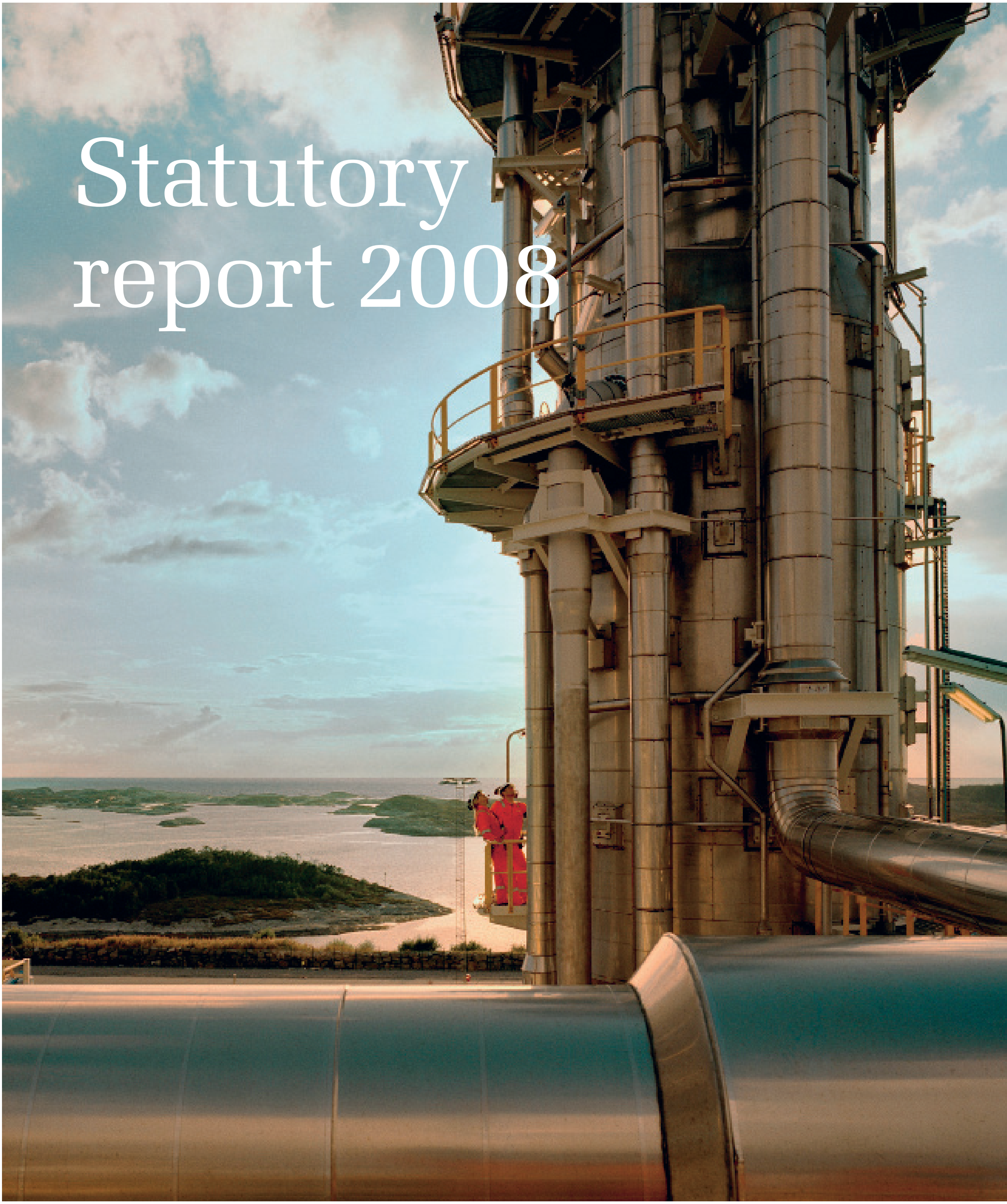
Statutory report 2008



StatoilHydro

Statutory report

Directors' report

StatoilHydro delivered strong operational performance in 2008, marked by record equity production, significant resource additions through exploration and solid financial results. In addition, we have delivered half of the identified merger synergies.

Our operating environment has changed dramatically during 2008. Comparatively low oil prices, combined with costs and investments at record high levels, are impacting cash flow and earnings. With a strong balance sheet and a flexible and robust portfolio, StatoilHydro is well positioned to manage through the global economic downturn, but we have to adapt to the new realities. We have made firm plans to respond to both upsides and downsides, and are prepared to act quickly to changing conditions. We aim to strike the right balance between retaining financial flexibility and building for the longer term.

A downturn also represents an opportunity for improvements. We seek to reduce our own costs, improve quality and processes and work with our suppliers to bring industry costs down to more sustainable levels. The ongoing integration and standardisation of operational activities is a key element in our improvement agenda.

Strong operational performance

In 2008, StatoilHydro increased total equity production by 5% to 1,925 mboe per day. Entitlement production increased by 2% to 1,751 mboe per day. Strong production and high prices contributed to a net operating income of NOK 198.8 billion in 2008, compared to NOK 137.2 billion in 2007.

The group delivered an extensive exploration programme in 2008. Of a total of 79 exploration wells completed before 31 December 2008, 40 were drilled outside the NCS. Thirty-five wells were declared as discoveries, of which eight are located outside the NCS. In 2008, 230 mmboe of proved reserves were added through revisions, extensions and discoveries, which resulted in a reserve replacement ratio of 34%. By comparison, an estimated 3.5 billion boe were added to overall resources through exploration and business development, preparing the ground for growing proved reserves in future periods.

StatoilHydro maintained a high activity level in maturing projects into production in 2008. Seven projects on the NCS and six international projects started production in 2008, while 13 new projects were sanctioned for development, of which four are outside Norway.

During 2008, the group gained access to 20 new exploration licences in the Gulf of Mexico, Alaska, Brazil, Canada and the Faroe Islands. The group was also granted access to 12 new licences on the NCS, as operator in nine and as partner in three. In addition, the group acquired a 15% interest in the Goliat field and a 10% interest in the Ragnarrock discovery on the NCS. In accordance with an agreement with Chesapeake Energy Corporation, StatoilHydro acquired a 32.5% interest in the Marcellus shale gas acreage in the USA. StatoilHydro also completed the purchase of the remaining 50% interest and became the operator of the Peregrino development offshore Brazil.

The StatoilHydro share

The Board of Directors proposes an ordinary dividend of NOK 4.40 per share for 2008 to the Annual General Meeting, as well as NOK 2.85 per share in special dividend, for a total of NOK 23.1 billion. Ordinary dividend for 2007 was NOK 4.20 per share, as well as NOK 4.30 per share in special dividend, for a total of NOK 27.1 billion in 2007.

The StatoilHydro share price development reflected the changing economic conditions through the year; peaking at an all time high of NOK 214.10 on 22 May 2008, but ending up with a drop from NOK 169.00 at the end of 2007 to NOK 113.90 at the end of 2008.

Group profit and loss analysis

Consolidated statements of income-IFRS (in NOK billion)	2008	Twelve months ended 31 December 2007	Change
Revenues and other income			
Revenues	**652.0**	521.7	25%
Net income (loss) from equity accounted investments	**1.3**	0.6	111%
Other income	**2.8**	0.5	428%
Total revenues and other income	**656.0**	522.8	25%
Operating expenses			
Purchase, net of inventory variation	**329.2**	260.4	26%
Operating expenses	**59.3**	60.3	(2%)
Selling, general and administrative expenses	**11.0**	14.2	(23%)
Depreciation, amortisation and impairment	**43.0**	39.4	9%
Exploration expenses	**14.7**	11.3	30%
Total operating expenses	**457.2**	385.6	19%
Net operating income	**198.8**	137.2	45%
Net financial items	**(18.4)**	9.6	(291%)
Income tax	**(137.2)**	(102.2)	(34%)
Net income	**43.3**	44.6	(3%)

Revenues and other income totalled NOK 656.0 billion in 2008, a NOK 133.2 billion increase from 2007. Most of the **revenues** derive from the sale of lifted crude oil, natural gas and refined products produced and marketed by StatoilHydro. StatoilHydro also markets and sells the Norwegian State's share of oil from the NCS. All purchases and sales of the Norwegian State's production are recorded as purchases net of inventory variations and sales.

From 2007 to 2008 realised prices of liquids measured in NOK increased by 29%. The increased prices of liquids contributed NOK 37.0 billion to the revenues, whereas the overall natural gas sales volumes contributed NOK 6.1 billion and the increase in prices of natural gas contributed NOK 29.2 billion to the change. This was partly offset by a decrease in liftings of liquids of NOK 9.0 billion.

The volumes of liquids lifted should over time correlate with the volumes produced. However, the volumes may be higher or lower than production in any period due to operational factors affecting the timing of when the group lifts the liquids from the fields. Entitlement volumes lifted is the basis for the revenue recognition while equity production volumes more directly affect operating costs. **Total liquids liftings** decreased from 1.081 mmboe per day in 2007 to 1.019 mmboe per day in 2008.

Total natural gas sales were 45.2 bcm in 2008 and 42.0 bcm in 2007. The 8% increase from 2007 to 2008 was mainly due to increased entitlement gas sales, but was partly offset by a net decrease in StatoilHydro's third party sales volumes. The increase in entitlement sales volumes mainly relates to higher production from the NCS in addition to the first full year of production from Shah Deniz in Azerbaijan.

Other income was NOK 2.8 billion in 2008 compared to NOK 0.5 billion in 2007. The income in 2008 and 2007 was mainly related to gain from sale of assets.

Purchase, net of inventory variation amounted to NOK 329.2 billion in 2008 compared to NOK 260.4 billion in 2007. The increase from 2007 to 2008 was mainly caused by higher prices of liquids measured in NOK.

Operating expenses were NOK 59.3 billion in 2008 compared to NOK 60.3 billion in 2007. The decrease was primarily due to restructuring costs related to the merger in 2007 and was only partly offset by increased costs related to start-up of new fields, higher activity and industry cost inflation in 2008.

Total equity production of oil and gas increased from 1.839 mboe per day in 2007 to 1.925 mboe per day in 2008. Total entitlement production increased from 1.724 mboe per day in 2007 to 1.751 mboe per day in 2008.

Production cost per boe of equity production was NOK 33.5 in 2008 and NOK 41.4 in 2007. The production cost per boe decreased significantly from 2007 to 2008 mainly due to non-recurring restructuring costs relating to the merger of Statoil ASA and Hydro Petroleum in 2007, but was partly offset by start-up of new fields, increased maintenance cost and general industry cost pressure. Adjusted for gas injection costs and restructuring costs and other costs arising from the merger, the production cost per boe of equity production was NOK 33.3 in 2008. The comparable figure for 2007 was NOK 31.2.

Selling, general and administrative expenses amounted to NOK 11.0 billion in 2008 compared to NOK 14.2 billion in 2007. The 23% decrease from 2007 to 2008 was mainly due to restructuring costs related to the merger in 2007 and was only partly offset by increased costs related to higher activity and industry cost inflation in 2008.

Depreciation, amortisation and impairment includes write-downs of impaired long-lived assets and amounted to NOK 43.0 billion in 2008, compared to NOK 39.4 billion in 2007.

The 9% increase in depreciation, amortisation and impairment expenses in 2008 compared to 2007 was due to impairment charges net of reversals of NOK 2.3 billion, mostly related to the US Gulf of Mexico, and an increase in production.

Exploration expenditures are capitalised to the extent the exploration efforts are considered successful, or pending such assessment. Otherwise, such expenditures are expensed. The exploration expense consists of the expensed portion of exploration expenditure in 2008 and write-offs of exploration expenditure capitalised in previous years. The exploration expense was NOK 14.7 billion in 2008 and NOK 11.3 billion in 2007.

The 30% increase in exploration expenses from 2007 to 2008 was mainly due to a higher number of wells drilled, generally more expensive wells, higher field evaluation costs and delineation of the oil sands project in Canada.

In 2008, a total of 79 exploration and appraisal wells and nine exploration extension wells were completed, 39 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 198.8 billion in 2008, compared to NOK 137.2 billion in 2007. The 45% increase from 2007 to 2008 was mainly due to higher realised prices on both liquids and natural gas, measured in NOK, and was only partly offset by increased operating expenses caused by a higher activity level and new, more expensive fields coming on stream.

In 2008, **Net financial items** amounted to a loss of NOK 18.4 billion, compared to a gain of NOK 9.6 billion in 2007.

The NOK 28.0 billion negative change from 2007 to 2008 was mostly attributable to NOK 32.6 billion in currency losses caused by a 29% weakening of NOK against USD in 2008 compared to a NOK 10.0 billion gain from a 14% strengthening of the NOK against the USD in 2007. The negative impact of currency exchange losses was partly offset by a NOK 9.9 billion increase in interest income and other financial items and a NOK 4.7 billion decrease in interest and other financial expenses.

In 2008 **income taxes** were NOK 137.2 billion, equivalent to a tax rate of 76.0%, compared to NOK 102.2 billion equivalent to a tax rate of 69.6% in 2007.

The increase in the tax rate in 2008 was mainly related to the net loss on financial items which is tax deductible at a lower tax rate than the average rate. In addition, the tax rate was increased by the deferred tax expense caused by currency effects in certain group companies which are taxable in a different currency than the functional currency. This was partly offset by the tax effect of a proportionally higher operating income being subject to a lower than average tax rate.

Net income was NOK 43.3 billion in 2008, compared to NOK 44.6 billion in 2007. The decrease was mainly due to a loss on financial items, high income taxes and increased operating expenses, and was only partly offset by higher prices on both liquids and natural gas, measured in NOK.

The Board of Directors proposes to the Annual General Meeting an **ordinary dividend** of NOK 4.40 per share for 2008, as well as NOK 2.85 per share in special dividend, making an aggregate total of NOK 23.1 billion. The remaining net income in the parent company will be allocated to reserve for valuation variances and retained earnings with NOK 18.6 billion and NOK (1.1) billion, respectively. The Company's distributable equity after allocations amounts to NOK 97.1 billion.

In accordance with Section 3-3 of the Norwegian Accounting Act, the Board of Directors confirms that the financial statements have been prepared on the basis of the **going concern** assumption.

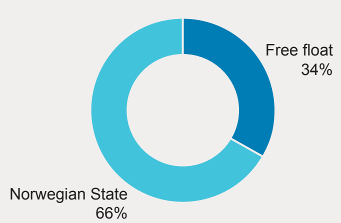
Our business

StatoilHydro is an integrated international energy company primarily focused on upstream oil and gas, has its business address in Stavanger (Norway) and is represented in 42 countries worldwide.

StatoilHydro is the leading operator on the Norwegian Continental Shelf and is experiencing strong growth in international production.

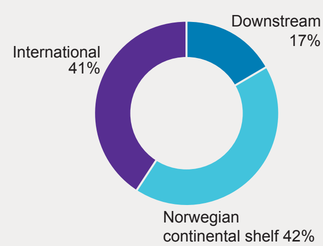
StatoilHydro ASA is a public limited company organised under the laws of Norway. The largest offices are in Stavanger, Bergen and Oslo, and the Group had approximately 29,500 employees as of 31 December 2008.

OWNERSHIP STRUCTURE *

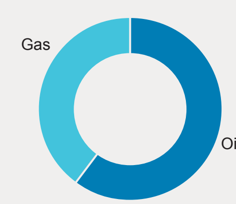


*As per 31 December 2008

FIXED ASSETS



OIL AND GAS*



*Entitlement production

The combined exploration and development business in Norway and internationally had an average equity liquids and natural gas production of 1.925 mmboe per day, and as of 31 December 2008, StatoilHydro had proved reserves of 2,201 mmbbl of oil and 537.8 bcm of natural gas, corresponding to aggregate proved reserves of 5,584 mmboe.

StatoilHydro ranks among the world's largest net sellers of crude oil and condensate and is the second largest supplier of natural gas to the European market. We have also substantial processing and refining activities and have approximately 2300 service stations in Scandinavia, Poland, the Baltic States and Russia.

StatoilHydro is contributing to developing new energy resources, and have ongoing activities in the fields of wind power, biofuels and is at the forefront in implementing 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 waters, heavy oil, harsh environments and gas value chains in order to exploit new opportunities and execute high quality projects.

The StatoilHydro group and our main business and functional areas are presented below:

Exploration & Production Norway is responsible for StatoilHydro's exploration, field development and production operations on the Norwegian Continental Shelf (NCS). The strategy focuses on safe, efficient and reliable operations and capturing of the full potential of NCS resources. The business area had 7964 employees as of 31 December 2008.

International Exploration & Production is responsible for exploration, development and production of oil and gas outside the NCS. The business area is expected to provide a major part of StatoilHydro's future production growth. The business area had 1567 employees as of 31 December 2008.

The Natural Gas business area is responsible for StatoilHydro's transportation, processing and marketing of pipelined gas and LNG worldwide, including the development of additional processing, transportation and storage capacity. The business area had 1274 employees as of 31 December 2008.

Manufacturing & Marketing is responsible for the processing and sale of our production of crude oil and natural gas liquids (NGL), and the retailing of refined products. The business area also markets and sells the Norwegian State's volumes of crude and NGL. The business area had 12,604 employees as of 31 December 2008.

Technology & New Energy is responsible for the development of technology and renewable energy contributing to global business success. The business support area had 2494 employees as of 31 December 2008.

Projects is responsible for planning and executing all development and modification projects exceeding NOK 50 million, as well as for contributing to safe and efficient operations in connection with such projects. The business support area had 1029 employees as of 31 December 2008.

Cash flows

Cash flows from operating activities

StatoilHydro's primary source of cash flow consists of funds generated from operations. Cash flows provided by operating activities were NOK 102.5 billion in 2008, compared to NOK 93.9 billion in 2007. The NOK 8.6 billion increase was due to an increase in cash flows from underlying operations of NOK 44.1 billion and cash flows from other non-current items related to operating activities of NOK 5.9 billion. These effects were partly offset by an increase in taxes paid of NOK 37.2 billion and negative cash flows from changes in working capital of NOK 4.3 billion.

Cash flows used in investing activities

Cash flows used in investing activities were NOK 85.8 billion in 2008, compared to NOK 75.1 billion in 2007. The NOK 10.7 billion increase is mostly related to the NOK 13.1 billion in payments related to recent acquisitions, NOK 3.6 billion in increased investments in other intangible assets and NOK 2.3 billion in increased capitalisation of exploration expenditures, partly offset by NOK 5.3 billion worth of lower investments in property, plant and equipment and NOK 4.3 billion in higher proceeds from sales of assets. Approximately 50% of the investments in 2008 were investments in assets expected to contribute to growth in oil and gas production, while approximately 35% related to investments in currently producing fields, and the remaining 15% represented investments in StatoilHydro's other activities.

Cash flows used in financing activities

Net cash flows used in financing activities in 2008 amounted to NOK 17.0 billion, compared to NOK 7.9 billion in 2007. The NOK 9.1 billion increase was mainly related to a decrease of the demerger balance with Norsk Hydro of NOK 18.7 billion in combination with increased dividend paid of NOK 1.4 billion. These effects were partly offset by increased financial liabilities of NOK 10.5 billion in 2008, mainly related to collateral and commercial papers.

Liquidity and capital resources

Liquidity

Annual cash flows from operations is highly dependent on oil and gas prices and levels of production, and it is only influenced to a small degree by seasonality and maintenance turnarounds. Fluctuations in oil and gas prices, which are outside StatoilHydro's control, will cause changes in its cash flows. Available liquidity will be used to finance investments, dividend payment and Norwegian petroleum tax payments (due on 1 February, 1 April, 1 June, 1 October and 1 December each year). The 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. StatoilHydro intends to keep ratios relating to net debt at levels consistent with its objective of maintaining its long-term credit rating at least within the single A category. In this context StatoilHydro carries out different risk assessments, some of them in line with financial matrixes used by S&P and Moody's, such as free cash flow from operations over net debt and net debt to capital employed.

StatoilHydro's long-term rating from Moody's is Aa2. The long-term rating from Standard & Poor's was raised to AA- in August 2007, reflecting the majority ownership by the Norwegian State. The current rating outlook is stable from both agencies.

As of 31 December 2008, StatoilHydro had liquid assets of NOK 28.4 billion, including NOK 18.6 billion in cash and cash equivalents and NOK 9.7 billion of current financial investments (domestic and international capital market investments). The increase of NOK 6.8 billion from 2007 was mainly due higher cash inflows from increased revenues in 2008 compared to 2007, partly offset by higher investments in 2008 compared to 2007. The average liquids price increased from USD 72 (NOK 423) per barrel in 2007 to USD 97 (NOK 548) per barrel in 2008.

StatoilHydro's general policy is to maintain a liquidity reserve in the form of cash and cash equivalents in its balance sheet, and committed, unused credit facilities and credit lines in order to ensure that it has sufficient financial resources to meet its short-term requirements. Long-term funding is raised when the group identifies a need for such financing based on its business activities and cash flows, as well as when market conditions are considered favourable.

As of 31 December 2008, the group had USD 2.0 billion available in a committed revolving credit facility from international banks, including a USD 500 million swing-line facility. The facility was entered into in 2004, and, after exercising an extension option in 2006, it is available for drawdowns until December 2011. At year end 2008, no amounts had been drawn under the revolving credit facility.

Taking StatoilHydro's established liquidity reserves (including committed credit facilities), credit rating and access to capital markets into consideration, StatoilHydro is well positioned to execute the planned long-term funding in the first half of 2009. As a part of this plan, the group utilised the updated EMTN program in March 2009 to issue a GBP 800 million bond with a 22 year tenure, a EUR 1.2 billion bond with a 12 year tenure and a EUR 1.3 billion bond with a six year tenure.

Gross interest bearing financial liabilities

Gross interest bearing financial liabilities were NOK 75.3 billion at year end 2008, compared with NOK 50.5 billion at the end of 2007. The increase of NOK 24.8 billion was mainly related to an increase in non-current financial liabilities by NOK 10.2 billion due to weakening of the NOK versus the USD (NOK 1.59). In addition cash collateral on financial counter parties and commercial papers increased by NOK 7.3 billion and NOK 3.0 billion, respectively in 2008.

Net interest bearing financial liabilities amounted to NOK 46.0 billion at 31 December 2008, compared with NOK 25.5 billion at 31 December 2007. The increase was mainly related to an increase in gross financial liabilities, partly offset by an increase in cash equivalents and current financial investments of NOK 6.8 billion.

The net debt to capital employed ratio, defined as net interest-bearing debt in relation to capital employed, was 17.5% as of 31 December 2008, compared with 12.4% as of 31 December 2007. The 5.1% increase was mainly related to an increase in net financial liabilities of NOK 20.5 billion, partly offset by an increase in cash equivalents and current financial investments of NOK 6.8 billion.

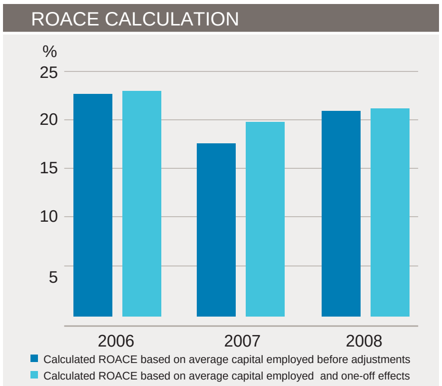
The group's borrowing needs are mainly covered through the issuing of short-term and long-term securities, including utilisation of a US Commercial Paper Programme and a Euro Medium Term Note (EMTN) Programme (the limits of the programme being USD 4 billion and USD 6 billion, respectively), and through draw-downs under committed credit facilities and credit lines.

After the effect of currency swaps, 100% of StatoilHydro's borrowings are in US dollars.

StatoilHydro's **financial policies** take into consideration funding sources, the maturity profile of long-term debt, interest rate risk management, currency risk and management of liquid assets. Borrowings are denominated in various currencies and swapped into USD, since the largest proportion of the group's net cash flow is denominated in USD. In addition, StatoilHydro uses interest rate derivatives, primarily consisting of interest rate swaps, to manage the interest rate risk of our long-term debt portfolio.

New long-term borrowings totalled NOK 2.6 billion in 2008 and NOK 1.7 billion in 2007. The repayment of long-term debt at 31 December 2008 was NOK 2.9 billion compared with NOK 2.9 billion at 31 December 2007.

Return on Average Capital Employed



StatoilHydro uses return on average capital employed to measure the return on capital employed, regardless of whether the financing is through equity or debt. The return on average capital employed was 21.3% in 2008, compared with 17.9% in 2007. The increase was due to higher income from higher prices and volumes of natural gas, partly offset by higher average capital employed.

Research and Development

In addition to technological development in field development projects, a significant part of StatoilHydro's research is carried out at centres for research and technology development in Trondheim, Bergen, Porsgrunn in Norway and Calgary in Canada. The research and development is carried out in close co-operation with universities, research institutions, other operators and the supplier industry. Research and development expenditures were NOK 2.2 billion in 2008.

The technology strategy is driven by the key business challenges, aiming to build even stronger industry positions. Technology is a key enabler to achieving this, and will make significant contributions to field development in frontier deep waters (for example, the Gulf of Mexico and Brazil) and Arctic areas, heavy oil production, subsalt exploration, and environmental and climate issues. The ambition is to achieve distinctiveness and industry leadership in selected technologies and to stay competitive in a broad range of core and emerging technologies along the energy provision value chain, such as offshore wind and sustainable biofuels.

Furthermore, improved oil recovery and improved drilling and well solutions are important to successfully growing our business. StatoilHydro has achieved some of the petroleum industry's highest recovery factors on the NCS by combining scientific and engineering capabilities and boldly introducing new technology. We intend to further advance the most important technologies to meet forthcoming improved oil recovery ambitions on the NCS and internationally. Drilling and well technology plays a key role in increasing production and ensuring regular delivery, and through its application we intend to achieve faster operations, reduced downtime, and improved well flow whilst improving safety during operations.

The renewable energy industry continues to grow, driven by ambitions to increase the contribution of sustainable energy to the total energy supply. Although energy production from renewables is still modest in most countries, wind power, solar energy and bio fuels are developing into significant industries, and StatoilHydro is graduallly building a position in the offshore wind power and biofuels segments.

Risks

The financial results of operations largely depend on a number of factors, most significantly those that affect the price we receive in NOK for our sold products. Specifically, such factors include the level of crude oil and natural gas prices; trends in the exchange rate between the USD and NOK; equity production and entitlement sales volumes of liquids and natural gas; available petroleum reserves, and StatoilHydro's, as well as its partners' expertise and co-operation in recovering oil and natural gas from those reserves; and changes in the portfolio of assets due to acquisitions and disposals.

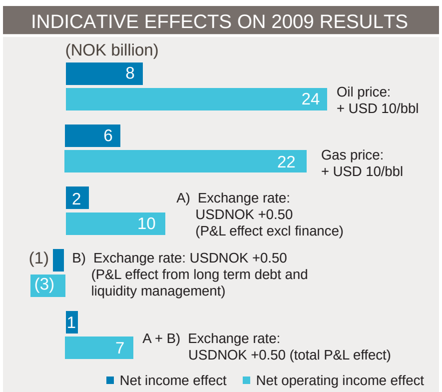
The results will also be affected by trends in the international oil industry, including possible actions by governments and other regulatory authorities in the jurisdictions in which the group operates. Also possible or continued actions by members of the Organization of Petroleum Exporting Countries (OPEC) that affect price levels and volumes, refining margins, increasing cost of oilfield services, supplies and equipment, increasing competition for exploration opportunities and operatorships, and deregulation of the natural gas markets 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 and the USDNOK exchange rates for 2008, 2007 and 2006.

Yearly average	2008	2007	2006
Crude oil (USD/bbl brent blend)	**91**	70.5	63.2
Natural gas (NOK per scm) [1]	**2.4**	1.66	1.94
FCC margins (USD/bbl) [2]	**8.2**	7.5	7.1
USDNOK average daily exchange rate	**5.63**	5.86	6.42

[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 USDNOK exchange rate, if sustained for a full year, could impact the financial results in 2009.

The estimated sensitivity of each of the factors on StatoilHydro's financial results has been estimated based on the assumption that all other factors would remain unchanged. The estimated effects on the financial results would differ from those that would actually appear in the consolidated financial statements because the consolidated financial statements would also reflect the effect on depreciation, trading margins, exploration expenses, inflation, potential tax system changes, and the effect of any hedging programmes in place.

The oil and gas price hedging policy is designed to assist StatoilHydro's 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. Revenues and cash flows are mainly denominated in or driven by US dollars, while most operating expenses and income taxes payable are accrued in NOK. The group seeks to manage this currency mismatch by issuing or swapping long-term debt in USD. This debt policy is an integrated part of the total risk management programme. StatoilHydro also engages in foreign currency hedging in order to cover its non-USD needs, which are primarily in NOK. Interest rate risk is managed 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.

Group outlook

StatoilHydro's forecasted **equity production** is 1950 mboe per day in 2009 and 2200 mboe per day in 2012. The estimate for 2009 excludes any adverse effects of potential OPEC quotas. The guidance for 2012 reflects expected effects of our recent acquisitions of US shale gas and 50% of the Peregrino development.

Capital expenditures for 2009, excluding acquisitions, are estimated at around USD 13.5 billion. Approximately 50% of the forecasted investments for 2009 are in assets expected to contribute to growth in oil and gas production, about one third are related to investments in currently producing assets, with the remainder in other activities.

Unit production cost for equity volumes is estimated in the range of NOK 33 to 36 per barrel in the period from 2009 to 2012, excluding purchases of fuel and gas for injection. For 2009, the unit production cost is expected to temporarily be in the upper end of this range.

Our ambition is to deliver a competitive **ROACE** compared with our peer group.

Exploration drilling is StatoilHydro's primary tool for growing its business. The company will continue to optimise the large portfolio of exploration assets and expects to maintain a high level of **exploration activity** in 2009, although slightly lower than in 2008. StatoilHydro expects to complete between 65 and 70 exploration and appraisal wells in 2009. Rigs have already been secured for most of the exploration drilling in 2009 and to some extent also for subsequent years. The exploration activity is estimated at USD 2.7 billion for 2009.

The year 2008 was one of the most **volatile periods in the product, gas liquid and crude oil markets**. While natural gas prices have been strong in Europe, crude oil and gas liquids prices decreased dramatically during the third and fourth quarters of 2008. We anticipate that crude oil and gas liquids prices will remain at relatively low levels and that prices will continue to be volatile at least in the near term.

The price development for natural gas is uncertain in the short term due to the financial turmoil. The natural gas market is also influenced by developments in the overall power market and the industrial segment where gas is competing with coal and fuel oil products, both having experienced significant fall in prices. Going forward, the value of natural gas will increasingly be determined in the power segment in competition with coal, renewable- and nuclear energy. Climate policy and regulations will be important factors in determining the gas pricing.

New LNG capacity is coming on stream, and will be directed to the most favourable markets. As the amount of available LNG is anticipated to be substantial, there is a corresponding uncertainty related to the price effects to the relevant markets.

In the long term, we continue to have a positive 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 US, StatoilHydro's position in the Marcellus shale gas acreage in combination with Gulf of Mexico production and the LNG re-gasification capacity position at Cove Point, are expected to provide a foundation for growth in the US market position in the years to come.

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.

People and the organisation

In StatoilHydro, the way in which the results are achieved is as important as the results themselves. We will create value for the owners based on a clear performance framework defined by our values and principles for HSE, ethics and leadership. The ambition is to be a globally competitive company. It is a key priority to create a stimulating working environment and provide employees with good opportunities for professional and personal development.

The group seeks to achieve this through developing a strong, value-based performance culture, clear principles for leadership and an effective management and control system. Corporate governance, StatoilHydro values, leadership model, operating model and corporate policies are described in the StatoilHydro Book, which has been made available for all employees both in Norwegian and English.

