Year 2008			
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

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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).

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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 assumes 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.

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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.

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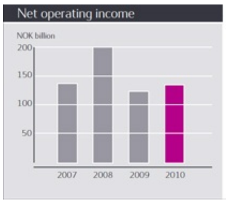
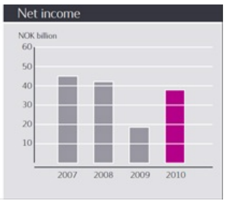
4.1 Operating and financial review 2010

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. new exploration licences EPN
new exploration licences INT 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.

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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.

	Year ended December 31,		
Sales Volumes	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.

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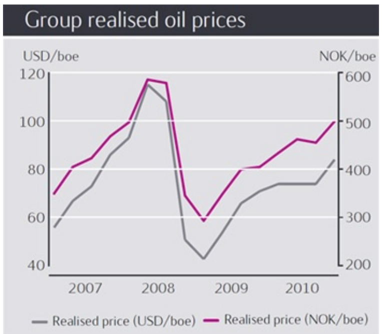
4.1.2 Group profit and loss analysis

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 (in NOK billion)	2010	Year ended 31 December 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	Year ended 31 December 2009	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.

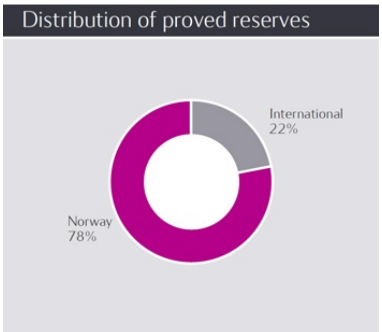


The NOK 64.1 billion increase in revenues from 2009 to 2010 was mainly attributable to higher prices for liquids and increased volumes of gas sold, partly offset by lower gas prices, reduced volumes of liquids sold and losses on derivatives.

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.

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.



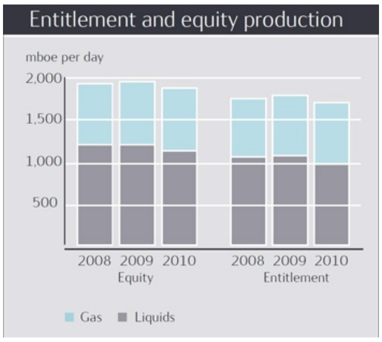
The average daily overlift was 1 mboe per day in 2010. In 2009, there was an average underlift of 21 mboe per day, while there was an average underlift of 37 mboe per day in 2008.

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.

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.

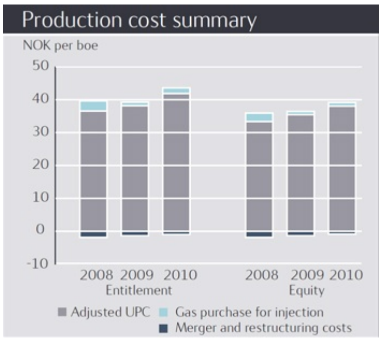
The 2% increase in equity production from 2008 to 2009 was primarily due to increased production from the start-up of new fields, ramp-up on existing fields, partly offset by declining production from mature fields, various operational issues and maintenance activities. Entitlement production increased 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.

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		Year ended 31 December			
(in NOK billion)	2010	2009	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.

	For the year ended 31 December				
Exploration (in NOK billion)	2010	2009	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.