications. This allows us to choose our exploration and development partners.

Production licences are awarded to joint ventures. As is the case for most fields on the NCS, our production activities are conducted through joint venture arrangements with other companies and, in some cases, with the Norwegian State through its wholly-owned company Petoro AS. The members of the joint venture are jointly and severally responsible to the Norwegian State for obligations arising from petroleum operations carried out under the licence. Once a production licence is awarded, the licensees are required to enter into a joint operating agreement and an accounting agreement that regulate the relationship between the partners. The Ministry of Petroleum and Energy decides the form of the joint operating agreements and accounting agreements.

The governing body of the joint venture is the management committee. In licences awarded since 1996 where the SDFI holds an interest, the Norwegian State, acting through Petoro AS, 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 licence with respect to the Norwegian State's exploitation policies or financial interests. This veto power has never been used.

The day-to-day management of a field is the responsibility of an operator appointed by the Ministry of Petroleum and Energy. By the end of 2010, we were the operator for 157 of our 213 licences on the NCS. The operator is in practice always a member of the joint venture holding the production licence, although this is not legally required. The terms of engagement of the operator are set out in the joint operating agreement, under which the operator can normally terminate its engagement by giving six months' notice. However, with the consent of the Ministry of Petroleum and Energy, the management committee may instruct the operator to continue to perform its duties until a new operator has been appointed. The management committee can terminate the operator's engagement by giving six months' notice through 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 undertake material contractual obligations or commence construction work without the prior consent of the Ministry of Petroleum and Energy.

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

If natural resources other than petroleum are discovered in the area covered by a production licence, 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 licence period. To date, such a delay has never been imposed.

If important public interests are at stake, the Norwegian State may direct us and other licensees on the NCS to reduce the production of petroleum. The last time the Norwegian State directed a reduction in oil production was in 2002.

Licensees may buy or sell interests in production licences 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 indirect transfers of interests in a licence, including changes in the ownership of a licensee, if they result in a third party obtaining a decisive influence over the licensee. In most licences there are no pre-emption rights in favour of the other licensees. However, the SDFI, or the Norwegian State, as appropriate, still holds pre-emption rights in all licences. Not all of our licencing transactions entered into in 2010 on the NCS were approved by the Ministry of Petroleum and Energy and the Ministry of Finance. However, all approvals are expected during the first half of 2011.

A licence from the Ministry of Petroleum and Energy is also required in order to establish facilities for the transportation and utilisation of petroleum. When applying for such licences, the owners, who in practice are licensees under a production licence, must prepare a plan for installation and operation. Licences for the establishment of facilities for transportation and utilisation 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 transportation and utilisation of petroleum in Norway and on the NCS is organised as joint ventures of a group of licence holders. The participants' agreements are similar to the joint operating agreements entered into by the members of joint ventures holding production licences. The PDO for Valemon was submitted to the Norwegian authorities at the end of October 2010, and the approval from the Ministry of Petroleum and Energy and the Ministry of Finance is expected during the first half of 2011. The remaining licencing transactions we entered into in 2010 on the NCS were approved by the Ministry of Petroleum and Energy and the Ministry of Finance by year end 2010.

Licensees are required to prepare a decommissioning plan before a production licence or a licence to establish and use facilities for the transportation and utilisation 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 licence or cessation of the use of the facility, and it 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.

The Norwegian State is entitled to take over the fixed facilities of the licensees when a production licence 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 the expropriation of private property apply. None of our production licences on the NCS expired in 2010 and none is due to expire in 2011 and 2012.

Licences for the establishment of facilities for transportation and utilisation of petroleum typically include a clause whereby the Norwegian State can require that the facilities be transferred to it free of charge on expiry of the licence period.

3.11.2 Gas sales and transportation

We market gas from the NCS on our own and the Norwegian State's behalf. Gas is transported through the Gassled pipeline network to customers in Europe.

Gas sales contracts with buyers for the supply of Norwegian gas are concluded individually with each company.

The upstream gas transportation system consists of several pipelines owned by a joint venture called Gassled. At year end 2010, our direct ownership interest in Gassled was 32.1%. From 1 January 2011, our direct ownership interest in Gassled is 28.5%. Statoil is responsible for technical operation of the majority of the gas export pipelines and onshore plants in the Gassled processing and transportation system.

By Royal Decree of 20 December 2002, the Norwegian authorities issued regulations relating to access to and tariffs for capacity in the upstream gas transportation system. The regulations are based on three main considerations. Firstly, the regulations implement the Gas Directive of the European Union. Secondly, they establish a system for access to the upstream gas transportation system that is compatible with company-based gas sales from the NCS. Thirdly, they provide for new ownership structure in upstream gas transportation system (Gassled).

Parts of the regulations have general application and parts - including the tariffs - are only applicable to the upstream gas transportation system owned by the Gassled joint venture. The regulations establish the main principles for access to the upstream gas transportation system. The access regime consists of a regulated primary market where, pursuant to the regulations, the right to book spare capacity is allocated to users with a need to transport natural gas. Furthermore, the access regime consists of a secondary market where capacity can be transferred between users after allocation in the primary market if transportation needs change.

Capacity in the primary market is released and booked through Gassco AS on the internet. Spare capacity is released for pre-defined time periods at announced points in time and with specific time limits for reservations. If reservations exceed the spare capacity, the spare capacity will be allocated on the basis of an allocation formula. However, in the event of scarce capacity, consideration must first be given to the owners' duly substantiated needs for capacity, limited to twice the owner's equity interest in the upstream pipeline network.

Based on authorisation granted under the regulations, tariffs for the use of capacity in Gassled are decided by the Ministry of Petroleum and Energy. The ministry's policy for determining the tariffs is to avoid excessive returns on the capital invested in the transportation system, allowing the return on Norwegian petroleum activity to be taken out on the fields instead of in the transportation systems. The tariffs are paid for booked capacity and not on the basis of the volume actually transported.

For further information, see section Operational review-Natural Gas-Norway's gas transport system.

3.11.3 The EU Gas Directives

The EU Gas Directives, which have been included in the EEA Agreement and incorporated into Norwegian legislation, regulates the European gas market in conjunction with the Gas Transmission Access Regulation of 2005.

Most of our gas is sold under long-term gas contracts to customers in the EU. This gas market continues to be affected by changes in EU regulations and the implementation of such regulations in EU member states. Such regulation affects our ability to expand or even maintain our current market position, as quantities sold under our gas sales contracts may be influenced by the changed market conditions resulting from the EU Gas Directives.

The Directives requires that, with effect from July 2007, all consumers in Europe should be able to choose their energy supplier. Fundamental changes to this directive were adopted by the European Union in July 2009 to be implemented by the EU member states at the latest in March 2011 (as set out in EC Directive 2009/73), with specific focus on the separation of ownership of transmission assets from supply activities. The objective of these changes is to increase competition in national markets and integrate them into regional and, eventually, a single EU-wide market for natural gas. It is difficult to predict the effect liberalisation measures will have on the development of gas prices, but the main objective of the single gas market is to create greater choice and reduce prices for customers through increased competition.

3.11.4 HSE regulation

Our petroleum operations are subject to extensive regulation with regard to health, safety and the environment, or HSE.

Norway

Under the Petroleum Act, which is administered by the Ministry of Petroleum and Energy, our 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. Following the accident that occurred on the BP-operated Macondo well in the deepwater Gulf of Mexico in April 2010, the Norwegian Ministry of Petroleum and Energy announced that the accident could result in changes to its NCS regulations. Statoil established a system for monitoring the technical safety of its facilities and plants in 2001. As part of this system, it collects and interprets information from, and incorporates risk management into, its operating activities.

The Petroleum Safety Authority Norway (PSA) has regulatory responsibility for safety, emergency preparedness and the working environment for all petroleum-related activities. The PSA's area of responsibility includes supervision of safety, emergency preparedness and the working environment for both offshore and onshore petroleum facilities. Following the accident in the Gulf of Mexico, the PSA now requires companies to demonstrate their ability to handle a potential blow-out and to inform the PSA about how they plan to shut down a well in the event of a blow-out before receiving permission to start drilling a new well.

We are required at all times to have a plan to deal with emergency situations in our petroleum operations. During an emergency, the Ministry of Labour, the Ministry of Fisheries and Coastal Affairs/the Norwegian Coastal 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 licensees' account.

In our capacity as holder of licences under the Petroleum Act, we are subject to strict statutory liability in respect of losses or damage suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of our licences. This means that anyone who suffers damage or loss as a result of pollution caused by any of our NCS licence 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 damages to a level it considers reasonable.

International
Statoil operates in more than 40 countries and is subject to a wide variety of health, safety and environmental regulations concerning our products, operations and activities. As a result of the accident in the Gulf of Mexico, health, safety and environmental laws and regulations are under review in the USA and elsewhere around the world. Any changes or additions to existing laws and regulations, both in the USA and around the world, could have a significant effect on the production, sale and profitability of many of our products. In addition, current and proposed fuel and product specifications, emission controls and climate change programmes under a number of environmental laws could have a significant effect on the production, sale and profitability of many of our products. There also are environmental laws that require us to remediate and restore areas damaged by the accidental or unauthorised release of hazardous materials or petroleum associated with our operations. These laws may apply to sites that Statoil currently owns or operates, sites that it previously owned or operated or sites used for the disposal of its and other parties' waste.

We anticipate that the health, safety and environmental laws and regulations to which we are subject, both in Norway and around the world, are likely to have an increasing impact on our operations. It is difficult, however, to predict accurately the effects of future developments in such laws and regulations on our future earnings and operations. Some risk of health, safety and environmental costs and liabilities is inherent in certain of our operations and products, as it is with other companies engaged in similar businesses. We cannot assure you that material costs and liablities will not be incurred; however, we do not currently expect any material adverse effect on our financial position or results of operations as a result of compliance with such laws and regulations.

3.11.5 Taxation of Statoil

We are subject to ordinary Norwegian corporate income tax and to a special petroleum tax relating to our offshore activities. We are also subject to a special carbon dioxide emissions tax and a nitrogen oxide tax.

Under our production licences, we are obliged to pay an area fee to the Norwegian State. 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. Norm prices are decided on a daily basis by the Petroleum Price Board, a body whose members are appointed by the Ministry of Petroleum and Energy. Norm prices are published quarterly. The Petroleum Taxation Act states that the norm prices shall correspond to the prices that could have been obtained in a sale of petroleum between independent parties in a free market. When adopting norm prices, the Petroleum Price Board takes a number of factors into consideration, including spot market prices and contract prices in the industry.

The maximum rate of depreciation of development costs related to offshore production installations and pipelines is 16.67% per year. Depreciation starts when the cost is incurred. Exploration costs may be deducted in the year in which they are incurred. Financial costs related to the offshore activity are calculated directly based on a formula set out in the Petroleum Tax Act. The financial costs deductible against the offshore tax regime are the total financial costs multiplied by 50% of tax values divided by the average interest-bearing debt. All other financial costs and income are allocated to the onshore tax regime.

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

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

Dividends received are subject to tax in Norway. The basis for taxation is 3% of the dividend received, which is subject to the standard 28% income tax rate. Dividends from low-tax countries or portfolio investments outside the EEA will, under certain circumstances, be subject to the standard 28% income tax rate based on the full amounts received.

Capital gains from the realisation of shares are taxable. The basis for taxation is 3% of the gain, which is subject to the standard 28% income tax. Capital losses from the realisation of shares are not deductible. Exceptions apply to shares held in companies domiciled in low-tax countries or portfolio investments outside the EEA, where, under certain circumstances, capital gains will be subject to the standard 28% income tax rate and capital losses will be deductible.

Special petroleum tax
A special petroleum tax is levied on profits 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 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 from the special petroleum tax, and a tax-free allowance, or uplift, is granted at a rate of 7.5% per year. The uplift is computed on the basis of the original capitalised cost of offshore production installations. The uplift can be deducted from taxable income for a period of four years, starting in the year in which the capital expenditure is incurred. Unused uplift can be carried forward indefinitely.

Abandonment costs
Abandonment costs incurred can be deducted as operating expenses. Provisions for future abandonment costs are not tax deductible.

Carbon dioxide emissions tax
A special carbon dioxide emissions tax applies to petroleum activities on the NCS. For 2010, the tax was NOK 0.47 and for 2011 it is NOK 0.48 per standard cubic metre of gas burned or directly released and per litre of oil burned. In addition, companies operating on the NCS have to buy allowances to cover the carbon dioxide emissions from the petroleum activities.

Nitrogen oxide emissions tax
With effect from 1 January 2007, the Norwegian government introduced a nitrogen oxide tax applicable to emissions of nitrogen oxide on the NCS. The tax was NOK 16.14 per kilogram of nitrogen oxide for 2010 and is NOK 16.43 for 2011.

As an alternative to paying the nitrogen oxide tax, companies can voluntarily agree to contribute to an industry nitrogen oxide fund for the years 2008-2010. The contribution to the fund is NOK 11 per kilogram of nitrogen oxide emissions. We have entered into an agreement to contribute to the fund.

Area fee
After the expiry of the initial exploration period, the holders of production licences are required to pay an area fee. The amount of the area fee is set out in regulations issued under the Petroleum Act. For most of the production licences, the initial annual area fee is currently NOK 30,000 per square kilometre. For the next year, the fee is increased to NOK 60,000 per square kilometre and thereafter the yearly fee increases to NOK 120,000 per square kilometre. Production licences for which a PDO has been submitted are, from the time of submission of the PDO and for as long as extraction from the deposit takes place, exempt from the obligation to pay the area fee for the area defining the deposits included in the PDO.

Taxation outside Norway
Statoil's international petroleum activities are subject to tax pursuant to local tax legislation. Fiscal regulation of our upstream operations is generally based on corporate income tax regimes and/or production sharing agreement regimes. Royalties may apply in each regime.

Generally, income from Statoil's upstream production outside Norway is subject to tax at the higher of the Norwegian onshore rate (28%) or the prevailing tax rate in the countries in which it operates. Statoil is subject to excess (or "windfall") profit tax in some of the countries where it produces crude oil.

Production sharing agreements
Under a PSA, the host government typically retains the right to the hydrocarbons in place. Under a PSA, the contractor normally receives a share of the oil produced to recover its costs, and is also entitled to an agreed share of the oil as profit. The allocation of profit oil between the state and the contractors is typically increasingly based on a success factor, such as surpassing certain specified internal rates of return, production rates or accumulated production. Normally, the contractors carry the exploration costs and risk prior to a commercial discovery and are then entitled to recover those costs during the producing phase. Fiscal provisions in a PSA contract are to a large extent negotiable and are unique to each PSA. Parties to a PSA are generally insulated against legislative changes in a country's general tax laws.

Income tax regimes
Under an income tax/royalty regime, companies are granted licences by the government to extract petroleum, and the state may be entitled to royalties in addition to tax based on the company's net taxable income from production. In general, the fiscal terms surrounding these licences are not negotiable and the company is subject to legislative changes in the tax laws.

3.11.6 The Norwegian State's participation

The Norwegian State's policy as a shareholder in Statoil 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 largely organised through Statoil. In 1985, the Norwegian State established the State's Direct Financial Interest, or SDFI, through which the Norwegian State has direct participating interests in licences and petroleum facilities on the NCS. As a result, the Norwegian State holds interests in a number of licences and petroleum facilities in which we also hold interests. Petoro AS, a wholly-owned company by the Norwegian State, was formed in 2001 to manage the SDFI assets.

3.11.7 Marketing and sale of SDFI oil and gas

Historically, we marketed and sold the Norwegian State's oil and gas as part of our own production. The Norwegian State has chosen to continue this arrangement.

Accordingly, at an extraordinary general meeting held on 27 February 2001, the Norwegian State, as sole shareholder, revised our articles of association by adding a new article that 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 25 May 2001, the Norwegian State, as sole shareholder, approved a resolution containing the instruction referred to in the new article. This resolution is referred to as the owner's instruction.

The Norwegian State has a coordinated ownership strategy aimed at maximising 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. It contains a general requirement that, in our activities on the NCS, we must take account of these ownership interests in decisions that could 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 set out 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 to ensure an equitable distribution of the total value creation between the Norwegian State and Statoil. In addition, the following considerations are important:

- to create the basis for long-term and predictable decisions concerning the marketing and sale of the Norwegian State's oil and gas;
- to ensure that results, including costs and revenues related to our oil and gas and the Norwegian State's oil and gas, are transparent and measurable; and
- to ensure 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 relating to the marketing and sale of the Norwegian State's oil and gas, other than those carried out jointly with other licensees under the production licence. This includes, but is not limited to, 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 for 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 that, in the underlying relationship between the Norwegian State and us, the Norwegian State has all rights and obligations related to the Norwegian State's oil and gas.

Costs

The Norwegian State does not pay us a specific consideration for performing these tasks, but it 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

The payment to the Norwegian State for sales of the Norwegian State's natural gas, both to us and to third parties, is based either on the prices achieved, 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 has been established in accordance with rules set out in the owner's instruction.

To ensure neutral weighting between the Norwegian State's and our own natural gas volumes, a list has been established for deciding the priority between each individual field. A mathematical optimisation model is used to decide the ranking. It describes existing and planned production facilities, infrastructure and processing terminals in which the Norwegian State and Statoil 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 apply:

- the effect of the draw on the depletion rate
- identification of time-critical fields
- influence on oil/liquid fields with associated gas requiring gas disposal; and
- spare capacity and flexibility in transportation systems and onshore facilities.

The different fields are ranked in accordance with their assumed total value creation for the Norwegian State and Statoil, assuming that 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 events occur that may significantly influence the ranking. Within each individual field in which both the Norwegian State and Statoil are licensees, the Norwegian State and Statoil will deliver volumes and share income in proportion to our respective participating interests.

The Norwegian State's oil and NGL is 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 at any time utilise its position as majority shareholder of Statoil to withdraw or amend the owner's instruction.

3.12 Competition

There is intense competition in the oil and gas industry for customers, production licences, operatorships, capital and experienced human resources.

In recent years, the oil and gas industry has experienced consolidation, as well as increased deregulation and integration in strategic markets.

Statoil competes with large integrated oil and gas companies, as well as with independent and government-owned companies for the acquisition of assets and licences for the exploration, development and production of oil and gas, and for the refining, marketing and trading of crude oil, natural gas and related products. Key factors affecting competition in the oil and gas industry are oil and gas prices and demand, exploration and production costs, global production levels, alternative fuels and government (including environmental) regulations.

Statoil's ability to remain competitive will depend, among other things, on the management continuing to focus on reducing unit costs and improving efficiency, maintaining long-term growth in our reserves and production through continuing technological innovation. It will also depend on our ability to seize international opportunities in areas where our competitors may also be actively pursuing exploration and development opportunities. We believe that we are in a position to compete effectively in each of our business segments.

3.13 Property, plants and equipment

We have interests in real property in many countries throughout the world, but no one individual property is significant to us as a whole.

Our head office, which is located at Forusbeen 50, NO-4035, Stavanger, Norway, comprises approximately 135,000 square metres of office space and is owned by Statoil.

A contract has been signed with IT Fornebu Holding AS in Oslo for the long-term lease of a new 60,000-square-metre office building to be built at Fornebu in Bærum municipality. The building, which will enable all of Statoil's activities in the Oslo region to be collocated, will be ready for occupation in autumn 2012. IT Fornebu Holding AS will be the owners and Statoil will be the tenant.

For a description of our significant reserves and sources of oil and natural gas, see note 35 - Supplementary oil and gas information in the Consolidated Financial Statements in this report.

3.14 Related party transactions

We have the following transactions with related parties.

Transactions with the Norwegian State
For a description of shares held by the Norwegian State, see report section Shareholder information-Major shareholders.

Transactions with other entities in which the Norwegian State is a major shareholder
Because the Norwegian State controls a substantial proportion of industry in Norway, there are many state-controlled entities with whom we do business. The financial value of most such transactions is relatively small, and the ownership interest of the Norwegian State in such counterparties has not had any effect on the arm's-length nature of the transactions. A full overview of the Norwegian State's shareholdings in commercial entities is found here:
http://www.regjeringen.no/nb/dep/nhd/tema/eierskap/statlig-eierskap/forvaltning-av-statlige-eierandeler.html?id=383095

Other transactions with the Norwegian State
Total purchases of liquids and natural gas from the Norwegian State amounted to NOK 81.4 billion (176 mmboe) in 2010. In 2009 and 2008, the total purchases amounted to NOK 74.3 billion (204 mmboe) and NOK 112.7 billion (223 mmboe), respectively. Purchases of natural gas from the Norwegian State (excluding purchases from licences and sales on behalf of the Norwegian State) amounted to NOK 0.4 billion in 2010. In 2009 and 2008, the purchases of natural gas amounted to NOK 0.3 billion and NOK 0.4 billion, respectively.

The significant amounts included in the line item Payables to equity accounted investments and other related parties in note 26 Trade and other payables to the Consolidated financial statement, are amount payables to the Norwegian State for these purchases. The prices paid by Statoil for the oil purchased from the Norwegian State are estimated at market prices. In addition, Statoil sells the Norwegian State's natural gas in its own name, but for the account and risk of the Norwegian State.

The Norwegian State compensates Statoil for its relative share of the costs related to certain Statoil natural gas storage and terminal investments and related activities. See report section Operational review-Regulation-Marketing and sale of the SDFI oil and gas for more details.

Although the Norwegian State is Statoil's majority owner, Statoil does not receive any preferential treatment with respect to licences granted by the Norwegian State or under any other regulatory rules enforced by the Norwegian State.

Employee loans
We have a general arrangement with DnBNOR whereby DnBNOR makes available to each of our employees personal consumer loans of up to NOK 300,000. The employees pay the "norm interest rate", which is variable and 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 10 million. The repayment period is up to eight years. Our obligations resulting from paying the interest rate difference will be dependent on the loan volume, but, based on current interest rates, it would not exceed NOK 5 million per year.

Members of the corporate executive committee and the board of directors may not take up loans under the current programme. None of the three employee-elected members of the board of directors and none of members of the corporate executive committee had any balances outstanding under this facility as of 12 March 2011.

Employees at certain employment levels are entitled to an interest-free car loan from the company. Members of the corporate executive committee and employee-elected members of the board are generally excluded from this arrangement, and none of them had any balances outstanding as of 12 March 2011.

Family members of certain corporate executive committee members or directors, who are also employees of Statoil, have participated in the employee loan and/or car loan programs prior to the appointment of such persons to the corporate executive committee or the board and may have balances outstanding.

Statoil's corporate assembly includes six employee representatives and three employee observers who, as part of their remuneration, may have balances outstanding under the Company's employee loan and/or car loan programs.

Other related party transactions
In the ordinary course of our business, we enter into transactions with various organizations with which certain of the members of Statoil's corporate assembly, board of directors or corporate executive committee are associated. Except as described in this report, Statoil did not have material transactions or transactions of an unusual nature with related parties in the period covered by this report.

3.15 Insurance

Statoil buys insurance policies for, amongst other things, physical loss of or damage to our oil and gas properties, liability to third parties, workers' compensation and employers liability, general liability, pollution and well control.

Our insurances are subject to:
i) Deductibles, excesses and Self Insured Retentions (SIR) that must be borne prior to recovery
ii) Exclusions and limitations

Our Well Control policy, which covers costs relating to well control incidents (including pollution and clean-up costs), is subject to a gross limit per incident. The gross limits for our two most significant geographical areas, the NCS and the GoM are:

Norwegian Continent Shelf (NCS)
NOK 2,500 million per incident for exploration wells
NOK 2,000 million per incident for production wells

Gulf of Mexico (GOM)
USD 300 million (approximately NOK 1,800 million) per incident

The limits assume~~s~~ 100% ownership interest in a given well and would be scaled to be equivalent to or percentage ownership interest in a given well.

Our SIR would vary between approximately NOK 16 and NOK 581 million per loss on the NCS depending on our ownership percentage interest in the well and certain other factors.

Our SIR in the GoM would be approximately NOK 150 million per incident assuming 100% ownership.

In excess of the well control insurance programs we have in place a third party liability insurance program with a gross limit of NOK 4,800 million per incident. The SIR is insignificant (maximum NOK 6 million).

We have a variety of other insurance policies related to other projects on a worldwide basis for which we have limited SIR.

There is no guarantee that our insurances will adequately protect us against liability for all potential consequences and damages.

4 Financial analysis and review

Statoil delivered strong financial results and cash flows in 2010. Production volumes were below our expectations in the second part of the year, mainly due to maintenance, operational issues and production permit restrictions.

Total equity liquids and gas production were 1,888 mboe per day in 2010, which is somewhat below the previously guided range of 1,925 - 1,975 mboe per day. However, the company has had a strong cash flow and has a sound financial position.

Net operating income was up by 13% compared with 2009, largely because of higher prices for oil. This was partly offset by lower gas prices and reduced volumes sold. Net operating income amounted to NOK 137.2 billion in 2010.

Around 90% of the expected Hydro merger synergies have been achieved, and monitoring of the merger value capture is now closed.

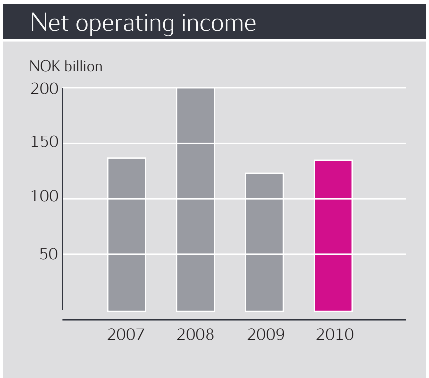
In 2010, Statoil agreed to partially sell interests in our operated assets in Brazil and Canada. Final investment decisions were made for nine new projects (operated by Statoil), and we carried out an initial public offering (IPO) of our energy and retail business.

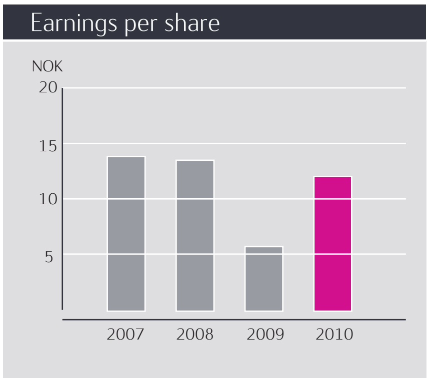
We acquired high potential exploration acreage in 2010 and the reserve replacement ratio grew to 87%, up from 73% in 2009. We believe we have the resource base required to improve this ratio going forward, and the high quality portfolio of yet-to-be-sanctioned projects is expected to add value to our business in the future.

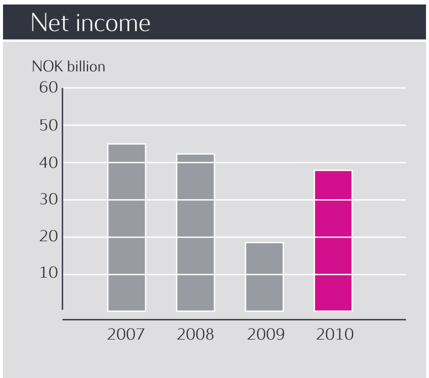
The board of directors is proposing a dividend of NOK 6.25 per share for 2010.

4.1 Operating and financial review 2010

Statoil delivered strong financial results and strong cash flows, despite reduced production. Exploration expenses and depreciation and impairment costs were down, largely as a result of reduced volumes and exploration activity.







In 2010, Statoil delivered total liquids and gas entitlement production of 1,705 mboe per day, down 6% from 1,806 mboe per day in 2009. Total equity production decreased by 4% from 2009, to 1,888 mboe per day in 2010. Higher maintenance activity, production permit restrictions, various operational issues and expected natural decline on mature fields caused the decrease. Limitations in the gas transportation systems from the Norwegian continental shelf (NCS) because of maintenance work also added to the decrease.

Despite reduced production and lower prices for gas, net operating income was up 13% at NOK 137.2 billion in 2010, compared with NOK 121.6 billion in 2009. The increase was mainly attributable to higher oil prices, decreased depreciation, amortisation and net impairment losses and decreased exploration expenses. It was partly offset by lower gas prices, reduced volumes of oil sold, losses on derivatives and a provision for an onerous contract relating to the US Cove Point Terminal.

Having realised approximately 90% of the expected synergies from the Hydro merger, Statoil has reduced overall expenses, reduced expenditures relating to logistics and procurement, improved operational efficiency, and increased value creation through commodities trading.

Statoil's exploration programme for 2010 totalled 35 exploration wells completed before 31 December 2010. Eighteen of them were drilled outside the Norwegian continental shelf (NCS). Eighteen wells were also announced as discoveries during the period. Six of them are located outside the NCS. In 2010, 526 mmboe of proved reserves were added through revisions, extensions and discoveries, compared with additions of 481 mmboe in 2009, also through revisions, extensions and discoveries.

In all, Statoil achieved a reserve replacement ratio of 87% in 2010. New resources were added to overall resources through exploration and business development, preparing the ground for growing proved reserves in the future.

Statoil progressed six new projects into production in 2010. The Gjøa, Vega, Vega South and Morvin fields on the NCS, the Eagle Ford field in the USA and the Leismer Demonstration project in Canada all came on stream in 2010.

Final investment decisions were made for nine new projects (operated by Statoil) in 2010, one of which is outside Norway.

In 2010, the group gained access to 12 new exploration licences in US Alaska, US GoM, Greenland, Newfoundland Canada and in the UK. On the NCS, we were awarded access to eight new licences, as operator for six and as partner in two. We were also awarded two licence extensions, both as operator. In addition, we have sold a 40% interest in the Kai Kos Dehseh oil sands development in Canada and entered into an agreement to sell a 40% interest in the Peregrino field off the coast of Brazil. We also acquired acreage in the Eagle Ford Shale area and in the Marcellus shale gas area in the USA.

4.1.1 Sales volumes

Sales volumes include our lifted entitlement volumes, the sale of SDFI volumes and our marketing of third-party volumes.

We take part in the production of oil and natural gas volumes, and incur capital expenditures and operating expenses on the basis of such equity volumes. Under certain production-sharing agreements (PSAs), a portion of the equity production is distributed to the relevant government before arriving at the volumes that we are ultimately entitled to sell (entitlement volumes). The timing of our lifting of our share of entitlement volumes may cause a difference at any given time between our share of entitlement volumes and the volumes lifted. This difference is called overlift if we have lifted more than our share of the entitlement production, and underlift if our cumulative lifting is less than our share of the entitlement volumes. The lifted volumes and volumes in inventory are the basis for what we can sell to third parties.

In addition to our own volumes of lifted entitlement production and production in storage, we market and sell oil and gas owned by the Norwegian state through the Norwegian state's share in production licences. This is known as the State's Direct Financial Interest, or SDFI. For additional information, see the section Operational review - Regulation - Marketing and sale of SDFI oil and gas. The following table shows SDFI and Statoil sales volume information for crude oil and natural gas, as applicable, for the periods indicated. The Statoil natural gas sales volumes include equity volumes sold by Natural Gas, natural gas volumes sold by International Exploration & Production and ethane volumes.

For more information on the differences between equity and entitlement production, sales volumes and lifted volumes, see the section Financial analysis and review - Operating and financial review 2010 - Definitions of reported volumes.

Sales Volumes	Year ended December 31 2010	2009	2008
Statoil: [1]			
Crude oil (mmbbls) [2]	354	381	372
Natural gas (bcf)	1,472	1,462	1,387
Natural gas (bcm) [3]	41.7	41.4	39.3
Combined oil and gas (mmboe)	616	642	619
Third party volumes: [4]			
Crude oil (mmbbls)[2]	310	257	242
Natural gas (bcf)	247	192	127
Natural gas (bcm) [3]	7.0	5.4	3.6
Combined oil and gas (mmboe)	354	291	265
SDFI assets owned by the Norwegian State:			
Crude oil (mmbbls) [2]	172	200	213
Natural gas (bcf)	1,610	1,431	1,440
Natural gas (bcm) [3]	45.6	40.5	40.8
Combined oil and gas (mmboe)	458	455	470
Total			
Crude oil (mmbbls) [2]	835	838	827
Natural gas (bcf)	3,329	3,085	2,955
Natural gas (bcm) [3]	94.3	87.4	83.7
Combined oil and gas (mmboe)	1,428	1,388	1,353

(1) The Statoil volumes included in the table above are based on the premise that volumes sold were equal to lifted volumes in the relevant year. Changes in inventory may cause these volumes to differ from the sales volumes reported elsewhere in this report by the Oil Trading and Supplies (OTS) organisation in the Manufacturing and Marketing segment in that such volumes include volumes still in inventory or transit held by other reporting entities within the group. Excluded from such volumes are volumes lifted by the International E&P but not sold by OTS, and volumes lifted by E&P Norway or International E&P and still in inventory or in transit.

(2) Sales volumes of crude oil include NGL and condensate. All sales volumes reported in the table above include internal deliveries to our manufacturing facilities.

(3) At a gross calorific value (GCV) of 40 MJ/scm.

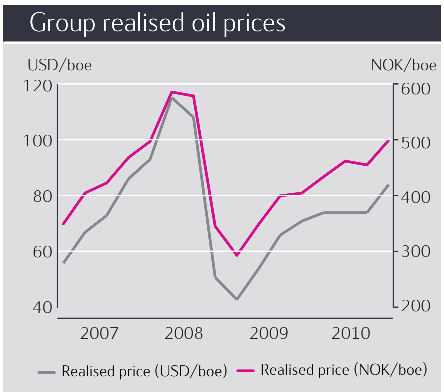
(4) Third party volumes of crude oil include both volumes purchased from partners in our upstream operations and other cargos purchased in the market. The third party volumes are purchased either for sale to third parties or for our own use. Third party volumes of natural gas include third party LNG volumes related to our activities at the Cove Point regasification terminal in the U.S.

4.1.2 Group profit and loss analysis

Revenues and other income amounted to NOK 529.6 billion in 2010, which is NOK 64.1 billion higher than in 2009 and NOK 126.4 billion lower than in 2008. Most of the revenues stem from the sale of lifted crude oil, natural gas and refined products produced and marketed by Statoil.

Consolidated statement of income			Year ended 31 December		
(in NOK billion)	2010	2009	2008	10-09 change	09-08 change
Revenues and other income					
Revenues	526.7	462.3	652.0	14%	(29%)
Net income from equity accounted investments	1.1	1.8	1.3	(36%)	39%
Other income	1.8	1.4	2.8	32%	(51%)
Total revenues and other income	529.6	465.4	656.0	14%	(29%)
Operating expenses					
Purchase [net of inventory variation]	257.4	205.9	329.2	25%	(37%)
Operating expenses	57.5	56.9	59.3	1%	(4%)
Selling, general and administrative expenses	11.1	10.3	11.0	7%	(6%)
Depreciation, amortisation and net impairment losses	50.6	54.1	43.0	(6%)	26%
Exploration expenses	15.8	16.7	14.7	(5%)	14%
Total operating expenses	392.4	343.8	457.2	14%	(25%)
Net operating income	137.2	121.6	198.8	13%	(39%)
Net financial items	(0.4)	(6.7)	(18.4)	(94%)	(64%)
Income tax	(99.2)	(97.2)	(137.2)	2%	(29%)
Net income	37.6	17.7	43.3	>100%	(59%)
Earnings per share for income attributable to equity holders of company basic and diluted	11.9	5.7	13.6	>100%	(58 %)

Operational data	2010	2009	Year ended 31 December 2008	10-09 change	09-08 change
Average liquids price (USD/bbl)	**76.5**	58.0	91.0	32 %	(36 %)
USDNOK average daily exchange rate	**6.05**	6.30	5.63	(4 %)	12 %
Average liquids price (NOK/bbl)	**462**	364	513	27 %	(29 %)
Gas prices (NOK/scm)	**1.72**	1.90	2.40	(10 %)	(21 %)
Refining margin, FCC (USD/boe)	**5.4**	4.3	8.2	26 %	(48 %)
Total entitlement liquids production (mboe per day)	**968**	1,066	1,055	(9 %)	1 %
Total entitlement gas production (mboe per day)	**738**	740	696	(0 %)	6 %
Total entitlement liquids and gas production (mboe per day)	**1,705**	1,806	1,751	(6 %)	3 %
Total equity liquids production (mboe per day)	**1,122**	1,202	1,200	(7 %)	0 %
Total equity gas prodcution (mboe per day)	**766**	760	725	1 %	5 %
Total equity liquids and gas production (mboe per day)	**1,888**	1,962	1,925	(4 %)	2 %
Total liquids liftings (mboe per day)	**969**	1,045	1,019	(7 %)	3 %
Total gas liftings (mboe per day)	**738**	740	696	(0 %)	6 %
Total liquids and gas liftings (mboe per day)	**1,706**	1,785	1,714	(4 %)	4 %
Production cost entitlement volumes (NOK/boe, last 12 months)	**42.8**	38.4	38.1	11 %	1 %
Production cost equity volumes (NOK/boe, last 12 months)	**38.6**	35.3	34.6	9 %	2 %
Equity production cost excluding restructuring and gas injection cost (NOK/boe, last 12 months)	**37.9**	35.3	33.3	7 %	6 %



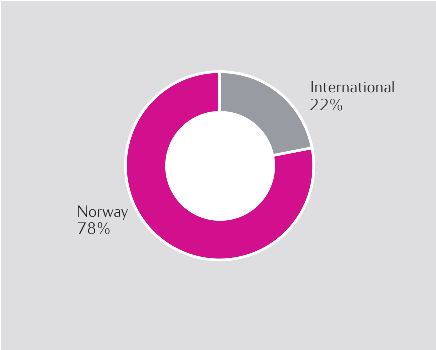
Revenues and other income amounted to NOK 529.6 billion in 2010, compared with NOK 465.4 billion in 2009 and NOK 656.0 billion in 2008. Most of the revenues stem from the sale of lifted crude oil, natural gas and refined products produced and marketed by Statoil. In addition, we also market and sell the Norwegian State's share of liquids from the Norwegian continental shelf (NCS). All purchases and sales of the Norwegian State's production of liquids are recorded as purchases net of inventory variations and sales, respectively.

The NOK 64.1 billion increase in revenues from 2009 to 2010 was mainly attributable to higher prices for liquids and increased volumes of gas sold, partly offset by lower gas prices, reduced volumes of liquids sold and losses on derivatives.

Realised prices of liquids measured in NOK increased by 27% from 2009 to 2010, contributing NOK 34.6 billion to the increase in revenues, while increased volumes of gas sold contributed NOK 5.9 billion to the increase in revenues. The increase was partly offset by a 7% decrease in liftings of liquids with a total off-setting effect of NOK 10.1 billion, while gas prices were down by 10% in 2010, affecting revenues negatively by NOK 9.5 billion.

The NOK 190.6 billion decrease in revenues from 2008 to 2009 was mainly attributable to lower prices for both liquids and gas. Realised prices of liquids measured in NOK decreased by 29% from 2008 to 2009, contributing NOK 56.5 billion to the reduction in revenues. Gas prices were down 21% in 2009 compared with 2008 and contributed NOK 25.0 billion to the reduction in revenues. The decrease in revenues related to volumes purchased from the Norwegian State contributed NOK 124.3 billion.

Distribution of proved reserves



Over time, the volumes lifted and sold will equal our production of entitlement volumes, but they may be higher or lower in any period due to differences between the capacity of the vessels lifting our volumes and the actual entitlement production in the period. Total liquids liftings were 969 mmboe per day in 2010, a decrease of 7% compared with the previous year. Total liquids liftings were 1.045 mmboe per day in 2009, an increase of 3% compared with 2008, when liftings were 1.019 mmboe per day.

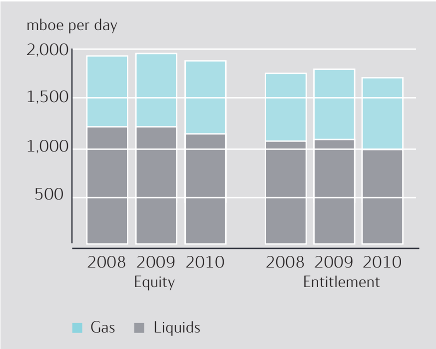
The average daily overlift was 1 mboe per day in 2010. In 2009, there was an average underlift of 21 mboe per day, while there was an average underlift of 37 mboe per day in 2008.

Entitlement volumes lifted form the basis for revenue recognition, while equity production volumes affect operating costs more directly. See the report section Financial analysis and review - Operating and financial review 2010 - Sales volumes for more details on the production-sharing agreement (PSA) effects that cause differences between equity and entitlement volumes. See below for more details on the difference between lifted and produced volumes.

Net income from equity accounted investments was NOK 1.1 billion in 2010, NOK 1.8 billion in 2009 and NOK 1.3 billion in 2008.

Other income was NOK 1.8 billion in 2010, compared with NOK 1.4 billion in 2009 and NOK 2.8 billion in 2008. Other income in 2010 and 2009 was mainly related to a gain on the sale of assets and insurance proceeds relating to business interruptions. Other income in 2008 was mainly related to gain on the sale of assets.

Entitlement and equity production



Purchase, net of inventory variation includes the cost of the oil and NGL production purchased from the Norwegian State pursuant to the Owners Instruction. See section Operational review - Regulation - Marketing and sale of SDFI oil and gas for more details. The purchase, net of inventory variation amounted to NOK 257.4 billion in 2010, compared with NOK 205.9 billion in 2009 and NOK 329.2 billion in 2008.

The 37% decrease from 2008 to 2009 mainly stems from lower prices of liquids measured in NOK, while the 25% increase from 2009 to 2010 was mainly caused by higher prices of liquids measured in NOK.

Operating expenses include field production costs, including payroll expenses and employee benefits, and costs incurred for transport systems related to the company's share of oil and natural gas production. In 2010, operating expenses amounted to NOK 57.5 billion, an increase of NOK 0.6 billion since 2009 when operating expenses were NOK 56.9 billion. The increase was mainly attributable to higher operating costs related to preparation for start up on new fields, partly offset by lower transportation costs because of reduced production, and cost saving activities.

Operating expenses were NOK 56.9 billion in 2009, down 4% on 2008, when operating expenses were NOK 59.3 billion. The reduction was mainly attributable to reduced transportation costs and the reversal of a provision relating to a take or pay contract in previous periods.

Total entitlement liquids and gas production decreased from 1.806 mmboe per day in 2009 to 1.705 mmboe per day in 2010. In 2008, total liquids and gas production was 1.751 mmboe per day.

Total equity liquids and gas production decreased from 1.962 mmboe per day in 2009 to 1.888 mmboe per day in 2010. In 2008, equity production of liquids and gas was 1.925 mmboe per day.

The 4% decrease in total equity production in 2010 compared to 2009, was primarily caused by relatively higher maintenance activity in 2010 leading to production shutdowns, limitations in the gas transportation system from the NCS because of planned maintenance, production permit restrictions on the Ormen Lange field, various operational issues and an expected natural production decline on several mature fields. The decrease in equity production was partly compensated by production from the start-up of new fields and ramp-up on existing fields. Entitlement production decreased by 6%. It was impacted by the same factors as equity production and also by changes in profit tranches for some of our fields in Angola and higher prices leading to reduced entitlement shares on other fields.

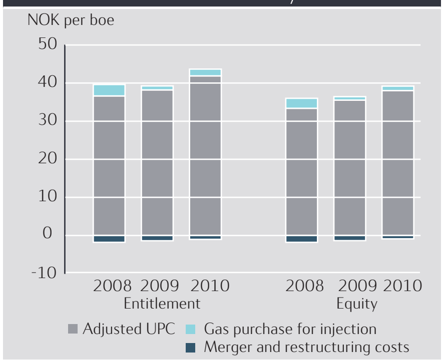
The 2% increase in equity production from 2008 to 2009 was primarily due to increased production from the start-up of new fields, ramp-up on existing fields, partly offset by declining production from mature fields, various operational issues and maintenance activities. Entitlement production increased by 3% for the same reasons and also due to a less adverse effect of production sharing agreements (PSA-effects).

The production cost of entitlement volumes per boe was NOK 42.8 for the 12 months ending 31 December 2010, compared with NOK 38.4 for the 12 months ending 31 December 2009. In 2008, the production cost per boe was NOK 38.1. Equity volumes represent produced volumes under PSA contracts that correspond to Statoil's ownership percentage in a specific field, while entitlement volumes represent Statoil's share of the volumes distributed to the partners in the field, which are subject to deductions. Production costs are incurred on the basis of our equity production. The management therefore believes that unit of production cost based on equity production is a better measure of cost control than unit of production cost based on entitlement volumes.

Based on equity volumes, the production cost per boe for the 12 months ending 31 December 2010 and 2009 was NOK 38.6 and NOK 35.3, respectively. In 2008, the production cost per boe was NOK 34.6. Adjusted for restructuring costs, reversal of restructuring costs and other costs arising from the merger recorded in the fourth quarter 2007 and gas injection costs, the production cost per boe of equity production for the 12 months ending 31 December 2010 and 2009, was NOK 37.9 and NOK 35.3, respectively. The corresponding figure for 2008 was NOK 33.3.

Adjustments are made for certain costs relating to the purchase of gas used for injection into oil-producing reservoirs. The adjustment facilitates comparison of field production costs with other fields that do not pay for their own gas used for injection into oil-producing reservoirs.

Production cost summary



Selling, general and administrative expenses include expenses relating to the sale and marketing of our products, such as business development costs, payroll expenses and employee benefits. These amount to NOK 11.1 billion in 2010, compared with NOK 10.3 billion in 2009 and NOK 11.0 billion in 2008. The NOK 0.8 billion increase from 2009 to 2010 mainly stems from a provision for an onerous contract in 2010. The increase was only partly offset by cost reductions from cost saving activities. The 6% decrease from 2008 to 2009 was due to numerous different factors, cost savings being one of them.

Depreciation, amortisation and net impairment losses include depreciation of production installations and transport systems, depletion of fields in production, amortisation of intangible assets and depreciation of capitalised exploration expenditure. It also includes impairment of long-lived assets and reversals of impairments. These expenses amounted to NOK 50.6 billion in 2010, compared with NOK 54.1 billion in 2009 and NOK 43.0 billion in 2008. The 6% decrease in depreciation, amortisation and net impairment losses in 2010 compared with 2009 was mainly due to lower impairment losses in 2010 and lower entitlement volumes. The 26% increase in depreciation, amortisation and impairment expenses in 2009 compared with 2008 was due to increased production on the NCS and impairment charges net of reversals of NOK 7.1 billion, mostly relating to assets in the Gulf of Mexico and refinery assets in Norway.

Depreciation, amortisation and net impairment losses (in NOK billion)	2010	2009	Year ended 31 December 2008	10-09 change	09-08 change
Ordinary depreciation	**45.8**	46.5	40.4	15 %	15 %
Amortisation of intangible assets	**0.2**	0.1	0.1	>100%	0 %
Impairments	**4.7**	8.2	3.5	(43 %)	>100%
Reversal of impairments	**(0.1)**	(1.7)	(1.1)	(94 %)	55 %
Impairment of intangible assets	**0.0**	1.0	0.0	<100%	>100%
Depreciation, amortisation and net impairment losses	**50.6**	54.1	43.0	26 %	26 %

Exploration expenditures are capitalised to the extent that exploration efforts are considered successful, or pending such assessment. Otherwise, such expenditures are expensed.

The exploration expense consists of the expensed portion of our exploration expenditure in 2010 and impairment of exploration expenditure capitalised in previous years. In 2010, the exploration expenses were NOK 15.8 billion, a 5% decrease since 2009, when exploration expenses were NOK 16.7 billion. Exploration expenses were NOK 14.7 billion in 2008.

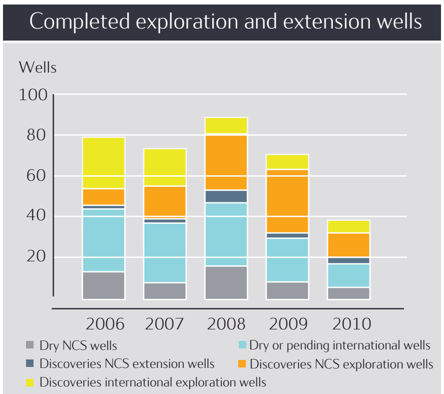
Exploration (in NOK billion)	2010	2009	For the year ended 31 December 2008	10-09 change	09-08 change
Exploration expenditure (activity)	**16.8**	16.9	17.8	(1 %)	(5 %)
Expensed, previously capitalised exploration expenditure	**2.9**	7.0	3.7	(59 %)	89%
Capitalised share of current periods exploration activity	**(3.9)**	(7.2)	(6.8)	(46 %)	6%
Exploration expense	**15.8**	16.7	14.7	(5 %)	14%

The 5% decrease in exploration expenses from 2009 to 2010 was mainly due to lower drilling activity and a smaller proportion of exploration expenditure capitalised in previous years being impaired. The decrease was partly offset by higher oil sands delineation drilling expenses, higher seismic expenditures and higher pre-sanctioning costs. The 14% increase in exploration expenses from 2008 to 2009 was mainly due a higher proportion of exploration expenditure capitalised in previous years being impaired.

In 2010, a total of 35 **exploration and appraisal wells** were completed, 17 on the NCS and 18 internationally. A total of 19 wells were announced as discoveries in the period, 12 on the NCS and seven internationally. In addition, four exploration extension wells were completed on the NCS in 2010, three of which were announced as discoveries.

In 2009, a total of 68 exploration and appraisal wells and two exploration extension wells were completed, 41 on the NCS and 29 internationally. Thirty-eight exploration and appraisal wells and two exploration extension wells have been declared as discoveries.

In 2008, a total of 79 exploration and appraisal wells and nine exploration extension wells were completed, 48 on the NCS and 40 internationally. Thirty-five exploration and appraisal wells and six exploration extension wells have been declared as discoveries.



Net operating income was NOK 137.2 billion in 2010, compared with NOK 121.6 billion in 2009 and NOK 198.8 billion in 2008. The 13% increase from 2009 to 2010 was primarily attributable to higher prices for liquids, partly offset by lower gas prices, reduced volumes of liquids sold, and losses on derivatives. The 39% decrease from 2008 to 2009 was primarily attributable to lower prices of liquids and gas, and increased depreciation, amortisation and impairment losses, partly offset by income from higher volumes sold.

In 2010, net operating income was negatively affected by impairment losses net of reversals (NOK 4.8 billion), lower fair value of derivatives (NOK 2.9 billion) and a provision for an onerous contract relating to the Cove Point terminal in the USA (NOK 0.8 billion), while overlift (NOK 1.4 billion) and gain on the sale of assets (NOK 1.3 billion) had a positive impact on net operating income.

In 2009, net operating income was negatively affected by impairment losses net of reversals (NOK 12.2 billion) and underlift (NOK 1.2 billion), while higher fair value of derivatives (NOK 2.2 billion), other accruals (NOK 1.3 billion), gain on the sale of assets (NOK 0.5 billion) and reversals of restructuring costs (NOK 0.3 billion) all had a positive effect on net operating income in 2009.

In 2008, net operating income was negatively affected by impairment charges net of reversals (NOK 4.8 billion), underlift (NOK 2.4 billion) and other accruals (NOK 2.3 billion), while increased fair value of derivatives (NOK 1.8 billion), higher fair value of derivatives (NOK 0.8 billion), gains on the sale of assets (NOK 1.4 billion) and reversal of restructuring cost accrual (NOK 1.6 billion) had a positive effect on net operating income in 2008.

Net financial items amounted to a loss of NOK 0.4 billion in 2010, compared with a loss of NOK 6.7 billion in 2009 and a loss of NOK 18.4 billion in 2008. The positive change of NOK 6.3 billion from 2009 to 2010 was mostly attributable to fair value changes on interest rate swap positions, due to decreasing US dollar interest rates in 2010, compared with increasing US dollar interest rates in combination with a 17% weakening of the US dollar in relation to NOK in 2009.

Net foreign exchange losses in 2010 of NOK 1.8 billion and net foreign exchange gains in 2009 of NOK 2.0 billion are mainly related to currency derivatives used for currency and liquidity risk management. They are partly offset by currency effects on the working capital.

Interest income and other financial items amounted to NOK 3.2 billion for the year ending 31 December 2010, compared with NOK 3.7 billion for the year ending 31 December 2009. The NOK 0.5 billion decrease was mainly related to a NOK 0.4 billion decrease in interest income on current financial assets in combination with a NOK 0.2 billion decrease in interest income on net securities.

Interest expenses and other financial expenses amounted to a net expense of NOK 1.8 billion for the year ending 31 December 2010, compared with a net expense of NOK 12.5 billion for the year ending 2009. The decrease of NOK 10.7 billion was mostly due to fair value changes on interest rate swap positions relating to the interest rate management of external loans. For the year ending 31 December 2010, fair value gains amounted to NOK 2.4 billion. Correspondingly, fair value losses for the year ending 31 December 2009 amounted to NOK 6.8 billion.

In 2009, net financial items amounted to a loss of NOK 6.7 billion in 2009, compared with a loss of NOK 18.4 billion in 2008.

The positive change of NOK 11.7 billion from 2008 to 2009 was mostly attributable to NOK 2.0 billion net currency gains caused by a 17% weakening of the US dollar in relation to NOK for the year ending 31 December 2009, compared with net currency losses of NOK 32.6 billion caused by a 29% strengthening of the US dollar in relation to NOK for the year ending 31 December 2008.

Net foreign exchange gains in 2009 and net foreign exchange losses in 2008 were mainly related to currency derivatives used for currency and liquidity risk management. Effective 1 January 2009, the functional currency changed to USD for the parent company. As a result USD-denominated non-current financial liabilities that affected net foreign exchange gains (losses) in 2008, did not affect the income statement in 2009. The positive impact of net currency exchange gains was partly offset by a NOK 8.5 billion decrease in interest income and other financial items, and a NOK 14.5 billion increase in interest and other financial expenses.

Interest income and other financial items amounted to NOK 3.7 billion for the year ending 31 December in 2009, compared with NOK 12.2 billion for the year ending 31 December 2008. The NOK 8.5 billion decrease was mainly related to NOK 3.9 billion in lower income from securities and NOK 5.5 billion in decreased interest income on current financial assets.

Interest expenses and other financial expenses amounted to net expenses of NOK 12.5 billion for the year ending 31 December 2009, compared with a net gain of NOK 2.0 billion for the year ending 31 December 2008. The decrease of NOK 14.5 billion mostly relates to fair value losses on interest rate derivatives used to manage the interest rate risk of the loan portfolio, as a result of increasing US dollar interest rates in 2009. Correspondingly, decreasing US dollar interest rates in 2008 resulted in fair value gains on these swap positions.

Income taxes were NOK 99.2 billion in 2010, equivalent to an effective tax rate of 72.5%, compared with NOK 97.2 billion in 2009, equivalent to an effective tax rate of 84.6%, and NOK 137.2 billion in 2008, equivalent to an effective tax rate of 76.0%.

The decrease in the effective tax rate from 2009 to 2010 was mainly due to high taxes in 2009 caused by higher taxable income than accounting income in companies that are taxable in other currencies than the functional currency. The decrease in the effective tax rate was also caused by relatively lower income from the NCS in 2010 compared with 2009. This income is subject to a higher than average tax rate.

The increase in the tax rate from 2008 to 2009 was mainly due to significant taxable exchange gains, which do not have an impact on the accounting income in the financial statements of companies whose functional currency is USD. In 2009, the taxable income relating to these exchange gains was estimated to be NOK 25.0 billion higher than income before tax, which increased the effective tax rate. In addition, the effective tax rate was increased by relatively higher income from the NCS where higher than average tax rates apply, and impairment losses with lower than average tax rates.

The effective tax rate is calculated as income taxes divided by income before taxes. Fluctuations in the effective tax rates from year to year are principally the result of non-taxable items (permanent differences), and changes in the components of income between Norwegian oil and gas production, taxed at a marginal rate of 78%. Other Norwegian income, including the onshore portion of net financial items is taxed at 28%, and income in other countries is taxed at the applicable income tax rates in those countries.

In 2010, the **non-controlling interest** (minority interest) in net profit was NOK 0.4 billion, compared with NOK 0.6 billion in 2009 and NOK 0.005 billion in 2008. The non-controlling interest in 2010 is primarily related to Statoil's 54% ownership of Statoil Fuel & Retail, starting in October 2010, and 79% ownership of Mongstad crude oil refinery.

Net income was NOK 37.6 billion in 2010, compared with NOK 17.7 billion in 2009 and NOK 43.3 billion in 2008. The 112% increase from 2009 to 2010 was mainly due to increased net operating income as a result of higher revenues from liquids and a lower net financial loss, only partly offset by higher income taxes.

The 59% decrease from 2008 to 2009 was mainly due to reduced operating income caused by lower revenues from liquids and gas sales and a higher effective tax rate, only partly offset by reduced loss on net financial items.

The board of directors will propose for approval at the annual general meeting an ordinary **dividend** of NOK 6.25 per share for 2010, an aggregate total of NOK 19.9 billion. In 2009, the ordinary dividend was NOK 6.00 per share, an aggregate total of NOK 19.1 billion. The ordinary dividend for 2008 was NOK 4.40 per share, and a special dividend of NOK 2.85 per share was distributed, making an aggregate total of NOK 23.1 billion.

4.1.3 Group outlook

Planned turnarounds are expected to have a negative impact on the equity production of liquids of around 40 mboe per day for the full year 2011. The main impact is expected to be in the third quarter of 2011.

Organic capital expenditures for 2011 i.e. excluding acquisitions and capital leases, are estimated at around USD 16 billion.

The company will continue to mature its large portfolio of **exploration** assets. In 2011, we expect to drill around 20 exploration wells on the NCS and around 20 exploration and appraisal wells internationally. We expect total exploration expenditure in 2011 of around USD 3 billion.

We expect prices for crude oil, products and natural gas to continue to be volatile in the short to medium term. Refining margins have increased compared to 2009; however, they are still low from an historical perspective. We anticipate that the refining margins will remain low, at least in the near term. The refining industry is expected to still face major challenges in 2011. Even though global oil demand has recovered from 2009 levels, refinery overcapacity persists.

We believe that global oil demand will continue to increase in 2011. In line with the economic recovery, global oil demand is expected to normalize in the next few years. The shift of higher oil consumption in emerging markets, and lower oil consumption in mature regions, is expected to continue. Emerging markets, led by China, are expected to increase usage of oil for industrial production, construction and transportation. Western Europe and the US are expected to see a fall in oil demand primarily due to efficiency gains in the transportation sector and less intake from stationary facilities. Diesel demand in Europe will be robust, but a surplus of European gasoline supply will need to be sold to the traditional export market in US, but also to markets as West Africa.

Supply of natural gas liquids (NGL) is expected to increase significantly, especially as supply associated with new US shale gas production reaches the market. European NGL production is likely to remain high as volumes associated with oil fields are replaced by NGL from non-associated production. The increase in LPG availability is expected to find solid demand from the premium residential/heating segment, and as feedstock into the price-sensitive petrochemical industry. Naphtha finds a home in both the petrochemical and transportation sector.

We continue to take a positive long term view of gas as an energy source. Domestic production of gas in the EU continues to decline, while demand for gas is expected to increase in the long term, particularly due to the lower carbon footprint of natural gas compared with oil and coal. In the USA, we believe that our position in the Marcellus and Eagle Ford shale gas acreage, in combination with Gulf of Mexico production, will provide a foundation for growth in our US market position in the years ahead.

Statoil's income could vary significantly with changes in commodity prices, even if volumes remain stable through the year. There is a small seasonal effect on volumes in the winter and summer seasons due to normally higher off-takes of natural gas during cold periods. There is normally an additional small seasonal effect on volumes as a result of the higher maintenance activity level on offshore production facilities during the second and third quarters each year, since generally better weather conditions allow for more maintenance work.

These forward-looking statements reflect current views about 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. See section Forward looking statements.

4.1.4 Segment performance and analysis

Oil and natural gas are subject to internal transactions between our business segments before being sold in the market. We have established a pricing policy for transfers based on the estimated market price.

The table below details certain financial information for our five business segments: Exploration & Production Norway (EPN), International Exploration & Production (INT), Natural Gas (NG), Manufacturing & Marketing (M&M), and Fuel & Retail (SFR). A new corporate structure was implemented from 1 January 2011, and the business segments will be changed accordingly going forward. See the section Business overview and strategy - New organisational structure as from January 2011.

The EPN and INT segments explore, develop and produce crude oil and natural gas, and extract natural gas liquids. The Natural Gas segment transports and markets natural gas and natural gas products. Manufacturing and Marketing is responsible for petroleum refining operations and the marketing of crude oil and refined petroleum products except for natural gas and natural gas products. Fuel & Retail markets fuel and related products, principally to retail consumers.

We eliminate intercompany sales when combining business segment results. These include transactions recorded in connection with our oil and natural gas production in the EPN or INT segments and also in connection with the sale, transportation or refining of our oil and natural gas production in the M&M, NG and SFR segments.

EPN produces oil, which it sells internally to Oil Sales, Trading & Supply (OTS) in the M&M segment. EPN also produces natural gas, which it sells internally to the NG segment, also for sale in the market. A large share of the oil and a small share of the natural gas produced by INT are also sold to the M&M segment or the NG segment, respectively. The remaining oil and gas from INT is sold directly in the market. Statoil has established an estimated market price-based transfer pricing policy whereby an internal price is set at which the EPN business area sells oil and natural gas to the M&M and NG segments.

In 2010, the **average transfer price** for natural gas per standard cubic metre was NOK 1.27 per scm. The average transfer price was NOK 1.38 per scm in 2009 and NOK 1.87 in 2008. For oil sold from EPN to M&M, the transfer price is the applicable market-reflective price minus a margin of NOK 0.70 per barrel.

For additional information please refer to the Consolidated Financial Statements - note 3 Segments.

The following table shows certain financial information for the five segments, including intercompany eliminations for each of the years in the three-year period ending 31 December 2010.

Following the change in segments in the fourth quarter of 2010 to report Statoil Fuel & Retail separately, prior periods have been restated to be comparable, see the Consolidated financial statement - note 3 Segments - for further information.

Business segments

(in NOK billion)	2010	For the year ended 31 December 2009	2008
Exploration & Production Norway			
Total revenues	**170.7**	158.7	219.8
Net operating income	**115.6**	104.3	166.9
Non-current assets	**199.3**	176.0	165.5
International Exploration & Production			
Total revenues	**51.0**	41.8	46.1
Net operating income	**12.6**	2.6	12.8
Non-current assets	**158.1**	152.7	160.6
Natural Gas			
Total revenues	**87.5**	98.6	110.8
Net operating income	**8.5**	18.5	12.5
Non-current assets	**38.7**	34.8	35.7
Manufacturing & Marketing			
Total revenues	**407.2**	323.8	495.7
Net operating income	**(2.0)**	(1.8)	4.7
Non-current assets	**17.7**	18.1	21.7
Fuel & Retail			
Total revenues	**65.9**	57.4	73.2
Net operating income	**2.4**	1.3	(0.1)
Non-current assets	**17.5**	12.2	14.0
Other and elimination			
Total revenues	**(252.7)**	(214.9)	(289.7)
Net operating income	**0.1**	(3.3)	2.1
Non-current assets	**4.0**	1.3	2.3
Statoil group			
Total revenues	**529.6**	465.4	656.0
Net operating income	**137.2**	121.6	198.8
Non-current assets	**435.3**	395.1	400.1
Non-current assets, not allocated to segments	**14.1**	51.4	33.5

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2010						
Norway	227,122	72,643	47,551	47,332	16,725	411,373
USA	22,397	7,817	1,815	14,918	5,771	52,718
Sweden	0	0	0	18,810	4,612	23,422
Denmark	0	0	0	14,275	3,027	17,302
Other	4,508	4,380	205	12,150	2,457	23,700
Total revenues (excluding net income from equity accounted investments)	254,027	84,840	49,571	107,485	32,592	528,515

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2009						
Norway	182,353	80,018	34,655	45,927	18,137	361,090
USA	19,836	5,555	117	14,017	672	40,197
Sweden	0	0	0	16,556	3,795	20,351
Denmark	0	0	0	15,105	1,957	17,062
Other	9,978	2,959	154	10,762	1,102	24,955
Total revenues (excluding net income from equity accounted investments)	212,167	88,532	34,926	102,367	25,663	463,655

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2008						
Norway	260,171	79,813	44,536	79,659	31,105	495,284
United States	24,712	8,795	1,660	20,182	2,545	57,894
Sweden	0	0	0	23,428	2,618	26,046
Denmark	0	0	0	16,858	2,558	19,416
Singapore	11,203	1,906	0	0	0	13,109
UK	1,982	10,878	2	0	2,800	15,662
Other	7,305	930	198	16,885	2,008	27,326
Total revenues (excluding net income from equity accounted investments)	305,373	102,322	46,396	157,012	43,634	654,737

4.1.5 Exploration & Production Norway

In 2010, Exploration & Production Norway delivered strong financial results and strong cash flows, despite reduced production. Exploration expenditure was down, largely due to lower exploration activity.

Statoil completed 17 exploration and appraisal wells on the NCS in 2010, 12 of which were discoveries. In addition, we completed four exploration extensions, three of which were discoveries. Based on the extensive exploration programme in 2008 and 2009, a number of discoveries were matured in the project phase and several prospects were identified. Total exploration expenditure was NOK 6.0 billion in 2010, compared with NOK 8.2 billion in 2009 and NOK 8.7 billion in 2008.

Gross investments amounted to NOK 31.9 billion in 2010, a decrease of NOK 3 billion from the NOK 34.9 billion invested in 2009. From 2008 to 2009, the investment amount remained at NOK 34.9 billion. Around half of our investments are related to new fields, while the other half are investments in existing fields.