The impact of the global economic turmoil on StatoilHydro employees and the labour market within the industry, is not yet fully evident. We are planning for growth and need to maintain and further develop the group's core competencies. The economic turmoil provides opportunities in the talent market, but also encourages focus on efficiency improvements and rightsizing to maintain room to manoeuvre. The main focus areas within people and organisation are to consolidate the organisation by completing the integration process, target recruitment and rightsizing and pursuing the strategic objective of being a value-based and performance driven organisation.

We promote diversity among our employees. The importance of diversity is stated explicitly in StatoilHydro's values and in its ethical codes of conduct. We aim to create the same opportunities for everyone and do not tolerate discrimination or harassment of any kind in our workplace. By December 2008, 37% of our employees were women, and 40% of the members on the board of directors were women. The proportion of female managers was 27%, and among managers under the age of 45, the proportion was 35%. Moreover, women are relatively well represented in the technical disciplines. In 2008, 25% of the staff engineers were women. The proportion of female skilled workers was 18% in 2008.

The group works systematically with recruitment and development programmes in order to increase the number of women in male-dominated positions and discipline areas. The reward system in StatoilHydro is gender neutral, meaning that men and women with the same position, experience and performance will be at the same salary levels. However, due to differences in types of positions and numbers of years' experience between women and men, some differences in compensation appear when comparing the general wage levels of men and women. On average, the earnings of female skilled workers across disciplines are 93% of the earnings of their male colleagues. There are no significant differences between the earnings of female and male staff engineers.

StatoilHydro's employees originate from 83 countries worldwide. By December 2008, 6% of the people based in StatoilHydro offices in Norway were of non-Norwegian origin, which is an increase of two percentage points since January 2007.

Health, safety and the environment

Safe and efficient operations are our first priority since accidents pose a major threat to our people and our business. Our goal is zero harm to people and we firmly believe that all accidents can be prevented. We have experienced a number of setbacks in this area, and we aim to better understand factors that create risks in order to avoid major accidents that could harm our people, our business or the environment. We work systematically to understand and mitigate risks critical to operating safely and reliably, and continuous improvement for better safety results has high attention in all our businesses.

In order to meet our goal of improving safety results in all our businesses, we plan to continue our safe behaviour programme and implement additional training on leadership and compliance with our safety standards. We plan to focus on monitoring technical integrity, safety critical maintenance, risk management and compliance with our procedures.

We suffered two fatal accidents in 2008. On a canoeing trip during a team building gathering, one person drowned. The second fatality occurred when a mooring line broke and struck a crew member onboard the vessel *Interservice.* An incident at the Statfjord A platform in May resulted in 50 to 70 cubic metres of oil being pumped into the sea. The company has implemented a number of initiatives to learn from the mistakes and to prevent similar incidents from happening in the future.

The overall Serious Incident Frequency indicator increased from 2.1 in 2007 to 2.2 in 2008.

We work systematically to ensure a working environment that promotes job satisfaction and good health. We closely monitor physical, chemical and organisational factors in the working environment. We have a system in place for following up on groups or individuals that are exposed to risks in their working environment. Special attention is devoted to chemical health hazard, and action plans are developed for the individual business areas.

The sick leave rate in StatoilHydro has been stable at 3.5% over the last few years but increased slightly in 2008 to 3.7%. It is still low compared to similar industries, and is closely followed up by managers at all levels. The average sick leave rate in all of Norway in the third quarter of 2008 was 6.9%

In 2008, StatoilHydro was fined NOK 2 million for an accident that occurred 26 April 2005 on Oseberg B where a drilling worker was seriously injured. StatoilHydro has also accepted some minor fines for breach of regulations at service stations.

Environment and climate

The group is committed through its climate policy to contribute to sustainable development. We recognise that there is a link between the use of fossil fuels and man-made climate change, and the climate policy takes into account the need for proactively combating global climate change, as well as the need to increase company efforts on renewables and clean technology. StatoilHydro's environmental management system is an integrated part of the overall management system. The group is certified according to the environmental standard ISO 14001. The environmental management system seeks to identify the most important environmental aspects of all facilities and set targets for improvement.

We continuously monitor our emissions. Several modification projects for further reductions are being implemented and StatoilHydro has established corporate wide principles for oil spill response in relation to our operations. The group also continued an extensive research and development portfolio aimed at adapting its oil spill response to arctic areas.

The group-wide indicators to measure environmental performance are oil spills, emissions of carbon dioxide and nitrogen oxides, energy consumption and the recovery rate for non-hazardous waste. The group works actively to limit the environmental impacts of its operations and fight global climate change. The current emissions of $CO2$ per tonne of oil and gas produced from StatoilHydro-operated fields correspond to 39% of the oil and gas industry average. The volume of accidental oil spills decreased from 4,989 cubic metres in 2007 to 342 cubic metres in 2008. Carbon dioxide emissions have decreased from 14.6 million tonnes in 2007 to 14.4 million tonnes in 2008. Nitrogen oxides emissions have decreased from 49.4 thousand tonnes in 2007 to 46.7 thousand tonnes in 2008. Energy consumption has decreased from 69.8 TWh in 2007 to 69.6 TWh in 2008. The recovery rate for non-hazardous waste has decreased from 41% in 2007 to 29% in 2008.

Pioneering development and implementation of new technology is challenging. During 2008, the onshore part of the Snøhvit plant changed operative status from running-in to ordinary production. Early in 2008, flaring at Hammerfest LNG was still quite extensive, but during the first half of 2008, adjusted start-up procedures was introduced. As a result, emissions have been reduced to less than 0.5% of the emissions at first start-up. During start-up of the last system in the production chain, StatoilHydro still experienced some emission disturbances. However, during the autumn of 2008 the group succeeded in significantly reducing the flaring problems. We expect the operational regularity to increase in all respects, thus reducing flaring to a design minimum.

StatoilHydro has approved a climate change policy which sets out the principles for addressing the challenge of global warming and the ambition of maintaining the position as industry leader in relation to sustainable development. The climate policy will be implemented in all business planning and strategy development.

StatoilHydro is continuously focusing on energy efficiency on our installations. Requirements for energy efficiency are incorporated in governing documents.

Society

Accessing, developing and producing oil and gas resources depends on the group's ability to forge enduring and mutually beneficial relationships with key stakeholders in the societies where it operates**.** Such stakeholders include governments, communities, partners, contractors and suppliers, employees, customers and investors.

It is StatoilHydro's responsibility to create value for its stakeholders. This is not only an ethical imperative; living up to these responsibilities is required to support long-term profitability and consistency in complex environments. We are therefore committed to contribute to sustainable development based on the core activities in the countries where the group operates:

- making decisions based on how they affect the group's interests and the interests of the affected societies.
- ensuring transparency, anti-corruption, and respect for human rights and labour standards.
- generating positive spin-offs from core activities to help meet the aspirations of the societies in which the group operates.

During 2008, integrity and human rights in the group's operations has been given a high priority. The main focus has been on strengthening the group's ability to manage and mitigate integrity and human rights risks in its operations. To this end, the group has implemented stricter requirements and processes for integrity due diligence for assessing and managing risks in its business relationships. To further comply with our Ethics Code of Conduct policy, the group rolled out an ethics training and awareness programme reaching staff from 37 countries of operation, especially targeting senior management, procurement staff and others regularly exposed to third parties.

Consultancy agreements related to Norsk Hydro's earlier activities in Libya contain issues which could be problematic in relation to Norwegian and US anti-corruption legislation. The external investigation into Hydro Oil & Energy's international operations was completed in October 2008 and its results submitted to the National Authority for Investigation and Prosecution of Economic and Environmental Crime in Norway (Økokrim), US authorities and Libyan authorities. The fundamental concern for the group is the relationship to our values, our ethical guidelines and our leadership principles. We view the matter from that perspective out of consideration for the group's integrity. Divergence between word and deed in dealing with such circumstances could undermine the legitimacy of our values, and represents an increased risk for the group.

Consistent with the proposal of the UN Special Representative on Business and Human Rights, the group also revised its human rights due diligence procedures.

In 2008 we continued to support local development in the countries where we operate. StatoilHydro paid taxes to governments totalling NOK 172.4 billion, up from NOK 132.0 billion the previous year. Direct and indirect taxes paid outside Norway totalled NOK 38.1 billion in 2008. StatoilHydro procurements from local suppliers in non-OECD countries increased to NOK 3.1 billion compared to NOK 2.5 billion in 2007. The group invested in capacity-building and skills development for its local employees and communities alike, as well as in local enterprise skills upgrading and development in Algeria, Brazil, Russia and Venezuela amongst others.

Board developments

On 1 April 2008, Svein Rennemo joined the board of directors as the new chair of the board. Rennemo also became a member of the board's compensation committee. The board held 13 meetings in 2008 and there were 97% attendance at the meetings. In September 2008 the board visited Canada, focusing on both technical, commercial, regulatory and HSE issues related to StatoilHydro's on-shore oil sand activities. The board's audit committee held eight meeting in 2008 and there was 97% attendance at the meetings and the compensation committee held six meetings in 2008 and there was 98% attendance at the meetings.

Stavanger, 17 March 2008

THE BOARD OF DIRECTORS OF STATOILHYDRO ASA

SVEIN RENNEMO
CHAIR

MARIT ARNSTAD
DEPUTY CHAIR

LILL-HEIDI BAKKERUD

KJELL BJØRNDALEN

CLAUS CLAUSEN

ROY FRANKLIN

KURT ANKER NIELSEN

ELISABETH GRIEG

GRACE REKSTEN SKAUGEN

MORTEN SVAAN

HELGE LUND
PRESIDENT AND CEO

Statement on compliance

Board and management confirmation

Today, the Board of Directors, the Chief Executive Officer and the Chief Financial Officer reviewed and approved the Board of Directors Report and the StatoilHydro ASA consolidated and separate annual financial statements as of 31 December 2008.

To the best of our knowledge, we confirm that:

- the Statoilhydro ASA consolidated annual financial statements for 2008 have been prepare in accordance with IFRSs and IFRICs as adopted by the European Union (EU), IFRSs as issued by the International Accounting Standards Board (IASB) and additional Norwegian disclosure requirements in the Norwegian Accounting Act, and that
- the separate financial statements for StatoilHydro ASA have been prepared in accordance with the Norwegian Accounting Act and Norwegian Accounting Standards, and that
- the Board of Directors Report for the group and the parent company is in accordance with the requirements in the Norwegian Accounting Act and Norwegian Accounting Standard no 16, and that
- the information presented in the financial statements gives a true and fair view of the company's and the group's assets, liabilities, financial position and results for the period viewed in their entirety, and that
- the Board of Directors' report gives a true and fair view of the development, performance, financial position, principle risks and uncertanties of the company and the group.

Stavanger, 17 March 2008

THE BOARD OF DIRECTORS OF STATOILHYDRO ASA

SVEIN RENNEMO
CHAIR

MARIT ARNSTAD
DEPUTY CHAIR

LILL-HEIDI BAKKERUD

KJELL BJØRNDALEN

CLAUS CLAUSEN

ROY FRANKLIN

KURT ANKER NIELSEN

ELISABETH GRIEG

GRACE REKSTEN SKAUGEN

MORTEN SVAAN

ELDAR SÆTRE
CHIEF FINANCIAL OFFICER

HELGE LUND
PRESIDENT AND CEO

The board of directors' statement on corporate governance

The objective of StatoilHydro is to create long-term value for its shareholders through exploration, production, transportation, refining and marketing of petroleum and petroleum derived products.

In pursuing our corporate objective, we are committed to the highest level of governance and to cultivate a value-based performance culture that rewards exemplary ethical standards, respect for the environment and personal and corporate integrity.

We believe that corporate governance is more than just an exercise in compliance and that there is a link between high-quality governance and the creation of shareholder value.

The following principles underline our approach to corporate governance:

- All shareholders will be treated equally
- StatoilHydro will ensure that all shareholders have access to up-to-date, reliable and relevant information about the company's activities
- StatoilHydro will have a board of directors that is independent of the group's management. The board focuses on there not being any conflicts of interest between owners, 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

As chair of the board, I recognise the importance of good governance and that it is a discrete task from management.

The work of the board of directors is based on the existence of clearly defined division of roles and responsibilities between the shareholders, the board of directors and the management in StatoilHydro. Governance is overseen by our board, while management is delegated to the group chief executive.

The foundation for our governance policies are Norwegian regulation and practices. Nevertheless, we continuously consider prevailing international standards of best practice in defining and exercising company policies. Moreover, our governance system is designed to ensure that we operate within a clear and efficient governance framework that goes beyond regulatory compliance and places shareholder interest first.

Governance is the task our owners entrust to the board. It has a clear objective - ensuring the pursuit of the company's objective and the effective promotion of shareholder interest.

Svein Rennemo
Chair of the Board

Statement of compliance
The Norwegian Code of Practice for Corporate Governance is issued by the Norwegian Corporate Government Board, last revised 4 December 2007. The Norwegian Code is based on company, accounting, stock exchange and securities legislation and includes provisions and guidance that in part elaborate on existing legislation and in part cover areas not addressed by legislation.

The Norwegian Code of Practice addresses 15 major topics, with a separate section for each topic. The code's recommendations are presented in *italic* under each heading.

Implementation and reporting on corporate governance

- *The board of directors must ensure that the company implements sound corporate governance.*
- *The board of directors must provide a report on the company's corporate governance in the annual report. The report must cover every section of the Code of Practice. If the company does not fully comply with this Code of Practice, this must be explained in the report.*
- *The board of directors should define the company's basic corporate values and formulate ethical guidelines in accordance with these values.*

StatoilHydro's board of directors endorses The Norwegian Code of Practice for Corporate Governance. This statement outlines our system of governance and describes how we comply with the Code. The foundation for the group's governance structure is Norwegian law and StatoilHydro's primary listing is on the Oslo stock exchange (Oslo Børs). The group is also registered with the US Securities and Exchange Commission and listed on the New York Stock Exchange (NYSE).

Corporate governance in StatoilHydro is subject to annual reviews and discussions by the corporate board of directors. It is the boards' view that StatoilHydro has complied with the code of practice throughout the year ended 31 December 2008.

We recognise that the internet has become the preferred means of communication by most of our investors and increasingly more of our interaction is therefore taking place via electronic channels. All provisions of the Code of Practice are covered in the printed version of our annual report.

The web version of our annual report allows our shareholders and other stakeholders to explore any topic of particular interest in more detail and makes navigation to related documentation easier. We therefore believe that the web version of the corporate governance statement serves the interest of our shareholders even better than can be achieved in print.

Ethics Code of Conduct
Together with StatoilHydro's values statement, the Ethics Code of Conduct constitutes the basis and framework for our performance culture and governance system.

Our ability to create value is dependent on high ethical standards, and we are determined that StatoilHydro shall be known for these. Ethics is treated as an integral part of our business activities. The group requires high ethical standards of everyone who acts on our behalf and will maintain an open dialogue on ethical issues, internally and externally.

The StatoilHydro Ethics Code of Conduct describes the requirements which apply to our business practice.

The Code's target group is all employees and members of the board of directors of StatoilHydro and its subsidiaries. The Ethics Code of Conduct is accessible on our web page.

Business partners are also expected to have ethical standards that are compatible with StatoilHydro's standards.

StatoilHydro has a dedicated ethics helpline that may be used by employees or any person that wants to express concerns or seek advice regarding the legal and ethical conduct of StatoilHydro's business.

Business

- *The company's business should be clearly defined in its articles of association.*
- *The company should have clear objectives and strategies for its business within the scope of the definition of its business in its articles of association.*
- *The annual report should include the business activities clause from the articles of association and describe the company's objectives and principal strategies.*

StatoilHydro's objective is defined in the company's articles of association: "The object of our company is, either by us or through participation in or together with other companies, to carry out exploration, production, transportation, refining and marketing of petroleum and petroleum derived products, as well as other businesses"

To support the company objective, goals and strategies are adopted, both for StatoilHydro as a company and for each business area. Our strategy is to maximise value as an upstream oriented, technology-based energy company. This strategy can be summarised as:

- Maximising long-term value creation on the NCS
- Building and delivering profitable international growth
- Developing profitable midstream and downstream positions
- Creating a platform for new energy solutions and production

In the short term, our main focus will be on delivering on our production targets and managing our cost base. This means delivering high operational performance, with a strong focus on HSE. In the longer term our focus is to develop the current project portfolio with quality and at a competitive cost to enable us to grow profitably.

Equity and dividends

- *The company should have an equity capital at a level appropriate to its objectives, strategy and risk profile.*
- *The board of directors should establish a clear and predictable dividend policy as the basis for the proposals on dividend payments that it makes to the general meeting. The dividend policy should be disclosed.*
- *Mandates granted to the board of directors to increase the company's share capital should be restricted to defined purposes and should be limited in time to no later than the date of the next annual general meeting. This should also apply to mandates granted to the board for the company to purchase its own shares.*

Shareholders' equity

The group's sharholders' equity at 31 December 2008 was NOK 214 billion, which represented 37% of the groups total assets. The board considers this satisfactory given the group's requirement for solidity in relation to its expressed goals, strategy and risk profile.

Dividend policy

Our dividend policy reflects our intention to return to our shareholders, through cash dividends and share repurchases, an amount in the range of 45 to 50% of consolidated net income pursuant to IFRS. It is our ambition to grow the ordinary cash dividend measured in NOK per share. In any one year, however, the aggregate of cash dividends paid to shareholders and share repurchases may be higher or lower than 45 to 50% of net income, depending on StatoilHydro's evaluation of expected cash flow development, capital expenditure plans, financing requirements and appropriate financial flexibility.

Share repurchases are an integrated part of our dividend policy. For the period 2008-2009 the board has not requested the general meeting in StatoilHydro for an authorisation to repurchase StatoilHydro shares in the market for subsequent cancellation. In 2007, the annual general meeting of Statoil authorised the board of directors to acquire Statoil shares in the market for subsequent cancellation. This authorisation was valid until 20 May 2008. StatoilHydro did not make use of this authorisation in 2007 or 2008.

Purchase of own shares for use in the share savings programme

Since 2004, StatoilHydro has had a share savings plan for its employees. 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 basic salary in shares. After a lock-in period of two calendar years, one extra share will be awarded for each share purchased. Shares transferred to employees are acquired by the company in the market.

With the objective of encouraging participation in the programme, StatoilHydro grants a contribution to the employees of 20 per cent of the saved amount, at a maximum of NOK 1,500 per employee per year. This amount is tax-exempt. The programme is in accordance with Norwegian tax legislation. Terms of company contribution may vary between participating entities in the group.

The board decides the manner in which the acquisition of StatoilHydro shares in the market shall take place. Shares acquired in accordance with the authorisation may only be used for sale and transfer to employees of the StatoilHydro group as part of the group's share investment plan as approved by the board. The minimum and maximum amount that may be paid per share will be NOK 50 and NOK 500, respectively. Within these limits, the board of directors may itself decide when shares will be acquired. However, the purchases follow a fixed plan for one year at a time. The authorisation was most recently renewed on 20 May 2008 and is valid until the next annual general meeting.

The nominal value of each share is NOK 2.50. At a maximum overall nominal value of NOK 15 million, the authorisation for the repurchase of shares in connection with the group's share savings plan covers the repurchase of no more than six million shares.

At 31 December 2008, StatoilHydro owned 3,781,209 shares reserved for the share saving programme.

Capital increase

The board is currently not authorised to undertake share issues.
If we issue any new shares, including bonus share issues, our articles of association must be amended, which requires two-thirds majority. Under Norwegian law, our shareholders have a preferential right to subscribe to issues of new shares by us. The preferential rights to subscribe to an issue may be waived by a resolution in a general meeting passed by the same percentage threshold required to approve amendments to our articles of association. The general meeting may, with a vote as described above, authorize the board of directors to issue new shares, and to waive the preferential rights of shareholders in connection with such issuances. Such authorization may be effective for a maximum of two years, and the par value of the shares to be issued may not exceed 50% of the nominal share capital when the authorization was granted.

Rights of redemption and repurchase of shares

Our articles of association do not authorize the redemption of shares. In the absence of authorization, the redemption of shares may still be decided by a general meeting of shareholders by a two-thirds majority under certain conditions. However, the share redemption would, for all practical purposes, depend on the consent of all shareholders whose shares are redeemed.

A Norwegian company may purchase its own shares if an authorization to do so has been given by a general meeting with the approval of at least two-thirds of the aggregate number of votes cast as well as two thirds of the share capital represented at the general meeting. The aggregate par value of treasury shares held by the company must not exceed 10% of the company's share capital and treasury shares may only be acquired if the company's distributable equity, according to the latest adopted balance sheet, exceeds the consideration to be paid for the shares. The authorization by the general meeting cannot be given for a period exceeding 18 months.

Equal treatment of shareholders and transactions with close associates

- *The company should only have one class of shares.*
- *Any decision to waive the pre-emption rights of existing shareholders to subscribe for shares in the event of an increase in share capital must be justified.*
- *Any transactions the company carries out in its own shares should be carried out either through the stock exchange or at prevailing stock exchange prices if carried out in any other way. If there is limited liquidity in the company's shares, the company should consider other ways to ensure equal treatment of all shareholders.*
- *In the event of any not immaterial transactions between the company and shareholders, members of the board of directors, members of the executive management or close associates of any such parties, the board should arrange for a valuation to be obtained from an independent third party. This will not apply if the transaction requires the approval of the general meeting pursuant to the requirements of the Public Companies Act. Independent valuations should also be arranged in respect of transactions between companies in the same group where any of the companies involved have minority shareholders.*
- *The company should operate guidelines to ensure that members of the board of directors and the executive management notify the board if they have any material direct or indirect interest in any transaction entered into by the company.*

StatoilHydro has one class of shares, and each share confers one vote at the general meeting. The Articles of Association contain no restrictions on voting rights. The repurchase of own shares for subsequent cancellation or use in the share savings programme for own employees is carried out through the Oslo Stock Exchange.

The company's ethical guidelines comprise rulings to avoid conflict of interest, and stipulates that anyone acting on behalf of StatoilHydro must behave impartially in all business dealings.

The Norwegian state as majority owner
The Norwegian State is the largest shareholder in StatoilHydro. Its ownership interest is managed by the Ministry of Petroleum and Energy.

Statoil was partially privatised and listed on 18 June 2001, when it became a public limited company. Before the merger with Hydro's oil and gas activities, the Norwegian state owned 70.9% of the shares in Statoil. Pursuant to the agreed exchange ratio, as part of the merger between Statoil ASA and Norsk Hydro ASA's oil and gas activities, the Norwegian state's ownership interest in the group was 62.5%, or 1,992,959,739 shares on 1 October 2007. In accordance with the Norwegian Parliament's decision of 2001 concerning a minimum state shareholding of two-thirds in Statoil, the Government expressed its intention to increase the state's shareholding in StatoilHydro over time to 67%. In 2008 the Government has built up the State's ownership interest in StatoilHydro by buying shares in the market. On 31 December 2008 the State's ownership interest in StatoilHydro was 66.42%.

The Norwegian state endorses the principles 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 follow the code.

The state's own principles for corporate governance are concerned with the management of the state's ownership interests in companies in which it is a shareholder. It is assumed that the state's ownership is organised in a manner that ensures that the state's different roles are kept separately in a proper fashion. The principles are presented in the state's ownership report and on the website:
http://www.eierberetningen.nhd.no/

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 influence 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 making decisions and passing resolutions.

Other contact between the state as owner and the management of companies must take place in the same manner as for other institutional investors. In all matters where the state acts in its capacity as shareholder, the exchange with the company is based on information that is available to all shareholders. We put great emphasis on ensuring that the objectives and intentions of any interaction between the Norwegian state and StatoilHydro are clearly defined and require that there is a clear distinction of the various roles that the Norwegian State encompass.

As majority shareholder, the state has appointed a member of StatoilHydro's election committee.

The state has no appointed board members in StatoilHydro, but it works on the principle that all board members will endeavour to safeguard the company and the shareholders' joint interests.

Sale of the state's oil and gas
In accordance with the company's Articles of Association, StatoilHydro's has a duty to sell the state's oil and natural gas together with the group's own.

The Norwegian state has a common ownership strategy aimed at maximising the total value of its ownership interests in StatoilHydro and its own oil and gas interests. This is preserved in the owner's rules of procedure which oblige StatoilHydro, in its activities on the Norwegian continental shelf, to emphasise these overall interests in decisions which may be of significance to the implementation of the sales arrangements.

The state-owned oil company Petoro AS handles commercial matters relating to the Norwegian state's direct involvement in petroleum activities on the Norwegian continental shelf and pertaining activities.

Freely negotiable shares

- *Shares in listed companies must, in principle, be freely negotiable. Therefore, no form of restriction on negotiability should be included in a company's articles of association.*

StatoilHydro's primary listing is on the Oslo stock exchange. Our American Depository Shares (ADRs) are traded on the New York Stock Exchange. Each StatoilHydro ADR represents the right to receive one ordinary share.

The shares are freely negotiable.

General meetings

The board of directors should take steps to ensure that as many shareholders as possible may exercise their rights by participating in general meetings of the company, and that general meetings are an effective forum for the views of shareholders and the board. Such steps should include:

- *making the notice calling the meeting and the support information on the resolutions to be considered at the general meeting, including the recommendations of the nomination committee, available on the company's website no later than 21 days prior to the date of the general meeting, and sending this information to shareholders no later than two weeks prior to the date of the general meeting*
- *ensuring that the resolutions and supporting information distributed are sufficiently detailed and comprehensive to allow shareholders to form a view on all matters to be considered at the meeting*
- *setting any deadline for shareholders to give notice of their intention to attend the meeting as close to the date of the meeting as possible*
- *ensuring that shareholders who cannot attend the meeting in person can vote by proxy*
- *ensuring that the members of the board of directors and the nomination committee and the auditor are present at the general meeting*
- *making arrangements to ensure an independent chairman for the general meeting*

The notice calling the general meeting shall provide information on the procedures shareholders must observe in order to participate in and vote at the general meeting. The notice should also set out:

- *the procedure for representation at the meeting through a proxy, including a form to appoint a proxy*
- *the right for shareholders to propose resolutions in respect of matters to be dealt with by the general meeting*
- *the Web pages where the notice calling the meeting and other supporting documents will be made available*

The company should, at the earliest possible opportunity, make available on its website:

- *information on the right of shareholders to propose matters to be considered by the general meeting*
- *proposals for resolutions to be considered by the general meeting, alternatively comments on matters where no resolution is proposed*
- *a form for appointing a proxy*

The board of directors and the chairman of the general meeting should ensure that the general meeting is given the opportunity to vote separately for each candidate nominated for election to the company's corporate bodies.

The annual general meeting of shareholders (AGM) is the company's supreme body with a sole objective - to ensure shareholder democracy.

Pursuant to StatoilHydro's articles of association and the Norwegian Public Limited Companies Act, the AGM:

- Elects the shareholders' representatives to the corporate assembly
- Elects the nomination committee (referred to as the election committee in the articles of association)
- Elects the external auditor and stipulates the auditor's fee
- Approves the board of directors' report in accordance with Norwegian requirements, the financial statements and the dividend, proposed by the board of directors and recommended by the corporate assembly
- Deals with any other matters listed in the notice convening the meeting

Pursuant to the company's articles of association, the AGM must be held by the end of June each year. The 2008 AGM is scheduled for 19 May, 2009.

Notice of the meeting and documents for the AGM are published on StatoilHydro's website together with the annual report at least 21 days prior to the meeting and consecutively sent by mail to all shareholders whose address is known. Documentation from previous AGMs is available on StatoilHydro's website.

In 2008, Benedicte Schilbred Fasmer and Erlend Grimstad announced that they would withdraw from the corporate assembly. The timing of this notification did not allow for the nomination committee to make a proper evaluation of new candidates before the notice of the annual general meeting was due. The recommendation from the nomination committee, including background information of the proposed candidates, was therefore published separately in advance of the general meeting.

All shareholders are entitled to have their proposal dealt with at the general meeting, if the proposal has been submitted in writing to the board of directors in sufficient time to allow inclusion in the distributed notice of meeting. If a notice of meeting has already been distributed, a new notice of meeting must be distributed no later than two weeks before the general meeting is to be held.

All shareholders who are registered in the Norwegian Central Securities Depository (VPS) will receive an invitation to the AGM. They are entitled to submit proposals and vote, in person or by proxy. The deadline for registration is four days prior to the AGM.

Given the large number of shareholders and their wide geographical distribution, the number of shareholders who are able to attend the AGM in person will be limited. StatoilHydro therefore offers its shareholders an opportunity to follow the proceedings by webcast. The business of the AGM is conducted in Norwegian and translated simultaneously into English.

StatoilHydro intends to make use of electronic voting at its general meetings as soon as Norwegian legislation allows this.

All of our ordinary shares carry an equal right to vote at general meetings. Except as otherwise provided, decisions which shareholders are entitled to make pursuant to Norwegian law or our articles of association may be made by a simple majority of the votes cast. In the case of elections, the persons who obtain the most votes cast are deemed elected. However, certain decisions, including resolutions to waive preferential rights in connection with any share issue, to approve a merger or demerger, to amend our articles of association or to authorise an increase or reduction in our share capital, must receive the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at a shareholders' meeting.

The chair of the AGM will normally be 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 in order to ensure impartiality in relation to the matters to be considered.

Extraordinary general meetings

Pursuant to Norwegian law, the corporate assembly, the chair of the corporate assembly, the auditor, or shareholders representing at least 5% of the share capital, may demand that an extraordinary general meeting be held in order to have a specific matter considered and decided. The board must ensure that the extraordinary general meeting is held within a month of such a demand being submitted.

Nomination committee

- *The company should have a nomination committee, and the general meeting should elect the chairperson and members of the nomination committee and should determine the committee's remuneration.*
- *The nomination committee should be laid down in the company's articles of association.*
- *The members of the nomination committee should be selected to take into account the interests of shareholders in general. The majority of the committee should be independent of the board of directors and the executive management. At least one member of the nomination committee should not be a member of the corporate assembly, committee of representatives or the board. No more than one member of the nomination committee should be a member of the board of directors, and any such member should not offer himself for re-election. The nomination committee should not include the company's chief executive or any other member of the company's executive management.*
- *The nomination committee's duties are to propose candidates for election to the corporate assembly and the board of directors and to propose the fees to be paid to members of these bodies.*
- *The nomination committee should justify its recommendations.*
- *The company should provide information on the membership of the committee and any deadlines for submitting proposals to the committee.*

In accordance with StatoilHydro's articles of association, the nomination committee (referred to as the election committee in the articles of association) consists of four members who are shareholders or representatives of shareholders. The committee is independent of both the board and the company's management.
The duties of the nomination committee are:

- to present a recommendations to the AGM for the election of shareholder-elected members and deputy members of the Corporate Assembly
- to present recommendations to the corporate assembly for the election of shareholder-elected members to the board of directors
- to present a proposal for the remuneration of members of the board of directors and the corporate assembly.

The members of the nomination committee is elected by the AGM. Two of the mebers are elected from among the shareholder-elected members of the corporate assembly. Members of the nomination committee are elected for a term of two years.
The members of the nomination committee are:

- Olaug Svarva (chair), managing director, Folketrygdfondet
- Gro Bækken, secretary general, Save the Children Norway
- Tom Rathke, managing director, Vital Forsikring and Executive Vice President, DnB NOR
- Bjørn Ståle Haavik, acting secretary general, Ministry of Petroleum and Energy

The nomination committee held 8 meetings in 2008.

The rules of procedure for the nomination committee are accessible at our website.

As part of the merger agreement, the current board of directors was elected with effect from 1 October 2007 when the merger between Statoil ASA and Norsk Hydro ASA's petroleum activities was effective. Their term of office will expire on the date of the annual general meeting in 2010. The same condition applies to Svein Rennemo who was elected chair of the board on 30 January 2008.

Corporate assembly and board of directors: composition and independence

- *The composition of the corporate assembly should be determined with a view to ensuring that it represents a broad cross-section of the company's shareholders.*
- *The composition of the board of directors should ensure that the board can attend to the common interests of all shareholders and meets the company's need for expertise, capacity and diversity. Attention should be paid to ensuring that the board can function effectively as a collegiate body.*
- *The composition of the board of directors should ensure that it can operate independently of any special interests. The majority of the shareholder-elected members of the board should be independent of the company's executive management and material business contacts. At least two of the members of the board elected by shareholders should be independent of the company's main shareholder(s).*
- *The board of directors should not include representatives of the company's executive management. If the board does include members of the executive management, the company should provide an explanation for this and implement consequential adjustments to the organisation of the work of the board, including the use of board committees to help ensure more independent preparation of matters for discussion by the board, cf. Section 9.*
- *The chairman of the board of directors should be elected by the general meeting so long as the Public Companies Act does not require that the chairman shall be appointed either by the corporate assembly or by the board of directors as a consequence of an agreement that the company shall not have a corporate assembly.*

- *The term of office for members of the board of directors should not be longer than two years at a time.*
- *The annual report should provide information to illustrate the expertise and capacity of the members of the board of directors and identify which members are considered to be independent.*
- *Members of the board of directors should be encouraged to own shares in the company.*

StatoilHydro's 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. The corporate assembly must be composed of at least 12 members or a larger quantity divisible by three. Shareholders elect two-thirds of the members to the corporate assembly while employees elect the remaining one-third.

Pursuant to StatoilHydro's articles of association, our corporate assembly consists of 18 members of which 12 are elected by the Annual General Meeting.

Members of the corporate assembly are 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 CEO's management of the company, to make decisions on investments of considerable magnitude in relation to the company's resources and to make 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 5 meetings in 2008.
The following is a list of the members of the corporate assembly as of 31 December 2008:

Members of the corporate assembly elected by the shareholders:

Olaug Svarva, managing director, the Norwegian National Insurance Fund (Chair)
Idar Kreutzer, CEO, Storebrand (Deputy Chair)
Karin Aslaksen, Senior vice president, HR and HSE, Elkem AS
Tore Ulstein, Senior vice president, Market & business development, Ulstein Mekaniske Verksted Holding ASA
Greger Mannsverk, managing director, Kimek AS
Steinar Olsen, chair of the board of directors, MI Norge AS
Benedicte Berg Schilbred, executive chair of the board of directors, Odd Berg Gruppen
Ingvald Strømmen, professor at the Norwegian University of Science and Technology(NTNU)
Inger Østensjø, chief administrative officer, Stavanger local authority
Rune Bjerke, CEO, DnB NOR
Gro Brækken, secretary general, Save the Children Norway
Kåre Rommetveit, university director, University of Bergen

Members of the corporate assembly elected by and among the employees:

Tore Amund Fredriksen
Per Martin Labråthen
Anne Synnøve Hebnes
Per Helge Ødegård
Arvid Færaas
Einar Arne Iversen

Composition of the board of directors

Pursuant to StatoilHydro's articles of association, our board of directors consists of 10 members. The management is not represented on the board.

A majority of the members of the board are deemed to be "independent" board members. As required by Norwegian company law, the company's employees are entitled to be represented by three board members. There are no board members service contracts that provide for benefits upon termination of office.

On our web pages, each board member is presented with information about other directorships and offices held (current and recent), skills and experience, as well as share ownership in StatoilHydro

The work of the board of directors

- *The board of directors should produce an annual plan for its work, with particular emphasis on objectives, strategy and implementation.*
- *The board of directors should issue instructions for its own work as well as for the executive management with particular emphasis on clear internal allocation of responsibilities and duties.*
- *A deputy chairman should be elected for the purpose of chairing the board in the event that the chairman cannot or should not lead the work of the board.*
- *The board of directors should consider appointing board committees in order to help ensure thorough and independent preparation of matters relating to financial reporting and compensation paid to the members of the executive management. Membership of such sub-committees should be restricted to members of the board who are independent of the company's executive management.*
- *The board of directors should provide details in the annual report of any board committees appointed.*
- *The board of directors should evaluate its performance and expertise annually.*

The board of directors of StatoilHydro ASA is responsible for the overall management of the StatoilHydro 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 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 work of the board is based on rules of procedure that describe the board's responsibility, duties and administrative procedures. The rules of procedure also describe the duties of the chief executive officer and his/her duties vis-à-vis the board of directors. The board's rules of procedures are accessible on our web page.

StatoilHydro's board of directors has two sub-committee's which act as preparatory bodies.

The board's audit committee
The role of the audit committee is to assist in the exercise of the board's management and control responsibilities and to ensure that the group has an independent and effective external and internal auditing system. The duties of the audit committee include maintaining continuous contact with StatoilHydro's elected auditor concerning the auditing of the company's accounts. The committee also supervises the implementation of and compliance with the group's ethical guidelines.

The audit committee assesses and makes a recommendation concerning the choice of external auditor, and it is responsible for ensuring that the external auditor meets the requirements set by the authorities in Norway and in other countries in which StatoilHydro is listed on the stock exchange.

The board's remuneration committee
The role of the remuneration committee is to assist the board in its work on terms and conditions of employment for the chief executive, and on the philosophy, principles and strategy for the compensation of leading executives in StatoilHydro.

Board developments in 2008
The board meets as often as deemed necessary to fulfil its role. The board held 13 meetings in 2008. Attendance at board meetings was 97%.

Besides the board of directors, members of the executive committee and other members of senior management attended board meetings by invitation. All directors receive regular information about operational and financial performance. StatoilHydro's business plan and strategy is regularly reviewed and evaluated by the board. The directors are free to consult third parties as well as group's executives in their work.

On 30 January 2008, the corporate assembly elected Svein Rennemo (60) as new chair of the board with effect from 1 April 2008, in accordance with the nomination committee's recommendation.

Risk management and internal control

- *The board of directors must ensure that the company has sound internal control and systems for risk management that are appropriate in relation to the extent and nature of the company's activities. Internal control and the systems should also encompass the company's corporate values and ethical guidelines.*
- *The board of directors should carry out an annual review of the company's most important areas of exposure to risk and its internal control arrangements.*
- *The board of directors should provide an account in the annual report of the main features of the company's internal control and risk management systems as they relate to the company's financial reporting.*

The board of directors and the company's management attach great importance to the quality of the control functions, and this is reflected in StatoilHydro's management and control systems.

Risk management
In order to handle the various market risks, StatoilHydro has developed a comprehensive model that is used to optimise risk exposure and returns.

In StatoilHydro, risk management is divided into three categories:

- Insurable risks are managed by our captive insurance company operating in the Norwegian and international insurance markets.
- Tactical risks, which are short-term trading risks based on underlying exposures, are managed by our principle business segment line managers.
- Strategic risks that are long-term fundamental risks, and which are monitored by the company's corporate risk committee, which gives advice and makes recommendations to the corporate executive committee.

The company has a separate corporate risk committee which is chaired by the chief financial officer. The committee meets 10 to 12 times a year to consider and adopt the company's strategies for risk management. A thorough report of the company's risk management is presented in chapter 6.2 in the annual report on Form 20-F.

The management's report on internal control over financial reporting
The management of StatoilHydro ASA is responsible for establishing and maintaining adequate internal control of financial reporting. Our internal control of 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 StatoilHydro's financial statements for external reporting purposes in accordance with International Financial Reporting Standards 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).

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, management has determined that StatoilHydro's internal control over financial reporting as of 31 December 2008 was effective.

Remuneration of the board of directors

- *The remuneration of the board of directors should reflect the board's responsibility, expertise, time commitment and the complexity of the company's activities.*
- *The remuneration of the board of directors should not be linked to the company's performance. The company should not grant share options to members of its board.*
- *Members of the board of directors and/or companies with which they are associated should not take on specific assignments for the company in addition to their appointment as a member of the board. If they do nonetheless take on such assignments this should be disclosed to the full board. The remuneration for such additional duties should be approved by the board.*
- *The annual report should provide information on all remuneration paid to each member of the board of directors. Any remuneration in addition to normal directors' fees should be specifically identified.*

Remuneration of the board of directors
Members of the board of directors receive remuneration in accordance with their individual roles. The remuneration of the board is not dependent on results, and none of the shareholder-elected board members has a pension scheme or agreement on pay after termination of their office with the company.

Information about all remuneration paid to each member of the board of directors is presented in our financial statements, note 3.

Remuneration of the executive management

- *The board of directors is required by law to establish guidelines for the remuneration of the members of the executive management. These guidelines are communicated to the annual general meeting.*
- *The guidelines for the remuneration of the executive management should set out the main principles applied in determining the salary and other remuneration of the executive management. The guidelines should help to ensure convergence of the financial interests of the executive management and the shareholders.*
- *Performance-related remuneration of the executive management in the form of share options, bonus programmes or the like should be linked to value creation for shareholders or the company's earnings performance over time. Such arrangements, including share option arrangements, should incentivise performance and be based on quantifiable factors over which the employee in question can have influence.*

StatoilHydro's remuneration policy
StatoilHydro's remuneration policy is strongly linked to the company's people policy and core values. It is believed that the development of a strong value based performance culture is an important success factor in creating values for the owners.

Certain key principles have been adopted for the design of the company's remuneration concept. These principles apply in general but they will be applied differently for the different remuneration systems and job categories.

The remuneration policy is intended to:

- Ensure that an overall perspective is taken into account through solutions that are integrated with StatoilHydro's value and performance-oriented framework
- Be competitive in the talent market without taking the lead in a total remuneration context
- Reward and recognize delivery and behaviour equally
- Ensure that there is a strong link between performance and reward
- Differentiate on the basis of responsibility and performance
- Reward both short- and long-term results and contributions
- Strengthen the common interests between employees, the company and it's owners
- Be transparent and in accordance with good corporate governance.

Our 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 StatoilHydro operates within.

The decision-making process

The decision-making process for the establishment and changing of remuneration policies and the determination of salaries and other remuneration for management is in accordance with the provisions of the Companies Act paragraphs 5-6, 6-14, 6-16 a) and the Board Instruction adopted on 1 October 2007.

The board of directors has appointed a separate compensation committee. The compensation committee is a preparatory body for the board. The committee's main objective is to assist the board of directors in its work relating to the terms of employment for StatoilHydro's chief executive officer and the main principles and strategy for the remuneration and leadership development of senior executives in StatoilHydro. The board of directors decides the salary and other terms of employment for the chief executive officer.

The remuneration concept for the corporate executive committee

StatoilHydro'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

The remuneration principles and concepts adopted and practised in StatoilHydro in 2008 will be continued in the accounting year 2009. However, due to the altered economic situation that also directly affects StatoilHydro, some extraordinary adjustments have been decided with effect for year 2009 only. These measures are carried out to limit our cost increases and contribute to a moderate development of labour costs.

The extraordinary adjustments regarding base salary and variable pay for 2009 and reduction in earned variable pay are temporary measures and are not intended as permanent changes in the company's remuneration concept.

In accordance with the Norwegian Companies Act § 6-16 a), the board will present a statement regarding remuneration of the corporate executive committee at the 2009 annual meeting.

The board's statement regarding remuneration of the corporate executive committee, as well as information about all remuneration paid to each member of the executive committee, is presented in our financial statements, note 3.

Information and communications

- *The board of directors should establish guidelines for the company's reporting of financial and other information based on openness and taking into account the requirement for equal treatment of all participants in the securities market.*
- *The company should publish an overview each year of the dates for major events such as its annual general meeting, publication of interim reports, public presentations, dividend payment date if appropriate etc.*
- *All information distributed to the company's shareholders should be published on the company's web site at the same time as it is sent to shareholders.*
- *The board of directors should establish guidelines for the company's contact with shareholders other than through general meetings.*

StatoilHydro is committed to ensure that timely information is distributed in an impartial fashion so that the valuation of the company takes place on the best possible basis.

The Investor Relations corporate staff function is responsible for coordinating the group's communication with capital markets and for relations between StatoilHydro and existing and potential investors in the company.

Investor Relations is responsible for distributing and registering information in accordance with the legislation and regulations that apply where StatoilHydro securities are listed. Investor Relations reports directly to the chief financial officer.

The group's management holds regular presentations for investors and analysts. The company's quarterly presentations are broadcast live on the internet. The pertaining reports are made available together with other relevant information on the company's website.

StatoilHydro meets the requirements for the information symbol and English symbol issued by the Oslo Stock Exchange.

Take-overs

- *The board of directors should establish guiding principles for how it will act in the event of a take-over bid.*
- *During the course of a take-over process, the board of directors and management of both the party making the offer and the target company have an independent responsibility to help ensure that shareholders in the target company are treated equally, and that the target company's business activities are not disrupted unnecessarily. The board of the target company has a particular responsibility to ensure that shareholders are given sufficient information and time to form a view of the offer.*
- *The board of directors should not seek to hinder or obstruct take-over bids for the company's activities or shares unless there are particular reasons for this. In the event of a take-over bid for the company's shares, the company's board of directors should not exercise mandates or pass any resolutions with the intention of obstructing the take-over bid unless this is approved by the general meeting following announcement of the bid.*
- *If an offer is made for a company's shares, the company's board of directors should issue a statement evaluating the offer and making a recommendation as to whether shareholders should or should not accept the offer. If the board finds itself unable to give a recommendation to shareholders on whether or not to accept the offer, it should explain the background for not making such a recommendation. The board's statement on a bid should make it clear whether the views expressed are unanimous, and if this is not the case it should explain the basis on which specific members of the board have excluded themselves from the board's statement. The board should consider whether to arrange a valuation from an independent expert. If any member of the board or executive management, or close associates of such individuals, or anyone who has recently held such a position, is either the bidder or has a particular personal interest in the bid, the board should arrange an independent valuation in any case. This shall also apply if the bidder is a major shareholder. Any such valuation should be either appended to the board's statement, be reproduced in the statement or be referred to in the statement.*
- *Any transaction that is in effect a disposal of the company's activities should be decided by a general meeting, except in cases where such decisions are required by law to be decided by the corporate assembly.*

StatoilHydro's Articles of Association do not set limits on share acquisitions.

StatoilHydro's board of directors endorses the principles concerning equal treatment of all shareholders, and it is obliged to act professionally and in accordance with the applicable principles for good corporate governance if a situation were to arise in which this principle in the Code of Practice is put to the test.

The Norwegian state is currently the majority owner of StatoilHydro. Any reduction in this interest in the company will require a majority decision of the Norwegian parliament.

Auditor

- *The auditor should submit the main features of the plan for the audit of the company to the board of directors annually.*
- *The auditor should participate in meetings of the board of directors that deal with the annual accounts. At these meetings the auditor should review any material changes in the company's accounting principles, comment on any material estimated accounting figures and report all material matters on which there has been disagreement between the auditor and the executive management of the company.*
- *The auditor should at least once a year present to the board of directors a review of the company's internal control procedures, including identified weaknesses and proposals for improvement.*
- *The board of directors should hold a meeting with the auditor at least once a year at which neither the chief executive nor any other member of the executive management is present.*
- *The board of directors should establish guidelines in respect of the use of the auditor by the company's executive management for services other than the audit. The board should receive annual written confirmation from the auditor that the auditor continues to satisfy the requirements for independence. In addition, the auditor should provide the board with a summary of all services in addition to audit work that have been undertaken for the company.*
- *The board of directors must report the remuneration paid to the auditor at the annual general meeting, including details of the fee paid for audit work and any fees paid for other specific assignments.*

Our independent registered public accounting firm (independent auditor) is independent in relation to StatoilHydro and is appointed by the general meeting of shareholders. The auditor's fee must be approved by the general meeting.

Pursuant to the rules of procedure, the board's audit committee is responsible for ensuring that the company is subject to an independent and effective external and internal audit.

When evaluating the independent auditor, emphasis is placed on the firm's competence, capacity, local and international availability and the size of the fee.

The board's audit committee evaluates and makes a recommendation regarding the choice of independent auditor, and is responsible for ensuring that the independent auditor meets the requirements in Norway and in the countries where StatoilHydro 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 board's 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 external auditor without the company's management being present.

Audit committee pre-approval policies and procedures
All services provided by the independent auditor must be pre-approved by the audit committee. Provided that the suggested types of services are permissible under SEC guidelines, pre-approval is usually granted in a regular audit committee meeting. The chair of the audit committee has been given the authority to pre-approve services according to policies established by the audit committee specifying in detail types of services qualifying, provided that any services pre-approved in this manner are presented to the full audit committee at its next meeting. Some pre-approvals may therefore be granted by the chair of the audit committee if an urgent reply is deemed necessary.

Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF INCOME

(in NOK million)	Note	2008	For the year ended 31 December 2007	2006
REVENUES AND OTHER INCOME				
Revenues		**651,977**	521,665	518,960
Net income (loss) from associated companies	13	**1,283**	609	679
Other income		**2,760**	523	1,843
Total revenues and other income	5	**656,020**	522,797	521,482
OPERATING EXPENSES				
Purchases [net of inventory variation]		**(329,182)**	(260,396)	(249,593)
Operating expenses		**(59,349)**	(60,318)	(44,801)
Selling, general and administrative expenses		**(10,964)**	(14,174)	(10,824)
Depreciation, amortisation and impairment losses	11	**(42,996)**	(39,372)	(39,450)
Exploration expenses		**(14,697)**	(11,333)	(10,650)
Total operating expenses		**(457,188)**	(385,593)	(355,318)
Net operating income	5	**198,832**	137,204	166,164
FINANCIAL ITEMS				
Net foreign exchange gains (losses)		**(32,563)**	10,043	4,457
Interest income and other financial items		**12,207**	2,305	3,675
Interest and other finance expenses		**1,991**	(2,741)	(3,060)
Net financial items	8	**(18,365)**	9,607	5,072
Income before tax		**180,467**	146,811	171,236
Income tax	9	**(137,197)**	(102,170)	(119,389)
Net income		**43,270**	44,641	51,847
Attributable to:				
Equity holders of the parent company		**43,265**	44,096	51,117
Minority interest		**5**	545	730
		43,270	44,641	51,847
Earnings per share for income attributable to equity holders of the company - basic and diluted	10	**13.58**	13.80	15.82

CONSOLIDATED BALANCE SHEETS

(in NOK million)		At 31 December 2008	2007
ASSETS			
Non-current assets			
Property, plant and equipment	11	**329,841**	278,352
Intangible assets	12	**66,036**	44,850
Investments in associated companies	13	**12,640**	8,421
Deferred tax assets	9	**1,302**	793
Pension assets	21	**30**	1,622
Financial investments	14	**16,465**	15,266
Derivative financial instruments	28	**2,383**	609
Financial receivables	14	**4,914**	3,515
Total non-current assets		**433,611**	353,428
Current assets			
Inventories	15	**15,151**	17,696
Trade and other receivables	16	**69,931**	69,378
Current tax receivable	3	**3,840**	0
Derivative financial instruments	28	**27,505**	21,093
Financial investments	17	**9,747**	3,359
Cash and cash equivalents	18	**18,638**	18,264
Total current assets		**144,812**	129,790
TOTAL ASSETS		**578,423**	483,218

CONSOLIDATED BALANCE SHEETS

(in NOK million)	Note	At 31 December 2008	2007
EQUITY AND LIABILITIES			
Equity			
Share capital		**7,972**	7,972
Treasury shares		**(9)**	(6)
Additional paid-in capital		**41,450**	41,370
Additional paid-in capital related to treasury shares		**(586)**	(359)
Retained earnings		**147,998**	140,909
Other reserves		**17,254**	(12,611)
StatoilHydro shareholders' equity		**214,079**	177,275
Minority interest		**1,976**	1,792
Total equity	19	**216,055**	179,067
Non-current liabilities			
Financial liabilities	20	**54,606**	44,374
Deferred tax liabilities	9	**68,144**	67,477
Pension liabilities	21	**25,538**	19,092
Asset retirement obligations, other provisions and other liabilities	22	**54,359**	43,845
Total non-current liabilities		**202,647**	174,788
Current liabilities			
Trade and other payables	23	**61,200**	64,624
Current tax payable	9	**57,074**	50,941
Financial liabilities	20	**20,695**	6,166
Derivative financial instruments	28	**20,752**	7,632
Total current liabilities		**159,721**	129,363
Total liabilities		**362,368**	304,151
TOTAL EQUITY AND LIABILITIES		**578,423**	483,218

CONSOLIDATED STATEMENTS OF RECOGNISED INCOME AND EXPENSE (SORIE)

(in NOK million)	For the year ended 31 December 2008	2007	2006
Foreign currency translation differences	**30,880**	(9,858)	(3,817)
Actuarial gains (losses) on employee retirement benefit plans	**(7,945)**	74	(3,032)
Change in fair value of available for sale financial assets	**(1,362)**	1,039	(524)
Change in fair value of available for sale financial assets transferred to the Consolidated statements of income	**0**	(113)	0
Income tax on income and expense recognised directly in equity	**(802)**	(175)	2,321
Income and expense recognised directly in equity	**20,771**	(9,033)	(5,052)
Net income for the period	**43,270**	44,641	51,847
Total recognised income and expense for the period	**64,041**	35,608	46,795
Attributable to:			
Equity holders of the parent company	**64,036**	35,063	46,065
Minority interest	**5**	545	730
	64,041	35,608	46,795

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in NOK million)	2008	For the year ended 31 December 2007	2006
OPERATING ACTIVITIES			
Income before tax	**180,467**	146,811	171,236
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortisation and impairment	**42,996**	39,372	39,450
Exploration expenditures written off	**3,872**	1,660	1,447
(Gains) losses on foreign currency transactions and balances	**15,243**	(559)	(1,197)
(Gains) losses on sales of assets and other items	**(2,704)**	(188)	(2,371)
Termination benefits	**0**	8,633	0
Changes in working capital (other than cash and cash equivalents):			
• (Increase) decrease in inventories	**2,470**	(2,434)	(2,850)
• (Increase) decrease in trade and other receivables	**(1,129)**	(6,493)	1,060
• (Increase) decrease in net current financial derivative instruments	**6,708**	1,307	(12,450)
• (Increase) decrease in current financial investments	**(6,388)**	(2,327)	5,810
• Increase (decrease) in trade and other payables	**(5,466)**	10,447	(3,496)
Taxes paid	**(139,604)**	(102,422)	(108,174)
(Increase) decrease in non-current items related to operating activities	**6,068**	119	128
Cash flows provided by operating activities	**102,533**	93,926	88,593
INVESTING ACTIVITIES			
Additions through business combinations	**(13,120)**	0	0
Additions to property, plant and equipment	**(58,529)**	(63,785)	(45,177)
Exploration expenditures capitalised	**(6,821)**	(4,569)	(4,188)
Additions to other intangibles	**(10,828)**	(7,186)	(10,507)
Change in long-term loans granted and other long-term items	**(1,910)**	(652)	(726)
Proceeds from sale of assets	**5,371**	1,080	3,423
Cash flows used in investing activities	**(85,837)**	(75,112)	(57,175)

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in NOK million)	For the year ended 31 December 2008	2007	2006
FINANCING ACTIVITIES			
New long-term borrowings	**2,596**	1,723	97
Repayment of long-term borrowings	**(2,864)**	(2,876)	(2,270)
Distribution (to)/from minority shareholders	**179**	(327)	(741)
Dividend paid *	**(27,082)**	(25,695)	(17,756)
Treasury shares purchased	**(308)**	(217)	(1,012)
Norsk Hydro ASA merger balance	**0**	18,687	(10,025)
Net short-term borrowings, bank overdrafts and other **	**10,450**	797	329
Cash flows used in financing activities	**(17,029)**	(7,908)	(31,378)
Net increase (decrease) in cash and cash equivalents	**(333)**	10,906	40
Effect of exchange rate changes on cash and cash equivalents	**707**	(160)	42
Cash and cash equivalents at the beginning of the period	**18,264**	7,518	7,436
Cash and cash equivalents at the end of the period	**18,638**	18,264	7,518
Interest paid	**2,771**	3,709	3,611
Interest received	**4,544**	2,256	2,296

* Dividend paid in 2007 includes NOK 6.1 billion charged to Hydro Petroleum from Norsk Hydro ASA under the terms of the merger plan.

** Regarding redemption of shares held by the state, StatoilHydro has paid the state NOK 2.4 billion in 2007.

1 Organisation

StatoilHydro ASA, formerly 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.

StatoilHydro's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products.

Effective 1 October 2007, Statoil ASA merged with the oil and gas activities of Norsk Hydro ASA (Hydro Petroleum). Statoil ASA's name changed to StatoilHydro ASA as of that date.

StatoilHydro ASA is listed on the Oslo Stock Exchange (Norway) and the New York Stock Exchange (USA).

2 Significant accounting policies

Statement of compliance

The Consolidated financial statements of StatoilHydro ASA and its subsidiaries (the "group") have been prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU). The accounting policies applied by the group 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 and in preparing an opening IFRS balance sheet at 1 January 2006 (subject to certain exemptions allowed by IFRS 1) for the purpose of the transition to IFRS. For details of the transition to IFRS see StatoilHydro's Consolidated Financial Statements for 2007.

Operating expenses in the statements 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 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.

Early adoption of standards and interpretations

The group has elected to adopt the following standards, amendments and interpretations in advance of their effective dates: IAS 23 (Revised) *Borrowing Costs* (effective for accounting periods beginning on or after 1 January 2009) and IFRS 8 *Operating Segments* (effective for accounting periods beginning on or after 1 January 2009). The standards have been implemented retrospectively for the periods presented as if the policies have always been applied.

Standards and interpretations in issue not yet adopted

At the date of these financial statements, other than the standards and interpretations adopted by the group in advance of their effective dates as described above, the following standards and interpretations were in issue but not yet effective:

The amendments to IAS 1 *Presentation of Financial Statements* issued in September 2007, which will be effective for annual periods beginning on or after 1 January 2009. This revised IAS introduces certain changes to the statement of recognised income and expense. The group will present a statement of comprehensive income and a statement of changes in equity where currently a statement of income and a statement of recognised income and expense are included. Actuarial gains and losses related to pensions will be presented in other comprehensive income, whereas these are currently presented in the statement of recognised income and expense. There will be no effect on the group's reported net income or equity.

The revised version of IFRS 3 *Business Combinations,* issued in January 2008, will be applicable to business combinations occurring in annual periods beginning on or after 1 July 2009. There will be no effect on the group's reported net income or equity on adoption.

The amended version of IAS 27 *Consolidated and Separate Financial Statements* issued in January 2008 is effective for periods beginning on or after 1 July 2009. There will be no effect on the group's reported net income or equity on adoption.

The amendments to IAS 32 *Financial Instruments: Presentation* and IAS 1 *Presentation of Financial Statements* issued in February 2008 are effective for annual periods beginning on or after 1 January 2009 and will not significantly impact the group's assets, liabilities, or note disclosures.

The Improvements to IFRS 2008 issued in May 2008 are effective for accounting periods beginning on or after 1 January 2009 and include amendments to a number of accounting standards. None of the amendments will significantly impact the group's net profit or equity or classifications in the Balance sheet or Statement of income.

The amended version of IFRS 1 *First-time adoption of IFRS* and IAS 27 *Consolidated and Separate Financial Statements* issued in May 2008 is effective for periods beginning on or after 1 January 2009 and will not significantly impact the group's assets, liabilities, or note disclosures.

The amendments to IAS 39 *Financial Instruments Recognition and Measurements* issued in July 2008 will have effect from1 July 2009 and will be applied by the group when relevant. There will be no impact on the group's assets, liabilities or net income for periods presented.

IFRIC 18 *Transfers of Assets from Customers*, issued in January 2009, is effective from 1 July 2009. The group has not yet completed its evaluation of the effect of the future adoption of IFRIC 18, but the preliminary assessement indicates that there will be no significant impact on the group's assets, liabilities or net income.

The amendments to IFRS 7 *Financial Instruments: Disclosures,* issued in March 2009, enhance disclosure requirements about fair value measurements and liquidity risk and is effective for annual periods beginning on or after 1 January 2009. The amendments, which do not require comparative disclosures in the first year of application, is currently being evaluated by the group and will be reflected in the group's note disclosure for the year ended 2009.

The amendment to IFRS 2 *Share-based payment* issued in January 2008, (effective 1 January 2009), IFRIC 15 Agreements for the Construction of Real Estate (effective 1 January 2009) and IFRIC 17 Distribution of Non-cash Assets to Owners (effective 1 July 2009) are currently not relevant to the group.

Basis of consolidation

Subsidiaries

The consolidated financial statements include the accounts of StatoilHydro ASA and its subsidiaries. Subsidiaries are entities controlled by the company. Control exists when the group 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 the group 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 intragroup transactions, have been eliminated in full. Minority interests represent the portion of profit or loss and net assets in subsidiaries that is not directly or indirectly held by the parent company and is presented separately within equity in the consolidated balance sheet.

Jointly controlled assets, associates and joint venture entities

Interests in jointly controlled assets are recognised by including the group'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 the group 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.

StatoilHydro as operator of jointly controlled assets

Indirect operating expences such as personnel expenses are accumulated in cost pools. These costs are allocated to business areas and StatoilHydro operated jointly controlled assets (licenses) on an hours incurred basis. Costs allocated to the other partners' share of operated jointly controlled assets reduce the costs in the group statement of income. Only StatoilHydro's share of the statement of income and balance sheet items related to StatoilHydro operated jointly controlled assets are reflected in the Consolidated statement of income and balance sheet.

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 statement of income. 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 statement of income and balance sheet 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 are recognised directly as a separate component of equity in the Statement of recognised income and expense.

Business combinations and goodwill
In order for a business combination to exist, the acquired asset or group of assets must constitute a business (an integrated set of activities and assets conducted and managed for the purpose of providing a return to investors), which generally consists of inputs, processes and outputs. This requires judgment to be applied on a case by case basis as to whether the acquisition meets the definition of a business combination. Acquired exploration and evaluation licences for which no decision has been made to develop are treated as asset purchases based on provisions in IFRS 6. Acquisitions of licences for which a development decision has been made are assessed under the criteria described above to establish whether the transaction represents a business combination or an asset purchase.

Business combinations, except for transactions between entities under common control, are accounted for using the purchase 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 cost of purchase over the net fair value of the identifiable assets acquired 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 recorded within investments in jointly controlled entities and associates, and any impairment of the goodwill is included in income from jointly controlled entities and associates.

Revenue recognition
Revenues associated with sale and transportation of crude oil, natural gas, petroleum and chemical products and other merchandise are recognised when title passes 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 the group have an interest with other companies are recognised on the basis of volumes lifted and sold to customers during the period (the sales method). Where the group has lifted and sold more than the ownership interest, an accrual is recorded for the cost of the overlift. Where the group 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
The group markets and sells the Norwegian State's share of oil and gas production from the Norwegian Continental Self (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 recorded as purchases [net of inventory variation] and revenue, respectively. The group 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 recorded net in the group's financial statements.

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
The group 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 expense, see note 6 Remuneration, and recorded as an equity transaction (included in additional paid-in capital).

Research and development
The group undertakes research and development both on a funded basis for licence holders, and unfunded projects at its own risk. The group'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 measure reliably 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 equity, in which case it is recognised in equity.

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 recorded in the period in which they are earned or incurred, and are presented as financial items in the statement of income.

Deferred tax is provided using the balance sheet liability method. 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 profits will be available against which the asset can be utilised. However, the existence of unused tax losses is strong evidence that future taxable profits may not be available. In order to recognise a deferred tax asset based on future taxable profits, 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 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 recorded 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

The group 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 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 the group has made arrangements to fund a portion of the selling partners' (farmor's) exploration and/or future development expenditures, these expenditures are also reflected in the financial statements as and when the exploration and development work progresses, in line with the group's policy. 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 amount 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 a major capital expenditure can be justified, may remain capitalised for more than one year. The main conditions are that either firm plans exist for future drilling in the license, or a development decision is planned in the near future. Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present.