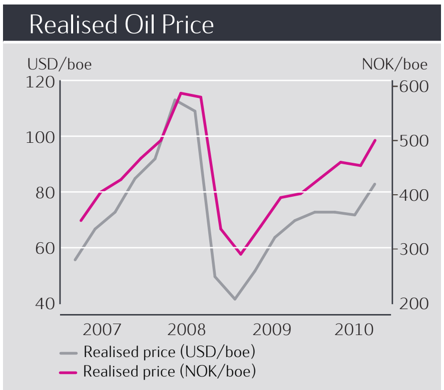
In total, four new fields came on stream on the Norwegian continental shelf (NCS) in 2010: Morvin, Gjøa, Vega and Vega South.

Our production of oil and gas on the NCS averaged 1.374 mmboe per day in 2010, compared with 1.450 mmboe per day in 2009 and 1.461 mmboe per day in 2008.

4.1.5.1 Profit and loss analysis

Exploration & Production Norway generated total revenues of NOK 170.7 billion in 2010 and its net operating income was NOK 115.6 billion. The average daily entitlement production in 2010 was 704 mboe per day for liquids and 669 mboe per day for gas.

Income statement (in NOK billion)	2010	2009	For the year ended 31 December 2008	10-09 change	09-08 change
Total revenues and other income	**170.7**	158.7	219.8	8 %	(28 %)
Operating expenses	**23.5**	23.4	23.5	0 %	(0 %)
Selling, general and administrative expenses	**0.1**	0.1	(0.1)	3 %	>(100%)
Depreciation, amortisation and net impairment losses	**26.0**	25.7	24.0	1 %	7 %
Exploration expenses	**5.5**	5.2	5.5	6 %	(6 %)
Total expenses	**55.1**	54.3	52.9	1 %	3 %
Net operating income	**115.6**	104.3	166.9	11 %	(37 %)
Operational data:					
Liquids price (USD/bbl)	**76.3**	57.8	91.5	32 %	(37 %)
Liquids price (NOK/bbl)	**461.0**	363	515	27 %	(30 %)
Transfer price natural gas (NOK/scm)	**1.27**	1.38	1.87	(8 %)	(26 %)
Liftings:					
Liquids (mboe per day)	**711**	778	808	(9 %)	(4 %)
Natural gas (mboe per day)	**669**	666	637	0 %	5 %
Total liquids and gas liftings (mboe per day)	**1,380**	1,444	1,445	(4 %)	(0 %)
Production:					
Entitlement liquids (mboe per day)	**704**	784	824	(10 %)	(5 %)
Entitlement natural gas (mboe per day)	**669**	666	637	0 %	5 %
Total entitlement liquids and gas production (mboe per day)	**1,374**	1,450	1,461	(5 %)	(1 %)

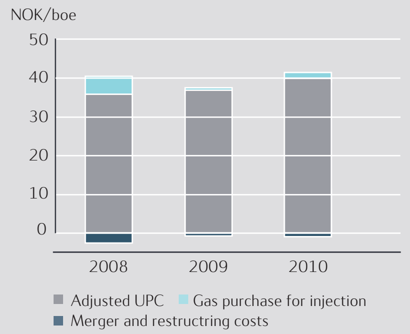


We generated **total revenues and other income** of NOK 170.7 billion in 2010, NOK 158.7 billion in 2009 and NOK 219.8 billion in 2008. An increase of 32% in the average price in USD of oil sold by E&P Norway to Manufacturing & Marketing accounted for NOK 29.3 billion of the increase in revenues and a minor increase in lifted volumes of natural gas, making a positive contribution of NOK 0.2 billion. This was partly offset by a decrease of 9% in lifted volumes of liquids, making a negative contribution of NOK 8.9 billion and a negative currency exchange rate deviation of NOK 4.7 billion due to a 4% increase in the USD/NOK exchange rate in 2010. Furthermore, an 8% decrease in the average transfer price in NOK of natural gas sold by E&P Norway to Natural Gas accounted for NOK 4.1 billion of the decrease in revenues.

There was a decrease in total revenues from NOK 219.8 billion in 2008 to NOK 158.7 billion in 2009. A decrease of 37% in the average price in USD of oil sold by E&P Norway to Manufacturing & Marketing accounted for NOK 52.1 billion of the decrease in revenues, and a 26% decrease in the average transfer price in NOK of natural gas sold by E&P Norway to Natural Gas accounted for NOK 18.9 billion of the decrease in revenues. This was partly offset by a positive currency exchange rate deviation of NOK 12.6 billion due to a 14% increase in the USD/NOK exchange rate. Furthermore, lifted volumes of liquids decreased by 4%, making a negative contribution of NOK 5.7 billion, which was partly offset by a 4% increase in lifted volumes of natural gas, making a positive contribution of NOK 2.9 billion in 2009 compared with 2008.

Operating expenses were NOK 23.5 billion in 2010, compared with NOK 23.4 billion in 2009 and NOK 23.5 billion in 2008. In 2010, increased operating plant costs and other expenses were partly offset by a decrease in transportation costs due to lower lifting of liquids. The decrease of NOK 0.1 billion in operating expenses from 2008 to 2009 was mainly due to lower operating plant costs, partly offset by increased processing/transportation costs.

Production unit cost



The average daily lifting of liquids in 2010 was 711 mboe per day, compared with 778 mboe per day in 2009 and 808 mboe per day in 2008. Over time, the volumes lifted and sold will equal the volumes produced, but they may be higher or lower in any period due to differences between the capacity of the vessels lifting our volumes and the actual entitlement production in the period. The average daily overlift was 6 mboe per day in 2010 and 6 mboe underlift per day in 2009, compared with an average underlift of 16 mboe per day in 2008.

The average daily production of entitlement liquids in 2010 was 704 mboe per day, compared with 784 mboe per day in 2009 and 824 mboe per day in 2008. The decrease in production from 2009 to 2010 is mainly related to the C-06 situation for more details, see section Operational review - E&P Norway - Fields in production on the NCS - Operations West, water injection issues and a decline in the main field on Gullfaks, reduced capacity at Kollsnes, a lower production permit than expected on Ormen Lange and operational challenges on Kristin and Oseberg. The negative effect on average daily production was approximately 70 mbbl in 2010. In addition, we had expected production profile reductions due to a natural decline on mature fields. The decrease was partly offset by increased production at Morvin and Tyrihans.

The decreased production from 2008 to 2009 was mainly related to expected production profile declines on several fields, various operational issues on the Kristin, Gullfaks South and Norne fields, a turnaround and less NGL due to less gas off-take on Oseberg and the closing down of the Tordis subsea separator from the end of May 2008 due to leakage from a well. The decrease was partly offset by a build-up of production on Ormen Lange and Snøhvit and new production at Alve, Tyrihans, Volve, Vilje and Yttergryta, and by Kvitebjørn returning to full production from July 2009 after it was shut down due to a damaged gas pipeline.

The average daily production of entitlement gas was 669 mboe per day in 2010 compared with 666 mboe in 2009 and 637 mboe in 2008.

The unit production cost was NOK 39.7 per boe in 2010, compared with NOK 36.9 per boe in 2009 and NOK 37.3 per boe in 2008. The total production cost was NOK 19.9 billion in 2010, compared with NOK 19.5 in 2009 and NOK 19.9 billion in 2008. The 8% increase in the unit production cost from 2009 to 2010 is due to a 5% decrease in production and a 2% increase in production costs. The increase in production cost is mainly related to new fields coming on stream and increased insurance. The 1% decrease in the unit production cost from 2008 to 2009, is mainly due to a 2% decrease in production costs, partly offset by a 1% decrease in production.

Depreciation, amortisation and net impairment losses were NOK 26.0 billion in 2010, compared with NOK 25.7 billion in 2009 and NOK 24.0 billion in 2008. The increase in 2010 compared with 2009 is mainly related to increased investments in mature fields, partly offset by change in the portfolio of producing fields and the impact on depreciation of reserve adjustments. The NOK 1.7 billion increase from 2008 to 2009 was mainly due to new fields in production in 2009.

Exploration expenditure (including capitalised exploration expenditure) in 2010 amounted to NOK 6.0 billion, compared with NOK 8.2 billion in 2009 and NOK 8.7 billion in 2008. The decrease from 2009 to 2010 was mainly due to fewer wells being drilled in 2010. The decrease from 2008 to 2009 was mainly due to fewer wells being drilled in 2009.

Exploration expenses in 2010 were NOK 5.5 billion, compared with NOK 5.2 billion in 2009 and NOK 5.5 billion in 2008.

In 2010, 17 exploration and appraisal wells and four exploration extensions were completed on the NCS, of which 12 exploration and appraisal wells and three of the exploration extension wells were announced as discoveries.

In 2009, 39 exploration and appraisal wells and two exploration extension wells were completed on the NCS, of which 31 exploration and appraisal wells and both exploration extension wells were announced as discoveries. In 2008, 39 exploration and appraisal wells and nine exploration extension wells were completed on the NCS, of which 27 exploration and appraisal wells and six exploration extension wells were discoveries.

The drilling of six exploration and appraisal wells was ongoing at the end of 2010. Six exploration and appraisal wells have been completed since 31 December 2010, three of which were discoveries.

The reconciliation of exploration expenditure with exploration expenses is shown in the table below.

Exploration (in NOK billion)	2010	For the year ended 31 December 2009	2008	10-09 change	09-08 change
Exploration expenditure (activity)	**6.0**	8.2	8.7	(27 %)	(6 %)
Expensed, previously capitalised exploration expenditure	**1.4**	1.2	0.7	19%	57%
Capitalised share of current period's exploration activity	**(1.9)**	(4.2)	(3.9)	54 %	(7 %)
Exploration expenses	**5.5**	5.2	5.5	6 %	(6 %)

Net operating income in 2010 was NOK 115.6 billion, compared with NOK 104.3 billion in 2009 and NOK 166.9 billion in 2008. The NOK 11.3 billion increase in 2010 was mainly due to increased liquid prices. The NOK 62.6 billion decrease in 2009 was mainly due to decreased prices for oil and gas.

4.1.6 International Exploration & Production

Our strategy is to deliver international growth in the short and medium term from existing positions, while creating new opportunities for long-term value creation.

Our international entitlement production was 332 mboe per day in 2010, compared with 357 mboe per day in 2009. The average daily equity production of oil and gas was 514 mboe per day in 2010, compared with 512 mboe in 2009.

Equity volumes represent produced volumes under a production sharing agreement (PSA) that correspond to Statoil's percentage ownership in a particular field. **Entitlement volumes**, on the other hand, represent Statoil's share of the volumes distributed to the partners in the field. They are subject to deductions for, among other things, royalties and the host government's share of profit oil. Entitlement volumes lifted are the basis for revenue recognition, while equity production volumes affect operating costs more directly. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes. The main countries in which we operate under PSAs are Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia.

Our international portfolio has been further strengthened in 2010 through agreements with Enduring Resources and Talisman in October for the acquisition of 67,000 net acres in the Eagle Ford shale area in southwest Texas. In January 2010, we increased our equity share in the St. Malo discovery in the US Gulf of Mexico from 6.25% to 21.5% by exercising our pre-emption rights. In September, Statoil announced that it will acquire 20.67% of Nautical Petroleum's interest in the Mariner field in UK. We have also entered into an agreement with the Chinese company Sinochem Group to sell 40% of our equity in the Peregrino field off the coast of Brazil and sold 40% of our equity in the Kai Kos Dehseh oil sands development in Northern Alberta in Canada to PTT Exploration and Production (PTTEP) of Thailand. An overview of portfolio transactions in 2010 is presented in section Operational review - International E&P - Our International E&P portfolio.

The total capital expenditure of NOK 44.9 billion in 2010 was higher than last year, mainly due to the acquisition of equity in Eagle Ford and St Malo in USA.

In total 18 exploration and appraisal wells were completed in 2010 and seven wells were announced as discoveries. At year end, five wells were pending final evaluation and the subsequent recertification process, which is still ongoing. Our international exploration activities in 2010 were affected by the drilling moratorium in the US Gulf of Mexico from 27 May to 12 October and subsequent re-certification process. The total exploration expenses were NOK 10.3 billion in 2010, compared with NOK 11.5 billion in 2009.

4.1.6.1 Profit and loss analysis

International Exploration & Production (INT) generated total revenues of NOK 51.0 billion in 2010 and net operating income of NOK 12.6 billion. The average daily entitlement production of liquids was 263 mboe and the average daily entitlement production of gas was 68 mboe.

	For the year ended 31 December				
IFRS income statement (in NOK billion)	2010	2009	2008	10-09 change	09-08 change
Total revenues and other income	**51.0**	41.8	46.1	22 %	(9 %)
Purchase [net of inventory variation]	**0.0**	1.1	1.7	(98 %)	(32 %)
Operating expenses	**8.5**	6.7	5.6	27 %	18%
Selling, general and administrative expenses	**2.9**	2.8	3.2	3 %	(11 %)
Depreciation, amortisation and net impairment losses	**16.7**	17.1	13.7	(3 %)	25 %
Exploration expenses	**10.3**	11.5	9.2	(11 %)	26%
Total expenses	**38.4**	39.2	33.3	(2 %)	18%
Net operating income	**12.6**	2.6	12.8	>100 %	(80 %)
Operational data:					
Liquids price (USD/bbl)	**76.8**	58.4	88.7	32 %	(34 %)
Liquids price (NOK/bbl)	**464.2**	366.5	499.3	27 %	(27 %)
Liftings:					
Liquids (mboe per day)	**258**	267	211	(3 %)	26 %
Natural gas (mboe per day)	**68**	74	59	(8 %)	25 %
Total liquids and gas liftings (mboe per day)	**327**	341	270	(4 %)	26 %
Production:					
Entitlement liquids (mboe per day)	**263**	283	232	(7 %)	22 %
Entitlement natural gas (mboe per day)	**68**	74	59	(8 %)	25 %
Total entitlement liquids and gas production (mboe per day)	**332**	357	290	(7 %)	23 %
Total equity liquids and gas production (mboe per day)	**514**	512	465	0 %	10 %

INT generated **total revenues and other income** of NOK 51.0 billion in 2010 compared with NOK 41.8 billion in 2009 and NOK 46.1 billion in 2008. The increase from 2009 to 2010 was mainly related to a 25% increase in realised liquid and gas prices which made a positive contribution of NOK 9.4 billion and a 63% increase in other income which made a positive contribution of NOK 1.2 billion. The increase was partly offset by a 4% reduction in lifted volumes which contributed negatively in the amount of NOK 1.4 billion. The decrease from 2008 to 2009 was mainly related to a 34% decrease in realised liquid and gas prices that made a negative contribution of NOK 14.3 billion. This reduction was partly offset by a 26% increase in the lifted volumes, which contributed positively in the amount of NOK 11.2 billion.

The average daily lifting of liquids was 258 mboe in 2010 compared with 267 mboe in 2009 and 211 mboe in 2008. Over time, the volumes lifted and sold will equal our production of entitlement volumes, but they may be higher or lower in any period due to differences between the capacity and timing of the vessels lifting our volumes and the actual entitlement production during the period. The average daily over/underlift in 2010, 2009 and 2008 was 8 mboe in overlift, 2 mboe in underlift and 4 mboe in underlift respectively.

The average daily entitlement production of liquids was 263 mboe in 2010 compared with 283 mboe in 2009, and 232 mboe in 2008. The 7% decrease in average daily liquids entitlement production from 2009 to 2010 was mainly related to a higher PSA effect due to changes in profit tranches and higher prices leading to reduced entitlement shares, a decline in production profile and operational issues in several fields in Angola, and a reduced ownership share in the Mabruk field in Libya. The decrease was partly offset by an increased ownership share in the Agbami field in Nigeria. The 22% increase in average daily liquids entitlement production from 2008 to 2009 was mainly related to the ramp-up of the Agbami field in Nigeria and Saxi-Batuque in Angola, the start-up of Tahiti in the Gulf of Mexico and a higher entitlement factor on PSA fields due to lower prices.

The average daily entitlement production of gas was 68 mboe in 2010 (equivalent to 11 mmcm or 384 mmcf) compared with 74 mboe in 2009 (equivalent to 12 mmcm or 413 mmcf) and 59 mboe in 2008 (equivalent to 9 mmcm or 331 mmcf). The decrease in daily gas production from 2009 to

2010 was mainly related to decline in mature fields in the Independence Hub in the US Gulf of Mexico. The 25% increase in daily gas production from 2008 to 2009 was mainly related to higher off-take from the In Salah field in Algeria and increased production from Independence Hub due to extensive hurricane activity negatively affecting the production in 2008.

The average daily equity liquids and gas production was 514 mboe in 2010 compared with 512 mboe in 2009 and 465 mboe in 2008. The 10 % increase from 2008 to 2009 was mainly due to new fields coming into production.

The unit of production cost based on entitlement volumes was USD 8.6 per boe in 2010 compared with USD 7.2 per boe in 2009 and USD 7.6 per boe in 2008. Measured in NOK, it was 52.0 per boe in 2010, 45.2 per boe in 2009 and 42.2 in 2008. The 13% increase in unit of production cost measured in NOK from 2009 to 2010 is mainly due to increased preparations for production in Brazil for the Peregrino field and lower entitlement factor (from higher realised oil and gas prices in 2010). The increase in unit of production cost measured in NOK from 2008 to 2009 was mainly due to the strengthening of USD in relation to NOK and increased preparation for fields coming on stream.

Production costs are incurred based on our equity production. Management therefore considers that unit of production cost based on equity production is a better measure of cost control than unit of production cost based on entitlement volumes. **The unit of production cost based on equity volumes** was USD 5.4 per boe in 2010, compared with USD 4.9 per boe in 2009 and USD 4.6 per boe in 2008. Measured in NOK, it was 32.9 per boe in 2010, 30.8 per boe in 2009 and 25.9 per boe in 2008. The increase from 2009 to 2010 is mainly due to increased preparations for operating activity in Brazil for the Peregrino field.

Operating expenses and purchase [net of inventory variation] were NOK 8.5 billion in 2010, compared with NOK 7.8 billion in 2009 and NOK 7.3 billion in 2008. The 9% increase from 2009 to 2010 is mainly due to increased preparation for operation costs on the Peregrino field in Brazil. The 7% increase from 2008 to 2009 was mainly due to new fields coming on stream during 2008 and 2009 (Agbami, Tahiti and Thunder Hawk).

Selling, general and administrative expenses were NOK 2.9 billion in 2010, compared with NOK 2.8 billion in 2009 and NOK 3.2 billion in 2008. The 12% decrease from 2008 to 2009 was mainly due to cost saving initiatives and allocation of costs.

Depreciation, amortisation and net impairment losses were NOK 16.7 billion in 2010 compared with NOK 17.1 billion in 2009 and NOK 13.7 billion in 2008. The 3% decrease from 2009 to 2010 was mainly due to the impact on depreciation of increased proved reserves. The decrease was partly offset by an increase of 1.1 billion in net impairments which was mainly due to the impairment of the Corrib asset in Ireland. The 25% increase from 2008 to 2009 was due to an increase of NOK 4.6 billion in ordinary depreciation, which was mainly due to new assets coming on stream.

This increase was partly offset by a NOK 1.2 billion decrease in net impairments, which was mainly due to adverse effects of market conditions in 2008.

Depreciation, amortisation and net impairment losses			For the year ended 31 December		
(in NOK billion)	2010	2009	2008	10-09 change	09-08 change
Ordinary depreciations	**15.2**	16.2	11.6	(6 %)	40 %
Impairments	**1.6**	2.6	3.2	(38 %)	(19 %)
Reversal of impairments	**(0.1)**	(1.7)	(1.1)	(94 %)	55 %
Depreciation, amortisation and net impairment losses	**16.7**	17.1	13.7	(2 %)	25 %

Exploration expenditure was NOK 10.8 billion in 2010 compared with NOK 8.7 billion in 2009 and NOK 9.1 billion in 2008. The increase from 2009 to 2010 was mainly due to increased exploration drilling costs and oil sands delineation drilling costs, increased seismic expenditures and higher pre-sanctioning costs. The average cost per well was significantly higher in 2010 compared to the previous year, mainly due to the situation in the US Gulf of Mexico, but also due to a few expensive wells with high equity share and technical challenges relating to some wells. The decrease from 2008 to 2009 was mainly due to a reduction in seismic spending, reduced drilling activity and lower field evaluation costs. The reduction was partly offset by the strengthening of the USD/NOK exchange rate from 2008 to 2009.

			For the year ended 31 December		
Exploration (in NOK billion)	2010	2009	2008	10-09 change	09-08 change
Exploration expenditure (activity)	**10.8**	8.7	9.1	24 %	(4 %)
Expensed, previously capitalised exploration expenditure	**1.5**	5.8	3.0	(74 %)	94%
Capitalised share of current period's exploration activity	**(2.0)**	(3.0)	(2.9)	(34 %)	4 %
Exploration expenses	**10.3**	11.5	9.2	10 %	26 %

Exploration expenses were NOK 10.3 billion in 2010, compared with NOK 11.5 billion in 2009 and NOK 9.2 billion in 2008. The decrease was mainly due to reduction in net impairment effect of capitalised exploration assets of NOK 5.1 billion, partly offset by higher oil sands delineation drilling, higher seismic expenditures and higher pre-sanctioning costs. The increase from 2008 to 2009 is mainly due to the net impairment effect of capitalised exploration assets of NOK 2.9 billion, partly offset by decreases in drilling activity and seismic spending.

In total, 18 exploration and appraisal wells were completed in 2010 and seven wells were announced as discoveries. In 2009, 29 exploration and appraisal wells were completed and seven wells were announced as discoveries, six of which were completed in 2009 while one well was completed in 2008. At year end, nine wells were pending final evaluation. In 2008, 40 exploration and appraisal wells were completed, eight of which were announced as discoveries.

Net operating income in 2010 was NOK 12.6 billion, compared with NOK 2.6 billion in 2009, and NOK 12.8 billion in 2008. The increase from 2009 to 2010 was mainly related to increased prices, which contributed NOK 9.4 billion, increased other income which contributed NOK 1.2 billion, decreased exploration expenses contributing NOK 1.2 billion and decreased depreciations contributing NOK 0.5 billion.

This was partly offset by a reduction in lifted volumes which contributed NOK 1.4 billion and an increase in purchase, operating, selling, general and administrative expenses contributing NOK 0.8 billion.

The decrease from 2008 to 2009 was mainly related to reduced prices, which contributed negatively NOK 14.3 billion, an increase in depreciation, depletion and amortisation of NOK 3.4 billion, an increase in exploration expenses contributing NOK 2.3 billion, a decrease in other income of NOK 1.2 billion mainly related to the sale of assets, and a miscellaneous increase of NOK 0.2 billion. This was partly offset by increased lifted volumes, which positively affected the result by NOK 11.2 billion.

4.1.7 Natural Gas

Gas sales in 2010 were characterised by recovering markets and increasing European gas prices. Trading and sourcing of third party volumes expanded further.

Gas prices developed positively in 2010 compared with price developments in the last quarter of 2009. However, average prices ended lower in 2010 compared to 2009 due to very high prices in the first quarter of 2009. Our volume-weighted average price was NOK 1.72 per scm in 2010 and 1.90 per scm in 2009, a decrease of approximately 9%.

The majority of our long-term gas supply contracts in Europe are indexed to oil products, which means that a change in oil prices will affect the gas markets after a certain time delay (6-9 months). Oil prices increased from the second quarter 2009, and had a positive effect on natural gas price development, particularly from the second half of 2010. In addition, European spot market contracts have seen a strong price recovery since the last quarter in 2009.

All of Statoil's gas produced on the Norwegian continental shelf (NCS) is sold by the Natural Gas business area and purchased from Exploration & Production Norway (EPN) at a market-based internal price. The gradually increasing natural gas sales prices in 2010 were largely offset by an increase in the internal purchase price. Our average internal purchase price was NOK 1.27 per scm in 2010, down from NOK 1.38 per scm in 2009, a decrease of 8%.

Natural gas sales volumes in 2010 were 52.8 bcm, compared to 49.8 bcm in 2009, an increase of 6%. Statoil sold 41.7 bcm of entitlement gas in 2010, a slight increase compared with 2009. In addition, we sold 35.3 bcm of NCS gas on behalf of the Norwegian State's direct financial interest (SDFI). Most of the gas was sold to European energy providers under long-term contracts. Our market share is approximately 20-25% in Germany and France and approximately 15% in the UK and the Netherlands.

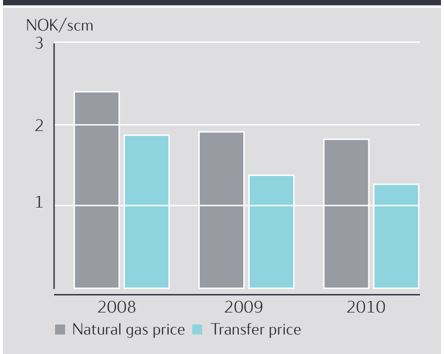
Sales of third party volumes amounted to 11.1 bcm in 2010, compared with 8.4 bcm in 2009, an increase of 32%. The increase was mainly due to optimisation and balancing of our portfolio.

4.1.7.1 Profit and loss analysis

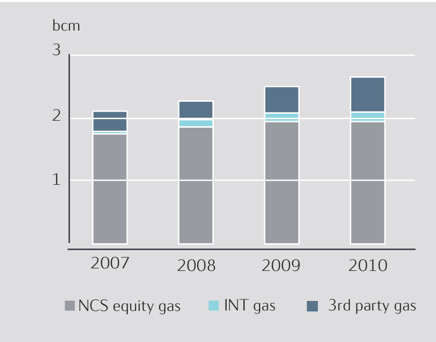
Revenues in Natural Gas largely come from gas sales under long-term gas sales contracts and tariff revenues from transportation and processing facilities. Natural Gas generated revenues of NOK 87.5 billion in 2010.

IFRS income statement (in NOK billion)	2010	2009	For the year ended 31 December 2008	10-09 change	09-08 change
Total revenues and other income	**87.5**	98.6	110.8	(11 %)	(11 %)
Purchase [net of inventory variation]	**61.0**	62.1	80.9	(2 %)	(23 %)
Operating expenses	**14.1**	14.4	13.8	(2 %)	4 %
Selling, general and administrative expenses	**2.0**	0.8	1.3	>100 %	(38 %)
Depreciation, amortisation and net impairment losses	**1.9**	2.8	2.3	(31 %)	22%
Total expenses	**79.0**	80.1	98.3	(1 %)	(19 %)
Net operating income	**8.5**	18.5	12.5	(54 %)	48 %
Operational data:					
Natural gas sales Statoil entitlement (bcm)	**41.7**	41.4	39.3	1 %	5 %
Natural gas sales (third-party volumes) (bcm)	**11.1**	8.4	5.9	33 %	41 %
Natural gas sales (bcm)	**52.8**	49.7	45.2	6 %	10 %
Natural gas sales on commission	**1.5**	1.3	1.4	12 %	(7 %)
Natural gas price (NOK/scm)	**1.72**	1.90	2.40	(10 %)	(21 %)
Transfer price natural gas (NOK/scm)	**1.27**	1.38	1.87	(8 %)	(26 %)
Regularity at delivery point	**100.0 %**	100.0 %	100.0 %	0 %	0 %

Sales price and transfer price



Natural gas sale



Natural Gas generated total revenues and other income of NOK 87.5 billion in 2010, compared with NOK 98.6 billion in 2009 and NOK 110.8 billion in 2008. The 11% total revenue decrease from 2009 to 2010 was mainly due to a 9% decrease in the volume-weighted average sales price reducing the marketing and trading margins, combined with a lower contribution from our processing and transport business. This was partly offset by a 6% increase in volumes sold.

The 11% decrease from 2008 to 2009 was mainly due to lower prices for natural gas throughout 2009 compared with 2008, which was partly offset by a 10% increase in sales volumes.

Purchase, net of inventory variation decreased by 2% from 2009 to 2010 and decreased by 23% from 2008 to 2009. The decrease from 2009 to 2010 was mainly related to an 8% decrease in the transfer price to E&P Norway. The decrease from 2008 to 2009 was mainly related to a 26% decrease in the transfer price to E&P Norway.

Operating expenses decreased by NOK 0.3 billion from 2009 to 2010. The decrease mainly consists of reduced transportation costs due to tariff reliefs relating to the closure of a compressor, production maintenance work and some regulatory problems at Kårstø and Kollsnes during 2010. Operating expenses increased by NOK 0.6 billion from 2008 to 2009. The increase is mainly related to higher operating costs in Gassled, and indirect costs of operation relating to the Cove Point expansion.

The selling, general and administrative expenses increased by NOK 1.2 billion compared with 2009. Most of this increase is related to the onerous contract provision at Cove Point in 2010 which amounts to NOK 0.7 billion. Selling, general and administrative expenses in 2009 decreased by NOK 0.5 billion compared to 2008. The decrease was mainly related to cost sharing with Petoro at Cove Point.

Depreciation, amortisation and impairment costs decreased by NOK 0.9 billion from 2009 to 2010. This decrease is mainly due to Cove Point impairment of NOK 1.0 billion in 2009. Depreciation, amortisation and impairment costs increased by NOK 0.5 billion from 2008 to 2009. The increase is mainly related to impairment at Cove Point.

Net operating income was NOK 8.5 billion in 2010, compared with NOK 18.5 billion in 2009. Seen in realtion to 2009, the result in 2010 was negatively affected by a NOK 6.8 billion decrease on derivatives and an increase in cost provisions of NOK 0.9 billion relating to an onerous contract in connection with a re-gasification terminal in the USA (Cove Point). The decrease in net operating income was also affected by a decrease of 9% in the volume-weighted average sales price reducing the marketing and trading margins, combined with lower contribution from our processing and transport business. This was partly offset by a 6% increase in volumes sold.

Net operating income for 2009 was NOK 18.5 billion, compared with NOK 12.5 billion in 2008. The increase of NOK 6 billion was mainly due to an increased margin between gas sale revenues and gas purchase costs in 2009 compared with 2008, which was partly offset by higher processing and transport income in 2009.

Natural Gas has two main business activities: Processing and transport and marketing and trading. Processing and transport activities mainly consist of our share in Gassled. Marketing and trading activities consist of our gas sales and trading activities. The transportation costs associated with the Natural Gas segment are included in the marketing and trading activity.

Net operating income in **Processing and Transport** was NOK 6.8 billion in 2010, compared with NOK 7.6 billion in 2009. Processing and transport revenue decreased by NOK 0.5 billion, while operating expenses and depreciation increased by NOK 0.2 billion. The income from Gassled was reduced compared to last year, mainly relating to the closure of a compressor at Kårstø, some regularity problems at Kårstø and Kollsnes, and production maintenance work during third quarter of 2010.

In 2009, net operating income amounted to NOK 7.6 billion, compared to NOK 6.3 billion in 2008. Processing and transport revenues increased by NOK 1.3 billion due to higher level of gas transported in 2009, while fixed operating expenses remained at the same level.

Net operating income in **Marketing and Trading** amounted to NOK 1.7 billion in 2010, compared with NOK 10.9 billion in 2009. The decrease of NOK 9.2 billion was largely due to a NOK 6.8 billion decrease in derivatives and increased cost provisions relating to an onerous contract. In addition, a positive volume deviation in 2010 compared with 2009 was more than offset by a negative margin deviation due to decreased sales prices and lower contribution from trading.

Net operating income in 2009 amounted to NOK 10.9 billion, compared with NOK 6.2 billion in 2008. The increase of NOK 4.7 billion was mainly due to a positive contribution from realised trading and optimisation positions in 2009 in addition to a NOK 2.7 billion gain on derivatives in 2009 compared with a NOK 1.2 billion gain in 2008.

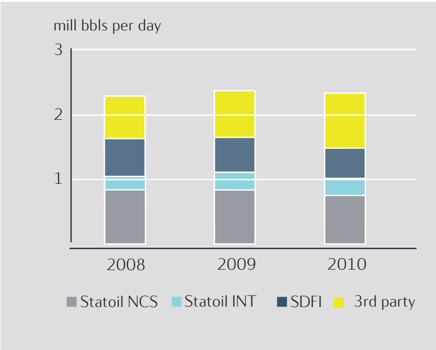
Total natural gas sales were 52.8 bcm (1.87 tcf) in 2010, 49.7 bcm (1.76 tcf) in 2009 and 45.2 bcm (1.60 tcf) in 2008. The 6% increase in gas volumes sold from 2009 to 2010 was mainly due to increased third party volumes. The 10% increase in gas volumes sold from 2008 to 2009 was due to an increase in both our own and third party volumes.

In 2010 **volume-weighted average sales price** was NOK 1.72 per scm, compared to NOK 1.90 per scm in 2009, a decrease of 9% which was mainly due to extraordinary high prices in the first quarter 2009 as a result of the peak in oil product prices in 2008.

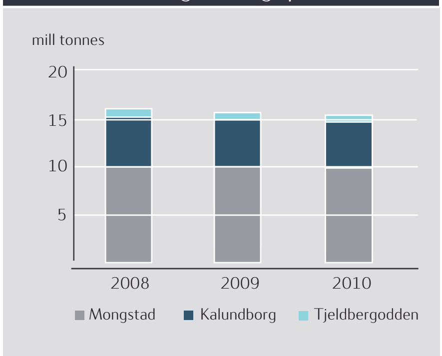
4.1.8 Manufacturing & Marketing

The refining market improved in 2010, but was still challenging. We also had large planned turnarounds in our plants. The forward price structure in the market was less favourable in relation to utilising our available storage capacity.

Traded volumes per day of oil



Manufacturing throughput



Our total capital expenditure was NOK 3.4 billion in 2010, mainly related to projects at our refineries, but also modifications at our South Riding Point terminal in the Bahamas. Capital expenditure was NOK 5.2 billion in 2009 when we acquired the long-term lease of the South Riding Point terminal, and NOK 4.9 billion in 2008.

Oil sales, trading and supply

With average crude, condensate and NGL sales of 2.3 mmbbl per day in 2010, we are one of the world's largest net sellers. Of these daily sales, approximately 1.0 mmbbl were our own volumes, 0.8 mmbbl were third party volumes and 0.5 mmbbl were SDFI volumes. Our average sales volume was 2.4 mmbbl per day in 2009, and 2.3 mmbbl per day in 2008. The average daily third party volumes we sold in 2010 were 0.84 mmbbl, compared with 0.70 mmbbl in 2009 and 0.66 mmbbl in 2008.

Manufacturing

Refinery throughput in 2010 was lower than in 2009 due to planned turnarounds (maintenance shutdowns) at the Mongstad and Kalundborg refineries. Otherwise, regularity was high in the refineries in 2010, and significantly improved in relation to 2009. The Tjeldbergodden methanol plant also had a turnaround in 2010, but production was still higher than 2009 due to depressed methanol market prices and maintenance shutdowns that year.

The refining industry continued to face major challenges in 2010. Even though global oil demand recovered markedly from 2009, refinery overcapacity was still present. This is especially true for the Atlantic Basin where some refineries decided to close operations permanently during 2010. However, margins did improve to some extent in line with increasing demand for refined products, but the improvement was also due to refineries constraining runs.

On 22 October 2010, Statoil Fuel & Retail ASA was listed on the Oslo stock exchange, and Fuel & Retail is now reported as a separate segment.

4.1.8.1 Profit and loss analysis

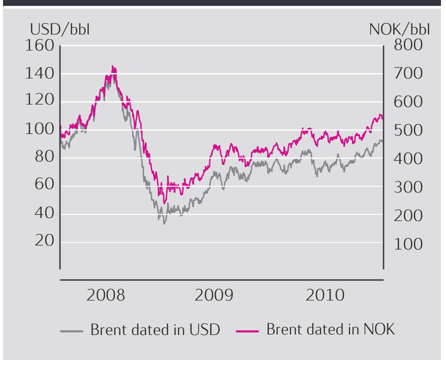
In Manufacturing & Marketing, total revenues and other income increased to NOK 407.2 billion, mainly due to higher oil prices.

Income statement (in NOK billion)	For the year ended 31 December 2010	2009	2008	10-09 change	09-08 change
Total revenues and other income	**407.2**	323.8	495.7	26 %	(35 %)
Purchase [net of inventory variation]	**392.5**	308.0	475.4	27 %	(35 %)
Operating expenses	**11.2**	9.7	13.4	15 %	(28 %)
Selling, general and administrative expenses	**1.5**	1.4	1.2	13 %	14 %
Depreciation, amortisation and net impairment losses	**4.0**	6.5	1.1	(39 %)	>100%
Total expenses	**409.2**	325.6	491.1	26 %	(34 %)
Net operating income	**(2.0)**	(1.8)	4.7	9 %	>(100%)
Operational data:					
FCC margin (USD/bbl)	**5.4**	4.3	8.2	26 %	(48 %)
Contract price methanol (EUR/tonne)	**254.0**	173.0	344.0	47 %	(50 %)

Following the change in segments in the fourth quarter 2010 to report Statoil Fuel & Retail separately, prior periods have been restated to be comparable. See the Consolidated financial statement - note 3 Segments - for further information.

Total revenues and other income were NOK 407.2 NOK billion in 2010, compared with NOK 323.8 billion in 2009 and NOK 495.7 billion in 2008. The increase in 2010 was mainly due to higher prices for crude and other oil products. The average crude price in USD increased by approximately 29% in 2010 compared to 2009, but this was partly offset by a weakening of the average USD exchange rate by almost 4%.

Brent dated in USD and NOK



The decrease from 2008 to 2009 was mainly due to lower prices for crude and other oil products. The average crude price in USD decreased by approximately 37% in 2009 compared to 2008, but this was partly offset by a strengthening of the average USD exchange rate by almost 12%.

Purchase (net of inventory variation) was NOK 392.5 billion in 2010, compared with NOK 308.0 billion in 2009 and NOK 475.4 billion in 2008. The increase in 2010 was mainly due to higher prices for volumes purchased. The decrease from 2008 to 2009 was mainly due to lower prices on volumes purchased.

Operating expenses were NOK 11.2 billion in 2010, compared with NOK 9.7 billion in 2009 and NOK 13.4 billion in 2008. The increase in 2010 was due to the reversal in 2009 of a provision of NOK 1.3 billion related to a take-or-pay contract made in 2008, the South Riding Point crude terminal acquired in the fourth quarter of 2009, and new pipeline and shipping activities. These effects were partly offset by a processing contract ending in 2009. The decrease in 2009 was due to the take-or pay contract (provision in 2008 and reversal in 2009) and lower freight rates.

Selling, general and administrative expenses were NOK 1.5 billion in 2010, compared with NOK 1.4 billion in 2009 and NOK 1.2 billion in 2008. The increase in 2010 was mainly due to the administration of a new time-chartered crude tanker fleet and international trading activities. The increase in 2009 was mainly due to an increase in international trading activities.

Depreciation, amortisation and net impairment losses were NOK 4.0 billion in 2010, compared with NOK 6.5 billion in 2009 and NOK 1.1 billion in 2008. The decrease in 2010 was mainly due to lower impairment losses in Manufacturing, NOK 2.9 billion in 2010 compared with NOK 5.4 billion in 2009. The increase from 2008 to 2009 was due to an impairment loss of NOK 5.4 billion in 2009 in Manufacturing.

In 2010, the **net operating loss** was NOK 2.0 billion, compared with a net operating loss of NOK 1.8 billion in 2009 and a net operating income of NOK 4.7 billion in 2008. The net operating loss in 2010 was affected by an impairment loss on refinery assets (NOK 2.9 billion), a loss on inventory hedge positions that do not qualify for hedge accounting (NOK 1.0 billion), a loss related to an onerous contract regarding a sales contract (NOK 0.4 billion), weaker trading results and turnarounds at the Mongstad and Kalundborg refineries. Positive effects in 2010 were a gain from price change for our operational storage, and higher refining margins and methanol prices.

The net operating loss in 2009 was affected by an impairment loss on refinery assets (NOK 5.4 billion), a loss on inventory hedge positions that do not qualify for hedge accounting (NOK 2.0 billion), and lower refining margins and methanol prices. Positive effects in 2009 were a gain from price change for our operational storage, a reversal of a take-or-pay contract provision (NOK 1.3 billion), and strong trading results.

The net operating income in 2008 was impacted by a positive currency effect on the value of inventories in commercial storage (NOK 3.3 billion), and a gain on inventory hedge positions that do not qualify for hedge accounting (NOK 0.8 billion). Negative effects in 2008 were a loss from price change for our operational storage, a take-or-pay contract provision (NOK 1.3 billion), and strong refining margins and methanol prices.

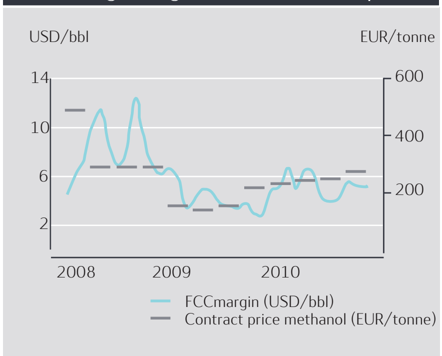
Oil sales, trading and supply

In 2010, net operating income was NOK 1.4 billion, compared with NOK 3.7 billion in 2009 and NOK 4.2 billion in 2008. The net operating income in 2010 was impacted by a loss on inventory hedge positions that do not qualify for hedge accounting (NOK 1.0 billion), loss related to an onerous contract regarding a sales contract (NOK 0.4 billion), and weaker trading results. The latter were mainly due to lower gains from storage strategies under prevailing market conditions with a flattened contango price structure, and losses due to the price drop in May. A gain from a price change for our operational storage was a positive effect in 2010.

The net operating income in 2009 was affected by a gain from a price change for our operational storage and strong trading results, especially in product and gas liquids trading. A loss on inventory hedge positions that do not qualify for hedge accounting (NOK 2.0 billion) was a major negative effect in 2009.

The net operating income in 2008 was affected by a positive currency effect on the value of inventories in commercial storage (NOK 3.3 billion), and a gain on inventory hedge positions that do not qualify for hedge accounting (NOK 0.8 billion) and strong overall trading results. Negative effects in 2008 were a loss from a price change for our operational storage, and negative results in product trading, leading to a scaling down of product trading by the end of the year.

Refining margin and methanol price



Manufacturing

In 2010, the net operating loss was NOK 3.2 billion, compared with a net operating loss of NOK 5.3 billion in 2009 and net operating income of NOK 0.7 billion in 2008. The net operating loss in 2010 was affected by an impairment loss on the Mongstad refinery assets (NOK 2.9 billion), turnarounds at the Mongstad and Kalundborg refineries, and also at the Tjeldbergodden methanol plant. The average refining margin increased by 26% from 2009, but was still lower than the average level during the last ten years. The contract price for methanol increased by 47%.

The net operating loss in 2009 was affected by impairment loss on the Mongstad and Kalundborg refinery assets (NOK 5.4 billion), low refining margins and high operating costs due to the increased activity levels in maintenance and modification. Both the average refining margin and the contract price for methanol decreased by approximately 50% in 2009 as drop in demand led to overcapacity and subsequent pressure on margins and prices. A reversal of a take-or-pay contract provision (NOK 1.3 billion) was a positive effect in 2009.

The net operating income in 2008 was affected by a take-or-pay contract provision (NOK 1.3 billion), and a large turnaround at Mongstad.

4.1.9 Statoil Fuel & Retail

In October 2010, Statoil Fuel & Retail became publicly traded on the Oslo stock exchange as a result of its initial public offering.

4.1.9.1 Profit and loss analysis

Income statement (in NOK billion)	2010	2009	For the year ended 31 December 2008	10-09 change	09-08 change
Total revenues and other income	**65.9**	57.4	73.2	15 %	(22 %)
Purchase [net of inventory variation]	**54.8**	46.9	63.6	17 %	(26 %)
Operating expenses	**0.8**	1.1	1.3	(23 %)	(19 %)
Selling, general and administrative expenses	**6.6**	7.0	7.4	(5 %)	(6 %)
Depreciation, amortisation and net impairment losses	**1.3**	1.2	1.0	8 %	21 %
Total expenses	**63.5**	56.1	73.3	13 %	(23 %)
Net operating income	**2.4**	1.3	(0.1)	86 %	>(100%)

Following the change in segments in the fourth quarter of 2010 to report Statoil Fuel & Retail separately, prior periods have been restated to be comparable, see the Consolidated financial statement - note 3 Segments - for further information.

At the end of 2010, Statoil's ownership interest in Statoil Fuel & Retail ASA was 54%.

Total revenues and other income increased from NOK 57.4 billion in 2009 to NOK 65.9 billion in 2010. The increase was mainly driven by higher underlying refined oil product prices and increased road transportation fuel volumes of 5.9%. The increase in volume was primarily due to organic growth and the consolidation of JET-branded stations in the second half of 2009. The cold weather and high electricity prices in the first and fourth quarters of 2010 resulted in higher demand for stationary energy such as heating oil, compared with the same period in 2009. The decrease from NOK 73.2 billion in 2008 to NOK 57.4 billion in 2009 was driven by a decline in road transportation fuel volumes of 2.7% due to the closure and divestment of 227 Hydro and Uno-X stations in Sweden during 2009 and the impact of the global financial crisis on the Baltic countries. In addition reduced refined oil product prices and a decline in revenues from convenience sales of NOK 1.3 billion caused by lower demand as a result of the global financial crisis also contributed to the decrease.

Purchase, net of inventory variation increased from NOK 46.9 billion in 2009 to NOK 54.8 billion in 2010, explained by the same factors described under total revenues and other income. The decrease from 2008 to 2009 was primarily due to reduced refined oil product prices combined with a decline in sales volumes described above.

Operating expenses decreased from NOK 1.1 million in 2009 to NOK 0.8 million in 2010. The reduction was primarily due to divestment of non-core business activities and the implementation of cost reductions. The decrease from NOK 1.3 billion in 2008 to NOK 1.1 billion in 2009 was driven by the implementation of cost reductions and efficiency initiatives, including divestments of non-core business activities.

Selling, general and administrative expenses decreased by 6% in 2010 compared to 2009. The decrease was mainly driven by divestments of non-core business activities, improved portfolio management, reduced credit losses in Central and Eastern Europe and the closure of stations with low throughput and profitability in Scandinavia during 2010. This decrease was partly offset by increased administrative expenses due to increased corporate headquarter costs as Statoil Fuel & Retail was separated from Statoil ASA and listed on the Oslo tock exchange in October 2010. Selling, general and administrative expenses also decreased by 5% from 2008 to 2009.

Depreciation, amortisation and net impairment losses totalled NOK 1.3 billion in 2010, compared to NOK 1.2 billion in 2009. The increase was mainly due to impairment of NOK 0.1 billion in 2010, which was largely related to the Statoil Fuel & Retail network in Lithuania.
The increase of NOK 0.2 billion in 2009 compared to 2008 was mainly due to additions of property, plant and equipment of NOK 2.0 billion during 2009, in addition to the consolidation of the JET business in the second half of 2009.

In 2010, the **net operating income** was NOK 2.4 billion, compared with a net operating income of NOK 1.3 billion in 2009. Net operating income in 2010 was affected by increased volumes and prices as described above, in addition to effect of improved use of micro market pricing and implementation of the COCO fuel concept. Moreover, the consolidation of JET-branded stations in the second half of 2009 and continued implementation of cost reductions and efficiency initiatives, including divestments of non-core business activities, contributed to increased net operating income in 2010 compared with 2009. A gain of NOK 0.3 billion from the sale of Swedegas was also included in other income in 2010. The increase in net operating income by NOK 1.4 billion in 2009 compared to 2008, was driven by increased road transportation fuel margins, particularly in Scandinavia, which more than offset the decreased contribution from convenience sales caused by the financial crisis. In addition, the implementation of cost reductions and efficiency initiatives, including divestments of non-core business activities, contributed to the improved performance.

4.1.10 Eliminations and other operations

Eliminations and other operations for the years endring 31 December 2010, 2009 and 2008.

Other operations consist of the activities of Corporate Services, Corporate Centre, Group Finance and the two corporate technical service providers, Technology and New Energy, and Projects.

In connection with our other operations, we recorded a net operating income of NOK 0.2 billion in 2010, compared with a loss of NOK 1.1 billion in 2009 and a loss of NOK 0.7 billion in 2008. The increase in net operating income is mainly related to a gain from the sale of Tampnet, a communication network between offshore installations, to HitecVision. Cost reductions also contributed positively to the development.

The increased loss from 2008 to 2009 was primarily due to the gain from the sale of IS Partner AS which was recorded in 2008.

4.1.11 Definitions of reported volumes

Here we explain some of the terms used when reporting our volumes, such as lifted entitlement volumes, equity volumes, entitlement volumes and proved reserves.

Volumes that explain revenues

In explaining revenues and changes in revenues, we report **lifted entitlement volumes**. This is because we can only recognise income from volumes to which we have legal title, and such title typically arises upon lifting (i.e. loading onto a vessel) of the volumes. Under a production sharing agreement (PSA), we are only entitled to receive and sell certain parts of the volumes produced, and we therefore refer to entitlement volumes for revenue recognition purposes. The difference between equity and entitlement volumes is described in more detail below.

Volumes of lifted liquids (crude oil, condensate and natural gas liquids) and natural gas correlate with production over time, but they may be higher or lower than entitlement production for the period due to operational factors that affect the timing ofthe lifting of the liquids from the fields by Statoil-chartered vessels. Volumes of natural gas produced on the Norwegian continental shelf (NCS) are deemed to be equal to lifted volumes of natural gas from the NCS.

Volumes of lifted liquids and natural gas may be sold or put into storage. The volumes that give rise to revenues from the sale of liquids and natural gas in the period are therefore equal to lifted volumes plus changes in inventories of liquids and natural gas.

Volumes that explain operating expenses

In explaining operating expenses, in total and production cost per barrel of oil equivalents, we believe that **produced (equity) volumes** are a better indicator of activity levels than lifted volumes. Moreover, we believe that equity volumes are a better indicator of the activity level under PSAs than entitlement volumes, since our capital expenditure and operating expenses under such contracts are linked to equity volumes produced rather than to entitlement volumes received.

Equity volumes represent produced volumes that correspond to Statoil's percentage ownership interest in a particular field. **Entitlement volumes**, on the other hand, represent Statoil's share of the volumes distributed under a PSA to the partners in the field, which are subject to deductions for, among other things, royalties and the host government's share of profit oil. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes. The main countries in which we operate under PSAs are Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia.

Volumes of proved reserves

Proved reserves are entitlement volumes recognised as reserves in accordance with the definitions of Rules 4-10 (a) of Regulation S-X and relevant guidance from the Securities and Exchange Commission (SEC) of the United States. They represent volumes that with reasonable certainty will be produced and to which we will have entitlement in the future. See section Operational review - Proved oil and gas reserves and note 35 - Supplementary oil and gas information in the Consolidated Financial Statements in this report, for details about how we measure and report proved reserves.

4.2 Liquidity and capital resources

4.2.1 Review of cash flows

The cash flows provided by operations were NOK 80.8 billion in 2010. As of 31 December 2010, the debt to capital employed ratio was 23.5%, and cash and cash equivalents and current financial investments totalled NOK 41.8 billion.

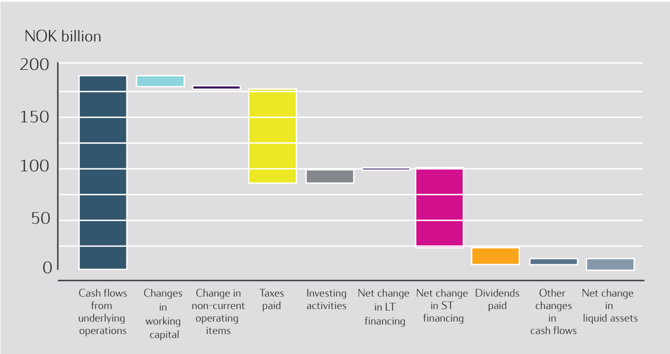
Condensed cash flow statement (in NOK billion)	2010	2009	For the year ended 31 December 2008	Change 10-09	Change 09-08
Cash flows from underlying operations	**190.1**	181.9	239.9	8.2	(57.9)
Cash flows from (to) changes in working capital	**(14.8)**	(2.0)	1.3	(12.8)	(3.4)
Taxes paid	**(92.3)**	(100.5)	(139.6)	8.2	39.1
Other changes	**(2.2)**	(6.4)	0.9	4.2	(7.4)
Cash flows provided by operations	**80.8**	73.0	102.5	7.8	(29.5)
Acquisitions	**0.0**	0.0	(13.1)	0.0	13.1
Additions to PP&E and intangible assets	**(78.3)**	(75.2)	(76.2)	(3.1)	1.0
Proceeds from sales	**6.0**	1.4	5.4	4.6	(3.9)
Other changes	**(4.0)**	(1.6)	(1.9)	(2.3)	0.3
Cash flows used in investing activities	**(76.2)**	(75.4)	(85.8)	(0.9)	10.5
Net change in long-term borrowing	**12.3**	41.4	(0.3)	(29.1)	41.7
Net change in short-term borrowing	**2.2**	(7.1)	10.5	9.3	(17.6)
Dividends paid	**(19.1)**	(23.1)	(27.1)	4.0	4.0
Other changes	**5.2**	0.1	(0.1)	5.1	0.2
Cash flows from (used in) financing activities	**0.6**	11.3	(17.0)	(10.7)	28.3
Net increase (decrease) in cash flows	**5.2**	8.9	(0.3)	(3.8)	9.3

Cash flows provided by operations

Statoil's primary source of cash flow consists of funds generated by operations. The cash flows provided by operations amounted to NOK 80.8 billion in 2010, compared with NOK 73.0 billion in 2009. The increase of NOK 7.8 billion was primarily due to NOK 8.2 billion higher cash flows from underlying activities and NOK 8.2 billion lower tax payments. These changes were offset by negative changes in working capital contributing NOK 12.8 billion.

The cash flows provided by operations were NOK 73.0 billion in 2009, compared with NOK 102.5 billion in 2008. The decrease of NOK 29.5 billion was primarily due to a NOK 57.9 billion decrease in cash flows from underlying operations, an increase of NOK 7.0 billion in cash flows used as working capital and a decrease of NOK 3.7 billion in cash flows used for non-current items relating to operating activities. These effects were partly offset by a decrease of NOK 39.1 billion in taxes paid.

Sources and use of cash flows in 2010



Cash flows used in investing activities amounted to NOK 76.2 billion in 2010, an increase of NOK 0.8 billion from 2009. Proceeds from sales increased by 4.6 billion, mainly related to prepayments from the sale of interests in the Kai Kos Dehseh oil sands development and the agreed sale of a share of our Peregrino asset.

Approximately 54% of the investments in 2010 were investments in assets expected to contribute to growth in oil and gas production, while approximately 32% relate to investments in currently producing fields. The remaining 14% represent investments in Statoil's other activities.

Cash flows used in investing activities amounted to NOK 75.4 billion in 2009, a decrease of NOK 10.5 billion from 2008. The decrease mostly stemmed from acquisitions paid for in 2008, partly offset by a reduction of NOK 3.9 billion in proceeds from sales.

Approximately 55% of the investments in 2009 were investments in assets expected to contribute to growth in oil and gas production, while approximately 35% related to investments in currently producing fields. The remaining 10% represented investments in Statoil's other activities.

Gross investments are defined as additions to property, plant and equipment (including capitalised financial lease), capitalised exploration expenditure, intangible assets, long-term share investments and non-current loans granted. Gross investments amounted to NOK 84.4 billion in 2010 and remain at the same level as in 2009, when gross investments amounted to NOK 84.3 billion. The increased proceeds from sales in 2010 compared with 2009 were offset by decreased financial lease in the same period.

Gross investments		For the year ended 31 December			
(in NOK billion)	2010	2009	2008	10-09 change	09-08 change
- E&P Norway	**31.9**	34.9	34.9	(9 %)	(0 %)
- International E&P	**44.4**	39.4	48.7	13 %	(19 %)
- Natural Gas	**3.0**	2.5	2.0	18 %	24 %
- Manufacturing & Marketing	**3.3**	3.0	4.9	11 %	(39 %)
- Fuel & Retail	**0.8**	1.5	3.6	(46 %)	(58 %)
- Other	**1.0**	3.0	1.3	(67 %)	>100%
Gross investments	**84.4**	84.3	95.4	0 %	(12 %)

Gross investments amounted to NOK 95.4 billion in 2008. Gross investments were higher in 2008 than in 2010 and 2009 due to significant investments in 2008, most notably in the remaining 50% share of the Peregrino development off the coast of Brazil and the investment in a 32.5% share in the Marcellus shale gas development in the USA.

Cash flows used in investing activities are reconciled with gross investments in the table below. In 2010, the difference between cash flows to investments and gross investments is largely related to proceeds from sales of assets. In 2009, the difference between cash flows to investments and gross investments is largely related to financial lease, whereas in 2008, the difference was mostly related to proceeds from sales of assets and other changes in non-current loans granted and joint venture activities.

		For the year ended 31 December	
Reconciliation of cash flow to gross investments (in NOK billion)	2010	2009	2008
Cash flows to investments	**76.2**	75.4	85.8
Proceeds from sales of assets	**6.0**	1.4	5.4
Financial lease	**1.4**	6.9	0.3
Other changes in non-current loans granted and JV balances	**0.8**	0.6	3.9
Gross investments	**84.4**	84.3	95.4

Net cash flows provided by (used in) financing activities

Net cash flows provided by (used in) financing activities in 2010 amounted to a positive NOK 0.6 billion, compared with a positive NOK 11.3 billion in 2009. The NOK 10.7 billion decrease is mainly related to a net change in non-current loans of NOK 29.1 billion due to fewer new bonds being issued in 2010 compared with 2009. The decrease was partly offset by a change in the net cash flow from non-controlling interests of NOK 5.1 billion. This was mainly related to cash received from Statoil Fuel & Retail ASA shareholders for 46% of Statoil Fuel & Retail's shares, a change of NOK 4.0 billion in dividends paid and a change of NOK 9.3 billion in net current loans, bank overdrafts and other (other includes collateral liabilities that are used as the security for trading activities).

New non-current loans in 2010 amounted to NOK 15.6 billion, compared with NOK 46.3 billion in 2009. Of the total new non-current loans in 2010, NOK 4.0 billion is related to the funding of Statoil Fuel & Retail ASA. The proceeds from the SFR drawdown were applied to repay intercompany debt to Statoil ASA. NOK 3.2 billion of non-current loans was repaid in 2010, compared with NOK 4.9 billion in 2009.

Net cash flows provided by (used in) financing activities in 2010 include a dividend of NOK 19.1 billion paid by Statoil ASA to shareholders relating to the annual accounts for 2009, while the dividend paid by Statoil ASA to its shareholders in 2009 relating to the annual accounts for 2008 amounted to NOK 23.1 billion.

Net cash flows provided by (used in) financing activities in 2009 amounted to NOK 11.3 billion, compared to NOK 17.0 billion for 2008. The NOK 28.3 billion change was mainly related to net change in non-current loans of NOK 41.7, NOK 4.0 billion less paid in dividends 2009, which was partly offset by the repayment of net current loans, bank overdrafts and other (other includes collateral liabilities that are used as the security for trading activities) of NOK 7.1 billion in 2009, compared with an increase of NOK 10.5 billion in 2008.

New non-current loans in 2009 amounted to NOK 46.3 billion compared with NOK 2.6 billion in 2008. This was due to the need to ensure a level of financial flexibility in a lower oil-price environment. NOK 4.9 billion of non-current loans were repaid in 2009, compared with NOK 2.9 billion in 2008.

Net cash flows provided by (used in) financing activities in 2009 included a dividend of NOK 23.1 billion paid by Statoil ASA to shareholders relating to the annual accounts for 2008, while the dividend paid by Statoil ASA to its shareholders in 2008 relating to the annual accounts for 2007 amounted to NOK 27.1 billion.

4.2.2 Selected balance sheet information

The following tables contain selected financial information relating to our balance sheet and financial ratios that form part of the basis for the subsequent analysis of financial assets and liabilities.

Selected financial data - Balance sheet (in NOK billion)	For the year ended 31 December 2010	2009
ASSETS		
Non-current assets		
Property, plant and equipment	348.2	340.8
Intangible assets	39.7	54.3
Equity accounted investments	13.9	10.1
Deferred tax assets	1.9	2.0
Pension assets	5.3	2.7
Financial investments	15.4	13.3
Derivative financial instruments	20.6	17.6
Financial receivables	4.5	5.7
Total non-current assets	449.4	446.5
Current assets		
Inventories	23.6	20.2
Trade and other receivables	76.1	58.9
Current tax receivables	1.1	0.2
Derivative financial instruments	6.1	5.4
Financial investments	11.5	7.0
Cash and cash equivalents	30.3	24.7
Total current assets	148.8	116.4
Assets classified as held for sale	44.9	0.0
TOTAL ASSETS	643.0	562.8

Selected financial data - Balance sheet (in NOK billion)	For the year ended 31 December 2010	2009
EQUITY AND LIABILITIES		
Equity		
Share capital	8.0	8.0
Treasury shares	(0.0)	(0.0)
Additional paid-in capital	41.8	41.7
Add. paid-in cap. rel.to treasury shares	(1.0)	(0.8)
Retained earnings	164.9	145.9
Other reserves	5.8	3.6
Statoil shareholder's equity	219.5	198.3
Non-controlling interests	6.9	1.8
Total equity	226.4	200.1
Non-current liabilities		
Financial liabilities	99.8	96.0
Derivative financial instruments	3.4	1.7
Deferred tax liabilities	78.1	76.3
Pension liabilities	22.1	21.1
Asset retirement obligations, other provisions ans other liabilities	67.9	55.8
Total non-current liabilities	271.3	250.9
Current liabilities		
Trade and other payables	73.6	59.8
Current tax payable	46.7	41.0
Financial liabilities	11.7	8.1
Derivative financial instruments	4.2	2.9
Total current liabilities	136.1	111.8
Liabilities directly associated with the assets classified as held for sale	9.2	0.0
Total liabilities	416.6	362.7
TOTAL EQUITY AND LIABILITIES	643.0	562.8

Other financial information	Year ended 31 December 2010	2009	2008
Net debt to capital employed (GAAP basis) (1)	**23.5 %**	26.6 %	17.8 %
Net debt to capital employed (2)	**24.6 %**	27.3 %	17.5 %
After-tax return on average capital employed (GAAP basis) (3)	**15.4 %**	10.5 %	21.0 %
Ratio of earnings to fixed charges (4)	**18.1**	7.1	52.1

(1) As calculated according to GAAP. 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. Capital employed is net debt, shareholders' equity and minority interest.

(2) As adjusted. In order to calculate the net debt to capital employed ratio that our management makes use of internally and which we report to the market, we make adjustments to capital employed as it would be reported under GAAP to adjust for project financing exposure that does not correlate to the underlying exposure and to add into the capital employed measure interest-bearing elements which are classified together with non-interest-bearing elements under GAAP. See report section Financial analysis and review - Non-GAAP measures for a reconciliation of capital employed and a description of why we make use of this measure.

(3) As calculated in accordance with GAAP. After-tax return on average capital employed (ROACE) is equal to net income before minority interest and before after-tax net financial items, divided by average capital employed over the last 12 months.

(4) Based on IFRS. For the purpose of these ratios, earnings consist of the income before (i) tax, (ii) minority interest, (iii) amortization of capitalized interest and (iv) fixed charges (which have been adjusted for capitalized interest) and after adjustment for unremitted earnings from equity accounted entities. Fixed charges consist of interest (including capitalized interest) and estimated interest within operating leases.

4.2.3 Financial assets and liabilities

Gross financial liabilities amounted to NOK 111.5 billion at 31 December 2010, while net financial liabilities were NOK 69.7 billion. The net debt to capital employed ratio was 23.5% at 31 December 2010.

Current items

Current items (total current assets minus total current liabilities) were positive in the amount of NOK 48.3 billion at 31 December 2010, compared to NOK 4.7 billion at 31 December 2009

The increase of NOK 43.6 billion was due to an increase in current receivables such as trade and other receivables of NOK 18.2 billion, held for sale of NOK 44.9 billion, inventories of NOK 3.4 billion, financial investments of NOK 4.5 billion and cash and cash equivalents of NOK 5.6 billion. This was partly offset by an increase in current liabilities such as trade and other payables of NOK 22.1, current taxes payable of NOK 5.8 billion and financial liabilities of NOK 3.6 billion.

We believe that, given Statoil's established liquidity reserves (including committed credit facilities) and Statoil's credit rating and access to capital markets, Statoil has sufficient working capital for its foreseeable requirements. Our main sources of liquidity are described below.

Liquidity

Our annual cash flow from operations is highly dependent on oil and gas prices and our levels of production. It is only influenced to a small degree by seasonality and maintenance turnarounds. Fluctuations in oil and gas prices, which are outside our control, will cause changes in our cash flows. We will use available liquidity to finance Norwegian petroleum tax payments (due on 1 February, 1 April, 1 June, 1 August, 1 October and 1 December each year), any dividend payment and investments. Our investment programme is spread over the year. There may be a gap between funds from operations and funds required to fund investments, which will be financed by short and long-term borrowings. We aim to keep ratios relating to net debt at levels consistent with our objective of maintaining our long-term credit rating at least within the single A category. In this context, Statoil carries out various risk assessments, some of them in line with financial matrices used by S&P and Moody's, such as funds from operations over net debt and net debt to capital employed.

Our long-term and short-term ratings from Moody's are Aa2 and P-1, respectively. Our long-term rating from Standard & Poor's was raised to AA- in August 2007, reflecting the majority ownership by the Norwegian State. Standard & Poor's short-term rating of Statoil is A-1+. The current rating outlook is "Stable" from both agencies.

Management of the portfolio of security investments, mainly related to equity securities, is held by our insurance capitive. Statoil Forsikring AS and commercial papers and money market investments held by Statoil ASA.