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 Construction in progress (Property, plant & 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 any decommissioning obligation, if any, and, for qualifying assets, borrowing costs.

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 and are 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, 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 the group has established separate depreciation categories for platforms, pipelines, and wells as a minimum.

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 derecognition 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.

Leases
Leases in terms of which the group assumes substantially all the risks and rewards of the ownership are recorded as finance leases within Property, plant and equipment and Financial liabilities. All other leases are classified as operating leases and the costs are charged to income on a straight line basis over the lease term, unless another basis is more representative of the benefits of the lease to the group.

Assets recorded under finance leases are stated 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 any impairment losses. When an asset leased by a jointly controlled asset in which the group participates qualifies as a finance lease, the group 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.

The group distinguishes between leases, which imply the right to use a specific asset for a period of time, and capacity contracts, which confer on the group 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 single assets or that do not involve substantially all the capacity of an undivided interest in a specific asset are not considered by the group 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 the group.

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.

Intangible assets relating to expenditure on the exploration for and evaluation of oil and natural gas resources are not amortised. These assets are subject to impairment testing when facts and circumstances suggest that the carrying amount of the 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 the group becomes a party to the contractual provisions of the asset. For additional information on fair value methods, refer to the "Measurement of fair value" section below. The subsequent measurement of the financial assets depends on what category they are classified into at inception.

At initial recognition the group classifies its financial assets into the following three main categories; financial investments at fair value through profit or loss; loans and receivables; and as available-for-sale (AFS) financial assets. The first main category; financial investments at fair value through profit or loss, consist further of two sub-categories; financial assets that as held for trading and financial assets that on initially recognition is designated as fair value through profit and loss. The latter is further also 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 Consolidated 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 an allowance made for doubtful receivables. Provision is made when there is objective evidence that the group will be unable to recover balances in full.

Non-listed equity securities are classified as AFS. AFS financial assets are carried on the balance sheet at fair value, with the change in fair value recognised directly into equity 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 equity is recognised in the statement of income.

A significant part of the group's commercial papers, bonds and listed equity securities are managed together as an investment portfolio by the group's captive insurance company and are held 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.

Financial assets are presented as current if the asset is expected to be recovered within 12 months after the balance sheet date, whereas assets expected to be recovered more than 12 months after the balance sheet date are classified as non-current, with the exception for derivative financial instruments classified in the held for trading category.

Financial assets are derecognised when the contractual rights to the cash flows expire or substantially all risk and rewards related to the ownership of the financial asset is transferred in a manner that meet the derecognising criterias.

Non-current financial investments comprise listed equity securities, non-listed equity securities, commercial papers and bonds.

Current financial investments comprise commercial papers and money market funds. The current financial investments are at initially recognition in the category 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 value recognised in the income statement.

Non-current financial receivables comprise long term interest bearing receivables and are classified in the loan and receivables category at initial recognition.

Trade and other receivables are in the category of loans and receivables.

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; and short-term highly liquid investments that are readily convertible to known amounts of cash and have a maturity of three months or less from the date of acquisition.

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
Intangible assets and property, plant and equipment
The group 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 the level that there are 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 is required in the carrying amount of a potentially impaired asset, the asset's carrying amount is compared to the recoverable amount. Generally the recoverable amount of an asset is the group's estimated value in use, which is determined using a discounted cash flow model. The estimated future cash flows are adjusted for risks specific to the asset and discounted in 2008, 2007 and 2006 using a real post-tax discount rate of 6.5%. The discount rate is calculated based on the group's post-tax weighted average cost of capital (WACC). The group considers post tax calculations sufficiently objective and consistently applicable across the various tax regimes, while still for all significant purposes leading to the same conclusion that application of the IAS 36 *Impairment of assets* assumed pre tax rates would have yielded.

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.

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 against goodwill and then pro-rata to the other assets of that unit. Impairments of goodwill are not reversed in future periods.

Financial assets
The group 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 trough 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 income statement. Any subsequent reversal of an impairment loss is recognised in the income statement.

If an available-for-sale financial asset is impaired, i.e. because the decline in fair value has been assessed to be significant or prolonged, the difference between cost and fair value is transferred from equity to the income statement. When impairments of equity instruments classified as available-for-sale are reversed this is recogniced directly to equity.

Financial liabilities
Financial liabilities are initially recognised at fair value when the group becomes a party to the contractual provisions of the liability. For additional information on fair value methods, refer to the "Measurement of fair value" section below. The subsequent measurement of the financial liabilities depends on what category they are classified into at inception. The categories applicable for the group is either financial liabilities at fair value through profit or loss or financial liability measured at amortised cost using the effective interest method.

Financial liabilities are presented as current if the liability is due to be settled within 12 months after the balance sheet date, whereas liabilities with the legal right to be settled more than 12 months after the balance sheet date are classified as non-current, with the exception for derivative financial instruments classified at fair value through profit or loss in in the held for trading category.

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 and interest and other finance expenses.

Non-current financial liabilities comprise interest-bearing bonds, bank loans, financial lease obligation and other debt.

Current financial liabilities comprise collateral liabilities, commercial papers, current portion of non-current financial liabilities, including financial lease obligations and other current debt.

Trade and other payables are carried at payment or settlement amounts.

Pension liabilities
The group 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 increases.

The group'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 Consolidated 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 Consolidated 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 StatoilHydro operated jointly controlled assets (licenses) on an hours incurred basis and recognised in the Consolidated 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 remeasured using current actuarial assumptions and the gain or loss is recognised in the Consolidated statement of income during the period in which the settlement or curtailment occurs.

Actuarial gains and losses are recognised in full in the Consolidated statement of recognised income and expense in the period in which they occur.

Contribution to defined contribution schemes are recognised in the Consolidated statement of income in the period in which the contribution amounts are earned by the employees.

Provisions
Provisions are recognised when the group 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.

Possible assets arising from past events that will only be confirmed by future uncertain events and are not wholly within the control of the group, are not recognised, but are disclosed when an inflow of economic benefits is probable.

Onerous Contracts
The group recognises as provisions the obligation under contracts defined as onerous. Contracts are deemed to be onerous if the unavoidable cost of meeting the obligations under the contract exceed 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)
Liabilities for decommissioning costs are recognised when the group has an obligation 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 oil and natural gas production or transportation facilities, upon construction or installation. An obligation for decommissioning may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations. At the time of the obligating event, a decommissioning liability is recognised and classified as Other provisions. 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 an expected license period have indefinite lives and therefore there is no measurable asset retirement obligation to be recorded. For retail outlets, decommissioning provisions are estimated on a portfolio basis.

When a liability for decommissioning cost is recognised, a corresponding amount is recorded 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.

Derivative financial instruments and hedge accounting
The group 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. 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 for derivative financial instruments classified in the held for trading category. For the group it is therefore only derivative financial instruments designated as an effective hedging instrument that is classified as non-current in line with the classification of the hedging object.

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 the group'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 that are accounted for as executory contracts.

Embedded derivatives
Derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of host contracts and the host contracts are not carried at fair value. Contracts are assessed for embedded derivatives when the group becomes a party to them, including at the date of a business combination. These 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.

Hedge accounting
For those derivatives designated as hedging instruments and where hedge accounting is to be applied, the hedging relationship is documented at its inception. This documentation identifies the hedging instrument, the hedged item or transaction, the nature of the risk being hedged and how effectiveness will be assessed throughout its duration. Such hedges are expected at inception to be highly effective.

Fair value hedges
Fair value hedges are used by the group when we are hedging the exposure to changes in the fair value of a recognised asset or liability. For fair value hedges, the carrying amount of the hedged item is adjusted for gains and losses attributable to the risk being hedged; the derivative is re-measured at fair value and gains and losses from both the hedging instrument and the hedged item are recognised in the same line in the income statement. For hedged items carried at amortised cost, the adjustment is amortised through the income statement such that it is fully amortised by maturity. The adjustment is included in the amortisation calculation at the time when the hedged item no longer is adjusted for changes in fair value, either because the hedging instruments have expired or the hedge no longer meets the requirements for hedge accounting. The group discontinues fair value hedge accounting if the hedging instrument expires or is sold, terminated or exercised, the hedge no longer meets the criteria for hedge accounting or the group revokes the designation.

Measurement of fair values
A financial instrument is regarded as quoted in an active market if the prices quoted are readily and regularly available, for example through an exchange, and the prices quoted by the exchange represent actual and regularly occurring market transactions. This will typically include, but is not limited to, commodity based futures, exchange traded option contracts and equity instruments with quoted market prices obtained from the relevant exchanges or clearing houses. The fair values of quoted financial assets and 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 the group also takes into consideration counterparty and own credit risk when valuing contracts not traded in an active market. This is either reflected in the discount rate used, or through direct adjustments to the calculated cash flows. Consequently, where the group records elements of long-term physical delivery commodity contracts at fair value, such fair value estimates are to the extent possible 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. Likewise, the fair value of interest and currency swaps is 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 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 above, the group markets and sells the Norwegian State's share of oil and gas production from the NCS. The group includes the costs of purchase and proceeds from the sale of the SDFI oil production in its Cost of goods sold and Revenue, respectively. In making the judgement the group considered the detailed criteria for the recognition of revenue from the sale of goods set out in IAS 18 Revenue, and assessed in particular by analogy whether the risk and reward of the ownership of the goods had been transferred from the SDFI to the group.

As also described above, the group 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 recorded net in the group's financial statements. In making the judgment the group 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 the group.

Method of accounting applied for the Hydro Petroleum merger
The merger between former Statoil ASA and Hydro Petroleum has been accounted for using the carrying amounts of the assets and liabilities. When making this judgement the group considered firstly whether the former Statoil ASA and Hydro Petroleum were under the common control of the Norwegian State, and secondly, given the conclusion that both entities were under the control of the Norwegian State, assessed what method of accounting would provide the most meaningful portrayal of the merger for accounting purposes. StatoilHydro concluded that such a reorganisation would be best presented using the carrying amounts of assets and liabilities, and restating all financial statements for all periods presented as if the companies had always been combined.

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.

The group is exposed to a number of underlying economic factors, such as liquids prices, natural gas prices, refining margins, foreign exchange rates, as well as financial instruments with fair value derived from changes in these factors, which affect the overall results. In addition, the results of the group are influenced by the level of production, which in the short term may be influenced by for instance maintenance. 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 in accordance with industry standards and governed by criteria established by regulations of the SEC. 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. An independent third party has evaluated StatoilHydro's proved reserves estimates, and the results of such evaluation do not differ materially from management estimates. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements but not on escalations based upon future conditions. 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 have been estimated by internal experts in accordance with 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 adverse effect on operating income as a result of increased impairment charges.

Exploration and leasehold acquisition costs. The group accounting policy is to capitalise the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. The group also capitalises leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Judgments on 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. The group has significant investments in property, plant and equipment and intangibles. 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 the 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. Exploratory wells that have found reserves, but classification of those reserves as proved depends on whether a major capital expenditure can be justified, may remain capitalised for more than one year. The main conditions are that either firm plans exist for future drilling in the license or a development decision is planned in the near future.

Estimating the recoverable amount involves complexity in estimating relevant future cash flows, based on future assumptions, 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, currency exchange rates and future output, discount rates and political and country risk among others, in order to establish relevant future cash flows. Long-term assumptions for major 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 consolidated balance sheet, and indirectly, the period's net pension expense in the consolidated statement of income, management make a number of critical assumptions affecting these estimates. Most notably, assumptions made on 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 material impact on the amounts presented. Significant changes in these assumptions between periods can have a material effect on the accounts.

Asset retirement obligations. The group has significant obligations to decommission and remove offshore installations at the end of the production period. Legal 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 income statement.

Income tax. The group 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.

3 Business combinations

In December 2008 StatoilHydro acquired the remaining 50% interest in the Peregrino heavy-oil field offshore Brazil, after closing the deal to acquire Anadarko's 50% stake on 10 December 2008. StatoilHydro paid a cash consideration of USD 1.8 billion, including expenditures incurred in the period 1 January to 11 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, StatoilHydro 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, has been recognised as part of the acquisition price. The Peregrino acquisition has been assessed to constitute a business combination under IFRS 3 and changes in the value or final payment of the contingent consideration element will be recorded as an adjustment to the book value of the assets acquired. See table below for further details on the purchase price allocation.

(in NOK million)	Carrying amount	Fair value
Property, plant and equipment	2,518	12,435
Intangible assets	0	1,543
Current assets	70	70
Total assets acquired	2,588	14,048
Current Liabilities	(316)	(323)
Net assets acquired	2,272	13,725

Intangible assets consists of licenses in the exploration and evaluation phase. No part of the purchase price was allocated to goodwill.

StatoilHydro's original share of 50% in South Atlantic Holding BV has previously been accounted for as an associated company using the equity method. As a result of the business combination, the entity is now consolidated and (in addition to the amounts shown in the table above) the book value of net assets previously accounted for using the equity method has been accounted for as additions through business combinations in note 11 Property, plant and equipment. The transaction has been recorded in the segment International Exploration and Production.

The acquired business has not generated any revenues and has not incurred significant operating expenses in the period from 1 January 2008 to the acquisition date, or in the period after the acquisition date, as the operations have mainly been related to development and exploration activities, for which the expenditures have been capitalised as intangible assets (exploration) and property, plant and equipment (development).

4 Significant acquisitions and dispositions

In November 2008 StatoilHydro 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. StatoilHydro paid a cash consideration of USD 1.3 billion and will pay an additional USD 2.1 billion in the form of future funding of 75% of Chesapeake's expenditures for drilling and completion of wells during the period 2009 to 2012. The Marcellus assets are in the exploration and evaluation phase and the funding of Chesapeake's expenditures will, on the basis of provisions in IFRS 6, be recorded in the financial statements at the time the expenditures for the wells are incurred. The transaction has been recorded in the segment International Exploration and Production, and was not considered a business combination.

In February 2008 StatoilHydro'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 PDVSA. 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 has been recognised in the Consolidated statements of income in 2008 by NOK 1.1 billion net of tax. The transaction has been recorded 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 on a line-by-line basis.

In the second quarter of 2007 StatoilHydro acquired all shares of North American Oil Sands Corporation (NAOSC) for a consideration of CAD 2.2 billion, equivalent to USD 2.0 billion. The principle asset in the acquisition was the 257,200 acres (1,110 square kilometres) of oil sands leases that NAOSC operates, located in the Athabasca region of Alberta, north-east of Edmonton. The transaction has been recorded in the segment International Exploration and Production, and was not considered a business combination.

In the first quarter of 2007 StatoilHydro acquired two of Anadarko Petroleum Corporation's US Gulf of Mexico discoveries and one prospect at a cost of USD 0.9 billion. The assets are located in the Greater Tahiti and Walker Ridge areas. As part of the transaction StatoilHydro acquired an additional 15% working interest in the Big Foot discovery and has now a 27.5% working interest, including the additions from the transaction mentioned below. The transaction has been recorded in the segment International Exploration and Production. The transaction was not considered a business combination.

In the fourth quarter of 2006 StatoilHydro acquired working interests in two US Gulf of Mexico deepwater discoveries and one exploration prospect at a cost of USD 0.7 billion. The assets are located in the Greater Tahiti and Walker Ridge areas. StatoilHydro acquired a 17.5% working interest in the Caesar discovery (the Caesar discovery has subsequently been unitised with the Tonga discovery) and a 12.5% working interest in the Big Foot discovery. The transaction has been recorded in the segment International Exploration and Production. The transaction was not considered a business combination.

5 Segments

Business segments

StatoilHydro manages its operations in four business segments; Exploration and Production Norway, International Exploration and Production, Natural Gas and Manufacturing and Marketing. 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.

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, defined as the Corporate Excecutive 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 and tax expense are not allocated to the operating segments. The measurement basis for the net operating income for each operating segments follows the accounting principles used in the financial statement as described in note 2 Significant accounting policies.

Segment data for the years ended 31 December, 2008, 2007 and 2006 is presented below:

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Other	Eliminations	Total
Year ended 31 December 2008							
Revenues third party and Other income	2,879	10,289	108,704	530,165	2,700	0	654,737
Revenues inter-segment	216,882	35,031	1,882	966	2,212	(256,973)	0
Net income (loss) from associated companies	82	809	225	216	(49)	0	1,283
Total revenues and other income	219,843	46,129	110,811	531,347	4,863	(256,973)	656,020
Net operating income	166,907	12,784	12,541	4,548	(731)	2,783	198,832
Significant non-cash items recognised in segment profit or loss:							
- Depreciation and amortisation	24,043	11,619	2,310	2,117	596	0	40,685
- Impairment losses	0	2,063	0	0	248	0	2,311
- Inventory valuation	0	0	24	5,203	0	(1,377)	3,850
- Commodity derivatives	(109)	0	(1,341)	(1,306)	(37)	0	(2,793)
- Exploration expenditure written off	749	2,957	0	0	0	0	3,706
Investments in associated companies	149	6,114	4,898	1,063	416	0	12,640
Other segment non-current assets*	165,493	160,580	35,735	34,420	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	8,488	1,256	0	95,420

* Excluding investments in associated companies.

** Deferred tax assets, post employment benefit assets and financial instruments are not allocated to segments.

*** Excluding additions due to changes in estimated cost of abandonment and removal.

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Other	Eliminations	Total
Year ended 31 December 2007							
Revenues third party and Other income	5,925	13,483	72,447	427,342	2,851	140	522,188
Revenues inter-segment	173,259	27,746	927	468	1,600	(204,000)	0
Net income (loss) from associated companies	60	372	60	233	(116)	0	609
Total revenues and other income	179,244	41,601	73,434	428,043	4,335	(203,860)	522,797
Net operating income	123,150	12,161	1,562	3,776	(2,260)	(1,185)	137,204
Significant non-cash items recognised in segment profit or loss:							
- Depreciation and amortisation	23,030	9,857	1,595	1,896	564	0	36,942
- Impairment losses	0	1,246	250	937	(3)	0	2,430
- Pension costs*	5,300	738	700	700	1,300	0	8,738
- Commodity derivatives	(2,920)	577	3,318	1,031	(88)	0	1,918
- Exploration expenditure written off	50	1,610	0	0	0	0	1,660
Investments in associated companies	125	2,253	4,516	1,066	461	0	8,421
Other segment non-current assets**	153,115	107,261	35,552	27,627	2,933	0	326,488
Non-current assets, not allocated to segments***							18,519
Total non-current assets							353,428
Additions to PP&E and intangible assets****	31,100	36,200	2,100	4,800	800	0	75,000

* Pension cost includes early retirement cost (exclusive of curtailment effects) and past service cost.

** Excluding investments in associated companies.

*** Deferred tax assets, post employment benefit assets and non-current financial instruments are not allocated to segments.

**** Excluding additions due to changes in estimated cost of abandonment and removal.

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Other	Eliminations	Total
Year ended 31 December 2006							
Revenues third party and Other income	3,576	11,987	96,040	410,689	1,778	(3,267)	520,803
Revenues inter-segment	175,544	20,608	832	899	1,986	(199,869)	0
Net income (loss) from associated companies	79	7	197	402	(6)	0	679
Total revenues and other income	179,199	32,602	97,069	411,990	3,758	(203,136)	521,482
Net operating income	135,140	3,917	21,693	7,280	(1,427)	(439)	166,164
Significant non-cash items recognised in segment profit or loss							
- Depreciation, amortisation and impairment losses	20,708	9,468	1,425	2,223	437	0	34,261
- Impairment losses	230	4,902	0	57	0	0	5,189
- Commodity derivatives	69	(354)	(6,894)	(136)	12	0	(7,303)
- Exploration expenditure written off	177	1,270	0	0	0	0	1,447
Investments in associated companies	235	2,381	4,771	964	205	0	8,556
Other segment non-current assets*	151,503	95,980	30,103	25,171	2,873	0	305,630
Non-current assets, not allocated to segments**							18,462
Total non-current assets							332,648
Additions to PP&E and intangible assets***	29,200	28,900	3,200	2,500	500	0	64,300

* Excluding investments in associated companies

** Deferred tax assets, post employment benefit assets and financial instruments are not allocated to segments.

*** Excluding additions due to changes in estimated cost of abandonment and removal.

The 2007 Financial Statements included an expense of NOK 10.7 billion before tax related to restructuring expenses and other expenses related to the merger in 2007. The major part of these expenses was related to pensions and early retirement packages offered to all employees above the age of 58 years. The total expense impacted the net operating income of all segments, and most significantly the segment Exploration and Production Norway. Based on a settlement and estimate changes in 2008, StatoilHydro has recognised NOK 1.7 billion before tax as a cost reduction in 2008. The main part of this amount relates to the segment Exploration and Production Norway.

In the International Exploration and Production segment, the Group recognised an impairment loss of NOK 4.5 billion in 2008, of which the main part relates to assets in the Gulf of Mexico. The impairment charges have been presented as Exploration expenses of NOK 2.4 billion and Depreciation, amortisation and impairment losses of NOK 2.1 billion on the basis of their nature as intangible assets (exploration assets) and fixed assets (development and producing assets), respectively.

In 2007, the International Exploration and Production segment recognised an impairment loss of NOK 1.2 billion in 2007, of which the main part related to exploration and production assets (Property, plant and equipment) in the Gulf of Mexico while the Manufacturing and Marketing segment recognised an impairment loss of NOK 0.9 billion related to property plant and equipment and intangible assets in the Energy and Retail business in Sweden.

Impairments of NOK 4.9 billion before tax in the International Exploration and Production segment in 2006 were related to Gulf of Mexico property, plant and equipment.

With effect from 1 January 2008, the internal price for natural gas sold between the segments Exploration and Production Norway and Natural Gas has been updated to better reflect changes in the markets for competing energies.

Geographical areas
StatoilHydro is present in 44 countries, and manages its four 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 2008, 2007 and 2006 is presented below:

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2008						
Norway	260,171	79,813	44,536	79,739	31,025	495,284
United States	24,712	8,795	1,660	20,182	2,545	57,894
Sweden	0	0	0	21,982	4,064	26,046
Denmark	0	0	0	21,170	(1,754)	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 associated companies)	305,373	102,322	46,396	159,958	40,688	654,737

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2007						
Norway	209,764	62,911	47,119	52,772	14,107	386,673
United States	24,142	5,269	1,766	22,823	(864)	53,136
Sweden	0	0	0	16,378	6,731	23,109
Denmark	0	0	0	16,958	(2,038)	14,920
Singapore	13,861	0	0	367	0	14,228
Other	13,290	2,485	139	11,517	2,691	30,122
Total revenues (excluding net income from associated companies)	261,057	70,665	49,024	120,815	20,627	522,188

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2006						
Norway	200,536	72,831	46,447	49,475	23,998	393,287
United States	21,070	3,731	2,089	17,436	1,296	45,622
Sweden	0	0	0	15,431	6,304	21,735
Denmark	0	0	0	14,552	87	14,639
Singapore	8,218	0	0	425	3	8,646
Other	10,768	7,157	3	15,999	2,947	36,874
Total revenues (excluding net income from associated companies)	240,592	83,719	48,539	113,318	34,635	520,803

Assets by geographic areas

(in NOK million)	2008	2007	2006
Norway	220,794	204,401	200,220
United States	50,587	38,672	33,841
Angola	23,807	15,906	16,371
Azerbaijan	21,396	16,279	17,444
Canada	17,151	14,423	3,160
Brazil	15,743	2,266	2,444
Algeria	11,270	8,371	9,699
Other areas	47,769	31,305	28,745
Non-current assets (excluding deferred tax asset, pension and financial non-current items) at 31 December	408,517	331,623	311,924

Major customers

StatoilHydro does not have transactions with single external customers where revenues amount to more than 10% of the group's total revenues.

6 Remuneration

(in NOK million, except number of man-labour year)	2008	For the year ended 31 December 2007	2006
Salaries	18,670	17,243	15,980
Pension cost*	2,851	3,131	2,281
Payroll tax	2,676	2,930	2,368
Other social benefits	2,102	1,997	1,567
Total payroll costs	26,299	25,301	22,196
Average man-labour year	28,001	27,641	26,899

*Pension cost for 2007 is exclusive of termination benefits.

Total payroll expenses are accumulated in cost-pools and partly charged to partners of StatoilHydro-operated licences on an hours incurred basis.

The calculation of pension costs and pension assets/liabilities is described in note 21 Pension liabilities.

Share based compensation
StatoilHydro's Share Saving Plan provides employees with the opportunity to purchase StatoilHydro shares through monthly salary deductions and a contribution by StatoilHydro. 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 StatoilHydro for purchased shares, amount vested for bonus shares granted and related social security tax was NOK 388, NOK 246 and NOK 96 million related to the 2008, 2007 and 2006 programs, respectively. For the 2009 program (granted in 2008) the estimated compensation expense is NOK 370 million. At 31 December 2008 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 773 million.

7 Other expenses

Auditors' remuneration

(in NOK million, excluding VAT)	Audit fee	Audit related and Other service fees	Total
2008			
Ernst & Young - Norway	35.0	5.0	40.0
Ernst & Young - outside Norway	25.3	3.9	29.2
Total	60.3	8.9	69.2
2007			
Ernst & Young - Norway	20.7	7.4	28.1
Ernst & Young - outside Norway	24.1	1.1	25.2
Total	44.8	8.5	53.3
2006			
Ernst & Young - Norway	15.9	4.2	20.1
Ernst & Young - outside Norway	19.9	2.4	22.3
Total	35.8	6.6	42.4

In addition to the figures in the table above for 2006 audit fee and other fees to Deloitte amount to NOK 39.4 and NOK 5.6 million, respectively and audit fees to Ernst & Young related to StatoilHydro-operated licenses amount to NOK 8.5, NOK 6.1 and NOK 4.0 million for 2008, 2007 and 2006, respectively.

The increases in audit fees and audit related and other fees from 2006 to 2007 and from 2007 to 2008 are mainly due to the increase in activity in connection with the merger with Hydro Petroleum.

Research and Development (R&D) expenditures

Research and Development (R&D) expenditures were NOK 2,243, NOK 1,969 and NOK 1,616 million in 2008, 2007 and 2006, respectively. R&D expenditures are partly financed by partners of StatoilHydro-operated licenses. StatoilHydro's share of the expenditures has been recognised as expense in the Consolidated statement of income.

8 Financial items

(In NOK million)	For the year ended 31 December 2008	2007	2006
Foreign exchange gains (losses) non-current financial liabilities	(11,252)	5,944	3,190
Foreign exchange gains (losses) derivative financial instruments	(25,001)	8,276	3,299
Other foreign exchange gains (losses)	3,690	(4,177)	(2,032)
Net foreign exchange gains (losses)	(32,563)	10,043	4,457
Dividends received	290	523	554
Gains (losses) financial investments	4,796	(723)	646
Interest income financial investments	975	338	612
Interest income non-current financial receivables	130	197	204
Interest and other financial income current financial assets	6,016	1,970	1,659
Interest income and other financial items	12,207	2,305	3,675
Capitalised borrowing costs	1,225	2,680	3,255
Accretion expense asset retirement obligation	(2,107)	(2,099)	(1,304)
Interest expense non-current financial liabilities	(2,743)	(2,795)	(3,059)
Gains (losses) derivative financial instruments	6,708	847	(365)
Interest and other financial expenses current financial liabilities	(1,092)	(1,374)	(1,587)
Interest and other financial expense	1,991	(2,741)	(3,060)
Net financial items	(18,365)	9,607	5,072

Included in the Foreign exchange gains (losses) derivative financial instruments classification are changes in the fair values of currency swap contracts related to liquidity and currency risk management. The weakening of the NOK versus the USD during 2008 resulted in fair value losses on these positions recognised in the annual figures for 2008.

Increase in Gains (losses) financial investments in 2008 is mainly related to currency effects, included in Fair value changes.

Increase in Interest and other financial income current financial assets in 2008 is mainly related to interest on currency swap contracts due to increased interest rate spread and accrued interest on prepaid tax.

Capitalised borrowing costs are reduced due to more fields going into production in 2008 compared to 2007.

Included in the Gains (losses) derivative financial instruments are changes in the fair values of swap positions which are used to manage the currency and interest rate risk on external loans. Decreasing USD interest rates during 2008 resulted in fair value gains on these positions. This resulted in a net financial income of NOK 2.0 billion reported on the Interest and other financial expenses classification in the annual figures for 2008.

The negative change in fair value of financial assets available for sale, included in non-listed equity securities in the balance sheet, recognised directly in equity was NOK 1,362 million in 2008, compared to a positive change in fair value of NOK 1,039 million in 2007 and a negative change in fair value of NOK 524 million in 2006.

9 Income taxes

Income before income taxes consists of

(in NOK million)	2008	2007	2006
Norway offshore	171,150	124,707	151,556
Norway onshore	(6,260)	7,331	6,402
Other countries upstream [1)]	14,610	13,727	7,038
Other countries downstream [1)]	967	1,046	6,240
Income before tax	180,467	146,811	171,236

Significant components of income tax expense were as follows

(in NOK million)	2008	2007	2006
Norway offshore	124,775	93,838	107,336
Norway onshore	3,378	1,924	1,149
Other countries upstream [1)]	9,704	9,928	628
Other countries downstream [1)]	306	535	5,434
Current income tax expense	138,163	106,225	114,547
Norway offshore	3,567	(555)	6,065
Norway onshore	(4,992)	373	856
Other countries upstream [1)]	993	(3,688)	(2,669)
Other countries downstream [1)]	(534)	(185)	589
Deferred tax expense	(966)	(4,055)	4,842
Income tax expense	137,197	102,170	119,389

1) Includes Norwegian taxes on income in other countries.

Reconciliation of Norwegian nominal statutory tax rate of 28% to effective tax rate

(in NOK million)	2008	2007	2006
Norway offshore	171,150	124,707	151,556
Norway onshore	(6,260)	7,331	6,402
Other countries upstream	14,610	13,727	7,038
Other countries downstream	967	1,046	6,240
Total income before tax	180,467	146,811	171,236
Calculated income taxes at statutory rates:			
Calculated income taxes at statutory rate (Norwegian statutory tax rate 28%)	50,531	41,107	47,946
Petroleum surtax at statutory rate (Norwegian special tax rate 50%)*	85,575	62,353	75,357
Uplift*	(5,047)	(4,365)	(3,759)
Other countries upstream (average statutory tax rates)	6,606	2,397	1,019
Other countries downstream (average statutory tax rates)	(497)	57	(754)
Other items	29	621	(420)
Income tax expense	137,197	102,170	119,389
Effective tax rate (%)	76.02	69.59	69.72

*Income from oil and gas activities on the NCS is taxed according to the Norwegian Petroleum Tax Act. In addition to normal corporation tax, a special tax of 50% is levied after deducting uplift, an investment tax credit. Uplift is deducted by 7.5% per year for four years, as from the year of investment. At the end of 2008 and 2007 unrecognised uplift credits amounted to NOK 15.1 and 17.3 billion, respectively.

The increase in the tax rate was mainly related to the net loss on financial items (mainly included in Norway onshore in the table above) which is tax deductible at a lower tax rate than the average rate.

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 2007									
Deferred tax assets	1,257	4,429	2,888	6,361	0	30,238	10,491	2,477	58,141
Deferred tax liabilities	0	(7,135)	0	(91,474)	(17,511)	0	0	(8,705)	(124,825)
Net asset/(liability) at 31 December 2007	1,257	(2,706)	2,888	(85,113)	(17,511)	30,238	10,491	(6,228)	(66,684)
Deferred tax at 31 December 2008									
Deferred tax assets	1,356	5,970	3,505	1,864	0	28,195	10,607	5,693	57,190
Deferred tax liabilities	0	(9,063)	0	(91,816)	(18,528)	0	0	(4,625)	(124,032)
Net asset/(liability) at 31 December 2008	1,356	(3,093)	3,505	(89,952)	(18,528)	28,195	10,607	1,068	(66,842)

Analysis of movements during the year	2008	2007	2006
Deferred tax liability at 1 January	66,684	71,276	69,300
Charged/(credited) to the Consolidated statements of income	(966)	(4,055)	4,842
Charged/(credited) to Equity	802	175	(2,321)
Translation differences and other	322	(712)	(545)
Deferred tax liability at 31 December	66,842	66,684	71,276

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.

Following the internal group reorganisation effective 1 January 2009, see note 31 Merger with Hydro Petroleum, StatoilHydro ASA is no longer subject to the special petroleum tax. As a consequence, the tax assets related to pension liabilities in StatoilHydro ASA have effective 31 December 2008 been recognised at 28%, which is the tax rate expected to be in effect at the realisation date. Previously the estimated tax rate was 56%, based on assumed amounts expected to be realised under the petroleum tax regime and the general tax regime, respectively. The effect is a reduction of the deferred tax assets on pensions and retained earnings by NOK 5.4 billion as of 31 December 2008.

Deferred tax assets

At the end of 2008, StatoilHydro had recognised net deferred tax assets of NOK 1.3 billion, primarily in the International Exploration and Production segment, as it is considered probable that taxable profit will be available to utilise the deferred tax assets.

Unrecognised deferred tax assets

(in NOK million)	31 December 2008	31 December 2007
Deductible temporary differences	8,016	3,860
Tax losses carry forward	4,744	3,143

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, primarily in Angola, 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.

10 Earnings per share

Basic earnings per share

For the purposes of calculating earnings per share in connection with the merger with Hydro Petroleum, weighted average number of ordinary shares outstanding was set as the total of former Statoil's weighted average number of ordinary shares outstanding and Hydro's weighted average number of outstanding shares multiplied by the number of Statoil's ordinary shares which Hydro shareholders received for each Hydro share in connection with the merger.

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 2008, 2007 and 2006 respectively, calculated as follows:

	2008	2007	2006
Net income attributable to equity holders of the parent company (in NOK million)	43,265	44,096	51,117
Weighted average number of ordinary shares outstanding (in thousands of shares):			
Issued ordinary shares at 1 January	3,188,647	2,166,144	2,189,586
Effect of own shares held	(2,693)	(21,681)	(28,558)
Effect of shares issued in the merger with Hydro Petroleum	-	1,051,404	1,069,822
Weighted average number of ordinary shares	3,185,954	3,195,867	3,230,850
Earnings per share for income attributable to equity holders of the company - basic and diluted (NOK)	13.58	13.80	15.82

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.

11 Property, plant and equipment

(in NOK million)	Machinery, equipment and transportation equipment	Production oil and gas, plants incl. pipelines	Refining and manufacturing plants	Buildings and land	Vessels	Assets under development	Total
Cost at 31 December 2006	12,890	470,361	41,220	14,885	2,754	67,861	609,971
Additions and transfers	1,579	63,879	1,661	1,196	2,174	(15,158)	55,331
Disposals assets at cost	(230)	(2,829)	(162)	(1,161)	(160)	(23)	(4,565)
Effect of movements in foreign exchange - assets	(198)	(9,869)	(1,557)	(178)	(121)	(3,570)	(15,493)
Cost at 31 December 2007	14,041	521,542	41,162	14,742	4,647	49,110	645,244
Accumulated depr. and impairment losses at 31 December 2006	(9,200)	(295,391)	(24,956)	(5,606)	(386)	(2,269)	(337,808)
Depreciation, depletion and amortisation for the year	(889)	(33,875)	(1,356)	(660)	(230)	0	(37,010)
Impairment losses for the year	0	(1,470)	(105)	0	0	0	(1,575)
Accumulated depreciation and impairment disposed assets	174	2,820	118	618	158	(16)	3,872
Effect of movements in foreign exchange – depreciation	170	4,425	538	161	28	307	5,629
Accumulated depr. and impairment losses at 31 December 2007	(9,745)	(323,491)	(25,761)	(5,487)	(430)	(1,978)	(366,892)
Carrying amount at 31 December 2007	4,296	198,051	15,401	9,255	4,217	47,132	278,352
Estimated useful lives (years)	3 - 10	*	15-20	20 - 33	20 - 25		

(in NOK million)	Machinery, equipment and transportation equipment	Production oil and gas, plants incl. pipelines	Refining and manufacturing plants	Buildings and land	Vessels	Assets under development	Total
Cost at 31 December 2007	14,041	521,542	41,162	14,742	4,647	49,110	645,244
Acquisitions through business combinations	160	0	0	0	0	14,068	14,228
Additions and transfers	3,139	47,327	3,234	1,103	819	9,627	65,249
Disposals assets at cost	(1,265)	(7,907)	(4,622)	(546)	(33)	(1,089)	(15,462)
Effect of movements in foreign exchange - assets	2,149	21,104	1,710	1,229	171	6,167	32,530
Cost at 31 December 2008	18,224	582,066	41,484	16,528	5,604	77,883	741,789
Accumulated depr. and impairment losses at 31 December 2007	(9,745)	(323,491)	(25,761)	(5,487)	(430)	(1,978)	(366,892)
Depreciation, depletion and amortisation for the year	(1,005)	(36,872)	(1,607)	(672)	(396)	0	(40,552)
Transfers	0	(2,343)	0	0	0	2,343	0
Impairment losses for the year	0	(735)	0	0	0	(1,409)	(2,144)
Accumulated depreciation and impairment disposed assets	1,138	6,667	1,446	336	0	117	9,704
Effect of movements in foreign exchange – depreciation and impairment losses	(1,241)	(8,801)	(897)	(488)	(43)	(594)	(12,064)
Accumulated depr. and impairment losses at 31 December 2008	(10,853)	(365,575)	(26,819)	(6,311)	(869)	(1,521)	(411,948)
Carrying amount at 31 December 2008	7,371	216,491	14,665	10,217	4,735	76,362	329,841
Estimated useful lives (years)	3 - 10	*	15-20	20 - 33	20 - 25		

In 2008 and 2007, capitalised borrowing cost amounted to NOK 1.2 and NOK 2.7 billion, respectively. In addition to depreciation, amortisation and impairment losses specified above, intangible assets, see note 12 Intangible assets, have been amortised by NOK 300 and NOK 787 million in 2008 and 2007, respectively.

Transfer of assets to Property, plant and equipment from Intangible assets in 2008 and 2007 amounted to NOK 1.5 and NOK 3.2 billion, respectively.

*Depreciation according to Unit of production method, see note 2 Significant accounting policies.

See note 5 Segments for description of asset impairments.

12 Intangible assets

(in NOK million)	Exploration expenditure	Other	Total
Cost at 31 December 2006	26,096	6,830	32,926
Additions	23,237	742	23,979
Disposals intangible assets at cost	0	(191)	(191)
Transfers of intangible assets	(3,090)	(79)	(3,169)
Expensed exploration expenditures previously capitalised	(2,061)	0	(2,061)
Reversal of impaired exploration wells previously capitalised	134	0	134
Effect of movements in foreign exchange – intangible assets	(3,805)	(704)	(4,509)
Cost at 31 December 2007	40,511	6,598	47,109
Accumulated amortisation and impairment losses at 31 December 2006	0	(1,721)	(1,721)
Depreciation, impairments and amortisation for the year	0	(787)	(787)
Disposals amortisation and impairment losses	0	191	191
Effect of movements in foreign exchange - amortisation and impairment losses	0	58	58
Accumulated amortisation and impairment losses at 31 December 2007	0	(2,259)	(2,259)
Carrying amount at 31 December 2007	40,511	4,339	44,850

(in NOK million)	Exploration expenditure	Other	Total
Cost at 31 December 2007	40,511	6,598	47,109
Acquisitions through business combinations	1,748	0	1,748
Other additions	17,472	176	17,648
Disposals intangible assets at cost	(160)	(1,696)	(1,856)
Transfers of intangible assets	(1,464)	12	(1,452)
Expensed exploration expenditures previously capitalised	(3,706)	0	(3,706)
Effect of movements in foreign exchange – intangible assets	7,087	441	7,528
Cost at 31 December 2008	61,488	5,531	67,019
Accumulated amortisation and impairment losses at 31 December 2007	0	(2,259)	(2,259)
Depreciation, impairments and amortisation for the year	0	(300)	(300)
Disposals amortisation and impairment losses	0	1,686	1,686
Effect of movements in foreign exchange - amortisation and impairment losses	0	(110)	(110)
Accumulated amortisation and impairment losses at 31 December 2008	0	(983)	(983)
Carrying amount at 31 December 2008	61,488	4,548	66,036

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite useful lives are amortised systematicaly over their estimated economic lives, ranging between 10-20 years.

Additions in Intangible assets of NOK 19.4 billion include acquisition of business from Anadarko Petroleum Corporation and assets acquired from Chesapeake Energy Corporation in addition to other exploration activity capitalised during 2008. See note 3 Business combinations and note 4 Significant acquisitions and dispositions for details on the acquisitions during 2008. For 2007, acquisition of assets from Anadarko Petroleum Corporation and North American Oil Sands Corporation were included in this line in addition to other exploration activity capitalised during 2007.

Included in Other Intangibles is goodwill of NOK 3 billion at 31 December 2008.

Impairment charges of NOK 2.4 billion relates to impairments of capitalised exploration mainly in the Gulf of Mexico and is classified as exploration expenses in the Statement of income. Amortisation and impairment charges relating to other intangible assets are recognised as depreciation, amortisation and impairment losses in the Consolidated statement of income. Reference is made to information in note 2 Significant accounting policies, regarding method and assumptions used in impairment tests performed.

13 Investments in associated companies

(in NOK million)	2008	2007
Carrying amount associated companies at 31 December	12,640	8,421
Net income (loss) from associated companies	1,283	609

The most significant associated companies included in the table above are South Caucasus PHC Ltd (ownership share 25,5%), BTC Pipeline company (ownership share 8,71%) and Petrocedeño S.A (ownership share 9,68%). Through contractual agreements the group has significant influence also over the BTC Pipeline company and Petrocedeño S.A, and consequently the ownership interests in these companies are accounted for using the equity method.

14 Non-current financial assets

Non-current financial investments

	At 31 December	
(in NOK million)	2008	2007
Commercial papers	0	605
Bonds	9,984	7,140
Listed equity securities	2,276	4,230
Non-listed equity securities	4,205	3,291
Financial investments	16,465	15,266

Of the non-current financial investments, NOK 12,301 million relate to the investment portfolio held by the group's captive insurance subsidiary and is accounted for using the fair value option. NOK 80 million of the group's captive insurance subsidiary portfolio is used as collateral for trading with OTC instruments.

StatoilHydro's acquisition of the Jet automated petrol retail station network was approved by the European Commission (EC) in October 2008. At 31 December 2008 it has been classified as non-listed equity securities in the balance sheet, in accordance with IAS 39, caused by certain divestment requirements set out by the EC which implies holding the activity ringfenced and thereby without StatoilHydro retaining the control prior to fulfilling the divestment requirement.

All non-current financial investments are measured at fair value. Fair value changes for non-listed equity securities are recognised in Equity - other reserves. Fair value changes for Commercial papers, Bonds and Listed equity securities are recognised in the statement of income.

When an active market exists, financial instruments are valued on the basis of quoted prices. The following table summarises the source for the group's fair value measurement of the non-current financial investments. Of the total fair value of NOK 6,402 million that is measured based on prices quoted in an active market, NOK 4,126 million are government bonds.

Source of fair value (in NOK million)	Commercial papers	Bonds	Listed equity securities	Non-listed equity securities	Total fair value
At 31 December 2008					
Fair value based on prices quoted in active market	-	4,126	2,276	-	6,402
Fair value based on price inputs from observable market transactions	-	5,858	-	717	6,575
Fair value based on inputs from other sources	-	-	-	3,488	3,488
Total fair value	-	9,984	2,276	4,205	16,465
At 31 December 2007					
Fair value based on prices quoted in active market	-	3,377	4,230	-	7,607
Fair value based on price inputs from observable market transactions	605	3,763	-	373	4,741
Fair value based on inputs from other sources	-	-	-	2,918	2,918
Total fair value	605	7,140	4,230	3,291	15,266

The table below contains the fair value and related equity price risk sensitivity of our listed and non-listed equity instruments, as accounted for under IAS 39. In 2008 the sensitivities have been calculated by using a 20% change for Listed equity securities and 40% change for Non-listed equity securities. Compared to the sensitivity calculated for 2007 the group's view of what is assessed to be reasonable possible changes for the coming year has been updated due to the changes taking place in the financial market.

Equity risk

(in NOK million)	Fair value	-20% sensitivity	20% sensitivity
At 31 December 2008			
Listed equity securities	2,276	(455)	455

(in NOK million)	Fair value	-40% sensitivity	40% sensitivity
At 31 December 2008			
Non-listed equity securities	4,205	(1,682)	1,682

(in NOK million)	Fair value	-10% sensitivity	10% sensitivity
At 31 December 2007			
Listed equity securities	4,230	(423)	423
Non-listed equity securities	3,291	(329)	329

Non-current financial receivables

(in NOK million)	At 31 December 2008	2007
Interest bearing receivables	2,736	2,784
Non-interest bearing receivables	2,178	731
Financial receivables	4,914	3,515

Of the interest bearing receivables at 31 December 2008 a balance of NOK 1,070 million relates to the BTC project financing structure and NOK 1,145 million relates to the PetroCedeño project financing structure. The receivable related to PetroCedeno SA is subordinated to the bank loan, if PetroCedeno SA is in default. Corresponding balances for 31 December 2007 were NOK 934 million for BTC and NOK 1,086 million for PetroCedeño.

Of the non-interest bearing receivables at 31 December 2008 NOK 1,024 relates to a reimbursement of a contingent liability pending the settlement of a dispute in which StatoilHydro is not a direct part. The contingent liability is included in other provisions.

All non-current financial receivables are classified in the loan and receivables category and carrying amounts reasonably approximate fair value. The following table summarises the source for the group's fair value measurement of the non-current financial receivables.

Source of fair value (in NOK million)	**Interest bearing receivables**	**Non-interest bearing receivables**	**Total fair value**
At 31 December 2008			
Fair value based on prices quoted in active market	-	-	-
Fair value based on price inputs from observable market transactions	2,736	998	3,734
Fair value based on inputs from other sources	-	1,180	1,180
Total fair value	2,736	2,178	4,914
At 31 December 2007			
Fair value based on prices quoted in active market	-	-	-
Fair value based on price inputs from observable market transactions	2,784	691	3,475
Fair value based on inputs from other sources	-	40	40
Total fair value	2,784	731	3,515

15 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.

	At 31 December	
(in NOK million)	**2008**	**2007**
Crude oil	7,249	8,097
Petroleum products	6,338	7,186
Other	1,564	2,413
Inventories	15,151	17,696

A write-down of inventory to net realisable value of NOK 3.9 billion has been recognised as Purchases [net of inventory variation] at year end 2008 (0 at year end 2007).

16 Trade and other receivables

(in NOK million)	At 31 December 2008	2007
Trade receivables	61,083	62,060
Receivables joint ventures	7,131	6,115
Receivables associated companies and other related parties	1,717	1,203
Trade and other receivables	69,931	69,378

17 Current financial investments

Current financial investments

(in NOK million)	At 31 December 2008	2007
Commercial papers	7,131	3,204
Money market funds	2,602	155
Other	14	0
Financial investments	9,747	3,359

All balances at are classified as held for trading investments, except from NOK 1,858 million at 31 December 2008 related to the investment portfolio held by the group's captive insurance subsidiary which is accounted for using fair value option.

All current financial investments are measured at fair value with gains and losses recognised in the Consolidated statements of income. When an active market exists, financial instruments are valued on the basis of quoted prices. The following table summarises the source for the group's fair value measurement of the financial instruments.

Source of fair value (in NOK million)	Commercial papers	Money market funds	Other	Total fair value
At 31 December 2008				
Fair value based on prices quoted in active market	1,744	-	-	1,744
Fair value based on price inputs from observable market transactions	5,387	2,602	14	8,003
Fair value based on inputs from other sources	-	-	-	-
Total fair value	7,131	2,602	14	9,747
At 31 December 2007				
Fair value based on prices quoted in active market	-	-	-	-
Fair value based on price inputs from observable market transactions	3,204	155	-	3,359
Fair value based on inputs from other sources	-	-	-	-
Total fair value	3,204	155	-	3,359

18 Cash and cash equivalents

(in NOK million)	At 31 December 2008	2007
Cash at bank	12,165	3,837
Time deposits and collateral deposits	6,473	14,427
Cash and cash equivalents	18,638	18,264

Cash and cash equivalents at 31 December 2008 include restricted cash of NOK 4,073 million related to trading activities. This restricted cash is related to certain collateral requirements set out by exchanges where the group is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

The overdraft bank balances and overdraft facilities are included under note 24 Current financial liabilities. For reconciliation of Cash and cash equivalents reported in the statement of financial position, see Consolidated statements of cash flows.

19 Shareholders equity

							Other reserves				
(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	Available for sale financial assets	Currency trans-lation adjust-ments	Statoil-Hydro share-holders' equity	Minority interest	Total
At 1 January 2006	3,232,247,836	8,081	(60)	44,623	(96)	101,518	727	0	154,793	1,592	156,385
Net income for the period						51,117			51,117	730	51,847
Income and expense recognised directly in equity						(958)	(277)	(3,817)	(5,052)		(5,052)
Total recognised income and expense for the period*											46,795
Dividend paid						(17,756)			(17,756)		(17,756)
Cash distributions (to) from minority shareholders										(748)	(748)
Reduction of share capital	(23,441,885)	(59)	59						0		0
Merger related adjustments consist of change in merger balance with Norsk Hydro ASA						(11,768)			(11,768)		(11,768)
Equity settled share based payments				61					61		61
Treasury shares purchased (net of allocated shares)			(53)		(3,509)				(3,562)		(3,562)
At 31 December 2006	3,208,805,951	8,022	(54)	44,684	(3,605)	122,153	450	(3,817)	167,833	1,574	169,407
Net income for the period						44,096			44,096	545	44,641
Income and expense recognised directly in equity						211	614	(9,858)	(9,033)		(9,033)
Total recognised income and expense for the period*											35,608
Dividend paid						(25,694)			(25,694)		(25,694)
Cash distributions (to) from minority shareholders										(327)	(327)
Merger related adjustments						143			143		143
Effectuation of annulment	(20,158,848)	(50)	50	(3,426)	3,426				0		0
Equity settled share based payments (net of allocated shares)				112					112		112
Treasury shares purchased (net of allocated shares)			(2)		(180)				(182)		(182)
At 31 December 2007	3,188,647,103	7,972	(6)	41,370	(359)	140,909	1,064	(13,675)	177,275	1,792	179,067

(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	StatoilHydro shareholders' equity	Minority interest	Total
At 31 December 2007	3,188,647,103	7,972	(6)	41,370	(359)	140,909	1,064	(13,675)	177,275	1,792	179,067
Net income for the period						43,265			43,265	5	43,270
Income and expense recognised directly in equity						(9,094)	(1,015)	30,880	20,771		20,771
Total recognised income and expense for the period*											64,041
Dividend paid						(27,082)			(27,082)		(27,082)
Cash distributions (to) from minority shareholders										179	179
Equity settled share based payments (net of allocated shares)				80					80		80
Treasury shares purchased (net of allocated shares)			(3)		(227)				(230)		(230)
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

* For detailed information, see Consolidated statements of recognised income and expense.

The NOK 9,094 million reduction in retained earnings in 2008, in the line item Income and expense recognised directly in equity, consist of actuarial losses, net of increase in the related deferred tax asset of NOK 3,704 million, and a reduction in deferred tax assets of NOK 5,390 million due to internal reorganisations, see note 32 Subsequent events for more details on the reorganisations.

The currency translation adjustments in 2008, on the line item Income and expense recognised directly in equity, relates to the translation of significant net assets amounts in subsidiaries, mainly whose functional currencies are USD and EUR, and are caused by the weakening of the NOK to the USD and EUR.

For information regarding changes in equity related to the merger with Hydro Petroleum, see information in note 31 Merger with Hydro Petroleum.

In 2001, 25,000,000 treasury shares were issued. During 2002 and 2003 a total of 1,558,115 of the treasury shares were distributed as bonus shares in favour of retail investors in the initial public offering in 2001. On 10 May 2006 the annual General Meeting resolved to reduce the company's share capital by a total of NOK 58,604,712.50 through the annulment of the rest of these treasury shares.

The annual General Meeting in 2006 authorised the Board of Directors to acquire treasury shares for subsequent annulment. Under an agreement with the Norwegian State a proportion of the State's shares should later be redeemed and annulled, so that the State's ownership interest remained unchanged. Both the acquired shares and the firm obligation have been included in Treasury shares since the date the treasury shares have been acquired in the market according to the authorisation. The extraordinary General Meeting on 5 July 2007 approved a reduction of the share capital by NOK 50,397,120 through the annulment of 5,867,000 acquired treasury shares, and redemption and annulment of an additional 14,291,848 shares held by the State. The State, represented by the Ministry of Petroleum and Energy, received a payment of NOK 2,441,899,894 for the shares. The amount corresponded to the average volume-weighted price of the Company's treasury shares acquired in the market with the addition of interest. As of 31 December 2008 the Norwegian State had an ownership interest in StatoilHydro of 66.42% (excluding Folketrygdfondet of 3.42% (Norwegian national insurance fund)). The Norwegian State is defined as a related party, see note 27 Related parties.

After the annulment in 2007, StatoilHydro's share capital of NOK 7,971,617,757.50 comprised 3,188,647,103 shares at a nominal value of NOK 2.50.

The Board of Directors is authorised on behalf of the Company to acquire StatoilHydro shares in the market. The authorisation may be used to acquire StatoilHydro shares with an overall nominal value of up to NOK 15 million. The Board decides the manner in which the acquisition of StatoilHydro shares in the market will take place. Such shares acquired in accordance with the authorisation may only be used for sale and transfer to employees of the StatoilHydro Group as part of the Group's share saving plan approved by the Board. The lowest amount which may be paid per share is NOK 50, the highest amount which may be paid per share is a maximum NOK 500. The authorisation is valid until the next ordinary General Meeting.

During 2008 a total of 2,106,223 treasury shares were purchased for NOK 308 million. At 31 December 2008 StatoilHydro had 3,781,209 treasury shares all of which are related to the group's share saving plan.

StatoilHydro 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 8.50 in 2008 for StatoilHydro ASA and NOK 9.12 and NOK 8.20 in 2008, 2007 and 2006, respectively for the former Statoil ASA. In addition, under terms of the merger plan Hydro Petroleum was charged the dividend payment of NOK 6.1 billion paid by Norsk Hydro ASA to its shareholders in 2007. Dividend payments for 2007 included in StatoilHydro's equity include both the former Statoil ASA and Hydro Petroleum dividend payments. A dividend for 2008 of NOK 7.25 per share, amounting to a total dividend of NOK 23.1 billion, will be proposed at the Annual General Meeting in May 2009. The proposed dividend is not recognised as a liability in the financial statements.

Retained earnings available for distribution of dividends at 31 December 2008 is limited to the retained earnings of the parent company based on Norwegian accounting principles and legal regulations and amounted to NOK 120,168 million (before provisions for proposed dividend for the year ended 31 December 2008 of NOK 23,090 million). This differs from retained earnings in the consolidated financial statements of NOK 147,998 million. In accordance with legal requirements dividends is not allowed to reduce the shareholders' equity of the parent company below 10% of total assets.

20 Non-current financial liabilities

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	
	2008	2007	2008	2007	2008	2007
Financial liabilities measured at amortised cost						
Unsecured bonds						
US dollar (USD)	6.78	7.00	24,202	17,418	25,709	20,016
Norwegian kroner (NOK)	-	6.21	-	500	-	501
Euro (EUR)	5.58	5.62	6,101	5,316	6,458	5,634
Swiss franc (CHF)	4.01	-	1,023	-	1,032	-
Japanese yen (JPY)	1.65	1.50	1,008	869	983	878
Great Britain Pound (GBP)	6.13	6.13	2,271	2,429	1,935	2,543
Total (A)			34,605	26,532	36,117	29,572
Unsecured bank loans						
US dollar (USD)	2.60	5.09	6,314	2,530	6,329	2,549
Secured bank loans						
US dollar (USD)	5.86	7.45	1,252	2,683	1,262	2,792
Other currencies	6.82	6.57	63	80	63	80
Financial lease liabilities			5,665	4,011	5,665	3,738
Other liabilities			864	38	855	38
Total (B)			14,158	9,342	14,174	9,197
Financial liabilities measured at amortised cost subject for hedge accounting						
US dollar (USD)	5.94	6.29	9,957	7,845	7,403	7,849
Euro (EUR)	5.13	5.13	2,097	1,627	2,050	1,636
Swiss franc (CHF)	-	4.01	-	982	-	979
Japanese yen (JPY)	-	0.47	-	241	-	241
Total (C)			12,054	10,695	9,453	10,705
Grand total liabilities outstanding (A+B+C)			60,817	46,569	59,744	49,474
Less current portion			6,211	2,196	6,183	2,196
Financial liabilities			54,606	44,373	53,561	47,278

The third section of the table above contains bonds valued at amortised cost as adjusted for the fair value of hedged interest rate risk for the bonds that qualify for hedge accounting. The table does not illustrate the economic effects of agreements entered into to swap the various currencies into USD. For further information see note 29 Financial instruments by category.

Weighted average interest rates are calculated on the loans per currency and do not reflect swap agreements.

Fair value is calculated by discounting cash flows based on year-end market interest rates from external sources. Year-end market interest rates used as discount rates are derived from LIBOR and EURIBOR adjusted for credit premiums. Credit premiums are based on indicative pricing from external financial institutions.

Details of largest unsecured bonds

Bond agreement	Fixed interest rate	Maturity (year)	Carrying amount in NOK million at 31 December 2008	2007
USD 500 million	6.500%	2028	3,462	2,675
USD 500 million	5.125%	2014	3,498	2,704
USD 480 million	7.250%	2027	3,363	2,600
USD 375 million	5.750%	2009	2,624*	2,026*
USD 300 million	7.750%	2023	2,100	1,623
USD 300 million	6.360%	2009	2,100	1,623
EUR 500 million	5.125%	2011	4,915	3,961
EUR 300 million	6.250%	2010	2,960	2,388
GBP 225 million	6.125%	2028	2,277	2,432

* Net after buy-backs NOK 2,288 million and NOK 1,765 million in 2008 and 2007, respectively.

Currency swaps are used for risk management purposes. Unsecured bonds are either denominated in US dollar, amounting to NOK 34,159 million or the amounts are swapped into US dollar, amounting to NOK 12,500 million. As a result of this the total portfolio is exposed to changes in the USDNOK exchange rate. None of the US dollar currency swaps entered into as economic hedges meet the criteria for hedge accounting. Interest rate swaps are used to manage the interest rate risk on the unsecured bond contracts with fixed interest rates. As a result of this 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 and investments in associated companies with a combined book value of NOK 2,908 million, collateral in bank deposits with book value of NOK 1,070 million, and the group's pro-rata share of income from certain applicable projects.

The group has 24 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 is NOK 42,722 million at the 31 December 2008 closing rate.

The group has an agreement with an international bank syndicate for a committed non-current revolving credit facility totalling USD 2.0 billion, all undrawn at the 31 December 2008. The commitment fee is 0.0575% per annum.

Non-current financial liabilities maturity profile

(undiscounted cash flows in NOK million)	At 31 December 2008	2007
1-3 years	14,635	13,112
3-5 years	14,095	13,651
After 5 years	53,324	46,438
Total repayment of non-current financial liabilities	82,055	73,201

Financial liabilities

	At 31 December 2008	2007
Non-current financial liabilities (in NOK million)	54,606	44,373
Weighted average maturity (years)	9	10
Weighted average annual interest rate (%)	5.64	6.11

21 Pension liabilities

The Norwegian companies in the group are obligated to follow the Act on Mandatory company pensions. The company's pension scheme follows the requirement as included in the Act.

StatoilHydro 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 the group have defined contribution plans. The period's contributions are recognised in the Consolidated Statements of Income as the pension cost for the period.

In Norway, the group is - due to National agreements - a member of the "agreement-based early retirement plan" (AFP). When an employee retires through AFP the group has an obligation to pay a percentage of the benefits. This part of the plan is defined as a multi-employer plan. The administrator is not able to calculate the group's share of assets and liabilities and this plan is consequently accounted for as a defined contribution plan. When an employee retires through AFP, the group also offers a gratuity from the company. This is a defined benefit plan, and included in the accrued obligations related to the defined benefit plans.

The obligations related to the defined benefit plans were measured at 31 December, 2008 and 2007. 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 2008 the discount rate for the defined benefit plans in Norway was estimated to be 4.5% based on the long-term interest rate on Norwegian government bonds extrapolated based on a 30 year yield curve to match StatoilHydro's payment portfolio for earned benefits.

The longest duration of Norwegian government bonds are 10 years. It is StatoilHydro's opinion that the most appropriate method to extrapolate the 10 years rate to a 30 year rate is based on the yield curves with reference to European and USA interest rates (equally weighted). In a long term perspective, these countries are assumed to have similar market trends and interest levels as Norway.

Actuarial gains and losses are recognised directly in retained earnings, outside the Consolidated Statements of Income, in the period in which they occur, and are presented in the statement of recognised income and expense. Actuarial gains and losses related to the accrual for termination benefits are recognised in the Consolidated Statements of Income in the period in which they occur.

Payroll tax is calculated based on the pension plan's net unfunded status. Payroll tax is included in the projected benefit obligation.

StatoilHydro 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 periodic pension cost

(in NOK million)	2008	2007	2006
Current service cost	2,361	2,611	2,065
Interest cost on prior years' benefit obligation	2,456	1,713	1,421
Expected return on plan assets	(2,101)	(1,829)	(1,407)
Amortisation of actuarial gain or loss related to termination benefits	(215)	0	0
Amortisation of past service cost	17	2,075	0
Losses (gains) from curtailment or settlement	(7)	(1,641)	0
Defined benefit plans	2,511	2,929	2,079
Defined contribution plans	268	160	155
Multi-employer plans	72	42	47
Termination benefits	0	8,633	49
Net pension cost	2,851	11,764	2,330

Pension cost includes payroll tax.

Pension cost is partly charged to partners of StatoilHydro operated licences.

For information regarding pension benefits for key management personnel, see note 27 Related parties.

In 2007, StatoilHydro ASA offered early retirement (termination benefits) to employees above the age of 58 years (contingent upon certain conditions). The expenses related to termination benefits of NOK 5.6 billion and NOK 3.0 billion were recognised as Operating expenses and Selling, general and administration expenses, respectively.