As of 31 December 2010, cash and cash equivalents and current financial investments amounted in total to NOK 41.8 billion, including NOK 30.3 billion in cash and cash equivalents and NOK 11.5 billion in current financial investments (domestic and international capital market investments). Cash and cash equivalents include NOK 2.6 billion deposited with Statoil's US dollar-denominated bank account in Nigeria. There are certain restrictions on the use of cash from Statoil's Nigerian operations following an injunction against Statoil by the Nigerian courts relating to an ongoing litigation claim. Both the injunction and the disputed claim have been appealed. Approximately 44% of our liquid assets were held in EUR-denominated assets, 21% in USD, 16% in NOK and 19% in other currencies (GBP, DKK, CAD, BRL), before the effect of currency swaps and forward contracts.

As of 31 December 2009, cash and cash equivalents and current financial investments amounted in total to NOK 31.7 billion, including NOK 24.7 billion in cash and cash equivalents and NOK 7.0 billion of current financial investments (domestic and international capital market investments). Approximately 46% of our liquid assets were held in NOK-denominated assets, 26% in USD, 14% in EUR and 15% in other currencies (GBP, CAD, BRL), before the effect of currency swaps and forward contracts.

Compared with year end 2009, cash and cash equivalents increased by NOK 5.6 billion and current financial investments increased by NOK 4.5 billion during 2010. The increase in liquid assets during 2010 was mainly due to high cash flow from operations in combination with high investment activity.

Our general policy is to maintain a liquidity reserve in the form of cash and cash equivalents in our balance sheet, and committed, unused credit facilities and credit lines in order 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, and when market conditions are considered favourable.

On 20 December 2010 the agreement for a USD 3 billion multicurrency revolving credit facility for Statoil ASA was signed with a group of 20 international banks. The facility replaced the company's USD 2 billion revolving credit facility which Statoil terminated as of 23 December 2010. The facility has a term of five years until December 2015, but includes two one-year extension options that may extend the facility to December 2017. Statoil Petroleum AS is the guarantor for the facility. One third of the facility, may also be utilised in the form of swingline advances, i.e. drawdowns on a committed swingline advance facility, available on a same day notice and with maximum maturities of ten days. Statoil Petroleum AS is guarantor for the facility.

To secure necessary financial flexibility, Statoil ASA issued new bonds in 2010 of USD 1.25 billion of notes maturing in August 2017 and USD 0.75 billion of notes maturing in August 2040, an aggregate of NOK 11.5 billion. Correspondingly Statoil ASA issued new bonds in 2009 of GBP 800 million due in March 2031, EUR 1.2 billion due in March 2021, EUR 1.3 billion due in March 2015, USD 0.5 billion due in April 2014, USD 1.5 billion due in April 2019 and USD 0.9 billion due in October 2014, an aggregate of NOK 46.3 billion in total. All of the bonds are guaranteed by Statoil Petroleum AS.

On 1 November 2010 Statoil Fuel & Retail ASA drew down NOK 4.0 billion on its term loan facility, maturing in 2013. The facility is part of a multicurrency term and revolving loan facility in the aggregate amount of NOK 7.0 billion, that has been entered into with nine international banks. In addition to the NOK 4.0 billion three-year term loan already drawn, the total facility agreement includes a NOK 3.0 billion five-year revolving loan facility.

In 2011, Statoil aims to continue to secure necessary financial flexibility and, depending, among other things, on oil and gas price developments, it may issue bonds should market conditions be viewed as attractive. See section Risk review - Risk management - Managing financial risk - Liquidity risk, for more information about liquidity.

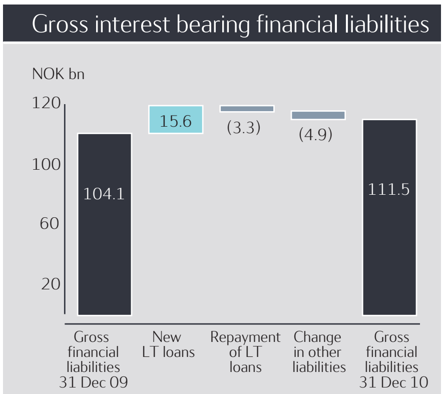
Gross interest-bearing financial liabilities (non-current financial liabilities and current financial liabilities)

Gross interest-bearing financial liabilities were NOK 111.5 billion at 31 December 2010, compared to NOK 104.1 billion at 31 December 2009. The NOK 7.4 billion increase was due to a combination of an increase of NOK 3.8 billion in non-current financial liabilities and an increase of NOK 3.6 billion in current financial liabilities.

On 17 August 2010 Statoil ASA issued USD 1.25 billion of notes maturing in August 2017 and USD 0.75 billion of notes maturing in August 2040, an aggregate of NOK 11.5 billion. All of the bonds are guaranteed by Statoil Petroleum AS.

On 1 November 2010 Statoil Fuel & Retail ASA drew down NOK 4.0 billion on its term loan facility, maturing in 2013. For further information see the section on Liquidity above.

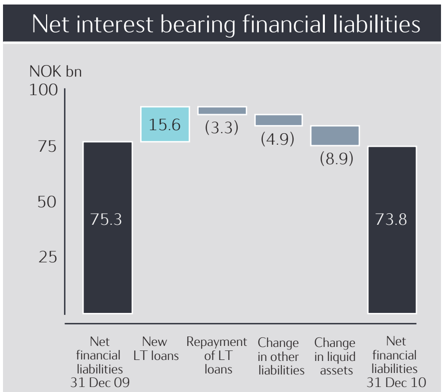
At 31 December 2009, the financial lease of NOK 7.4 billion related to the Peregrino FPSO vessel, was included in non-current financial liabilities. At 31 December 2010, the financial lease of NOK 8.6 billion relating to the Peregrino FPSO vessel, was reclassified from non-current financial liabilities to held for sale.



For risk management purposes, currency swaps are used to ensure that Statoil keeps long-term interest-bearing debt in USD. As a result, most of the group's non-current financial liabilities are exposed to changes in the USDNOK exchange rate.

Net interest-bearing financial liabilities
Net interest-bearing financial liabilities were NOK 69.7 billion at 31 December 2010, compared to NOK 72.4 billion at 31 December 2009. The decrease of NOK 2.7 billion was mainly related to an increase in gross financial liabilities of NOK 7.4 billion, offset by an increase in cash and cash equivalents and current financial investments of NOK 10.1 billion.

Adjusted net interest-bearing financial liabilities were NOK 73.8 billion at 31 December 2010, compared to NOK 75.3 billion at 31 December 2009. The decrease of NOK 1.5 billion was mainly related to an increase in gross financial liabilities of NOK 7.4 billion and a change in adjustments to net interest-bearing debt of NOK 1.2 billion, offset by an increase in cash and cash equivalents and current financial investments of NOK 10.1 billion.



The net debt to capital employed ratio
The net debt to capital employed ratio before adjustments, defined as net interest-bearing debt in relation to capital employed, was 23.5% in 2010, compared with 26.6% in 2009

The adjusted net debt to capital employed ratio was 24.6% at 31 December 2010, compared to 27.3% at 31 December 2009. The 2.7% decrease was mainly related to a decrease in net financial liabilities of NOK 1.5 billion, in combination with an increase in capital employed of NOK 24.8 billion.

In the calculation of net interest-bearing debt, we make certain adjustments, which make net interest-bearing debt and the net debt to capital employed ratio non-GAAP financial measures. For an explanation and calculation of the ratio, see report section Financial analysis and review - Non-GAAP measures - Net debt to capital employed ratio.

The group's borrowing needs are mainly covered through the issuing of short-term and long-term securities, including utilisation of a US Commercial Paper Programme and a Euro Medium Term Note (EMTN) Programme (the limits of the programme being USD 4 billion and USD 6 billion, respectively), and through draw-downs under committed credit facilities and credit lines. After the effect of currency swaps, 100% of our borrowings are in USD.

Our **financial policies** take into consideration funding sources, the maturity profile of long-term debt, interest rate risk management, currency risk and the management of liquid assets. Our borrowings are denominated in various currencies and swapped into USD, since the largest proportion of our net cash flow is denominated in USD. In addition, we use interest rate derivatives, primarily consisting of interest rate swaps, to manage the interest rate risk of our long-term debt portfolio.

The company's central finance function manages the funding, liability and liquidity activities at group level on the basis of adopted financial policies.

Cash, cash equivalents and current financial investments
Cash, cash equivalents and current financial investments amounted to NOK 41.8 billion at 31 December 2010, compared to NOK 31.7 billion at 31 December 2009. The NOK 10.1 billion increase reflects the high cash flow from operations in combination with new long-term debt in 2010, offset by high investment activity during both 2009 and 2010. Cash and cash equivalents were NOK 30.3 billion at 31 December 2010, compared to NOK 24.7 billion at 31 December 2009. Current financial investments, which are part of our cash management, amounted to NOK 11.5 billion at 31 December 2010, compared to NOK 7.0 billion at 31 December 2009.

4.2.4 Principal contractual obligations

The table summarises our principal contractual obligations and other commercial commitments as of 31 December 2010.

The table includes contractual obligations, but excludes derivatives and other hedging instruments as well as asset retirement obligations, as these obligations for the most part are expected to lead to cash disbursements more than five years in the future. Obligations payable by Statoil to unconsolidated equity affiliates are included gross in the table. Where Statoil includes both an ownership interest and the transport capacity cost for a pipeline in the consolidated accounts, the amounts in the table include the transport commitments that exceed Statoil's ownership share. See also report section Risk review - Risk management - Disclosures about market risk, for more information.

	As at 31 December, 2010 Payment due by period *				
Contractual obligations (in NOK billion)	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Undiscounted non-current financial liabilities	8.6	14.8	34.0	89.6	147.0
Minimum operating lease payments	17.6	28.2	10.0	11.1	67.0
Nominal minimum payments related to transport capacity, terminal capacity and similar commitments	8.1	14.2	12.9	34.7	69.8
Total contractual obligations	34.3	57.2	56.9	135.4	283.8

* "Less than 1 year" represents 2010; "1-3 years" represents 2011 and 2012, "3-5 years" represents 2013 and 2014, while "More than 5 years" includes amounts for 2015 and later periods.

Non-current financial liabilities in the table represent principal payment obligations. For information on interest commitments relating to long-term debt, reference is made to note 23 - Non-current financial liabilities and note 28 - Leases, to our Consolidated Financial Statements included in this report.

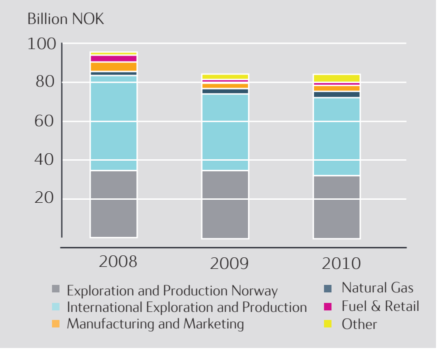
Contractual obligations relating to capital expenditures, acquisitions of intangible assets and construction in progress amounted to NOK 41.7 billion as of 31 December 2010, payment of NOK 22.9 billion of which are due within one year.

The group's projected pension benefit obligation was NOK 67.8 billion, and the fair value of plan assets amounted to NOK 51.0 billion as of 31 December 2010. Actuarial losses amounted to NOK 33 million as of 31 December 2010 and are reported as part of the Statement of comprehensive income (equity). Company contributions are mainly related to employees in Norway.

4.2.5 Investments

Our investments in 2010 were at the same level as in 2009.

Investments



Capital expenditure

Our capital expenditures from 2008 through 2010 in our five principal business segments are described below, including the allocation per segment as a percentage of gross investments. Capital expenditure is expected to amount to approximately USD 16.0 billion in 2011, compared to USD 13.7 billion in 2010 (exclusive of capitalisation of financial leases).

Gross investments (in NOK billion)	2010	2009	For the year ended 31 December 2008	10-09 change	09-08 change
- E&P Norway	**31.9**	34.9	34.9	(9 %)	(0 %)
- International E&P	**44.4**	39.4	48.7	13 %	(19 %)
- Natural Gas	**3.0**	2.5	2.0	18 %	24 %
- Manufacturing & Marketing	**3.3**	3.0	4.9	11 %	(39 %)
- Fuel & Retail	**0.8**	1.5	3.6	(46 %)	(58 %)
- Other	**1.0**	3.0	1.3	(67 %)	>100%
Gross investments	**84.4**	84.3	95.4	0 %	(12 %)

Gross investments (in NOK billion)	2010	% of total	2009	For the year ended 31 December % of total	2008	% of total
- E&P Norway	**31.9**	38 %	34.9	41 %	34.9	37 %
- International E&P	**44.4**	53 %	39.4	47 %	48.7	51 %
- Natural Gas	**3.0**	4 %	2.5	3 %	2.0	2 %
- Manufacturing & Marketing	**3.3**	4 %	3.0	4 %	4.9	5 %
- Fuel & Retail	**0.8**	1 %	1.5	2 %	3.6	4 %
- Other	**1.0**	1 %	3.0	4 %	1.3	1 %
Total gross investments	**84.4**	100 %	84.3	100 %	95.4	100 %

This section describes our estimated capital expenditure for 2011 relating to potential capital expenditure requirements for the principal investment opportunities available to us and other capital projects currently under consideration. The figure is based on Statoil developing organically, and it excludes possible expenditures relating to acquisitions. The expenditure estimates and descriptions of investments in the segment descriptions below could therefore differ materially from the actual expenditure. For more information about the various projects in each of the segments, see the respective sub-sections described under the Operational and financial review.

We finance our capital expenditures both internally and externally. For more information, see section Financial analysis and review - Liquidity and capital resources - Financial assets and liabilities.

A substantial proportion of our 2011 capital expenditure will be spent on ongoing development projects such as Skarv, Gudrun, Goliat, Visund South, Valemon, the Gullfaks fields and IOR projects.

We currently estimate that a substantial proportion of our 2011 capital expenditure will be spent on the following ongoing and planned development projects: Pazflor, CLOV and PSVM in Angola, Tahiti, St. Malo and BigFoot in the US Gulf of Mexico, Marcellus Shale Gas and Eagle Ford onshore USA, and West Qurna 2 in Iraq.

We currently estimate that most of the 2011 capital expenditures will be spent on projects relating to upgrading of the Kårstø processing plant and the Gassled transportation system, and on transport solutions for Marcellus Shale Gas and Eagle Ford. In addition, projects are under execution to increase our flexibility to move gas in time, to improve robustness in relation to delivery obligations and to exploit opportunities relating to daily and seasonal gas price fluctuations. These projects involve both Gassled on the Norwegian continental shelf (NCS) and our assets in the UK.

We are focussing some of our capital expenditure on upgrading our refineries in order to increase robustness and flexibility, as well as developing extra heavy oil value chains based on E&P assets. The main projects at Mongstad in 2011 are modifications to improve performance in relation to health, safety and environment. At Kalundborg, the main focus is on infrastructure improvements, and at the Bahamian South Riding Point crude terminal, we are upgrading the terminal to enable it to take new, potentially heavier crudes.

As illustrated in the section Financial analysis and review - Liquidity and capital resources - Principal contractual obligations, we have committed to certain investments in the future. The proportion of estimated investments that we have committed to at year end 2010 will decline with time. The further into the future, the more flexibility we will have to revise expenditure. This flexibility is partly dependent on the expenditure our partners in joint ventures agree to commit to.

Exploration expenditure

We experienced a reduction in exploration activities in 2010 compared with the level in 2009. Exploration expenditure in 2010 amounted to NOK 16.8 billion, compared to NOK 16.9 billion in 2009 and NOK 17.8 billion in 2008. Exploration expenditure is expected to increase to approximately NOK 17.6 billion in 2011. The group expects to participate in the drilling of approximately 40 wells in 2011. However, no guarantees can be given with regard to the number of wells drilled, the cost per well and the results of drilling. Evaluation of the results of drilling will influence the amount of exploration expenditure capitalised and expensed. See the section Financial analysis and review - Liquidity and capital resources - Critical accounting judgements.

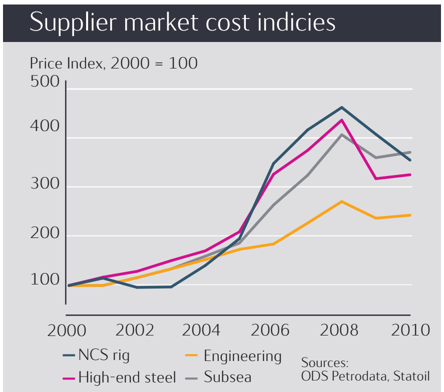
We use the "Successful efforts" method of accounting for oil and natural gas-producing activities. Expenditure on drilling and equipping exploratory wells is capitalised until it is clarified whether there are proved reserves. Expenditure on drilling exploratory wells that do not find proved reserves and geological, geophysical and other exploration expenditure is expensed. Unproved oil and gas properties are assessed quarterly; unsuccessful wells are expensed. Exploratory wells that have found reserves, but where classification of those reserves as proved depends on whether major capital expenditure can be justified, may remain capitalised for more than one year. The main conditions are either that firm plans exist for future drilling in the licence or that a development decision is planned in the near future.

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

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

4.2.6 Impact of inflation

Our results in recent years have been affected by increases in the price for raw materials and services that are necessary for the development and operation of oil and gas-producing assets.



Although the price pressure has abated since it peaked in 2008, our results have been significantly affected in the last few years by inflation in the cost of certain raw materials and services that are necessary for the development and operation of oil and gas-producing assets. Other parts of our business are not exposed to similar cost pressures.

While some of the cost pressure relates to capitalised expenditures and thus only affects our annual profit through increased depreciation, certain elements of operating expenditures have also been affected by this inflation. See our analysis of profit and loss as well as the Group outlook section in the section Financial analysis and review - Operating and financial review.

As measured by the general consumer price index, average annual inflation in Norway for the years ended 31 December 2010, 2009 and 2008 was 2.5%, 2.1% and 3.8%, respectively.

4.2.7 Critical accounting judgements

This section describes key sources of estimation uncertainty and the critical judgements that the group has made when applying accounting policies.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU). The accounting policies applied by the group also comply with IFRS as issued by the International Accounting Standards Board (IASB). This means that we are required to make estimates and assumptions. We believe that, of the company's significant accounting policies (see note 2 - Significant accounting policies, to our consolidated financial statements included in this report), the following may involve a greater degree of judgement and complexity, which, in turn, could materially affect the net income if various assumptions were significantly changed.

Critical judgements when applying accounting policies
The following are the critical judgements, apart from those involving estimations (see below), that the group has made in the process of applying the accounting policies and that have the most significant effect on the amounts recognised in the financial statements:

Revenue recognition - gross versus net presentation of traded SDFI volumes of oil and gas production
As described under Transactions with the Norwegian State in note 2 to the consolidated financial statements, Statoil markets and sells the Norwegian State's share of oil and gas production (SDFI) from the Norwegian continental shelf (NCS). Statoil includes the costs of purchase and proceeds from the sale of the SDFI oil production in Purchases [net of inventory variation] and Revenues, respectively. In making the judgement Statoil considered the detailed criteria for the recognition of revenue from the sale of goods, and in particular concluded that the risk and reward of the ownership of the goods had been transferred from the SDFI to Statoil.

As also described in note 2 to the consolidated financial statements, Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. This sale, and related expenditures refunded by the State, are shown net in Statoil's financial statements. In making the judgment Statoil considered the same criteria as for oil production and concluded that the risk and reward of the ownership of the gas had not been transferred from the SDFI to Statoil.

Key sources of estimation uncertainty
The preparation of consolidated financial statements requires that management make estimates and assumptions that affect reported amounts of assets and liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the result of which form the basis for making the judgements about carrying values of assets and liabilities that are not readily apparent from other sources. The actual results may differ from these estimates. The estimates and underlying assumptions are reviewed on an ongoing basis in light of the current and expected future market conditions.

Statoil is exposed to a number of underlying economic factors which affect the overall results, such as liquids prices, natural gas prices, refining margins, foreign exchange rates, interest rates as well as financial instruments with fair values derived from changes in these factors. In addition, Statoil's results are influenced by the level of production, which in the short term may be influenced by for instance maintenance programmes. In the long term, the results are affected by the success of exploration and field development activities.

The matters described below are considered to be the most important in understanding the key sources of estimation uncertainty that are involved in preparing these financial statements and the uncertainties that could most significantly affect the amounts reported for the results of operations, financial position and cash flows.

Proved oil and gas reserves. Proved oil and gas reserves have been estimated by internal experts on the basis of industry standards and criteria established by regulations of the SEC. The SEC revised Rule 4-10 of Regulation S-X and changed a number of oil and gas reserve estimation requirements effective for the year ending 31 December 2009. The revised Rule requires, on a prospective basis, the use of a price based on a 12-month average for reserve estimation instead of a single end-of-year price. It allows for non-traditional sources such as bitumen extracted from oil sands to be included as reserves. The Financial Accounting Standards Board (FASB) aligned the requirements for supplemental oil and gas disclosures contemporaneously with the changes made by the SEC. Statoil estimates that implementation of the revisions has had an immaterial impact on proved reserves and unit of production depreciation. The comparability of disclosures between years has been impacted however, by the new requirements that were applied on a prospective basis.

Reserves estimates are based on subjective judgments involving geological and engineering assessments of in-place hydrocarbon volumes, the production, historical extraction recovery and processing yield factors and installed plant operating capacity. For future development projects, proved reserves estimates are only included where there is a significant commitment to project funding and execution and when relevant governmental and regulatory approvals have been secured or are reasonably certain to be secured. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. An independent third party has evaluated Statoil's proved reserves estimates, and the results of such evaluation do not differ materially from management estimates. Proved oil and gas reserves are those quantities of oil and gas, which, through the analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. Unless evidence indicates that renewal is reasonably certain, estimates of economically producible reserves only reflect the period before the contracts providing the right to operate expire. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence within a reasonable time. Future changes in proved oil and gas reserves, for instance as a result of changes in prices, could have a material impact on unit of production rates used for depreciation and amortisation.

Expected oil and gas reserves. Expected oil and gas reserves, which differ from proved reserves, have been estimated by internal experts on the basis of industry standards and are used for impairment-testing purposes and for the calculation of asset retirement obligations. Reserves estimates are based on subjective judgments involving geological and engineering assessments of in-place hydrocarbon volumes, the production, historical extraction recovery and processing yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. Future changes in expected oil and gas reserves, for instance as a result of changes in prices, could have a material impact on asset retirement obligations, as well as on the impairment testing of upstream assets, which could have a material effect on operating income as a result of changed impairment charges.

Exploration and leasehold acquisition costs. Statoil capitalises the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. Statoil also capitalises leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Judgments as to whether these expenditures should remain capitalised or written down due to impairment losses in the period may materially affect the operating income for the period.

Impairment/reversal of impairment. Statoil has significant investments in property, plant and equipment and intangible assets. Changes in the circumstances or expectations of future performance of an individual asset may be an indicator that the asset is impaired, thus requiring the book value to be written down to its recoverable amount. Impairments are reversed if conditions for impairment are no longer present. Evaluating whether an asset is impaired or wether an impairment should be reversed, requires a high degree of judgement and may depend to a large extent on the selection of key assumptions about the future.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount and at least annually. If, following an evaluation, an exploratory well has not found proved reserves, the previously capitalised costs are tested for impairment. Subsequent to the initial evaluation phase for a well it will be considered a trigger for impairment testing of a well if no development decision is planned for the near future, and moreover, there is no concrete plan for future drilling in the licence. The impairment of unsuccessful wells is reversed to the extent that conditions for impairment are no longer present.

Estimating recoverable amounts involves complexity in estimating relevant future cash flows, based on assumptions about the future, and discounted to their present value. Impairment testing requires long-term assumptions to be made concerning a number of often volatile economic factors such as future market prices, refinery margins, currency exchange rates and future output, discount rates and political and country risk, in order to establish relevant future cash flows.Impairment testing also frequently requires judgements about probabilities and probability distributions as well as levels of sensitivity inherent to the establishment of recoverable amount estimates, and consequently in ensuring that, where relevant, the recoverable amount estimates' robustness, is sufficiently factored into the impairment evaluations and reflected in the impairment or reversal of impairment recognised in the financial statements. Long-term assumptions relating to major economic factors are made at group level, and there is a high degree of reasoned judgement involved in establishing these assumptions, in determining other relevant factors such as forward price curves, in estimating production outputs, and in determining the ultimate termination value of an asset.

Employee retirement plans. When estimating the present value of defined pension benefit obligations that represent a gross long-term liability in the balance sheet, and indirectly, the period's net pension expense in the statement of income, the management makes a number of critical assumptions that affect these estimates. Most notably, assumptions made about the discount rate to be applied to future benefit payments, the expected return on plan assets and the annual rate of compensation increase have a direct and potentially material impact on the amounts presented. Significant changes in these assumptions between periods can have a material effect on the financial statements.

Asset retirement obligations. Statoil has significant obligations to decommission and remove offshore installations at the end of the production period. Legal and constructive obligations associated with the retirement of non-current assets are recognised at their fair value at the time the obligations are incurred. On initial recognition of a liability, the cost is capitalised as part of the related non-current asset and allocated to expense over the useful life of the asset.

It is difficult to estimate the costs of these decommissioning and removal activities, which are based on current regulations and technology, considering relevant risks and uncertainties. Most of the removal activities will take place many years in the future and the removal technology and costs are constantly changing. The estimates include assumptions about both the time required and the day rates for rigs, marine operations and heavy lift vessels. These can vary considerably depending on the assumed removal complexity. As a result, the initial recognition of the liability and the capitalised cost associated with decommissioning and removal obligations, and the subsequent adjustment of these balance sheet items, involves the exercise of significant judgement.

Derivative financial instruments. When not directly observable in active markets, the fair value of derivative contracts must be computed internally based on internal assumptions as well as on directly observable market information, including forward and yield curves for commodities, currencies and interest. Changes in internal assumptions and forward curves could materially impact the internally computed fair value of derivative contracts, particularly long-term contracts, resulting in corresponding impact on income or loss in the consolidated statement of income.

Income tax. Statoil annually incurs significant amounts of income taxes payable to various jurisdictions around the world, and also recognises significant changes to deferred tax assets and deferred tax liabilities, all of which are based on management's interpretations of applicable laws, regulations and relevant court decisions. The quality of these estimates is highly dependent on management's ability to properly apply what can be very complex sets of rules, to recognise changes in applicable rules and, in the case of deferred tax assets, management's ability to project future earnings from activities that may apply loss carryforward positions against future income taxes.

4.2.8 Off balance sheet arrangements

This section describes various agreements that are not recognised in the balance sheet, such as operational leases and transportation and processing capacity contracts.

We have entered into various agreements, such as operational leases and transportation and processing capacity contracts, that are not recognised in the balance sheet. For more information, see the section Financial analysis and review - Liquidity and capital resources - Principal contractual obligations and note 28 Leases to the Consolidated Financial Statements, for more information.

We are not party to any off-balance sheet arrangements such as the use of variable interest entities.

The group is party to certain guarantees, commitments and contingencies that, pursuant to IFRS, are not necessarily recognised in the balance sheet as liabilities. For more information, see note 29 Other commitments and contingencies in the Consolidated Financial Statements.

4.3 Non-GAAP measures

This section describes the non-GAAP financial measures that SEC regulations require us to disclose.

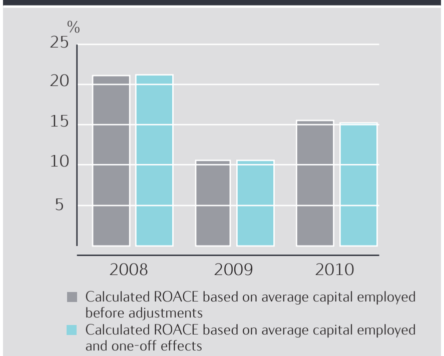
We are subject to SEC regulations regarding the use of "non-GAAP financial measures" in public disclosures. Non-GAAP financial measures are defined as numerical measures that either exclude or include amounts that are not excluded or included in the comparable measures calculated and presented in accordance with generally accepted accounting principles, which in our case refers to IFRS.

The following financial measures may be considered non-GAAP financial measures:
- Return on Average Capital Employed (ROACE).
- Production cost per barrel of entitlement and equity volumes.
- Net debt to capital employed ratio.

4.3.1 Return on average capital employed (ROACE)

We use ROACE to measure the return on capital employed, regardless of whether the financing is through equity or debt.

Roace calculation



We use ROACE to measure the return on capital employed, regardless of whether the financing is through equity or debt. In the company's view, this measure provides useful information for both the company and investors about performance during the period under evaluation. We make regular use of this measure to evaluate our operations. Our use of ROACE should not be viewed as an alternative to income before financial items, income taxes and minority interest, or to net income, which are measures calculated in accordance with generally accepted accounting principles or ratios based on these figures.

ROACE was 15.4% in 2010, compared to 10.5% in 2009 and 21.0% in 2008. The increase from last year was due to a 55% increase in net income adjusted for financial items after tax and a 6% increase in capital employed.

Adjusted for the effects of restructuring costs and other costs arising from the merger, ROACE was 15.2% in 2010 compared to 10.5% in 2009 and 21.1% in 2008. The increase from 2009 to 2010 was due to an increase in income and a relatively lower increase in capital employed. ROACE is defined as a non-GAAP financial measure.

Calculation of numerator and denominator used in ROACE calculation (in NOK billion, except percentages)	For the year ended 31 December 2010	2009	2008
Net income for the year	37.6	17.7	43.3
After-tax net financial items for the year	6.1	10.5	6.4
Net income adjusted for financial items after tax (A1)	43.8	28.2	49.7
Adjustment for restructuring costs and other costs arising from the merger	0.0	(0.1)	(0.4)
Net income adjusted for restructuring costs and other costs arising from the merger (A2)	43.8	28.2	49.3
Calculated average capital employed:			
Average capital employed before adjustments (B1)	284.3	268.7	236.4
Average capital employed (B2)	287.8	268.7	233.3
Calculated ROACE:			
ROACE based on average capital employed before adjustments (A1/B1)	15.4 %	10.5 %	21.0 %
ROACE based on average capital employed and adjusted for restructuring costs (A2/B2)	15.2 %	10.5 %	21.1 %

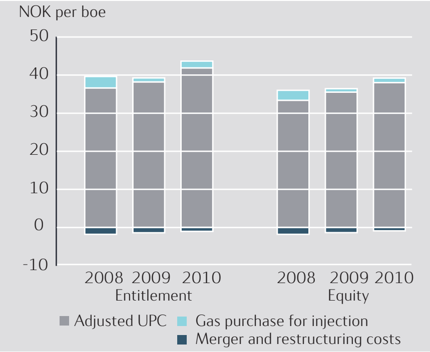
4.3.2 Unit of production cost

In order to evaluate the underlying development in production costs, the production cost is computed on the basis of entitlement volumes and equity volumes.

Production cost per boe of equity volumes is used to evaluate the underlying development in production costs. Significant parts of Statoil's international production are subject to production-sharing agreements with countries' authorities. Under these agreements, we cover our share of the operating expenditures relating to the equity volumes produced. Our international production costs are thus affected by the amount of equity barrels produced, more than by the entitlement volumes received. In order to exclude the effects that production-sharing agreements have on entitlement volumes (PSA effects), we also compute the unit of production cost based on equity volumes.

	Entitlement production For the year ended 31 December			Equity production For the year ended 31 December		
Production cost summary (in NOK per boe)	2010	2009	2008	2010	2009	2008
Calculated production cost	**42.8**	38.4	38.1	**38.6**	35.3	34.6
Calculated production cost, excluding restructuring cost from the merger	**43.5**	38.8	40.6	**39.2**	35.7	36.9
Calculated production cost, excluding restructuring and gas injection cost	**42.0**	38.4	36.7	**37.9**	35.3	33.3

Production cost summary



Entitlement volumes used in the calculation of the normalised production cost per boe have therefore been adjusted for PSA effects. Higher oil price levels negatively affect the production entitlement volumes, and hence the production unit cost.

Entitlement volumes are highly affected by production-sharing agreements (PSA effects). On average, the equity volumes exceeded entitlement volumes by 182 mboe per day in 2010, 156 mboe per day in 2009 and 174 mboe per day in 2008. With the same cost basis but higher volumes, the cost per barrel of equity volumes will always be lower than the cost per barrel of entitlement volumes. Based on equity volumes, the average production cost was NOK 38.6 per boe in 2010, compared with NOK 35.3 per boe in 2009 and NOK 34.6 per boe in 2008.

The following is a reconciliation of our overall operating expenses per year with production cost per year as used when computing the unit of production cost per oil equivalent of entitlement and equity volumes.

Reconcilliation of overall operating expenses to production cost (in NOK billion)	For the year ended 31 December 2010	2009	2008
Operating expenses, Statoil Group	57.5	56.9	59.3
Deductions of costs not relevant to production cost calculation			
1) Business Areas non-upstream	25.5	26.8	30.2
Total operating expenses upstream	32.0	30.1	29.1
2) Operation over/underlift	0.8	(0.2)	(0.6)
3) Transportation pipeline/vessel upstream	4.4	5.2	4.7
4) Miscellaneous items	0.5	0.1	0.7
Total operating expenses upstream excl. over/underlift & transportation	26.3	25.0	24.2
5) Grane gas purchase	0.8	0.6	1.8
6) Restructuring costs from the merger	(0.4)	(0.3)	(1.6)
7) Change in ownership interest	0.1	(0.3)	0.8
Total operating expenses upstream for adjusted cost per barrel calculation	25.9	25.0	23.3

4.3.3 Net debt to capital employed ratio

In the company's view, the calculated net debt to capital employed ratio gives a more complete picture of the group's current debt situation than gross interest-bearing debt.

In the company's view, the calculated net debt to capital employed ratio gives a more complete picture of the group's current debt situation than gross interest-bearing debt. The calculation uses balance sheet items relating to total debt and adjusts for cash, cash equivalents and short-term investments. Certain adjustments are made, since different legal entities in the group lend to projects and others borrow from banks. Project financing through an external bank or similar institution will not be netted in the balance sheet and will over-report the debt stated in the balance sheet in relation to the underlying exposure in the group. Similarly, certain net interest-bearing debts incurred from activities pursuant to the Owners Instruction from the Norwegian State are set off against receivables on the Norwegian State's Direct Financial Interest (SDFI).

The net interest-bearing debt adjusted for these two items is included in the average capital employed, which is also used in the calculation of ROACE.

The table below reconciles the net interest-bearing debt, capital employed and net debt to capital employed ratio with the most directly comparable financial measure or measures calculated in accordance with GAAP.

Calculation of capital employed and net debt to capital employed ratio (in NOK billion, except percentages)	2010	For the year ended 31 December 2009	2008
Total shareholders' equity	219.5	198.3	214.1
Non-controlling interests	6.9	1.8	2.0
Total equity and minority interest (A)	226.4	200.1	216.1
Short-term debt	11.7	8.1	20.7
Long-term debt	99.8	96.0	54.6
Gross interest-bearing debt	111.5	104.1	75.3
Cash and cash equivalents	30.3	24.7	18.6
Current financial investments	11.5	7.0	9.7
Cash and cash equivalents and current financial investments	41.8	31.7	28.4
Net debt before adjustments (B1)	69.7	72.4	46.9
Other interest-bearing elements	6.2	5.0	1.9
Marketing instruction adjustment	(1.5)	(1.4)	(1.7)
Adjustment for project loan	(0.6)	(0.7)	(1.1)
Net interest-bearing debt (B2)	73.8	75.3	46.0
Calculation of capital employed:			
Capital employed before adjustments to net interest-bearing debt (A+B1)	296.1	272.5	263.0
Capital employed, adjusted (A+B2)	300.2	275.4	262.0
Calculated net debt to capital employed:			
Net debt to capital employed before adjustments (B1/(A+B1))	23.5 %	26.6 %	17.8 %
Net debt to capital employed (B2/(A+B2))	24.6 %	27.3 %	17.5 %

4.4 Accounting Standards (IFRS)

We prepare our consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU and as issued by the International Accounting Standards Board.

We prepared our first set of consolidated financial statements pursuant to IFRS for 2007. The IFRS standards have been applied consistently to all periods presented in the consolidated financial statements and when preparing an opening IFRS balance sheet as of 1 January 2006 (subject to certain exemptions allowed by IFRS 1) for the purpose of the transition to IFRS.

Change in parent company functional currency
With effect from 2009, we have reported using USD as the functional currency in the parent company, while we use NOK as the reporting currency. Prior period financial statements have not been restated, since this is not required by the standard.

5 Risk review

5.1 Risk factors

Statoil is exposed to a number of risks that could affect our operational and financial performance. Here, we discuss some of the key risk factors.

5.1.1 Risks related to our business

This section describes some of the potential risks relating to our business, such as oil prices, operational risks, competition and international relations.

A substantial or prolonged decline in oil or natural gas prices would have a material adverse effect on us.
Historically, the prices of oil and natural gas have fluctuated greatly in response to changes in many factors. We do not and will not have control over the factors that affect the prices of oil and natural gas. These factors include:

- global and regional economic and political developments in resource-producing regions, particularly in the Middle East and South America;
- global and regional supply and demand;
- the ability of the Organization of the Petroleum Exporting Countries (Opec) and other producing nations to influence global production levels and prices;
- prices of alternative fuels that affect the prices realised under our long-term gas sales contracts;
- governmental regulations and actions;
- global economic conditions;
- war or other international conflicts;
- changes in population growth and consumer preferences;
- the price and availability of new technology; and
- weather conditions.

It is impossible to predict future price movements for oil and natural gas with certainty. A prolonged decline in oil and natural gas prices will adversely affect our business, the results of our operations, our financial condition, our liquidity and our ability to finance planned capital expenditure. In addition to the adverse effect on revenues, margins and profitability from any fall in oil and natural gas prices, a prolonged period of low prices or other indicators could lead to further reviews for impairment of the group's oil and natural gas properties. Such reviews would reflect the management's view of long-term oil and natural gas prices and could result in a charge for impairment that could have a significant effect on the results of our operations in the period in which it occurs. Rapid material and/or sustained reductions in oil, gas and product prices can have an impact on the validity of the assumptions on which strategic decisions are based and can have an impact on the economic viability of projects that are planned or in development. For an analysis of the impact of changes in oil and gas prices on net operating income, see the section Risk Review - Risk management.

Exploratory drilling involves numerous risks, including the risk that we will encounter no commercially productive oil or natural gas reservoirs. This could materially adversely affect our results.
We are exploring or considering exploring in various geographical areas, including resource provinces such as the Norwegian Sea, the Barents Sea, the deepwater US Gulf of Mexico, the Arctic, onshore Algeria and Libya, as well as off the coasts of Alaska, Angola, Brazil and Venezuela, where environmental conditions are challenging and costs can be high. In addition, our use of advanced technologies requires greater pre-drilling expenditure than traditional drilling strategies. The cost of drilling, completing and operating wells is often uncertain. As a result, we may experience cost overruns or may be required to curtail, delay or cancel drilling operations because of a variety of factors, including equipment failures or accidents, changes in governmental requirements, unexpected drilling conditions, pressure or irregularities in geological formations, adverse weather conditions and shortages of or delays in the availability of drilling rigs and the delivery of equipment. For example, we have entered into long-term leases for drilling rigs that may turn out not to be required for the operations for which they were originally intended, and we cannot be certain that these rigs will be re-employed or at what rates they will be re-employed. Fluctuations in the market for leases of drilling rigs will also have an impact on the rates we can charge in re-employing these rigs. Our overall drilling activity or drilling activity within a particular project area may be unsuccessful. Such failure will have a material adverse effect on the results of our operations and financial condition.

We are exposed to a wide range of health, safety, security and environmental risks that could result in significant losses.
Exploration for, and the production and transportation of oil and natural gas is hazardous, and technical integrity failure, operator error, natural disasters or other occurrences can result, among other things, in oil spills, gas leaks, loss of containment of hazardous materials, blowouts, cratering, fires, equipment failure and loss of well control. The risks associated with exploration for and production and transportation of oil and natural gas are heightened in the difficult geographies, climate zones and environmentally sensitive regions in which we operate. All modes of transportation of hydrocarbons, including by road, rail, sea or pipeline, are particularly susceptible to a loss of containment of hydrocarbons and other hazardous materials, and, given the high volumes involved, could present a significant risk to people and the environment. Offshore operations are subject to marine perils, including severe storms and other adverse weather conditions and vessel collisions, as well as interruptions or termination by governmental authorities based on safety, environmental and other considerations. Acts of terrorism against our plants and offices, pipelines, transportation or computer systems could severely disrupt businesses and operations and could cause harm to people. Failure to manage the foregoing risks could result in injury or loss of life, damage to the environment, damage or destruction of wells and production facilities, pipelines and other property and could result in regulatory action, legal liability, damage to our reputation, a significant reduction in our revenues and an increase in our costs, and could have a material adverse effect on our operations or financial condition.

Our crisis management systems may be ineffective.
We have developed contingency plans to continue or recover operations following a disruption or incident. An inability to restore or replace critical capacity to an agreed level within an agreed time frame could prolong the impact of any disruption and could severely affect business and operations. Likewise, we have crisis management plans and capability to deal with emergencies at every level of our operations. If we do not respond or are not seen to respond in an appropriate manner to either an external or internal crisis, our business and operations could be severely disrupted.

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 proven reserves are on the Norwegian continental shelf (NCS), a maturing resource province. Unless we conduct successful exploration and development activities and/or acquire properties containing proved reserves, our proved reserves will decline as reserves are produced. Successful implementation of our group strategy is critically dependent on sustaining long-term reserves replacement. If upstream resources are not progressed to proved reserves in a timely and efficient manner, we will be unable to sustain the long-term replacement of reserves. In addition, the volume of production from oil and natural gas properties generally declines as reserves are depleted. For example, some of our major fields, such as Gullfaks, are dependent on satellite fields to maintain production and, unless efforts to improve the development of satellite fields are successful, production will gradually decline.

In a number of resource-rich countries, national oil companies control a significant proportion of oil and gas reserves that remain to be developed. To the extent that national oil companies choose to develop their oil and gas resources without the participation of international oil companies or if we are unable to develop partnerships with national oil companies, our ability to find and acquire or develop additional reserves will be limited.

Our future production is highly dependent on our succeeding in finding or acquiring and developing additional reserves. If we are unsuccessful, we may not meet our long-term ambitions for growth in production, and our future total proved reserves and production will decline, adversely affecting the results of our operations and financial condition.

We encounter competition from other oil and natural gas companies in all areas of our operations, including the acquisition of licences, exploratory prospects and producing properties.
The oil and gas industry is extremely competitive, especially with regard to exploration for, and exploitation and development of new sources of oil and natural gas.

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

- diversification and the reduction of risk;
- the financial strength necessary for capital-intensive developments;
- exploitation of benefits of integration;
- exploitation of economies of scale in technology and organisation;
- exploitation of advantages in terms 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 licences. They may also be able to invest more in developing technology than our financial or human resources permit. Our performance could be impeded if competitors were to develop or acquire intellectual property rights to technology that we require or if our innovation were to lag behind the industry. For more information on the competitive environment, see the section Operational Review - Competition.

Our development projects and production activities involve many uncertainties and operating risks that can prevent us from realising profits and cause substantial losses.
Our development projects and production activities may be curtailed, delayed or cancelled for many reasons, including equipment shortages or failures, natural hazards, unexpected drilling conditions or reservoir characteristics, pressure or irregularities in geological formations, accidents, mechanical and technical difficulties and industrial action. These projects and activities will also often require the use of new and advanced technologies, which may be expensive to develop, purchase and implement, and may not function as expected. In addition, some of our developments will be located in deep waters or

other hostile environments, such as the Gulf of Mexico and the Barents Sea, or may be in challenging reservoirs, which can exacerbate such problems. There is a risk that development projects that we undertake may not yield adequate returns.

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

We face challenges in achieving our strategic objective of successfully exploiting growth opportunities.
An important element of our strategy is to continue to pursue attractive growth opportunities available to us, by both enhancing and repositioning our asset portfolio and expanding into new markets. The opportunities that we are actively pursuing may involve the acquisition of businesses or properties that complement or expand our existing portfolio. The challenges to renewal of our upstream portfolio are growing due to increasing global competition for access to opportunities.

Our ability to successfully implement this strategy will depend on a variety of factors, including our ability to:
- identify acceptable opportunities;
- negotiate favorable terms;
- develop new market opportunities or acquire properties or businesses promptly and profitably;
- integrate acquired properties or businesses into our operations;
- arrange financing, if necessary; and
- comply with legal regulations.

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

Any such new projects we acquire will require additional capital expenditure and will increase the cost of our discoveries and development. These projects may also have different risk profiles than our existing portfolio. These and other effects of such acquisitions could result in us having to revise either or both of our forecasts with respect to unit production costs and production.

In addition, the pursuit of acquisitions or new business opportunities could divert financial and management resources away from our day-to-day operations to the integration of acquired operations or properties. We may require additional debt or equity financing to undertake or consummate future acquisitions or projects, and such financing may not be available on terms satisfactory to us, if at all, and it may, in the case of equity, be dilutive to our earnings per share.

We face challenges in the renewable energy sector.
Although energy production from renewables is currently modest in most countries, wind power, solar energy and biofuels are developing into significant industries. We cannot predict the demand for renewables. We believe that technological innovation and the integration of trend-breaking technologies, such as biotechnology and other new ideas, are key to advancing in the renewable energy sector and ensuring a profitable, sustainable, low-carbon energy future. Some of our competitors may be able to invest more in developing technology in the renewable energy sector than we do. Our performance in the renewable energy sector could be impeded if competitors develop or acquire intellectual property rights to technology that we require or if our innovation lags behind the industry. In addition, projects in renewable energy involve emerging technologies, evolving manufacturing techniques and/or cutting edge implementation. There is little precedence for incorporating certain renewable aspects into new or existing projects.

We may not be able to produce some of our oil and gas economically due to the lack of necessary transportation infrastructure when a field is in a remote location.
Our ability to exploit economically any discovered petroleum resources beyond our proved reserves will depend, among other factors, on the availability of the infrastructure required to transport oil and gas to potential buyers at a commercially acceptable price. Oil is usually transported by tankers to refineries, and natural gas is usually transported by pipeline to processing plants and end-users. 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 politically, economically and socially unstable regions around the world where threats such as war, terrorism, border disputes, guerrilla activities, expropriation, nationalisation of property, civil strife, strikes, political unrest and insurrections are present. These threats or some of them, may impact on our activities in regions such as the Middle East, North Africa, the Caspian and countries like Nigeria, Angola and Venezuela. The occurrence of incidents resulting from political, economic or social instability could disrupt our operations and further business opportunities in any of these regions, including leading to a decline in production. This could have a material adverse effect on the results of our operations or financial condition.

Our operations are subject to political and legal factors in the countries in which we operate.
We have assets in a number of countries with emerging or transitioning economies that lack well-established and reliable legal systems, where the enforcement of contractual rights is uncertain or where the governmental and regulatory framework is subject to unexpected change. Our exploration and production activities in these countries are often undertaken together with national oil companies and are subject to a significant degree of state control. In recent years, governments and national oil companies in some regions have begun to exercise greater authority and impose more stringent conditions on

companies engaged in exploration and production activities. We expect this trend to continue. Intervention by governments in such countries can take a wide variety of forms, including:

- restrictions on exploration, production, imports and exports;
- the awarding or denial of exploration and production interests;
- the imposition of specific seismic and/or drilling obligations;
- price controls;
- tax or royalty increases, including retroactive claims;
- nationalisation or expropriation of our assets;
- unilateral cancellation or modification of our licence or contractual rights;
- the renegotiation of contracts;
- payment delays; and
- currency exchange restrictions or currency devaluation.

The likelihood of these occurrences and their overall effect on us vary greatly from country to country and are not predictable. If such risks materialise, they could cause us to incur material costs and/or cause our production to decrease, potentially having a material adverse effect on our operations or financial condition.

Due to the outbreak of political unrest in Libya, in February 2011, the US, the UN, the EU and several countries implemented certain sanctions in relation to Libya. The future impact of the ongoing unrest, potential political changes and international sanctions on Statoil's current Libyan operations is uncertain.

Our activities in certain countries could lead to US sanctions.

Certain countries, including Iran and Cuba, have been identified by the US State Department as state sponsors of terrorism. In October 2002, we signed a participation agreement with Petropars of Iran, pursuant to which we assumed the operatorship for the offshore part of phases 6-7-8 of the South Pars gas development project in the Persian Gulf. In total, Statoil's estimated capital expenditures for the offshore development of South Pars phases 6-7-8 is USD 746 million. Final settlement with the partner on the sharing of parts of the capital expenditures may lead to an adjustment of Statoil's final investment amount. Adjusted for an impairment in 2005, a partial reversal of impairment in 2009 and cumulative depreciation charges, the net book value was USD 227 million at year end 2010. In addition, as a result of the merger with Norsk Hydro's oil and gas business, Statoil owns a 75% interest in the Anaran Block in Iran, which was acquired by Norsk Hydro in 2000. Following the commerciality declaration of the Azar discovery in the Anaran Block in August 2006, Norsk Hydro agreed to conduct negotiations with the National Iranian Oil Company for a Master Development Plan and a Development Service Contract. The Anaran Block is currently in the exploration phase. Statoil had invested USD 104 million in the project, but this amount has been fully written off following an impairment review in 2008. Work on this project has stopped. Also as a result of the merger with Norsk Hydro's oil and gas business, Statoil now owns a 100% interest in the Khorramabad Exploration Block, for which Statoil is the operator. In September 2006, Norsk Hydro signed the Khorramabad Exploration and Development Contract with the National Iranian Oil Company, with a total commitment of USD 49.5 million over four years relating to seismic surveys and other exploration activities. We completed the gathering of seismic data in the Khorramabad Exploration Block in the fourth quarter of 2008. No further activity is planned for this licence. Statoil will not make any future investments in Iran under the present circumstances, but is committed to fulfilling its contractual obligations in respect of South Pars. See the section Operational Review - International E&P - International fields in development and production - The Middle East and Asia - Iran.

On 30 September 2010, the US State Department announced that Statoil was eligible to avoid sanctions under the Comprehensive Iran Sanctions, Accountability and Divestment Act of 2010 (CISADA) relating to its activities in Iran because Statoil had pledged to end its investments in Iran's energy sector. In 2009, Statoil had voluntarily provided officials from the US State Department with information about its activities and investments in Iran. CISADA came into effect on 1 July 2010. Among other things, CISADA amends certain sections of the Iran Sanctions Act of 1996 (ISA). CISADA requires the President of the United States to sanction companies that make investments that enhance Iran's ability to develop petroleum resources or provide or facilitate the production or importation of refined petroleum products into Iran. Such sanctions could include prohibiting transactions in foreign exchange in which the sanctioned entity has any interest, prohibiting transfers of credit or payments via financial institutions in which the sanctioned entity has any interest, prohibiting property transactions by the sanctioned entity in which the property is subject to the jurisdiction of the United States, the denial of US bank loans and restrictions on the importation of goods produced by the sanctioned company.

Our activities in Cuba consist of a 30% interest in six deepwater exploration blocks acquired from Repsol-YPF in 2006. As of 31 December 2010, we had invested USD 12.5 million in these projects. These activities are not material to our business, financial condition or results of operations, as the total amount invested in these operations represented less than 0.02% of our total assets as of 31 December 2010.

We are also aware of initiatives by certain US states and US institutional investors, such as pension funds, to adopt or consider adopting laws, regulations or policies requiring among other things divestment from, reporting of interests in, or agreeing not to make future investments in, companies that do business with countries designated as state sponsors of terrorism. These policies could have an adverse impact on investment by certain investors in our securities.

Our activities in certain countries could lead to other sanctions.

In 2010, the UN and the EU adopted new restrictive measures in relation to Iran. With effect from 14 January 2011, Norway adopted similar regulations. These restrictive measures cover the areas of trade, financial services, energy and transport, as well as additional measures relating to visa bans and asset freezes. Although we cannot predict the interpretation or implementation of the new legislation or restrictive measures with respect to our activities in and relating to Iran, the restrictive measures will not apply to the Shah Deniz gas field in Azerbaijan, in which NIOC has an interest.

We are exposed to potentially adverse changes in the tax regimes of each jurisdiction in which we operate.
We operate in approximately 40 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 to other companies in our industry. In addition, in the long-term, the marginal tax rate in the oil and gas industry tends to change 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 the results of our operations.

Our insurance coverage may not adequately protect us.
Statoil maintains insurance coverage that includes coverage for physical damage to our oil and gas properties, third party liability, workers' compensation and employers' liability, general liablity, sudden pollution and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery. Additionally, our insurance is subject to caps, exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

In light of the accident at the BP-operated Macondo well in the Gulf of Mexico, we may not be able to secure similar coverage for the same costs. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable.

The crude oil and natural gas reserve data in this annual report are only estimates, and our future 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 governmental regulations, contracts and 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. The results of drilling, testing and production after the date of the estimates may require substantial upward or downward revisions in our reserve data. In addition, fluctuations in oil and gas prices will have an impact on our proven reserves relating to fields governed by production sharing agreements, or PSAs, since part of our entitlement under PSAs relates to the recovery of development costs. Any downward adjustment could lead to lower future production and thus adversely affect our financial condition, future prospects and market value.

We face foreign exchange risks that could adversely affect the results of our operations.
Our business faces foreign exchange risks because a large percentage of our revenues and cash receipts are denominated in USD, while sales of refined products can be in a variety of currencies. Fluctuations between the USD and other currencies may adversely affect our business and can give rise to foreign exchange exposures, with a consequent impact on underlying costs and revenues. See the section Risk review - Risk management - Managing financial risk - Market risk.

We are exposed to risks relating to trading and supply activities.
Statoil is engaged in substantial trading and commercial activities in the physical markets. We also use financial instruments such as futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity in order to manage price volatility. We also use financial instruments to manage foreign exchange and interest rate risk.

Although we believe we have established appropriate risk management procedures, trading activities involve elements of forecasting and Statoil bears the risk of market movements - the risk of significant losses if prices develop contrary to expectations - and the risk of default by counterparties. See the section Risk review - Risk management - Managing financial risk for more information about risk management. Any of these risks could have an adverse effect on the results of our operations and financial condition.

We may fail to attract and retain senior management and skilled personnel.
The attraction and retention of senior management and skilled personnel is a critical factor in the successful implementation of our strategy as an international oil and gas group. We may not always be successful in hiring or retaining suitable senior management and skilled personnel. Failure to recruit or retain senior management and skilled personnel or to more generally maintain good employee relations could compromise the achievement of our strategy. Such failure could cause disruption to the management structure and relationships, an increase in costs associated with staff replacement, lost business relationships or reputational damage. An inability to attract or retain suitable employees could have a significant adverse impact on our ability to operate.

Failure to meet our ethical and social standards could harm our reputation and our business.
Our code of conduct, which applies to all employees of the group, including hired personnel, consultants, intermediaries, lobbyists and others who act on our behalf, defines our commitment to high ethical standards and compliance with applicable legal requirements wherever we operate. Incidents of ethical misconduct or non-compliance with applicable laws and regulations could be damaging to our reputation, competitiveness and shareholder value. Multiple events of non-compliance could call into question the integrity of our operations.

We set ourselves high standards of corporate citizenship and aspire to contribute to a better qualify of life through the products and services we provide. If it is perceived that we are not respecting or advancing the economic and social progress of the communities in which we operate, our reputation and shareholder value could be damaged.

5.1.2 Risks related to increased regulation and regulatory compliance

This section discusses potential risks to our business relating to regulatory regimes, such as having to comply with new laws and regulations.

Compliance with health, safety and environmental laws and regulations that apply to Statoil's operations could materially increase our costs.
We incur, and expect to continue to incur, substantial capital, operating, maintenance and remediation costs relating to compliance with increasingly complex laws and regulations for the protection of the environment and human health and safety, including:

- costs of preventing, controlling eliminating or reducing certain types of emissions to air and discharges to the sea, including costs incurred in connection with government action to address the risk of spills and concerns about climate change;
- remediation of environmental contamination caused by our activities or accidents at various facilities owned or previously-owned by us and at third party sites where our products or waste have been handled or disposed of;
- compensation of persons and/or entities claiming damages as a result of our activities or accidents; and
- costs in connection with the decommissioning of drilling platforms and other facilities.

For example, under the Norwegian Petroleum Act of 29 November 1996, as a holder of licences on the NCS, we are subject to statutory strict liability in respect of losses or damage suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of our licences. This means that anyone who suffers losses or damage as a result of pollution caused by operations in any of our NCS licence areas can claim compensation from us without having to demonstrate that the damage is due to any fault on our part.

Furthermore, in countries where we operate or expect to operate in the near future, new laws and regulations, the imposition of stricter requirements on licences, increasingly strict enforcement of or new interpretations of existing laws and regulations, the aftermath of operational catastrophes in which we or members of our industry are involved or the discovery of previously unknown contamination may require future expenditure in order to, among other things:

- modify operations;
- install pollution control equipment;
- implement additional safety measures;
- perform site clean-ups;
- curtail or cease certain operations;
- temporarily shut down our facilities;
- meet technical requirements; or
- establish credentials in order to be permitted to commence drilling.

In particular, following the incident on the BP-operated Macondo well, we may be required to incur significant costs in connection with changes in laws or regulations and/or drilling delays and recertifications that could affect our operations in the Gulf of Mexico, on the NCS and around the world. Any such changes, delays or recertifications could have a material adverse effect on our operations, results or financial condition.

Compliance with laws, regulations and obligations relating to climate change and other environmental regulations could result in substantial capital expenditure, reduced profitability as a result of changes in operating costs, and revenue generation and strategic growth opportunities being affected. Many of our mature fields are producing increasing quantities of water with oil and gas. Our ability to dispose of this water in environmentally acceptable ways may have an impact on our oil and gas production.

If we do not apply our resources to overcome the perceived trade-off between global access to energy and the protection or improvement of the natural environment, we could fail to live up to our aspirations of zero or minimal damage to the environment and contributing to human progress.

As a result of EU directives, competition is expected to increase in the European gas market, currently our main market for gas sales.
The general liberalisation of European gas markets could increase competition and adversely affect our ability to expand or even maintain our current market position or result in a reduction in prices in our gas sales contracts.

Most of our gas is sold under long-term gas contracts to customers in the EU, a gas market that will continue to be affected by changes in EU regulations and the implementation of such regulations in EU member states. As a result of the directives, our ability to expand or even maintain our current market position could be materially adversely affected and quantities sold under our gas sales contracts may be subject to a material reduction in gas prices.

Fundamental changes continue to take place in the organisation and operation of the European gas market with the aim 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.

In July 2009, the EU adopted an expansive legislative package setting out new regulations for the internal markets for energy, electricity and gas that is required to be implemented by the member states by March 2011. The new regulations contain numerous requirements for energy companies relating to supply, transmission and distribution. The requirements include greater separation of production and supply activities from transmission and distribution activities; the establishment of independent national electricity regulators charged with supporting competitive, secure and environmentally-sustainable internal markets for electricity and gas, and the harmonisation of technical standards in order to promote cross-border collaboration and investment. The new regulations also provide for a European Agency for the Cooperation of Energy Regulators with competence to oversee many parts of the legislative package.

Another EU initiative that is likely to impact on the market for gas involves the environmental package implemented in December 2008, which strengthens and extends the Emissions Trading Scheme and creates national targets for renewable energy. This will have positive and negative impacts on the competitive position of natural gas as a fuel.

The third focus area of EU energy policy is supply security, which has led to increased focus on projects that diversify gas supplies to the EU. As a result, the Caspian region, where Statoil participates in the Shah Deniz field, is now receiving increasing attention from the EU. Solutions aimed at bringing Caspian gas to Europe are receiving political support from the EU in an attempt to resolve the complex transportation issue in the region.

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 State's Direct Financial Interest (SDFI) and its indirect impact through tax and environmental laws and regulations, the Norwegian State awards licences for reconnaissance, production and transportation, and it approves, among other things, exploration and development projects, gas sales contracts and applications for (gas) production rates for individual fields. The Norwegian State may, if important public interests are at stake, also instruct us and other oil companies to reduce the production of petroleum. Furthermore, in the production licences 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 under 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 the results of our operations could be materially and adversely affected. For more information about the Norwegian State's regulatory powers, see the section Operational Review - Regulation.

5.1.3 Risks related to ownership by the principal shareholder and its involvement in the SDFI

This section discusses some of the potential risks relating to our business that could derive from the Norwegian State's majority ownership and from our involvement in the SDFI.

The interests of our majority shareholder, the Norwegian State, may not always be aligned with the interests of our other shareholders, and this 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 interest in NCS licences must be managed in accordance with 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 oil and gas as a single economic unit.

Pursuant to the coordinated ownership strategy for the Norwegian State's shares in Statoil 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 that may affect the development and marketing of our own and the Norwegian State's oil and gas.

The Norwegian State directly held 67% of our ordinary shares as of 12 March 2011. A two-thirds majority is required to decide matters submitted to a vote of shareholders. The Norwegian state therefore effectively has the power to influence the outcome of any vote of shareholders due to the percentage of our shares it owns, including amending our articles of association and electing all non-employee members of the corporate assembly. The employees are entitled to be represented by up to one-third of the members of the board of directors and one-third of the corporate assembly.

The corporate assembly is responsible for electing our board of directors. It also makes recommendations to the general meeting concerning the board of directors' proposals relating to the company's annual accounts, balance sheet, allocation of profits and coverage of loss. The interests of the Norwegian State in deciding these and other matters and the factors it considers when casting its votes, especially under the coordinated ownership strategy for the SDFI and our shares held by the Norwegian State, could be different from the interests of our other shareholders. Accordingly, when making commercial decisions relating to the NCS, we have to take the Norwegian State's coordinated ownership strategy into account, and we may not be able to fully pursue our own commercial interests, including those relating to our strategy for the 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 oil and gas 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 the section Operational review - Regulation - The Norwegian State's participation.

5.2 Risk management

Our overall risk management approach includes identifying, evaluating, and managing risk in all our activities. We manage risk in order to ensure safe operations and to reach our corporate goals in compliance with our requirements.

We have an enterprise-wide risk management approach, which means that we:

- have a risk and reward focus at all levels of the organisation,
- evaluate significant risk exposure related to major commitments, and
- manage and coordinate risk at the corporate level.

We divide risk management into three categories:

- Strategic risks, which are long-term fundamental risks monitored by our Corporate Risk Committee. Our Corporate Risk Committee, which is headed by our chief financial officer and which includes, among others, representatives of our principal business areas, is responsible for reviewing, defining and developing our strategic market risk policies. The committee meets monthly to decide our risk management strategies, including hedging and trading strategies and valuation methodologies.
- Tactical risks, which are short-term trading risks based on underlying exposures managed by our principal business area line managers, and
- Operational risks, such as those described under risk factors which cover all major operational goals and underlying risk drivers, are managed by our principal business area line managers. In addition, insurable risks are managed by our captive insurance company operating in the Norwegian and international insurance markets.

To address our strategic and tactical risks, we have developed policies aimed at managing the volatility inherent in some of these natural business exposures, and, in accordance with these policies, we enter into various financial and commodity-based transactions (derivatives). While the policies and mandates are set at the group level, the business areas responsible for marketing and trading commodities are also responsible for managing the commodity-based price risks. The interest, liquidity, liability and credit risks are managed by the company's central finance department.

The following section describes in some detail the market risks to which we are exposed and how we manage these risks.

5.2.1 Managing financial risk

The results of our operations depend on a number of factors, most significantly those that affect the price we receive in NOK for our products.

Specifically, such factors include the level of crude oil and natural gas prices, trends in the exchange rate between the USD, in which the trading price of crude oil is generally stated and to which natural gas prices are frequently related, and NOK, in which our accounts are reported and a substantial proportion of our costs are incurred; our oil and natural gas production volumes, which in turn depend on entitlement volumes under PSAs and available petroleum reserves, and our own, as well as our partners' expertise and cooperation in recovering oil and natural gas from those reserves; and changes in our portfolio of assets due to acquisitions and disposals.

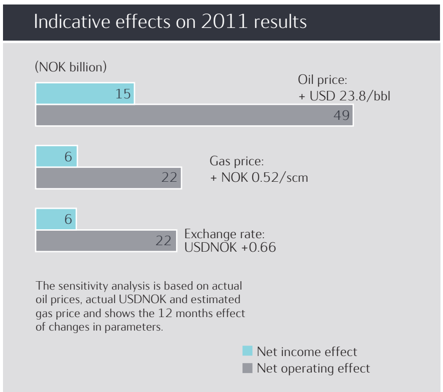
Our results will also be affected by trends in the international oil industry, including possible actions by governments and other regulatory authorities in the jurisdictions in which we operate, or possible or continued actions by members of the Organisation of Petroleum Exporting Countries (OPEC) that affect price levels and volumes, refining margins, the cost of oilfield services, supplies and equipment, competition for exploration opportunities and operatorships, and deregulation of the natural gas markets, all of 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 averages for quoted Brent Blend crude oil prices, natural gas contract prices, fluid catalytic cracking (FCC) margins and the USD/NOK exchange rates for 2010, 2009 and 2008.

Yearly average	2010	2009	2008
Crude oil (USD/bbl brent blend)	**76.5**	58.0	91.0
Natural gas (NOK per scm)(1)	**1.7**	1.9	2.4
FCC margins (USD/bbl)(2)	**5.4**	4.3	8.2
USDNOK average daily exchange rate	**6.1**	6.3	5.6

(1) From the Norwegian Continental Shelf.

(2) Refining margin.



The illustration shows how certain changes in the crude oil price, natural gas contract prices and the USD/NOK exchange rate, if sustained for a full year, could affect our financial results in 2011.