Change in projected benefit obligation (PBO)

(in NOK million)	2008	2007
Projected benefit obligation at 1 January	52,791	40,185
Current service cost	2,361	2,611
Interest cost on prior years' benefit obligation	2,456	1,713
Actuarial loss (gain)	3,581	198
Past service cost	18	2,075
Benefits paid	(1,302)	(605)
Curtailments	0	(1,641)
Early retirement	0	8,633
Sale of subsidiary	(670)	0
Settlement	0	(329)
Foreign currency translation	(29)	(49)
Projected benefit obligation at 31 December	59,206	52,791

Change in pension plan assets

(in NOK million)	2008	2007
Fair value of plan assets at 1 January	35,158	30,110
Expected return on plan assets	2,101	1,829
Actuarial gain (loss)	(4,149)	(236)
Company contributions (including payroll tax)	1,377	3,777
Benefits paid	(346)	(338)
Sale of subsidiary	(443)	11
Foreign currency translation	0	5
Fair value of plan assets at 31 December	33,698	35,158

Change in net pension liabilities

(in NOK million)	2008	2007
Net pension liabilities at 1 January	(17,633)	(10,078)
Net periodic pension costs defined benefit plans	(2,511)	(2,929)
Net actuarial loss (gain) recognised in SORIE	(7,945)	(434)
Less employer contributions	1,377	3,777
Less benefit paid during the year	956	259
Acquisition and sale	227	11
Settlement	0	340
Foreign currency translation and other changes	21	54
Termination benefits	0	(8,633)
Net pension liabilities at 31 December	(25,508)	(17,633)

Surplus (deficit) at 31 December for the current and previous two periods are as follow:

(in NOK million)	2008	2007	2006
Surplus (deficit) at 31 December	(25,508)	(17,633)	(10,078)
Represented by:			
Asset recognised as pension asset	30	1,622	1,113
Liability recognised as non-current pension liability	(25,538)	(19,092)	(11,028)
Liability recognised as current liability	0	(163)	(163)

The defined benefit obligation may be analysed as follows:

(in NOK million)	2008	2007
Funded pension plans	37,446	33,278
Unfunded pension plans	21,760	19,513
Projected benefit obligation at 31 December	59,206	52,791

Actuarial gains and losses recognised directly in retained earnings:

(in NOK million)	2008	2007	2006
Unrecognised actuarial losses (gains) at 1 January	0	0	0
Actuarial losses (gains) on plan assets occur during the year	4,149	(272)	(1,139)
Actuarial losses (gains) on benefit obligation occur during the year	3,581	198	4,169
Recognised in the income statement during the year	215	0	0
Recognised in SORIE during the year	(7,945)	74	(3,030)
Unrecognised actuarial losses (gains) at 31 December	0	0	0

Actual return on plan assets

(in NOK million)	2008	2007	2006
Actual return on plan assets	(2,048)	1,593	2,546

History of experience gains and losses for the current and previous two periods are as follow:

(in NOK million)	2008	2007	2006
Actual return less expected return on plan assets (NOK million)	(4,149)	272	1,139
As % of plan assets at beginning of year	(11.80%)	0.90%	4.45%
Experience gains/(losses) on plan liabilities (NOK million)	(3,581)	(198)	(4,169)
As % of present value of plan liabilities at beginning of year	(6.78%)	(0.49%)	(12.60%)
Total actuarial gain/(loss) (NOK million)	(7,730)	74	(3,030)
As % of present value of plan liabilities at beginning of year	(14.64%)	0.25%	(9.16%)

The cumulative amount of actuarial gains and losses recognised in the Statement of recognised income and expense amounted to NOK 13.3, NOK 4.2 billion and NOK 4.5 billion net of tax (negative effect on retained earnings) in 2008, 2007 and 2006, respectively.

Assumptions for the year (Profit and Loss items) in %	2008	2007
Discount rate	5.00	4.50
Expected return on plan assets	6.25	5.75
Rate of compensation increase	4.50	4.25
Expected rate of pension increase	3.25	2.75
Expected increase of social security base amount (G-amount)	4.25	4.00
Expected Inflation	2.25	2.25

Assumptions at end of year (Balance sheet items) in %	2008	2007
Discount rate	4.50	5.00
Expected return on plan assets	5.75	6.25
Rate of compensation increase	4.00	4.50
Expected rate of pension increase	2.75	3.25
Expected increase of social security base amount (G-amount)	3.75	4.25
Expected Inflation	2.00	2.25
Average remaining service period in years	15	15

The assumptions presented are for the Norwegian companies in the group which are members of StatoilHydro's pension fund. The defined benefit plans of other subsidiaries are not significant to the pension assets and liabilities of the group.

Expected turnover at 31 December 2008 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 turnover at 31 December 2007 was 4.0%, 1.5%, 1.3%, 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 Agreement-based early retirement pension (AFP) is 50% for employees at 62 years and 30% for employees at 63-66 years.

For the population in Norway, the mortality table K 2005 plus one extra year of living 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 StatoilHydro in Norway.

Below is shown a selection related to demographic assumptions used at 31 December 2008. The table shows the probability of disability or death, within one year, by age groups as well as expected lifetime.

	Disability in %		Mortality in %		Expected lifetime	
Age	Men	Women	Men	Women	Men	Women
20	0.12	0.15	0.015	0.015	81.51	85.35
40	0.21	0.35	0.083	0.046	81.83	85.60
60	1.48	1.94	0.716	0.386	83.27	86.51
80	N/A	N/A	6.550	4.142	88.97	90.74

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 2008. 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)	0.5%	-0.5%	0.5%	-0.5%	0.5%	-0.5%	0.5%	-0.5%
Changes in:								
Projected benefit obligation at 31 December 2008	(4.8)	5.5	3.9	(3.5)	(1.5)	1.5	3.1	(2.8)
Service cost 2009	(0.3)	0.4	0.3	(0.3)	(0.1)	0.1	0.2	(0.2)

Pension assets

The plan assets related to the defined benefit plans were measured at fair value at 31 December 2008 and 2007. The long-term expected return on pension assets is based on long-term risk-free rate adjusted for the expected long-term risk premium for the respective investment classes. A risk free interest (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 give 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 %)	2008	2007
Equity securities	19.10	31.90
Debt securities	70.20	50.50
Commercial papers	3.30	8.60
Real estate	6.90	6.90
Other assets	0.50	2.10
Total	100.00	100.00

Properties owned by StatoilHydro pension fund amounted to NOK 2.2 billion and NOK 2.3 billion of total pension assets at 31 December 2008 and 2007, respectively, and are rented to companies in the group.

StatoilHydro'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 StatoilHydro pension fund for 2009. The portfolio weight during a year will depend on the risk capacity.

Finance portfolio StatoilHydro's pension fund

(All figures in %)	Portfolio weight 1)		Expected rate of return
Equity securities	40.00	(+/- 5)	X + 4
Debt securities	59.50	(+/- 5)	X
Certificates	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.

Contributions to pension plans may either be paid in cash or be deducted from the pension premium fund. The pension premium fund amounted to NOK 4.5 billion and NOK 7.3 billion at 31 December 2008 and 2007, respectively. The decision whether to pay in cash or deduct from the pension premium fund is made on an annual basis. In 2008, NOK 2.9 billion was deducted from the pension premium fund. The company contribution in 2008, paid in cash, was NOK 0.2 billion (exclusive payroll tax). In addition, NOK 1.2 billion was paid to StatoilHydro pension fund as a capital increase in 2008. In 2007, the company contribution, paid in cash, was NOK 3.4 billion (exclusive payroll tax) of which NOK 1.0 billion was a voluntary payment to the premium fund.

The expected company contribution related to 2009 amounts to NOK 2.5 billion.

22 Asset retirement obligations, other provisions and other liabilities

(in NOK million)	
Asset retirement obligations at 1 January 2007	39,912
Liabilities incurred/revision in estimates	(1,644)
Amounts used and charged against provision	(636)
Unused amounts reversed	0
Effects of change in the discount rate	443
Reduction due to disposals	(120)
Accretion	2,099
Currency exchange difference	(473)
Asset retirement obligations at 31 December 2007	39,581
Current portion of asset retirement obligations	575
Analysis of provisions and other liabilities at 31 December 2007:	
Non-current portion of asset retirement obligations	39,006
Other provisions and other liabilities	4,839
Asset retirement obligations, other provisions and other liabilities	43,845
Asset retirement obligations at 1 January 2008	39,581
Liabilities incurred/revision in estimates	5,470
Amounts used and charged against provision	(675)
Unused amounts reversed	0
Effects of change in the discount rate	(2,234)
Reduction due to disposals	(1,402)
Accretion	2,107
Currency exchange difference	1,239
Asset retirement obligations at 31 December 2008	44,086
Current portion of asset retirement obligations	905
Analysis of provisions and other liabilities at 31 December 2008:	
Non current portion of asset retirement obligations	43,181
Other provisions and other liabilities	11,178
Asset retirement obligations, other provisions and other liabilities	54,359

Asset retirement obligations

A majority of expenditures related to asset retirement obligations are currently expected to be paid in the period between 2015 and 2025. Only a minor portion of expenditures are expected to be paid in the next five years. The timing depends primarily on when the production ceases at the various facilities. For further discussion of methods applied and estimates required, see note 2 Significant accounting policies.

Obligations related to environmental remediation and cleanup related to oil and gas producing assets are included in the estimated asset retirement obligations.

23 Trade and other payables

(in NOK million)	At 31 December 2008	2007
Trade payables	15,582	21,776
Non-trade payables, accrued expenses and provisions	38,155	29,918
Payables to associated companies and other related parties	7,463	12,930
Trade and other payables	61,200	64,624

Non-trade payables and accrued expenses include provisions for certain claims and litigations that are further described in note 26 Other commitments and contingencies.

24 Current financial liabilities

(in NOK million)	At 31 December 2008	2007
Current financial liabilities measured at amortised cost		
Bank loans and overdraft facilities	906	1,100
Collateral liabilities	10,123	2,797
Commercial paper liabilities	2,989	0
Current portion of non-current financial liabilities	5,604	1,919
Current portion of financial lease obligations	607	277
Other	466	73
Financial liabilities	20,695	6,166
Weighted interest rate	2.50%	5.56%

Current financial liabilities' carrying amounts reasonably approximate fair value. Fair value is based on price inputs from observable markte transactions.

Collateral liabilities relates to cash received in order to offset a portion of the group credit exposure.

Commercial paper liabilities relates to the US Commercial Paper (CP) program available for short term funding. StatoilHydro can borrow maximum USD 4 billion under the current CP programme.

At 31 December 2008 and 2007 the group had no committed short-term credit facilities available or drawn.

25 Leases

StatoilHydro leases certain assets, notably vessels and drilling rigs.

StatoilHydro has entered into certain operational lease contracts for a number of drilling rigs as of 31 December 2008. The remaining significant contracts' terms range from three months to five years. Certain contracts contain renewal options. Rig lease agreements are for the most part based on fixed day rates. StatoilHydro'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 parts of the lease term for the most part to StatoilHydro-operated licenses on the Norwegian Continental Shelf (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, StatoilHydro only includes its proportional share of the rig lease.

As a member of the Snøhvit sellers' group StatoilHydro has entered into leasing arrangements for three LNG vessels on behalf of StatoilHydro and the SDFI respectively. StatoilHydro accounts for the combined StatoilHydro and the SDFI share of these agreements as financial leases in the balance sheet, and further accounts for the SDFI related portion as operating sub-leases. The finance leases included in the balance sheet reflect a leasing term of 20 years. In addition, StatoilHydro has the option to extend the leases for two additional periods of five years each.

In 2008, net rental expense was NOK 10.2 billion (NOK 5.7 billion in 2007 and NOK 4.9 billion in 2006) of which minimum lease payments were NOK 11.8 billion (NOK 7.1 billion in 2007 and NOK 5.9 billion in 2006) and sublease payments received were NOK 1.7 billion (NOK 1.5 billion in 2007 and NOK 1.0 billion in 2006). No material contingent rents expensed in 2008, 2007 or 2006.

The information in the table below shows future minimum lease payments under non-cancellable leases at 31 December 2008.

Amounts related to financial leases include future minimum lease payments for assets in the financial statements at year-end 2008.

			Financial lease		
(in NOK million)	Operating leases	Operating subleases	Minimum lease payments	Interest	Net present value minimum lease payments
2009	16,101	(2,161)	742	(101)	641
2010	13,400	(1,274)	684	(110)	574
2011	9,107	(138)	700	(115)	585
2012	6,383	(131)	694	(107)	587
2013	4,375	(131)	469	(108)	361
Thereafter	3,955	(1,203)	4,731	(1,815)	2,916
Total future minimum lease payments	53,321	(5,038)	8,020	(2,356)	5,664

Property, plant and equipment include the following amounts for leases that have been capitalised at 31 December 2008 and 2007:

(in NOK million)	2008	2007
Vessels and equipment	6,501	5,503
Accumulated depreciation	(1,205)	(836)
Capitalised amount	5,296	4,667

26 Other commitments and contingencies

Contractual commitments

(in NOK million)	2009	2010	Thereafter	Total
Joint Venture related:				
Construction in progress	12,005	5,559	3,866	21,430
Property, plant and equipment and other investments	3,161	4,176	10,110	17,447
Acquisition of intangible assets	2,881	173	15	3,069
Subtotal joint venture related commitments	18,047	9,908	13,991	41,946
Non Joint Venture related:				
Construction in progress	3,004	2,150	309	5,463
Total	21,051	12,058	14,300	47,409

The contractual commitments reflect StatoilHydro's share and mainly comprise construction and acquisition of property, plant and equipment.

Other long-term commitments

StatoilHydro 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 31 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 unconsolidated equity associates are included gross in the tables below. Where the group reflects both ownership interests and transport capacity cost for a pipeline or other asset in the consolidated accounts, the amounts in the table include the net commitment payable for StatoilHydro.

Nominal minimum commitments at 31 December 2008:

(in NOK million)	Transport and terminal commitments	Refinery related commitments	Total
2009	7,847	127	7,974
2010	7,851	262	8,113
2011	8,201	271	8,472
2012	7,310	292	7,602
2013	6,196	314	6,510
Thereafter	41,653	21,561	63,214
Total	79,058	22,827	101,885

The above table outlines nominal minimum obligations for future years, and mainly includes commitments within StatoilHydro's natural gas operations in addition to various other transport and similar commitments. StatoilHydro has entered into pipeline transportation 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.

StatoilHydro has contractual commitments to the US-based energy company Dominion for terminal capacity at the Cove Point liquefied natural gas terminal in the USA. As of 2009 the commitment will include an annual capacity of approximately 10.1 bcm for a 20 year period. Such commitments have been included in full in the table above, but have been made in part on behalf of and for the account and risk of the SDFI. StatoilHydro's and the SDFI's respective future shares of the Cove Point terminal capacity and related commitments are subject to future consideration, and the outcome may consequently impact the extent of the future net terminal capacity and related net commitments assumed by StatoilHydro.

In 2008 Sonatrach and StatoilHydro signed an agreement under the terms of which Sonatrach will receive access to an annual of 2 bcm of StatoilHydro's regasification capacity at the Cove Point terminal for 15 years from the beginning of 2009. This arrangement which reduces StatoilHydro's net exposure at the Cove Point terminal has however not been substracted from the above table.

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.

StatoilHydro has entered into a number of general or field specific long-term frame agreements mainly related to crude oil loading and transport capacity availability. The main contracts run up until the end of the respective field lives. Such contracts have not been included in the above table of contractual commitments unless they entail specific minimum payment obligations.

Guarantees
Statoil Detaljhandel has issued guarantees amounting to a total of SEK 1.0 billion (NOK 0.9 billion), the main part of which relates to financial guarantee commitments on behalf of retailers. The liability recognized at fair value under IAS 39 related to these guarantee commitments is immaterial at year end.

StatoilHydro 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, StatoilHydro is obligated to deliver indemnity reserves to Petro Canada in the event that recoverable reserves prove lower than a specified volume. At year end 2008 the value of the remaining volume covered by the guarantee has been estimated to a total of NOK 2.1 billion at current market prices. A provision of NOK 0.8 billion has been recognised at year end 2008 related to this guarantee.

Under the Norwegian public limited companies act section 14-11, StatoilHydro 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 StatoilHydro is jointly liable for is approximately NOK 6.6 billion with terms extending until 2050. As of the current date, the probability that these guarantee commitments will impact StatoilHydro is deemed to be remote. No liability has been recognised in the accounts at year end 2008.

Insurance
The group has taken out insurance to cover certain potential liabilities arising from its operations world wide. This covers liabilities for claims arising from pollution damage. Most of the group's production installations are covered through Statoil Forsikring a.s, which reinsures parts of the risk in the international insurance market. As all significant activities of Statoil Forsikring a.s. relates to insurance for entities and operations consolidated in the group accounts, IFRS 4 has not been applied to such activities in the group financial statements.

Statoil Forsikring a.s is member of two mutual insurance companies, Oil Insurance Ltd and sEnergy Insurance Ltd. sEnergy ceased operations on 15 May 2006 and the company is in the wind-up phase. Membership in these companies means that Statoil Forsikring is liable for its proportionate share of any losses which might arise in connection with the business operations of the companies. Members of the companies have joint and several liability for any losses that arise within the insurance pool.

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 2008, StatoilHydro was committed to participate in 22 wells in Norway and 53 wells outside Norway, with an average ownership interest of approximately 46%. StatoilHydro's share of estimated expenditures to drill these wells amounts to approximately NOK 12 billion. Additional wells that StatoilHydro may become committed to participate in depending on future discoveries in certain licenses are not included in these numbers.

StatoilHydro ASA issued a declaration to the Norwegian Ministry of Petroleum and Energy (MPE) in 1999 in connection with a dispute between four Åsgard partners and StatoilHydro related to the construction of new facilities for the Åsgard development at the Kårstø Terminal. The declaration confirmed that the MPE will receive similar treatment as the four Åsgard partners with respect to the disputed issues. On the basis of the declaration, the MPE on 29 April 2008 issued a writ involving a multi-component compensation claim, the aggregate principal exposure of which for StatoilHydro approximates between NOK 4 and 7 billion after tax. In November 2008 ExxonMobil, the final Åsgard partner at the time of the original dispute, has issued a similar writ with a compensation claim approximating an estimated exposure of up to NOK 1 billion after tax. StatoilHydro rejects both claims.

The price reviews of two long-term natural gas contracts previously in arbitration have been settled during 2008 without any significant effect on the income statement.

StatoilHydro ASA has offered early retirement packages to employees above the age of 58 years (contingent upon certain conditions). The offer is divided into two phases; employees working onshore (first phase) and employees working offshore and on onshore plants and terminals (second phase). A settlement concerning restructuring cost charges related to the first phase has been reached between StatoilHydro and the partners on the Norwegian continental shelf, see further in note 5 Segments. Contingent receivables related to the second phase remain unrecorded.

StatoilHydro was informed on 26 September 2007 of possible consultancy agreements and transactions associated with Hydro's petroleum activities in Libya, which were transferred to StatoilHydro as of 1 October 2007 as part of the merger with Hydro Petroleum, and which could be in conflict with applicable Norwegian and US anti-corruption legislation. Following a preliminary assessment by StatoilHydro, an external review of the relevant aspects was initiated. The external US and Norwegian legal counsels that have conducted the review delivered their report to StatoilHydro ASA's CEO on 6 October 2008. The report has also been delivered to the National Authority for Investigation and Prosecution of Economic and Environmental Crime in Norway (Økokrim), the US Department of Justice, the US Securities and Exchange Commission and Libyan authorities. The report does not draw any legal conclusions. In accordance with the mandate for the review, the report entails the facts relevant to applicable Norwegian and US anti-corruption legislation to which StatoilHydro ASA may be subject as a result of the merger.

During the normal course of its business StatoilHydro is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset, respectively, in respect of such litigation and claims cannot be determined at this time. StatoilHydro has provided in its accounts for probable liabilities related to litigation and claims based on the Company's best judgement. StatoilHydro does not expect that the financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings.

27 Related parties

Transactions with the Norwegian State

The Norwegian State is the majority shareholder of StatoilHydro and also holds major investments in other entities. This ownership structure means that StatoilHydro 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 a normal arms-length basis.

The ownership interests of the Norwegian State in StatoilHydro are held by the Norwegian Ministry of Petroleum and Energy (MPE). The following transactions with SDFI volumes were made between StatoilHydro and MPE for the years presented:

Total purchases of oil and natural gas liquid from the Norwegian State amounted to NOK 112,682 million, (223 million barrels oil equivalents), NOK 98,498 million (237 million barrels oil equivalents) and NOK 104,628 (254 million barrels oil equivalents) in 2008, 2007 and 2006, respectively. Purchases of natural gas from the Norwegian State (excluding purchases from licenses) amounted to NOK 375 million, NOK 287 million and NOK 293 million in 2008, 2007 and 2006, respectively. The significant amounts included in the line item Payables to associated companies and other related parties in Trade and other payables, see note 23 Related parties, are amounts payable to the Norwegian State for these purchases.

The State's natural gas production, which StatoilHydro is selling, in its own name, but for the Norwegian State's account and risk as well as related expenditures refunded by the State, are presented net in StatoilHydro's financial statements.

Other transactions

In relation to its ordinary business operations such as pipeline transport, gas storage and processing of petroleum products, StatoilHydro also has regular transactions with certain unconsolidated affiliated entities. 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 Executive Committee) during the year was as follows:

(in NOK thousand)	2008	2007	2006
Current benefits	50,949	44,463	41,602
Post-employment benefits	12,534	12,764	13,938
Other non-current benefits	129	111	135
Share based payment benefits	278	94	40
Total	63,890	57,432	55,715

Loans to key management total less than NOK 0.3 million.

28 Financial risk management

General information relevant to risks

StatoilHydro's business activities naturally expose the group to 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 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. Due to this 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 (i.e. utilize the natural hedges embedded in our portfolio). This approach also reduces the number of unnecessary transactions (i.e. reducing transaction costs and avoiding sub-optimisation).

In order to achieve the above effects, the group has centralized trading mandates such that all major/strategic transactions are co-ordinated through our Corporate Risk Committee. This implies that local trading mandates are relatively small.

The group's Corporate Risk Committee which is headed by the Chief Financial Officer and which includes, among others, representatives from the principal business segments is responsible for defining, developing, and reviewing the group's risk policies. The Chief Financial Officer in co-operation with the Corporate Risk Committee is also responsible for overseeing and developing StatoilHydro's Enterprise-Wide Risk Management and proposing appropriate risk adjusting measures at the corporate level. To help facilitate its role, the Committee meets at least six times per annum and regularly receives risk information relevant for the group from our Corporate Risk Department.

Financial risks

StatoilHydro's activities expose the group to financial risks as defined by IFRS 7:

- Market risk (including commodity price risk, interest rate risk, currency risk, and equity price risk)
- Liquidity risk
- Credit risk

Market risk

StatoilHydro operates in the worldwide crude oil, refined products, natural gas, and electricity markets and are exposed to such market risks as 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 focus on achieving the highest risk adjusted returns for the group within the given mandate. Long-term is generally viewed as risks managed at the corporate level and (or) normally having a six months or longer time horizon for significant volumes while short term is generally viewed as risks managed at segment and lower levels according to trading strategies and pre-defined mandates.

The group has established guidelines for entering into contractual arrangements (derivatives) in order to manage our commodity price, foreign currency rate, and interest rate risk. The group uses both financial and commodity-based derivatives to manage the risks in overall earnings and the future value of cash flows.

Commodity price risk

Commodity price risk represents the group's most important short-term market risk and is monitored everyday 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, which consist of futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity.

Derivatives associated with crude oil and petroleum products are traded mainly on the InterContinental 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, 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 usually three years or less.

Currency risk

Fluctuations in exchange rates can have significant effects on the group's results. Foreign exchange risk is assessed on a portfolio basis in accordance with approved strategies and mandates and the group uses only well-understood, conventional derivative instruments which include futures and options traded on regulated exchanges, OTC-swaps, -options and forward contracts.

The group's cash inflows are largely influenced by USD while the group's cash outflows are to a large extent, tax and dividend payments in NOK, as well as certain investments, payment of salaries and various other costs payable in NOK. Accordingly, a significant portion of our exposure to foreign currency rates exists with USD versus NOK. StatoilHydro seeks to manage this currency mismatch by issuing or swapping non-current financial debt into USD.

The group further seeks to manage short-term currency mismatches by using derivative instruments both for currency and liquidity management purposes. Typically, the group purchases 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 a subsequent year. This means, from time to time, the group purchases substantial NOK amounts on a forward basis using derivative instruments.

Interest rate risk
The existence of assets earning and liabilities owing variable rates of interest expose the group to cash flow risk caused by market interest rate fluctuations. The group enters into various types of interest rate contracts in managing interest rate risk. The group enters into interest rate derivatives, particularly interest rate swaps, to alter interest rate exposures, to lower expected funding costs over time and to diversify sources of funding. 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.

StatoilHydro principally manages the group's interest rates on the basis that the non-current debt portfolio has floating rate interest payments. The modified duration (the percentage change in value for one percentage point change in yield) expresses the way the group monitors the interest rate risk. Generally, the group's modified duration is to be between 0 and 1.0%. Other strategies can be approved from time to time if justified by factors such as corporate risk considerations, tax considerations, large non-recurring transactions, credit rating concerns, etc.

Liquidity risk
Liquidity risk is the risk that StatoilHydro will not be able to meet obligations when due. The purpose of liquidity and short term liability management is to make certain that the group at all times has sufficient funds available to cover financial obligations.

StatoilHydro's operating cashflows are negatively impacted by declines in oil and gas prices, however, during 2008 the group's overall liquidity position remained strong and the policies for managing liquidity remained unchanged.

StatoilHydro's business activities normally generate, on a monthly basis, a positive cashflow 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) cashflows are typically limited. 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 and subsequently followed by a new accumulation of liquid assets.

Short-term financing 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 financing programmes or under documentation established ad hoc. These financing programmes are as follows:

- A USD 4 billion US commercial paper programme. This is the most flexible programme used for working capital, including timing issues on corporate tax and dividend payments, as well as for periodic acquisition financing.
- A USD 2 billion committed multi-currency revolving credit facility from international banks, including a USD 500 million swing-line facility. The facility was entered into in 2004, and is available for draw-downs until December 2011. This facility is primarily intended as a "back-up" facility for the US commercial paper programme, and should be regarded as support for the credit rating of this programme.
- Uncommitted credit lines. Short-term financing source occasionally required beyond the other short-term programmes and accumulated cash.

In order to have access to sufficient liquidity at all times, StatoilHydro 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.

Capital and liability management
As a basic principle, StatoilHydro separates investment decisions from financing decisions. Financing 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.

The group aims at all times to maintain access to a variety of financing sources, both in respect of instruments and geography, and maintain relationships with a core group of international banks that provide various kinds of banking and financing services.

The group has 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 at favourable terms and conditions. The group's current long-term ratings are Aa2 and AA- 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. The group intends to keep financial ratios relating to debt at levels consistent with objectives for maintaining the group's long-term credit rating at least within the single A category. In managing the group's capital structure and thus seeking to maintain a credit rating of at least single A, the group partly relies on the use of Standard & Poor's guidelines to test, among others, the key ratios free funds from operations over net debt and the debt ratio.

In order to control the group's refinancing risk, the maturity and redemption profile of non-current debt issued is managed within certain limitations. The limits are expressed as maximum annual mandatory redemptions as a share of StatoilHydro's capital employed.

Liquidity forecasts serve as tools for financial planning. In order to maintain necessary financial flexibility, StatoilHydro has requirements for maximum (forecasted) current debt and minimum (forecasted) liquidity reserve. Issuance 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 reveal non-compliance with given limits, unless further detailed considerations indicate that the non-compliance is likely to be very temporary. In this case, the situation will be further monitored before additional non-current debt is drawn.

For further information on the group's debenture bonds, bank loans, and other debt portfolio profile, see note 20 Non-current financial liabilities.

StatoilHydro's dividend policy includes providing a return to the group's shareholders through cash dividends and share repurchases. The level of cash dividends and share repurchases in any one year can fluctuate depending on the group's assessment of future cashflows, capital expenditure plans, financing requirements, and appropriate financial flexibility. See note 19 Shareholders equity for additional information on the group's dividend policy.

Credit risk

Credit risk is the risk that the group's customers or counterparties to financial instruments will cause the group financial loss by failing to honour their obligation. Credit risk arises from credit exposures with customer accounts receivables as well as from derivative financial instruments and deposits with financial institutions. Theoretically, the group's maximum credit exposure for financial assets is the aggregated balance sheet carrying amounts of financial investments (excluding equity investments of NOK 6.5 billion in 2008 and NOK 7.5 billion in 2007), derivative financial instruments, financial receivables, trade and other receivables, and cash and cash equivalents. The group manages this exposure through its credit risk management policies and procedures.

The current financial crisis has brought into focus the need for all entities to have robust credit policies with close monitoring of associated risks. Over the years, we have established a clear credit policy which has proven especially valuable during this period of widespread financial pressure. The tools StatoilHydro uses to manage and monitor credit risk have been tested by the continuing crisis and no significant credit losses have materialised for the group during 2008.

Key elements of our credit risk management approach include

- A global credit risk policy
- Credit mandates
- 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, approved, and assigned internal credit ratings as well as exposure limits. Once established, all counterparties are re-assessed minimum annually with high risk counterparties reviewed 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. Exposure limits are determined based on assigned internal credit ratings combined with other factors, such as expected transaction and industry characteristics, as outlined in our credit policy. The mandate for setting credit limits is regularly reviewed with regard to changes in market conditions.

There are several instruments available to the group to reduce or control credit risk both on an individual counterparty and portfolio level. The main tools used by StatoilHydro are variations of bank and parental guarantees, prepayments and cash collateral. For bank guarantees only investment grade international banks are accepted.

StatoilHydro manages credit risk both on a portfolio and counterparty level. The group has pre-defined limits regarding 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 versus limits on a daily basis. The total credit exposure portfolio of StatoilHydro is well diversified with respect to number and quality of counterparties, industries and geographically. The majority of the group's credit exposure is typically with investment grade counterparties.

The following table contains the fair market value of open non-exchange traded derivative assets split by the group's assessment of the counter-party's credit risk.

	At 31 December	
(in NOK million)	**2008**	**2007**
Counter-party rated:		
Investment grade, rated A or above	21,727	19,647
Other investment grade	7,094	928
Non-investment grade or not rated	761	689

As of 31 December 2008, NOK 10.1 billion is received in cash as collateral to offset a portion of this group credit exposure. See note 24 Current financial liabilities for more information on collateral held.

Consistent with our policies, commodity derivative counter-parties have been assigned credit ratings corresponding to those of their respective parent companies. If the parent company is highly rated, it may not be necessary to obtain a parent company guarantee from such a counter-party.

29 Financial instruments by category

Financial instruments by IAS 39 category

The following tables provide a view of financial instruments and their carrying amounts as defined by IAS 39 categories. 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 20 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**	**Hedge accounting**	**Fair value option**	**Total carrying amount**
31 December 2008							
Assets							
Non-current financial investments	14	-	4,164	-	-	12,301	16,465
Non-current derivative financial instruments	30	-	-	-	2,383	-	2,383
Non-current financial receivables	14	4,914	-	-	-	-	4,914
Current trade and other receivables	16	69,931	-	-	-	-	69,931
Current derivative financial instruments	30	-	-	27,436	69	-	27,505
Current financial investments	17	15	-	7,874	-	1,858	9,747
Cash and cash equivalents	18	18,638	-	-	-	-	18,638
Total		93,498	4,164	35,310	2,452	14,159	149,583

(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: Hedge accounting	Fair value through profit or loss: Fair value option	Total carrying amount
31 December 2007							
Assets							
Non-current financial investments	14	-	3,291	-	-	11,975	15,266
Non-current derivative financial instruments	30	-	-	-	609	-	609
Non-current financial receivables	14	3,515	-	-	-	-	3,515
Current trade and other receivables	16	69,378	-	-	-	-	69,378
Current derivative financial instruments	30	-	-	21,051	42	-	21,093
Current financial investments	17	-	-	3,359	-	-	3,359
Cash and cash equivalents	18	18,264	-	-	-	-	18,264
Total		91,157	3,291	24,410	651	11,975	131,484

(in NOK million)	Note	Amortised cost	Hedge accounting	Fair value through profit or loss	Total carrying amount
31 December 2008					
Liabilities					
Non-current financial liabilities	20	52,065	2,541	-	54,606
Current trade and other payables	23	61,200	-	-	61,200
Current financial liabilities	24	20,695	-	-	20,695
Current derivative financial instruments	30	-	-	20,752	20,752
Total		133,960	2,541	20,752	157,253

(in NOK million)	Note	Amortised cost	Hedge accounting	Fair value through profit or loss	Total carrying amount
31 December 2007					
Liabilities					
Non-current financial liabilities	20	43,649	724	1	44,374
Current trade and other payables	23	64,624	-	-	64,624
Current financial liabilities	24	6,166	-	-	6,166
Current derivative financial instruments	30	-	-	7,632	7,632
Total		114,439	724	7,633	122,796

Included in Current trade and other payables are provisions for certain claims and litigations in accordance with IAS 37 which are further described in note 26 Other commitments and contingencies.

The following tables include amounts from the Consolidated statements of income related to financial instruments. Excluded from Net financial items is accretion expense on our asset retirement obligations of NOK 2,107, NOK 2,099 and NOK 1,304 million for the years ended 2008, 2007 and 2006, respectively. See note 8, Financial items, for additional information on the Net financial items.

	Fair value through profit or loss						
(in NOK million)	Held for trading	Hedge accounting	Fair value option	Loans & receivables	Financial liabilities at amortised cost	Available-for-sale assets	Total
For the year ended 31 December 2008:							
Operating income	19,917	-	-	-	-	-	19,917
Net financial items							
Net foreign exchange gains (losses)	(23,061)	-	(1,256)	3,900	(12,145)	-	(32,563)
Interest income and other financial items	8,927	-	(213)	3,461	-	31	12,207
Interest and other finance expenses	6,725	(27)	(1)	-	(2,599)	-	4,098
Total	12,508	(27)	(1,470)	7,361	(14,744)	31	3,659

	Fair value through profit or loss						
(in NOK million)	Held for trading	Hedge accounting	Fair value option	Loans & receivables	Financial liabilities at amortised cost	Available-for-sale assets	Total
For the year ended 31 December 2007:							
Operating income	(2,043)	-	-	-	-	129	(1,914)
Net financial items							
Net foreign exchange gains (losses)	8,610	-	596	(8,630)	9,467	-	10,043
Interest income and other financial items	(82)	-	139	1,820	-	428	2,305
Interest and other finance expenses	361	9	(40)	-	(972)	-	(642)
Total	6,846	9	695	(6,810)	8,495	557	9,792

	Fair value through profit or loss						
(in NOK million)	Held for trading	Hedge accounting	Fair value option	Loans & receivables	Financial liabilities at amortised cost	Available-for-sale assets	Total
For the year ended 31 December 2006:							
Operating income	7,303	-	-	-	-	-	7,303
Net financial items							
Net foreign exchange gains (losses)	3,947	-	112	(1,067)	1,465	-	4,457
Interest income and other financial items	780	-	965	1,751	(79)	258	3,675
Interest and other finance expenses	(1,352)	(7)	(27)	-	(349)	(21)	(1,756)
Total	10,678	(7)	1,050	684	1,037	237	13,679

30 Financial instruments and hedging

Fair value hedges

Fair value hedges are hedges of StatoilHydro's exposure to changes in the fair value of a recognised asset and liability. StatoilHydro has designated certain interest rate swaps as fair value hedge to hedge against changes in the fair value, due to changes in the interest rates, of certain parts of the group's financial liabilities. The net loss recognised in earnings in Income before tax during the year for ineffectiveness of fair value hedges was insignificant.

The fair value of the hedging instruments and the hedged item subject to hedge accounting are presented below together with related annual gains and losses.

(in NOK million)	Fair value	Gains /(losses)
At 31 December 2008		
Hedging instruments	2,452	2,036
Hedged item	(2,541)	(2,063)
At 31 December 2007		
Hedging instruments	651	221
Hedged item	(724)	(212)
At 31 December 2006		
Hedging instruments	430	(459)
Hedged item	(512)	452

Fair value of derivative financial instruments

The group recognises all derivative financial instruments in the balance sheet at fair value. Changes in the fair value of these derivatives are included in the Consolidated statements of income either in revenue or in financial items. For more information about the methodology and assumption used when calculating the fair value of our financial instruments see note 2 Significant accounting policies.

The following table contains the estimated fair values and net carrying amounts of derivative financial instruments including certain derivative commodity contracts. Of the total ending balance at 31 December 2008 NOK 9.7 billion relates to certain earn-out agreements recognised as derivative financial instruments in accordance with IAS 39. At the end of 2007 the estimated fair value of these agreements were NOK 9.6 billion.

(in NOK million)	Fair value of assets	Fair value of liabilities	Net carrying amount
At 31 December 2008			
Debt-related instruments	13,083	(989)	12,094
Non-debt-related instruments	403	(14,032)	(13,629)
Crude Oil and Refined products	13,136	(2,491)	10,645
Gas and Electricity	3,267	(3,239)	28
At 31 December 2007			
Debt-related instruments	4,676	(125)	4,551
Non-debt-related instruments	1,802	(163)	1,639
Crude Oil and Refined products	11,115	(2,533)	8,582
Gas and Electricity	4,219	(4,921)	(702)

Where an active market exists, derivative financial instruments are valued on the the basis of quoted information from the active market. The following table summarises the basis for the group's fair value estimation and the maturity of our derivative financial instruments.

(in NOK million)	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Maturity in excess of 5 years	Total fair value
At 31 December 2008					
Fair value based on prices quoted in an active market	55	(180)	(20)	0	(145)
Fair value based on price inputs from observable market transactions	(11,330)	4,287	2,229	8,297	3,483
Fair value based on inputs from other sources	348	485	729	4,236	5,798
At 31 December 2007					
Fair value based on prices quoted in an active market	175	1,731	178	2,108	4,192
Fair value based on price inputs from observable market transactions	5	7	0	0	12
Fair value based on inputs from other sources	13	(1)	(1)	9,854	9,865

The first level in the above table, Fair value based on prices quoted in an active market, refers to values generated for standardised products actively traded where our values is calculated based on observable prices on equal product. This category will in most cases only be relevant for exchange traded contracts.

Fair value based on price inputs from observable market transactions is used for fair values that are calculated for our non-standardised contracts based on price inputs that are from observable market transaction. This will typically be when we use forward prices on crude oil, natural gas, interest rates, and foreign exchange rates as inputs into our valuation models.

Fair value based on input from other sources refers to fair values calculated based on input and assumptions that are not from observable market transactions. The fair values presented in this category will mainly be based on internal assumptions. The internal assumptions are only used due to the absence of quoted price from an active market or other observable price inputs for the financial instruments subject to the valuation.

Even though the major part of the fair value from certain earn-out agreements and embedded derivative contracts are calculated with price inputs from observable market transaction they have been classified in the third category in the above table due to part of the value being from internal generated assumptions. Another reasonable assumption to be used when calculating the fair value of these contracts might be to extrapolate the last observed forward prices. By extrapolating the forward curves with inflation the fair value of the contracts included will decrease by approximately NOK 1.0 billion. This decreased change in fair value would be recognised in the Consolidated statements of income.

There are significant measurement risks associated with estimating the fair value of financial instruments that are not traded in active markets. While these are StatoilHydro's best estimates of fair value, other assumptions may be made by other parties for instance with respect to future commodity prices, exchange rates and interest rates. The sensitivity of the fair value of all commodity-based contracts on changes in commodity prices is illustrated in the sensitivity table below. Changes in the fair value of commodity-based financial instruments due to different assumptions made on future exchange rates and interest rates are deemed immaterial.

Market risk sensitivities

Commodity price risk

The table below contains the fair value and related commodity price risk sensitivity of our commodity based derivatives contracts, as accounted for under IAS 39. For further information related to the type of commodity risks and how the group manages these risks see note 28 Financial risk management.

Substantially all of these fair value assets and liabilities are related to non-exchange traded derivative instruments, including embedded derivatives that in accordance with IAS 39 have been bifurcated and recognised with fair value in the balance sheet. Included in the fair values and basis for sensitivity figures are immaterial derivative positions held for speculative trading purposes.

Price risk sensitivities by end of 2008 have been calculated by assuming a 50% change in all commodity prices. Compared to the sensitivity calculated by end of 2007 and 2006 the group's assessment of what are reasonable possible changes in the commodity prices for the coming year have been changed due to the changes taking place in the markets where we operate. By end of 2007 and 2006 this sensitivity was calculated by assuming a 10% change in all commodity prices.

Since none of the derivative financial instruments included in the table below are part of a hedging relationship, any changes in the fair value will be recognised in the Consolidated statements of income.

(in NOK million)	Fair value asset	Fair value liability	-50% sensitivity	50% sensitivity
At 31 December 2008				
Crude Oil and Refined Products	13,136	(2,491)	(4,124)	4,440
Natural Gas and Electricity	3,267	(3,239)	3,447	(3,431)
			-10% sensitivity	10% sensitivity
At 31 December 2007				
Crude Oil and Refined Products	11,115	(2,533)	(651)	652
Natural Gas and Electricity	4,219	(4,921)	1,530	(1,522)
At 31 December 2006				
Crude Oil and Refined Products	7,593	(797)	(466)	410
Natural Gas and Electricity	7,501	(4,432)	1,742	(1,671)

As part of the tools to monitor and manage risk, the group uses value at risk (VaR) method for certain parts of its commodity trading activity within the Natural Gas and Manufacturing and Marketing segment.

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 revalued 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 12 month rolling observation window and input parameters such as simulation intervals are recalibrated when model performance moves outside acceptable bounds.

Natural Gas mainly measures its market risk exposure using a variance/covariance VaR model. Furthermore a 95% confidence interval and a one day holding period is applied. The variance/covariance model 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 model 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 model calculates the VaR as a function of standard deviation per instrument in the portfolio and the correlation between the instruments while the historical simulation method is based on deriving daily percentage market price and volatility changes for all significant products in the 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.

Within the 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 the group's balance sheet. Within Natural Gas embedded derivatives as well as certain physical forward contracts recognised as derivative financial instrument that is not held as part of a trading position is not included in the portfolio subject to VaR limits.

The calculated VaR numbers for 2008 and a summary of the assumptions used are presented in the following table.

(in NOK million)	High	Low	Average
Crude Oil and Refined Products	143	28	79
Natural Gas and Electricity	392	88	216

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

Interest and currency risk.

Interest and currency risks constitute significant financial risks for the StatoilHydro group. Total exposure is managed at a portfolio level in accordance with approved strategies and mandates on a regular basis.

The following currency risk sensitivities by end of 2008 have been calculated by assuming a 20% change foreign exchange rates. Compared to the sensitivity calculated by end of 2007 and 2006 the group's assessment of what are reasonable possible changes in foreign currencies we are exposed to for the coming year have been changed due to the changes taken place in the world financial markets. By end for 2007 and 2006 a 10% change was assumed in the calculation. Included in currency risk calculations are financial assets, financial liabilities and financial derivatives exclusive commodity derivatives. For the interest rate risk sensitivity a one percentage point change in the interest rates have been used in the calculation which is the same as by end of 2007 and 2006. The estimated gains and losses that will impact our income statement are presented in the following table.

(in NOK million)	Gains	Losses
At 31 December 2008		
Currency risk (20% sensitivity)	28,116	(28,116)
Interest rate risk (1 percentage point sensitivity)	3,395	(3,395)
At 31 December 2007		
Currency risk (10% sensitivity)	10,387	(10,387)
Interest rate risk (1 percentage point sensitivity)	2,714	(2,714)
At 31 December 2006		
Currency risk (10% sensitivity)	7,620	(7,620)
Interest rate risk (1 percentage point sensitivity)	2,354	(2,354)

For further information related to the interest and currency risks and how the group manages these risks see note 28 Financial risk management.

Equity risk

Listed equity securities, consisting mainly of the portfolio held by the group's captive insurance company, are recorded at fair value and have exposure to price risk. The fair value of listed equity securities is based on quoted market prices. In addition to the portfolio held by the group's captive insurance company, the group also has some other non-listed equity securities classified as Available for sale investments in accordance with IAS 39.

For more information about the fair values recognised in the balance sheet, the assumption used when calculating the fair value and the price risk sensitivities of the equity securities see note 14 Non-current financial assets.

Liquidity risk

The liquidity risk in terms of crude oil and refined products derivative contracts is usually less than one year. The term of natural gas forwards is usually three years or less. In the table below the maturity profile for the group's financial liability related to exchange traded and non-exchange traded commodity based derivatives together with financial derivatives is presented. The maturity profile is based on the underlying delivery period of the contracts included in the portfolio. For further information on management of the liquidity risk, see note 28 Financial risk management.

(in NOK million)	2008	2007
Less than 1 year	(18,194)	(5,279)
1 - 3 years	(1,551)	(2,094)
4 - 5 years	(276)	(113)
After 5 years	(698)	(147)
Derivative financial instruments	(20,719)	(7,633)

31 Merger with Hydro Petroleum

The shareholders of Statoil ASA and Norsk Hydro ASA (Hydro) at extraordinary General Meetings on 5 July 2007 approved a merger between Statoil ASA and the oil and gas activities of Norsk Hydro ASA (Hydro Petroleum). The merger was effective 1 October 2007.

As a result of the merger in 2007 StatoilHydro's share capital increased by NOK 2,606,655,590 from NOK 5,364,962,167.50 to NOK 7,971,617,757.50 from the issuing of 1,042,662,236 shares with a nominal value of NOK 2.50 to Hydro's shareholders. Hydro's shareholders received 0.8622 shares in the merged company for each Hydro share. After the increase Hydro's shareholders held 32.7% and former Statoil's shareholders held 67.3% of the merged company, StatoilHydro ASA.

Given that both Statoil ASA and Norsk Hydro ASA were under the control of the Norwegian State, the merger was accounted for as a business combination between entities under common control. Management concluded that for a merger of entities under common control, the most meaningful portrayal for accounting purposes was to combine StatoilHydro and Hydro Petroleum using the carrying amounts of assets and liabilities and restating the financial statements for all periods presented as if the companies had always been combined. Consistent with this accounting treatment, the financial statements of Hydro Petroleum were adjusted to conform to the accounting policies of Statoil ASA for the tax benefit of uplift in Norway, the sales method of accounting for revenues for over- and underlift in the production of oil and gas and pension accounting. The combined impact of these changes was to decrease net equity by approximately NOK 3 billion for the year ended 31 December 2006.

Under provisions of the merger plan, an inter-company balance was established between former Statoil and Norsk Hydro ASA as of 31 December 2006 that provides that debt less cash and short term investments of Hydro Petroleum be set at a defined level by an adjustment to a merger payable or receivable between the companies. This resulted in StatoilHydro having a merger receivable from Norsk Hydro ASA that was included in the 2007 cash flows upon its settlement.

Hydro Petroleum was not a separate legal entity from Hydro and, therefore, had combined cash and equity balances with Hydro. As a consequence in accounting for the merger, certain cash flows to or from Hydro were treated as equity distributions or injections to or from Hydro. This is reflected in the consolidated statements of cash flows as "Norsk Hydro ASA merger balance" and in the consolidated shareholders equity of StatoilHydro as "Merger related adjustments", see note 19 Shareholders equity.

StatoilHydro, subsequent to the merger, recorded a total expense in 2007 of NOK 10.7 billion before tax related to restructuring expenses and other expenses related to the merger. The major part of these expenses was related to pensions and early retirement packages offered to employees in StatoilHydro ASA above the age of 58 years (contingent upon certain conditions).

Below is a table showing the effects of the merger on the Statement of Income for the year ended 31 December 2006. The column "Hydro Petroleum" includes the IFRS financial information derived from the audited carve-out combined financial statements of Hydro Petroleum. The column "Former Statoil group" is derived from the IFRS transition document of Statoil ASA. The column " Merger adjustments and other eliminations" includes StatoilHydro's managements consolidation entries and adjustments to a) conform the Hydro Petroleum IFRS financial information to the accounting policies of StatoilHydro and b) eliminate internal transactions between the merged companies.

Condensed Statements of Income

	For the year ended 31 December 2006			
(in NOK million)	**Hydro Petroleum**	**Former Statoil group**	**Merger adjustments and other eliminations**	**StatoilHydro group**
Total revenues and other income	97,910	433,966	(10,394)	521,482
Total operating expenses	(51,192)	(315,009)	10,883	(355,318)
Net financial items	563	3,797	712	5,072
Income tax	(36,188)	(81,889)	(1,312)	(119,389)
Net income	11,093	40,865	(111)	51,847

32 Subsequent events

Effective 1 January 2009, StatoilHydro completed an internal group reorganisation in which the parts of the Exploration and Production Norway segment activities and assets previously owned by StatoilHydro ASA, excluding employees employed by StatoilHydro ASA, were transferred to the wholly owned subsidiary StatoilHydro Petroleum AS. Some parts of the Natural Gas segment activities and assets, but no employees, were also transferred. Following these reorganisations the operations of StatoilHydro ASA is no longer subject to the special petroleum tax on the Norwegian Continental Shelf. As a consequence, the tax assets related to pension liabilities in StatoilHydro ASA have effective 31 December 2008 been recognised at 28%, which is the tax rate expected to be in effect at the realisation date. Previously the estimated tax rate was 56%, based on assumed amounts expected to be realised under the petroleum tax regime and the general tax regime, respectively. The effect is a reduction of the deferred tax assets related to pensions and a corresponding reduction to retained earnings by NOK 5.4 billion as of 31 December 2008.

The 1 January 2009 internal group reorganisation has also resulted in a change of functional currency from NOK to USD in StatoiHydro ASA effective from the same date and with prospective effect. The functional currency of StatoilHydro Petroleum AS has not changed and remains NOK. The change of functional currency in StatoilHydro ASA has no impact on the consolidated financial statements for 2008. The presentation currency for the StatoiHydro group will remain NOK.

On 4 March 2009 StatoilHydro ASA issued a GBP 0.8 billion bond maturing in 22 years, a EUR 1.2 billion bond maturing in 12 years and a EUR 1.3 billion bond maturing in six years. All three bonds were fully subscribed. The bonds are issued under StatoilHydro ASA's Euro Medium Term Note Programme and will be listed on London Stock Exchange. The bonds have been guaranteed by StatoilHydro Petroleum AS.

33 Supplementary oil and gas information (UNAUDITED)

In accordance with Statement of Financial Accounting Standards No. 69 "Disclosures about Oil and Gas Producing Activities" (FAS 69), StatoilHydro is making certain supplemental disclosures about oil and gas exploration and production operations. 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 StatoilHydro or its expected future results.

Certain reclassifications have been made to prior periods' figures to be consistent with the current period's classifications.

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

StatoilHydro's oil and gas reserves have been estimated by its experts in accordance with industry standards under the requirements of the US Securities and Exchange Commission (SEC), 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.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

1. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
2. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
3. Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Over time, undeveloped reserves will be reclassified to proved developed reserves as new wells are drilled, existing wells are recompleted or facilities to produce from existing wells and planned wells comes in operation.

Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

From the Norwegian Continental Shelf (NCS) StatoilHydro 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, StatoilHydro will deliver gas to customers in accordance with various types of sales contracts. In order to fulfil the commitments, StatoilHydro will utilise a field supply schedule which provides the highest possible total value for the joint portfolio of oil and gas between StatoilHydro and SDFI.

As of 31 December 2008, the StatoilHydro / SDFI arrangement amounted to a total of 31.9 tcf in total expected gas commitments on the NSC. The principles for booking of proved reserves are limited to contracted gas sales and gas with access to a market.

The majority of StatoilHydro's gas volumes are sold under long term contracts with Take or Pay clauses. For each individual year, StatoilHydro and SDFI express their delivery commitments as the sum of the Annual Contract Quantity (ACQ). In the contract years 2008 to 2011, the joint ACQ for the respective years are; 2.66, 2.59, 2.62, and 2.56 tcf. The majority of delivery commitments will be fulfilled by expected production of proved reserves from fields were StatoilHydro and/or SDFI participates, while potential shortfalls will be covered by sourcing existing gas markets.

StatoilHydro experiences a situation with reduced supply of LNG due to production problems at the Snøhvit LNG liquefaction plant in Norway. Actions and efforts have been carried out in order to mitigate the effect of the reduced supply. The production problems contributed to a shortfall of approximately 2.0% of StatoilHydro's delivery commitments throughout the year 2008. The effect of the production problems may also result in some shortfalls in LNG supply for 2009.

StatoilHydro 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 StatoilHydro 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 StatoilHydro. 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 may be changed or withdrawn by the StatoilHydro general meeting. Due to this uncertainty and the Norwegian State's estimate of proved reserves not being available to StatoilHydro, it is not possible to determine the total quantities to be purchased by StatoilHydro under the owner's instruction from properties in which it participates in the operations.

In 2002, StatoilHydro entered into a buy-back contract in Iran. StatoilHydro also participates in a number of production sharing agreements (PSAs) in Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia. Reserves from such agreements are based on the volumes to which StatoilHydro has access (cost oil and profit oil), limited to available market access. Proved reserves at end of year associated with PSA and buy-back agreements are disclosed separately in the following table.

Rule 4-10 of Regulation S-X requires that the appraisal of reserves is based on the economic environment and operating conditions existing at year end. Reserves at year-end 2008 have been determined based on the Brent price on 31 December 2008 ($36.55/bbl). The reduction in oil price from year-end 2007 (Brent blend price of $96.02/bbl) to year-end 2008 has lowered the profitable oil and gas to be recovered from the accumulations while StatoilHydro's proved oil and gas reserves under PSAs and similar contracts have as a result increased. These changes are included in the revisions category in the table below.

The transformation process of the Sincor joint venture in Venezuela, into the new mixed company Petrocedeño was finalised in February 2008 reducing StatoilHydro's shareholding interest from 15.0% in the Sincor joint venture to 9.677% in Petrocedeño. The change in StatoilHydro share has resulted in a reduction of proved reserves corresponding to 68 million boe in 2008.

StatoilHydro acquired Anadarco's 50.0 % share in Peregrino, Brazil, in 2008 resulting in a 100 % ownership of this asset, and becoming the operator. The related increase in proved reserves was 69 million boe.

The acquisition of a 32.5 % interest in the Chesapeake's Marcellus shale gas acreage in the Appalachia region of the northeastern USA was completed in November 2008. Few wells are currently in production and the nature of shale gas deposits limits the reserves that can currently be booked as proved. Proved gas reserves at year-end 2008 related to this ownership is immaterial compared to StatoilHydro's total proved reserves and hence not included.

StatoilHydro is booking, as proved reserves, volumes equivalent to our tax liabilities payable in-kind under negotiated fiscal arrangements (production sharing agreements or income sharing agreements).

The following table reflects the estimated proved reserves of oil and gas at 31 December 2005 to 2008, 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
At 31 December 2005	1,835	779	2,614	19,595	1,392	20,986	5,316	1,025	6,341
Of which:									
Proved developed reserves	1,363	295	1,659	13,899	208	14,107	3,833	332	4,165
Proved reserves under PSA and buy-back agreements	-	433	433	-	973	973	-	606	606
Production from PSA and buy-back agreements	-	46	46	-	83	83	-	61	61
Revisions and improved recovery	122	37	159	529	250	780	219	81	300
Extensions and discoveries	26	12	38	256	9	265	72	13	86
Purchase of reserves-in-place	-	-	-	-	-	-	-	-	-
Sales of reserves-in-place	-	(2)	(3)	-	-	-	-	(2)	(3)
Production	(315)	(70)	(385)	(1,250)	(84)	(1,335)	(539)	(85)	(624)
At 31 December 2006	1,667	756	2,423	19,129	1,567	20,696	5,068	1,032	6,101
Of which:									
Proved developed reserves	1,188	334	1,523	13,378	283	13,661	3,566	385	3,951
Proved reserves under PSA and buy-back agreements	-	441	441	-	1,169	1,169	-	649	649
Production from PSA and buy-back agreements	-	47	47	-	56	56	-	57	57
Revisions and improved recovery	197	16	214	598	(27)	571	311	14	325
Extensions and discoveries	38	105	143	405	-	405	110	105	215
Purchase of reserves-in-place	-	-	-	-	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-	-	-	-	-
Production	(299)	(92)	(391)	(1,238)	(114)	(1,352)	(519)	(112)	(632)
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
Proved reserves under PSA and buy-back agreements	-	387	387	-	977	977	-	561	561
Production from PSA and buy-back agreements	-	67	67	-	80	80	-	82	82

	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
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 affiliated company *	-	(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
Proved reserves under PSA and buy-back agreements	-	433	433	-	1,106	1,106	-	630	630
Production from PSA and buy-back agreements	-	66	66	-	88	88	-	82	82
Reserves in affiliates									
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 affiliates as of 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 15.0% to 9.677% interest

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 expenditures related to Oil and Gas producing activities

(in NOK million)	2008	At 31 December 2007	2006
Unproved properties	61,484	40,513	26,096
Proved properties, wells, plants and other equipment	611,251	526,634	501,472
Total capitalised expenditures	672,735	567,147	527,568
Accumulated depreciation, depletion, amortisation and valuation allowances	(349,428)	(309,527)	(283,428)
Net capitalised expenditures	323,307	257,620	244,140

Net capitalised expenditures related to affiliates as of 31 December 2008 was NOK 4.6 billion.

Expenditures incurred in Oil and Gas Property Acquisition, Exploration and Development Activities
These expenditures include both amounts capitalised and expensed

(in NOK million)	Norway	Outside Norway	Total
Year ended 31 December 2008			
Exploration costs	8,672	9,136	17,808
Development costs [1), 2)]	29,478	14,215	43,693
Acquired proved properties [3)]	-	12,435	12,435
Acquired unproved properties [4)]	1,255	12,323	13,578
Total	39,405	48,109	87,514
Year ended 31 December 2007			
Exploration costs	5,749	8,499	14,248
Development costs [1), 2)]	28,428	13,330	41,758
Acquired unproved properties	-	17,133	17,133
Total	34,177	38,962	73,139
Year ended 31 December 2006			
Exploration costs	4,649	9,484	14,133
Development costs [1), 2)]	27,303	14,009	41,312
Acquired unproved properties	511	9,588	10,099
Total	32,463	33,081	65,544

(1) Development costs include investments in Norway in facilities for liquefaction of natural gas and storage of LNG amounting to NOK 90 million in 2008, NOK 661 million in 2007 and NOK 112 million in 2006.
(2) Includes minor development costs in unproved properties.
(3) Includes the acquisition of Anadarco's 50% share in Peregrino, Brazil.
(4) 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 affiliates in 2008 was NOK 448 million.

Results of Operation for Oil and Gas Producing Activities
As required by FAS 69, the revenues and expenses included in the following table reflect only those relating to the oil and gas producing operations of StatoilHydro.

Activities included in StatoilHydro's segment disclosures in note 5 Segments to the financial statements but excluded from the table below relates to gas trading activities, commodity based derivatives, transportation, and business development as well as effects of disposals of oil and gas interests.

Income tax expense is calculated on the basis of statutory tax rates in addition to uplift and tax credits only. No deductions are made for interest or overhead.

(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 operating expenses	(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
Year ended December 2007			
Sales	36	13,064	13,100
Transfers	173,238	27,705	200,943
Total revenues	173,274	40,769	214,043
Exploration expense	(3,638)	(7,695)	(11,333)
Production costs	(22,793)	(7,132)	(29,925)
DD&A	(23,030)	(11,103)	(34,133)
Total operating expenses	(49,461)	(25,930)	(75,391)
Results of operations before tax	123,813	14,839	138,651
Tax expense	(92,058)	(4,327)	(96,385)
Result of operations	31,754	10,512	42,266
Year ended December 2006			
Sales	143	10,640	10,784
Transfers	175,476	20,523	195,999
Total revenues	175,619	31,163	206,783
Exploration expense	(3,480)	(7,170)	(10,650)
Production costs	(12,774)	(4,176)	(16,950)
DD&A	(20,938)	(14,370)	(35,308)
Total operating expenses	(37,192)	(25,716)	(62,908)
Results of operations before tax	138,427	5,447	143,874
Tax expense	(98,994)	(2,133)	(101,127)
Result of operations	39,433	3,314	42,748

The results of operations for oil and gas producing activities of affiliates outside of Norway amounts to NOK 428 million in the year ended December 2008.

Corrections increasing the results of operations for 2007 and 2006 by NOK 9.0 and 10.3 billion, respectively, were made to the previously reported figures.

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 presented. The analysis is computed in accordance with FAS 69, by applying year end market prices, costs, 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. Future net cash flow pre-tax 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 information provided does not represent management's estimate of StatoilHydro's expected future cash flows or value of proved oil and gas reserves. Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, identified reserves and contingent resources that may become proved in the future, are excluded from the calculations. The standardised measure of discounted future net cash flows prescribed under FAS 69 requires assumptions as to the timing and amount of future development and production costs and income from the production of proved reserves. This does not reflect management's judgment and should not be relied upon as an indication of StatoilHydro's future cash flow or value of its proved reserves.

(in NOK million)	Norway	Outside Norway	Total
At 31 December 2008			
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
Standardised measure of discounted future net cash flows related to affiliates	-	2,024	2,024
Total standardised measure of discounted future net cash flows including affiliates	146,238	39,377	185,615
At 31 December 2007			
Future net cash inflows	1,788,440	429,335	2,217,775
Future development costs	(107,966)	(57,332)	(165,298)
Future production costs	(338,834)	(102,838)	(441,672)
Future income tax expenses	(1,009,179)	(97,850)	(1,107,029)
Future net cash flows	332,461	171,315	503,776
10 % annual discount for estimated timing of cash flows	(135,717)	(67,289)	(203,006)
Standardised measure of discounted future net cash flows	196,744	104,026	300,770
At 31 December 2006			
Future net cash inflows	1,643,982	310,129	1,954,111
Future development costs	(113,121)	(36,496)	(149,617)
Future production costs	(321,208)	(53,377)	(374,585)
Future income tax expenses	(939,061)	(70,481)	(1,009,542)
Future net cash flows	270,592	149,775	420,367
10 % annual discount for estimated timing of cash flows	(116,469)	(58,184)	(174,653)
Standardised measure of discounted future net cash flows	154,123	91,591	245,714

Of the NOK 154,376 million of expected future development costs as of 31 December 2008, NOK 92,010 million is expected to be expended within the next three years, as allocated in the table below.

Future development cost

(in NOK million)	2009	2010	2011	Total
Norway	29,904	22,981	15,572	68,457
Outside Norway	11,968	6,558	5,027	23,553
Total	41,872	29,539	20,599	92,010
Future development cost expected to be spent on proved undeveloped reserves	28,224	20,125	12,556	60,905

In 2008, StatoilHydro incurred NOK 56,128 million in development costs, of which NOK 36,955 million related to proved undeveloped reserves.

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

(in NOK million)	2008	2007
Standardised measure at beginning of year	300,770	245,714
Net change in sales and transfer prices and in production (lifting) costs related to future production	(74,453)	239,091
Changes in estimated future development costs	(56,924)	(30,740)
Sales and transfers of oil and gas produced during the period, net of production cost	(234,199)	(189,992)
Net change due to extensions, discoveries, and improved recovery	1,866	15,967
Net change due to purchases and sales of minerals in place	(4,936)	-
Net change due to revisions in quantity estimates	51,574	78,122
Previously estimated development costs incurred during the period	56,128	41,758
Accretion of discount	50,960	(54,374)
Net change in income taxes	92,805	(44,776)
Total change in the standardised measure during the year	(117,179)	55,056
Standardised measure at end of year	183,591	300,770
Change in the standardised measure related to affiliates	2,024	-
Standardised measure at end of year including affiliates	185,615	300,770

Operational statistics

Productive oil and gas wells and developed and undeveloped acreage

The following tables show the number of gross and net productive oil and gas wells and total gross and net developed and undeveloped oil and gas acreage in which StatoilHydro had interests at 31 December 2008.