The estimated sensitivity of our financial results to each of the factors has been estimated based on the assumption that all other factors would remain unchanged. The estimated effects on our financial results would differ from those that would actually appear in our consolidated financial statements because our consolidated financial statements would also reflect the effects of depreciation, trading margins, exploration expenses, inflation, potential tax system changes and of any hedging programmes in place.

Our oil and gas price hedging policy is designed to support our long-term strategic development and our attainment of targets by protecting financial flexibility and cash flows.

Fluctuating foreign exchange rates can have a significant impact on our operating results. Our revenues and cash flows are mainly denominated in or driven by US dollars, while our operating expenses and income taxes payable largely accrue in NOK. We seek to manage this currency mismatch by issuing or swapping long-term debt in USD. This debt policy is an integrated part of our total risk management programme. We also engage in foreign currency hedging in order to cover our non-USD needs, which are primarily in NOK. We manage the risk arising from our interest rate exposure through the use of interest rate derivatives, primarily interest rate swaps, based on a benchmark for the interest reset profile of our long-term debt portfolio. In general, an increase in the value of USD in relation to NOK can be expected to increase our reported earnings. Please see notes 8, 31 and 32 to the consolidated financial statements for quantitative and qualitative disclosures about market risk.

We sell the Norwegian State's share of oil and natural gas production from the NCS. Amounts payable to the Norwegian State for these purchases are included as Accounts payable - related parties in the consolidated balance sheets. The pricing of the crude oil is based on market reflective prices. NGL prices are based on either attained prices, market value or market reflective prices.

Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's natural gas production. This sale, as well as related expenses refunded by the State, is shown net in our financial statements. Expenses refunded by the State include expenses incurred in connection with activities and investments that are necessary in order to secure market access and optimise the profit from the sale of the Norwegian State's natural gas. For sales of the Norwegian State's natural gas, both for our own use and to third parties, the payment to the Norwegian State is based on prices attained, a net back formula or market value. We purchase a small proportion of the Norwegian State's gas. For further details, see section Operational review-Related party transactions.

High oil prices have contributed to higher earnings and profitability from international projects with production sharing agreements (PSAs) than previously anticipated. Under a PSA, the partners are generally entitled to production volumes that cover the development costs and an agreed share of the remaining volumes. When oil prices are high, this means that these projects will move from a phase where earnings cover development costs to a phase where profits are generated at an earlier point in time. In PSA contracts, the higher the oil price, the sooner the field is profitable and the smaller the share of production that goes to the partners. The actual effect varies between different agreements and countries. These tax regimes are often asymmetric, i.e. the company's upside is somewhat limited, while the company is fully exposed to the downside. See section Financial analysis and review - Operational and financial review 2010 - Sales volumes, for a description of the impact of the PSA effects.

Historically, our revenues have largely been generated from the production of oil and natural gas on the NCS. Norway imposes a 78% marginal tax rate on income from offshore oil and natural gas activities (a symmetrical tax system). See section Operational review - Regulation - Taxation of Statoil. Our earnings volatility is moderated as a result of the significant proportion 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. Most of the taxes we pay are paid to the Norwegian State. Dividends received in Norway are 97% exempt from tax, with the remaining 3% taxed at the ordinary rate of 28%. For dividends received from companies in a low-tax jurisdiction within the EEA, the 97% exemption applies only if real business acitivities are conducted in that jurisdiction. Dividends received from companies in non-EEA countries are 97% exempt if the Norwegian receiver has held at least 10% of the shares for a minimum of 2 years and the foreign country is not a low-tax jurisdiction.

Government fiscal policy is an issue in several of the countries in which we operate, such as, but not limited to, Venezuela, the United States, Nigeria, Algeria and Angola. For instance, government fiscal policy could require royalties in cash or in kind, increased tax rates, increased government participation, and changes in terms and conditions as defined in various production or income-sharing contracts. Our financial statements are based on currently enacted regulations and on any current claims from tax authorities regarding past events. Developments in government fiscal policy may have a negative effect on future net income.

Financial risk management

Statoil's business activities naturally expose the group to financial risk. The group's approach to risk management includes identifying, evaluating and managing risk in all activities using a top-down approach for the purpose of avoiding sub-optimisation and utilising correlations observed from a group perspective. Only summing up the different market risks without including the correlations will overestimate our total market risk. For this reason, the group utilises correlations between all the most important market risks, such as oil and natural gas prices, product prices, currencies and interest rates, to calculate the overall market risk and thereby utilise the natural hedges embedded in our portfolio. This approach also reduces the number of unnecessary transactions, which reduces transaction costs and avoids sub-optimisation.

In order to achieve the above effects, the group has centralised trading mandates (financial positions taken to achieve financial gains, in addition to established policies) so that all major/strategic transactions are co-ordinated through our Corporate Risk Committee. Local trading mandates are therefore relatively small.

The group's Corporate Risk Committee, which is chaired by the chief financial officer and includes representatives of the principal business areas, is responsible for defining, developing, and reviewing the group's risk policies. The chief financial officer, assisted by the Corporate Risk Committee, is also responsible for overseeing and developing Statoil's enterprise-wide risk management and proposing appropriate measures to adjust risk at the corporate level. The committee meets at least six times per annum and regularly receives risk information relevant to the group from our corporate risk department.

Our financial risk management covers market risks, including commodity price risk, interest rate risk, currency risk and equity price risk; liquidity risk, and credit risk.

Market risk

Statoil operates in the worldwide crude oil, refined products, natural gas and electricity markets and is exposed to market risks, including fluctuations in hydrocarbon prices, foreign currency rates, interest rates and electricity prices that can affect the revenues and costs of operating, investing and financing. These risks are primarily managed on a short-term basis, with the focus on achieving the highest risk-adjusted returns for the group within the given mandate. Long-term positions, defined as having a time horizon of six months or more, are managed at the corporate level, while short-term positions are managed at segment and lower levels in accordance with trading strategies and mandates approved by the Corporate Risk Committee.

The group has established guidelines for entering into contractual arrangements (derivatives) in order to manage its commodity price, foreign currency rate and interest rate risk. The group uses both financial and commodity-based derivatives to manage the risks in revenues and the present value of future cash flows.

Commodity price risk

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

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

The term of oil and refined oil products derivatives is usually less than one year, and the term for natural gas and electricity derivatives is three years or less. The commodity price risk was managed by the marketing and trading organisations in the Natural Gas and Manufacturing & Marketing business areas, respectively, prior to 1 January 2011 and is currently managed by the crude oil, liquids and products and natural gas organizations in the Marketing, Processing and Renewable Energy business area. The risks are managed in the trading currencies of the commodities in question, and not necessarily in the functional or reporting currency of the company.

Currency risk

Statoil manages its currency risks for operations on the basis of USD. Fluctuations in exchange rates can have significant effects on our results. Foreign exchange risk is assessed on a portfolio basis in accordance with approved strategies and mandates. We only use well-understood, conventional derivative instruments, including futures and options traded on regulated exchanges, OTC swaps, options and forward contracts.

Our cash inflows are largely denominated in or driven by USD, while our cash outflows mainly derive from tax and dividend payments in NOK, as well as certain investments, payments of salaries and various other costs payable in NOK. Accordingly, our exposure to foreign currency rates is primarily related to the USD/NOK exchange rate. We seek to manage this currency mismatch by issuing or swapping non-current financial debt into USD.

We further seek to manage short-term currency mismatches by using derivative instruments for both currency and liquidity management purposes. Typically, we purchase NOK during the course of a calendar year in order to cover projected NOK payments of Norwegian income taxes and dividends in the first half of the subsequent year. This means, from time to time, that we purchase substantial amounts in NOK on a forward basis using derivative instruments.

Interest rate risk

The group has assets and liabilities with variable interest rates that expose the group to cash flow risk caused by market interest rate fluctuations. The group enters into interest rate derivatives, particularly interest rate swaps, to alter interest rate exposure, to lower expected funding costs over time and to diversify sources of funding. By using the fixed interest rate debt market when issuing new debt while at the same time altering the interest rate exposure by entering into interest rate swaps, funding sources become more diversified than if we were only able to use the floating rate debt market.

We principally manage the group's interest rate risk by converting cash flows from our long-term debt portfolio with fixed coupon rates into floating interest rate payments. Bond issues are normally issued at fixed rates in local currency (including JPY, EUR, CHF, GBP and USD). These bonds are converted into floating USD bonds by using interest rate and currency swaps. Under interest rate swaps, the group agrees 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. The group's interest rate policy also includes a mandate to deviate from base policy and keep part of the long-term debt in fixed interest rates.

Equity price risk

The group's captive insurance company holds listed equity securities as a part of its portfolio. In addition, the group has some other non-listed equity securities acquired for long-term strategic purposes. By holding these assets, the group is exposed to equity price risk defined as the risk of declining equity prices leading to a decline in the fair value of the group's assets recognised in the balance sheet. The equity price risk in the portfolio held by the group's captive insurance company with the aim of maintaining a moderate risk profile is managed through geographical diversification, the use of broad benchmark indexes and the use of several different fund managers.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our obligations when they fall due. The purpose of liquidity and short-term liability management is to make certain that the group has sufficient funds available at all times to cover financial obligations.

On a monthly basis, Statoil's business activities normally generate a positive cash flow from operations. However, in months when taxes are paid (February, April, June, August, October and December) or annual dividend is paid (typically in May/June) cash flows are typically limited. Our operating cash flows are negatively affected by any decline in oil and gas prices.

As a rule, the amount of liquid assets will follow a cyclical pattern and increase from month to month, with the exception of months when tax or dividend payments are made, when the amount is sharply reduced. In the period following tax and dividend payments, the amount of liquid assets will often be significantly reduced. A need for short-term funding will then be triggered for a period until the debt is repaid. This is then followed by a new accumulation of liquid assets.

Short-term funding can be carried out bilaterally through direct borrowing from banks, insurance companies etc. An alternative is to issue short-term debt securities under one of the existing funding programmes or under documentation established ad hoc. These funding programmes are as follows:

- A USD 4 billion US commercial paper programme. This is a flexible programme used for short-term funding.
- A USD 3 billion committed multi-currency revolving credit facility from international banks, including a USD 1 billion swing-line facility. The facility was entered into in December 2010. It is available for draw-downs until December 2015, but includes two one-year extension options that could extend the facility to December 2017.
- Uncommitted credit lines. A short-term funding source occasionally used by Statoil.

In order to have access to sufficient liquidity at all times, Statoil defines and continuously maintains a minimum liquidity reserve, which comprises unused committed external credit facilities, cash and cash equivalents, and current financial investments, excluding the current portion of the investment portfolio held by the group's captive insurance subsidiary.

Liquid assets (in NOK billion)	2010	2009	2008
Cash & cash equivalents	30.3	24.7	18.6
Financial investments	11.5	7.0	9.7
Total liquid assets	41.8	31.7	28.4

Funding and liability

As a basic principle, we separate investment decisions from financing decisions. Funding needs arise as a result of the group's general business activity. The main rule is to establish financing at corporate level. Project financing may be applied in cases involving joint ventures with other companies.

We aim at all times to have access to a variety of funding sources, in respect of both instruments and geography, and to maintain relationships with a core group of international banks that provide various kinds of banking and funding services.

We have credit ratings from Moody's and Standard & Poor's, and the stated objective is to have a rating at least within the single A category. This rating ensures necessary predictability when it comes to funding access on favourable terms and conditions. Our current long-term ratings are Aa2 stable outlook and AA- stable outlook from Moody's and Standard & Poor's, respectively. The short-term rating from Moody's is P-1 and A-1+ from Standard & Poor's. We intend to keep financial ratios relating to our debt at levels consistent with our objective of maintaining our long-term credit rating at least within the single A category to sustain financial flexibility going forward. In this context we carry out different risk assessments, some of them in line with financial matrices used by S&P and Moody's, such as free funds from operations over net debt and net debt to capital employed.

Statoil's long-term debt refinancing risk is controlled by keeping the maximum annual mandatory redemptions as a share of capital employed within predefined limits.

Liquidity forecasts serve as tools for financial planning. In order to maintain the necessary financial flexibility, we have requirements for maximum (forecasted) current debt and minimum (forecasted) liquidity reserve. The issuing of long-term debt is used as a tool for reducing current debt and/or increasing the liquidity reserve. New non-current funding will be initiated if liquidity forecasts uncover non-compliance with given limits, unless further detailed consideration indicates that the non-compliance is likely to be very temporary. In such case, the situation will be further monitored before additional non-current debt is drawn.

For further information about our debenture bonds, bank loans and other debt portfolio profile, see note 23 Non-current financial liabilities in the consolidated financial statements.

Statoil's dividend policy includes providing a return to our shareholders through cash dividends and share repurchases. The level of cash dividends and share repurchases can fluctuate in any one year, depending on our assessment of future cash flows, capital expenditure plans, financing requirements and appropriate financial flexibility. See the Shareholder information section for additional information about our dividend policy.

Credit risk
Credit risk is the risk that the group's customers or counterparties will cause the group financial loss by failing to honour their obligations. Credit risk arises from credit exposure to customer accounts receivables as well as from financial investments, derivative financial instruments and deposits with financial institutions.

Key elements of our credit risk management approach include:
- A global credit risk policy
- Credit mandates
- An internal credit rating process
- Credit risk mitigation tools
- Continuously monitoring and managing credit exposures

Prior to entering into transactions with new counterparties, the group's credit policy requires all counterparties to be formally identified and approved. All sales, trading and financial counterparties are also assigned internal credit ratings as well as exposure limits. Once established, all counterparties are re-assessed at least annually and monitored continuously. Counterparty risk assessments are based on a quantitative and qualitative analysis of recent financial statements and other relevant business information. In addition, Statoil evaluates any past payment performance, the counterparties' size and business diversification, and the inherent industry risk. The internal credit ratings reflect our assessment of the counterparties' credit risk. Exposure limits are determined based on assigned internal credit ratings combined with other factors, such as expected transaction and industry characteristics. Credit mandates define acceptable credit risk thresholds and are endorsed by management and regularly reviewed with regard to changes in market conditions.

The group uses risk mitigation tools to reduce or control credit risk, both at counterparty and portfolio level. The main tools include bank and parental guarantees, prepayments and cash collateral. For bank guarantees, only investment grade international banks are accepted as counterparties.

The group has pre-defined limits for the minimum average credit rating allowed at any given time at the group portfolio level as well as maximum credit exposures for individual counterparties. The group monitors the portfolio on a regular basis and individual exposures in relation to limits on a daily basis. Statoil's total credit exposure portfolio is geographically diversified among a number of counterparties in the oil and energy sector, as well as larger oil and gas consumers and financial counterparties. The majority of the group's credit exposure is with investment grade counterparties.

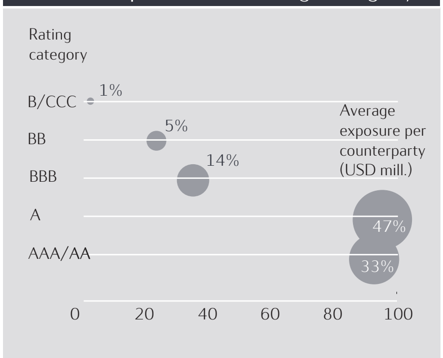
The following table contains the carrying amount of Statoil's financial receivables and derivative financial instruments that are neither past due nor impaired broken down by the group's assessment of the counterparty's credit risk. Only non-exchange traded instruments are included in current and non-current derivative financial instruments.

(in NOK million)	Non-current financial receivables	Trade and other receivables	Non-current derivative financial instruments	Current derivative financial instruments
At 31 December 2010				
Investment grade, rated A or above	987	29,614	12,444	4,291
Other investment grade	565	8,132	8,119	1,081
Non-investment grade or not rated	765	32,157	0	640
Total financial asset	2,317	69,903	20,563	6,012
At 31 December 2009				
Investment grade, rated A or above	1,081	25,119	10,975	3,501
Other investment grade	1,387	5,417	6,669	1,060
Non-investment grade or not rated	696	22,471	0	635
Total financial asset	3,164	53,007	17,644	5,196

As of 31 December 2010, counterparties have paid NOK 5.7 billion in cash, which is held by us as collateral to offset a portion of this credit exposure.

Consistent with our policies, commodity derivative counterparties have been assigned internal credit ratings corresponding to those of their respective parent companies. In cases where the parent company is highly rated, it may not be necessary to seek a parent company guarantee from such counterparties.

Credit exposure on rating category



The graph illustrates the magnitude as of 31 December 2010 of our credit risk exposure broken down by our assessment of the counterparties' credit risk. As can be seen from the illustration, most of our credit risk exposure is with counterparties assessed by us as having an investment grade credit rating. Our assessment of each counterparty's credit risk is often consistent with the credit ratings published by major credit rating agencies, but it may vary on a case-by-case basis due to differences in the timing and/or the judgments inherent in the specific credit risk assessment. Our assessment of each counterparty's credit risk may also change over time due to changes in company-specific or general conditions.

In accordance with our internal credit rating policy, we reassess counterparty credit risk at least annually and assess counterparties that we identify as high risk more frequently. The internal credit ratings reflect our assessment of the counterparties' credit risk and are similar to rating categories used by well known credit rating agencies, Standard & Poor's and Moody's. The mandate for setting the credit limit is regularly reviewed with regard to changes in market conditions.

5.2.2 Disclosures about market risk

Statoil uses financial instruments to manage commodity price risks, interest rate risks, currency risks and liquidity and funding risks. Significant amounts of assets and liabilities are accounted for as financial instruments.

See note 31 to the Consolidated financial statements, Financial instruments by category, for details of the nature and extent of such positions, and note 32, Financial instruments: fair value measurement and sensitivity analysis of market risk, for qualitative and quantitative disclosures of the risks associated with these instruments.

5.3 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.

We are currently not aware of any legal proceedings or claims that we believe could, individually or in aggregate, have significant effects on our financial position or profitability or on the results of our operations or liquidity.

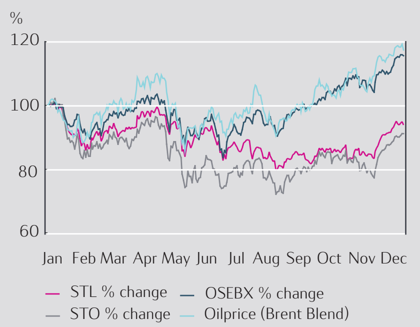
6 Shareholder information

Statoil is the largest company listed on the Oslo Stock Exchange, where it trades under the ticker code STL. Statoil is also listed on the New York Stock Exchange under the ticker code STO.

Statoil share	2010	2009	2008	2007	2006
Share price STL high (NOK)	**149.20**	146.80	214.10	191.50	210.50
Share price STL low (NOK)	**117.60**	108.90	96.40	151.50	147.25
Share price STL average (NOK)	**131.80**	129.50	153.60	169.70	174.25
Share price STL year-end (NOK)	**138.60**	144.80	113.90	169.00	165.25
Market value year-end (NOK billion)	**442**	462	363	539	358
Daily turnover (million shares)	**9.7**	9.6	13.5	16.5	12.6
Ordinary and diluted earnings per share (EPS) (NOK)	**11.94**	5.75	13.58	13.80	15.82
P/E [1]	**11.61**	25.18	8.39	12.25	10.45
Total dividend per share (NOK) [2]	**6.25**	6.00	7.25	8.50	9.12
Ordinary dividend per share (NOK) [2]	**6.25**	6.00	4.40	4.20	4.00
Special dividend per share (NOK)	**0.00**	0.00	2.85	4.30	5.12
Growth in ordinary dividend per share [3]	**4.2 %**	36.4 %	4.8 %	5.0 %	11.1 %
Growth in total dividend per share	**4.2 %**	(17.2 %)	(14.7 %)	(6.8 %)	11.2 %
Total dividend per share (USD) [4]	**1.07**	1.04	1.26	1.47	1.58
Pay-out ratio [5]	**52%**	104%	53%	61%	57%
Dividend yield [6]	**4.5 %**	4.1 %	6.4 %	5.0 %	5.5 %
Net interest bearing debt to capital employed	**24.6%**	27.3%	17.5%	12.4%	20.5 %
Ordinary shares outstanding, weighted average	**3,182,574,787**	3,183,873,643	3,185,953,538	3,195,866,843	3,230,849,707
Ordinary shares outstanding, year-end	**3,188,647,103**	3,188,647,103	3,188,647,103	3,188,647,103	3,208,800,400

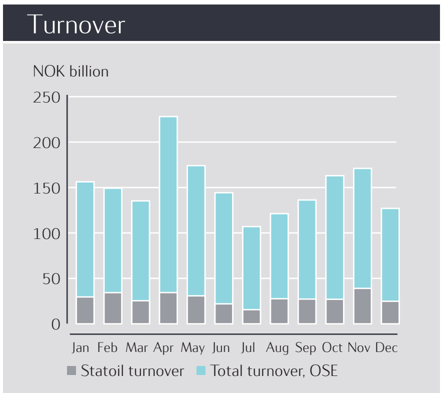
1) Share price at year-end divided by EPS.
2) Proposed cash dividend for 2010.
3) Excluding special dividend and share buy-back.
4) The USD amounts are based on the Norwegian Central Bank's exchange rate at 31 December 2010.
5) Total dividend paid per share divided by EPS. Total capital distribution in 2006 is 67%, including share buy-back of NOK 1.55 per share in 2006.
6) Total dividend paid per share divided by year-end share price.

Quote history



As of 31 December 2010, Statoil represented 26% of the total value of all companies registered on the Oslo stock exchange, with a market value of NOK 442 billion.

Statoil's share price closed at NOK 138.60 at the end of 2010. Taking into consideration the dividend of NOK 6.00 per share paid in 2010, the total return was minus NOK 0.20 per share. Quote history shows the development of the Statoil share price compared with the oil price and the Oslo Stock Exchange Benchmark Index (OSEBX).The board of directors proposes a dividend of NOK 6.25 per share for 2010, for approval by the annual general meeting on 19 May 2011. The dividend of NOK 6.25 per share that is proposed to be distributed to our shareholders is equivalent to a direct yield of approximately 4.5%, and we will distribute 52% of our net income from 2010. Net income per share amounted to NOK 11.94 in 2010, an increase of 107.7% compared with 2009.



The turnover of shares is a measure of traded volumes. On average, 9.7 million Statoil shares were traded on the Oslo stock exchange every day in 2010, which is virtually unchanged from 9.6 million shares the year before. Statoil shares accounted for 19% of the total market value traded throughout the year (see illustration).

Statoil ASA has one class of shares, and each share confers one vote at the general meeting. Statoil ASA had 3,188,647,103 ordinary shares outstanding at year end.

As of 31 December 2010, Statoil had approximately 102,800 shareholders registered in the Norwegian Central Securities Depository (VPS), which is a decrease from 103,900 shareholders the year before.

6.1 Dividend policy

It is Statoil's ambition to grow the annual cash dividend, measured in NOK per share, in line with long-term underlying earnings.

When deciding the annual dividend level, the board of directors will take into consideration expected cash flows, capital expenditure plans, financing requirements and needs for appropriate financial flexibility. In addition to the cash dividend, Statoil may buy back shares as part of its total distribution of capital to the shareholders.

The dividend policy was revised in February 2010 in order to create a more predictable dividend level. The board of directors emphasises the importance of maintaining an attractive dividend level in the future.

6.1.1 Dividends

Dividends for a fiscal year are declared at our annual general meeting the following year. The Norwegian Public Limited Companies Act forms the legal framework for dividend payments.

Under this Act, dividends may only be paid in respect of a financial period for 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.

We can only distribute dividends (1) if our equity, based on Statoil ASA's unconsolidated balance sheet, amounts to 10% or more of the total assets reflected in our unconsolidated balance sheet without following a creditor notice procedure as required for reducing the share capital, (2) to an extent that is compatible with good and careful business practice with due regard to any losses that we may have incurred after the last balance sheet date or that we may expect to incur, and (3) provided that the dividend to be distributed is calculated on the basis of our unconsolidated financial statements.

Although we currently intend to pay annual dividends on our ordinary shares, we cannot assure that dividends will be paid or 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.

The following table shows the cash dividend amounts paid to all shareholders since 2006 on a per share basis and in aggregate, as well as the cash dividend proposed by our board of directors to be paid in 2011 on our ordinary shares for the fiscal year 2010.

In 2006, 2007 and 2008, the total dividend per share consisted of an ordinary dividend and a special dividend. In 2009 the dividend per share consisted of an ordinary dividend only. The proposed dividend per share for 2010 is an ordinary dividend only. The special dividends paid in the past were the result of increased annual net income due to high realised oil and gas prices.

Year	Ordinary dividend per share NOK	Special dividend per share NOK	Total dividend per share NOK	Total NOK billion
2006	4.00	5.12	9.12	19.7
2007	4.20	4.30	8.50	27.1
2008	4.40	2.85	7.25	23.1
2009	6.00		6.00	19.1
2010	6.25*		6.25*	19.9*

*Proposed

The proposed dividend for 2010 will be considered at the annual general meeting on 19 May 2011. The Statoil share will be traded ex-dividend from 20 May 2011, and if approved, the dividend will be disbursed on 1 June 2011.

Since we will only pay dividends in Norwegian kroner (NOK), exchange rate fluctuations will affect the amounts in USD received by holders of ADRs after the ADR depositary converts cash dividends into USD. The dividend will be made available to the depositary on 1 June 2011. The depositary will convert the dividend into USD at the prevailing exchange rate for NOK and pay the US ADR holders the USD equivalent of the dividend in NOK, minus prevailing bank charges. The payment date for dividend in USD to US ADR holders is expected to be 13 June 2011.

Share repurchases

In addition to a cash dividend, Statoil may buy back shares as part of its total distribution of capital to its shareholders. For the period 2010-2011, the board of directors received authorization at the annual general meeting of Statoil to repurchase Statoil shares in the market for subsequent annulment. We did not undertake any share repurchases in 2010 and 2009, and no shares were acquired in the market for subsequent cancellation.

Future share repurchases will depend on the authorization of our shareholders, as well as a number of factors prevailing at the time our board of directors considers any share repurchase.

6.2 Equity securities purchased by issuer

Shares are acquired in the market for transfer to employees under the share savings scheme in accordance with the limits set by the board of directors. However, no shares were repurchased in the market for the purpose of subsequent cancellation in 2010.

6.2.1 Statoil's share savings plan

Since 2004, Statoil has had a share savings plan for employees of the group. The purpose of this plan is to strengthen the business culture and encourage loyalty through employees becoming part-owners of the company.

Through regular salary deductions, employees can invest up to 5% of their base salary in Statoil shares. In addition, the company contributes 20% of the amount to employees in Norway, up to a maximum of NOK 1,500 per year (approximately USD 250). This company contribution is a tax-free employee benefit under current Norwegian tax legislation. After a lock-in period of two calendar years, one extra share will be awarded for each share purchased. Under current Norwegian tax legislation, the share award is a taxable employee benefit, with a value equal to the value of the shares and taxed at the time of the award. Shares transferred to employees are acquired by the company in the market.

The board of directors is authorised to acquire Statoil shares in the market on behalf of the company. The authorisation may be used to acquire own shares at a total nominal value of up to NOK 20,000,000. Shares acquired pursuant to this authorisation may only be used for sale and transfer to employees of the Statoil group as part of the group's share saving plan, as approved by the board of directors. The minimum and maximum amount that may be paid per share is NOK 50 and 500, respectively.

The authorisation is valid until the next annual general meeting, but not beyond 30 June 2011. This authorisation replaces the previous authorisation to acquire Statoil's own shares for implementation of the share saving plan for employees granted by the annual general meeting on 19 May 2009.

The nominal value of each share is NOK 2.50. With a maximum overall nominal value of NOK 20,000,000, the authorisation for the repurchase of shares in connection with the group's share savings plan covers the repurchase of no more than eight million shares.

Share savings plan

Period in which shares where repurchased	Number of shares repurchased	Average price per share in NOK	Total number of shares purchased as part of program [1]	Maximum number of shares that may yet be purchased under the program authorisation [1]
January 2010	452,500	147.11	3,678,300	2,321,700
February 2010	519,000	128.88	4,197,300	1,802,700
March 2010	495,500	135.61	4,692,800	1,307,200
April 2010	466,000	144.64	5,158,800	841,200
May 2010	486,340	139.29	5,645,140	354,860
June 2010	248,600	136.71	248,600	7,751,400
July 2010	262,800	129.94	511,400	7,488,600
August 2010	275,800	123.61	787,200	7,212,800
September 2010	548,200	125.50	1,335,400	6,664,600
October 2010	542,500	127.83	1,877,900	6,122,100
November 2010	555,000	126.99	2,432,900	5,567,100
December 2010	529,000	134.13	2,961,900	5,038,100
January 2011	481,000	141.70	3,442,900	4,557,100
February 2011	493,000	138.64	3,935,900	4,064,100
Total	6,355,240 [2]	134.39 [3]	3,935,900	4,064,100

(1) The authorisation to repurchase a maximum of six million shares with a maximum overall nominal value of NOK 15 million for repurchase of shares in connection with the share savings plan was given by the annual general meeting on 19 May 2009. The authorisation was renewed by the annual general meeting on 19 May 2010 maintaining a maximum of eight million shares with a maximum overall nominal value of 20 million for repurchase of shares, and valid until 30 June 2011.

(2) All shares repurchased have been purchased in the open market and pursuant to the authorisation mentioned above.

(3) Weighted average price per share.

6.3 Information and communications

Providing the market with updated information about Statoil's financial performance and future prospects is the basis for assessing the value of the company.

Information provided to the stock market must be transparent and ensure equal treatment, and it must aim to provide shareholders with correct, clear, relevant and timely information that forms the basis for assessing the value of the company.

Statoil shares are listed on the Oslo Stock Exchange, and its ADRs are listed on the New York Stock Exchange. The company distributes its share price-sensitive information through the international wire services, Oslo Stock Exchange in Norway, the Securities and Exchange Commission in the USA, and the company's website.

Our registrar manages our shares listed on the Oslo Stock Exchange on our behalf and provides the connection to the Norwegian Central Securities Depository (VPS). Major services provided by the registrar are investor services for private shareholders, the disbursement of dividend and assistance at our general meetings. DnB NOR bank is currently account registrar for Statoil.

6.3.1 Investor contact

Our investor relations staff function (IR) coordinates the dialogue with our shareholders.

We place great emphasis on ensuring that relevant and timely information is distributed to the capital markets. Given the size and diversity of our shareholder base, the opportunities for direct shareholder interaction are limited to a certain extent. Our "Investor Centre" web pages are therefore specially designed for investors and analysts who wish to follow the company's progress - http://www.statoil.com/ir

Our quarterly presentations and other relevant presentations by management are broadcasted directly on the internet, and the related reports are made available together with other relevant information on the company's website.

Statoil meets the requirements for the information symbol and English symbol issued by Oslo Stock Exchange (Oslo Børs).

Ticker Codes

Oslo Stock Exchange STL
New York Stock Exchange STO
Reuters STL.OL
Bloomberg STL NO

Financial calendar for 2011

09 February	Fourth quarter results 2010 and strategy update
25 March	Annual report 2010
04 May	First quarter 2011
19 May	Annual general meeting 2011
20 May	Share trading ex-dividend
01 June	Dividend payment
20 June	Investor day 2011
28 July	Second quarter 2011
27 October	Third quarter 2011

6.4 Market and market prices

The principal trading market for our ordinary shares is the Oslo Stock Exchange. The the ordinary shares are also listed on the New York Stock Exchange, trading in the form of American Depositary Shares (ADSs).

Statoil's shares have been listed on the Oslo stock exchange since our initial public offering on 18 June 2001. The ADSs traded on the New York Stock Exchange are evidenced by American Depositary Receipts (ADRs), and each ADS represents one ordinary share. Statoil has a sponsored ADR facility with The Bank of New York Mellon as depositary.

6.4.1 Share prices

These are the reported high and low quotations at market closing for the ordinary shares on the Oslo stock exchange and New York Stock Exchange for the periods indicated.

They are derived from the Oslo Stock Exchange Daily Official List, and the highest and lowest sales prices of the ADSs as reported on the New York Stock Exchange composite tape.

	NOK per ordinary share		USD per ADS	
Share price	High	Low	High	Low
Year ended 31 December				
2006	210.50	147.25	34.52	22.39
2007	191.50	151.50	35.19	23.90
2008	214.10	96.40	42.47	13.37
2009	146.80	108.90	26.41	15.11
2010	149.20	117.60	26.47	18.68
Quarter ended				
31 March 2009	131.00	108.90	20.09	15.11
30 June 2009	140.70	113.80	22.19	17.01
30 September 2009	137.90	119.40	23.20	18.26
31 December 2009	146.80	126.00	26.41	21.69
31 March 2010	149.20	126.90	26.47	21.57
30 June 2010	147.00	123.90	24.98	19.15
30 September 2010	131.70	117.60	21.59	18.68
31 December 2010	140.50	122.40	23.77	19.99
March up until 12 March 2011	154.10	136.30	27.67	23.35
Month of				
September 2010	126.40	120.50	20.98	19.66
October 2010	128.00	124.00	21.46	19.99
November 2010	129.40	122.40	22.05	21.47
December 2010	140.50	126.30	23.77	22.06
January 2011	142.70	137.90	24.65	23.35
February 2011	149.00	136.30	26.39	23.45
March up until 12 March 2011	154.10	147.40	27.67	26.00

6.4.2 Fees related to Statoil's ADR program

Fees and charges payable by a holder of ADSs

As depositary, The Bank of New York Mellon collects its fees for the delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal, or from intermediaries acting for them. The depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of distributable property to pay the fees. The depositary may refuse to provide fee-attracting services until its fees for those services are paid.

The charges of the depositary payable by investors are as follows:

Persons depositing or withdrawing shares must pay:	For:
USD 5.00 (or less) per 100 ADSs (or portion of 100 ADSs)	· Issuance of ADSs, including issuances resulting from a distribution of shares or rights or other property · Cancellation of ADSs for the purpose of withdrawal, including if the deposit agreement terminates
USD 0.02 (or less) per ADS	· Any cash distribution to ADS registered holders
A fee equivalent to the fee that would be payable if securities distributed to you had been shares and the shares had been deposited for issuance of ADSs	· Distribution of securities distributed to holders of deposited securities which are distributed by the Depositary to ADS registered holders
Registration or transfer fees	· Transfer and registration of shares on our share register to or from the name of the Depositary or its agent when you deposit or withdraw shares
Expenses of the Depositary	· Cable, telex and facsimile transmissions (as provided in the deposit agreement) · Converting foreign currency to U.S. dollars
Taxes and other governmental charges the Depositary or the custodian have to pay on any ADS or share underlying an ADS, for example, stock transfer taxes, stamp duty or withholding taxes	· As necessary
Any charges incurred by the Depositary or its agents for servicing the deposited securities	· As necessary

Reimbursements and payments made and fee waivers granted by the depositary

The depositary has agreed to reimburse certain company expenses related to the company's ADR programme and incurred by the company in connection with the programme. In the year ended 31 December 2010, the depositary reimbursed USD 1,142,913 to the company.

The table below sets forth the types of expenses that the depositary has agreed to reimburse and the amounts reimbursed in the year ended 31 December 2010:

Category of Expenses	USD Amount Reimbursed for the year ended 31 December 2010
NYSE listing fees	61,953
US investor relations expenses and other miscellaneous expenses	1,080,960
Total Amount Reimbursed	1,142,913*

* Net of withholding tax paid by the Depository.

The depositary has also agreed to waive fees for standard costs associated with the administration of the ADR programme, and it has paid certain expenses directly to third parties on behalf of the company. The expenses paid to third parties include expenses relating to the mailing of notices and meeting material as well as the tabulation of votes in connection with the company's annual general meeting.

The table below sets forth the expenses that the depositary waived or paid directly to third parties in the year ended 31 December 2010:

Category of Expenses	USD Amount Waived or Paid for the year ended 31 December 2010
Third-party expenses paid directly by the Depositary*	132,420
Service fees waived by the Depositary	130,000
Total Amount Waived or Paid Directly to Third Parties	262,420

*Statoil paid indirectly USD125,468 of the third-party expenses paid by the depositary via a decrease in the amount reimbursable to Statoil by the depositary.

Under certain circumstances, including removal of the depositary or termination of the ADR programme by the company, the company is required to repay to the depositary amounts reimbursed and/or expenses paid to or on behalf of the company during the twelve-month period prior to notice of removal or termination.

6.5 Taxation

This section describes the material Norwegian tax consequences that apply to shareholders resident in Norway and to non-resident shareholders in connection with the acquisition, ownership and disposal of shares and ADSs.

Norwegian tax matters
This section does not provide a complete description of all tax regulations that might be relevant (i.e. for investors to whom special regulations may be applicable). This section is based on current law and practice. Shareholders should consult their professional tax adviser for advice concerning individual tax consequences.

Taxation of dividends
Under the participation exemption model, corporate shareholders resident in Norway for tax purposes are exempt from tax on dividends distributed by Norwegian companies. However, effective from 7 October 2008, 3% of net income that is tax free under the participation exemption model will be included in the Norwegian corporate shareholder's general taxable income. For individual shareholders, double taxation applies: dividend income exceeding a "deductible allowance", which is an amount equal to the risk-free interest after tax on the base cost of the shareholding, will be taxable at a flat rate, currently 28%. The average interest on Treasury bills of three months' maturity will be applied when calculating the deductible allowance.

Non-resident shareholders are as a rule subject to withholding tax at a rate of 25% on dividends distributed by Norwegian companies. This withholding tax does not apply to corporate shareholders that document that they are genuinely resident for tax purposes in a country in the European Economic Agreement area (EEA area) and that they are involved in genuine economic business activity in that country, provided that Norway is entitled to receive information from the state of residency pursuant to a tax treaty or other international treaty. If no such treaty exists with the state of residency, the shareholder may instead present certification issued by the tax authorities of the state of residency verifying the documentation.

The withholding rate of 25% is often reduced in tax treaties between Norway and other countries. 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 withholding tax rate in the tax treaty between the United States and Norway is currently 15% in all cases. The treaty is currently being renegotiated, but it is uncertain at what point in time a new treaty will be in place. Shareholders that carry on business activities in Norway and whose shares are effectively connected with such activities are not liable to the withholding tax. In such case, the rules described in the above paragraph regarding shareholders resident in Norway will generally be applicable. We are obliged by law to deduct any applicable withholding tax when paying dividends to non-resident shareholders.

Under the tax treaty between Norway and the United States, the 15% withholding rate will apply to dividends paid on shares held directly by holders who are able to properly demonstrate to the company that they are entitled to the benefits of the tax treaty.

Dividends paid to the depositary for redistribution to shareholders who hold ADSs will in principle be subject to withholding tax of 25%. The beneficial owners will in this case have to apply to the Central Office - Foreign Tax Affairs (COFTA) for a refund of the excess amount of tax withheld.

An application for a refund of withholding tax must contain the following:

1. Specification of the distributing company(ies) involved, the exact number of shares, the date the dividend payments were made, the total dividend payment, the withholding tax deducted in Norway and the amount that is being reclaimed. The withholding tax must be calculated in Norwegian currency and all sums specified accordingly (in NOK).
2. Documentation that shows that the refund claimant received the dividends, and the withholding tax rate that was applied in Norway.
3. A certificate of residence issued by the tax authorities stating that the refund claimant is resident for tax purposes in that state in the income year in question or at the time the dividends were decided. This documentation must be the original document.
4. If the refund application is based on an assertion that the shareholder is covered by the participation exemption method, the application must also contain the information necessary to decide whether the refund claimant is an entity covered by the tax exemption model.
5. The information required to decide whether the refund claimant is the beneficial owner of the dividend payment(s).
6. If the securities are registered with a foreign custodian/bank/clearing house, the claimant must provide information about which foreign custodian/bank/clearing house the securities are registered with in Norway.

The application must be signed by the applicant. If the application is signed by a proxy, a copy of the letter of authorisation must be enclosed.

However, pursuant to agreements with the Financial Supervisory Authority of Norway and the Norwegian Directorate of Taxes, The Bank of New York Mellon, 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, if the beneficial holder has provided The Bank of New York Mellon with appropriate certification to establish such holder's eligibility for the benefits under the tax treaty with Norway.

Wealth tax

The shares are included in the basis for the computation of wealth tax imposed on individuals who are considered to be resident in Norway for tax purposes. Norwegian limited companies and certain similar entities are not subject to wealth tax. Currently, the marginal wealth tax rate is 1.1% of the value assessed. The assessment value of listed shares is 100% of the listed value of such shares on 1 January in the assessment year.

Non-resident shareholders are not subject to wealth tax in Norway for shares in Norwegian limited 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. However, if a Norwegian citizen is not a resident of Norway at the time of his or her death, Norwegian inheritance tax will not be levied if 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 conducting of a trade or business through a permanent establishment in Norway.

Taxation on the realization of shares

Under the participation exemption model, corporate shareholders resident in Norway for tax purposes are exempt from tax on gains on the sale, redemption or other disposal of shares in Norwegian companies. Corporate shareholders will not be allowed a deduction for losses incurred on the sale, redemption or other disposal of shares in Norwegian companies if a gain would be exempted from taxation. However, effective from 7 October 2008, 3% of net income that is tax free under the participation exemption model will be included in the Norwegian corporate shareholder's general taxable income.

For individual shareholders resident in Norway for tax purposes, the sale, redemption or other disposal of shares will be deemed to be a taxable realization of shares. Gains or losses in connection with such realization are included in or deducted from the individual's ordinary taxable income in the year of disposal. Ordinary income is taxed at a flat rate of 28%. Any gain is subject to tax and any loss is deductible irrespective of the length of the ownership and the number of shares disposed of.

The taxable gain or loss is calculated as the sales price adjusted for transaction expenses minus the taxable basis. A shareholder's tax basis is normally equal to the acquisition cost of the shares. Any unused "deductible allowance" from previous years attributable to the individual shares realized may be deducted, but the deduction cannot exceed the gain on the shares.

Shareholders not resident in Norway are generally not subject to tax in Norway on capital gains, and losses are not deductible on the sale, redemption or other disposal of shares or ADSs in Norwegian companies, unless the shareholder carries on business activities in Norway and such shares or ADSs are or have been effectively connected with such activities. Individual shareholders previously resident in Norway may, on certain conditions, be liable to tax in Norway on such gains if the realization takes place within five years of the end of the calendar year in which the shareholder ceased to be a resident of Norway for tax purposes, or, alternatively, within five years of the Norwegian tax residency expiring pursuant to Norwegian domestic law or tax treaty.

Transfer tax

No transfer tax is imposed in Norway in connection with the sale or purchase of shares.

United States tax matters

This section describes the material United States federal income tax consequences for US holders (as defined below) of owning shares or ADSs. It only applies to you 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 organisations;
- life insurance companies;
- persons liable to 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 USD.

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 will generally be treated as the owner of the ordinary shares represented by those ADRs. Exchanges of shares for ADRs and ADRs for shares will not generally be subject to United States federal income tax.

If a partnership holds the shares or ADSs, the United States federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership. A partner in a partnership holding the shares or ADSs should consult its tax advisor with regard to the United States federal income tax treatment of an investment in the shares or ADSs.

You are a "US holder" if you are a beneficial owner of shares or ADSs and you are for United States federal income tax purposes:

- an individual who is a citizen or resident of the United States;
- a United States domestic corporation;
- 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 authorised to control all substantial decisions of the trust.

You should consult your own tax adviser regarding the United States federal, state and local and the Norwegian and other tax consequences of owning and disposing of shares and ADSs in your particular circumstances.

Taxation of dividends

If you are a US holder, 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) is subject to United States federal income taxation. If you are a non-corporate US holder, dividends paid to you in taxable years beginning before 1 January 2013 will be eligible to be taxed at a maximum tax rate of 15% so long as, in the year that you receive the dividend, the shares or ADSs are readily tradable on an established securities market in the United States or Statoil is eligible for benefits under the Treaty. To qualify for the 15% maximum tax rate, you must hold the shares or ADSs for more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meet certain other requirements. Furthermore, these tax consequences would be different if Statoil were to be treated as a PFIC as discussed below.

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 taxable for you 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 value in US dollars (USD) of the payments made in Norwegian kroner (NOK) determined at the spot NOK/USD rate on the date the dividend distribution is includible in your income, regardless of whether or not 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 to Norway will be creditable or deductible against your United States federal income tax liability. Special rules apply when determining the foreign tax credit limitation with respect to dividends that are subject to the maximum 15% rate. To the extent a refund of the tax withheld is available to you under Norwegian law, the amount of tax withheld that is refundable will not be eligible for credit against your United States federal income tax liability. Dividends will be income from sources outside the United States. Dividends paid in taxable years beginning before 1 January 2007 will generally be "passive income" or "financial services income", and dividends paid in taxable years beginning after 31 December 2006 will, depending on your circumstances, be either "passive" or "general" income for purposes of computing the foreign tax credit allowable to you.

Any gain or loss resulting from currency exchange rate fluctuations during the period from the date you include the dividend payment in income until the date you convert the payment into US dollars will generally be treated as ordinary income or loss and will not be eligible for the special tax rate applicable to qualified dividend income. Such gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes.

Taxation of capital gains

Subject to the PFIC rules discussed below, if you are a US holder and you sell or otherwise dispose of your shares or ADSs, you will generally recognise a capital gain or loss for United States federal income tax purposes equal to the difference between the value in US dollars of the amount that you realise 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 preferential rates where the property is held for more than one year. The gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes.

If you receive any foreign currency on the sale of shares or ADSs, you may recognise 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.

PFIC Rules

We believe that the shares and ADSs should not be treated as stock of a PFIC for United States federal income tax purposes, but this conclusion is a factual determination that is made annually and thus may be subject to change. If we were to be treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to the shares or ADSs, a gain realised on the sale or other disposition of the shares or ADSs would in general not be treated as a capital gain. Instead, if you are a US holder, you would be treated as if you had realised such gain and certain "excess distributions" ratably over your holding period for the shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain or distribution was allocated, together with an interest charge in respect of the tax attributable to each such year. With certain exceptions, the shares or ADSs will be treated as stock in a PFIC if we were a PFIC at any time during the period you held the shares or ADSs. Dividends that you receive from us will not be eligible for the special tax rates applicable to qualified dividend income if we are treated as a PFIC with respect to you, either in the taxable year of the distribution or the preceding taxable year, but will instead be taxable at rates applicable to ordinary income.

6.6 Exchange controls and other limitations

Under Norwegian foreign exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior government approval.

The exception to this applies to the physical transfer of payments in currency exceeding certain thresholds, which must be declared to Norwegian custom authorities.

This means that non-Norwegian resident shareholders may receive dividend payments without Norwegian exchange control consent as long as the payment is made through a licensed bank, or other licensed payment institutions.

There are no restrictions affecting the rights of non-Norwegian residents or foreign owners to hold or vote for our shares.

6.7 Exchange rates

The table below shows the high, low, average and end-of-period exchange rates for the Norwegian krone per USD 1.00 as announced by Central Bank of Norway.

The average is computed using the monthly average exchange rates announced by the Central Bank of Norway during the period indicated.

Year ended December 31	Low	High	Average	End of Period
2006	6.0125	6.8381	6.4135	6.2551
2007	5.2751	6.4727	5.8610	5.4110
2008	4.9589	7.2183	5.6390	6.9989
2009	5.5433	7.2048	6.2898	5.7767
2010	**5.6026**	**6.6840**	**6.0437**	**5.8564**

	Low	High
2010		
September	5.8382	6.2070
October	5.7226	5.9118
November	5.7203	6.2248
December	5.8564	6.1456
2011		
January	5.7499	5.9742
February	5.5725	5.8636
March (up to and including 11 March 2011)	5.5318	5.6672

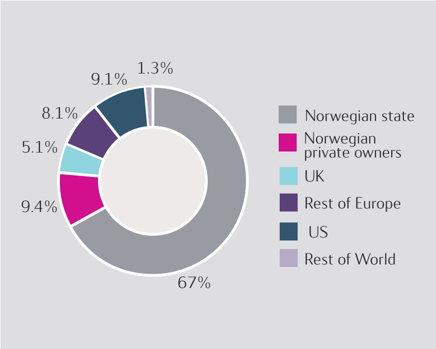
On 11 March 2011, the exchange rate announced by the Central Bank of Norway for the Norwegian krone was USD 1.00 = NOK 5.6672.

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

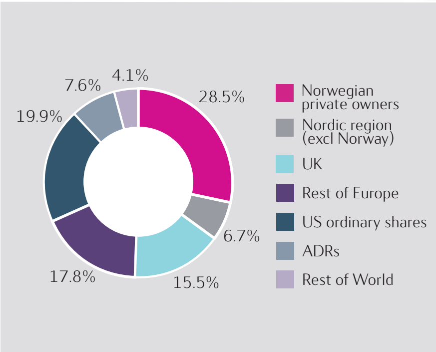
6.8 Major shareholders

The Norwegian State is the largest shareholder in Statoil, with a direct ownership interest of 67%. Its ownership interest is managed by the Ministry of Petroleum and Energy.

Distribution of shareholders



Free float breakdown



Pursuant to the exchange ratio agreed in connection with the merger with Hydro's oil and gas activities, the State's ownership interest in the merged company was 62.5%, or 1,992,959,739 shares, on 1 October 2007. In accordance with the parliament's decision of 2001 concerning a minimum state shareholding of two-thirds in Statoil, the Government built up the State's ownership interest in Statoil by buying shares in the market during the period from June 2008 to March 2009. In March 2009, the Government announced that the State's direct ownership interest had reached 67%, and the Government's direct purchase of Statoil shares was completed. As of 12 March 2011, the Norwegian State had a 67% direct ownership interest in Statoil and a 3.07% indirect interest through the National Insurance Fund (Folketrygdfondet), totalling 70.07%.

The Norwegian State is the only person or entity known to us to own beneficially, directly or indirectly more than 5% of our outstanding shares. We have not been notified of any other beneficial owner of 5% or more of our ordinary shares as of 12 March 2011.

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 Mellon 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 Mellon that in the United States, as of 12 March 2011, there were 96,919,623 ADRs outstanding (representing approximately 3.0% of the ordinary shares outstanding). As of 12 March 2011, there were 731 registered holders of ADRs resident in the United States. According to Norwegian Central Securities Depository (VPS) 295,655,269 ordinary shares were held by 489 registered holders resident in the United States representing approximately 9.3% of Statoil's ordinary shares in total. The number of beneficial holders is not known. Dividend was paid to approximately 94,000 beneficiaries in the USA in 2010 according to the records of The Bank of New York Mellon. The number of American Depositary Receipts traded on the New York Stock Exchange increased by 31% during the course of the year to 80.1 million shares at the end of 2010.

Statoil has one class of shares, and each share confers one vote at the general meeting. The Norwegian State does not have any voting rights that differ from the rights of other ordinary shareholders. Pursuant to the Norwegian Public Limited Liability Companies Act, a majority of more than two-thirds of the votes cast as well as of the votes represented at a general meeting is required 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. Since the Norwegian State, acting through the Minister of Petroleum and Energy, has in excess of two-thirds of the shares in the company, it has sole power to amend 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 proposed by the board of directors.

The Norwegian State endorses the principles set out in "The Norwegian Code of Practice for Corporate Governance", and it has stated that it expects companies in which the State has ownership interests to adhere to the code. The principle of ensuring equal treatment of different groups of shareholders is a key element in the State's own guidelines. In companies in which the State is a shareholder together with others, the State wishes to exercise the same rights and obligations as any other shareholder and not act in a manner that has a detrimental effect on the rights or financial interests of other shareholders. In addition to the principle of equal treatment of shareholders, emphasis is also placed on transparency in relation to the State's ownership and on the general meeting being the correct arena for owner decisions and formal resolutions.

Shareholders at 12 March 2011	Type	Number of shares	Ownership in %
The Norwegian State (Ministry of Petroleum and Energy)		2,136,393,559	67.00
Folketrygdfondet (Norwegian national insurance fund)		97,840,003	3.07
Bank of New York ADR Department	Nominee	81,689,768	2.56
Clearstream Banking	Nominee	52,717,492	1.65
State Street Bank	Nominee	34,300,407	1.08
JPMorgan Chase Bank	Nominee	32,320,699	1.01
State Street Bank	Nominee	29,583,696	0.93
The Northern Trust	Nominee	28,615,000	0.90
Bank of New York Mellon	Nominee	19,316,549	0.61
State Street Bank	Nominee	17,525,121	0.55
Vital Forsikring ASA		17,018,483	0.53
Bank of New York Depositary Receipts	Nominee	15,229,855	0.48
State Street Bank	Nominee	15,114,795	0.47
Danske bank operations	Nominee	11,789,997	0.37
Six SIS AG	Nominee	11,199,064	0.35
Bank of New York Mellon	Nominee	9,615,882	0.30
State Street Bank	Nominee	8,918,874	0.28
Skandinaviska Enskilda Bank	Nominee	8,779,887	0.28
DnB NOR Norge		8,548,283	0.27
Euroclear bank	Nominee	8,380,704	0.26

Source: Norwegian Central Securities Depository (VPS)

7 Corporate governance

Statoil's objective is to create long-term value for its shareholders through exploration for, and production, transportation, refining and marketing of petroleum and petroleum-derived products and other forms of energy.

In pursuing our corporate objective, we are committed to the highest standard of governance and to cultivating a value-based performance culture that rewards exemplary ethical standards, respect for the environment and personal and corporate integrity. We believe that there is a link between high-quality governance and the creation of shareholder value.

The work of the board of directors is based on the existence of a clearly defined division of roles and responsibilities between the shareholders, the board of directors and the company's management.

Our governing structures and controls help to ensure that we run our business in a profitable manner for the benefit of our shareholders, employees and other stakeholders in the societies in which we operate.

The following principles underline our approach to corporate governance:

- All shareholders will be treated equally
- Statoil will ensure that all shareholders have access to up-to-date, reliable and relevant information about the company's activities
- Statoil will have a board of directors that is independent (as defined by Norwegian Standards) of the group's management. The board focuses on there not being any conflicts of interest between shareholders, the board of directors and the company's management
- The board of directors will base its work on the principles for good corporate governance applicable at all times

Corporate governance in Statoil is subject to annual review and discussion by the board of directors.

Statoil's board of directors endorses the "Norwegian Code of Practice for Corporate Governance", last revised on 21 October 2010. The company's compliance with and, if applicable, deviation from the code of practice is commented on, and these comments are made available to Statoil's shareholders.

In the board's view, Statoil has complied with the code of practice throughout the year ended 31 December 2010. In the statutory report, the board presents its statement on corporate governance, structured as the Norwegian code of practice stipulates.

7.1 Articles of association

The articles of association and the Norwegian Public Limited Companies Act form the legal framework for Statoil's operations.

Statoil's current articles of association were adopted at the annual general meeting of shareholders on 19 May 2010.

Summary of our articles of association

Name of the company
Our registered name is Statoil ASA. We are a Norwegian public limited company.

Registered office
Our registered office is in Stavanger, Norway, registered with the Norwegian Register of Business Enterprises under number 923 609 016.

Object of the company
The object of our company, as set forth in Article 1, is, either ourselves or through participation in or together with other companies, to carry out exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, and other forms of energy, as well as other businesses.

Share capital
Our share capital is NOK 7,971,617,757.50 divided into 3,188,647,103 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 consist of ten directors. The board, including the chair and the deputy chair, shall be elected by the corporate assembly.

Corporate assembly
We have a corporate assembly comprising 18 members who are elected for two-year terms. The general meeting elects 12 members with four deputy members, and six members with deputy members are elected by and from among the employees.

Annual general meeting
Our annual general meeting is held no later than June 30 each year.

The meeting will consider the annual report and accounts, including the distribution of any dividend, and any other matters 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 licences on the NCS as well as petroleum received by the Norwegian State paid as royalty together with our own production. Our general meeting adopted an instruction in respect of such marketing on 25 May 2001.

Nomination committee
The tasks of the nomination committee are to make recommendations to the general meeting regarding the election of and fees for shareholder-elected members and deputy members of the corporate assembly, to make recommendations to the corporate assembly regarding the election of and fees for shareholder-elected members of the board of directors, to make recommendations to the corporate assembly regarding the election of the chair and the deputy chair of the board and to make recommendations to the general meeting regarding the election of and fees for members of the nomination committee.

Electronic distribution of documentation to general meetings of shareholders
A revision of our articles of association in 2010 states that documents relating to matters to be dealt with at the general meeting do not need to be sent to all shareholders if the documents are accessible on Statoil's home pages. A shareholder may nevertheless request that documents be sent to him/her.

The full articles of association are available at www.statoil.com/articlesofassociation.

7.2 Ethics Code of Conduct

Together with Statoil's values statement, the Ethics Code of Conduct constitutes the basis and framework for our performance culture.

Our ability to create value is dependent on applying high ethical standards, and we are determined that Statoil shall be known for these standards. Ethics is treated as an integral part of our business activities. We demand high ethical standards of our employees and everyone who acts on our behalf and will conduct an open dialogue on ethical issues both internally and externally.

The Statoil Ethics Code of Conduct describes our commitment and requirements in connection with issues of an ethical nature that relate to business practice and personal conduct.

In our business activities, we will comply with applicable laws and regulations and act in an ethical, sustainable and socially responsible manner. Respect for human rights is an integral part of Statoil's values base.

The Ethics Code of Conduct applies to the whole organisation and to its individual employees, board members, hired personnel, consultants, intermediaries, lobbyists and others who act on Statoil's behalf, including the chief executive officer, the chief financial officer and the principal accounting controller. The Ethics Code of Conduct is available at www.statoil.com together with our anti-corruption compliance programme.

Business partners are also expected to adhere to ethical standards that are consistent with our ethical requirements.

We have a dedicated ethics helpline that can be used by employees who wish to express concerns or seek advice regarding the legal and ethical conduct of Statoil's business.

7.3 General meeting of shareholders

The general meeting of shareholders is the company's supreme body. The objective of the general meeting is to ensure shareholder democracy. Statoil encourages all shareholders to participate in person or by proxy.

The general meeting of shareholders is the company's supreme corporate body. The 2011 annual general meeting (AGM) is scheduled for 19 May 2011 in Stavanger, Norway, with simultaneous transmission by webcast. The AGM is conducted in Norwegian, with simultaneous English translation during the webcast.

The main framework for convening and holding Statoil's AGM is as follows:

Pursuant to the company's articles of association, the AGM must be held by the end of June each year. Notice of the meeting and documents relating to the AGM are published on Statoil's website and sent to all shareholders with known addresses at least 21 days prior to the meeting. All shareholders who are registered in the Norwegian Central Securities Depository (VPS) will receive an invitation to the AGM. Other documents relating to Statoil's AGMs will be made available on Statoil's website. A shareholder may nevertheless request that documents that relate to matters to be dealt with at the AGM be sent to him/her.

Shareholders are entitled to have their proposals dealt with at the AGM if the proposal has been submitted in writing to the board of directors in sufficient time to enable it to be included in the distributed notice of meeting. Shareholders who are prevented from attending may vote by proxy.

The deadline for registration for the AGM in Statoil is the day before the AGM is due to take place.

The AGM is normally opened and chaired by the chair of the corporate assembly. If there is a dispute concerning individual matters and the chair of the corporate assembly belongs to one of the disputing parties, or is for some other reason not perceived as being impartial, another person will be appointed to chair the AGM. This is in order to ensure impartiality in relation to the matters to be considered. As Statoil has a large number of shareholders with a wide geographical distribution, Statoil offers shareholders the opportunity to follow the AGM by webcast.

The following matters are decided at the AGM:
- Election of the shareholders' representatives to the corporate assembly and stipulation of the corporate assembly's fees
- Election of the nomination committee and stipulation of the nomination committee's fees
- Election of the external auditor and stipulation of the auditor's fee
- Approval of the board of directors' report, the financial statements and any dividend proposed by the board of directors and recommended by the corporate assembly
- Any other matters listed in the notice convening the AGM

All shares carry an equal right to vote at general meetings. Resolutions at AGMs are normally passed by simple majority. However, Norwegian company law requires a qualified majority for certain resolutions, including resolutions to waive preferential rights in connection with any share issue, approval of a merger or demerger, amendment of the articles of association or authorisation to increase or reduce the share capital. Such matters require 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 AGM.

The minutes of the AGM are made available on Statoil's website immediately after the AGM.

As regards extraordinary general meetings (EGM), an EGM will be held in order to consider and decide a specific matter if demanded by the corporate assembly, the chair of the corporate assembly, the auditor or shareholders representing at least 5% of the share capital. The board must ensure that the extraordinary general meeting is held within a month of such demand being submitted.

In the following, we outline certain types of resolutions by the general meeting of shareholders:

New share issues

If we issue any new shares, including bonus shares, our articles of association must be amended, which requires the same majority 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 right to subscribe to an issue may be waived by a resolution of a general meeting passed by the same percentage as required to approve amendments to our articles of association. The general meeting may, with a majority as described above, authorise the board of directors to issue new shares, and to waive the preferential rights of shareholders in connection with such share issues. Such authorisation 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 authorisation was granted.

The issuing of shares through the exercise of preferential rights to holders who are citizens or residents of the USA may require us to file a registration statement in the USA under US securities laws. If we decide not to file a registration statement, these holders may not be able to exercise their preferential rights.

Right of redemption and repurchase of shares

Our articles of association do not authorise the redemption of shares. In the absence of authorisation, the redemption of shares may nonetheless be decided by a general meeting of shareholders by a two-thirds majority on 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 authorisation to do so has been granted by a general meeting with the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at the general meeting. The aggregate par value of such treasury shares held by the company must not exceed 10% of the company's share capital, and treasury shares may only be acquired if, according to the most recently adopted balance sheet, the company's distributable equity exceeds the consideration to be paid for the shares. Authorisation by the general meeting cannot be granted for a period exceeding 18 months.

Distribution of assets on liquidation

Under Norwegian law, a company may be wound up by a resolution of the company's shareholders at a general meeting passed by both a two-thirds majority of the aggregate votes cast and a two-thirds majority of the aggregate share capital represented at the general meeting. The shares are ranked equally in the event of a return on capital by the company upon winding-up or otherwise.

7.4 Nomination committee

Pursuant to Statoil's articles of association, the nomination committee shall consist of four members who are shareholders or representatives of shareholders.

The committee is independent of both the board of directors and the company's management.

The duties of the nomination committee are to submit recommendations to

- the annual general meeting concerning the election of shareholder-elected members and deputy members of the corporate assembly and remuneration of members of the corporate assembly;
- the annual general meeting concerning the election and remuneration of members of the nomination committee;
- the corporate assembly concerning the election of shareholder-elected members of the board of directors and remuneration of the members of the board of directors, and
- the corporate assembly concerning the election of the chair and deputy chair of the corporate assembly.

Using a form on the company's website, shareholders can propose candidates for the board of directors, the corporate assembly and the nomination committee.

The members of the nomination committee are elected by the AGM. Two of the members are elected from among the shareholder-elected members of the corporate assembly. Members of the nomination committee are normally elected for a term of two years.

The members of the nomination committee are:

- Olaug Svarva (chair), managing director, Folketrygdfondet
- Live Haukvik Aker, partner in the Considium Consulting Group AS
- Tom Rathke, managing director, Vital Forsikring and executive vice president, DnB NOR
- Bjørn Ståle Haavik, counsellor for energy, Mission of Norway to the EU.

The nomination committee held 19 meetings in 2010.

The rules of procedure for the nomination committee are available at www.statoil.com/nominationcommittee.

7.5 Corporate assembly

Pursuant to the Norwegian Public Limited Liability Companies Act, companies with more than 200 employees must elect a corporate assembly unless otherwise agreed between the company and a majority of its employees.

Name	Occupation	Place of residence	birth	Position	Family relations to corporate executive committee, board or corporate assembly members	Share ownership for members pr0 31.12.201	Share ownership for members pr 12.03.2011	First time elected	Expiration date of current term
Olaug Svarva	Managing director, Folketrygdfondet	Oslo	1957	Chair, Shareholder elected	No	0	0	2007	2012
Idar Kreutzer	CEO, Storebrand	Oslo	1962	Deputy chair, Shareholder elected	No	0	0	2007	2012
Karin Aslaksen	Executive vice president, Orkla ASA	Hosle	1959	Shareholder elected	No	0	0	2008	2012
Greger Mannsverk	Managing director, Bergen Group Kimek AS	Kirkenes	1961	Shareholder elected	No	0	0	2002	2012
Steinar Olsen	Chair of the board, MI Norge AS	Stavanger	1949	Shareholder elected	No	0	0	2007	2012
Ingvald Strømmen	Dean, NTNU	Ranheim	1950	Shareholder elected	No	0	0	2006	2012
Rune Bjerke	CEO, DnBNOR	Oslo	1960	Shareholder elected	No	0	0	2007	2012
Tore Ulstein	Deputy CEO, Ulstein Group	Ulsteinvik	1967	Shareholder elected	No	0	0	2008	2012
Live Haukvik Aker	Partner, Group AS Considium Consulting	Tønsberg	1963	Shareholder elected	No	0	0	2010	2012
Thor Oscar Bolstad	Manager, Herøya Industripark, Norsk Hydro ASA	Porsgrunn	1954	Shareholder elected	No	0	0	2010	2012
Barbro Hætta-Jacobsen	Medical doctor, Universitetssykehuset Nord-Norge	Harstad	1972	Shareholder elected	No	0	0	2010	2012
Siri Kalvig	StormGeo AS and the University of Stavanger	Stavanger	1970	Shareholder elected	No	0	0	2010	2012
Eldfrid Irene Hognestad	Union representative, Tekna. Leader, Business process improvements	Stavanger	1966	Employee representative	No	876	984	2009	2011
Stig Lægreid	Union representative, NITO	Oslo	1963	Employee representative	No	676	727	2009	2011
Per Martin Labråthen	Union representative, Industri Energi. Production technician	Brevik	1961	Employee representative	No	562	1286	2007	2011
Anne K.S. Horneland	Union representative, Industri Energi	Hafrsfjord	1956	Employee representative	No	2061	2317	2006	2011
Jan-Eirik Feste	Union representative, YS	Lindås	1952	Employee representative	No	428	542	2008	2011
Per Helge Ødegård	Union representative, Lederne. Discipl resp operation process	Porsgrunn	1963	Employee representative	No	1099	1254	1994	2011
Anne Synnøve Hebnes	Union representative, Tekna. Department manager	Stavanger	1972	Employee representative, observer	No	0	0	2006	2011
Oddbjørn Viken	Union representative, Tekna. Production supervisor	Røyken	1961	Employee representative, observer	No	2064	2347	2009	2011
Frode Solberg	Union representative, Industri Energi	Bergen	1969	Employee representative, observer	No	0	0	2009	2011

Benedicte Berg Schilbred, Kåre Rommetveit and Inger Østensjø were members of the corporate assembly until 19 May 2010. None of them owned shares in Statoil ASA on this date.

The corporate assembly must consist of at least 12 members or a larger number divisible by three. Shareholders elect two-thirds of the members of the corporate assembly, while employees elect the remaining third.

Pursuant to Statoil's articles of association, the corporate assembly consists of 18 members. Twelve members and four deputy members are elected at the general meeting by the shareholders, and six members, three observers and deputy members are elected by and from among the employees. Such employees are non-executive personnel.

Members of the corporate assembly are normally elected for a term of two years. Members of the board of directors and the general manager cannot be members of the corporate assembly, but they are entitled to attend and to speak at meetings of the corporate assembly unless the corporate assembly decides otherwise in individual cases.

The corporate assembly's main duty is to elect the board of directors.

Its responsibilities also include overseeing the board and the CEO's management of the company, making decisions on investments of considerable magnitude in relation to the company's resources and making decisions involving the rationalisation or reorganisation of operations that will entail major changes in or reallocation of the workforce.

The duties of the corporate assembly are defined in section 6-37 of the Norwegian Public Limited Liability Companies Act.

The corporate assembly held four meetings in 2010.

All members of the corporate assembly live in Norway. Members of the corporate assembly do not have service contracts with the company or its subsidiaries providing for benefits upon termination of office.

7.6 Board of directors

Pursuant to Statoil's articles of association, the board of directors consists of 10 members. The management is not represented on the board, and all shareholder-elected directors are independent.

As required by Norwegian company law, the company's employees are entitled to be represented by three board members. There are no board member service contracts that provide for benefits upon termination of office. Statoil's board of directors has determined that, in its judgement, all of the shareholder-elected directors are independent as defined by the Norwegian Code of Practice for Corporate Governance.

The board of directors of Statoil ASA is responsible for the overall management of the Statoil group, and for supervising the group's activities in general. The board of directors handles matters of major importance or of an extraordinary nature. However, it may require the management to refer any matter to it. The board of directors appoints the president and chief executive officer (CEO), and stipulates the job instructions, powers of attorney and terms and conditions of employment for the president and CEO.

The board of directors has three sub-committees, the audit committee, the HSE and ethics committee and the compensation committee.

The board held 16 meetings in 2010. Attendance at board meetings was 95%.

Members of the board of directors


Svein Rennemo

Svein Rennemo
Position: Chair of the board and member of the board's compensation committee.
Born: 1947
Term of office: Chair of the board of Statoil ASA since 1 April 2008.
Independent: Yes
Other directorships: Chair of the board of Tomra Systems ASA and Pharmaq AS.
Number of shares in Statoil ASA as of 31 December 2010: 10,000
Loans from Statoil: None
Experience: Rennemo was CEO of Petroleum Geo-Services ASA from 2002 until 1 April 2008 (when he took up office as chair of the board of Statoil ASA). From 1994 to 2001, Rennemo worked for Borealis, first as deputy CEO and CFO and, from 1997, as CEO.
He held various management positions in Statoil from 1982 to 1994, latterly as head of the petrochemical division. During the period 1972 to 1982, he was an analyst and monetary policy and economics adviser at Norges Bank (the Norwegian Central Bank), the OECD Secretariat in Paris and the Ministry of Finance.
Education: Economist, University of Oslo.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: Svein Rennemo is a Norwegian citizen, and he lives in Norway.


Marit Arnstad

Marit Arnstad
Position: Deputy chair of the board and member of the board's HSE and ethics committee.
Born: 1962
Term of office: Member of the board of Statoil ASA since June 2006, deputy chair since 1 October 2007.
Independent: Yes
Other directorships: Chair of the board of the Norwegian University of Science and Technology (NTNU) and of Statskog SF. Deputy chair of the board of Polaris Media ASA. Board member of Aker Seafoods ASA.
Number of shares in Statoil ASA as of 31 December 2010: None
Loans from Statoil: None
Experience: Arnstad is a lawyer with the law firm Arntzen de Besche Trondheim AS. Arnstad was minister of petroleum and energy during the period 1997 - 2000. She was a member of the Norwegian parliament, the Storting, representing the Centre Party from 1993 to 1997 and 2001 to 2005, and was leader of the party's parliamentary group from 2003 to 2005. Before 1993, she was a higher executive officer with the Ministry of the Environment.
Education: Law graduate (cand. jur.) from the University of Oslo.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: Marit Arnstad is a Norwegian citizen, and she lives in Norway.

Roy Franklin

Roy Franklin
Position: Member of the board, the board's audit committee and chair of the HSE and ethics committee.
Born: 1953
Term of office: Member of the board of Statoil ASA since 1 October 2007.
Independent: Yes
Other directorships: Non-executive chair of the board of Keller Group plc, a London-based international engineering company. Board member of the Australian oil and gas company Santos Ltd, and Boart Longyear Limited, a Salt Lake City-headquartered and Australian-listed provider of drilling services and equipment to the minerals exploration industry worldwide.
Number of shares in Statoil ASA as of 31 December 2010: None
Loans from Statoil: None
Experience: Franklin has broad experience from management positions in several countries, including positions with BP, Paladin Resources plc and Clyde Petroleum plc.
Education: Bachelor of Science in geology from the University of Southampton, UK.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: Roy Franklin is a UK citizen and he lives in the UK.
In 2004, he was awarded an OBE for his work for the British oil and gas industry.

Bjørn Tore Godal

Bjørn Tore Godal
Position: Member of the board, the board's compensation committee and the HSE and ethics committee.
Born: 1945
Term of office: Member of the board of Statoil ASA from 1 September 2010.
Independent: Yes
Other directorships: Chairman of the Council of the Norwegian Defence University College (NDUC).
Number of shares in Statoil ASA as of 31 December 2010: None
Loans from Statoil ASA: None
Experience: Godal was a member of the Norwegian parliament for 15 years during the period 1986-2001. He served as minister for trade and shipping, minister for defence and minister of foreign affairs for a total of eight years between 1991 and 2001.
From 2007-2010, he was special adviser for international energy and climate issues at the Ministry of Foreign Affairs. From 2003-2007, he was Norway's ambassador to Germany and from 2002-2003 he was senior adviser at the Department of Political Science at the University of Oslo.
Education: Godal has a Bachelor of Arts degree in political science, history and sociology from the University of Oslo.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: Bjørn Tore Godal is a Norwegian citizen, and he lives in Norway.

Lady Barbara Judge

Lady Barbara Judge
Position: Member of the board and the board's audit committee.
Born: 1946
Term of office: Member of the board of Statoil ASA since 1 September 2010.
Independent: Yes
Other directorships: Board member and chair of the UK Pension Protection Fund and Motricity Inc and board member of NV Bekaert SA and Magna International Inc.
Number of shares in Statoil ASA as of 31 December 2010: None
Loans from Statoil ASA: None
Experience: Judge has served for 10 years as a commercial lawyer focusing on securities and corporate finance. In 1980, she became the youngest person ever appointed by the president of the United States to the position as commissioner, US Securities and Exchange Commission. Between 1984 and 1994, she held a number of senior executive positions in the finance industry. Since 1994, she has developed a broad portfolio of public and private non-executive and advisory roles focusing on energy and regulatory frameworks. Among other things she served as chair of the UK Atomic Energy Authority from 2004 to 2010, has been deputy chair of the Financial Reporting Council, the UK regulatory authority for accounting and corporate governance and a board member of the Energy Group of the UK Department of Trade and Industry. From 2000 to 2005, Judge was a founder and executive chair of Private Equity Investor PLC in London.
Education: Lady Barbara Judge is a JD from New York University Law School and has a Bachelor of Arts degree in History from the University of Pennsylvania.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: Lady Barbara Judge holds American and British citizenships, and she lives in London.


Jakob Stausholm

Jakob Stausholm
Position: Member of the board and chair of the board's audit committee.
Born: 1968
Term of office: Member of the board of Statoil ASA since July 2009.
Independent: Yes
Other directorships: No
Number of shares in Statoil ASA as of 31 December 2010: 2,600
Loans from Statoil: None
Experience: Stausholm is chief financial officer of the global facility services provider ISS A/S.
Before joining ISS's corporate executive committee in 2008, he was employed by the Shell Group for 19 years and held a number of management positions, including vice president finance for the group's exploration and production in Asia and the Pacific, chief internal auditor and CFO of group subsidiaries.
Education: M.Sc. in economics from the University of Copenhagen.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: Jakob Stausholm is a Danish citizen and he lives in Denmark.


Grace Reksten Skaugen

Grace Reksten Skaugen
Position: Member of the board and chair of the board's compensation committee.
Born: 1953
Term of office: Member of the board of Statoil ASA since 2002.
Independent: Yes
Other directorships: Chair of the boards of Entra Eiendom AS, Ferd Holding and Norsk Institutt for Styremedlemmer, and member of the board of the Swedish listed company Investor AB.
Number of shares in Statoil ASA as of 31 December 2010: 400
Loans from Statoil: None
Experience: Self-employed business consultant. She was a director in corporate finance in Enskilda Securities in Oslo from 1994 to 2002. She has previously worked in the fields of venture capital and shipping in Oslo and London and carried out research in microelectronics at Columbia University in New York.
Education: She has a doctorate in laser physics from the Imperial College of Science and Technology at the University of London and an MBA from the Norwegian School of Management (BI).
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: Grace Reksten Skaugen is a Norwegian citizen, and she lives in Norway.


Lill-Heidi Bakkerud

Lill-Heidi Bakkerud
Position: Employee-elected member of the board and member of the board's HSE and ethics committee.
Born: 1963.
Term of office: Member of the board of Statoil ASA from 1998 to 2002, and again since 2004.
Independent: No
Other directorships: Bakkerud is a member of the executive committee of the Industry Energy (IE) trade union and holds a number of offices as a result of this.
Number of shares in Statoil ASA as of 31 December 2010: 330
Loans from Statoil: None
Experience: She has worked as a process technician at the petrochemical plant in Bamble and on the Gullfaks field in the North Sea. She is now a full-time employee representative as the leader of IE Statoil branch.
Education: Bakkerud has a craft certificate as a process/chemistry worker.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: Lill-Heidi Bakkerud is a Norwegian citizen, and she lives in Norway.

Morten Svaan

Morten Svaan
Position: Employee-elected member of the board and member of the board's audit committee.
Born: 1956
Term of office: Member of the board of Statoil ASA since 2002.
Independent: No
Other directorships: None
Number of shares in Statoil ASA as of 31 December 2010: 1,651
Loans from Statoil: None
Experience: Svaan has worked for Statoil since 1985. He now works on health, safety and the environment (HSE) for the Technology, Projects & Drilling business area, largely focusing on security and emergency response. Svaan was chief employee representative for the Statoil branch of the NIF/Tekna trade union from 2000 until 2004.
Education: He has a PhD in chemistry from the Norwegian University of Science and Technology and a degree in business economics from the Norwegian School of Management (BI).
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: Morten Svaan is a Norwegian citizen, and he lives in Norway.

Einar Arne Iversen

Einar Arne Iversen
Position: Employee-elected member of the board.
Born: 1962
Term of office: Member of the corporate assembly of Statoil ASA from 2000 to 2009. Member of the board of Statoil ASA since June 2009.
Independent: No
Other directorships: None
Number of shares in Statoil ASA as of 31 December 2010: 2,995
Loans from Statoil: None
Experience: Iversen joined Statoil in 1986, worked on technical training in Bergen and was training manager at Tjeldbergodden. He has held the offices of deputy head/head of the NITO trade union since 1998.
Education: He qualified as an engineer at the NKI Technical College in 1982.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: Einar Arne Iversen is a Norwegian citizen, and he lives in Norway.

In addition, there are five employee-elected deputy members of the board who attend board meetings in the event an employee-elected member of the board is unable to attend.

7.6.1 Audit committee

The board of directors elects at least three of its members to serve on the board's audit committee and appoints one of them to act as chair. The employee representatives on the board may nominate one committee member.

At year end 2010, the audit committee members were Jakob Stausholm (chair), Barbara Judge, Roy Franklin and Morten Svaan (employee representative).

The audit committee is a sub-committee of the board, and its objective is to act as a preparatory body in connection with the board's supervisory roles with respect to financial reporting and the effectiveness of the company's internal control system. It also attends to other tasks assigned to the it in accordance with the provisions of the instructions for the audit committee adopted by the board. The audit committee is instructed to assist the board in its supervising of matters such as:

- Monitoring the financial reporting process, including reviewing the implementation of accounting principles and policies
- Monitoring the effectiveness of the company's internal control, internal audit and risk management systems
- Maintaining continuous contact with the statutory auditor regarding the annual and consolidated accounts
- Reviewing and monitoring the independence of the company's internal auditor and the independence of the statutory auditor, ref. the Norwegian Auditors Act chapter 4 and, in particular, whether other services than audits delivered by the statutory auditor or the audit firm are a threat to the statutory auditor's independence.

The audit committee supervises implementation of and compliance with the group's Ethics Code of Conduct in relation to financial reporting.

The internal audit function reports directly to the board of directors and to the chief executive officer.

Under Norwegian law, the external auditor is elected by the shareholders at the annual general meeting. Based on its evaluation of the qualifications and independence of the auditor proposed for election or re-election, the audit committee makes a recommendation to the board and the general meeting concerning the appointment of the external auditor. The audit committee meets at least five times a year, and it meets separately with the internal auditor and the external auditor on a regular basis.

The audit committee is also charged with reviewing the scope of the audit and the nature of any non-audit services provided by external auditors. The external auditors report directly to the audit committee on a regular basis.

The audit committee is tasked with ensuring that the company has procedures in place for receiving and dealing with complaints received by the company regarding accounting, internal control or auditing matters, and procedures for the confidential and anonymous submission, via the group's ethics helpline, by company employees of concerns regarding accounting or auditing matters as well as other matters regarded as being in breach of the group's Ethics Code of Conduct or statutory provisions. The audit committee is designated as the company's qualified legal compliance committee for the purposes of section 307 of the Sarbanes-Oxley Act of 2002.

The audit committee may examine all activities and circumstances relating to the operations of the company in the execution of its tasks. In this connection, the audit committee may request the chief executive officer or any other employee to grant it access to information, facilities and personnel and such assistance as it requests. The audit committee is authorised to carry out or instigate such investigations as it deems necessary in order to carry out its tasks and it may use the company's internal audit or investigation unit, the external auditor or other external advice and assistance. The costs of such work will be covered by the group.

The audit committee is responsible to the board of directors only for the execution of its tasks. The work of the audit committee in no way alters the responsibility of the board and its individual members, and the board retains full responsibility for the audit committee's tasks.

The audit committee held six meetings in 2010. There was 87.5% attendance at the committee's meetings.

The committee's mandate is available at www.statoil.com/auditcommittee.

7.6.1.1 Audit committee financial expert

The board of directors has decided that a member of the audit committee, Jakob Stausholm, qualifies as an "audit committee financial expert", as defined in Item 16A of Form 20F.

The board of directors has also concluded that Jakob Stausholm is independent within the meaning of Rule 10A-3 under the Securities Exchange Act.

7.6.2 Compensation committee

The compensation committee is a sub-committee of the board of directors that assists the board of directors in matters relating to management compensation and leadership development.

The compensation committee is a sub-committee of the board of directors and its main responsibilities are:

(1) as a preparatory body for the board, to make recommendations to the board in all matters relating to principles for executive rewards, remuneration strategies and concepts, the CEO's contract and terms of employments and leadership development, assessments and succession planning

(2) to be informed about and advise the company's management in its work on Statoil's remuneration strategy and in drawing up appropriate remuneration policies for senior executives, and

(3) to review Statoil's remuneration policies in order to safeguard the owners' long-term interests.

The committee consists of three board members. At year end 2010, the committee members were Grace Reksten Skaugen (chair), Svein Rennemo and Bjørn Tore Godal. All of the committee members are independent, non-executive directors.

The committee held 10 meetings in 2010. There was 100% attendance at the committee's meetings.

The committee's mandate is available at
http://www.statoil.com/en/About/CorporateGovernance/GoverningBodies/BoardsCompensationCommittee/Pages/default.aspx

7.6.3 HSE and Ethics Committee

The HSE and ethics committee is a sub-committee of the board of directors that assists the board in matters relating to health, safety and the environment (HSE), ethics and corporate social responsibility (CSR).

In the second half of 2010, Statoil's board of directors decided to establish a new sub-committee dedicated to the areas of HSE, ethics and CSR. The HSE and ethics committee (the committee) is chaired by Roy Franklin, and the other members are Marit Arnstad, Bjørn Tore Godal and Lill-Heidi Bakkerud.

Statoil is commited in its business activities to complying with applicable laws and regulations and to acting in an ethical, sustainable, safe and socially responsible manner. The new committee has been established to support Statoil's commitment in this regard, and it will assist the board of directors in its supervision of the company's HSE, ethics and CSR policies, systems and principles.

Establishing a committee dedicated to HSE, ethics and CSR will ensure that the board of directors has an even stronger focus on and greater knowledge of these complex, important and constantly evolving areas. The committee will act as a preparatory body for the board of directors and will, inter alia, monitor and assess the practice, development and implementation of policies, systems and principles within the areas of HSE, ethics and CSR.

The board's HSE and ethics committee held one meeting in 2010, and attendance was 75%.

For a more detailed description of the objective, duties and composition of the new committee, see the Instructions for the board's HSE and ethics committee, which are available at Statoil.com.

7.7 Compliance with NYSE listing rules

Statoil's primary listing is on the Oslo stock exchange (Oslo Børs). Consequently, Statoil's corporate governance practices follow the requirements of Norwegian law. Statoil is also registered as a foreign private issuer with the US Securities and Exchange Commission, with American Depositary Shares representing its ordinary shares listed on the New York Stock Exchange (NYSE). Statoil is therefore also subject to the NYSE's listing rules ("NYSE rules"). As a foreign private issuer, Statoil is exempt from most of the NYSE corporate governance standards that domestic US companies must follow. However, Statoil is required to disclose any significant ways in which its corporate governance practices differ from those applicable to domestic US companies under the NYSE rules. A statement of differences is set out below:

Corporate governance guidelines

The NYSE rules require domestic US companies to adopt and disclose corporate governance guidelines. Statoil's corporate governance principles are developed by management and the board of directors. Oversight of the board of directors and management is exercised by the corporate assembly.

Director independence

The NYSE rules require domestic US companies to have a majority of "independent directors". The NYSE definition of an "independent director" sets out five specific tests of independence and also requires an affirmative determination by the board of directors that the director has no material relationship with the company.

Pursuant to Norwegian company law, Statoil's board of directors consists of members elected by shareholders and employees. Statoil's board of directors has determined that, in its judgement, all of the shareholder-elected directors are independent. In making its determinations of independence, the board focuses on there not being any conflicts of interest between shareholders, the board of directors and the company's management, but it does not explicitly take into consideration the NYSE's five specific tests. The directors elected from among Statoil's employees would not be considered independent under the NYSE rules because they are employees of Statoil. None of the employee-elected directors is an executive officer of the company.

Board committees

Pursuant to Norwegian company law, managing the company is the responsibility of the board of directors. Statoil has an audit committee, an HSE and ethics committee and a compensation committee. They are responsible for preparing certain matters for the board of directors. The audit committee and the compensation committee operate pursuant to charters that are broadly comparable to the form required by the NYSE rules. They report on a regular basis to, and are subject to, continuous oversight by the board of directors.

Statoil complies with the NYSE rule regarding the obligation to have an audit committee that meets the requirements of Rule 10A-3 of the US Securities Exchange Act of 1934.

As required by Norwegian company legislation, the members of Statoil's audit committee include an employee-elected director. Statoil relies on the exemption provided for in Rule 10A-3(b)(1)(iv)(C) from the independence requirements of the US Securities Exchange Act of 1934 with respect to the employee-elected director. Statoil does not believe that its reliance on this exemption will materially adversely affect the ability of the audit committee to act independently or to satisfy the other requirements of Rule 10A-3 relating to audit committees. The other members of the audit committee meet the independence requirements under Rule 10A-3.

Among other things, the audit committee evaluates the qualifications and independence of the company's external auditor. However, in accordance with Norwegian law, the auditor is elected by the annual general meeting of the company's shareholders.

Statoil's board of directors does not have a nominating/corporate governance board sub-committee. Instead, the roles prescribed for a nominating/corporate governance committee under the NYSE rules are principally carried out by the corporate assembly and the nomination committee.

Shareholder approval of equity compensation plans

The NYSE rules require that, with limited exemptions, all equity compensation plans must be subject to a shareholder vote. Although the issuance of shares and authority to buy back company shares must be approved by Statoil's annual general meeting of shareholders under Norwegian company law, the approval of equity compensation plans is normally reserved for the board of directors.

7.8 Management

The president and CEO has overall responsibility for day-to-day operations in Statoil and also appoints the corporate executive committee (CEC). Each of the CEC members is head of a separate business area or staff function.

The president and CEO has overall responsibility for day-to-day operations in Statoil. The president and CEO is responsible for developing Statoil's business strategy and presenting it to the board of directors for decision, for the development and execution of the business strategy, and for cultivating a performance-driven, value-based culture.

The president and CEO appoints the corporate executive committee. Members of the CEC have a collective duty to safeguard and promote Statoil's corporate interests and to provide the president and CEO with the best possible basis for deciding the company's direction, making decisions and executing and following up business activities. In addition, each of the CEC members is head of a separate business area or staff function.

Members of Statoil's corporate executive committee

Helge Lund. Chief executive officer

Helge Lund
Born: 1962
Position: President and CEO of Statoil ASA since August 2004.
External offices: None
Number of shares in Statoil ASA as of 31 December 2010: 33,453
Loans from Statoil: None
Experience: Came to Statoil from the position of CEO in Aker Kværner ASA. Held central managerial positions in the Aker RGI system from 1999. Has been political adviser to the Conservative Party of Norway's parliamentary group, a consultant with McKinsey & Co and deputy managing director of Nycomed Pharma AS.
Education: MA in business economics (siviløkonom) from the Norwegian School of Economics and Business Administration (NHH) in Bergen and Master of Business Administration (MBA) from INSEAD in France.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Helge Lund is a Norwegian citizen, and he lives in Norway.

Torgrim Reitan. Chief financial officer (CFO)

Torgrim Reitan
Born: 1969
Position: Executive vice president and Chief Financial Officer of Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2010: 8,533
Loans from Statoil: None
Experience: He has held several managerial positions in Statoil, including senior vice president (SVP) in trading and operations in the Natural Gas business area (2009 - 2010), SVP in performance management and analysis (2007 - 2009) and SVP in performance management, tax and M&A (2005 - 2007). From 1995 to 2004, he held various positions in the Natural Gas business area and corporate functions in Statoil.
Education: Master of Science degree from the Norwegian School of Economics and Business Administration.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Torgrim Reitan is a Norwegian citizen, and he lives in Norway.

Tove Stuhr Sjøblom. Chief staff officer (CSO)

Tove Stuhr Sjøblom
Born: 1966
Position: Executive vice president, chief staff officer in Statoil ASA from 1 January 2011.
External offices: Chair of the Norwegian Petroleum Association (NPF), member of the board of ONS.
Number of shares in Statoil as of 31 December 2010: 3,348
Loans from Statoil: None
Experience: She has held several managerial positions in Statoil since 2007, including the position of senior vice president (SVP) for exploration in Exploration & Production Norway. In Norsk Hydro ASA, she held various managerial positions from 1991-2007, including exploration, asset management and project management in Canada on assignment from Norsk Hydro to Petro-Canada from 2000-2003.
Education: MSc from the Norwegian University of Science and Technology (NTNU).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Tove Stuhr Sjøblom holds both Norwegian and Canadian citizenships and lives in Norway.

Eldar Sætre. Executive vice president Marketing, Processing and Renewable energy

Eldar Sætre
Born: 1956
Position: Executive vice president in Statoil ASA since October 2003.
External offices: Member of the board of Strømberg Gruppen AS and Trucknor AS.
Number of shares in Statoil ASA as of 31 December 2010: 13,764
Loans from Statoil: None
Experience: He joined Statoil in 1980 and has since held several management positions in the group, mainly in the fields of accounting and finance, including the position of CFO from October 2003 until 31 December 2010.
Education: MA in business economics from the Norwegian School of Economics and Business Administration (NHH) in Bergen.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Eldar Sætre is a Norwegian citizen, and he lives in Norway.

Øystein Michelsen. Executive vice president, Exploration & Production Norway

Øystein Michelsen
Born: 1956
Position: Executive vice president in Statoil ASA since 10 November 2008.
External offices: Member of the board of Oljeindustriens Landsforening (OLF, the Norwegian Oil Industry Association)
Number of shares in Statoil ASA as of 31 December 2010: 9,758
Loans from Statoil ASA: None
Experience: Recruited to Hydro's research centre in Porsgrunn in 1981, he was attached to Hydro's oil and energy division from 1985, and was head of the operations unit for Hydro's oil activities from 2004. He has been senior vice president for Statoil's Operations North cluster since 1 October 2007.
Education: MA in applied physics (sivilingeniør) from the Norwegian Institute of Technology (NTH) in Trondheim.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Øystein Michelsen is a Norwegian citizen, and he lives in Norway.

Peter Mellbye. Executive vice president Development and Production International

Peter Mellbye
Born: 1949
Position: Executive vice president in Statoil ASA since 1992.
External offices: Member of the board of the Energy Policy Foundation of Norway (EPF).
Number of shares in Statoil ASA as of 31 December 2010: 16,533
Loans from Statoil: None
Experience: Worked for the Ministry of Trade and the Norwegian Export Council before joining Statoil in 1982. Held several central management positions in Statoil. Executive vice president of Natural Gas from 1992 to 2004.
Education: Cand. polit. degree from the University of Oslo.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Peter Mellbye is a Norwegian citizen, and he lives in Norway.

William Maloney. Executive vice president Development and Production North America.

William Maloney
Born: 1955
Position: Executive vice president in Statoil ASA from 1 January 2011.
External offices: Corporate advisory board (AAPG) & API board member.
Number of shares in Statoil ASA as of 31 December 2010: 467 shares.
Loans from Statoil: None
Experience: He held the position of senior vice president for global exploration in International Operations in Statoil from 2002 to 2010. He previously held managerial positions in Shell, Davis Petroleum Corp and Texaco between 1981 and 2002.
Education: Bill Maloney has an MS degree in Geology from Syracuse University.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Bill Maloney is an American citizen and lives in the USA

John Knight. Executive vice president Global Strategy and Business Development

John Knight
Born: 1958
Position: Executive vice president in Statoil ASA from 1 January 2011.
External offices: None
Numbers of shares in Statoil ASA as of 31 December 2010: 26,180
Loans from Statoil ASA: None
Experience: He has held several central managerial positions in International Operations in Statoil since 2002, mainly in business development. Between 1987 and 2002, he held various positions in energy investment banking. From 1977 to 1987, he qualified and worked as a barrister/lawyer, and was employed by Shell Petroleum in London during the period 1985-1987.
Education: Has first and post-graduate degrees in law from Cambridge University and the Inns of Court School of Law in London.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: John Knight is a British citizen, and he lives in England.

Tim Dodson. Executive vice president, Exploration

Tim Dodson
Born: 1959
Position: Executive vice president in Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2010: 7,798
Loans from Statoil ASA: None
Experience: Has worked in Statoil since 1985 and held central management positions in the company, including the positions of senior vice president for global exploration, Exploration & Production Norway and the technology arena.
Education: MSc in Geology and Geography from the University of Keele.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Tim Dodson is a British citizen and lives in Norway.

Margareth Øvrum. Executive Vice President Technology, Projects and Drilling

Margareth Øvrum
Born: 1958
Position: Executive vice president in Statoil ASA since September 2004.
External offices: Member of the board of Atlas Copco AB and Ratos AB.
Number of shares in Statoil ASA as of 31 December 2010: 16,497
Loans from Statoil: None
Experience: Øvrum has worked for Statoil since 1982 and has held central management positions in the company, including the position of executive vice president for health, safety and the environment and executive vice president for Technology & Projects. She was the company's first female platform manager, on the Gullfaks field. She was senior vice president for operations for Veslefrikk and vice president of operations support for the Norwegian continental shelf.
Education: MA in engineering (sivilingeniør) from the Norwegian Institute of Technology (NTH) in Trondheim, specialising in technical physics.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Margareth Øvrum is a Norwegian citizen, and she lives in Norway.

7.9 Compensation paid to governing bodies

This section describes the compensation paid to the board of directors, the corporate executive committee and the corporate assembly.

In 2010, aggregate compensation totalling NOK 921,000 was paid to the members of the corporate assembly, NOK 4,441,000 to the members of the board of directors and NOK 48,159,000 to the members of the corporate executive committee (all in rounded figures).

Detailed information about the individual compensation paid to the members of the board of directors and members of the corporate executive committee in 2010 is provided in the tables below.

Members of the board (In NOK thousand)	Board remuneration	Audit committee	Compensation committee	HSEE committee*	Total remuneration
Svein Rennemo	606		66		672
Marit Arnstad	385	82			467
Elisabeth Grieg***	204		51		255
Kjell Bjørndalen***	204		51		255
Grace Reksten Skaugen	308		93		401
Roy Franklin	475	156			631
Jakob Stausholm	308	129			437
Bjørn Tore Godal**	105		8		113
Barbara Judge**	143	31			174
Lill-Heidi Bakkerud	308				308
Morten Svaan	308	112			420
Einar Arne Iversen	308				308
Total	3,662	510	269	0	4,441

* The HSEE committee was established in 2010, but no fees were paid
** Member since 1 September 2010
*** Member until 31 August 2010

Management remuneration in 2010 (in NOK thousand)

Members of Corporate Executive Committee	Fixed remuneration Base pay [1]	LTI [2]	Bonus	Taxable benefits in kind	Taxable reimbursements	Taxable salary	Non-taxable benefits in kind	Non-taxable reimbursements	Non-taxable salary	Total remuneration	Estimated pension cost [3]	Estimated present value of pension obligation
Lund Helge (CEO)	6,841	1,937	1,670	533	16	10,997	492	25	517	11,514	3,973	30,202
Bjørnson Rune (Executive vice president (E.V.P), Natural Gas)	2,964	654	483	249	14	4,364	0	29	29	4,393	767	22,179
Jacobsen Jon Arnt (E.V.P, Manufacturing & Marketing)	3,023	686	512	165	14	4,400	0	27	27	4,427	1,398	18,431
Mellbye Peter (E.V.P, International Exploration & Production)	3,804	833	622	327	22	5,608	0	35	35	5,643	1,339	37,898
Sætre Eldar (CFO and E.V.P)	3,119	734	609	326	22	4,810	172	19	191	5,001	870	2,8018
Øvrum Margareth (E.V.P, Technology & New Energy)	3,150	712	531	126	9	4,528	0	48	48	4,576	902	27,875
Nes Helga (E.V.P, Staff functions & corporate services)	2,286	562	364	169	0	3,381	181	8	189	3,570	684	19,023
Michelsen Øystein (E.V.P, Exploration & Production Norway)	3,324	766	507	209	9	4,815	303	25	328	5,143	749	23,412
Myrebøe Gunnar (E.V.P, Projects & Procurement)	2,567	587	351	63	7	3,575	305	12	317	3,892	732	28,350
Total	31,078	7,471	5,649	2,167	113	46,478	1,453	228	1,681	48,159	11,414	235,388

1) Base pay consists of base salary, holiday allowance and other administrative benefits.
2) Fixed long-term incentive (LTI) element. The LTI implies an obligation to invest the net amount in Statoil shares. A lock-in period of 3 years applies for the investment.
3) Estimated pension cost for 2010 based on actuarial assumptions and pensionable salary. Payroll tax is not included.

Statoil's remuneration policy

Statoil's remuneration policy is strongly linked to the company's people policy and core values. Certain key principles have been adopted for the design of the company's remuneration concept.

The remuneration concept is an integrated part of our values-based performance framework and shall:

- reflect our global competitive market strategy and local market conditions
- strengthen the common interests of people in the Statoil group and its shareholders
- be in accordance with statutory regulations and good corporate governance
- be fair, transparent and non-discriminatory
- reward and recognise delivery and behaviour equally
- differentiate on the basis of responsibilities and performance, and
- reward both short and long-term contributions and results.

Rewards and recognition are designed to attract and retain the right people - people who perform, change and learn. The overall remuneration level and composition of the total reward reflect the national and international framework and business environment Statoil operates within.

The decision-making process

The decision-making process for implementing or changing remuneration policies and concepts and determining salaries and other remuneration of the corporate executive committee are in accordance with the provisions of the Norwegian Public Limited Liability Companies Act sections 5-6, 6-14, 6-16 a) and the board's Rules of Procedure as last amended on 10 February 2010.

The remuneration concept for the corporate executive committee

Statoil's remuneration concept for the corporate executive committee consists of the following main elements:

- Fixed remuneration
- Variable pay
- Pensions and insurance schemes
- Severance pay arrangements
- Other benefits.

Fixed remuneration

Fixed remuneration consists of a base salary and a long-term incentive system.

Base salary

The base salary shall be competitive in the markets in which the company operates and shall reflect the individual's responsibility and performance. The evaluation of performance is based on the fulfilment of certain pre-defined goals; see "Variable pay" below. The base salary is normally reviewed once a year.

Long-term incentive (LTI) system

Statoil will continue with the established long-term incentive system for the members of the corporate executive committee and a limited number of other senior executives.

The long-term incentive system consists of a fixed, monetary compensation paid subject to acquiring Statoil shares. It is calculated as a percentage of the participant's base salary; ranging from 20% to 30% depending on the participant's position. The participant is obliged to use the LTI amount (after tax deduction) to buy Statoil shares in the market every year and to hold the shares for a lock-in period of three years.

The long-term incentive system aims to ensure that Statoil's management is holding Statoil shares and contributes to strengthening the common interests between top management and the shareholders of Statoil. The long-term incentive and the annual variable pay system constitute a remuneration concept which focuses both on short- and long-term goals and results.

Variable pay

The company's variable pay concept will also be continued in 2011. Based on performance, the chief executive officer is entitled to an annual variable pay of 25% of the fixed remuneration if agreed targets are reached and, if agreed targets are exceeded, the chief executive officer may receive between 25 % and 50 % of his fixed remuneration. The scheme has a maximum potential of 50% of the fixed remuneration. The executive vice presidents have an annual variable pay scheme with a maximum potential of 40% of the fixed remuneration with a pay out at 20 % if agreed targets are reached.

The effect of remuneration policies on risk

The remuneration concept is an integrated part of Statoil's performance management system. It is an overarching principle that there should be a close link between performance and remuneration.

Individual salaries and the annual variable pay review shall be based on the performance evaluation in the performance management system. Participation in the long-term incentive (LTI) scheme and the size of the annual LTI element are related to the position level and aims to ensure that our top management holds Statoil shares.

The goals that form the basis for the performance assessment are established between the manager and the employee as part of our performance management process. The performance goals have two dimensions: delivery and behaviour, which are equally weighted. Delivery goals are established for each of the five perspectives: HSE, operations, market, finance and people and organisation. In each perspective, longer- term strategic objectives, shorter-term targets and key performance indicators (KPI) are set, as well as an agreed set of actions to be taken. Behaviour goals are based on Statoil's core values and leadership principles. They address the behaviour required and expected in order to achieve our delivery goals.

The performance evaluation is a holistic evaluation combining measurement and assessment of performance against both delivery and behaviour goals. The KPIs are used as *indicators* only. Hence, sound judgement and hindsight information are applied before final conclusions are drawn. For example, KPI results are reviewed against their strategic contribution, sustainability and significant changes in assumptions.

This balanced scorecard approach, which involves a broad set of goals defined in relation to both the delivery and behaviour dimensions and an overall performance evaluation, should significantly reduce the risk that remuneration policies stimulate excessive risk-taking or have other material adverse effects.

In the performance contracts of the chief executive officer and the chief financial officer, one of several goals is related to the company's relative total shareholder return (TSR). The amount of the annual variable pay is decided on the basis of an overall assessment of performance in relation to various targets, including but not limited to the company's relative TSR.

7.10 Share ownership

This section describes the number of Statoil shares owned by the members of the board of directors and the corporate executive committee.

The number of Statoil shares owned by the members of the board of directors and the executive committee and/or owned by their close associates is shown below. Individually, each member of the board of directors and the corporate executive committee owned less than 1% of the outstanding Statoil shares.

Individually, each member of the corporate assembly owned less than 1% of outstanding Statoil shares as of 31 December 2010 and as of 12 March 2011. In aggregate, members of the corporate assembly owned a total of 7,766 shares as of 31 December 2010 and a total of 9,457 shares as of 12 March 2011. Information about the individual share ownership of the members of the corporate assembly is presented in the section Corporate governance - Corporate assembly.

The voting rights of members of the board of directors, the corporate executive committee and the corporate assembly do not differ from those of ordinary shareholders.

Ownership of Statoil shares (including share ownership of «close associates»)	As of 31 December 2010	As of 12 March 2011
Members of the corporate executive committee		
Helge Lund	33,453	35,156
Eldar Sætre	13,764	14,590
Margareth Øvrum	16,497	17,579
Peter Mellbye	16,533	17,359
Øystein Michelsen	9,758	10,413
William Maloney*	467	3,288
John Knight*	26,180	26,180
Torgrim Reitan*	8,533	9,186
Tim Dodson*	7,798	8,379
Tove Stuhr Sjøblom*	3,348	3,603
Rune Bjørnson**	11,650	
Jon Arnt Jacobsen**	15,037	
Gunnar Myrebøe**	8,851	
Helga Nes**	5,828	
Members of the board of directors		
Svein Rennemo	10,000	10,000
Marit Arnstad	0	0
Barbara Judge	0	0
Bjørn Tore Godal	0	0
Grace Reksten Skaugen	400	400
Jakob Stausholm	2,600	2,600
Roy Franklin	0	0
Lill-Heidi Bakkerud	330	330
Morten Svaan	1,651	1,922
Einar Arne Iversen	2,995	3,210

* Member of the corporate executive committee from 1 January 2011
** Member of the corporate executive committee until 31 December 2010

Elisabeth Grieg and Kjell Bjørndalen were members of the board of directors until 31 August 2010. On that date, Kjell Bjørndalen and close associates owned no shares in Statoil ASA. Elisabeth Grieg and close associates owned a total of 33,108 shares in Statoil ASA.

7.11 Independent auditor

This section provides details about the independent auditor, and about the remuneration of and policies and procedures relating to the auditor.

Our independent registered public accounting firm (independent auditor) is independent in relation to Statoil and is elected by the general meeting of shareholders. The independent auditor's fee must be approved by the general meeting of shareholders.

Pursuant to the instructions for the board's audit committee approved by the board of directors, the audit committee is responsible for ensuring that the company is subject to an independent and effective external and internal audit.

Every year, the independent auditor presents a plan for the audit committee for the execution of the independent auditor's work.

The independent auditor attends the board meeting that deals with the preparation of the annual accounts.

The independent auditor participates in meetings with the audit committee.

When evaluating the independent auditor, emphasis is placed on the firm's qualifications, capacity, local and international availability and the size of the fee.

The audit committee evaluates and makes a recommendation to the board and the general meeting of shareholders regarding the choice of independent auditor. The committee is responsible for ensuring that the independent auditor meets the requirements in Norway and in the countries where Statoil is listed. The independent auditor is subject to the provisions of US securities legislation, which stipulate that a responsible partner may not lead the engagement for more than five consecutive years.

The audit committee considers all reports from the independent auditor before they are considered by the board of directors. The audit committee holds regular meetings with the independent auditor without the company's management being present.

The audit committee's policies and procedures for pre-approval
In its instructions for the audit committee, the board of directors has delegated authority to the audit committee to pre-approve assignments to be performed by the independent auditor. The audit committee has issued guidelines for the management's pre-approval of assignments to be performed by the independent auditor.

All audit-related and other services provided by the independent auditor must be pre-approved by the audit committee. Provided that the proposed types of services are permissible under SEC guidelines, pre-approval is usually granted at a regular audit committee meeting. The chair of the audit committee has been authorised to pre-approve services that are in accordance with policies established by the audit committee that specify in detail the types of services that qualify. It is a condition that any services pre-approved in this manner are presented to the full audit committee at its next meeting. Some pre-approvals can therefore be granted by the chair of the audit committee, if an urgent reply is deemed necessary.

Remuneration of the independent auditor in 2010
In the annual consolidated financial statements and in the parent company's financial statements, the independent auditor's remuneration is split between the audit fee and the fee for audit-related and other services. The chair presents the breakdown between the audit fee and the fee for audit-related and other sevices to the annual general meeting of shareholders.

Ernst & Young AS is the company's independent registered public accounting firm. The table below itemises the expensed remuneration paid to the external auditor in 2010, 2009 and 2008, respectively:

(in NOK million, excluding VAT)	Audit fee	Audit related fee	Other service fee	Total
2010				
Ernst & Young - Norway	35,2	12,2	0,1	47,5
Ernst & Young - outside Norway	29,3	2,0	0,1	31,4
Total	64,5	14,2	0,2	78,9
2009				
Ernst & Young - Norway	34.2	5.3	3.7	43.2
Ernst & Young - outside Norway	27.1	1.5	0.9	29.5
Total	61.3	6.8	4.6	72.7
2008				
Ernst & Young - Norway	35.0	4.9	0.1	40.0
Ernst & Young - outside Norway	25.3	3.8	0.1	29.2
Total	60.3	8.7	0.2	69.2

All fees included in the table were approved by the audit committee.

Audit fee are defined as the standard audit work that must be performed every year in order to issue an opinion on Statoil's consolidated financial statements and to issue reports on the IFRS statutory financial statements. It also includes other audit services, which are services that only the independent auditor can reasonably provide, such as the auditing of non-recurring transactions and the application of new accounting policies, audits of significant and newly implemented system controls and limited reviews of quarterly financial results.

Audit-related fee include other assurance and related services provided by auditors, but not limited to those that can only reasonably be provided by the external auditor who signs the audit report, that are reasonably related to the performance of the audit or review of the company's financial statements, such as acquisition due diligence, audits of pension and benefit plans, consultations concerning financial accounting and reporting standards.

Other services fee include services provided by the auditors within the framework of Sarbanes Oxley Act, i.e. certain agreed upon procedures.

Audit fees amounting to NOK 8.8 million, NOK 8.9 million and NOK 8.5 million relating to Statoil-operated licences were paid to Ernst & Young for the years 2010, 2009 and 2008, respectively.

7.12 Controls and procedures

This section describes controls and procedures relating to our financial reporting.

Evaluation of disclosure controls and procedures
Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by Form 20-F. Based on that evaluation, the chief executive officer and chief financial officer have concluded that these disclosure controls and procedures are effective at a reasonable level of assurance.

In order to facilitate the evaluation, the disclosure committee reviews material disclosures made by Statoil for any errors, misstatements and omissions. The disclosure committee is chaired by the chief financial officer. It consists of the heads of investor relations, accounting and financial control, tax and general counsel and may be supplemented by other internal and external personnel. The head of the internal audit is an observer at the committee's meetings.

In designing and evaluating our disclosure controls and procedures, our management, with the participation of the chief executive officer and chief financial officer, recognised that any controls and procedures, no matter how well designed and operated, can only provide reasonable assurance that the desired control objectives will be achieved, and that our management must necessarily exercise judgment when evaluating the cost-benefit aspects of possible controls and procedures. Because of the limitations inherent in all control systems, no evaluation of controls can provide absolute assurance that all control issues and any instances of fraud in the company have been detected.

The management's report on internal control over financial reporting
The management of Statoil ASA is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed, under the supervision of the chief executive officer and chief financial officer, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Statoil's financial statements for external reporting purposes in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU). The accounting policies applied by the group also comply with IFRS as issued by the International Accounting Standards Board (IASB).

The management has assessed the effectiveness of internal control over financial reporting based on the Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, the management has concluded that Statoil's internal control over financial reporting as of 31 December 2010 was effective.

Statoil's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets, provide reasonable assurance that transactions are recorded in the manner necessary to permit the preparation of financial statements in accordance with IFRS, and that receipts and expenditures are only carried out in accordance with the authorisation of the management and directors of Statoil; and provide reasonable assurance regarding the prevention or timely detection of any unauthorised acquisition, use or disposition of Statoil's assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Moreover, projections of any evaluation of the effectiveness of internal control to future periods are subject to a risk that controls may become inadequate because of changes in conditions and that the degree of compliance with the policies or procedures may deteriorate.

The effectiveness of internal control over financial reporting as of 31 December 2010 has been audited by Ernst & Young AS, an independent registered public accounting firm that also audits our consolidated financial statements included in this annual report. Their audit report on the internal control over financial reporting is included in section 8 in the Consolidated Financial Statements of this report.

Changes in internal control over financial reporting
No changes occurred in our internal control over financial reporting during the period covered by Form 20-F that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

8 Consolidated financial statements

CONSOLIDATED STATEMENT OF INCOME

			For the year ended 31 December	
(in NOK million)	Note	2010	2009	2008
REVENUES AND OTHER INCOME				
Revenues		526,718	462,292	651,977
Net income from equity accounted investments	16	1,133	1,778	1,283
Other income		1,797	1,363	2,760
Total revenues and other income	3	529,648	465,433	656,020
OPERATING EXPENSES				
Purchases [net of inventory variation]		(257,427)	(205,870)	(329,182)
Operating expenses		(57,531)	(56,860)	(59,349)
Selling, general and administrative expenses		(11,081)	(10,321)	(10,964)
Depreciation, amortisation and net impairment losses	14,15	(50,608)	(54,056)	(42,996)
Exploration expenses		(15,773)	(16,686)	(14,697)
Total operating expenses		(392,420)	(343,793)	(457,188)
Net operating income	3	137,228	121,640	198,832
FINANCIAL ITEMS				
Net foreign exchange gains (losses)		(1,836)	1,993	(32,563)
Interest income and other financial items		3,175	3,708	12,207
Interest and other finance expenses		(1,751)	(12,451)	1,991
Net financial items	11	(412)	(6,750)	(18,365)
Income before tax		136,816	114,890	180,467
Income tax	12	(99,169)	(97,175)	(137,197)
Net income		37,647	17,715	43,270
Attributable to:				
Equity holders of the company		38,082	18,313	43,265
Non-controlling interest (Minority interest)		(435)	(598)	5
		37,647	17,715	43,270
Earnings per share for income attributable to equity holders of the company - basic and diluted	13	11.94	5.75	13.58

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in NOK million)	Note	For the year ended 31 December 2010	2009	2008
Net income		37,647	17,715	43,270
Foreign currency translation differences		2,039	(13,637)	30,880
Actuarial gains (losses) on employee retirement benefit plans	24	(33)	3,191	(7,945)
Change in fair value of available for sale financial assets	17	209	(66)	(1,362)
Income tax on income and expense recognised directly in OCI		16	(742)	(802)
Other comprehensive income		2,231	(11,254)	20,771
Total comprehensive income		39,878	6,461	64,041
Attributable to:				
Equity holders of the parent company		40,313	7,059	64,036
Non-controlling interest (Minority interest)		(435)	(598)	5
		39,878	6,461	64,041

CONSOLIDATED BALANCE SHEET

(in NOK million)	Note	At 31 December 2010	At 31 December 2009
ASSETS			
Non-current assets			
Property, plant and equipment	14	348,204	340,835
Intangible assets	15	39,695	54,253
Equity accounted investments	16	13,884	10,056
Deferred tax assets	12	1,878	1,960
Pension assets	24	5,265	2,694
Financial investments	17	15,357	13,267
Derivative financial instruments	31	20,563	17,644
Financial receivables	17	4,510	5,747
Total non-current assets		449,356	446,456
Current assets			
Inventories	18	23,627	20,196
Trade and other receivables	19	76,139	58,895
Current tax receivable		1,076	179
Derivative financial instruments	31	6,074	5,369
Financial investments	20	11,509	7,022
Cash and cash equivalents	21	30,337	24,723
Total current assets		148,762	116,384
Assets classified as held for sale	4	44,890	0
TOTAL ASSETS		643,008	562,840

CONSOLIDATED BALANCE SHEET

(in NOK million)	Note	At 31 December 2010	At 31 December 2009
EQUITY AND LIABILITIES			
Equity			
Share capital		7,972	7,972
Treasury shares		(18)	(15)
Additional paid-in capital		41,789	41,732
Additional paid-in capital related to treasury shares		(952)	(847)
Retained earnings		164,935	145,909
Other reserves		5,816	3,568
Statoil shareholders' equity		219,542	198,319
Non-controlling interest (Minority interest)		6,853	1,799
Total equity	22	226,395	200,118
Non-current liabilities			
Financial liabilities	23	99,797	95,962
Derivative financial instruments	31	3,386	1,657
Deferred tax liabilities	12	78,052	76,322
Pension liabilities	24	22,110	21,142
Asset retirement obligations, other provisions and other liabilities	25	67,910	55,834
Total non-current liabilities		271,255	250,917
Current liabilities			
Trade and other payables	26	73,551	59,801
Current tax payable		46,693	40,994
Financial liabilities	27	11,730	8,150
Derivative financial instruments	31	4,161	2,860
Total current liabilities		136,135	111,805
Liabilities directly associated with the assets classified as held for sale	4	9,223	0
Total liabilities		416,613	362,722
TOTAL EQUITY AND LIABILITIES		643,008	562,840

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in NOK million, except share data)	Number of shares issued	Share capital	Treasury shares	Additional paid-in capital	Additional paid-in capital related to treasury shares	Retained earnings	Other reserves: Available for sale financial assets	Other reserves: Currency translation adjustments	Statoil shareholders' equity	Non-controlling interest (Minority interest)	Total
At 31 December 2009	3,188,647,103	7,972	(15)	41,732	(847)	145,909	0	3,568	198,319	1,799	200,118
Net income for the period						38,082			38,082	(435)	37,647
Income and expense recognised directly in OCI						(17)	209	2,039	2,231		2,231
Total comprehensive income for the period*											39,878
Dividend paid						(19,095)			(19,095)		(19,095)
Cash distributions (to) from non-controlling interest										5,489	5,489
Equity settled share based payments (net of allocated shares)				57		56			113		113
Treasury shares purchased (net of allocated shares)			(3)		(105)				(108)		(108)
At 31 December 2010	3,188,647,103	7,972	(18)	41,789	(952)	164,935	209	5,607	219,542	6,853	226,395

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in NOK million, except share data)	Number of shares issued	Share capital	Treasury shares	Additional paid-in capital	Additional paid-in capital related to treasury shares	Retained earnings	Other reserves: Available for sale financial assets	Other reserves: Currency translation adjustments	Statoil shareholders' equity	Non-controlling interest (Minority interest)	Total
At 31 December 2008	3,188,647,103	7,972	(9)	41,450	(586)	147,998	49	17,205	214,079	1,976	216,055
Net income for the period						18,313			18,313	(598)	17,715
Income and expense recognised directly in OCI						2,432	(49)	(13,637)	(11,254)		(11,254)
Total comprehensive income for the period*											6,461
Dividend paid						(23,085)			(23,085)		(23,085)
Cash distributions (to) from non-controlling interest										421	421
Merger related adjustments						251			251		251
Equity settled share based payments (net of allocated shares)				282					282		282
Treasury shares purchased (net of allocated shares)			(6)		(261)				(267)		(267)
At 31 December 2009	3,188,647,103	7,972	(15)	41,732	(847)	145,909	0	3,568	198,319	1,799	200,118

*For detailed information, see *Consolidated statement of comprehensive income*.

Refer to note 22 for *Transactions impacting shareholders equity*.

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK million)	Note	For the year ended 31 December 2010	2009	2008
OPERATING ACTIVITIES				
Income before tax		136,816	114,890	180,467
Adjustments to reconcile net income to net cash flows provided by operating activities:				
Depreciation, amortisation and impairment losses	14, 15	50,608	54,056	42,996
Exploration expenditures written off		2,916	6,998	3,872
(Gains) losses on foreign currency transactions and balances		1,481	6,512	15,243
(Gains) losses on sales of assets and other items		(1,104)	(526)	(2,704)
Changes in working capital (other than cash and cash equivalents):				
· (Increase) decrease in inventories		(3,431)	(5,045)	2,470
· (Increase) decrease in trade and other receivables		(16,584)	11,036	(1,129)
· Increase (decrease) in trade and other payables		9,667	(1,365)	(5,466)
(Increase) decrease in current financial investments		(4,487)	2,725	(6,388)
(Increase) decrease in net financial derivative instruments	31	(594)	(9,360) *	4,934 *
Taxes paid		(92,266)	(100,473)	(139,604)
(Increase) decrease in non-current items related to operating activities		(2,207)	(6,447) *	7,842 *
Cash flows provided by operating activities		80,815	73,001	102,533
INVESTING ACTIVITIES				
Additions through business combinations		0	0	(13,120)
Additions to property, plant and equipment		(66,710)	(67,152)	(58,529)
Exploration expenditures capitalised		(3,941)	(7,203)	(6,821)
Additions to other intangibles		(7,628)	(795)	(10,828)
Change in non-current loans granted and other non-current items		(3,972)	(1,636)	(1,910)
Proceeds from sale of assets		1,909	1,430	5,371
Prepayment received related to the held for sale transactions		4,124	0	0
Cash flows used in investing activities		(76,218)	(75,356)	(85,837)

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK million)	Note	2010	2009	2008
			For the year ended 31 December	
FINANCING ACTIVITIES				
New non-current loans		15,562	46,318	2,596
Repayment of non-current loans		(3,249)	(4,905)	(2,864)
Payment (to)/from non-controlling interests		5,489 **	421	179
Dividend paid	22	(19,095)	(23,085)	(27,082)
Treasury shares purchased	22	(294)	(343)	(308)
Net current loans, bank overdrafts and other		2,154	(7,115)	10,450
Cash flows provided by (used in) financing activities		567	11,291	(17,029)
Net increase (decrease) in cash and cash equivalents		5,164	8,936	(333)
Effect of exchange rate changes on cash and cash equivalents		450	(2,851)	707
Cash and cash equivalents at the beginning of the period		24,723	18,638	18,264
Cash and cash equivalents at the end of the period	21	30,337	24,723	18,638
Interest paid		2,591	2,912	2,771
Interest received		2,080	3,962	4,544

*Reclassifications between the indicated line items of NOK 3,678 million and NOK (6,924) for the year ended 31 December 2009 and for the year ended 31 December 2008, respectively have been made in order to be consistent with the classification for the year ended 31 December 2010. The reclassifications did not impact the Cash flow provided by operations and was deemed immaterial to the previously issued financial statements.

**Including net cash of NOK 5,195 million received from non-controlling interests related to the listing of Statoil's subsidiary Statoil Fuel and Retail ASA as a separate company on the Oslo Stock Exchange on 22 October 2010. For more information see note 22 *Transactions impacting shareholders equity*.

8.1 Notes to the Consolidated Financial Statements

8.1.1 Organisation

Statoil ASA, originally Den Norske Stats Oljeselskap AS, was founded in 1972 and is incorporated and domiciled in Norway.

The address of its registered office is Forusbeen 50, N-4035 Stavanger, Norway.

Statoil's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, and other forms of energy.

Statoil ASA is listed on the Oslo Stock Exchange (Norway) and the New York Stock Exchange (USA).

Statoil's oil and gas activities and net assets on the Norwegian Continental Shelf (NCS) were until 31 December 2008 owned by Statoil ASA and by Statoil Petroleum AS. With effect from 1 January 2009, Statoil ASA transferred the ownership of its NCS net assets to Statoil Petroleum AS, a 100% owned operating subsidiary. Following the transfer, all NCS net assets are owned by Statoil Petroleum AS. As a result of this group internal reorganisation, the nature of the parent company Statoil ASA's operations and transactions were changed so that its functional currency also changed from NOK to USD effective as of the same date and with prospective effect. The functional currency of Statoil Petroleum AS was not changed and remains NOK. The presentation currency for the Statoil group remains NOK.

The consolidated financial statements of Statoil for the year ended 31 December 2010 were authorised for issue in accordance with a resolution of the board of directors on 14 March 2011.

8.1.2 Significant accounting policies

Statement of compliance
The Consolidated financial statements of Statoil ASA and its subsidiaries ("Statoil") have been prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU). The accounting policies applied by Statoil also comply with IFRSs as issued by the International Accounting Standards Board (IASB).

Basis of preparation
The financial statements are prepared on the historical cost basis with some exceptions, as detailed in the accounting policies set out below. These policies have been applied consistently to all periods presented in these consolidated financial statements.

Operating expenses in the consolidated statement of income are presented as a combination of function and nature in conformity with industry practice. Purchases [net of inventory variation] and Depreciation, amortisation and net impairment losses are presented in separate lines by their nature, while Operating expenses and Selling, general and administrative expenses as well as Exploration expenses are presented on a functional basis. Significant expenses such as salaries, pensions, etc. are presented by their nature in the notes to the financial statements.

Standards and interpretations in issue, not yet adopted
At the date of these financial statements the following standards and interpretations were in issue but not yet effective:

IFRS 9 *Financial Instruments,* issued for the first part in November 2009 and for the second in October 2010, covers the classification and measurement of financial assets and financial liabilities, respectively. IFRS 9 will be effective from 1 January 2013, and also entails amendments to various other IFRSs effective from the same date. Statoil has not yet determined its adoption date for this standard, and is still evaluating the potential impact of this standard.

The revised IAS 24 *Related Party Disclosures* issued in November 2009 defines the term related party and establishes disclosure requirements to be applied, and will be effective from 1 January 2011. Statoil does not expect that the revised standard will lead to significant changes in the level of related party disclosure provided, and will comply with the revised standard and provide relevant disclosure upon adoption as applicable.

The amendment to IFRIC 14 *Prepayments of a Minimum Funding Requirement* issued in November 2009 and effective as of 1 January 2011 is not expected to have any material effect on Statoil's reported net income or equity on adoption.

The *Improvements to IFRS 2010* issued in May 2010 include amendments effective for annual periods beginning on or after 1 July 2010 or 1 January 2011 respectively, depending on the standard involved, and include amendments to a number of accounting standards. None of the amendments are expected to significantly impact Statoil's net income, equity or classifications in the balance sheet or statement of income. Where the improvements impact the content of note disclosure Statoil will comply with the requirements upon adoption as applicable.

The amendments to IFRS 7 Financial *Instruments: Disclosures,* issued in October 2010, cover risk exposure related to transfer of assets and will be effective for annual periods beginning after 1 July 2011. Statoil does not expect that the amendments to the standard will lead to significant changes in the level of disclosure currently provided, and will comply with the revised standard and provide relevant disclosure upon adoption as applicable.

The amendment to IAS 32 *Classification of Rights Issues* issued in November 2009 and effective for annual periods beginning 1 February 2010 or later, IFRIC 19 *Extinguishing Financial Liabilities with Equity Instruments* issued in November 2009 and effective for annual periods beginning on or after 1 July 2010, and the amendment to IAS 12 *Income Taxes* issued in December 2010 and effective for annual periods beginning 1 January 2012 are currently not relevant for Statoil.

Significant changes in accounting policies

As of 31 December 2009 Statoil adopted revisions to the oil and gas estimation and disclosure requirements. For additional information see "Critical accounting judgements and key sources of estimation uncertainty; Proved oil and gas reserves".

The revised version of IFRS 3 *Business Combinations,* issued in January 2008 and implemented on 1 January 2010, covers definition, identification, accounting for and disclosure of business combinations, inclusive of business combinations achieved in stages. There has not been any material effect on Statoil's reported net income, assets, liabilities or equity following adoption of the revised standard on 1 January 2010.

The amended version of IAS 27 *Consolidated and Separate Financial Statements,* issued in January 2008, primarily covers amendments related to accounting for non-controlling interests and the loss of control of a subsidiary. There has not been any material effect on Statoil's reported net income, assets, liabilities or equity following adoption of the amendment on 1 January 2010.

Basis of consolidation

Subsidiaries

The consolidated financial statements include the accounts of Statoil ASA and its subsidiaries. Subsidiaries are entities controlled by Statoil. Control exists when Statoil has the power, directly or indirectly, to govern the financial and operating policies of an entity so as to obtain benefits from its activities. Subsidiaries are consolidated from the date of their acquisition, being the date on which Statoil obtains control, and continue to be consolidated until the date that such control ceases.

All intercompany balances and transactions, including unrealised profits and losses arising from group internal transactions, have been eliminated in full. Non-controlling interests (minority interests) represent the portion of profit or loss and net assets in subsidiaries that are not directly or indirectly held by the parent company and are presented separately within equity in the balance sheet.

Jointly controlled assets, associates and joint venture entities

Interests in jointly controlled assets are recognised by including Statoil's share of assets, liabilities, income and expenses on a line-by-line basis. Interests in jointly controlled entities are accounted for using the equity method. Investments in companies in which Statoil does not have control or joint control, but has the ability to exercise significant influence over operating and financial policies, are classified as associates and are accounted for using the equity method.

Statoil as operator of jointly controlled assets

Indirect operating expenses such as personnel expenses are accumulated in cost pools. These costs are allocated to business areas and Statoil operated jointly controlled assets (licences) on an hours incurred basis. Costs allocated to the other partners' share of operated jointly controlled assets reduce the costs in the consolidated statements of income. Only Statoil's share of the statement of income and balance sheet items related to Statoil operated jointly controlled assets are reflected in the consolidated statement of income and balance sheet.

Reportable Segments

Statoil identifies its operating segments on the basis of those components of the Statoil group that are regularly reviewed by the chief operating decision maker, Statoil's Corporate Executive Committee (CEC). Statoil considers combining operating segments when these satisfy relevant aggregation criteria. Quantitative thresholds related to reported revenue, net operating income and assets are also applied. Segments as reported align with internal management reporting to Statoil's CEC. The accounting policies of reportable segments correspond to Statoil's accounting policies as described in this note.

Foreign currency

Functional currency

A group entity's functional currency is the currency of the primary economic environment in which the entity operates.

Foreign currency translation

In preparing the financial statements of the individual entities, transactions in foreign currencies (those other than functional currency) are translated at the foreign exchange rate at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency at the foreign exchange rate at the balance sheet date. Foreign exchange differences arising on translation are recognised in the consolidated statement of income as net foreign exchange gains or losses.

Foreign exchange differences arising from the translation of estimate-based provisions however generally are accounted for as part of the change in the underlying estimate, and as such may be included within the operating expenses or income tax sections of the consolidated statement of income depending on the nature of the provision. Non-monetary assets that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transactions.

Presentation currency

For the purpose of the consolidated financial statements, the statements of income and balance sheets in functional currency of each entity are translated into Norwegian kroner (NOK), which is the presentation currency of the consolidated financial statements. The assets and liabilities of entities whose functional currencies are other than NOK are translated into NOK at the foreign exchange rate at the balance sheet date. The revenues and expenses of such entities are translated using average monthly foreign exchange rates, which approximates the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation from functional currency to presentation currency are recognised separately in Other comprehensive income.

Business combinations and goodwill

An acquisition of a business, (an integrated set of activities and assets that is capable of being conducted and managed for the purpose of providing a return directly to investors), is a business combination. Determining whether the acquisition meets the definition of a business combination requires judgment to be applied on a case by case basis. Acquisitions are assessed under the relevant criteria to establish whether the transaction represents a business combination or an asset purchase. Depending on the specific facts, acquisitions of exploration and evaluation licences for which a development decision has not yet been made, have largely been concluded to represent asset purchases.

Business combinations, except for transactions between entities under common control, have been accounted for using the acquisition method of accounting. The acquired identifiable tangible and intangible assets, liabilities and contingent liabilities are measured at their fair values at the date of the acquisition. Any excess of the acquisition cost over the net fair value of the identifiable assets acquired and liabilities assumed is recognised as goodwill.

Goodwill on acquisition is initially measured at cost. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses.

Goodwill may also arise upon investments in jointly controlled entities and associates, being the surplus of the cost of investment over the group's share of the net fair value of the identifiable assets. Such goodwill is reflected as part of the applicable investment in jointly controlled entities and associates. Any impairment of such goodwill will result from an impairment assessment of the investment as a whole, and will be reflected in income from equity accounted investments.

Revenue recognition

Revenues associated with sale and transportation of crude oil, natural gas, petroleum and chemical products and other merchandise are recognised when title and risk pass to the customer, which is normally at the point of delivery of the goods based on the contractual terms of the agreements.

Revenues from the production of oil and gas properties in which Statoil has an interest with other companies are recognised on the basis of volumes lifted and sold to customers during the period (the sales method). Where Statoil has lifted and sold more than the ownership interest, an accrual is recognised for the cost of the overlift. Where Statoil has lifted and sold less than the ownership interest, costs are deferred for the underlift.

Revenue is presented net of customs, excise taxes and royalties paid in-kind on petroleum products.

Sales and purchases of physical commodities, which are not settled net, are presented on a gross basis as revenue and cost of goods sold in the statement of income. Activities related to trading and commodity-based derivative instruments are reported on a net basis, with the margin included in revenue.

Transactions with the Norwegian State

Statoil markets and sells the Norwegian State's share of oil and gas production from the Norwegian Continental Shelf (NCS). The Norwegian State's participation in petroleum activities is organised through the State's direct financial interest (SDFI). All purchases and sales of the SDFI's oil production are classified as purchases [net of inventory variation] and revenue, respectively. Statoil ASA sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. This sale, and related expenditures refunded by the State, are presented net in Statoil's financial statements. Sales made by Statoil subsidiaries in their own name, and related expenditure, are however presented gross in Statoil's financial statements where the applicable subsidiary is considered the principal when selling natural gas on behalf of the Norwegian State. In accounting for these sales activities, the State's share of profit or loss is reflected in Statoil's Selling, general and administrative expenses as expenses or reduction of expenses, respectively.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of the group. The accounting policy for share-based payments and pension obligations is described below.

Share-based payments

Statoil operates an employee bonus share program. The cost of equity-settled transactions (bonus share awards) with employees is measured by reference to the estimated fair value at the date at which they are granted and is recognised as an expense over the average vesting period of 2.5 years. The awarded shares are accounted for as personnel expenses, and recognised as an equity transaction (included in additional paid-in capital).

Research and development

Statoil undertakes research and development both on a funded basis for licence holders, and unfunded projects at its own risk. Statoil's share of the licence holders' funding and the total costs of the unfunded projects are development costs that are considered for capitalisation.

Development costs which are expected to generate probable future economic benefits are capitalised as intangible assets if, and only if, all of the following have been demonstrated: The technical feasibility of completing the intangible asset so that it will be available for use or sale; the intention to complete the intangible asset and use or sell it; the ability to use or sell the intangible asset; how the intangible asset will generate probable future economic benefits; the availability of adequate technical, financial and other resources to complete the development and to use or sell the intangible asset, and the ability to reliably measure the expenditure attributable to the intangible asset during its development. All other research and development expenditure is expensed as incurred.

Subsequent to initial recognition, capitalised development costs are reported at cost less accumulated amortisation and accumulated impairment losses.

Income tax

Income tax in the consolidated statement of income for the year comprises current and deferred tax expense. Income tax is recognised in the consolidated statement of income except to the extent that it relates to items recognised directly in Other comprehensive income.

Current tax is the expected tax payable on the taxable income for the year and any adjustment to tax payable in respect of previous years. Uncertain tax positions and potential tax exposures are analysed individually and the best estimate of the probable amount for liabilities to be paid (unpaid potential tax exposure amounts, including penalties) and virtually certain amount for assets to be received (disputed tax positions for which payment has already been made) in each case is recognised within current tax or deferred tax as appropriate. Interest income and interest expenses relating to tax issues are estimated and recognised in the period in which they are earned or incurred, and are presented as financial items in the consolidated statement of income.

Deferred tax assets and liabilities are recognised for the future tax consequences attributable to differences between the carrying amounts of existing assets and liabilities in the financial statements and their respective tax bases, subject to the initial recognition exemption. The amount of deferred tax provided is based on the expected manner of realisation or settlement of the carrying amount of assets and liabilities, using tax rates enacted or substantially enacted at the balance sheet date.

A deferred tax asset is recognised only to the extent that it is probable that future taxable income will be available against which the asset can be utilised. In order for a deferred tax asset to be recognised based on future taxable income, convincing evidence is required taking into account the existence of contracts, production of oil or gas in the near future based on volumes of proved reserves, observable prices in active markets, expected volatility of trading profits and similar facts and circumstances.

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 Norwegian 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 7.5% per year. The uplift is computed on the basis of the original capitalised cost of offshore production installations. The uplift may be deducted from taxable income for a period of four years, starting in the year in which the capital expenditures are incurred. Uplift benefit is recognised when the deduction is included in the current year tax return and impacts taxes payable. Unused uplift may be carried forward indefinitely.

Oil and gas exploration and development expenditure

Statoil uses the "successful efforts" method of accounting for oil and gas exploration costs. Expenditures to acquire mineral interests in oil and gas properties and to drill and equip exploratory wells are capitalised as exploration and evaluation expenditure within intangible assets until the well is complete and the results have been evaluated. If, following evaluation, the exploratory well has not found proved reserves, the previously capitalised costs are evaluated for de-recognition or tested for impairment. Geological and geophysical costs and other exploration expenditures are expensed as incurred.

For exploration and evaluation asset acquisitions (farm-in arrangements) in which Statoil has made arrangements to fund a portion of the selling partners' (farmor's) exploration and/or future development expenditures, these expenditures are reflected in the financial statements as and when the exploration and development work progresses. Exploration and evaluation asset dispositions (farm-out arrangements) are accounted for on a historical cost basis with no gain or loss recognition.

Exchanges (swaps) of exploration and evaluation assets are accounted for at the carrying amounts of the assets given up with no gain or loss recognition.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount, and at least once a year. Exploratory wells that have found reserves, but where classification of those reserves as proved depends on whether major capital expenditure can be justified or where the economic viability of that major capital expenditure depends on the successful completion of further exploration work, will remain capitalised during the evaluation phase for the exploratory finds. Thereafter it will be considered a trigger for impairment evaluation of the well if no development decision is planned for the near future, and there moreover are no concrete plans for future drilling in the licence. Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present. Impairment and reversals of impairment of exploration and evaluation assets are charged to Exploration expenses in the consolidated statement of income.

Capitalised exploration and evaluation expenditure, including expenditures to acquire mineral interests in oil and gas properties, related to wells that find proved reserves are transferred from Exploration expenditure (Intangible assets) to Assets under development (Property, plant and equipment) at the time of sanctioning of the development project.

Property, plant and equipment

Property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of an asset retirement obligation, if any, and, for qualifying assets, borrowing costs. Property, plant and equipment also include assets acquired under the terms of profit sharing agreements (PSAs) in certain countries, and which qualify for recognition as assets of the group. State-owned entities in the respective countries however normally hold the legal title to such PSA-based Property, plant and equipment.

Exchanges of assets are measured at the fair value of the asset given up unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset is replaced and it is probable that future economic benefits associated with the item will flow to the group, the expenditure is capitalised. Inspection and overhaul costs associated with major maintenance programs are capitalised and amortised over the period to the next inspection. All other maintenance costs are expensed as incurred.

Capitalised exploration and evaluation expenditure, development expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, and field-dedicated transport systems for oil and gas are capitalised as producing oil and gas properties within Property, plant and equipment. Such capitalised cost is depreciated using the unit of production method based on proved developed reserves expected to be recovered from the area during the concession or contract period. Capitalised acquisition costs of proved properties are depreciated using the unit of production method based on total proved reserves. Depreciation of other assets and transport systems used by several fields is calculated on the basis of their estimated useful lives, normally using the straight-line method. Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item is depreciated separately. For exploration and production (E&P) assets Statoil has established separate depreciation categories which as a minimum distinguish between platforms, pipelines, and wells.

The estimated useful lives of property, plant and equipment are reviewed on an annual basis and changes in useful lives are accounted for prospectively. An item of property, plant and equipment is derecognised upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on de-recognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in other income or operating expenses, respectively, in the period the item is derecognised.

Non-current assets held for sale

Non-current assets are classified separately as held for sale in the balance sheet when their carrying amount will be recovered through a sale transaction rather than through continuing use. This condition is met only when the sale is highly probable, the asset is available for immediate sale in its present condition, and management is committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification. Liabilities directly associated with the assets classified as held for sale and expected to be included as part of the sale transaction are correspondingly also classified separately. Property, plant and equipment and intangible assets once classified as held for sale are not subject to depreciation or amortisation. The net assets and liabilities of a disposal group classified as held for sale are measured at the lower of their carrying amount and fair value less cost to sell.

Leases

Leases in terms of which Statoil assumes substantially all the risks and rewards of the ownership are reflected as finance leases within Property, plant and equipment and Financial liabilities. Assets under development for finance lease purposes, and for which Statoil carries substantially all the risk in the construction period, are reflected as finance leases under development within Property, plant and equipment based on the stage of completion at period end, unless another amount better reflects the realities of the arrangement. All other leases are classified as operating leases and the costs are charged to operating expenses on a straight line basis over the lease term, unless another basis is more representative of the benefits of the lease to the group.

Finance lease assets are reflected at an amount equal to the lower of fair value and the present value of the minimum lease payments at inception of the lease, and subsequently reduced by accumulated depreciation and impairment losses, if any. When an asset leased by a jointly controlled asset in which Statoil participates qualifies as a finance lease, Statoil reflects its proportionate share of the leased asset and related obligations in the balance sheet as Property, plant and equipment and Financial liabilities, respectively. Capitalised leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term using the depreciation methods described under Property, plant and equipment above, depending on the nature of the leased asset.

Statoil distinguishes between lease and capacity contracts. Lease contracts provide the right to use a specific asset for a period of time, while capacity contracts confer on Statoil the right to and the obligation to pay for certain capacity volume availability related to transport, terminalling, storage etc. Such capacity contracts that do not involve specified assets or that do not involve substantially all the capacity of an undivided interest in a specific asset are not considered by Statoil to qualify as leases for accounting purposes. Capacity payments are reflected as Operating expenses in the consolidated statements of income in the period for which the capacity contractually is available to Statoil.

Intangible assets

Intangible assets are stated at cost, less accumulated amortisation and accumulated impairment losses. Intangible assets include expenditure on the exploration for and evaluation of oil and natural gas resources, goodwill and other intangible assets. Intangible assets acquired separately from a business are carried initially at cost. An intangible asset acquired as part of a business combination is recognised separately from goodwill at its fair value if the asset is separable or arises from contractual or other legal rights and its fair value can be measured reliably.

Expenses related to the drilling of exploration wells are initially capitalised as intangible assets pending determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort. This evaluation is normally finalised within one year after well completion. Exploration wells that discover potentially economic quantities of oil and natural gas remain capitalised as intangible assets during the evaluation phase of the find, see further on this under "Oil and gas exploration and development expenditure".

Intangible assets relating to expenditure on the exploration for and evaluation of oil and natural gas resources are not amortised. Such assets are subject to impairment testing when facts and circumstances suggest that the carrying amount of an asset may exceed its recoverable amount (or at least on an annual basis), and are reclassified to property, plant and equipment when the decision to develop a particular area is made.

Other intangible assets are amortised on a straight-line basis over their expected useful lives. The expected useful lives of the assets are reviewed on an annual basis and changes in useful lives are accounted for prospectively.

Financial assets

Financial assets are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the asset. For additional information on fair value methods, refer to the "Measurement of fair values" section below. The subsequent measurement of the financial assets depends on which category they have been classified into at inception.

At initial recognition the group classifies its financial assets into the following three main categories; financial instruments at fair value through profit or loss; loans and receivables; and available-for-sale (AFS) financial assets. The first main category, financial instruments at fair value through profit or loss, further consists of two sub-categories; financial assets held for trading and financial assets that on initial recognition are designated as fair value through profit and loss. The latter approach may also be referred to as the "fair value option".

Financial assets classified in the loans and receivables category are carried at amortised cost using the effective interest method. Gains and losses are recognised in the statement of income when the loans and receivables are derecognised or impaired, as well as through the amortisation process. Trade and other receivables are carried at the original invoice amount, less a provision for doubtful receivables, which is made when there is objective evidence that Statoil will be unable to recover the balances in full.

Financial assets classified as AFS mainly include non-listed equity instruments. AFS equity instruments are carried on the balance sheet at fair value, with the change in fair value recognised directly in Other comprehensive income until the investment is derecognised or until the investment is determined to be impaired, at which time the cumulative change in fair value previously reported in Other comprehensive income is recognised in the consolidated statement of income.

A significant part of Statoil's investments in commercial papers, bonds and listed equity securities are managed together as an investment portfolio of the group's captive insurance company and are held in order to comply with specific regulations for capital retention. The investment portfolio is managed and evaluated on a fair value basis in accordance with an investment strategy and is accounted for using the fair value option with changes in fair value recognised through profit or loss.

Current financial investments are initially recognised in the category financial instruments at fair value through profit or loss, either as held for trading or through the group's application of the fair value option. Following from that classification the current financial investments are carried in the balance sheet at fair value with changes in their fair values recognised in the statement of income.

Financial assets are presented as current if they contractually will expire or otherwise are expected to be recovered within 12 months after the balance sheet date, or if they are derivative financial instruments held for the purpose of being traded. Other financial assets expected to be recovered more than 12 months after the balance sheet date and for which there is no plan of realisation are classified as non-current.

Financial assets are derecognised when the contractual rights to the cash flows expire or substantially all risks and rewards related to the ownership of the financial asset are transferred to a third party.

Financial assets and financial liabilities are shown separately in the balance sheet unless Statoil has both a legal right and a demonstrable intention to net settle certain balances payable to and receivable from the same counterparty, in which case they are shown net in the balance sheet. Such offsetting of balances takes place and is reflected within Trade and other receivables and Trade and other payables, and Derivative financial instrument assets and liabilities, respectively.

Inventories

Inventories are stated at the lower of cost and net realisable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses.

Impairment

Impairment of intangible assets and property, plant and equipment

Statoil assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Individual assets are grouped based on levels with separately identifiable and largely independent cash inflows. Normally, separate cash-generating units are individual oil and gas fields or plants. For capitalised exploration expenditure, the cash-generating units are individual wells.

In assessing whether a write-down of the carrying amount of a potentially impaired asset is required, the asset's carrying amount is compared to the recoverable amount. Frequently the recoverable amount of an asset proves to be Statoil's estimated value in use, which is determined using a discounted cash flow model.

The estimated future cash flows applied are based on reasonable and supportable assumptions and represent management's best estimates of the range of economic conditions that will exist over the remaining useful life of the cash flow generating assets, set down in Statoil's most recently approved long term plans. Statoil's long term plans are approved by corporate management and updated at least annually. The plans cover a 10-year period and reflect expected production volumes for oil and natural gas in that period. For assets and cash generating units with an expected useful life or timeline for production of expected reserves extending beyond 10 years, the related cash flows also include project or asset specific estimates established in line with group consistent assumptions and principles.

In performing a value in used-based impairment test, the estimated future cash flows are adjusted for risks specific to the asset and discounted using a real post-tax discount rate based on Statoil's post-tax weighted average cost of capital (WACC). The use of post-tax discount rates in determining value in use does not result in a materially different determination of the need for, or the amount of, impairment that would be required if pre-tax discount rates had been used.

If assets are determined to be impaired, the carrying amounts of those assets are written down to the recoverable amount which is the higher of fair value less costs to sell and value in use.

Impairments are reversed as applicable to the extent that conditions for impairment are no longer present.

Impairment losses and reversals of impairment losses are presented as Exploration expenses or Depreciation, amortisation and net impairment losses respectively, on the basis of their nature as either exploration assets (intangible exploration assets) or development and producing assets (property, plant and equipment, and other intangible assets).

Impairment of goodwill
Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired. At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units expected to benefit from the business combination's synergies.

Impairment is determined by assessing the recoverable amount of the cash-generating unit to which the goodwill relates. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognised, firstly on goodwill and then pro-rata on the other assets of that unit. Impairments of goodwill once recognised are not reversed in future periods.

Impairment of financial assets
Statoil assesses at each balance sheet date whether a financial asset or group of financial assets is impaired, except for the financial assets classified in the fair value through profit and loss category.

If there is objective evidence that an impairment loss has been incurred for assets carried at amortised cost, the carrying amount of the asset is reduced, with the amount of the loss recognised in the statement of income. Any subsequent reversal of an impairment loss correspondingly also is recognised in the statement of income.

If an AFS financial asset is impaired, i.e. a decline in the fair value of an equity instrument has been assessed to be significant or prolonged, the difference between cost and fair value is transferred from Other comprehensive income to the consolidated statement of income. When impairments of equity instruments classified as AFS are reversed this is recognised directly in Other comprehensive income.

Financial liabilities
Financial liabilities are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the liability. For additional information on fair value methods, refer to the "Measurement of fair values" section below. The subsequent measurement of financial liabilities depends on which category they have been classified into. The categories applicable for Statoil is either financial liabilities at fair value through profit or loss or financial liabilities measured at amortised cost using the effective interest method. The latter applies to Statoil's non-current bank loans and bonds.

Trade and other payables are carried at payment or settlement amounts.

Financial liabilities are presented as current if the liability is due to be settled within 12 months after the balance sheet date, or if they are derivative financial instruments held for the purpose of being traded. Other financial liabilities which contractually will be settled more than 12 months after the balance sheet date are classified as non-current.

Financial liabilities are derecognised when the contractual obligation expires, is discharged or cancelled. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised either in Interest income and other financial items or in Interest and other finance expenses.

Derivative financial instruments
Statoil uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices. Such derivative financial instruments are initially recognised at fair value on the date on which a derivative contract is entered into and are subsequently re-measured at fair value through profit and loss. The impact of commodity based derivative financial instruments is recognised in the consolidated statement of income under Revenues, as such derivative instruments for all significant purposes are related to sales contracts or revenue related risk management. The impact of other financial instruments is reflected under Net Financial Items.

Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative. Derivative assets or liabilities expected to be recovered, or with the legal right to be settled more than 12 months after the balance sheet date are classified as non-current, with the exception of derivative financial instruments held for the purpose of being traded.

Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments, as if the contracts were financial instruments, are accounted for as financial instruments. However contracts that are entered into and continued to be held for the purpose of the receipt or delivery of a non-financial item in accordance with Statoil's expected purchase, sale or usage requirements, also referred to as "own use", are not accounted for as financial instruments. This is applicable to a significant number of contracts for the purchase or sale of crude oil and natural gas, which are recognised upon delivery.

Derivatives embedded in other financial instruments or in non-financial host contracts are recognised as separate derivatives when their risks and economic characteristics are not closely related to those of the host contracts, and the host contracts are not carried at fair value. Where there is an active market for a commodity or other non-financial item subject of a purchase or sale contract, a pricing formula will, for instance, be considered to be closely related to the host purchase or sales contract if the price formula is based on the active market in question. A price formula with indexation to other markets or products will however result in the recognition of a separate derivative. Where there is no active market for the commodity or other non-financial item in question, Statoil assesses the characteristics of such a price related embedded derivative to be closely related to the host contract if the price formula is based on relevant indexations commonly used by other market participants. This applies to a number of Statoil's long term natural gas sales agreements. Contracts are assessed for embedded derivatives when Statoil becomes a party to them, including at the date of a business combination. Such embedded derivatives are measured at fair value at each period end, and the changes in fair value are recognised in profit or loss for the period.

Pension liabilities
Statoil has pension plans for employees that either provide a defined pension benefit upon retirement, or a pension dependent on defined contributions. For defined benefit schemes, the benefit to be received by employees generally depends on many factors including length of service, retirement date and future salary levels.

Statoil's net obligation in respect of defined benefit pension plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in return for their services in the current and prior periods. That benefit is discounted to determine its present value, and the fair value of any plan assets is deducted. The discount rate is the yield at the balance sheet date reflecting the maturity dates approximating the terms of the group's obligations. The calculation is performed by an external actuary. Current service cost is an element of net periodic pension cost and recognised in the statement of income.

The interest element of the defined benefit cost represents the change in present value of scheme obligations resulting from the passage of time, and is determined by applying the discount rate to the opening present value of the benefit obligation, taking into account material changes in the obligation during the year. The expected return on plan assets is based on an assessment made at the beginning of the year of long-term market returns on scheme assets, adjusted for the effect on the fair value of plan assets of contributions received and benefits paid during the year. The difference between the expected return on plan assets and the interest cost is recognised in the statement of income as a part of the net periodic pension cost.

Net periodic pension cost is accumulated in cost pools and allocated to business areas and Statoil operated jointly controlled assets (licences) on an hours incurred basis and recognised in the statement of income based on the function of the cost.

Past service cost is recognised immediately when the benefits become vested or on a straight-line basis until the benefits become vested. When a settlement (eliminating all obligations for benefits already accrued) or a curtailment (reducing future obligations as a result of a material reduction in the scheme membership or a reduction in future entitlement) occurs, the obligation and related plan assets are re-measured using current actuarial assumptions and the gain or loss is recognised in the statement of income during the period in which the settlement or curtailment occurs.

Actuarial gains and losses are recognised in full in the statement of comprehensive income in the period in which they occur. Due to the parent company Statoil ASA's functional currency being USD, the significant part of the group's pension obligations will be payable in a foreign currency (i.e. NOK). Actuarial gains and losses related to the parent company's pension obligation as a consequence include the impact of exchange rate fluctuations.

Contributions to defined contribution schemes are recognised in the statement of income in the period in which the contribution amounts are earned by the employees.

Provisions and contingent assets and liabilities
Provisions are recognised when Statoil has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market

assessments of the time value of money and, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognised as Other finance expenses.

Contingent liabilities arising from past events and for which it is not probable that an outflow of resources will be required to settle the obligation, if any, are not recognised but disclosed with indication of uncertainties relating to amounts and timing involved, unless the possibility of an outflow in settlement is remote.

Possible assets arising from past events that will only be confirmed by future uncertain events and are not wholly within Statoil's control (contingent assets), are not recognised, but are disclosed when an inflow of economic benefits is probable. The asset and related income are subsequently recognised in the consolidated financial statements in the period in which the inflow of economic benefits becomes virtually certain.

Onerous contracts

Statoil recognises as provisions the net obligation under contracts defined as onerous. Contracts are deemed to be onerous if the unavoidable cost of meeting the obligations under the contract exceeds the economic benefits expected to be received in relation to the contract. A contract which forms an integral part of the operations of a cash generating unit whose assets are dedicated to that contract, and for which the economic benefits cannot be reliably separated from those of the cash generating unit, is included in impairment considerations for the applicable cash generating unit.

Asset retirement obligations (ARO)

Provisions for ARO costs are recognised when Statoil has an obligation (legal or constructive) to dismantle and remove a facility or an item of property, plant and equipment and to restore the site on which it is located, and when a reliable estimate of that liability can be made. Cost is estimated upon current regulation and technology, considering relevant risks and uncertainties, to arrive at best estimates. Normally an obligation arises for a new facility, such as an oil and natural gas production or transportation facility, upon construction or installation. An obligation for ARO may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations. The provision is classified under Asset retirement obligations, other provisions and other liabilities in the balance sheet. The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. Refining and processing plants that are not limited by licence periods are deemed to have indefinite lives and in consequence no asset retirement obligation has been recognised. For retail outlets, ARO provisions are estimated on a portfolio basis.

When a provision for ARO cost is recognised, a corresponding amount is recognised to increase the related property, plant and equipment. This is subsequently depreciated as part of the costs of the facility or item of property, plant and equipment.

Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment.

Measurement of fair values

Quoted prices in active markets represent the best evidence of fair value, and are used by Statoil in determining the fair values of assets and liabilities to the extent possible.

A financial instrument is regarded as quoted in an active market if the prices quoted are readily and regularly available, normally through an exchange, and the prices quoted by the exchange represent actual and regularly occurring market transactions that in all significant aspects are identical to the instrument being valued. Statoil considers both the actual volume and the timing of recent market transactions in determining whether prices are quoted in a sufficiently active market. Financial instruments quoted in active markets will typically include commodity based futures, exchange traded option contracts, commercial papers, bonds and equity instruments with quoted market prices obtained from the relevant exchanges or clearing houses. The fair values of quoted financial assets, financial liabilities and derivative instruments are determined by reference to bid and ask prices, at the close of business on the balance sheet date.

Where there is no active market, fair value is determined using valuation techniques. These include using recent arm's-length market transactions; reference to other instruments that are substantially the same; discounted cash flow analysis; and pricing models. In the valuation techniques Statoil also takes into consideration the counterparty and its own credit risk. This is either reflected in the discount rate used, or through direct adjustments to the calculated cash flows. Consequently, where Statoil reflects elements of long-term physical delivery commodity contracts at fair value, such fair value estimates to the extent possible are based on quoted forward prices in the market and underlying indexes in the contracts, as well as assumptions of forward prices and margins where market prices are not available. Similarly, the fair values of interest and currency swaps are estimated based on relevant quotations from active markets, quotes of comparable instruments, and other appropriate valuation techniques.

Critical accounting judgements and key sources of estimation uncertainty

Critical judgements in applying accounting policies

The following are the critical judgements, apart from those involving estimations (see below), that Statoil has made in the process of applying the accounting policies and that have the most significant effect on the amounts recognised in the financial statements.

Revenue recognition - gross versus net presentation of traded SDFI volumes of oil and gas production

As described under Transactions with the Norwegian State above, Statoil markets and sells the Norwegian State's share of oil and gas production from the NCS. Statoil includes the costs of purchase and proceeds from the sale of the SDFI oil production in Purchases [net of inventory variation] and Revenues, respectively. In making the judgement Statoil considered the detailed criteria for the recognition of revenue from the sale of goods, and in particular concluded that the risk and reward of the ownership of the goods had been transferred from the SDFI to Statoil.

As also described above, Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. This sale, and related expenditures refunded by the State, are shown net in Statoil's financial statements. In making the judgment Statoil considered the same criteria as for the oil production and concluded that the risk and reward of the ownership of the gas had not been transferred from the SDFI to Statoil.

Key sources of estimation uncertainty

The preparation of consolidated financial statements requires that management make estimates and assumptions that affect reported amounts of assets and liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the result of which form the basis of making the judgements about carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. The estimates and underlying assumptions are reviewed on an ongoing basis considering the current and expected future market conditions.

Statoil is exposed to a number of underlying economic factors, such as liquids prices, natural gas prices, refining margins, foreign exchange rates, interest rates as well as financial instruments with fair values derived from changes in these factors, which affect the overall results. In addition, Statoil's results are influenced by the level of production, which in the short term may be influenced by for instance maintenance programmes. In the long term, the results are impacted by the success of exploration and field development activities.

The matters described below are considered to be the most important in understanding the key sources of estimation uncertainty that are involved in preparing these financial statements and the uncertainties that could most significantly impact the amounts reported on the results of operations, financial position and cash flows.

Proved oil and gas reserves. Proved oil and gas reserves have been estimated by internal experts on the basis of industry standards and governed by criteria established by regulations of the SEC. The SEC revised Rule 4-10 of Regulation S-X and changed a number of oil and gas reserve estimation requirements effective for the year ending 31 December 2009. The revised Rule requires, on a prospective basis, the use of a price based on a 12-month average for reserve estimation instead of a single end-of-year price and allows for non-traditional sources such as bitumen extracted from oil sands to be included as reserves. The Financial Accounting Standards Board (FASB) aligned the requirements for supplemental oil and gas disclosures contemporaneously with the changes made by the SEC. Statoil estimates that implementation of the revisions have had an immaterial impact on proved reserves and unit of production depreciation. The comparability of disclosures between years has however been impacted by the new requirements which were applied on a prospective basis.

Reserves estimates are based on subjective judgments involving geological and engineering assessments of in-place hydrocarbons volumes, the production, historical extraction recovery and processing yield factors and installed plant operating capacity. For future development projects, proved reserves estimates are included only where there is a significant commitment to project funding and execution and when relevant governmental and regulatory approvals have been secured or are reasonably certain to be secured. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. An independent third party has evaluated Statoil's proved reserves estimates, and the results of such evaluation do not differ materially from management estimates. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. Unless evidence indicates that renewal is reasonably certain, estimates of economically producible reserves only reflect the period before the contracts providing the right to operate expire. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence within a reasonable time. Future changes in proved oil and gas reserves, for instance as a result of changes in prices, could have a material impact on unit of production rates used for depreciation and amortisation.

Expected oil and gas reserves. Expected oil and gas reserves, which differ from proved reserves, have been estimated by internal experts on the basis of industry standards and are used for impairment testing purposes and for calculation of asset retirement obligations. Reserves estimates are based on subjective judgments involving geological and engineering assessments of in-place hydrocarbons volumes, the production, historical extraction recovery and processing yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. Future changes in expected oil and gas reserves, for instance as a result of changes in prices, could have a material impact on asset retirement obligations, as well as for the impairment testing of upstream assets, which could have a material effect on operating income as a result of changed impairment charges.

Exploration and leasehold acquisition costs. Statoil capitalises the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. Statoil also capitalises leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Judgments as to whether these expenditures should remain capitalised or written down due to impairment losses in the period may materially affect the operating income for the period.

Impairment/reversal of impairment. Statoil has significant investments in property, plant and equipment and intangible assets. Changes in the circumstances or expectations of future performance of an individual asset may be an indicator that the asset is impaired requiring the book value to be written down to its recoverable amount. Impairments are reversed if conditions for impairment are no longer present. Evaluating whether an asset is impaired or if an impairment should be reversed requires a high degree of judgement and may to a large extent depend upon the selection of key assumptions about the future.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount and at least annually. If, following evaluation, an exploratory well has not found proved reserves, the previously capitalised costs are tested for impairment. Subsequent to the initial evaluation phase for a well it will be considered a trigger for impairment testing of a well if no development decision is planned for the near future, and there moreover is no concrete plan for future drilling in the licence. Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present.

Estimating recoverable amounts involves complexity in estimating relevant future cash flows, based on assumptions about the future, and discounted to their present value. Impairment testing requires long-term assumptions to be made concerning a number of often volatile economic factors such as future market prices, refinery margins, currency exchange rates and future output, discount rates and political and country risk among others, in order to establish relevant future cash flows. Impairment testing frequently also requires judgement regarding probabilities and probability distributions as well as levels of sensitivity inherent in the establishment of recoverable amount estimates, and consequently in ensuring that the recoverable amount estimates' robustness where relevant is factored sufficiently into the impairment evaluations and reflected in the impairment or reversal of impairment recognised in the financial statements. Long-term assumptions for major economic factors are made at group level, and there is a high degree of reasoned judgement involved in establishing these assumptions, in determining other relevant factors such as forward price curves, in estimating production outputs, and in determining the ultimate termination value of an asset.

Employee retirement plans. When estimating the present value of defined pension benefit obligations that represent a gross long-term liability in the balance sheet, and indirectly, the period's net pension expense in the statement of income, management make a number of critical assumptions affecting these estimates. Most notably, assumptions made about the discount rate to be applied to future benefit payments, the expected return on plan assets and the annual rate of compensation increase have a direct and potentially material impact on the amounts presented. Significant changes in these assumptions between periods can have a material effect on the financial statements.

Asset retirement obligations. Statoil has significant obligations to decommission and remove offshore installations at the end of the production period. Legal and constructive obligations associated with the retirement of non-current assets are recognised at their fair value at the time the obligations are incurred. Upon initial recognition of a liability, that cost is capitalised as part of the related non-current asset and allocated to expense over the useful life of the asset.

It is difficult to estimate the costs of these decommissioning and removal activities, which are based on current regulations and technology, considering relevant risks and uncertainties. Most of the removal activities are many years into the future and the removal technology and costs are constantly changing. The estimates include assumptions of both the time required and the day rates for rigs, marine operations and heavy lift vessels that can vary considerably depending on the assumed removal complexity. As a result, the initial recognition of the liability and the capitalised cost associated with decommissioning and removal obligations, and the subsequent adjustment of these balance sheet items, involve the application of significant judgement.

Derivative financial instruments. When not directly observable in active markets, the fair value of derivative contracts must be computed internally based on internal assumptions as well as directly observable market information, including forward and yield curves for commodities, currencies and interest. Changes in internal assumptions and forward curves could materially impact the internally computed fair value of derivative contracts, particularly long-term contracts, resulting in corresponding impact on income or loss in the consolidated statement of income.

Income tax. Statoil annually incurs significant amounts of income taxes payable to various jurisdictions around the world, and also recognises significant changes to deferred tax assets and deferred tax liabilities, all of which are based on management's interpretations of applicable laws, regulations and relevant court decisions. The quality of these estimates is highly dependent upon management's ability to properly apply at times very complex sets of rules, to recognise changes in applicable rules and, in the case of deferred tax assets, management's ability to project future earnings from activities that may apply loss carry forward positions against future income taxes.

8.1.3 Segments

Operating segments

For the years covered by these financial statements, Statoil managed its operations in the following operating segments; Exploration and Production Norway, International Exploration and Production, Natural Gas, Manufacturing and Marketing, and Fuel and Retail. 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. The Natural Gas segment transports and markets natural gas and natural gas products. Manufacturing and Marketing is responsible for petroleum refining operations and the marketing of crude oil and refined petroleum products except for natural gas and natural gas products. Fuel and Retail markets fuel and related products principally to retail consumers.

The "Other" section consists of the activities of Corporate services, Corporate center, Group Finance, Technology & New energy and Projects. The "Eliminations" section encompasses elimination of inter-segment sales and related unrealised profits, mainly from the sale of crude oil and products. Inter-segment revenues are based upon estimated market prices.

Operating segments align with internal management reporting to the company's chief operating decision maker, Statoil's Corporate Executive Committee (CEC). The operating segments are determined based on differences in the nature of their operations, products, services and geographical location of the activity. The measure of segment profit is Net operating income. Financial items, tax expense and tax assets are not allocated to the operating segments. The measurement basis for the net operating income for each operating segment follows the accounting principles used in the financial statements as described in note 2 *Significant accounting policies*.

Statoil's internal management reporting changed and led to changes in Statoil's operating segments effective from the fourth quarter 2010. The activity included in Statoil Fuel and Retail (SFR) was previously reported as part of the Manufacturing and Marketing segment. Following the listing SFR is now being reported separately to the Corporate Executive Committee and has been assessed to constitute a separate operating segment. In the tables below, the activities of SFR and Manufacturing and Marketing have been presented in accordance with the new segment structure. Comparable periods have been restated accordingly.

Segment data for the years ended 31 December 2010, 2009 and 2008 is presented below:

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Fuel and Retail	Other	Eliminations	Total
Year ended 31 December 2010								
Revenues and Other income third party	4,101	8,358	84,480	367,782	62,283	1,511	0	528,515
Revenues and Other income, inter-segment	166,571	41,930	2,765	39,224	3,571	2,207	(256,268)	0
Net income from equity accounted investments	56	707	276	226	4	(136)	0	1,133
Total revenues and other income	170,728	50,995	87,521	407,232	65,858	3,582	(256,268)	529,648
Net operating income	115,615	12,623	8,511	(1,973)	2,354	170	(72)	137,228
Significant non-cash items recognised in segment profit or loss								
- Depreciation and amortisation	26,019	15,183	1,916	1,055	1,215	693	0	46,081
- Impairment losses	0	1,469	0	2,913	97	48	0	4,527
- Commodity derivatives	(1,866)	0	4,542	(226)	0	0	0	2,450
- Exploration expenditure written off	1,441	1,470	0	0	0	0	0	2,911
Equity accounted investments	133	8,842	2,629	712	43	1,525	0	13,884
Other segment non-current assets*	188,194	133,482	36,078	15,895	11,115	3,135	0	387,899
Assets classified as held for sale	0	44,890	0	0	0	0	0	44,890
Non-current assets, not allocated to segments*								47,573
Total non-current assets and assets classified as held for sale								494,246
Additions to PP&E and intangible assets**	31,902	40,385	2,995	3,348	829	969	0	80,428

* Deferred tax assets, post employment benefit assets and financial instruments are not allocated to segments.

** Excluding movements due to changes in asset retirement obligations.

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Fuel and Retail	Other	Eliminations	Total
Year ended 31 December 2009								
Revenues and Other income third party	4,153	12,301	96,973	292,990	55,951	1,287	0	463,655
Revenues and Other income inter-segment	154,431	28,459	1,241	30,583	1,404	2,295	(218,413)	0
Net income from equity accounted investments	79	1,075	399	253	27	(55)	0	1,778
Total revenues and other income	158,663	41,835	98,613	323,826	57,382	3,527	(218,413)	465,433
Net operating income	104,318	2,599	18,488	(1,809)	1,268	(1,146)	(2,078)	121,640
Significant non-cash items recognised in segment profit or loss								
- Depreciation and amortisation	25,653	16,231	1,778	1,178	1,212	687	0	46,739
- Impairment losses	0	873	1,001	5,369	0	74	0	7,317
- Commodity based derivatives	(1,781)	0	(2,814)	1,072	0	(122)	0	(3,645)
- Exploration expenditure written off	1,177	5,821	0	0	0	0	0	6,998
Equity accounted investments	214	4,962	2,829	682	235	1,134	0	10,056
Other segment non-current assets	175,998	152,678	34,797	16,813	11,774	3,028	0	395,088
Non-current assets, not allocated to segments*								41,312
Total non-current assets								446,456
Additions to PP&E and intangible assets**	34,875	39,354	2,528	5,010	2,608	1,340	0	85,715

* Deferred tax assets, post employment benefit assets and non-current financial instruments are not allocated to segments.

** Excluding movements due to changes in asset retirement obligations.

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Fuel and Retail	Other	Eliminations	Total
Year ended 31 December 2008								
Revenues third party and Other income	2,879	10,289	108,704	456,940	73,225	2,700	0	654,737
Revenues and Other income inter-segment	216,882	35,031	1,882	38,583	(13)	2,212	(294,577)	0
Net income from equity accounted investments	82	809	225	222	(6)	(49)	0	1,283
Total revenues and other income	219,843	46,129	110,811	495,745	73,206	4,863	(294,577)	656,020
Net operating income	166,907	12,784	12,541	4,693	(145)	(731)	2,783	198,832
Significant non-cash items recognised in segment profit or loss:								
- Depreciation and amortisation	24,043	11,619	2,310	1,083	1,034	596	0	40,685
- Impairment losses	0	2,063	0	0	0	248	0	2,311
- Inventory valuation	0	0	24	5,203	0	0	(1,377)	3,850
- Commodity based derivatives	(109)	0	(1,341)	(1,306)	0	(37)	0	(2,793)
- Exploration expenditure written off	749	2,957	0	0	0	0	0	3,706
Equity accounted investments	149	6,114	4,898	786	277	416	0	12,640
Other segment non-current assets	165,493	160,580	35,735	22,398	12,022	3,854	0	400,082
Non-current assets, not allocated to segments*								20,889
Total non-current assets								433,611
Additions to PP&E and intangible assets**	34,941	48,694	2,041	6,611	1,877	1,256	0	95,420

* Deferred tax assets, post employment benefit assets and non-current financial instruments are not allocated to segments.

** Excluding movements due to changes in asset retirement obligation.

See note 14 *Property, plant and equipment* and note 15 *Intangible assets* for information on impairments recognised in the International Exploration and Production segment and in the Manufacturing and Marketing segment.

Geographical areas
Statoil is present in 42 countries, and manages its business segments on a worldwide basis. In presenting information on the basis of geographical areas, revenues from external customers are attributed to the country of the legal entity executing the external sale.

Assets are based on the geographical location of the assets.

Geographical data for the year ended 31 December 2010, 2009 and 2008 is presented below:

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2010						
Norway	227,122	72,643	47,551	47,332	16,725	411,373
USA	22,397	7,817	1,815	14,918	5,771	52,718
Sweden	0	0	0	18,810	4,612	23,422
Denmark	0	0	0	14,275	3,027	17,302
Other	4,508	4,380	205	12,150	2,457	23,700
Total revenues (excluding net income from equity accounted investments)	254,027	84,840	49,571	107,485	32,592	528,515

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2009						
Norway	182,353	80,018	34,655	45,927	18,137	361,090
USA	19,836	5,555	117	14,017	672	40,197
Sweden	0	0	0	16,556	3,795	20,351
Denmark	0	0	0	15,105	1,957	17,062
Other	9,978	2,959	154	10,762	1,102	24,955
Total revenues (excluding net income from equity accounted investments)	212,167	88,532	34,926	102,367	25,663	463,655

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2008						
Norway	260,171	79,813	44,536	79,659	31,105	495,284
USA	24,712	8,795	1,660	20,182	2,545	57,894
Sweden	0	0	0	23,428	2,618	26,046
Denmark	0	0	0	16,858	2,558	19,416
Singapore	11,203	1,906	0	0	0	13,109
UK	1,982	10,878	2	0	2,800	15,662
Other	7,305	930	198	16,885	2,008	27,326
Total revenues (excluding net income from equity accounted investments)	305,373	102,322	46,396	157,012	43,634	654,737

Assets by geographic areas

(in NOK million)	2010	2009	2008
Norway	239,363	228,153	220,794
USA	53,635	38,993	50,587
Brazil	37,008	29,549	15,743
Angola	29,050	23,345	23,807
Canada	24,495	20,533	17,151
Azerbaijan	17,296	17,331	21,396
Algeria	9,308	9,265	11,270
Other areas	36,518	37,975	47,769
Total non-current assets (excluding deferred tax assets, pension assets and financial non-current items) and assets classified as held for sale at 31 December	446,673	405,144	408,517

Major customers
Statoil does not have transactions with single external customers where revenues amount to more than 10% of the group's total revenues.

8.1.4 Assets classified as held for sale

On 21 May 2010 Statoil entered into an agreement with Sinochem Group to sell 40% of the Peregrino offshore heavy-oil field in Brazil. Following the transaction Statoil will hold a 60% ownership share and together with Sinochem jointly control the Peregrino assets. Statoil will remain operator of the field which is set to start production in first half of 2011.

Sinochem Group will pay a total of USD 3.1 billion in cash for the 40% share of the net assets, through acquisition of shares in various Statoil entities. The transaction is subject to governmental approvals in Brazil. The consideration is based on an economic date of 1 January 2010 and is subject to adjustments for working capital and for a proportional share of operational and capital expenditures incurred in the period between the economic date and the date for final closing of the transaction. As at 1 January 2010 the net carrying amount of the Peregrino assets was NOK 21.4 billion (100%). The transaction will be recognised in the International Exploration and Production segment when the transaction closes, which is expected to occur in the first half of 2011.

On the basis of the agreement, the carrying amount of assets and liabilities relating to the divestment has been classified as held for sale in the *Consolidated balance sheet*. Assets and liabilities have been classified as held for sale on a 100% basis for entities subject to the transaction (disposal group), including entities for which Statoil will retain a jointly controlled 60% interest after the transaction. Assets and liabilities related to the Peregrino licence owned through entities not subject to the transaction with Sinochem have not been classified as held for sale. The current and non-current financial liabilities classified as held for sale as listed in the table below, relate to a financial lease liability directly associated with the disposal group. A corresponding financial lease asset has been included in the Property, plant and equipment amount classified as held for sale.

On 21 November 2010 Statoil entered into an agreement with PTT Exploration and Production (PTTEP) to sell a 40% interest in Statoil's Kai Kos Dehseh oil sands project in Alberta, Canada, legally organised as a partnership. Following the transaction Statoil will hold a 60% ownership share and together with PTTEP jointly control the project assets of the partnership. Statoil will remain managing partner and operator of the project.

The total cash consideration, USD 2.3 billion, is subject to adjustments for working capital and for a proportional share of operational and capital expenditures incurred in the period between the economic date, set to 1 January 2011, and the date of final closing of the transaction. As at 31 December 2010 the net carrying amount of the Kai Kos Dehseh assets was NOK 21.2 billion (100%).

As at 31 December 2010 the transaction was subject to governmental approvals in Canada. These approvals were received in January 2011 and the transaction was closed on 21 January 2011. The transaction will be recognised in the International Exploration and Production segment in 2011.

On the basis of the agreement, the carrying amount of assets and liabilities relating to the divestment has been classified as held for sale in the Consolidated balance sheet on a 100% basis.

The table below shows a specification of assets and liabilities classified as held for sale:

(in NOK million)	31 December 2010
Property plant and equipment	32,515
Intangible assets	12,375
Total assets classified as held for sale	44,890
Non-current financial liabilities	7,796
Asset retirement obligation, other provisions and other liabilities	549
Current financial liabilities	878
Total liabilities directly associated with the assets held for sale	9,223

8.1.5 Business combinations

In 2008 Statoil increased the interest in the Peregrino offshore heavy-oil field in Brazil from 50% to 100%, after closing the deal to acquire Anadarko's 50% interest on 10 December 2008. Statoil paid a cash consideration of USD 1.8 billion, including expenditures incurred in the period 1 January to 10 December 2008, for 100% of the shares in Anadarko's wholly owned company Anadarko Petroleo Ltda and Anadarko's 50% share of the company South Atlantic Holding BV. Conditional on future oil prices above pre-defined threshold levels, Statoil will pay an additional maximum pre-tax amount of USD 0.3 billion to be earned by 2020, related to the Peregrino field. The value of the contingent consideration element at the time of closing the deal, estimated to USD 0.2 billion, was recognised as part of the acquisition price. The Peregrino acquisition has been assessed to constitute a business combination under IFRS 3 (2004) and changes in the fair value of the contingent consideration element are being recorded as adjustments to the book value of the assets acquired. The contingent element was estimated to USD 0.3 billion as of 31 December 2010. The transaction was recognised in the segment International Exploration and Production.

In May 2010 Statoil agreed with Sinochem to sell a 40% stake in the Peregrino project. See note 4 *Assets classified as held for sale* for further information on the divestment.

8.1.6 Asset acquisitions and disposals

On 8 October 2010 Statoil signed a Purchase and Sale agreement with Talisman Energy Inc. and Enduring Resources LLC under which Statoil, through a 50/50 joint venture with Talisman Energy Inc., acquired 67,000 net acres in the Eagle Ford shale formation in Southwest Texas. The transaction was accounted for as an asset acquisition. Total consideration for Statoil's share is USD 0.9 billion. The transaction was completed on 8 December 2010 and has been recognised in the International Exploration and Production segment. Parts of the assets acquired are organised in a jointly controlled entity and accounted for under the equity method.

In November 2008 Statoil acquired a 32.5% interest in the Marcellus shale gas acreage from Chesapeake Appalachia, L.L.C. The Marcellus shale gas acreage covers 1.8 million net acres (7,300 square kilometres) in the Appalachia region of the Northeastern USA. Statoil paid a cash consideration of USD 1.3 billion and are paying an additional USD 2.1 billion in the form of funding of 75% of Chesapeake's expenditures for drilling and completion of wells during the period 2009 to 2012. The funding of Chesapeake's expenditures is recorded as drilling and completion expenditures in the financial statements at the time the expenditures for the wells are incurred. The transaction was recognised in the segment International Exploration and Production.

In February 2008 Statoil's participation in the Petrocedeño project (former Sincor project) was reduced from 15% to 9.677% as a result of the transformation of the Sincor project into the incorporated joint venture Petrocedeño, S.A., which has 60% participation by the Venezuelan state through its wholly owned company Petroleos de Venezuela, S.A. The Petrocedeño project involves the exploitation of extra heavy crude oil from the reservoirs in the Orinoco Belt offshore Venezuela. An accounting gain from the reduction of the participation interest was recognised in the Consolidated statements of income in 2008 by NOK 1.1 billion net of tax. The transaction was recognised in the segment International Exploration and Production. The remaining interest in Petrocedeño is reflected in the Consolidated financial statements under the equity method, while the previous interest in the Sincor project was accounted for as a jointly controlled asset consolidated on a line-by-line basis.

8.1.7 Capital management

Capital management

The objective of Statoil's capital management policy is to maximise value creation over time, while maintaining a strong financial position and long-term credit ratings at least within the single A category.

Management makes regular use of Free funds from operations over Net adjusted debt (FFO/ND) and Net adjusted debt over Capital employed (ND/CE) ratios in its assessment of Statoil's financial flexibility and ability to incur additional debt.

FFO is net operating cash flows provided by operating activities with the addition of certain adjustments employed by major rating agencies. These adjustments include cash effects from operating leases, post retirement benefit obligations, capitalised interest, asset retirement obligations and reclassifications of working capital cash flow changes.

ND in this respect is defined as Statoil's current and non-current financial liabilities adjusted for Statoil's liquidity positions and adjusted for the adjustments defined above. In addition certain adjustments are made through the addition of project financing, balances related to the Marketing instruction, and balances held by the group's captive insurance company.

CE is Statoil's total equity (including non-controlling interest) plus net interest bearing debt, including debt adjustments defined above.

Credit rating

Credit rating is important for Statoil in order to provide necessary financial flexibility to support a dynamic strategy and through economic and market cycles. Statoil has credit ratings from Moody's and Standard & Poor's and our stated objective is to have credit ratings at least within the single A category. This rating ensures necessary predictability when it comes to funding access to relevant capital markets at favourable terms and conditions. We have the intention to maintain financial ratios that we consider adequate for maintaining credit ratings at levels consistent with our rating target.

Funding of subsidiaries, associates and jointly controlled entities

Normally the parent company, Statoil ASA, incurs debt and then extends loans or equity to wholly owned subsidiaries to fund capital requirements within the group. With effect from 1 January 2009, Statoil ASA transferred the ownership of its Norwegian Continental Shelf (NCS) net assets to Statoil Petroleum AS. Following the transfer, the majority of Norwegian assets are owned by Statoil Petroleum AS. Effective from the same date, Statoil Petroleum AS became co-obligor or guarantor of existing debt securities and other loan arrangements of Statoil ASA. As co-obligor, Statoil Petroleum AS assumes and agrees to perform, jointly and severally with Statoil ASA, all payment and covenant obligations for this debt.

When partially owned subsidiaries or investments in associates and jointly controlled entities are financed, it is Statoil's policy to finance according to ownership share and on equal terms with the other owners. Statoil ASA does not extend loans to the Statoil Fuel & Retail subgroup (SFR). The SFR subgroup raises debt in the external market to fund its capital requirements within the SFR group. All terms for financing of subsidiaries, associates and jointly controlled entities is based on arm's-length principles. Project specific financing may also be used with the primary objective to mitigate risk.

Capital distribution

Capital distribution consists of dividend payments and share buy-backs. Present dividend policy states:

"It is Statoil's ambition to grow the annual cash dividend, measured in NOK per share in line with long-term underlying earnings. When deciding the annual dividend level, Statoil will take into consideration expected cash flows, capital expenditure plans, financing requirements and appropriate financial flexibility. In addition to cash dividend, Statoil might buy back shares as part of total distribution of capital to the shareholders."

The dividend policy has no direct link to the reported net income, and the focus will be on growing the annual cash dividend per share in line with long-term underlying earnings. Statoil emphasises the importance of maintaining an attractive cash dividend level (dividend and including potential share buy-back) also in the future.

8.1.8 Financial risk management

General information relevant to financial risks

Statoil's business activities naturally expose the group to financial risk. The group's approach to risk management includes identifying, evaluating, and managing risk in all activities using a top-down approach with the purpose of avoiding sub-optimisation by utilising correlations existing at the group level. Simply adding the different market risks without considering these correlations, would have overestimated our total market risk. Statoil utilises correlations between all the most important market risks, such as oil and natural gas prices, refined oil product prices, currencies, and interest rates, to calculate the overall market risk and thereby take into account the hedges inherent in our portfolio. This approach allows us to reduce the number of hedging transactions and thereby reduce transaction costs and avoids sub-optimisation.

An important element in the risk management approach is the use of centralised trading mandates requiring all major strategic transactions to be co-ordinated through our Corporate risk committee. Mandates delegated to the trading organisations within crude oil, refined products, natural gas, and electricity are relatively small compared to the total market risk of the company.

The group's Corporate risk committee, which is headed by the Chief financial officer and includes representatives from the principal business segments, is responsible for defining, developing, and reviewing the group's risk policies. The Chief financial officer assisted by the Corporate risk committee is also responsible for overseeing and developing Statoil's Enterprise-Wide Risk Management and proposing appropriate measures to adjust risk at the corporate level. The committee meets at least six times per year and regularly receives risk information relevant for the group.

Financial risks

Statoil's activities expose the group to the following financial risks as defined by IFRS 7:

- Market risk (including commodity price risk, currency risk, interest rate risk and equity price risk)
- Liquidity risk
- Credit risk

Market risk

Statoil operates in the worldwide crude oil, refined products, natural gas, and electricity markets and is exposed to market risks including fluctuations in hydrocarbon prices, foreign currency rates, interest rates and electricity prices that can affect the revenues and costs of operating, investing and financing. These risks are managed primarily on a short-term basis with a focus on achieving the highest risk adjusted returns for the group within the given mandate. Long-term positions, defined as having a time horizon of six months or more, are managed at the corporate level while short-term positions are managed at segment and lower levels according to trading strategies and mandates approved by the group's Corporate risk committee.

The group has established guidelines for entering into derivative contracts in order to manage our commodity price, foreign currency rate, and interest rate risks. The group uses both financial and commodity-based derivatives to manage the risks in revenues, financial items and the present value of future cash flows.

For more information on sensitivity analysis of market risk see note 32 *Financial instruments*: *fair value measurement and sensitivity analysis of market risk*.

Commodity price risk

Commodity price risk represents the group's most important short-term market risk and is monitored every day against established mandates as defined by the group's governing policies. To manage short-term commodity risk, the group enters into commodity-based derivative contracts, including futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity.

Derivatives associated with crude oil and refined oil products are traded mainly on the Inter Continental Exchange (ICE) in London, the New York Mercantile Exchange (NYMEX), the OTC Brent market, and in crude and refined products swaps markets. Derivatives associated with natural gas and electricity are mainly OTC physical forwards and options, NASDAQ OMX Oslo (formerly named Nordpool) forwards and futures traded on the NYMEX and ICE.

The term of crude oil and refined oil products derivatives is usually less than one year and the term for natural gas and electricity derivatives is usually three years or less. For more detailed information about the group's commodity based derivative financial instruments see note 32 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

Currency risk

In addition to price developments, Statoil's operating results and cash flows are affected by foreign currency fluctuations of the most significant currencies, the NOK, EUR and GBP, against the USD.

Statoil manages its currency risk from operations with USD as the basis currency. Foreign exchange risk is managed at corporate level in accordance with given policies and mandates.

Statoil's cash flows derived from oil and gas sales, operating expenses and capital expenditures are mainly in USD, but taxes and dividends are mainly in NOK. Accordingly, the group's currency management is primarily linked to secure tax and dividend payments in NOK. This means that the group regularly purchase substantial NOK amounts on a forward basis using conventional derivative instruments.

Interest rate risk

Statoil principally manages the group's interest rates by converting a portion of cash flows from the long-term debt portfolio issued with fixed coupon rates into floating rate interest payments. Statoil aims to achieve lower expected funding costs over time and to diversify sources of funding. By using the fixed interest rate debt market when issuing new debt and at the same time altering the interest rate exposure by entering into interest rate swaps, funding sources becomes more diversified than by only being able to use the US floating rate debt market.

Bonds are normally issued at fixed rates in local currency (JPY, EUR, CHF, GBP and USD). These bonds are converted to floating USD bonds by using interest rate- and currency swaps. Statoil's interest rate policy includes a mandate to keep a portion of the long term debt at fixed interest rates. For more detailed information about the group's long term debt-portfolio see note 23 *Non-current financial liabilities*.

Equity price risk
The group's captive insurance company holds listed equity securities as a part of its portfolio. In addition, the group holds some other non-listed equity securities for long-term strategic purposes. By holding these assets the group is exposed to equity price risk, defined as the risk of declining equity prices, which can result in a decline in the carrying value of the group's assets recognised in the balance sheet. The equity price risk in the portfolio held by the group's captive insurance company is managed, with the aim of maintaining a moderate risk profile, through geographical diversification and the use of broad benchmark indexes. For more information about the group's equity securities see note 17 *Non-current financial assets* and note 20 *Current financial investments*.

Liquidity risk
Liquidity risk is the risk that Statoil will not be able to meet obligations of financial liabilities when they become due. The purpose of liquidity and current liability management is to make certain that Statoil has sufficient funds available at all times to cover its financial obligations.

Statoil manages liquidity and funding at the corporate level, ensuring adequate liquidity to cover group operational requirements. Statoil has high focus and attention on credit and liquidity risk throughout its entire organisation. In order to secure necessary financial flexibility, which includes meeting the group's financial obligations, Statoil maintain what it believes to be a conservative liquidity management policy. To secure financial flexibility and identify future long-term financing needs, Statoil carries out three-year cash forecasts at least monthly.

Statoil's operating cash flows are significantly impacted by the volatility in the oil and gas prices. During 2010 the group's overall liquidity position remained strong. Statoil's policy for managing liquidity was updated in 2010 in that the minimum required cash level was increased.

The main cash outflows are the annual dividend payment and Norwegian Petroleum Tax payments six times per year. If the monthly cash flow forecast shows that the liquid assets one month after tax- and dividend payments will fall below the defined policy level, new long-term funding will be considered.

Current funding needs will normally be covered by using the US Commercial Papers Programme (CP), USD 4 billion which is backed by a revolving credit facility of USD 3 billion, supported by 20 core banks. The facility is undrawn and provides secure access to funding, supported by best available (A1/P1) short-term rating. The credit facility has a term of five years until December 2015, but includes two one year extension options which may extend the facility to December 2017. The facility agreement does not contain any repeating material adverse change clauses, or any financial covenants. Statoil Petroleum AS is guarantor of the facility.

On 1 November 2010 Statoil Fuel & Retail ASA drew down NOK 4 billion on its term loan facility, maturing in October 2013. The facility is part of a multicurrency term and revolving loan facility in the aggregate amount of NOK 7 billion, which has been entered into with nine international banks. In addition to the NOK 4 billion three year term loan already drawn, the total facility agreement includes a NOK 3 billion five year revolving loan facility. Of this facility NOK 0.3 billion was drawn at year end 2010.

For long term funding purposes Statoil raises debt in all major capital markets (USA, Europe and Japan). In order to comply with the group's financial policies, Statoil uses derivatives such as currency and interest rate swaps to convert cash flows into floating rate USD interest payments. Our policy is to have a smooth maturity profile with repayments not exceeding five percent of capital employed in any year for the nearest five years. Statoil's non-current financial liability has an average maturity of approximately nine years.

For more information about the group's non-current financial liabilities see note 23 *Non-current financial liabilities*.

The table below shows a maturity profile, based on undiscounted contractual cash flows, for the group's financial liabilities and financial assets held to manage liquidity risk, where the assets held by the group's captive insurance company have been excluded both at the end 2010 and at the end of 2009. Included in the assets held to manage liquidity risk are certain foreign currency derivative instruments.

(in NOK million)	Due within 1 year	Due between 1 and 2 years	Due between 3 and 4 years	Due between 5 and 10 years	Due after 10 years	Total specified
At 31 December 2010						
Non-derivative financial liabilities	(87,755)	(15,822)	(35,010)	(38,356)	(58,012)	(234,955)
Derivative financial instruments	(20)	241	(1,879)	(1,377)	(1,529)	(4,564)
Financial assets held for managing liquidity risk						
Current derivative financial instruments	1,462	0	0	0	0	1,462
Current financial investments	5,348	0	0	0	0	5,348
Cash and cash equivalents	30,251	0	0	0	0	30,251
Total assets held	37,061	0	0	0	0	37,061
At 31 December 2009						
Non-derivative financial liabilities	(72,540)	(17,910)	(24,854)	(49,836)	(52,349)	(217,489)
Derivative financial instruments	(613)	24	(766)	(1,672)	(1,064)	(4,091)
Financial assets held for managing liquidity risk						
Current derivative financial instruments	301	0	0	0	0	301
Current financial investments	2,017	0	0	0	0	2,017
Cash and cash equivalents	24,567	0	0	0	0	24,567
Total assets held	26,885	0	0	0	0	26,885

For further information about the groups Cash and cash equivalents see note 21 *Cash and cash equivalents*.

Credit risk

Credit risk is the risk that the group's customers or counterparties will cause the group financial loss by failing to honour their obligations. Credit risk arises from credit exposures with customer accounts receivables as well as from financial investments, derivative financial instruments and deposits with financial institutions.

Key elements of our credit risk management approach include:

- A global credit risk policy
- Credit mandates
- An internal credit rating process
- Credit risk mitigation tools
- A continuous monitoring and managing of credit exposures

Prior to entering into transactions with new counterparties, the group's credit policy requires all counterparties to be formally identified and approved. In addition all sales, trading and financial counterparties are in addition assigned internal credit ratings as well as exposure limits. Once established, all counterparties are re-assessed at a minimum annually and continuously monitored. Counterparty risk assessments are based on a quantitative and qualitative analysis of recent financial statements and other relevant business information. In addition, Statoil evaluates any past payment performance, the counterparties' size and business diversification, and the inherent industry risk. The internal credit ratings reflect our assessment of the counterparties' credit risk. Exposure limits are determined based on assigned internal credit ratings combined with other factors, such as expected transaction and industry characteristics. Credit mandates define acceptable credit risk thresholds and are endorsed by management and regularly reviewed with regard to changes in market conditions.

The group uses risk mitigation tools to reduce or control credit risk both on a counterparty and portfolio level. The main tools include bank and parental guarantees, prepayments and cash collateral. For bank guarantees, only investment grade international banks are accepted as counterparties.

The group has pre-defined limits for the minimum average credit rating allowed at any given time on the group portfolio level as well as maximum credit exposures for individual counterparties. The group monitors the portfolio on a regular basis and individual exposures against limits on a daily basis. The total credit exposure portfolio of Statoil is geographically diversified among a number of counterparties within the oil and energy sector, as well as larger oil and gas consumers and financial counterparties. The majority of the group's credit exposure is with investment grade counterparties.

The following table contains the carrying amount of Statoil's financial receivables and derivative financial instruments that are neither past due nor impaired split by the group's assessment of the counter-party's credit risk. Included in current and non-current derivative financial instruments are only non exchange traded instruments.

(in NOK million)	Non-current financial receivables	Trade and other receivables	Non-current derivative financial instruments	Current derivative financial instruments
At 31 December 2010				
Investment grade, rated A or above	987	29,614	12,444	4,291
Other investment grade	565	8,132	8,119	1,081
Non-investment grade or not rated	765	32,157	0	640
Total financial asset	2,317	69,903	20,563	6,012
At 31 December 2009				
Investment grade, rated A or above	1,081	25,119	10,975	3,501
Other investment grade	1,387	5,417	6,669	1,060
Non-investment grade or not rated	696	22,471	0	635
Total financial asset	3,164	53,007	17,644	5,196

As of 31 December 2010, NOK 5.7 billion of cash was held as collateral to mitigate a portion of this group credit exposure. See note 27 *Current financial liabilities* for more information on collateral held.

8.1.9 Remuneration

(in NOK million except number of man-labour year)	2010	For the year ended 31 December 2009	2008
Salaries*	19,831	18,221	18,426
Pension costs	4,138	3,538	2,851
Payroll tax	2,972	3,023	2,676
Other compensations and social costs	2,158	2,177	2,102
Total payroll costs	29,099	26,959	26,055
Average man-labour year	28,396	28,107	28,001

*Salaries are inclusive reimbursement from the The Norwegian Labour and Welfare Administration.

Total payroll expenses are accumulated in cost-pools and partly charged to partners of Statoil-operated licences on an hours incurred basis.

The calculation of pension costs and pension assets/liabilities is described in note 24 *Pensions and other non-current employee benefits*.

Share based compensation

Statoil's share saving plan provides employees with the opportunity to purchase Statoil shares through monthly salary deductions and a contribution by Statoil. If the shares are kept for two full calendar years of continued employment, the employees will be allocated one bonus share for each one they have purchased.

Estimated compensation expense including the contribution by Statoil for purchased shares, amount vested for bonus shares granted and related social security tax was NOK 427, NOK 370 and NOK 340 million related to the 2010, 2009 and 2008 programs, respectively. For the 2011 program (granted in 2010) the estimated compensation expense is NOK 451 million. At 31 December 2010 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 910 million.

8.1.10 Other expenses

Auditors' remuneration

(in NOK million, excluding VAT)	Audit fee	Audit related fee	Other service fee	Total
2010				
Ernst & Young - Norway	35.2	12.2	0.1	47.5
Ernst & Young - outside Norway	29.3	2.0	0.1	31.4
Total	64.5	14.2	0.2	78.9
2009				
Ernst & Young - Norway	34.2	5.3	3.7	43.2
Ernst & Young - outside Norway	27.1	1.5	0.9	29.5
Total	61.3	6.8	4.6	72.7
2008				
Ernst & Young - Norway	35.0	4.9	0.1	40.0
Ernst & Young - outside Norway	25.3	3.8	0.1	29.2
Total	60.3	8.7	0.2	69.2

In addition to the figures in the table above, the audit fees and audit related fees to Ernst & Young related to Statoil-operated licences amount to NOK 8.8, NOK 8.9 and NOK 8.5 million for 2010, 2009 and 2008, respectively.

Research and development expenditures (R&D)
Research and development expenditures were NOK 2,045, NOK 2,073 and NOK 2,243 million in 2010, 2009 and 2008, respectively. R&D expenditures are partly financed by partners of Statoil-operated licences. Statoil's share of the expenditures has been recognised as expense in the Consolidated statement of income.

8.1.11 Financial items

(in NOK million)	2010	For the year ended 31 December 2009	2008
Foreign exchange gains (losses) non-current financial liabilities	0	0	(11,252)
Foreign exchange gains (losses) derivative financial instruments	(1,736)	9,722	(25,001)
Foreign exchange gains (losses) taxes payable	(473)	(1,930)	-
Other foreign exchange gains (losses)	373	(5,799)	3,690
Net foreign exchange gains (losses)	(1,836)	1,993	(32,563)
Dividends received	132	66	290
Gains (losses) financial investments	660	875	4,796
Interest income financial investments	325	354	975
Interest income non-current financial receivables	123	106	130
Interest income current financial assets and other financial income	1,935	2,307	6,016
Interest income and other financial items	3,175	3,708	12,207
Capitalised borrowing costs	995	1,351	1,225
Accretion expense asset retirement obligation	(2,508)	(2,432)	(2,107)
Interest expense non-current financial liabilities and net interst on related derivatives	(2,359)	(2,386)	(1,850)
Gains (losses) derivative financial instruments	2,611	(6,593)	5,632
Interest expense current financial liabilities and other finance expense	(490)	(2,391)	(909)
Interest and other finance expenses	(1,751)	(12,451)	1,991
Net financial items	(412)	(6,750)	(18,365)

Foreign exchange gains (losses) derivative financial instruments include fair value changes of currency derivatives related to liquidity and currency risk management. Strengthening of USD versus NOK for the year ended 31 December 2010 resulted in fair value losses on these positions which are recognised in the Consolidated statement of income. Correspondingly, weakening of USD versus the NOK for the year ended 31 December 2009 resulted in fair value gains and strengthening of USD versus NOK for the year ended 31 December 2008 resulted in fair value losses.

In addition, other foreign exchange effects in 2010 and 2009 are not directly comparable with 2008, because the parent company Statoil ASA changed its functional currency from NOK to USD effective from 1 January 2009. For further information see note 1 *Organisation*.

Gains (losses) derivative financial instruments include fair value changes of interest rate derivatives which are used to manage the interest rate risk of the loan portfolio. Decreasing USD interest rates for the year ended 31 December 2010 resulted in fair value gains on these positions. Correspondingly, increasing USD interest rates for the year ended 31 December 2009 resulted in fair value losses and decreasing USD interest rates for the year ended 31 December 2008 resulted in fair value gains.

Included in Interest expense current financial liabilities and other finance expenses is an impairment loss of NOK 1.4 billion related to the Pernis refinery investment for the year ended 31 December 2009.

Capitalised borrowing costs were reduced in 2010 compared to 2009 and 2008 due to completion of development projects and more fields going into production in 2010.

All hedge accounting relationships, which related to a portion of the non-current debt portfolio, were discontinued in the first quarter of 2009. Fair value hedge adjustments of NOK 2.5 billion are amortised over the remaining life of these loans (13 to 18 years). The amortised income recognised in Gains (losses) derivative financial instruments is NOK 248 million for the year ended 31 December 2010 and NOK 198 million for the year ended 31 December 2009.

8.1.12 Income taxes

Significant components of income tax expense were as follows

(in NOK million)	2010	2009	2008
Norway offshore	90,219	80,944	124,775
Norway onshore	167	4,027	3,378
Other countries upstream*	6,004	5,149	9,704
Other countries downstream*	393	770	306
Current income tax expense	96,783	90,890	138,163
Norway offshore	1,549	9,358	3,567
Norway onshore	(2,877)	242	(4,992)
Other countries upstream*	2,322	(3,094)	993
Other countries downstream*	1,392	(221)	(534)
Deferred tax expense	2,386	6,285	(966)
Income tax expense	99,169	97,175	137,197

*Includes Norwegian taxes on income in other countries.

Reconciliation of Norwegian nominal statutory tax rate of 28% to effective tax rate

(in NOK million)	2010	2009	2008
Norway offshore	122,935	122,074	171,150
Norway onshore	368	(10,700)	(6,260)
Other countries upstream	12,123	2,733	14,610
Other countries downstream	1,390	783	967
Total income before tax	136,816	114,890	180,467
Calculated income taxes at statutory rates:			
Calculated income taxes at statutory rate (Norwegian statutory tax rate 28%)	38,308	32,169	50,531
Petroleum surtax at statutory rate (Norwegian special tax rate 50%)*	61,468	61,037	85,575
Uplift*	(4,957)	(5,052)	(5,047)
Other countries upstream	4,566	1,289	6,606
Other countries downstream	(170)	330	(497)
Permanent differences caused by currency effects	1,283	6,935	0
Prior period adjustments	(736)	156	(74)
Other items	(593)	311	103
Income tax expense	99,169	97,175	137,197
Effective tax rate (%)	72.48	84.58	76.02

*When computing the special petroleum tax on income from the Norwegian Contintental Shelf, a tax-free allowance, or uplift, is granted at a rate of 7.5% per year. The uplift is computed on the basis of the original capitalised cost of offshore production installations. The uplift may be deducted from taxable income for a period of four years, starting in the year in which the capital expenditure is incurred. Unused uplift may be carried forward indefinitely. At year end 2010 and 2009 unrecognised uplift credits amounted to NOK 14.5 and 15.5 billion, respectively.

For several entities, the tax computation is based on other currencies than the functional currency of the entity. Taxable exchange gains and losses included in the currency used as a basis for tax computation causes significant permanent differences. These taxable exchange gains and losses do not impact the Income before tax in the Consolidated statement of income. Tax on these permanent differences amounts to NOK 1.3 billion in 2010.

Deferred tax assets and liabilities comprise

(in NOK million)	Inventory	Other current items	Tax losses carried forwards	Property, plant and equipment	Exploration expenditure	ARO	Pensions	Other non-current items	Total
Deferred tax at 31 December 2010									
Deferred tax assets	1,060	3,302	2,812	6,705	0	43,378	7,490	3,389	68,136
Deferred tax liabilities	0	(10,793)	0	(103,493)	(19,128)	0	0	(10,896)	(144,310)
Net asset (liability) at 31 December 2010	1,060	(7,491)	2,812	(96,787)	(19,128)	43,378	7,490	(7,508)	(76,174)
Deferred tax at 31 December 2009									
Deferred tax assets	907	2,123	3,098	10,162	0	34,072	8,148	2,668	61,178
Deferred tax liabilities	0	(9,014)	0	(96,799)	(20,091)	0	0	(9,636)	(135,540)
Net asset (liability) at 31 December 2009	907	(6,891)	3,098	(86,637)	(20,091)	34,072	8,148	(6,968)	(74,362)

Analysis of movements during the year	2010	2009	2008
Deferred tax liability at 1 January	74,362	66,842	66,684
Charged (credited) to the Consolidated statement of income	2,386	6,285	(966)
Other comprehensive income pensions	(16)	759	1,166
Charged (credited) to Equity	0	155	(364)
Translation differences and other	(558)	321	322
Deferred tax liability at 31 December	76,174	74,362	66,842

Deferred tax assets and liabilities are offset to the extent that the deferred taxes relate to the same fiscal authority and there is a legally enforceable right to offset current tax assets against current tax liabilities.

Deferred tax assets

As at 31 December 2010 Statoil had recognised net deferred tax assets of NOK 1.9 billion, primarily in the International Exploration and Production segment, as it is considered probable that taxable profit will be available to utilise these deferred tax assets.

Unrecognised deferred tax assets

(in NOK million)	At 31 December 2010	2009
Deductible temporary differences	14,129	14,519
Tax losses carry forward	9,063	4,461

The tax losses carry-forwards that have not been recognised, primarily in the US, expire in the period 2019-2025. The unrecognised deductible temporary differences do not expire under the current tax legislation. Deferred tax assets have not been recognised in respect of these items because evidence as required by prevailing accounting standards is currently not sufficient to support that future taxable profits will be available to secure utilisation of the benefits.

8.1.13 Earnings per share

Basic earnings per share

The calculation of basic earnings per share is, based on the net income attributable to ordinary shareholders of the parent company and a weighted average number of ordinary shares outstanding during the years ended 31 December 2010, 2009 and 2008 respectively, as follows:

	2010	2009	2008
Net income attributable to equity holders of the parent company (in NOK million)	38,082	18,313	43,265
Weighted average number of ordinary shares outstanding (in thousands of shares):			
Issued shares at 1 January	3,189,689	3,189,902	3,188,647
Effect of treasury shares held	(7,114)	(6,028)	(2,693)
Weighted average number of ordinary shares at 31 December	3,182,575	3,183,874	3,185,954
Earnings per share for income attributable to equity holders of the company - basic and diluted (NOK)	11.94	5.75	13.58

The group has no share programs with significant dilutive effects and the calculated diluted earnings per share rounds to be the same amount as the calculated basic earnings per share.

8.1.14 Property, plant and equipment

(in NOK million)	Machinery, equipment and transportation equipment	Production plants oil and gas, incl. pipelines	Refining and manufacturing plants	Buildings and land	Vessels	Assets under development	Total
Cost at 31 December 2009	18,542	618,487	43,354	15,735	4,079	89,221	789,418
Additions and transfers	(268)	60,600	11,364	1,086	195	17,519	90,496
Disposals assets at cost	(721)	(2,894)	(418)	(291)	(11)	(1,426)	(5,761)
Assets classified as held for sale **	0	0	0	0	0	(32,515)	(32,515)
Effect of movements in foreign exchange - assets	145	1,597	154	3	171	1,029	3,099
Cost at 31 December 2010	17,698	677,790	54,454	16,533	4,434	73,828	844,737
Accumulated depr. and impairment losses at 31 December 2009	(12,201)	(397,591)	(31,703)	(6,003)	(1,018)	(67)	(448,583)
Depreciation and impairments for the year	(1,251)	(41,758)	(4,800)	(671)	(286)	(1,656)	(50,422)
Accumulated depreciation and impairment disposed assets	531	2,681	266	144	11	0	3,633
Effect of movements in foreign exchange - depreciation and impairment losses	(33)	(940)	(144)	(118)	(12)	86	(1,161)
Accumulated depr. and impairment losses at 31 December 2010	(12,954)	(437,608)	(36,381)	(6,648)	(1,305)	(1,637)	(496,533)
Carrying amount at 31 December 2010	4,744	240,182	18,073	9,885	3,129	72,191	348,204
Estimated useful lives (years)	3 - 10	*	15-20	20 - 33	20 - 25		

*Depreciation according to Unit of production method, see note 2 *Significant accounting policies*.
**See note 4 *Assets classified as held for sale*.

In 2010 and 2009 capitalised borrowing cost amounted to NOK 1.0 and NOK 1.4 billion, respectively.
Transfer of assets to Property, plant and equipment from Intangible assets in 2010 and 2009 amounted to NOK 11.0 and NOK 4.9 billion, respectively.

(in NOK million)	For the year ended 31 December 2010	2009	2008
Impairment losses	(4,586)	(8,176)	(3,541)
Reversal of impairment losses	90	1,743	1,124
Net impairment losses	(4,496)	(6,433)	(2,417)

In 2010 Statoil recognised impairment losses of NOK 2.9 billion related to refinery assets in the Manufacturing and Marketing segment. The basis for the impairment losses are value in use estimates triggered by decreasing expectations on refining margins. The impairment losses have been presented as Depreciation, amortisation and net impairment losses.

In 2010 Statoil also recognised an impairment loss of NOK 1.6 billion related to a gas development project in the International Exploration and Production segment. The basis for the impairment loss is reduced value in use estimate mainly driven by project delays, changes in certain cost estimates and market conditions. In 2009, Statoil recognised net impairment losses of NOK 5.4 billion related to development and production assets recognised in the Manufacturing and Marketing segment. Impairment in 2008 is mainly related to development and production assets in the International Exploration and Production segment. The impairment losses have been presented as Depreciation, amortisation and net impairment losses.

In assessing the need for impairment of the carrying amount of a potentially impaired asset, the asset's carrying amount is compared to the recoverable amount. The recoverable amount is the higher of fair value less costs to sell and estimated value in use. When preparing a value in use calculation the estimated future cash flows are adjusted for risks specific to the asset. For upstream assets, the main assumptions used when estimating future cash flows relates to expected production profiles, oil and gas prices and costs. For mid- and downstream assets, the main assumptions relate to expectations on utilisation of capacity and expectations on future margins. The expected future cash flows are discounted using a real post-tax discount rate adjusted for asset specific differences, such as tax rates and time horizon of cash flows. The base discount rate used is 6.5% real after tax in a 28% tax regime with a 10 year duration. The discount rate is derived from Statoil's weighted average cost of capital. A derived pre tax discount rate would generally be in the range of 8-12%, depending on asset specific characteristics, such as specific tax treatments, cash flow profiles and economic life. For certain assets a pre tax discount rate could be outside this range, mainly due to special tax elements (i.e. permanent differences) affecting the pre tax equivalent.

8.1.15 Intangible assets

(in NOK million)	Exploration expenditure	Other	Total
Cost at 31 December 2009	49,360	6,649	56,009
Additions	11,317	253	11,570
Disposals intangible assets at cost	(795)	(222)	(1,017)
Transfers of intangible assets	(10,964)	(16)	(10,980)
Assets classified as held for sale	(12,375)	0	(12,375)
Expensed exploration expenditures previously capitalised	(2,911)	0	(2,911)
Effect of movements in foreign exchange	1,243	84	1,327
Cost at 31 December 2010	34,875	6,748	41,623
Accumulated amortisation and impairment losses at 31 December 2009	-	(1,756)	(1,756)
Amortisation and impairments for the year	-	(186)	(186)
Disposals amortisation and impairment losses	-	10	10
Effect of movements in foreign exchange - amortisation and imp. losses	-	4	4
Accumulated amortisation and impairment losses at 31 December 2010	-	(1,928)	(1,928)
Carrying amount at 31 December 2010	34,875	4,820	39,695

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite useful lives are amortised systematically over their estimated economic lives, ranging between 10-20 years.

Included in Other intangible assets is goodwill of NOK 4.0 billion as at 31 December 2010 (NOK 4.0 billion as at 31 December 2009).

Impairment losses and reversal of impairment losses are presented as *Exploration expenses* and *Depreciation, amortisation and net impairment losses* on the basis of their nature as exploration assets and other intangible assets, respectively. The table below shows the net impairment losses related to intangible assets which have been recognised in the reporting periods for each line item under which it has been reported.

(in NOK million)	For the year ended 31 December 2010	2009	2008
Depreciation, amortisation and net impairment losses	31	1,003	0
Exploration expenses	1,935	5,418	3,544
Impairment losses	1,966	6,421	3,544
Depreciation, amortisation and net impairment losses	0	0	0
Exploration expenses	(1,636)	0	(1,123)
Reversal of impairment losses	(1,636)	0	(1,123)
Net impairment losses	330	6,421	2,421

The impairment losses are based on value in use estimates triggered by changes in reserve estimates, cost estimates and market conditions and relate mainly to exploration assets in the Gulf of Mexico, recognised in the International Exploration and Production segment. See note 14 *Property, plant and equipment* for further information on the basis for impairment assessments.

8.1.16 Equity accounted investments

(in NOK million)	2010	2009
Carrying amount equity accounted investments at 31 December	13,884	10,056
Net income from equity accounted investments	1,133	1,778

The increase in equity accounted investments in 2010 is mainly related to the 50% acquisition of 67,000 net acres in the Eagle Ford shale formation in Southwest Texas. Parts of the assets acquired are organised in a jointly controlled entity and accounted for under the equity method.

In addition to the acquisition in the Eagle Ford shale formation, the most significant equity accounted investments included in the table above are Petrocedeño S.A. (ownership share 9.68%), BTC Pipeline company (ownership share 8.71%) and South Caucasus PHC Ltd (ownership share 25.5%). Statoil has assessed that through contractual agreements the group has significant influence over the BTC Pipeline company and Petrocedeño S.A., and consequently the ownership interests in these companies are accounted for under the equity method.

See note 6 *Asset acquisitions and disposals* for more information.

8.1.17 Non-current financial assets

(in NOK million)	At 31 December 2010	2009
Bonds	7,213	6,726
Listed equity securities	5,102	4,318
Non-listed equity securities	3,042	2,223
Financial investments	15,357	13,267

Bonds and Listed equity securities relates to investment portfolios held by the group's captive insurance company which are accounted for using the fair value option.

Non-listed equity securities are classified as available for sale assets and changes in fair value are recognised in Other comprehensive income except for impairment losses which are recognised in the Consolidated statement of income. The total change of NOK 0.8 billion in 2010 is mainly caused by fair value adjustments of NOK 0.5 billion related to the Pernis refinery investment and capital payments of NOK 0.4 billion related to the Shtokman investment.

During 2010 a gain of NOK 0.2 billion was recognised in Other comprehensive income. For 2009 NOK 0.07 billion was transferred out of Other comprehensive income.

(in NOK million)	At 31 December 2010	2009
Financial receivables interest bearing	2,317	3,164
Prepayments and other non-interest bearing receivables	2,193	2,583
Financial receivables	4,510	5,747

Included in Financial receivables interest bearing are project financing of the equity accounted investments BTC and Petrocedeño and financing of the associated companies Naturkraft and the European CO2 Technology Centre.

The Financial receivables interest bearing are classified in the loan and receivables category, the Prepayments and other non-interest bearing receivables are classified as non-financial assets.

The carrying amount of Non-current financial receivables and Current financial receivables (classified as Trade and other receivables, see note 19), including accrued interest reasonably approximate fair value.

8.1.18 Inventories

Inventories are valued at the lower of cost and net realisable value. Inventories of crude oil, refined products and non-petroleum products are determined under the first-in, first-out (FIFO) method.

The carrying amount of inventory at the beginning of the year has in all material respects been recognised as an expense through Purchases [net of inventory variation] during the year.

(in NOK million)	At 31 December 2010	2009
Crude oil	14,856	11,371
Petroleum products	7,210	7,778
Other	1,561	1,047
Inventories	23,627	20,196

8.1.19 Trade and other receivables

(in NOK million)	At 31 December 2010	2009
Financial trade and other receivables:		
Trade receivables	63,242	48,827
Financial receivables	1,932	0
Receivables joint ventures	4,213	3,579
Receivables equity accounted investments and other related parties	516	601
Total financial trade and other receivables	69,903	53,007
Non-financial trade and other receivables	6,236	5,888
Trade and other receivables	76,139	58,895

For more information about the credit quality of Statoils financial assets see note 8 *Financial risk management*. For currency sensitivities see note 32 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

For further information on Financial receivables see note 17 *Non-current financial assets*.

8.1.20 Current financial investments

(in NOK million)	At 31 December 2010	2009
Bonds	1,183	675
Commercial papers	8,767	4,681
Money market funds	1,559	1,584
Other	0	82
Financial investments	11,509	7,022

Current financial investments at 31 December 2010 are classified as held for trading, except for NOK 6.2 billion related to investment portfolios held by the group's captive insurance company which are accounted for using the fair value option. The corresponding balance at 31 December 2009 was NOK 5.0 billion accounted for using the fair value option.

Current financial investments are measured at fair value with gains and losses recognised in the Consolidated statement of income.

8.1.21 Cash and cash equivalents

(in NOK million)	At 31 December 2010	2009
Cash at bank available	10,942	9,872
Time deposits	13,004	13,073
Restricted cash, inlcuding collateral deposits	6,391	1,778
Cash and cash equivalents	30,337	24,723

Restricted cash at 31 December 2010 include collateral deposits of NOK 3.8 billion related to trading activities, correspondingly collateral deposits at 31 December 2009 were NOK 1.8 billion. Collateral deposits are related to certain requirements set out by exchanges where the group is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

Restricted cash at 31 December 2010 include NOK 2.6 billion deposited with Statoil's US dollar denominated bank account in Nigeria. There are certain restrictions on the use of cash from Statoil's Nigerian operations following an injunction against Statoil by the Nigerian courts related to an ongoing litigation claim. Both the injunction and the disputed claim have been appealed.

The overdraft bank balances and overdraft facilities are included in note 27 *Current financial liabilities*.

8.1.22 Transactions impacting shareholders equity

Statoil share capital of NOK 7,971,617,757.50 comprised 3,188,647,103 shares at a nominal value of NOK 2.50.

Statoil ASA has only one class of shares and all shares have voting rights. The holders of ordinary shares are entitled to receive dividends as declared from time to time and are entitled to one vote per share at general meetings of the company.

Dividends declared and paid per share were NOK 6.00 in 2010 for Statoil ASA and NOK 7.25 and NOK 8.50 in 2009 and 2008, respectively. A dividend for 2010 of NOK 6.25 per share, amounting to a total dividend of NOK 19.9 billion, will be proposed at the annual general meeting in May 2011. The proposed dividend is not recognised as a liability in the financial statements.

Retained earnings available for distribution of dividends at 31 December 2010 is limited to the retained earnings of the parent company based on Norwegian accounting principles and legal regulations and amounted to NOK 127,596 million (before provisions for proposed dividend for the year ended 31 December 2010 of NOK 19,890 million). This differs from retained earnings in the Consolidated financial statements of NOK 164,935 million. In accordance with Norwegian legal requirements dividends are not allowed to reduce the shareholders' equity of the parent company below 10% of total assets.

The annual general meeting in 2010 authorised the board of directors of Statoil ASA to acquire Statoil shares in the market on behalf of the company. The authorisation may be used to acquire Statoil shares with an overall nominal value of up to NOK 20 million. Shares acquired pursuant to this authorisation may only be used for sale and transfer to employees of the Statoil group as part of the group's share saving plan, as approved by the board of directors. The minimum and maximum amount that may be paid per share will be NOK 50 and 500, respectively. The authorisation is valid until the next ordinary general meeting. This authorisation replaces the previous authorisation to enquire own shares for implementation of the share saving plan for employee granted by the annual general meeting in 2009.

The annual general meeting in 2010 also authorised the board of directors of Statoil ASA to acquire Statoil shares in the market for subsequent annulment on behalf of the company with a nominal value of up to NOK 187.5 million. The minimum and maximum amount that can be paid per share will be NOK 50 and 500 respectively. Within these limits, the board of directors shall decide at what price and at what time such acqusition shall take place, if any. Own shares acquired pursuant to this authorisation may only be used for annulment through a reduction of the company's share capital, pursuant to the Public Limited Companies Act section 12-1. The authorisation is valid until the next ordinary general meeting

During 2010 a total of 2,200,232 treasury shares were purchased for NOK 294 million. At 31 December 2010 Statoil had 7,113,863 treasury shares all of which are related to the group's share saving plan.

On 1 October 2010 Statoil transferred all activities relating to Statoil's Energy & Retail business from the Manufacturing and Marketing segment to Statoil Fuel & Retail ASA (SFR) and its consolidated subsidiaries. On 22 October 2010 the shares of SFR were listed on the Oslo Stock Exchange and Statoil sold 46% of its shares for an amount of NOK 5.4 billion less of share issue cost of NOK 0.2 billion. The carrying amount of related shareholders equity was NOK 3.5 billion. After the completion of the sale, Statoil ASA remains the majority shareholder of SFR as at year end 2010. Statoil's internal management reporting changed following the SFR listing and led to Fuel and Retail becoming a separate operating segment. For further information see Note 3 *Segments* to these financial statements.

8.1.23 Non-current financial liabilities

	Weighted average interest rates in %		Carrying amount in NOK million at 31 December		Fair value in NOK million at 31 December	
	2010	2009	2010	2009	2010	2009
Financial liabilities measured at amortised cost						
Unsecured bonds						
US dollar (USD)	5.41	5.85	52,586	40,610	57,736	43,632
Euro (EUR)	5.01	5.13	23,504	27,515	26,698	30,397
Japanese yen (JPY)	1.66	1.66	360	312	368	322
Great Britain Pound (GBP)	6.71	6.71	9,302	9,556	11,456	11,391
Total			85,752	77,993	96,258	85,742
Unsecured loans						
US dollar (USD)	0.74	0.71	5,779	5,697	5,747	5,639
Norwegian kroner (NOK)	3.88	-	3,974	-	3,974	-
Japanese yen (JPY)	1.65	1.65	576	501	589	516
Secured bank loans						
US dollar (USD)	3.70	3.74	695	864	695	894
Other currencies	3.31	4.63	142	135	142	135
Financial lease liabilities			7,159	13,747	7,159	13,747
Other liabilities			347	293	347	293
Total			18,672	21,237	18,653	21,224
Grand total liabilities outstanding			104,424	99,230	114,911	106,966
Less current portion			4,627	3,268	4,627	3,268
Financial liabilities			99,797	95,962	110,284	103,698

On 17 August 2010 Statoil ASA issued a USD 1.25 billion bond maturing in August 2017 and a USD 0.75 billion bond maturing in August 2040. The registered bonds were issued under the registration Form F-3 ("Shelf Registration") filed with the SEC in the United States.

On 1 November 2010 Statoil Fuel & Retail ASA drew down NOK 4.0 billion on its term loan facility, maturing in 2013. The facility is part of a multicurrency term and revolving loan facility in the aggregate of NOK 7.0 billion, which has been entered into with nine international banks. The proceeds from the drawdown were applied to repay intercompany debt to Statoil ASA.

Non-current financial liabilities include financial lease obligations. More information is provided in note 28 *Leases*.

The table does not include the effects of agreements entered into to swap the various currencies into USD. For further information see note 31 *Financial instruments by category*.

Weighted average interest rates are calculated based on the contractual rates on the loans per currency at 31 December and do not include the effect of swap agreements.

The fair value of the non-current financial liabilities is determined using a discounted cash flow model. Interest rates used in the model are derived from the LIBOR and EURIBOR forward curves and will vary based on the time to maturity for the non-current financial liabilities subject to fair value measurement. The credit premium used is based on indicative pricing from external financial institutions.

Details of largest unsecured bonds

Bond agreement	Fixed interest rate	Issued (year)	Maturity (year)	Carrying amount in NOK million at 31 December 2010	2009
USD 1500 million	5.250%	2009	2019	8,738	8,613
USD 1250 million	3.125%	2010	2017	7,278	-
USD 900 million	2.900%	2009	2014	5,251	5,174
USD 750 million	5.100%	2010	2040	4,340	-
USD 500 million	3.875%	2009	2014	2,914	2,870
USD 500 million	5.125%	2004	2014	2,927	2,887
USD 500 million	6.500%	1998	2028	2,900	2,859
USD 481 million	7.250%	2000	2027	2,814	2,776
USD 300 million	7.750%	1993	2023	1,757	1,733
EUR 1300 million	4.375%	2009	2015	10,135	10,782
EUR 1200 million	5.625%	2009	2021	9,297	9,887
EUR 500 million	5.125%	1999	2011	3,903	4,148
GBP 800 million	6.875%	2009	2031	7,224	7,421
GBP 225 million	6.125%	1998	2028	2,040	2,096

Currency swaps are used for risk management purposes. Unsecured bonds are either denominated in US dollar, amounting to NOK 52.6 billion or the bonds are swapped into US dollar, amounting to NOK 33.2 billion. Interest rate swaps are used to manage the interest rate risk on the unsecured bond contracts with fixed interest rates. As a result the majority of the portfolio is swapped from fixed to floating interest rate.

Substantially all unsecured 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.

The group's secured bank loans in USD have been secured by mortgage of shares in a subsidiary with a book value of NOK 2.1 billion, in addition, security includes the group's pro-rata share of income from certain applicable projects.

The group has 28 unsecured bond agreements outstanding, which contain provisions allowing the group to call the debt prior to its final redemption at par or at certain specified premiums if there are changes to the Norwegian tax laws. The agreements carrying value are NOK 83.9 billion at the 31 December 2010 closing rate.

Statoil ASA has an undrawn revolving credit facility for USD 3.0 billion supported by 20 core banks. For more information see note 8 *Financial risk management*.

Non-current financial liabilities maturity profile

(in NOK million)	At 31 December 2010	2009
Year 2 and 3	12,555	11,757
Year 4 and 5	23,205	11,496
After 5 years	64,037	72,709
Total repayment of non-current financial liabilities	99,797	95,962

Maturity profile for undiscounted cash flows is shown in note 8 *Financial risk management*.

Non-current financial liabilities

	At 31 December 2010	2009
Non-current financial liabilities (in NOK million)	99,797	95,962
Weighted average maturity (years)	9	9
Weighted average annual interest rate (%)	5.01	4.77

8.1.24 Pensions and other non-current employee benefits

The Norwegian companies in the group are obligated to follow the Act on Mandatory company pensions. The pension scheme follows the requirement as included in the Act.

The main pension schemes in Norway are funded by Statoil Pension. Statoil Pension is an independent trust, which covers employees of Statoil ASA and the Norwegian subsidiaries. The objective of Statoil Pension is to provide retirement and disability pensions for its members as well as pensions for surviving spouses, registered partners, cohabitants and children. Statoil Pension's assets are kept separate from those of Statoil. Statoil Pension is licensed to conduct Statoil Pension activities under the supervision of the Financial Supervisory Authority of Norway (Finanstilsynet).

Statoil ASA 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 level. The cost of pension benefit plans is expensed over the period that the employee renders services and becomes eligible to receive benefits. The obligations related to defined benefit plans are calculated by external actuaries.

Some companies in Statoil have defined contribution plans. The period's contributions are recognised in the Statement of income as pension cost for the period.

Due to National agreements in Norway, Statoil is a member of the "agreement-based early retirement plan" (AFP).The current AFP scheme will be replaced by a new AFP scheme from 1 January 2011. Statoil will pay a contribution for pension in payment under the current scheme and premium for both schemes (new and old scheme) up until 31.12.2015. The premium in the new scheme will be calculated on the basis of the employees` income between 1 and 7.1 G. The premium is payable for all employees until age 62. Pension from the new APF scheme will be paid to employees for their full lifetime.

The employers have an obligation to pay a percentage of the benefits under the AFP scheme. This obligation is accounted for as a defined benefit plan. In the current early retirement system Statoil offers a supplementary company pension for employees. This is also accounted for as a defined benefit plan, and is included in the liabilities related to the defined benefit plans. Statoil therefore has a combined early retirement commitment to the employees irrespectively of the level of funding from the governmental AFP-funding. Hence the replacement of the old AFP with a new AFP in 2010 is not viewed as a termination of the plan.

New legislation affecting Norwegian pension and insurance schemes have been passed during 2010 as part of the Norwegian pension and insurance reform. The legislation requires some adaptations in Statoil's Norwegian pension scheme, in particular related to increased flexibility of retirement.

The obligations related to the defined benefit plans were measured at 31 December, 2010 and 2009. The present values of the projected defined benefit obligation and the related current service cost and past service cost are measured using the projected unit credit method. The assumptions for salary increases, increases in pension payments and social security base amount have been tested against historical observations. At 31 December 2010 the discount rate for the defined benefit plans in Norway was estimated to be 4.25% based on the long-term interest rate on Norwegian government bonds extrapolated based on a 22 year yield curve to match Statoil's payment portfolio for earned benefits.

Actuarial gains and losses are recorded directly in Other comprehensive income in the period in which they occur, outside the Statement of income. Actuarial gains and losses related to the provision for termination benefits are recognised in the Statement of income in the period in which they occur.

Social security tax is calculated based on the pension plan's net funded status. Social security tax is included in the projected benefit obligation.

Statoil has more than one defined benefit plan but the disclosure is made in total since the plans are not subject to materially different risks. Pension plans outside Norway are insignificant and not disclosed separately.

Net pension cost

(in NOK million)	2010	2009	2008
Current service cost	3,491	2,747	2,361
Interest cost	2,725	2,550	2,456
Expected return on plan assets	(2,661)	(1,896)	(2,101)
Actuarial (gain)/loss related to termination benefits	185	(172)	(215)
Past service cost	3	0	17
Effect of limit in IAS 19.58(b)	4	0	0
Losses (gains) from curtailment or settlement	0	0	(7)
Defined benefit plans	3,747	3,229	2,511
Defined contribution plans	230	240	268
Multi-employer plans	161	69	72
Total net pension cost	4,138	3,538	2,851

Pension cost includes associated social security tax.

Pension cost is partly charged to partners of Statoil operated licences.

For information regarding pension benefits for key management personnel, see note 30 *Related parties*.

Change in projected benefit obligation (PBO)

(in NOK million)	2010	2009
Projected benefit obligation at 1 January	61,427	59,206
Current service cost	3,491	2,747
Interest cost	2,725	2,550
Actuarial loss (gain)	1,955	(1,308)
Benefits paid	(1,821)	(1,520)
Foreign currency translation	44	(248)
Projected benefit obligation at 31 December	67,821	61,427

Change in pension plan assets

(in NOK million)	2010	2009
Fair value of plan assets at 1 January	42,979	33,698
Expected return on plan assets	2,661	1,896
Actuarial gain (loss)	1,678	2,819
Company contributions (including social security tax)	4,122	4,956
Benefits paid	(505)	(385)
Foreign currency translation	41	(5)
Fair value of plan assets at 31 December	50,976	42,979

The tables above for Change in projected benefit obligation (PBO) and Change in pension plan assets do not include currency effects for Statoil ASA. For more information see table Actuarial gains and losses recognised directly in Other comprehensive income below.

Reconciliation of changes in net pension liability

(in NOK million)	2010	2009
Balance sheet provision at 1 January	(18,448)	(25,508)
Net periodic pension costs defined benefit plans	(3,747)	(3,229)
Net actuarial (loss) gain recognised in Other comprehensive income	(33)	3,191
Less employer contributions	4,122	4,956
Less benefit paid during year	1,316	1,135
Foreign currency translation and other changes	(55)	1,007
Balance sheet provision at 31 December	(16,845)	(18,448)

Surplus (deficit) at 31 December

(in NOK million)	2010	2009	2008
Surplus (deficit) at 31 December	(16,845)	(18,448)	(25,508)
Represented by:			
Asset recognised as Non-current pension asset	5,265	2,694	30
Liability recognised as Non-current pension liability	(22,110)	(21,142)	(25,538)

Projected benefit obligation specified by funded and unfunded plans

(in NOK million)	2010	2009	2008
Funded pension plans	(45,753)	(40,212)	(37,446)
Unfunded pension plans	(22,068)	(21,215)	(21,760)
Projected benefit obligation at 31 December	(67,821)	(61,427)	(59,206)

Actuarial gains and losses recognised directly in Other comprehensive income

(in NOK million)	2010	2009	2008
Unrecognised actuarial losses (gains) at 1 January	0	0	0
Actuarial losses (gains) on plan assets occurred during the year	(1,678)	(2,819)	4,149
Actuarial losses (gains) on benefit obligation occurred during the year	1,955	(1,308)	3,581
Actuarial losses (gains) related to currency effects on net obligation	(245)	3,867	0
Foreign exchange translation	186	(3,103)	0
Recognised in the income statement during the year	(185)	172	215
Recognised in Other comprehensive income during the year	(33)	3,191	(7,945)
Unrecognised actuarial losses (gains) at 31 December	0	0	0

Statoil ASA changed its functional currency as of 1 January 2009, for further information see note 1 *Organisation* and note 2 *Significant accounting policies*. In the table above Actuarial losses (gains) related to currency effects on net obligation refer to translation of the net pension obligation in Statoil ASA in NOK to the functional currency US dollar. The line Foreign exchange translation refer to translation from functional currency US dollar to presentation currency NOK.

Actual return on plan assets

(in NOK million)	2010	2009	2008
Actual return on plan assets	4,339	4,715	(2,048)

History of experience gains and losses

(in NOK million)	2010	2009
Difference between the expected and actual return on plan assets		
a) Amount	(1.678)	(2.819)
b) Percentage of plan assets	(3.29%)	(6.56%)
Experience (gain)/loss on plan liabilities		
a) Amount	17	(1.996)
b) Percentage of present value of plan liabilities	0.00%	(3.40%)

The cumulative amount of actuarial gains and losses recognised directly in Other comprehensive income amounted to NOK 10.9, NOK 10.9 and NOK 13.3 billion net of tax (negative effect on Other comprehensive income) in 2010, 2009 and 2008, respectively.

Assumptions used to determine benefit costs for the year in %	2010	2009
Discount rate	4.75	4.50
Expected return on plan assets	6.00	5.75
Rate of compensation increase	4.25	4.00
Expected rate of pension increase	3.00	2.75
Expected increase of social security base amount (G-amount)	4.00	3.75

Assumptions used to determine benefit obligations as of 31 December in %	2010	2009
Discount rate	4.25	4.75
Expected return on plan assets	5.75	6.00
Rate of compensation increase	4.00	4.25
Expected rate of pension increase	2.75	3.00
Expected increase of social security base amount (G-amount)	3.75	4.00
Average remaining service period in years	15	15

The assumptions presented are for the Norwegian companies in Statoil which are members of Statoil's pension fund. The defined benefit plans of other subsidiaries are not significant to the consolidated pension assets and liabilities.

Expected attrition at 31 December 2010 2.0%, 2.0%, 1.0%, 0.5% and 0.0% for the employees under 30 years, 30-39 years, 40-49 years, 50-59 years and 60-67 years, respectively. Expected attrition at 31 December 2009 was 2.0%, 2.0%, 1.5%, 0.5% and 0.0% for the employees under 30 years, 30-39 years, 40-49 years, 50-59 years and 60-67 years, respectively.

Expected utilisation of AFP is 50% for employees at 62 years and 30% for the remaining employees at 63-66 years.

For the population in Norway, the mortality table K 2005 including the minimum requirements from The Financial Supervisory Authority of Norway (Finanstilsynet), hence reducing the mortality rate with a minimum of 15% for male and 10% for female for each employee is used as the best mortality estimate. The disability table, KU, developed by the insurance company Storebrand, aligns with the actual disability risk for Statoil in Norway.

Below is shown a selection related to demographic assumptions used at 31 December 2010. The table shows the probability of disability or mortality, within one year, by age groups as well as expected lifetime.

Age	Disability in % Men	Women	Mortality in % Men	Women	Expected lifetime Men	Women
20	0.12	0.15	0.02	0.02	82.46	85.24
40	0.21	0.35	0.09	0.05	82.74	85.47
60	1.48	1.94	0.75	0.41	84.02	86.31
80	N/A	N/A	6.69	4.31	89.26	90.29

Sensitivity analysis

The table below shows an estimate of the potential effects of changes in the key assumptions for the defined benefit plans. The following estimates are based on facts and circumstances as of 31 December 2010. Actual results may materially deviate from these estimates.

	Discount rate		Rate of compensation increase		Social security base amount		Expected rate of pension increase	
(in NOK billion)	0.25%	-0.25%	0.25%	-0.25%	0.25%	-0.25%	0.25%	-0.25%
Changes in:								
Projected benefit obligation								
at 31 December 2010	(2.82)	3.01	1.86	(1.76)	(0.70)	0.71	1.68	(1.61)
Service cost 2011	(0.20)	0.22	0.18	(0.17)	(0.07)	0,07	0.10	(0.09)

Pension assets

The plan assets related to the defined benefit plans were measured at fair value at 31 December 2010 and 2009. The long-term expected return on pension assets is based on long-term risk-free interest rate adjusted for the expected long-term risk premium for the respective investment classes. A risk free interest rate (the Norwegian Government bond with a life of 10 year included markup for estimating a longer interest rate than ten year) is applied as a starting point for calculation of return on plan assets. The return in the money market is calculated by taking a deduction on bond yield. Based on historical data, equities and real estate are expected to provide a long-term additional return above money market.

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

Pension assets allocated on respective investments classes

(in %)	2010	2009
Equity securities	40.10	39.60
Bonds	38.10	39.40
Commercial papers	14.70	14.70
Real estate	4.90	5.10
Other assets	2.20	1.20
Total	100.00	100.00

Properties owned by Statoil Pension fund amounted to NOK 2.3 billion and NOK 2.1 billion of total pension assets at 31 December 2010 and 2009, respectively, and are rented to Statoil companies.

Statoil's pension fund invests in both financial assets and real estate. The expected rate of return on real estate is expected to be between the rate of return on equity securities and debt securities. The table below presents the portfolio weight and expected rate of return of the finance portfolio as approved by the Board of the Statoil pension fund for 2011. The portfolio weight during a year will depend on the risk capacity.

Finance portfolio Statoil's pension funds

(All figures in %)	Portfolio weight [1]		Expected rate of return
Equity securities	40.00	(+/- 5)	X + 4
Bonds	59.50	(+/- 5)	X
Commercial papers	0.50	(+15/- 0.5)	X - 0.4
Total finance portfolio	100.00		

1) The brackets express the scope of tactical deviation by Statoil Kapitalforvaltning ASA (the asset manager).
X) Long-term rate of return on debt securities.

The expected company contribution related to 2011 amounts to NOK 2.3 billion.

8.1.25 Asset retirement obligations, other provisions and other liabilities

(in NOK million)	Asset retirement obligations	Other provisions	Other liabilities	Total
Non-current portion at 31 December 2009	48,412	5,889	1,533	55,834
Long term interest bearing provisions reported as Non-current liabilities	0	293	0	293
Current portion at 31 December 2009	515	1,044	0	1,559
Asset retirement obligation, other provisions and other liabilities at 31 December 2009	48,927	7,226	1,533	57,686
New provisions in the period	1,443	2,908	61	4,412
Revision in the estimates	6,551	1,273	0	7,824
Amounts charged against provisions	(535)	(1,266)	(554)	(2,355)
Unused amounts reversed	0	(87)	0	(87)
Effects of change in the discount rate	2,647	0	0	2,647
Reduction due to disposals	(215)	(2)	0	(217)
Accretion expenses	2,508	0	0	2,508
Liability directly associated with the assets classified as held for sale	(549)	0	0	(549)
Reclassification	0	(1,331)	867	(464)
Currency translation	72	90	0	162
Asset retirement obligation, other provisions and other liabilities at 31 December 2010	60,849	8,811	1,907	71,567
Current portion at 31 December 2010	828	2,482	0	3,310
Long term interest bearing provisions reported as Non-current liabilities	0	347	0	347
Non-current portion at 31 December 2010	60,021	5,982	1,907	67,910

Expected timing of cash outflows

(in NOK million)	Asset retirement obligations	Other provisions	Other liabilities	Total
2011 - 2017	6,413	6,468	1,432	14,313
2018 - 2022	9,629	591	475	10,695
2023 - 2027	13,023	81	0	13,104
2028 - 2032	12,851	115	0	12,966
Thereafter	18,933	1,556	0	20,489
At 31 December 2010	60,849	8,811	1,907	71,567

The timing of cash outflows primarily depends on when the production ceases at the various facilities.

The revision in estimates for Asset retirement obligations for the year mainly relates to increased cost estimates for plugging and abandonment of wells. The revised cost estimates was a result of an update of Statoil's asset retirement obligations study performed in the fourth quarter taken new geological and technical experiences into consideration.

The increased estimate in asset retirement obligations has been added to property, plant and equipment and will increase depreciation expenses by approximately NOK 2.8 billion in 2011 assuming the same production and reserves levels as of 31 December 2010 and no changes in other relevant parameters.

The Other provisions category includes provisions for estimated losses on onerous contracts and expected payments on unresolved claims. The timing and amounts of potential settlements in respect of these provisions are uncertain and dependent on various factors that are outside management's control.

For further discussion of methods applied and estimates required, see note 2 *Significant accounting policies*.

8.1.26 Trade and other payables

(in NOK million)	At 31 December 2010	2009
Financial trade and other payables:		
Trade payables	23,209	17,362
Non-trade payables and accrued expenses	24,061	18,112
Liability joint ventures	13,623	13,430
Payables to equity accounted investments and other related parties	9,994	9,144
Total financial trade and other payables	70,887	58,048
Non-financial trade and other payables	2,664	1,753
Trade and other payables	73,551	59,801

Included in non-trade payables and accrued expenses are certain provisions that are further described in note 29 *Other commitments and contingencies*.

For information regarding currency sensitivities see note 32 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

Further information on payables to equity accounted investments and other related parties see note 30 *Related parties*.

8.1.27 Current financial liabilities

(in NOK million)	At 31 December 2010	2009
Bank loans and overdraft facilities	1,404	196
Collateral liabilities	5,680	4,654
Current portion of non-current financial liabilities	4,038	2,686
Current portion of financial lease obligations	589	582
Other	19	32
Financial liabilities	11,730	8,150
Weighted interest rate	2.45	2.24

Carrying amount for Current financial liabilities, at amortised cost, and accrued interest reasonably approximate fair value.

Collateral liabilities relate to cash received as security for a portion of the group's credit exposure.

At 31 December 2010 Statoil Fuel & Retail has drawn NOK 0.3 billion on a revolving loan facility. The loan matured in February 2011. At 31 December 2009 Statoil had no current amount drawn under any committed revolving credit facility.

8.1.28 Leases

Statoil leases certain assets, notably drilling rigs, vessels and office buildings.

Statoil has entered into certain operational lease contracts for a number of drilling rigs as of 31 December 2010. The remaining significant contracts' terms range from six months to five years. Certain contracts contain renewal options. Rig lease agreements are for the most part based on fixed day rates. Statoil's rig leases have been entered into in order to ensure drilling capacity for sanctioned projects and planned wells and to secure long-term strategic capacity for future exploration and production drilling. Certain rigs have been subleased in whole or for part of the lease term mainly to Statoil-operated licences on the NCS. These leases are shown gross as operating leases in the table below. However, for rig leases where the joint venture is the original lessee, Statoil only includes its proportional share of the rig lease.

In 2010 Statoil entered into a long term time charter agreement with Teekay for offshore loading and transport in the North Sea. The contract covers the life time of applicable producing fields and initially includes seven crude tankers. The contract's estimated nominal amount is approximately NOK 6 billion at year end 2010, and is accounted for as operating lease. The estimated future leasing commitment depends on assumptions made concerning field production quantities and related life time, expected decrease in the number of vessels employed over time, as well as development in other factors impacting Statoil's payable amounts under the terms of the contract.

Statoil has entered into leasing arrangements for three LNG vessels on behalf of Statoil and the SDFI. Statoil accounts for the combined Statoil and SDFI share of these agreements as finance leases in the balance sheet, and further accounts for the SDFI related portion as operating subleases. The finance leases included in the balance sheet reflect the original lease term of 20 years from 2006. In addition, Statoil has the option to extend the leases for two additional periods of five years each.

On 21 December 2010 the commercial operation of the Combined Heat and Power plant at Mongstad started. Statoil leases this plant from DONG Energy. Statoil accounts for this agreement as a finance lease in the balance sheet, and the contract period is 20 years from commercial operation date. At the end of the period Statoil has the option to either take title at no charge or extend the contract period to either 25 or 30 years.

In 2010, net rental expense was NOK 12.4 billion (NOK 10.9 billion in 2009 and NOK 10.2 billion in 2008) of which minimum lease payments were NOK 13.8 billion (NOK 12.7 billion in 2009 and NOK 11.8 billion in 2008) and sublease payments received were NOK 1.5 billion (NOK 1.8 billion in 2009 and NOK 1.7 billion in 2008). No material contingent rent payments have been expensed in 2010, 2009 or 2008.

The information in the table below shows future minimum lease payments under non-cancellable leases at 31 December 2010.

Amounts related to finance leases include future minimum lease payments for assets recognised in the financial statements at year end 2010.

(in NOK million)	Operating leases Rigs	Vessels	Other leases	Sublease	Finance leases Minimum lease payments	Discount element	Net present value minimum lease payments
2011	13,931	2,568	999	(2,041)	817	(74)	743
2012	13,175	1,809	911	(1,801)	784	(86)	698
2013	9,968	1,379	819	(1,699)	594	(101)	493
2014	4,412	1,055	807	(658)	588	(116)	472
2015	1,747	864	779	(191)	614	(132)	482
Thereafter	329	3,173	4,804	(1,968)	6,828	(2,557)	4,271
Total future minimum lease payments	43,562	10,848	9,119	(8,358)	10,225	(3,066)	7,159

In addition, Statoil has entered into a leasing agreement with Maersk for a Floating Production, Storage and Offloading (FPSO) vessel for the production from the Peregrino field in Brazil. Statoil accounts for this agreement as a finance lease, and the lease term is five years starting from 2011. Statoil has an option to purchase the FPSO after five years. The FPSO and the related lease obligation has been classified as assets held for sale and financial liabilities held for sale at year end 2010, see note 4 *Assets classified as held for sale*.

Property, plant and equipment include the following amounts for leases that have been capitalised at 31 December 2010 and 2009:

(in NOK million)	2010	2009
Leased assets under development	0	8,983
Vessels	4,421	4,079
Refining and manufacturing plants	2,849	0
Other	1,646	797
Accumulated depreciation	(1,795)	(1,404)
Capitalised amount	7,121	12,455

8.1.29 Other commitments and contingencies

Contractual commitments

(in NOK million)	2011	2012	Thereafter	Total
Joint Venture related:				
Construction in progress	17,911	11,492	6,853	36,256
Property, plant and equipment and other investments	1,017	149	53	1,219
Acquisition of intangible assets	74	0	0	74
Subtotal joint venture related commitments	19,002	11,641	6,906	37,549
Non Joint Venture related:				
Construction in progress	2,103	13	0	2,116
Property, plant and equipment and other investments	1,797	102	148	2,047
Subtotal non joint venture related commitments	3,900	115	148	4,163
Total	22,902	11,756	7,054	41,712

The contractual commitments reflect Statoil's share and mainly comprise construction and acquisition of property, plant and equipment.

Other long-term commitments

Statoil has entered into various long-term agreements for pipeline transportation as well as terminal, processing, storage and entry/exit capacity commitments and commitments related to specific purchase agreements. The agreements ensure the rights to the capacity or volumes in question, but also impose on the group the obligation to pay for the agreed-upon service or commodity, irrespectively of actual use. The contracts' terms vary, with duration of up to 30 years.

Take-or-pay contracts for the purchase of commodity quantities are only included in the tables below if their contractually agreed pricing is of a nature that will or may deviate from the obtainable market prices for the commodity at the time of delivery.

Obligations payable by the group to entities accounted for using the equity method are included gross in the tables below. For assets (e.g. pipelines) that the group accounts for by recognising its share of assets, liabilities, income and expenses (capacity costs) on a line-by-line basis in the Consolidated financial statements, the amounts in the table include the net commitment payable by Statoil (gross commitment less Statoil's ownership share).

Nominal minimum commitments at 31 December 2010:

(in NOK million)	Transport and terminal commitments	Refinery related commitments	Total
2011	8,087	386	8,473
2012	7,434	611	8,045
2013	6,738	624	7,362
2014	6,727	625	7,352
2015	6,155	617	6,772
Thereafter	34,701	14,602	49,303
Total	69,842	17,465	87,307

The above table outlines nominal minimum obligations for future years, and mainly includes commitments within Statoil's natural gas operations in addition to various other transport and similar commitments. Statoil has entered into pipeline transportation agreements for most of its prospective gas sales contracts. These agreements ensure the right to transport the production of gas through the pipelines, while also imposing an obligation to pay for booked capacity.

Statoil has contractual commitments to the US-based energy company Dominion for terminal capacity at the Cove Point liquefied natural gas terminal in the USA. At year end 2010 the commitment includes an annual capacity of approximately 10.1 bcm for the period until the end of 2016, thereafter reduced to

4 bcm until the end of 2020, and finally reduced to 2.4 bcm for the remaining period ending September 2023. Such commitments have been included in full in the table above, but part of the commitment has been made on behalf of and for the account and risk of the SDFI. Statoil's and the SDFI's respective future shares of the Cove Point terminal capacity and related commitments depend on actual usage of the terminal. Statoil covers substantially all the costs of any unused capacity, while the costs of used capacity are split in proportion to the produced natural gas volumes of Statoil and the SDFI, respectively.

The Mongstad refinery has entered into a long-term take-or-pay contract related to purchase of heat from the Troll licence partners. The contract term expires in 2040, and future expected minimum annual obligations under this contract represents the most significant part of Refinery related commitments included in the table above.

Guarantees

Statoil has guaranteed certain recoverable reserves of crude oil in the Veslefrikk field on the NCS as part of an asset exchange with Petro Canada in 1996. Under the guarantee, Statoil is obligated to deliver indemnity reserves to Petro Canada in the event that recoverable reserves prove lower than a specified volume. At year end 2010 the value of the remaining volume covered by the guarantee has been estimated to a total of NOK 1.7 billion. A provision of NOK 0.3 billion has been recognised at year end related to this guarantee.

Statoil has guaranteed 50%, corresponding to its ownership percentage, of the contractual commitments entered into by Scira Offshore Energy Ltd. (Scira) in connection with the development of the Sheringham Shoal Offshore Wind Farm in the UK. Scira is included in the group financial statements using the equity method. At year end 2010 the maximum exposure under Statoil's guarantee has been estimated to NOK 1.8 billion. The carrying amount of the guarantee is immaterial.

Under the Norwegian public limited companies act section 14-11, Statoil and Norsk Hydro are jointly and severally liable for certain guarantee commitments entered into by Norsk Hydro prior to the merger between Statoil and Hydro Petroleum in 2007. The total amount Statoil is jointly liable for is approximately NOK 1.1 billion. As of the current date, the probability that these guarantee commitments will impact Statoil is deemed to be remote. No liability has been recognised in the Consolidated financial statements at year end 2010.

Other commitments and contingencies

As a condition for being awarded oil and gas exploration and production licenses, participants may be committed to drill a certain number of wells. At the end of 2010, Statoil was committed to participate in 16 wells in Norway and 35 wells outside Norway, with an average ownership interest of approximately 47%. Statoil's share of estimated expenditures to drill these wells amounts to approximately NOK 6.3 billion. Additional wells that Statoil may become committed to participate in depending on future discoveries in certain licenses are not included in these numbers.

During the normal course of its business Statoil is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset in respect of such litigation and claims cannot be determined at this time. Statoil has provided in its financial statements for probable liabilities related to litigation and claims based on the group's best judgement. Statoil does not expect that the financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings.

8.1.30 Related parties

Transactions with the Norwegian State

The Norwegian State is the majority shareholder of Statoil and also holds major investments in other Norwegian companies. As of 31 December 2010 the Norwegian State had an ownership interest in Statoil of 67% (excluding Folketrygdfondet (Norwegian national insurance fund) of 3,05%). This ownership structure means that Statoil participates in transactions with many parties that are under a common ownership structure and therefore meet the definition of a related party. All transactions are considered to be on an arm's length basis.

Statoil markets and sells the Norwegian State's share of oil and gas production from the Norwegian Continental Shelf (NCS). The Norwegian State's participation in petroleum activities is organised through the State's direct financial interest (SDFI). All purchases and sales of SDFI oil production are classified as purchases [net of inventory variation] and revenue, respectively. Statoil ASA sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. These sales, and related expenditures refunded by the State, are presented net in Statoil's financial statements. Sales made by Statoil subsidiaries in their own name, and related expenditure, are however presented gross in Statoil's financial statements where the applicable subsidiary is considered the principal when selling natural gas on behalf of the Norwegian State. In accounting for these sales activities, the State's share of profit or loss is reflected in Statoil's Selling, general and administrative expenses as expenses or reduction of expenses, respectively. The following purchases were made from the SDFI for the years presented:

Total purchases of oil and natural gas liquids from the Norwegian State amounted to NOK 81.4 billion (176 million barrels oil equivalents), NOK 74.3 billion (204 million barrels oil equivalents) and NOK 112.7 billion (223 million barrels oil equivalents) in 2010, 2009 and 2008, respectively. Purchases of natural gas from the Norwegian State amounted to NOK 0.4 billion, NOK 0.3 billion and NOK 0.4 billion in 2010, 2009 and 2008, respectively. The major part included in the line item payables to equity accounted investments and other related parties in note 26 *Trade and other payables*, are amounts payable to the Norwegian State for these purchases.

Other transactions
In relation to its ordinary business operations such as pipeline transport, gas storage and processing of petroleum products, Statoil also has regular transactions with certain entities in which Statoil has ownership interests. Such transactions are carried out on an arm's length basis, and are included within the applicable captions in the Statements of income.

Compensation of key management personnel
The remuneration to key management personnel (members of board of directors and the corporate executive committee) during the year was as follows:

(in NOK thousand)	2010	2009	2008
Current employee benefits	49,857	50,573	50,949
Post-employment benefits	11,414	11,391	12,534
Other non-current benefits	95	137	129
Share based payment benefits	840	444	278
Total	62,205	62,545	63,890

At 31 December 2010 there are no loans to key management personnel.

8.1.31 Financial instruments by category

Financial instruments by IAS 39 category
The following tables present Statoil's classes of financial instruments and their carrying amounts by the categories as they are defined in IAS 39. All financial instruments' carrying amounts are measured at fair value or their carrying amounts reasonably approximate fair value except non-current financial liabilities. See note *23 Non-current financial liabilities* for fair value information of non-current financial liabilities.

See also note 2 *Significant accounting policies* for further information regarding measurement of fair values.

				Fair value through profit or loss			
(in NOK million)	Note	Loans and receivables	Available-for-sale	Held for trading	Fair value option	Non-financial assets	Total carrying amount
31 December 2010							
Assets							
Non-current financial investments	17	-	3,042	-	12,315	-	15,357
Non-current derivative financial instruments	32	-	-	20,563	-	-	20,563
Non-current financial receivables	17	2,317	-	-	-	2,193	4,510
Current trade and other receivables	19	69,903	-	-	-	6,236	76,139
Current derivative financial instruments	32	-	-	6,074	-	-	6,074
Current financial investments	20	-	-	5,347	6,162	-	11,509
Cash and cash equivalents	21	30,337	-	-	-	-	30,337
Total		102,557	3,042	31,984	18,477	8,429	164,489

(in NOK million)	Note	Loans and receivables	Available-for-sale	Fair value through profit or loss: Held for trading	Fair value through profit or loss: Fair value option	Non-financial assets	Total carrying amount
31 December 2009							
Assets							
Non-current financial investments	17	-	2,223	-	11,044	-	13,267
Non-current derivative financial instruments	32	-	-	17,644	-	-	17,644
Non-current financial receivables	17	3,164	-	-	-	2,583	5,747
Current trade and other receivables	19	53,007	-	-	-	5,888	58,895
Current derivative financial instruments	32	-	-	5,369	-	-	5,369
Current financial investments	20	55	-	1,962	5,005	-	7,022
Cash and cash equivalents	21	24,723	-	-	-	-	24,723
Total		80,949	2,223	24,975	16,049	8,471	132,667

(in NOK million)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
31 December 2010					
Liabilities					
Non-current financial liabilities	23	99,797	-	-	99,797
Non-current derivative financial instruments	32	-	3,386	-	3,386
Current trade and other payables	26	70,887	-	2,664	73,551
Current financial liabilities	27	11,730	-	-	11,730
Current derivative financial instruments	32	-	4,161	-	4,161
Total		182,414	7,547	2,664	192,625

(in NOK million)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
31 December 2009					
Liabilities					
Non-current financial liabilities	23	95,962	-	-	95,962
Non-current derivative financial instruments	32	-	1,657	-	1,657
Current trade and other payables	26	58,048	-	1,753	59,801
Current financial liabilities	27	8,150	-	-	8,150
Current derivative financial instruments	32	-	2,860	-	2,860
Total		162,160	4,517	1,753	168,430

The following tables present amounts recognised in the Consolidated statement of income related to Statoil's financial instruments by the categories as they are defined in IAS 39.

	Fair value through profit or loss							
(in NOK million)	Held for trading	Hedge accounting	Fair value option	Loans and receivables	Financial liabilities at amortised cost	Available-for-sale assets	Non-financial assets or liabilities	Total
For the year ended 31 December 2010								
Net operating income	(3,450)	-	-	-	-	-	140,678	137,228
Net financial items								
Net foreign exchange gains (losses)	(5,451)	-	-	1,487	2,128	-	-	(1,836)
Interest income	1,146	-	314	908	-	-	-	2,368
Other financial items	(134)	-	861	17	-	50	13	807
Interest income and other financial items	1,012	-	1,175	925	-	50	13	3,175
Interest expenses	2,448	-	-	-	(4,150)	-	-	(1,702)
Impairment loss recognised	-	-	-	-	-	-	-	-
Other financial expenses	2,363	-	-	-	225	-	(2,637)	(49)
Interest and other financial expenses	4,811	-	-	-	(3,925)	-	(2,637)	(1,751)
Net financial items	372	-	1,175	2,412	(1,797)	50	(2,624)	(412)
Total	(3,078)	-	1,175	2,412	(1,797)	50	138,054	136,816

	Fair value through profit or loss							
(in NOK million)	Held for trading	Hedge accounting	Fair value option	Loans and receivables	Financial liabilities at amortised cost	Available-for-sale assets	Non-financial assets or liabilities	Total
For the year ended 31 December 2009								
Net operating income	12,337	-	-	-	-	(159)	109,462	121,640
Net financial items								
Net foreign exchange gains (losses)	16,661	-	-	(10,568)	(4,076)	-	(24)	1,993
Interest income	1,290	-	326	1,088	-	-	-	2,704
Other financial items	518	-	403	111	-	(28)	-	1,004
Interest income and other financial items	1,808	-	729	1,199	-	(28)	-	3,708
Interest expenses	2,123	-	-	-	(3,748)	-	-	(1,625)
Impairment loss recognised	-	-	-	-	-	(1,404)	-	(1,404)
Other financial expenses	(6,807)	-	-	-	(183)	-	(2,432)	(9,422)
Interest and other financial expenses	(4,684)	-	-	-	(3,931)	(1,404)	(2,432)	(12,451)
Net financial items	13,785	-	729	(9,369)	(8,007)	(1,432)	(2,456)	(6,750)
Total	26,122	-	729	(9,369)	(8,007)	(1,591)	107,006	114,890

(in NOK million)	Fair value through profit or loss Held for trading	Hedge accounting	Fair value option	Loans and receivables	Financial liabilities at amortised cost	Available-for-sale assets	Non-financial assets or liabilities	Total
For the year ended 31 December 2008								
Net operating income	19,917	-	-	-	-	(346)	179,261	198,832
Net financial items								
Net foreign exchange gains (losses)	(24,266)	-	-	3,848	(12,145)	-	-	(32,563)
Interest income	3,230	-	437	3,392	-	-	-	7,059
Other financial items	6,006	-	(971)	52	-	61	-	5,148
Interest income and other financial items	9,236	-	(534)	3,444	-	61	-	12,207
Interest expenses	959	-	-	-	(2,243)	-		(1,284)
Other financial expenses	5,660	(27)	-	-	(251)	-	(2,107)	3,275
Interest and other financial expenses	6,619	(27)	-	-	(2,494)	-	(2,107)	1,991
Net financial items	(8,411)	(27)	(534)	7,292	(14,639)	61	(2,107)	(18,365)
Total	11,506	(27)	(534)	7,292	(14,639)	(285)	177,154	180,467

8.1.32 Financial instruments: fair value measurement and sensitivity analysis of market risk

Fair value measurement of financial instruments

Derivative financial instruments
Statoil measures all derivative financial instruments at fair value. Changes in the fair value of the derivative financial instruments are recognised in the Consolidated statement of income, within Revenues or within Net financial items, respectively, depending on their nature as commodity based derivative contracts or interest rate and foreign exchange rate derivative instruments.

When determining fair value of derivative financial instruments Statoil uses prices quoted in an active market to the extent possible. When such prices are not available Statoil uses inputs that are directly or indirectly observable in the market as a basis for valuation techniques such as discounted cash flow analysis or pricing models. For more information about the methodology and assumption used when measuring the fair value of Statoil's derivative financial instruments see note 2 *Significant accounting policies*.

The following table contains the estimated fair values and net carrying amounts of Statoil's derivative financial instruments. Of the total ending balance at 31 December 2010 NOK 15.1 billion relates to certain earn-out agreements and embedded derivatives recognised as derivative financial instruments in accordance with IAS 39. At the end of 2009 the estimated fair value of these agreements was NOK 13.0 billion.

(in NOK million)	Fair value of assets	Fair value of liabilities	Net carrying amount
At 31 December 2010			
Debt-related instruments	8,404	(3,631)	4,773
Non-debt-related instruments	1,520	(106)	1,414
Crude oil and refined products	10,187	(691)	9,496
Natural gas and electricity	6,526	(3,119)	3,407
Total	26,637	(7,547)	19,090
At 31 December 2009			
Debt-related instruments	6,405	(1,708)	4,697
Non-debt-related instruments	347	(867)	(520)
Crude oil and refined products	8,034	(842)	7,192
Natural gas and electricity	8,227	(1,100)	7,127
Total	23,013	(4,517)	18,496

Financial investments

Statoil measures all financial investments at fair value. Statoil's financial investments consist of the portfolios held by the group's captive insurance company (mainly bonds, listed equity securities and commercial papers) and investments in money market funds held for liquidity management purposes. The group also holds some other non-listed equity securities for long term strategic purposes. These are classified as available-for-sale assets (AFS). Changes in fair value of the financial investments are recognised in the Consolidated statement of income within Net financial items, with the exception of the investments that are classified as AFS assets. Changes in fair value of these investments are recognised in the Consolidated statement of comprehensive income, while any impairment losses are recognised in the Consolidated statement of income within Net financial items.

When determining fair value of financial investments, the group uses prices quoted in an active market to the extent possible. This will typically be for listed equity securities and government bonds. Where there is no active market, fair value is determined using valuation techniques such as discounted cash flow analysis. For more information about methodology and assumptions used when measuring fair value of the group's financial investments see note 2 *Significant accounting policies*. For information about fair values of the group's financial investments recognised in the balance sheet see note 17 *Non-current financial assets* and note 20 *Current financial investments*.

Fair value hierarchy

The following table summarises each class of financial instruments which are recognised in the balance sheet at fair value, split by the group's basis for fair value measurement.

(in NOK million)	Non-current financial investment	Non-current derivative financial instruments-assets	Current financial investments	Current derivative financial instruments-assets	Non-current derivative financial instruments-liabilities	Current derivative financial instruments-liabilities	Net fair value
At 31 December 2010							
Fair value based on prices quoted in an active market for identical assets or liabilities (Level 1)	8,182	0	4,939	0	0	0	13,121
Fair value based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability (Level 2)	4,396	6,798	6,570	4,667	(3,386)	(4,154)	14,891
Fair value based on unobservable inputs (Level 3)	2,779	13,765	0	1,407	0	(7)	17,944
Total fair value	15,357	20,563	11,509	6,074	(3,386)	(4,161)	45,956
At 31 December 2009							
Fair value based on prices quoted in an active market for identical assets or liabilities (Level 1)	6,663	0	4,339	42	0	(18)	11,026
Fair value based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability (Level 2)	4,683	6,191	2,683	3,827	(1,657)	(2,756)	12,971
Fair value based on unobservable inputs (Level 3)	1,921	11,453	0	1,500	0	(86)	14,788
Total fair value	13,267	17,644	7,022	5,369	(1,657)	(2,860)	38,785

Level 1, fair value based on prices quoted in an active market for identical assets or liabilities, includes financial instruments actively traded and for which the values recognised in Statoil's balance sheet are determined based on observable prices on identical instruments. For Statoil this category will, in most cases, only be relevant for investments in listed equity securities and government bonds.

Level 2, fair value based on inputs other than quoted prices included within Level 1, which are derived from observable market transactions, includes Statoil's non-standardised contracts for which fair values are determined on the basis of price inputs from observable market transactions. This will typically be when the group uses forward prices on crude oil, natural gas, interest rates, and foreign exchange rates as inputs to the valuation models to determining the fair value of its derivative financial instruments.

Level 3, fair value based on unobservable inputs, includes financial instruments for which fair values are determined on the basis of input and assumptions that are not from observable market transactions. The fair values presented in this category are mainly based on internal assumptions. The internal assumptions are only used in the absence of quoted prices from an active market or other observable price inputs for the financial instruments subject to the valuation.

The fair value of certain earn-out agreements and embedded derivative contracts are determined by the use of valuation techniques with price inputs from observable market transactions as well as internal generated price assumptions and volume profiles. The discount rate used in the valuation is a risk free rate based on the applicable currency and time horizon of the underlying cash flows adjusted for a credit premium to reflect either Statoil's credit premium, if the value is a liability, or an estimated counterparty credit premium if the value is an asset. The fair value of these derivative financial instruments have been classified in their entirety in the third category within Current and Non-current derivative financial instruments - assets in the above table. Another reasonably assumption, that could have been applied when determining the fair value of these contracts, would be to extrapolate the last observed forward prices with inflation. Had Statoil applied this assumption the fair value of the contracts included would have increased by approximately NOK 0.1 billion at end of 2010 and NOK 1.5 billion at end of 2009 and impacted the Consolidated statement of income with corresponding amounts.

The reconciliation of the changes in fair value during 2010 and 2009 for all financial assets and liabilities classified in the third level in the hierarchy are presented in the following table.

(in NOK million)	Non-current financial investment	Non-current derivative financial instruments-assets	Current derivative financial instruments-assets	Non-current derivative financial instruments-liabilities	Current derivative financial instruments-liabilities
For the year ended 31 December 2010					
Opening balance	1,921	11,453	1,500	0	(86)
Total gains and losses recognised					
- in statement of income	(4)	2,312	1,407	0	(7)
- in other comprehensive income	213	0	0	0	0
Purchases	634	0	0	0	0
Settlement	(22)	0	(1,500)	0	86
Transfer into level 3	(10)	0	0	0	0
Transfer out of level 3	47	0	0	0	0
Closing balance	2,779	13,765	1,407	0	(7)
For the year ended 31 December 2009					
Opening balance	3,488	8,852	1,319	(760)	(91)
Total gains and losses recognised					
- in statement of income	(1,499)	2,601	1,500	760	(86)
- in other comprehensive income	0	0	0	0	0
Purchases	941	0	0	0	0
Settlement	(327)	0	(1,319)	0	91
Transfer into level 3	307	0	0	0	0
Transfer out of level 3	(989)	0	0	0	0
Closing balance	1,921	11,453	1,500	0	(86)

The assets and liabilities within the level 3 have during 2010 had a net increase in the fair value of NOK 3.2 billion. Of the NOK 3.7 billion recognised in the Consolidated statement of income during 2010 NOK 2.1 billion are related to changes in fair value of certain earn-out agreements and embedded derivatives.

Practically all gains and losses recognised in the Consolidated statement of income during 2010 are related to assets and liabilities held by the group at the end of 2010.

Certain divestment requirements were set out by the European Commission (EC) in relation to Statoil's acquisition of the Jet automated petrol retail station network in 2008. As a consequence the investment was classified as an available for sale asset at end 2008. During 2009 the divestment requirements was fulfilled. By end of 2009 the remaining Jet activity was fully consolidated and the values previously included in level 3 in the above table have been transferred out.

Sensitivity analysis of market risk

Commodity price risk

The table below contains the fair value and related commodity price risk sensitivities of Statoil's commodity based derivatives contracts. For further information related to the type of commodity risks and how the group manages these risks see note 8 *Financial risk management*.

Statoil's assets and liabilities resulting from commodity based derivatives contracts are mainly related to non-exchange traded derivative instruments, including embedded derivatives that have been bifurcated and recognised with fair value in the balance sheet.

Price risk sensitivities by end of 2010 and 2009 have been calculated assuming a reasonably possible change of 30% in crude oil, refined products and electricity prices, and 50% change for natural gas prices. At the end of 2008 these sensitivities were calculated by assuming a 50% reasonably possible change for all commodities.

Since none of the derivative financial instruments included in the table below are part of hedging relationships, any changes in the fair value would be recognised in the Consolidated statement of income.

(in NOK million)	Net fair value	-30% sensitivity	30% sensitivity
At 31 December 2010			
Crude oil and refined products	9,496	(2,762)	2,762

		-50%/-30% sensitivity	50%/30% sensitivity
At 31 December 2010			
Natural gas and electricity	3,407	3,680	(3,666)

		-30% sensitivity	30% sensitivity
At 31 December 2009			
Crude oil and refined products	7,192	(2,087)	1,580

		-50%/-30% sensitivity	50%/30% sensitivity
At 31 December 2009			
Natural gas and electricity	7,127	3,871	(3,886)

		-50% sensitivity	50% sensitivity
At 31 December 2008			
Crude oil and refined products	10,645	(4,124)	4,440
Natural gas and electricity	26	3,447	(3,431)

As part of the tools to monitor and manage risk, the group uses the value at risk (VaR) method for certain parts of its commodity trading activity within the Natural Gas and Manufacturing and Marketing segments.

Oil sales, trading and supply (OTS), within the Manufacturing and Marketing segment, uses the historical simulation method where daily percentage market price and volatility changes for all significant products in the OTS portfolio over a given time period are applied to the current portfolio value, in order to estimate a probability distribution of future market value changes for the portfolio. Non-linear instruments such as options are remeasured on a daily basis over the simulation interval using the historical price and volatility inputs; and the daily historical value changes are an integral part of the portfolio value changes. The relationship between VaR estimates and actual portfolio value changes are monitored on a monthly basis using a four years rolling observation window and input parameters such as simulation intervals are recalibrated when model performance moves outside acceptable bounds.

The Natural Gas segment mainly measures its market risk exposure using a variance/covariance VaR method. Furthermore a 95% confidence interval and a one day holding period is applied. The variance/covariance method is applied to the current portfolio in order to quantify portfolio movements caused by possible future changes in the market prices over a 24-hour holding period. The variance/covariance method calculates the VaR as a function of standard deviation per instrument in the portfolio and the correlation between the instruments. The practical understanding is that there is a 95% probability that the value of the portfolio will change by less than the calculated VaR number during the next trading day. VaR does not quantify the worst case loss.

The variance/covariance method calculates the VaR as a function of the standard deviation per instrument in the portfolio and the correlation between the instruments. The historical simulation method derives daily percentage market price and volatility changes for all significant products in the portfolio over a given time period and apply those to the current portfolio value, in order to estimate a probability distribution of future market value changes for the portfolio. Different VaR-methods are used within OTS and the Natural Gas segment to best reflect the nature of the relevant commodity markets.

Within OTS all physical and financial contracts that are managed together for risk management purposes are subject to VaR limits, independently of how they are recognised in Statoil's Consolidated balance sheet. Within Natural Gas embedded derivatives as well as certain physical forward contracts recognised as derivative financial instrument that are not held as part of a trading position are not included in the portfolio subject to VaR limits.

The calculated VaR numbers for 2010, 2009 and 2008 and a summary of the assumptions used are presented in the following table.

(in NOK million)	High	Low	Average
For the year ended 31 December 2010			
Crude Oil and Refined Products	151	59	105
Natural Gas and Electricity	300	6	116
For the year ended 31 December 2009			
Crude Oil and Refined Products	189	42	103
Natural Gas and Electricity	219	8	80
For the year ended 31 December 2008			
Crude Oil and Refined Products	143	28	79
Natural Gas and Electricity	218	40	116

Assumptions used	Method used	Confidence level	Holding period
Crude Oil and Refined Products	Historical simulation VaR	95%	1 day
Natural Gas and Electricity	Variance/Covariance	95%	1 day

Currency risk

Currency risks constitute significant financial risks for the Statoil group. Total exposure is managed at a portfolio level, in accordance with approved strategies and mandates, on a regular basis. For further information related to the currency risks and how the group manages these risks see note 8 *Financial risk management*.

At the end of 2010 and 2009 the following currency risk sensitivities have been calculated by assuming a 12% reasonably possible change in foreign exchange rates that the group is exposed to. At the end of 2008 a 20% reasonably possible change was assumed in the calculation.

The groups underlying exposure at the end of 2009 towards USD, EUR, GBP and NOK have been updated to be consistent with the method applied for the exposure estimation at the end of 2010.

As of 1 January 2009 Statoil ASA's functional currency changed from NOK to USD, see note 1 *Organisation*. The change of functional currency has impacted the currency risk sensitivities when comparing 2010 and 2009 with 2008.

(in NOK million)	USD	EUR	GBP	CAD	NOK	SEK	DKK
At 31 December 2010							
Net gains/losses (12% sensitivity)	(12,215)	826	(339)	88	11,239	371	134
Net gains/losses (-12% sensitivity)	12,215	(826)	339	(88)	(11,239)	(371)	(134)
At 31 December 2009							
Net gains/losses (12% sensitivity)	(9,999)	746	818	(299)	7,354	558	819
Net gains/losses (-12% sensitivity)	9,999	(746)	(818)	299	(7,354)	(558)	(819)
At 31 December 2008							
Net gains/losses (20% sensitivity)	(31,369)	(11,906)	11	(170)	39,856	1,976	1,636
Net gains/losses (-20% sensitivity)	31,369	11,906	(11)	170	(39,856)	(1,976)	(1,636)

Interest rate risk

Interest rate risks constitute significant financial risks for the Statoil group. Total exposure is managed at a portfolio level, in accordance with approved strategies and mandates, on a regular basis. For further information related to the interest risks and how the group manages these risks see note 8 *Financial risk management*.

For the interest rate risk sensitivity a decline of 0.5 percentage point and an increase of 1.5 percentage point in the interest rates have been used as reasonably possible changes in the calculation. Compared to the sensitivities calculated by end of 2009 and 2008 Statoil's assessment of what are reasonably possible changes in interest rates that the group is exposed to has been changed from a 1.5 percentage point and one percentage point respectively for 2009 and 2008. The estimated gains following from a decline in the interest rates and the estimated losses following from an interest rate increases that would impact the Consolidated statement of income are presented in the following table.

(in NOK million)	Gains	Losses
At 31 December 2010		
Interest rate risk (-0.5 percentage point sensitivity)	2,785	
Interest rate risk (1.5 percentage point sensitivity)		(8,355)
At 31 December 2009		
Interest rate risk (1.5 percentage point sensitivity)	8,456	(8,456)
At 31 December 2008		
Interest rate risk (1 percentage point sensitivity)	3,395	(3,395)

Equity risk

The following table contains the fair value and related equity price risk sensitivity of Statoil's listed and non-listed equity securities. The equity price risk sensitivity has been calculated based on what Statoil views to be reasonably possible changes in the equity prices for the coming year. For 2010 a 20% and 35% change in the equity prices has been used in the calculation of the sensitivity. At the end of 2009 and 2008 the group's view was a 20% and 40% change in the equity price for the listed and non-listed equity securities respectively.

For the listed equity securities changes in fair values would be recognised as gains or losses in the Consolidated statement of income. While for the non-listed equity securities that are classified as available for sale assets, a decline in the fair value would be recognised in the Consolidated statement of income as an impairment loss, while an increase in the fair value would be recognised in Other comprehensive income.

(in NOK million)	Fair value	-20% sensitivity	20% sensitivity
At 31 December 2010			
Listed equity securities	5,102	(1,020)	1,020
At 31 December 2009			
Listed equity securities	4,318	(864)	864
At 31 December 2008			
Listed equity securities	2,276	(455)	455
		-35% sensitivity	35% sensitivity
At 31 December 2010			
Non-listed equity securities	3,042	(1,065)	1,065
		-40% sensitivity	40% sensitivity
At 31 December 2009			
Non-listed equity securities	2,223	(889)	889
At 31 December 2008			
Non-listed equity securities	4,205	(1,682)	1,682

8.1.33 Subsequent events

The composition of Statoil's reportable segments will change with effect from 1 January 2011 following the changes in the internal organisational structure.

8.1.34 Condensed consolidating financial information related to guaranteed debt securities issued by parent company

At 31 December 2008, Statoil's oil and gas activities and net assets on the Norwegian Continental Shelf (NCS) were owned by Statoil ASA and by Statoil Petroleum AS. With effect from 1 January 2009, Statoil ASA has transferred the ownership of its NCS net assets to Statoil Petroleum AS, a 100% owned operating subsidiary. Following the transfer, all NCS net assets are owned by Statoil Petroleum AS. Effective from the same date, Statoil Petroleum AS became the co-obligor of certain existing debt securities of Statoil ASA that are registered under the US Securities Act of 1933 ("US registered debt securities"). As co-obligor, Statoil Petroleum AS fully, unconditionally and irrevocably assumes and agrees to perform, jointly and severally with Statoil ASA, the payment and covenant obligations for these US registered debt securities. In addition, Statoil ASA also became the co-obligor of a US registered debt security of Statoil Petroleum AS. As co-obligor, Statoil ASA fully, unconditionally and irrevocably assumes and agrees to perform, jointly and severally with Statoil Petroleum AS, the payment and covenant obligations of that security.

During 2009 and 2010, Statoil ASA issued five additional US registered debt securities which are fully and unconditionally guaranteed by Statoil Petroleum AS, with Statoil Petroleum AS being the sole guarantor of such securities. In the future, Statoil ASA may issue future US registered debt securities from time to time for which debt securities Statoil Petroleum AS will be the co-obligor or guarantor.

The following financial information on a condensed consolidating basis provides investors with financial information about Statoil ASA, as issuer and co-obligor, Statoil Petroleum AS, as co-obligor and guarantor, and all other subsidiaries as required by SEC Rule 3-10 of Regulation S-X. The transfer of ownership of the NCS net assets from Statoil ASA to Statoil Petroleum AS was a common control transaction. Statoil ASA accounts for common control transactions by recognising the carrying amounts of assets and liabilities transferred and restating the financial statements for all periods presented to reflect the transaction as if it occurred at the beginning of the periods presented. The condensed consolidating information presented below reflects the transfer of NCS assets to the Statoil Petroleum AS for all periods presented. The condensed consolidating information is prepared in accordance with the group's IFRS accounting policies as described in note 2 *Significant accounting policies*, except that investments in subsidiaries are accounted for using the equity method as required by Rule 3-10.

The following is condensed consolidated financial information as of 31 December, 2010 and 2009 and for the years ended 31 December 2010, 2009 and 2008.

CONSOLIDATED STATEMENT OF INCOME

2010 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
REVENUES AND OTHER INCOME					
Revenues	384,578	198,574	182,443	(238,877)	526,718
Net income from equity accounted investments	37,378	(3,296)	888	(33,837)	1,133
Other income	12	994	1,201	(410)	1,797
Total revenues and other income	421,968	196,272	184,532	(273,124)	529,648
OPERATING EXPENSES					
Purchases [net of inventory variation]	(368,465)	(6,701)	(111,366)	229,105	(257,427)
Operating expenses	(9,575)	(34,576)	(16,791)	3,411	(57,531)
Selling, general and administrative expenses	(6,014)	(608)	(11,191)	6,732	(11,081)
Depreciation, amortisation and net impairment losses	(796)	(27,825)	(21,987)	0	(50,608)
Exploration expenses	(786)	(5,497)	(9,490)	0	(15,773)
Total operating expenses	(385,636)	(75,207)	(170,825)	239,248	(392,420)
Net operating income	36,332	121,065	13,707	(33,876)	137,228
FINANCIAL ITEMS					
Net foreign exchange gains (losses)	(2,553)	725	17	(25)	(1,836)
Interest income and other financial items	4,677	786	4,716	(7,004)	3,175
Interest and other finance expenses	(420)	(3,943)	(2,630)	5,242	(1,751)
Net financial items	1,704	(2,432)	2,103	(1,787)	(412)
Income before tax	38,036	118,633	15,810	(35,663)	136,816
Income tax	1,833	(90,274)	(10,716)	(12)	(99,169)
Net income	39,869	28,359	5,094	(35,675)	37,647

CONSOLIDATED STATEMENT OF INCOME

2009 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
REVENUES AND OTHER INCOME					
Revenues	313,684	195,318	155,555	(202,265)	462,292
Net income from equity accounted investments	28,187	(3,693)	3,313	(26,029)	1,778
Other income	5	1,121	237	0	1,363
Total revenues and other income	341,876	192,746	159,105	(228,294)	465,433
OPERATING EXPENSES					
Purchases [net of inventory variation]	(294,442)	(5,276)	(93,256)	187,104	(205,870)
Operating expenses	(10,649)	(34,979)	(13,247)	2,015	(56,860)
Selling, general and administrative expenses	(7,928)	(610)	(12,112)	10,329	(10,321)
Depreciation, amortisation and net impairment losses	(814)	(27,316)	(25,926)	0	(54,056)
Exploration expenses	(861)	(5,187)	(10,638)	0	(16,686)
Total operating expenses	(314,694)	(73,368)	(155,179)	199,448	(343,793)
Net operating income	27,182	119,378	3,926	(28,846)	121,640
FINANCIAL ITEMS					
Net foreign exchange gains (losses)	10,608	(4,632)	3,002	(6,985)	1,993
Interest income and other financial items	4,693	1,017	(9,995)	7,993	3,708
Interest and other finance expenses	(10,629)	(4,118)	(5,059)	7,355	(12,451)
Net financial items	4,672	(7,733)	(12,052)	8,363	(6,750)
Income before tax	31,854	111,645	(8,126)	(20,483)	114,890
Income tax	(6,556)	(88,266)	(3,141)	788	(97,175)
Net income	25,298	23,379	(11,267)	(19,695)	17,715

CONSOLIDATED STATEMENT OF INCOME

2008 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
REVENUES AND OTHER INCOME					
Revenues	389,618	249,432	242,995	(230,068)	651,977
Net income from equity accounted investments	57,648	4,408	1,105	(61,878)	1,283
Other income	521	20	2,572	(353)	2,760
Total revenues and other income	447,787	253,860	246,672	(292,299)	656,020
OPERATING EXPENSES					
Purchases [net of inventory variation]	(360,897)	(4,045)	(181,803)	217,563	(329,182)
Operating expenses	(13,718)	(37,081)	(14,293)	5,743	(59,349)
Selling, general and administrative expenses	(11,500)	36	(8,789)	9,289	(10,964)
Depreciation, amortisation and net impairment losses	(693)	(26,215)	(16,088)	0	(42,996)
Exploration expenses	(551)	(5,540)	(8,606)	0	(14,697)
Total operating expenses	(387,359)	(72,845)	(229,579)	232,595	(457,188)
Net operating income	60,428	181,015	17,093	(59,704)	198,832
FINANCIAL ITEMS					
Net foreign exchange gains (losses)	(38,112)	2,154	3,395	0	(32,563)
Interest income and other financial items	10,449	1,895	10,740	(10,877)	12,207
Interest and other finance expenses	1,025	(4,705)	(5,206)	10,877	1,991
Net financial items	(26,638)	(656)	8,929	0	(18,365)
Income before tax	33,790	180,359	26,022	(59,704)	180,467
Income tax	9,476	(132,310)	(13,612)	(751)	(137,197)
Net income	43,266	48,049	12,410	(60,455)	43,270

CONSOLIDATED BALANCE SHEET

At 31 December 2010 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
ASSETS					
Non-current assets					
Property, plant and equipment	5,096	210,892	132,216	0	348,204
Intangible assets	15	7,774	31,906	0	39,695
Shares in subsidiaries	298,670	84,419	0	(383,089)	0
Equity accounted investments	0	1,301	12,583	0	13,884
Deferred tax assets	2,922	0	1,878	(2,922)	1,878
Pension assets	5,087	0	178	0	5,265
Financial investments	10	5	15,342	0	15,357
Derivative financial instruments	8,360	12,203	0	0	20,563
Financial receivables	1,480	1,315	1,715	0	4,510
Financial receivables from subsidiaries	88,346	93	32,813	(121,252)	0
Total non-current assets	409,986	318,002	228,631	(507,263)	449,356
Current assets					
Inventories	15,021	0	12,596	(3,990)	23,627
Trade and other receivables	45,221	10,124	21,314	(521)	76,139
Current tax receivables	343	450	285	0	1,076
Receivables from subsidiaries	16,797	35,800	146,738	(199,335)	0
Derivative financial instruments	4,320	1,361	393	0	6,074
Financial investments	5,230	0	6,279	0	11,509
Cash and cash equivalents	18,131	0	12,206	0	30,337
Total current assets	105,063	47,734	199,811	(203,846)	148,762
Assets classified as held for sale	0	0	44,890	0	44,890
TOTAL ASSETS	515,049	365,736	473,332	(711,109)	643,008

CONSOLIDATED BALANCE SHEET

At 31 December 2010 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
EQUITY AND LIABILITIES					
Equity					
Paid in Capital and Retained Earnings	222,497	104,901	298,862	(412,534)	213,726
Other reserves	(1,194)	(2,693)	(16,868)	26,571	5,816
Statoil shareholders' equity	221,303	102,208	281,994	(385,963)	219,542
Non-controlling interest (Minority interest)	0	0	6,853	0	6,853
Total equity	221,303	102,208	288,847	(385,963)	226,395
Non-current liabilities					
Financial liabilities	90,190	350	9,257	0	99,797
Non-current liabilities to subsidiaries	63	69,810	51,377	(121,250)	0
Derivative financial instruments	3,386	0	0	0	3,386
Deferred tax liabilities	0	76,260	4,900	(3,108)	78,052
Pension liabilities	21,497	0	613	0	22,110
Asste retirement obligations, other provisions and other liabilities	1,217	50,039	16,987	(333)	67,910
Total non-current liabilities	116,353	196,459	83,134	(124,691)	271,255
Current liabilities					
Trade and other payables	33,803	14,449	25,487	(188)	73,551
Current tax payable	0	42,761	4,861	(929)	46,693
Financial liabilities	9,749	9	1,972	0	11,730
Derivative financial instruments	3,863	21	277	0	4,161
Current liabilities to subsidiaries	129,978	9,829	59,531	(199,338)	0
Total current liabilities	177,393	67,069	92,128	(200,455)	136,135
Liabilities directly associated with the assets classified as held for sale	0	0	9,223	0	9,223
Total liabilities	293,746	263,528	184,485	(325,146)	416,613
TOTAL EQUITY AND LIABILITIES	515,049	365,736	473,332	(711,109)	643,008

CONSOLIDATED BALANCE SHEET

At 31 December 2009 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
ASSETS					
Non-current assets					
Property, plant and equipment	4,771	197,537	138,527	0	340,835
Intangible assets	29	8,365	45,859	0	54,253
Shares in subsidiaries	290,648	87,156	0	(377,804)	0
Equity accounted investments	605	823	9,416	(788)	10,056
Deferred tax assets	2,380	3,732	0	(4,153)	1,960
Pension assets	2,665	0	29	0	2,694
Financial investments	11	5	13,251	0	13,267
Derivative financial instruments	7,132	10,512	0	0	17,644
Financial receivables	1,285	1,323	3,139	0	5,747
Financial receivables from subsidiaries	47,651	97	30,327	(78,076)	0
Total non-current assets	357,177	309,551	240,549	(460,821)	446,456
Current assets					
Inventories	11,976	50	12,124	(3,954)	20,196
Trade and other receivables	31,983	9,354	17,558	0	58,895
Current tax receivables	179	0	0	0	179
Receivables from subsidiaries	0	4,184	129,227	(133,411)	0
Derivative financial instruments	3,888	1,200	281	0	5,369
Financial investments	1,905	0	5,117	0	7,022
Cash and cash equivalents	14,460	3	10,260	0	24,723
Total current assets	64,391	14,792	174,566	(137,365)	116,384
TOTAL ASSETS	421,568	324,344	415,114	(598,186)	562,840

CONSOLIDATED BALANCE SHEET

At 31 December 2009 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
EQUITY AND LIABILITIES					
Equity					
Paid in Capital and Retained Earnings	201,736	105,975	295,004	(407,964)	194,751
Other reserves	(3,417)	(4,543)	(15,012)	26,540	3,568
Statoil shareholders' equity	198,319	101,432	279,992	(381,424)	198,319
Non-controlling interest (Minority interest)	0	0	1,799	0	1,799
Total equity	198,319	101,432	281,791	(381,424)	200,118
Non-current liabilities					
Financial liabilities	83,443	292	12,227	0	95,962
Non-current liabilities to subsidiaries	50	46,545	31,480	(78,076)	0
Derivative financial instruments	1,657	0	0	0	1,657
Deferred tax liabilities	0	80,740	862	(5,280)	76,322
Pension liabilities	20,682	0	460	0	21,142
Asset retirement obligations, other provisions and other liabilities	1,916	40,138	13,780	0	55,834
Total non-current liabilities	107,748	167,715	58,809	(83,356)	250,917
Current liabilities					
Trade and other payables	27,243	14,104	18,454	0	59,801
Current tax payable	4,182	33,472	3,340	0	40,994
Financial liabilities	7,386	0	764	0	8,150
Derivative financial instruments	2,530	18	312	0	2,860
Current liabilities to subsidiaries	74,160	7,602	51,644	(133,406)	0
Total current liabilities	115,501	55,196	74,514	(133,406)	111,805
Total liabilities	223,249	222,912	133,323	(216,762)	362,722
TOTAL EQUITY AND LIABILITIES	421,568	324,344	415,114	(598,186)	562,840

CASH FLOW STATEMENT

At 31 December 2010 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
Cash flows provided by operating activities	21,623	67,543	29,825	(38,176)	80,815
Cash flows used in investing activities	(4,371)	(32,268)	(42,219)	2,640	(76,218)
Cash flows provided by (used in) financing activities	(13,780)	(35,278)	14,089	35,536	567
Net increase (decrease) in cash and cash equivalents	3,472	(3)	1,695	0	5,164
Effect of exchange rate changes on cash and cash equivalents	199	0	251	0	450
Cash and cash equivalents at the beginning of the period	14,460	3	10,260	0	24,723
Cash and cash equivalents at the end of the period	18,131	0	12,206	0	30,337

CASH FLOW STATEMENT

At 31 December 2009 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
Cash flows provided by operating activities	(3,547)	64,133	27,711	(15,296)	73,001
Cash flows used in investing activities	21,639	(62,931)	(44,366)	10,302	(75,356)
Cash flows provided by (used in) financing activities	(8,809)	(1,199)	16,305	4,994	11,291
Net increase (decrease) in cash and cash equivalents	9,283	3	(350)	0	8,936
Effect of exchange rate changes on cash and cash equivalents	(1,095)	0	(1,756)	0	(2,851)
Cash and cash equivalents at the beginning of the period	6,272	0	12,366	0	18,638
Cash and cash equivalents at the end of the period	14,460	3	10,260	0	24,723

CASH FLOW STATEMENT

At 31 December 2008 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
Cash flows provided by operating activities	(11,182)	75,887	44,181	(6,353)	102,533
Cash flows used in investing activities	(70,188)	(52,003)	(36,492)	72,846	(85,837)
Cash flows provided by (used in) financing activities	87,618	(23,879)	(14,275)	(66,493)	(17,029)
Net increase (decrease) in cash and cash equivalents	6,248	5	(6,586)	0	(333)
Effect of exchange rate changes on cash and cash equivalents	0	(5)	712	0	707
Cash and cash equivalents at the beginning of the period	23	0	18,241	0	18,264
Cash and cash equivalents at the end of the period	6,271	0	12,367	0	18,638

8.1.35 Supplementary oil and gas information (unaudited)

In accordance with FASB Accounting Standards Codification "Extractive Activities - Oil and Gas" (Topic 932), Statoil is making certain supplemental disclosures about oil and gas exploration and production operations as previously required by Statement of Financial Accounting Standards No. 69 "Disclosures about Oil and Gas Producing Activities" (FAS 69). While this information is developed with reasonable care and disclosed in good faith, it is emphasised 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.

Financial Accounting Standard Board aligned in January 2010 the oil and gas reserves estimation and disclosure requirements of "Extractive Activities - Oil and Gas" (Topic 932) with the requirements in the U.S. Securities and Exchange Commission's final rule, "Modernization of the Oil and Gas Reporting Requirements" issued in December 2008. Our reporting in 2009 and 2010 are in accordance with the updated requirements. Disclosures at 31 December 2008 are not adjusted as retroactive adoption was not permitted. For further information regarding revision of the reserves estimation requirement, see note 2 *Significant accounting policies* - Critical judgement and key sources of estimation uncertainty - Proved oil and gas reserves.

No events have occurred since 31 December 2010 that would mean a significant change in the estimated proved reserves or other figures reported as of that date.

The subtotals and totals in some of the tables may not equal the sum of the amounts shown due to rounding.

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 U.S. Securities and Exchange Commission (SEC), Rule 4-10 of Regulation S-X. 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. 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.

Statoil's proved reserves are recognized under various forms of contractual agreements including production sharing agreements (PSAs) where Statoil's share of reserves can vary due to commodity prices or other factors. Reserves from agreements such as PSAs are based on the volumes to which Statoil has access (cost oil and profit oil), limited to available market access. At 31 December 2010, 12% of total proved reserves were related to such agreements (22% of oil and NGL and 5% of gas). This compares with 11% and 12% of total proved reserves for 2009 and 2008 respectively. Net cumulative oil and gas production from fields with such agreements was 84 million boe during 2010 (98 million boe for 2009 and 82 million boe for 2008). Statoil participates in such agreements in Algeria, Angola, Azerbaijan, Iran, Iraq, Libya, Nigeria and Russia.

Statoil is recording, as proved reserves, volumes equivalent to our tax liabilities under negotiated fiscal arrangements (PSAs) where the tax is paid on behalf of Statoil.

Rule 4-10 of Regulation S-X requires that the appraisal of reserves is based on existing economical conditions including a 12-month average price prior to the end of the reporting period, unless prices are defined by contractual arrangements. Oil reserves at year-end 2010 have been determined based on a 12-month average 2010 Brent price equivalent to USD 79.02/bbl. The increase in oil price from 2009 when the average Brent blend price was USD 59.91/bbl has increased the profitable oil to be recovered from the accumulations while Statoil's proved oil reserves under PSAs and similar contracts have as a result decreased. Gas reserves at year end 2010 has been determined based on achieved gas prices during 2010 giving a volume weighted average gas price of 1.7 NOK/Sm3. The average gas prices achieved have in general decreased from 2009 to 2010 and have affected the profitable gas reserves to be recovered accordingly. These changes are included in the revision category in the tables below.

From the Norwegian continental shelf (NCS) Statoil is required, on behalf of the Norwegian State's direct financial interest (SDFI), to manage, transport and sell the Norwegian State's oil and gas. These reserves are sold in conjunction with our own reserves. As part of this arrangement, Statoil will deliver gas to customers in accordance with various types of sales contracts. In order to fulfil the commitments, Statoil will utilise a field supply schedule which provides the highest possible total value for the joint portfolio of oil and gas between Statoil and SDFI.

Statoil and SDFI receive income from the joint natural gas sales portfolio based upon their respective share in the supply volumes. For sales of the SDFI natural gas, both to Statoil and to third parties, the payment to the Norwegian State is based on either achieved prices, a net back formula calculated price or market value. All of the Norwegian State's oil and NGL is acquired by Statoil. Pricing of the crude oil is based on market reflective prices. NGL prices are either based on achieved prices, market value or market reflective prices.

The owner's instruction, as described above, may be changed or withdrawn by the Statoil general meeting. Due to this uncertainty and the Norwegian State's estimate of proved reserves not being available to Statoil, it is not possible to determine the total quantities to be purchased by Statoil under the owner's instruction from properties in which it participates in the operations.

Topic 932 requires the presentation of reserves and certain other supplemental oil and gas disclosures by geographical area, defined as country or continent containing 15% or more of total proved reserves. Norway contains 78% of total proved reserves at 31 December 2010 and no other country or continent contains reserves approaching 15% of total proved reserves. Accordingly, management has determined that the most meaningful presentation of geographical areas would be to include Norway and the continents of Eurasia (excluding Norway), Africa and America.

Statoil announced during 2010 sale of 40% interests in the Peregrino field in Brazil and sale of 40% interest in the oil sand leases in Alberta, Canada. As of 31 December 2010 these sales had not been approved by the relevant authorities and therefore the reduction in reserves is not reflected in the 2010 proved reserves statement. The expected effect on 2011 proved reserves statement is approximately 66 million boe sales of reserves-in-place.

The following tables reflect the estimated proved reserves of oil and gas at 31 December 2007 to 2010, and the changes therein.

	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
Reserves in consolidated companies									
At 31 December 2007	1,604	785	2,389	18,893	1,426	20,319	4,971	1,039	6,010
Of which:									
Proved developed reserves	1,187	323	1,510	15,084	748	15,832	3,875	456	4,331
Revisions and improved recovery	81	95	177	7	141	148	83	120	203
Extensions and discoveries	12	-	12	29	-	29	17	-	17
Purchase of reserves-in-place	-	69	69	-	-	-	-	69	69
Sales of reserves-in-place	-	(3)	(3)	-	(43)	(43)	-	(10)	(10)
Transfer to equity accounted investment *	-	(191)	(191)	-	-	-	-	(191)	(191)
Production	(302)	(78)	(380)	(1,348)	(121)	(1,469)	(542)	(100)	(642)
At 31 December 2008	1,396	677	2,074	17,581	1,403	18,984	4,529	927	5,456
Of which:									
Proved developed reserves	1,113	381	1,494	14,482	727	15,209	3,693	510	4,204
Reserves in equity accounted investments									
Remaining reserves after transfer*	-	123	123	-	-	-	-	123	123
Revisions and improved recovery	-	11	11	-	-	-	-	11	11
Production	-	(6)	(6)	-	-	-	-	(6)	(6)
At 31 December 2008	-	127	127	-	-	-	-	127	127
Total Proved Reserves including reserves in equity accounted investments at 31 December 2008	1,396	805	2,201	17,581	1,403	18,984	4,529	1,055	5,584
Of which:									
Proved developed reserves	1,113	406	1,519	14,482	727	15,209	3,693	536	4,229

*Sincor to Petrocedeño; reduction from 15% to 9.677% interest

The transformation process of the Sincor joint venture in Venezuela, into the new mixed company Petrocedeño was finalised in February 2008 reducing Statoil's shareholding interest from 15.0% in the Sincor joint venture to 9.677% in Peterocedeño. The change in Statoil share resulted in a reduction of proved reserves corresponding to 68 million boe in 2008.

Statoil acquired Anadarco's 50.0% share in Peregrino, Brazil, in 2008 resulting in a 100% ownership of the asset, and becoming the operator. The related increase in proved reserves was 69 million boe.

	Norway	Eurasia excluding Norway	Africa	America	Total
			Net proved oil and NGL reserves in million barrels		
Reserves in consolidated companies					
At 31 December 2008	1,396	177	265	235	2,074
Revisions and improved recovery	195	(22)	64	6	243
Extensions and discoveries	39	6	44	45	134
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	(4)	-	-	(4)
Production	(279)	(19)	(63)	(15)	(376)
At 31 December 2009	1,351	138	310	272	2,070
Revisions and improved recovery	100	(7)	31	(2)	123
Extensions and discoveries	46	56	25	47	174
Purchase of reserves-in-place	-	-	-	1	1
Sales of reserves-in-place	-	-	-	-	-
Production	(256)	(18)	(53)	(21)	(348)
At 31 December 2010	1,241	170	313	297	2,020
Reserves in equity accounted investments					
At 31 December 2008	-	-	-	127	127
Revisions and improved recovery	-	-	-	(18)	(18)
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(5)	(5)
At 31 December 2009	-	-	-	105	105
Revisions and improved recovery	-	-	-	1	1
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	3	3
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(5)	(5)
At 31 December 2010	-	-	-	104	104
Total Proved Oil and NGL Reserves including reserves in equity accounted investments at 31 December 2009	1,351	138	310	376	2,174
Total Proved Oil and NGL Reserves including reserves in equity accounted investments at 31 December 2010	1,241	170	313	400	2,124

Statoil's proved reserves of bitumen in America, representing less than 3% of our proved reserves, is included as oil in the table above.

	Norway	Eurasia excluding Norway	Africa	America	Total
			Net proved gas reserves in billion standard cubic feet		
Reserves in consolidated companies					
At 31 December 2008	17,581	827	481	95	18,984
Revisions and improved recovery	690	(31)	(89)	(9)	561
Extensions and discoveries	35	-	-	87	122
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	(1,367)	(49)	(54)	(48)	(1,519)
At 31 December 2009	16,938	747	338	125	18,148
Revisions and improved recovery	394	(62)	(4)	4	332
Extensions and discoveries	381	-	227	340	948
Purchase of reserves-in-place	-	-	-	25	25
Sales of reserves-in-place	-	-	-	-	-
Production	(1,370)	(51)	(41)	(47)	(1,509)
At 31 December 2010	16,343	634	521	446	17,945
Reserves in equity accounted investments					
At 31 December 2008	-	-	-	-	-
Revisions and improved recovery	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	-	-
At 31 December 2009	-	-	-	-	-
Revisions and improved recovery	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	20	20
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(0)	(0)
At 31 December 2010	-	-	-	20	20
Total Proved Gas Reserves including reserves in equity accounted investments at 31 December 2009	16,938	747	338	125	18,148
Total Proved Gas Reserves including reserves in equity accounted investments at 31 December 2010	16,343	634	521	466	17,965

	Norway	Eurasia excluding Norway	Africa	America	Total
	Net proved oil, NGL and gas reserves in million barrels oil equivalent				
Reserves in consolidated companies					
At 31 December 2008	4,529	324	351	252	5,456
Revisions and improved recovery	318	(28)	48	5	343
Extensions and discoveries	45	6	44	60	155
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	(4)	-	-	(4)
Production	(523)	(28)	(73)	(24)	(647)
At 31 December 2009	4,369	271	370	294	5,304
Revisions and improved recovery	170	(18)	30	(1)	182
Extensions and discoveries	114	56	65	108	343
Purchase of reserves-in-place	-	-	-	5	5
Sales of reserves-in-place	-	-	-	-	-
Production	(500)	(27)	(60)	(29)	(617)
At 31 December 2010	4,153	283	406	376	5,218
Reserves in equity accounted investments					
At 31 December 2008	-	-	-	127	127
Revisions and improved recovery	-	-	-	(18)	(18)
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(5)	(5)
At 31 December 2009	-	-	-	105	105
Revisions and improved recovery	-	-	-	1	1
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	6	6
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(5)	(5)
At 31 December 2010	-	-	-	107	107
Total Proved Reserves including reserves in equity accounted investments at 31 December 2009	4,369	271	370	398	5,408
Total Proved Reserves including reserves in equity accounted investments at 31 December 2010	4,153	283	406	483	5,325

Statoil's proved reserves of bitumen in America, representing less than 3% of our proved reserves, is included as oil in the table above.

	Norway	Eurasia excluding Norway	Africa	America	Total
Proved developed oil and NGL reserves in million barrels					
At 31 December 2009					
Consolidated companies	1,028	94	208	83	1,413
Equity accounted investments	-	-	-	28	28
At 31 December 2010					
Consolidated companies	950	99	192	81	1,321
Equity accounted investments	-	-	-	36	36
Proved developed gas reserves in billion standard cubic feet					
At 31 December 2009					
Consolidated companies	14,138	523	256	73	14,990
Equity accounted investments	-	-	-	-	-
At 31 December 2010					
Consolidated companies	13,721	421	221	329	14,691
Equity accounted investments	-	-	-	7	7
Proved developed oil, NGL and gas reserves in million barrels oil equivalent					
At 31 December 2009					
Consolidated companies	3,548	187	254	96	4,084
Equity accounted investments	-	-	-	28	28
At 31 December 2010					
Consolidated companies	3,394	174	231	139	3,939
Equity accounted investments	-	-	-	37	37

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 (boe) and 1,000 standard cubic meter gas = 1 standard cubic meter oil equivalent.

Capitalised cost related to Oil and Gas production activities

Consolidated companies

(in NOK million)	At 31 December 2010	2009
Unproved Properties	34,873	49,497
Proved Properties, wells, plants and other equipment	703,885	655,886
Total Capitalised cost	738,758	705,383
Accumulated depreciation, depletion, amortisation and valuation allowances	(419,920)	(379,575)
Net Capitalised cost	318,838	325,808

Net capitalised cost related to equity accounted investments as of 31 December 2010 was NOK 7.5 billion, and NOK 3.7 billion in 2009.
In addition capitalised cost related to Oil and Gas production activities classified as Held for Sale amounts to NOK 44.9 billion as of 31 December 2010.

Expenditures incurred in Oil and Gas Property Acquisition, Exploration and Development Activities
These expenditures include both amounts capitalised and expensed for 2010 and 2009.

Consolidated companies

(in NOK million)	Norway	Eurasia excluding Norway	Africa	America	Total
Year ended 31 December 2010					
Exploration expenditures	5,974	1,647	1,987	7,195	16,803
Development costs 1)	29,284	2,531	11,262	10,439	53,516
Acquired proved properties	0	0	0	48	48
Acquired unproved properties	31	1,046	0	5,804	6,881
Total	35,289	5,224	13,249	23,486	77,248
Year ended 31 December 2009					
Exploration expenditures	8,170	1,310	2,465	4,950	16,895
Development costs 1)	30,704	3,611	10,627	11,958	56,900
Acquired unproved properties	0	0	12	1,313	1,325
Total	38,874	4,921	13,104	18,221	75,120

These expenditures include both amounts capitalised and expensed in 2008.

Consolidated companies

(in NOK million)	Norway	Outside Norway	Total
Year ended 31 December 2008			
Exploration expenditures	8,672	9,136	17,808
Development costs [1]	29,478	14,215	43,693
Acquired proved properties [2]	0	12,435	12,435
Acquired unproved properties [3]	1,255	12,323	13,578
Total	39,405	48,109	87,514

(1) Includes minor development costs in unproved properties.
(2) Includes the acquisition of Anadarco's 50% share in Peregrino, Brazil.
(3) Includes signature bonuses and the acquisition of a share in Goliat and Marcellus shale gas development.

Expenditures incurred in Oil and Gas Development Activities related to equity accounted investments in 2010 was NOK 4 365 million, NOK 286 million in 2009 and NOK 448 million in 2008.

Results of Operation for Oil and Gas Producing Activities
As required by Topic 932, 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 *Segments* to the financial statements but excluded from the table below relates to gas trading activities, commodity based derivatives, transportation, 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.

Consolidated companies

(in NOK million)	Norway	Eurasia excluding Norway	Africa	America	Total
Year ended December 2010					
Sales	1	2,706	2,526	713	5,946
Transfers	166,219	6,871	24,232	10,656	207,978
Total revenues	166,220	9,577	26,758	11,369	213,924
Exploration expenses	(5,497)	(1,448)	(2,033)	(6,795)	(15,773)
Production costs	(21,372)	(1,297)	(3,165)	(4,071)	(29,905)
Depreciation, amortisation and impairment losses	(25,731)	(4,099)	(7,503)	(5,034)	(42,367)
Total costs	(52,600)	(6,844)	(12,701)	(15,900)	(88,045)
Results of operations before tax	113,620	2,733	14,057	(4,531)	125,879
Tax expense	(82,226)	(755)	(6,868)	969	(88,880)
Result of operations	31,394	1,978	7,189	(3,562)	36,998
Year ended December 2009					
Sales	5	2,968	7,950	689	11,612
Transfers	154,440	5,320	16,877	6,085	182,722
Total revenues	154,445	8,288	24,827	6,774	194,334
Exploration expenses	(5,187)	(1,047)	(2,238)	(8,218)	(16,690)
Production costs	(19,395)	(1,440)	(3,432)	(1,768)	(26,035)
Depreciation, amortisation and impairment losses	(25,566)	(2,464)	(9,721)	(4,902)	(42,653)
Total costs	(50,148)	(4,951)	(15,391)	(14,888)	(85,378)
Results of operations before tax	104,297	3,337	9,436	(8,114)	108,956
Tax expense	(75,690)	(102)	(3,182)	1,684	(77,290)
Result of operations	28,607	3,235	6,254	(6,430)	31,666

(in NOK million)	Norway	Outside Norway	Total
Year ended December 2008			
Sales	151	8,274	8,425
Transfers	216,809	34,718	251,527
Total revenues	216,960	42,992	259,952
Exploration expense	(5,536)	(9,157)	(14,693)
Production costs	(19,744)	(6,009)	(25,753)
Depreciation, depletion and amortisation (DD&A)	(24,043)	(13,689)	(37,732)
Total costs	(49,323)	(28,855)	(78,178)
Results of operations before tax	167,637	14,137	181,774
Tax expense	(124,564)	(9,710)	(134,274)
Result of operations	43,073	4,427	47,500

The results of operations for oil and gas producing activities of equity method investments outside of Norway amounts to NOK 119 million in the year ended December 2010, NOK 26 million in the year ended December 2009 and NOK 428 million in the year ended December 2008.

Standardised measure of discounted future net cash flows relating to proved oil and gas reserves

The table below shows the standardised measure of future net cash flows relating to proved reserves. The analysis is computed in accordance with Topic 932, by applying average market prices for 2009 and 2010 and year end market prices for 2008 as defined by the SEC, year end costs, year end statutory tax rates, and a discount factor of 10% to year end quantities of net proved reserves. The standardised measure of discounted future net cash flows 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. Pre-tax future net cash flow is net of decommissioning and removal costs. Estimated future income taxes are calculated by applying the 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 a discount rate of 10% per year. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced. The standardised measure of discounted future net cash flows prescribed under Topic 932 requires assumptions as to the timing and amount of future development and production costs and income from the production of proved reserves. The information does not represent management's estimate or Statoil's expected future cash flows or the value of its proved reserves and therefore should not be relied upon as an indication of Statoil's future cash flow or value of its proved reserves.

Statoil announced during 2010 sale of 40% interests in the Peregrino field in Brazil and sales of 40% interest in the oil sand leases in Alberta, Canada. As of 31 December 2010 these sales had not been approved by the relevant authorities and therefore the reduction of standardized measure is not reflected in the 2010 discounted future net cash flows. Based on this year's economic assumptions, the expected effect on 2011 discounted future net cash flows is a reduction of approximately NOK 8.4 billion.

(in NOK million)	Norway	Eurasia excluding Norway	Africa	America	Total
At 31 December 2010					
Consolidated companies					
Future net cash inflows	1,353,424	99,326	163,551	143,202	1,759,503
Future development costs	(139,961)	(23,457)	(29,041)	(18,150)	(210,609)
Future production costs	(440,344)	(30,608)	(51,363)	(61,656)	(583,971)
Future income tax expenses	(567,513)	(6,773)	(30,296)	(17,282)	(621,864)
Future net cash flows	205,606	38,488	52,851	46,114	343,059
10 % annual discount for estimated timing of cash flows	(86,668)	(16,096)	(21,596)	(16,423)	(140,783)
Standardised measure of discounted future net cash flows	118,938	22,392	31,255	29,691	202,276
Equity accounted investments					
Standardised measure of discounted future net cash flows	0	0	0	3,880	3,880
Total standardised measure of discounted future net cash flows including equity accounted investments	118,938	22,392	31,255	33,571	206,156
At 31 December 2009					
Consolidated companies					
Future net cash inflows	1,387,084	66,055	113,642	90,548	1,657,329
Future development costs	(118,505)	(12,362)	(22,047)	(12,095)	(165,009)
Future production costs	(437,396)	(22,806)	(33,665)	(42,932)	(536,799)
Future income tax expenses	(624,221)	(3,033)	(21,199)	(7,642)	(656,095)
Future net cash flows	206,962	27,854	36,731	27,879	299,426
10 % annual discount for estimated timing of cash flows	(94,462)	(11,806)	(11,479)	(7,537)	(125,284)
Standardised measure of discounted future net cash flows	112,500	16,048	25,252	20,342	174,142
Equity accounted investments					
Standardised measure of discounted future net cash flows	0	0	0	2,097	2,097
Total standardised measure of discounted future net cash flows including equity accounted investments	112,500	16,048	25,252	22,439	176,239

(in NOK million)	Norway	Outside Norway	Total
At 31 December 2008			
Consolidated companies			
Future net cash inflows	1,738,693	204,808	1,943,501
Future development costs	(109,456)	(44,920)	(154,376)
Future production costs	(412,340)	(77,398)	(489,738)
Future income tax expenses	(919,740)	(30,118)	(949,858)
Future net cash flows	297,157	52,372	349,529
10 % annual discount for estimated timing of cash flows	(150,919)	(15,019)	(165,938)
Standardised measure of discounted future net cash flows	146,238	37,353	183,591
Equity accounted investments			
Standardised measure of discounted future net cash flows	0	2,024	2,024
Total standardised measure of discounted future net cash flows including equity accounted investments	146,238	39,377	185,615

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

(in NOK million)	2010	2009	2008
Consolidated companies			
Standardised measure at beginning of year	174,142	183,591	300,770
Net change in sales and transfer prices and in production (lifting) costs related to future production	130,402	(288,973)	(74,453)
Changes in estimated future development costs	(53,006)	(48,980)	(56,924)
Sales and transfers of oil and gas produced during the period, net of production cost	(194,954)	(179,072)	(234,199)
Net change due to extensions, discoveries, and improved recovery	11,447	9,403	1,866
Net change due to purchases and sales of minerals in place	(42)	(530)	(4,936)
Net change due to revisions in quantity estimates	47,285	101,298	51,574
Previously estimated development costs incurred during the period	53,516	56,900	56,128
Accretion of discount	32,859	214,065	50,960
Net change in income taxes	627	126,440	92,805
Total change in the standardised measure during the year	28,134	(9,449)	(117,179)
Standardised measure at end of year	202,276	174,142	183,591
Equity accounted investments			
Standardised measure at end of year	3,880	2,097	2,024
Standardised measure at end of year including equity accounted investments	206,156	176,239	185,615

8.2 Report of independent registered public accounting firms

8.2.1 Report of Independent Registered Public Accounting firm

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Statoil ASA

We have audited the accompanying consolidated balance sheets of Statoil ASA as of 31 December 2010 and 2009, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended 31 December 2010. 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 the standards of the Public Company Accounting Oversight Board (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 misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. 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 at 31 December 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended 31 December 2010, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board and International Financial Reporting Standards as adopted by the European Union.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Statoil ASA's internal control over financial reporting as of 31 December 2010, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated 14 March 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young AS

Stavanger, Norway
14 March 2011

8.2.2 Report of Ernst & Young AS on Statoil's internal control over financial reporting

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Statoil ASA

We have audited Statoil ASA's internal control over financial reporting as of 31 December 2010, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Statoil ASA's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's report on internal control over financial reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Statoil ASA maintained, in all material respects, effective internal control over financial reporting as of 31 December 2010, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Statoil ASA as of 31 December 2010 and 2009 and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended 31 December 2010 of Statoil ASA and our report dated 14 March 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young AS

Stavanger,Norway
14 March 2011

9 Terms and definitions

An overview of organisational abbreviations.

- ACG - Azeri-Chirag-Gunashli
- ACQ - Annual Contract Quantity
- AFP - Agreement-based Early Retirement Plan
- AnLNG - Angola LNG
- ÅTS - Åsgard Transport System
- APA - Awards in Predefined Areas
- BTC - Pipeline Baku-Tbilisi-Ceyhan
- CCS - Carbon Capture and Storage
- CEPF - Corporate Exploration and Production Forecasting
- CHP - Combined heat and power plant
- CO_2 - Carbon Dioxide
- E&P - Exploration & Production
- EEA - European Economic Agreement
- EFTA - European Free Trade Association
- EMTN - Euro Medium Term Note
- EPN - Exploration & Production Norway Business Area
- FCC - Fluid Catalytic Cracking
- FEED - Frond end engineering design
- FID - Final investment decision
- FPSO - Floating Production Storage Offloading
- FTWT - Formation-testing-while-tripping tool
- GBS - Gravity-Based Structure
- GDP - Gross Domestic Product
- GoM - Gulf of Mexico
- HSE - Health, Safety, Environment
- HTHP - High-temperature/high pressure
- IASB - International Accounting Standards Board
- IEA - International Energy Agency
- IFRS - International Financial Reporting Standards
- INT - International Exploration & Production business area
- IO - Integrated Operations
- IOR - Improved Oil Recovery
- KEP2010 - Kårstø Upgrading Project
- LNG - Liquefied Natural Gas
- LPG - Liquefied Petroleum Gas
- M&M - Manufacturing and Marketing business area
- MPE - Norwegian Ministry of Petroleum and Energy
- NAOSC - North American Oil Sands Corporation
- NCS - Norwegian Continental Shelf
- NG - Natural Gas Business Area
- NGO - Non Governmental Organization
- NIOC - National Iranian Oil Company
- NOC - National Oil Companies
- NOK - Norwegian Kroner
- NO_x- Nitrogen Oxide
- OECD - Organisation of Economic Co-Operation and Development
- OTC - Over the Counter
- OTS - Oil Trading and Supply Department
- PBO - Project Benefit Obligation
- PDO - Plan for Development and Operation
- PRO - Projects Business Area
- PSA - Production Sharing Agreement
- R&D - Research and Development
- ROACE - Return on Average Capital Employed

- SAGD - Steam Assisted Gravity Drainage
- SCP - South Caucasus Pipeline System
- SDAG - Shtokman Development AG
- SDFI - Norwegian State's Direct Financial Interest
- SDL - Significant discovery licence
- SFR - Statoil Fuel & Retail ASA
- SO_2 - Sulphur Dioxide
- SORIE - Statement of Recognised Income and Expense
- TAP - Trans Adriatic Pipeline
- TNE - Technology & New energy Functional Area
- TSP - Technical Service Provider
- UKCS - UK Continental Shelf
- USD - United States Dollar

Metric abbreviations etc:
- bbl - barrel
- mbbl - thousand barrels
- mmbbl - million barrels
- boe - barrels-of-oil equivalent
- mboe - thousand barrels-of-oil equivalent
- mmboe - million barrels-of-oil equivalent
- mmcf - million cubic feet
- bcf - billion cubic feet
- tcf - trillion cubic feet
- scm - standard cubic metre
- mcm - thousand cubic metres
- mmcm - million cubic metres
- bcm - billion cubic metres
- mmtpa - million tonnes per annum
- km - kilometre
- ppm - part per million
- one billion - 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 metres
- 1 barrel of oil equivalent equals 1 barrel of crude oil
- 1 barrel of oil equivalent equals 159 standard cubic metres of natural gas
- 1 barrel of oil equivalent equals 5,612 cubic feet of natural gas
- 1 barrel of oil equivalent equals 0.0837 tonnes of NGLs
- 1 billion standard cubic metres of natural gas equals 1 million standard cubic metres of oil equivalent
- 1 cubic metre equals 35.3 cubic feet
- 1 kilometre equals 0.62 miles
- 1 square kilometre equals 0.39 square miles
- 1 square kilometre equals 247.105 acres
- 1 cubic metre of natural gas equals one standard cubic metre of natural gas
- 1,000 standard cubic meter gas equals 1 standard cubic meter oil equivalent
- 1,000 standard cubic metres of natural gas equals 6.29 boe
- 1 standard cubic foot equals 0.0283 standard cubic metres
- 1 standard cubic foot equals 1000 British thermal units (btu)
- 1 tonne of NGLs equals 1.9 standard cubic metres of oil equivalents
- 1 degree Celsius equals minus 32 plus five-ninths of the number of degrees Fahrenheit

Miscellaneous terms:
- Appraisal well: A well drilled to establish the extent and the size of a discovery.
- Biofuel: A solid, liquid or gaseous fuel derived from relatively recently dead biological material and is distinguished from fossil fuels, which are derived from long dead biological material.
- BOE: Barrels of oil-equivalent A measure to quantify crude oil, natural gas liquids and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content.
- Carbon footprint: Total set of greenhouse gas emissions caused directly and indirectly by an individual, organization, event or product.
- Clastic reservoir systems: The integrated static and dynamic characteristics of a hydrocarbon reservoir formed by clastic rocks of a specific depositional sedimentary succession and its seal.

- Condensates: 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
- Development: The drilling, construction, and related activities following discovery that are necessary to begin production of crude oil and natural gas fields.
- Downstream: The selling and distribution of products derived from upstream activties.
- Equity and entitlement volumes of oil and gas: Equity volumes represent volumes produced under a Production Sharing Agreement (PSA) that correspond to Statoil's percentage ownership in a particular field. Entitlement volumes, on the other hand, represent Statoil's share of the volumes distributed to the partners in the field, which are subject to deductions for, among other things, royalties and the host government's share of profit oil. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes, whereas it is not applicable in most concessionary regimes such as those in Norway, the UK, Canada and Brazil. The overview of equity production provides additional information for readers, as certain costs described in the profit and loss analysis were directly associated with equity volumes produced during the reported years.
- FCC: Fluid catalytic cracking A process used to convert the high-boiling hydrocarbon fractions of petroleum crude oils to more valuable gasoline, gases and other products.
- GTL: Gas to liquids, means the technology used for chemical conversion of natural gas into transportable liquids (diesel and naphtha) and specialty products (base oils).
- Heavy Oil: Crude oil with high viscosity (typically above 10 cp), and high specific gravity. The API classifies heavy oil as crudes with a gravity below 22.3° API. In addition to high viscosity and high specific gravity, heavy oils typically have low hydrogen-to-carbon ratios, high asphaltene, sulfur, nitrogen, and heavy-metal content, as well as higher acid numbers.
- High Grade: Relates to selectively harvesting goods, to cut the best and leave the rest. In reference to exploration and production this entails strict prioritisation and sequencing of drilling targets.
- Hydro: A reference to the oil and energy activities of Norsk Hydro ASA which merged with Statoil ASA.
- IOR: Increased oil recovery is used about actual measures resulting in an increased oil recovery factor from a reservoir as compared with the expected value at a certain reference point in time. IOR comprises both of conventional and emerging technologies.
- Liquids: Refers to oil, condensates and NGL.
- LNG: Liquefied Natural Gas, lean gas - primarily methane - converted to liquid form through refrigeration to minus 163 degrees Celsius under atmospheric pressures
- LPG: 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.
- Midstream: Processing, storage, and transport of crude oil, natural gas, natural gas liquids and sulphur.
- Naphtha is an inflammable oil obtained by the dry distillation of petroleum
- Natural gas: Petroleum that consists principally of light hydrocarbons. It can be divided into 1) lean gas, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and 2) wet gas, primarily ethane, propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure
- NGL: Natural gas liquids, light hydrocarbons mainly consisting of ethane, propane and butane which are liquid under pressure at normal temperature
- Oil sands: A naturally occurring mixture of bitumen, water, sand, and clay. A heavy viscous form of crude oil.
- Oil and gas value chains: Describes the value that is being added at each step from 1) exploring; 2) developing; 3) producing; 4) transportation and refining; and 5) marketing and distribution.
- Petroleum: A collective term for hydrocarbons, whether solid, liquid or gaseous. Hydrocarbons are compounds formed from the elements hydrogen (H) and carbon (C). The proportion of different compounds, from methane and ethane up to the heaviest components, in a petroleum find varies from discovery to discovery. If a reservoir primarily contains light hydrocarbons, it is described as a gas field. If heavier hydrocarbons predominate, it is described as an oil field. An oil field may feature free gas above the oil and contain a quantity of light hydrocarbons, also called associated gas.
- Proved reserves: Proved reserves are those reserves claimed to have a reasonable certainty (normally at least 90% confidence) of being recoverable under existing economic and political conditions, and using existing technology. They are the only type the U.S. Securities and Exchange Commission allows oil companies to report.
- Share turnover: Turnover of shares is a measure of stock liquidity calculated by dividing the total number of shares traded over a period by the average number of shares outstanding for the period. The higher the share turnover, the more liquid the share of the company.
- Syncrude: The output from bitumen extra heavy oil upgrader facility used in connection with oil sand production.
- Upstream: Includes the searching for potential underground or underwater oil and gas fields, drilling of exploratory wells, subsequent operating wells which bring the liquids and or natural gas to the surface.
- VOC: Volatile Organic Compounds, are organic chemical compounds that have high enough vapor pressures under normal conditions to significantly vaporise and enter the earth's atmosphere, e.g. gasses formed under loading and offloading of crude oil.
- Wildcat well: The first well to test a new, clearly defined geological unit (prospect).
- Økokrim: Prosecution of Economic and Environmental Crime in Norway.

10 Forward looking statements

This Annual Report on Form 20-F contains certain forward-looking statements that involve risks and uncertainties, in particular in the sections "Business overview" and "Operational review". In some cases, we use words such as "aim", "anticipate", "believe", "continue", "could", "estimate", "expect", "intend", "likely", "objective", "outlook", "may", "plan", "should", "target" and similar expressions to identify forward-looking statements. All statements other than statements of historical fact, including, among others, statements regarding future financial position, results of operations and cash flows; future financial ratios and information; future financial or operational portfolio or performance; future market position and conditions; business strategy; growth strategy; sales, trading and market strategies; research and development initiatives and strategy; market outlook and future economic projections and assumptions; competitive position; projected regularity and performance levels; effects of the Macondo oil spill and future drilling in the Gulf of Mexico; expectations related to our recent transactions and projects, such as our interest in the Marcellus and Eagle Ford shale gas developments and Peregrino field; completion and results of acquisitions, disposals and other contractual arrangements; reserve information; reserve replacement ratios; recovery factors and levels; future margins; projected returns; future levels or development of capacity, reserves or resources; future decline of mature fields; planned turnarounds and other maintenance; oil and gas production forecasts and reporting; growth, expectations and development of production, projects, pipelines or resources; estimates related to production and development levels and dates; operational expectations, estimates, schedules and costs; exploration and development activities, plans and expectations; projections and expectations for upstream and downstream activities; oil, gas, alternative fuel and energy prices and volatility; oil, gas, alternative fuel and energy supply and demand; renewable energy production, industry outlook and carbon capture and storage; new organisational structure and policies; planned responses to climate change; technological innovation, implementation, position and expectations; future energy efficiency; projected operational costs or savings; our ability to create or improve value; future sources of financing; exploration and project development expenditure; our goal of safe and efficient operations; effectiveness of our internal policies and plans; our ability to manage our risk exposure; our liquidity levels and management; estimated or future liabilities, obligations or expenses; expected impact of currency and interest rate fluctuations; expectations related to contractual or financial counterparties; capital expenditure estimates and expectations; projected outcome, impact or timing of HSE regulations; HSE goals and objectives of management for future operations; impact of PSA effects; projected impact or timing of administrative or governmental rules, standards, decisions, standards or laws (including taxation laws); plans for capital distribution and amounts of dividends 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 "Risk review", and in "Operational review", and elsewhere in this Annual Report on Form 20-F.

These forward-looking statements reflect current views about 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; the political and economic policies of Norway and other oil-producing countries; EU directives; general economic conditions; political stability and economic growth in relevant areas of the world; global political events and actions, including war, terrorism and sanctions; changes or uncertainty in or non-compliance with laws and governmental regulations; the timing of bringing new fields on stream; an inability to exploit growth opportunities; material differences from reserves estimates; unsuccessful drilling; an inability to find and develop reserves; ineffectiveness of crisis management systems; adverse changes in tax regimes; the development and use of new technology, particularly in the renewable energy sector; geological or technical difficulties; operational problems; operator error; inadequate insurance coverage; the lack of necessary transportation infrastructure when a field is in a remote location; the actions of competitors; the actions of field partners; the actions of the Norwegian state as majority shareholder; counterparty defaults; natural disasters and adverse weather conditions and other changes to business conditions; an inability to attract and retain personnel and other factors discussed elsewhere in this report.

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

11 Signature page

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/ Torgrim Reitan
Name: Torgrim Reitan
Title: Executive Vice President and Chief Financial Officer

Dated: 25 March 2011

12 Exhibits

The following exhibits are filed as part of this Annual Report:

Exhibit no	Description
Exhibit 1	Articles of Association of Statoil ASA, as amended, effective from 19 May 2010. (English translation).
Exhibit 4(a)(i)	Technical Services Agreement between Gassco AS and Statoil ASA, dated February 27, 2002 (incorporated by reference to Exhibit 4(a)(i) to Statoil's Annual Report and Form 20-F for the fiscal year ended December 31, 2001 (File No. 1-15200)).
Exhibit 4(c)	Employment agreement with Helge Lund (English translation) (incorporated by reference to Exhibit 4(c) to Statoil's Annual Report and Form 20-F for the fiscal year ended December 31, 2003 (File No. 1-15200)).
Exhibit 7	Calculation of ratio of earnings to fixed charges.
Exhibit 8	Subsidiaries (see Section 3.8.4 "Organisational Structure" included in this Annual Report).
Exhibit 12.1	Rule 13a-14(a) Certification of Chief Executive Officer.
Exhibit 12.2	Rule 13a-14(a) Certification of Chief Financial Officer.
Exhibit 13.1	Rule 13a-14(b) Certification of Chief Executive Officer.*
Exhibit 13.2	Rule 13a-14(b) Certification of Chief Financial Officer.*
Exhibit 15(a)(i)	Consent of Ernst & Young AS.
Exhibit 15(a)(ii)	Consent of DeGolyer and MacNaughton.
Exhibit 15(a)(iii)	Report of DeGolyer and MacNaughton.

* Furnished only

The total amount of long-term debt securities of the Registrant and its subsidiaries authorized under any one instrument does not exceed 10% of the total assets of Statoil ASA and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the Securities and Exchange Commission upon request.

13 Cross reference to Form 20-F

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