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

At 31 December 2008		Norway	Outside Norway	Total
Number of productive oil and gas wells				
Oil wells	— gross	927	882	1,809
	— net	368	130	498
Gas wells	— gross	163	100	263
	— net	72	33	105

The total gross number of productive wells as of end 2008 includes 354 oil wells and 15 gas wells with multiple completions or wells with more than one branch.

At 31 December 2008 (in thousands of acres)		Norway	Outside Norway	Total
Developed and undeveloped oil and gas acreage				
Acreage developed	— gross	876	1,323	2,199
	— net	328	405	733
Acreage undeveloped	— gross	15,973	71,617	87,590
	— net	8,099	35,231	43,330

Remaining terms of leases and concessions are between one and 37 years.

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 StatoilHydro in the past two years. Productive wells include wells in which hydrocarbons were found, and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing sufficient quantities to justify completion as an oil or gas well.

	Norway	Outside Norway	Total
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	-	0.5
— Net productive development wells drilled	27.4	23.7	51.1
Year 2007			
Net productive and dry exploratory wells drilled	13.2	14.0	27.1
— Net dry exploratory wells drilled	4.5	5.9	10.4
— Net productive exploratory wells drilled	8.7	8.0	16.7
Net productive and dry development wells drilled	34.7	19.7	54.4
— Net dry development wells drilled	0.7	1.0	1.7
— Net productive development wells drilled	34.0	18.7	52.7
Year 2006			
Net productive and dry exploratory wells drilled	11.1	15.1	26.2
— Net dry exploratory wells drilled	6.4	7.3	13.7
— Net productive exploratory wells drilled	4.7	7.8	12.5
Net productive and dry development wells drilled	21.1	14.0	35.1
— Net dry development wells drilled	0.8	-	0.8
— Net productive development wells drilled	20.3	14.0	34.3

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 StatoilHydro at December 31, 2008.

At 31 December 2008		Norway	Outside Norway	Total
Number of wells in progress				
Developement Wells	— gross	32	47	79
	— net	13.6	7.7	21.3
Exploratory Wells	— gross	7	9	16
	— net	4.3	2.9	7.2

Average sales price and unit production cost

	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 costs, in NOK per boe	37.3	42.2
Year ended 31 December 2007		
Average sales price liquids in USD per bbl	70.9	69.1
Average sales price natural gas in NOK per Sm3	1.69	1.17
Average production costs, in NOK per boe	46.3	34.4
Year ended 31 December 2006		
Average sales price liquids in USD per bbl	63.6	60.9
Average sales price natural gas in NOK per Sm3	1.94	1.64
Average production costs, in NOK per boe	26.9	37.5

Parent company financial statements

STATEMENTS OF INCOME STATOILHYDRO ASA - NGAAP

(in NOK million)	Note	2008	2007
REVENUES AND OTHER INCOME			
Revenues		**559,493**	397,850
Net income (loss) from equity accounted investments	8	**27,950**	17,485
Other income		**979**	159
Total revenues and other income		**588,422**	415,494
OPERATING EXPENSES			
Purchases [net of inventory variation]		**(360,894)**	(257,612)
Operating expenses	3	**(39,353)**	(37,118)
Selling, general and administrative expenses	3	**(11,469)**	(9,444)
Depreciation, amortisation and impairment losses	10	**(19,494)**	(15,513)
Exploration expenses		**(3,956)**	(3,191)
Total operating expenses		**(435,166)**	(322,878)
Net operating income		**153,256**	92,616
FINANCIAL ITEMS			
Net foreign exchange gains (losses)		**(38,319)**	16,018
Interest income and other financial items		**10,450**	4,301
Interest and other finance expenses		**(5,441)**	(5,976)
Net financial items	12	**(33,310)**	14,343
Income before tax		**119,946**	106,959
Income tax	13	**(79,309)**	(63,090)
Net income		**40,637**	43,869

BALANCE SHEETS STATOILHYDRO ASA - NGAAP

(in NOK million)	Note	At 31 December 2008	2007
ASSETS			
Non-current assets			
Property, plant and equipment	10	**136,312**	119,532
Intangible assets	10	**5,110**	3,514
Investments in subsidiaries	8	**281,045**	164,386
Investments in associated companies	8	**1,040**	1,083
Pension assets	17	**0**	1,561
Financial assets	9	**574**	299
Financial receivables from subsidiaries		**44,188**	46,805
Total non-current assets		**468,269**	337,180
Current assets			
Inventories	7	**6,820**	8,308
Trade and other receivables	11	**47,278**	44,286
Receivables form subsidiaries		**10,921**	10,356
Derivative financial instruments		**2,091**	2,464
Financial investments	9	**2,616**	155
Cash and cash equivalents	6	**6,272**	24
Total current assets		**75,998**	65,593
TOTAL ASSETS		**544,267**	402,773

BALANCE SHEETS STATOILHYDRO ASA - NGAAP

(in NOK million)	Note	At 31 December 2008	2007
EQUITY AND LIABILITIES			
Equity			
Share capital		**7,972**	7,972
Treasury shares		**(9)**	(6)
Additional paid-in capital		**17,330**	17,330
Retained earnings		**97,078**	110,587
Reserves for valuation variances		**60,095**	7,841
Total equity	23	**182,466**	143,724
Non-current liabilities			
Financial liabilities	15	**44,988**	36,689
Deferred tax liabilities	13	**34,942**	34,921
Pension liabilities	17	**24,961**	18,384
Accruals and other provisions	18	**26,250**	24,726
Total non-current liabilities		**131,141**	114,720
Current liabilities			
Trade and other payables		**33,641**	42,093
Current tax payable	13	**32,643**	28,037
Financial liabilities	14	**19,039**	4,731
Derivative financial instruments		**15,878**	3,694
Dividens payable		**23,090**	27,085
Financial liabilities to subsidiaries		**106,369**	38,689
Total current liabilities		**230,660**	144,329
Total liabilities		**361,801**	259,049
TOTAL EQUITY AND LIABILITIES		**544,267**	402,773

STATEMENTS OF CASH FLOWS STATOILHYDRO ASA - NGAAP

(in NOK million)	2008	2007
OPERATING ACTIVITIES		
Income before tax	**119,946**	106,959
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortisation and impairment	**19,494**	15,513
Exploration expenditures written off	**354**	40
(Gains) losses on foreign currency transactions and balances	**11,840**	(5,318)
(Gains) losses on sales of assets and other items	**(22,209)**	(4,989)
Termination benefits	**0**	6,516
Changes in working capital (other than cash and cash equivalents):		
• (Increase) decrease in inventories	**1,488**	(1,755)
• (Increase) decrease in trade and other receivables	**(169)**	(11,982)
• (Increase) decrease in net current financial derivative instruments	**12,557**	3,243
• (Increase) decrease in current financial investments	**(2,461)**	(68)
• Increase (decrease) in trade and other payables	**(11,899)**	15,055
• Increase (decrease) in receivables/liabilities to/from subsidiaries	**(531)**	(10,793)
Taxes paid	**(83,004)**	(60,853)
• (Increase) decrease in non-current items related to operating activities	**1,056**	2,002
Cash flows provided by operating activities	**46,462**	53,570
INVESTING ACTIVITIES		
Cash flows used in investing activities	**(97,092)**	(52,401)
FINANCING ACTIVITIES		
New long-term borrowings	**2,521**	1,703
Repayment of long-term borrowings	**(2,258)**	(2,082)
Dividend paid	**(27,082)**	(19,560)
Treasury shares purchased	**(308)**	(217)
Norsk Hydro ASA merger receivable	**0**	18,687
Net short-term borrowings, bank overdrafts and other	**10,495**	322
Increase (decrease) in financial receivables and payables to/from subsidiaries	**73,510**	0
Cash flows (used in)/provided by financing activities	**56,878**	(1,147)
Net increase (decrease) in cash and cash equivalents	**6,248**	22
Cash and cash equivalents at the beginning of the period	**24**	2
Cash and cash equivalents at the end of the period	**6,272**	24
Interest paid	**1,871**	5,492
Interest received	**6,439**	3,916

1 Organisation

StatoilHydro ASA, formerly 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.

StatoilHydro's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products.

Effective 1 October 2007, Statoil ASA merged with the oil and gas activities of Norsk Hydro ASA (Hydro Petroleum). Statoil ASA's name changed to StatoilHydro ASA as of that date.

StatoilHydro ASA is listed on the Oslo Stock Exchange (Norway) and the New York Stock Exchange (USA).

2 Summary of significant accounting policies

Statement of compliance

The financial statements of StatoilHydro ASA are prepared in accordance with the Norwegian Accounting Act of 1998 and good accounting practice (NGAAP).

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 financial statements.

Reclassifications

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

Subsidiaries, associated companies and jointly controlled entities

Shareholdings and interests in subsidiaries, associated companies (companies in which StatoilHydro ASA does not have control, or joint control, but has the ability to exercise significant influence over operating and financial policies; generally when the ownership share is between 20 and 50%) and jointly controlled entities are accounted for using the equity method.

Jointly controlled assets

Interests in jointly controlled assets are recognised by including StatoilHydro ASA's share of assets, liabilities, income and expenses on a line-by-line basis.

StatoilHydro as operator of jointly controlled assets

Indirect operating expenses such as personnel expenses are accumulated in cost pools. These expenses are allocated to business areas and StatoilHydro operated jointly controlled assets (licenses) on an hours incurred basis. Costs allocated to the other partners' share of operated jointly controlled assets reduce the expenses in the company's statement of income. Only StatoilHydro's share of statement of income and balance sheet items related to StatoilHydro operated jointly controlled assets are reflected in the statement of income and balance sheet.

Asset transfers between StatoilHydro ASA and its subsidiaries

Transfers of assets and liabilities between StatoilHydro ASA and entities directly or indirectly controlled by StatoilHydro ASA are accounted for at the carrying amounts of the assets and liabilities transferred.

Foreign currency translation

Transactions in foreign currencies are translated into NOK at the foreign exchange rate at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to NOK at the foreign exchange rate at the balance sheet date. Foreign exchange differences arising on translation are recognised in the income statement. 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.

Revenue recognition

Revenues associated with sale and transportation of crude oil, natural gas, petroleum and chemical products, and other merchandises are recorded when title passes 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 from properties in which StatoilHydro ASA has an interest with other companies are recognised on the basis of volumes lifted and sold to customers during the period (sales method). Where StatoilHydro ASA has lifted and sold more than the ownership interest, an accrual is recorded for the cost of the overlift. Where the Company has lifted and sold less than the ownership interest, costs are deferred for the underlift.

Sales and purchases of physical commodities, which are not settled net, are presented on a gross basis as Revenue and Purchases [net of inventory variation] in the Statement of income. Activities related to the trading of commodity based derivative instruments are reported on a net basis, with the margin included in Revenue.

Transactions with the Norwegian State

StatoilHydro ASA 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 recorded as Purchases [net of inventory variation] and Revenue, respectively. StatoilHydro 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 recorded net in StatoilHydro's financial statements.

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 StatoilHydro ASA. The accounting policy for pensions and share-based payments is described below.

Share-based payments

The Company 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 salary expense and recorded as an equity transaction (included in additional paid-in capital).

Research and development

The Company undertakes research and development both on a funded basis for licence holders, and unfunded projects at its own risk. The Company'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; the ability to measure reliably 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 Statement of Income for the year comprises current and deferred tax. Income tax is recognised in the income statement except to the extent that it relates to items recognised directly in equity, in which case it is recognised in equity.

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 recorded in the period in which they are earned or incurred, and are presented as financial items in the Statement of Income.

Deferred tax is provided using the balance sheet liability method. 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 profits will be available against which the asset can be utilised. However, the existence of unused tax losses is strong evidence that future taxable profits may not be available. In order to recognise a deferred tax asset based on future taxable profits, 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 Norwegian Continental Shelf (NCS). The special petroleum tax is currently levied at a rate of 50%. The special tax is applied to relevant income in addition to the standard 28% income tax, resulting in a 78% marginal tax rate on income subject to petroleum tax. The basis for computing the special petroleum tax is the same as for income subject to ordinary corporate income tax, except that onshore losses are not deductible against the special petroleum tax, and a tax-free allowance, or uplift, is granted at a rate of 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 recorded 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
StatoilHydro 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 tested for impairment. Geological and geophysical costs and other exploration expenditures are expensed as incurred.

Unproved oil and gas properties are assessed for impairment on a quarterly basis or when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount. Exploratory wells that have found reserves, but classification of those reserves as proved depends on whether a major capital expenditure can be justified, may remain capitalised for more than one year. The main conditions are that either firm plans exist for future drilling in the license or a development decision is planned in the near future. Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present.

Expenditures to drill and equip exploratory wells that find proved reserves are capitalised and depreciated using the unit of production method based on proved developed reserves expected to be recovered from the well. Development expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells are capitalised as producing oil and gas properties within property, plant and equipment and are 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. Pre-production costs are expensed as incurred.

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 a decommissioning obligation, if any, and, for qualifying assets, borrowing costs.

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 Company, 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.

Depreciation of production installations and field-dedicated transport systems for oil and gas is calculated using the unit of production method based on proved developed reserves expected to be recovered from the area during the concession or contract period. Depreciation of other assets and of transport systems used by several fields is calculated on the basis of their estimated useful lives, 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 the Company has established separate depreciation categories for platforms, pipelines, and wells as a minimum.

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 derecognition 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.

Leases
Leases in terms of which the Company assumes substantially all the risks and rewards of the ownership are recorded as finance leases within property, plant and equipment and loans and borrowings. All other leases are classified as operating leases and the costs are charged to income on a straight line basis over the lease term, unless another basis is more representative of the benefits of the lease to the Company.

Assets recorded under finance leases are stated 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 any impairment losses. Capitalised leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

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.

Intangible assets relating to expenditure on the exploration for and evaluation of oil and natural gas resources are not amortised. These assets are subject to impairment testing when facts and circumstances suggest that the carrying amount of the 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.

Impairment

Intangible assets and property, plant and equipment
The Company 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 the level that there are separately identifiable and largely independent cash inflows. Normally, separate cash-generating units are individual oil and gas fields or plants. For capitalised exploration expenditure cash-generating units are individual wells.

If assets are determined to be impaired, the carrying amounts of those assets are written down to 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.

Financial assets
The Company assesses at each balance sheet date whether a financial asset or group of financial assets is impaired.

For assets carried at amortised cost, if there is objective evidence that an impairment loss on loans and receivables has been incurred, the carrying amount of the asset is reduced. Any subsequent reversal of an impairment loss is recognised in the income statement.

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

Derivative financial instruments
The following accounting policies are applied for the principal financial instruments and commodity-based derivatives:
• Currency swap agreements:
Currency swaps are recognised at fair value in the balance sheet and changes in fair value are recognised in the statement of income.
• Interest rate swap agreements:
Interest rate swap agreements are valued according to the lower of cost or market principle.
• Commodity-based derivatives:
Commodity-based derivatives traded on organised exchanges are valued at market value and the resulting gains and losses are charged to income. Other commodity-based derivatives are valued according to the lower of cost or market principle.

Financial liabilities
Interest-bearing loans and borrowings are initially recognised at cost. After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest method. Amortised cost is calculated by taking into account any issue costs, and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised respectively in interest income and other financial items and interest and other financial expenses.

Pension liabilities
StatoilHydro ASA has pension plans that provide employees with a defined pension benefit upon retirement. The benefit to be received by employees generally depends on many factors including length of service, retirement date and future salary increases.

The Company'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 to the terms of the company'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 StatoilHydro operated jointly controlled assets (licenses) 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 resulting 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 company's retained earnings in the period in which they occur.

Provisions

Provisions are recognised when the Company 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 assets arising from past events, and which will only be confirmed by future uncertain events, are not recognised, but are disclosed when an inflow of economic benefits is probable.

Asset retirement obligations

Liabilities for decommissioning expenses are recognised when the Company has an obligation 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 reasonable estimate of that liability can be made. The expenses are estimated based 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 oil and natural gas production or transportation facilities, on construction or installation. An obligation for decommissioning may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations. At the time of the obligating event, a decommissioning liability is recognised. 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 an expected license period have indefinite lives and therefore there is no measurable asset retirement obligation to be recorded. For retail outlets, decommissioning provisions are estimated on a portfolio basis.

When a liability for decommissioning cost is recognised, a corresponding amount is recorded 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 or change in timing of the decommissioning is reflected as an adjustment to the provision and the corresponding property, plant and equipment.

Trade and other payables

Trade and other payables are carried at payment or settlement amounts.

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.

Use of estimates

Preparation of the financial statements requires the Company to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as disclosures of contingencies. Actual results may ultimately differ from the estimates and assumptions used.

The nature of StatoilHydro's operations, and the many countries in which StatoilHydro operates, are subject to changing economic, regulatory and political conditions. StatoilHydro does not believe it is vulnerable to the risk of a near-term severe impact as a result of any concentration of its activities.

3 Remuneration

(in NOK million, except average work-year)	2008	2007
Salaries	14,516	14,129
Pension costs	2,550	2,865
Payroll tax	2,184	2,508
Other social costs	1,743	1,790
Total	20,993	21,292
Average number of work-years	16,525	16,064

Management remuneration in 2008 (in NOK thousand)

Members of Corporate Executive Committee	Fixed Salary 2)	LTI 3)	Bonus 4)	Benefits in kind	Taxable re-imburse-ments	Taxable salary	Benefits in kind	Re-imbur-sements	Non taxable salary	Total Remuner-ation	Pension cost 5)	Present value of pension obligation
Lund Helge (CEO)	6,847	1,890	550	369	21	9,677	479	17	496	10,173	5,317	22,289
Bjørnson Rune (Executive vice president (E.V.P), Natural Gas)	2,535	600	113	191	21	3,460	0	26	26	3,486	822	18,346
Jacobsen Jon Arnt (E.V.P, Manufacturing & Marketing)	3,038	669	131	59	15	3,912	0	44	44	3,956	1,514	15,286
Mellbye Peter (E.V.P, International Exploration & Production)	4,194	813	108	141	22	5,278	54	39	93	5,371	1,364	41,945
Sætre Eldar (CFO)	3,047	713	154	196	30	4,140	177	24	201	4,341	924	25,129
Øvrum Margareth (E.V.P, Technology & New Energy)	3,375	694	138	54	23	4,284	55	50	105	4,389	876	22,623
Nes Helga 1) (E.V.P, Staff functions & corporate services for the period 10.11.08 - 31.12.08)	412	0	0	18	6	436	21	5	26	462	369	8,306
Michelsen Øystein 1) (E.V.P, Exploration & Production Norway for the period 10.11.08 - 31.12.08)	591	0	0	26	1	618	37	19	56	674	581	14,741
Myrebø Gunnar 1) (E.V.P, Projects for the period 10.11.08 - 31.12.08)	452	0	0	2	4	458	0	7	7	465	501	13,589
Ruud Morten 1) (E.V.P, Projects for the period 01.01.08 - 06.10.08)	1,980	590	0	11	15	2,596	0	28	28	2,624	0	19,460
Torvund Tore 1) (E.V.P, Exploration & Production Norway for the period 01.01.08 - 06.10.08)	2,958	863	0	16	8	3,845	168	33	201	4,046	0	36,541
Aasheim Hilde Merete 1) (E.V.P, Staff functions & corporate services for the period 01.01.08 - 01.11.08)	2,239	131	500	153	0	3,023	217	6	223	3,246	0	1,645
Total	31,668	6,963	1,694	1,236	166	41,727	1,208	298	1 506	43,233	12,268	239,900

1) The figures presented are total direct compensation for the period when a position in the Corporate Executive Committee is held.
2) Fixed salary consists of base salary, holiday allowance and any other administrative benefits.
3) Fixed long-term incentive element.
4) Bonus received in 2008 is related to the variable long-term incentive system that was terminated in 2007. Bonuses for the period 1 October 2007 to 31 December 2008 will be paid in 2009.
5) Pension cost is calculated based on actuarial assumptions and pensionable salary at 31 December 2008 and will be recognised as pension cost in the Statement of Income in 2009. The figures presented represent benefits earned assuming that a position in the Corporate Executive Committee is held for a full year. Payroll tax is not included.

Board of directors remuneration in 2008 (in NOK thousand)

Members of the board	Position	Board remuneration	Audit Committee	Compensation Committee	Total Remuneration
Rennemo Svein	Chair of the board*	440	0	14	454
Arnstad Marit	Deputy chair	417	100	0	517
Bjørndalen Kjell	Board member	294	0	35	329
Franklin Roy	Board member	492	100	0	592
Grieg Elisabeth	Board member	294	0	28	322
Nielsen Kurt Anker	Board member	294	150	0	444
Skaugen Grace R	Board member	294	0	50	344
Bakkerud Lill Heidi	Board member	294	0	0	294
Clausen Claus	Board member	294	0	0	294
Svaan Morten	Board member	294	100	0	394
Fritsvold Ragnar Per	Observer	294	0	0	294
Nilsen Geir	Observer	294	0	0	294
Total		3,995	450	127	4,572

*Chairman of the board from 1 April 2008

STATEMENT ON REMUNERATION AND OTHER EMPLOYMENT TERMS FOR STATOILHYDRO'S CORPORATE EXECUTIVE COMMITTEE

In accordance with the Norwegian Companies Act § 6-16 a), the Board has the intention to present the following statement regarding remuneration of the Corporate Executive Committee to the General Meeting at the 2009 annual meeting:

1. Remuneration policy and concept for the accounting year 2009

1.1 Policy and principles
The remuneration principles and concepts adopted and practised in StatoilHydro in 2008 will be continued in the accounting year 2009. However, due to the altered economic situation that also directly affects StatoilHydro, some extraordinary adjustments have been decided with effect for year 2009 only. These measures are carried out to limit our cost increases and contribute to a moderate development of labour costs. The temporary adjustments are defined in section 1.3 and 2 below.

The extraordinary adjustments regarding base salary and variable pay for 2009 and reduction in earned variable pay for 4Q 2007 - 2008, details of which are given below, are temporary measures and are not intended as permanent changes in the company's remuneration concept.

StatoilHydro's remuneration policy is strongly linked to the company's people policy and core values. It is believed that the development of a strong value based performance culture is an important success factor in creating values for the owners.

Certain key principles have been adopted for the design of the company's remuneration concept. These principles apply in general but they will be applied differently for the different remuneration systems and job categories.

The remuneration policy is intended to:

- Ensure that an overall perspective is taken into account through solutions that are integrated with StatoilHydro's value and performance-oriented framework
- Be competitive in the talent market without taking the lead in a total remuneration context
- Reward and recognize delivery and behaviour equally
- Ensure that there is a strong link between performance and reward
- Differentiate on the basis of responsibility and performance
- Reward both short- and long-term results and contributions
- Strengthen the common interests between employees, the company and it's owners
- Be transparent and in accordance with good corporate governance.

Our 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 StatoilHydro operates within.

1.2 The decision-making process

The decision-making process for the establishment and changing of remuneration policies and the determination of salaries and other remuneration for management is in accordance with the provisions of the Companies Act paragraphs 5-6, 6-14, 6-16 a) and the Board Instruction adopted on 1 October 2007.

The Board of directors has appointed a separate Compensation Committee. The Compensation Committee is a preparatory body for the Board. The Committee's main objective is to assist the Board of directors in its work relating to the terms of employment for StatoilHydro's Chief Executive Officer and the main principles and strategy for the remuneration and leadership development of senior executives in StatoilHydro. The Board of directors decides the salary and other terms of employment for the Chief Executive Officer.

1.3 The remuneration concept for the Corporate Executive Committee

StatoilHydro'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 base salary and a long-term incentive.

Base salary

The base salary shall be competitive in the markets where the company operates and shall reflect the individual's responsibility and performance. The evaluation of performance is based on fulfilment of certain pre-defined goals; refer to "Variable Pay" below. The base salary is normally reviewed once a year.

As an extraordinary measure the base salary of The Chief Executive Officer and the other members of the Corporate Executive Committee will remain unchanged in 2009 in relation to 2008.

Long Term Incentive (LTI)

StatoilHydro will carry on the established long-term incentive system for a limited number of senior managers, including the members of the Corporate Executive Committee.

The long-term incentive system is a fixed, monetary compensation calculated in per cent of the participant's base salary; ranging from 20 - 30 per cent depending on the participant's position. The participant is obliged to buy StatoilHydro shares in the market with the fixed LTI amount (after tax deduction) every year and to hold the shares for a lock-in period of 3 years.

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. The long-term incentive contributes to a strengthening of the common interests between the shareholders of StatoilHydro, the company and the individual.

Variable pay

The intention is to continue with the company's variable pay concept in 2009; however, it has been decided to reduce the maximum pay potential by 50 per cent having effect on variable pay for 2009. Accordingly, the maximum pay potential in the Chief Executive Officer's variable pay scheme is reduced from 50 per cent to 25 per cent in 2009 whereas the maximum pay potential in the Executive Vice President's variable pay schemes is reduced from 40 per cent to 20 per cent this year.

The payout of variable pay is based on the executive's performance. For performance at target level the payout is 2/3 of the maximum potential.

The targets forming the basis for the individual variable pay evaluation are established between the manager and the employee as part of our Performance Management process. In StatoilHydro this evaluation is performed along two axes, delivery (what you have delivered) and behaviour (how the goals are achieved). Targets regarding delivery are set for each business/staff area related to finance, operations, markets, health, safety and environment as well as for people and organisation. Evaluation of behaviour is based on targets related to the core values of StatoilHydro, the leadership principles and the manager's individual development plan.

In the performance contract of the Chief Executive officer and Chief Financial Officer one of several targets is related to the company's relative total shareholder return (TSR). The amount of the annual variable pay is decided based on an overall assessment of the performance of various targets including but not limited to the company's relative TSR.

Pension and insurance schemes
StatoilHydro's general pension plan is a defined benefit arrangement with a pension level amounting to 66 per cent of the pensionable salary provided at least 30 years service period. Pension from the National Insurance scheme is taken into account when the pension is estimated. The retirement age is generally 67 years, for offshore employees 65 years.

The pension schemes for members of the Corporate Executive Committee including the Chief Executive Officer are supplementary agreements to the company's general pension plan.

The Chief Executive Officer is under specific terms according to his pension agreement of 7 March 2004, entitled to a pension amounting to 66 per cent of pensionable salary and a retirement age of 62. The full service period is 15 years.

Four of the Executive Vice Presidents have individual pension terms according to a previous standard arrangement decided October 2006. These executives are entitled, under specific terms, to a pension amounting to 66 per cent of pensionable salary and a retirement age of 62. When calculating the number of years of membership in the StatoilHydro's general pension plan, these Executive Vice Presidents have the right to an extra period corresponding to half a year of extra membership for each year the person has served the company as an Executive Vice President.

One of the Executive Vice Presidents is entitled, under specific terms, to a pension amounting to 66 per cent of pensionable salary and a retirement age of 62. Another Executive Vice President is, under specific terms, entitled to a pension amounting 70 % of pensionable salary and a pension age of 62.

The individual pension terms outlined above are results of commitments according to previous arrangements. The previous standard arrangement for the Executive Vice Presidents, as described above, was terminated in 2007. Until a new standardized, competitive model appropriate for the company's needs is established, StatoilHydro will apply a retirement age of 65 years and a pension level amounting to 66 % for Executive Vice Presidents. This arrangement applies for two of the Executive Vice Presidents.

In addition to the pension benefits outlined above the Executive Vice Presidents are offered other benefits in accordance with StatoilHydro's general pension plan including pension from the age of 67 based on the defined benefit arrangement.

Members of the Corporate Executive Committee are covered by the general insurance schemes applicable within StatoilHydro.

Severance pay arrangements
If the Board of Directors gives the Chief Executive Officer notice of termination of employment, he shall be entitled to severance pay corresponding to 24 months of base salary. The severance pay shall be calculated as from the expiry of the notice period of 6 months. The same amount of severance pay shall also be paid if the parties agree that the employment should be discontinued and the Chief Executive Officer gives notice pursuant to a written agreement with the Board. These terms and conditions apply according to Chief Executive Officer's employment contract of 7 March 2004.

Executive Vice Presidents are entitled to severance pay equivalent to six months salary, excluding term of notice of six months, when the resignation is at the request from the company. The same amount of severance pay shall also be paid if the parties agree that the employment should be discontinued and the Executive Vice President gives notice pursuant to a written agreement with the Company. Any other payment earned by the Executive Vice President during the period in which severance pay is payable, will be fully deducted. This relates to earnings from any employment or business activity where the Executive Vice President has active ownership.

One of the Executive Vice Presidents is according to a previous agreement entitled to severance pay of 18 months, excluding term of notice of six months, provided the resignation is at the request of the company.

The entitlement to severance pay is conditional on the Chief Executive Officer or the Executive Vice President not being guilty of gross misconduct, gross negligence, disloyalty or other material breach of his/her duties.

The Chief Executive Officer's/Executive Vice President's own notice will as a general rule not release any severance pay.

Other benefits
StatoilHydro has a Share Saving Plan, available to all employees including members of the Corporate Executive Committee. The Share Saving Plan gives the employees the opportunity to purchase StatoilHydro shares in the market limited to five per cent of their annual gross salary. If the shares are kept for two full calendar years of continued employment the employees will be allocated bonus shares in proportion to their savings. Shares to be used for sale and transfer to employees are acquired by StatoilHydro in the market, in accordance with the authorization from the General Meeting.

The members of the Corporate Executive Committee have benefits in kind such as company car and free telephone.

2. Execution of the remuneration policy and principles in 2008
The long term incentive as described in section 1.3 above was implemented for the members of the Corporate Executive Committee in 2008.

During the year three Executive Vice Presidents resigned from their positions in the Corporate Executive Committee, one of whom has left the company in 2008. The new appointed Executive Vice Presidents are given terms and conditions within the standards and framework described in section 1.3 above.

As a one-time adjustment, and reflecting the significant increase in the company's size and complexity following the 2007 merger , the base salary of the Chief Executive Officer was increased by 20 per cent effective 1 October 2007. After a further increase of 5.5 per cent 1 January 2008, in line with the general wage settlement for StatoilHydro employees, the CEO's annual base salary is 6.3 MNOK.

There has been no general review of the base salary of the Executive Vice President in 2008. A review of the base salary was carried out in connection with the merger effective from 1 October 2007.

A performance evaluation and payout of annual variable pay for the period 1 January - 30 September 2007 was executed before the merger. Furthermore it was decided that variable pay for quarter 4 2007 should be paid out in 2009 together with variable pay for 2008.

As an extraordinary measure due to the altered economic situation, each member of the Corporate Executive Committee, including the Chief Executive Officer, has agreed that the earned variable pay for quarter 4 2007 and 2008 shall be reduced by 50 %.

3. Concluding remarks
StatoilHydros's remuneration policy and solutions are aligned with the company's overall people policy and are integrated with the company's value and performance-oriented framework. Furthermore, the remuneration systems and practice are transparent and in accordance with prevailing guidelines and good corporate governance.

4 Asset impairment

There have been no material impairments of assets in 2008 or 2007, except for write-down of inventory as described in note 7 Inventory.

5 Auditors' remuneration

(in NOK million, excluding VAT)	2008	2007
Audit fees	25.0	15.5
Audit-related and Other service fees	5.3	7.4
Total	30.3	22.9

In addition audit fee related to StatoilHydro-operated licences amounts to NOK 5.8 and NOK 4.7 million for 2008 and 2007, respectively.

The increase in audit fees from 2007 to 2008 are mainly due to increased activity in connection with the merger with Hydro Petroleum.

6 Cash and cash equivalents

(in NOK million)	At 31 December 2008	2007
Cash at bank	707	24
Time deposits and Collateral deposits	5,565	-
Cash and cash equivalents	6,272	24

Cash and cash equivalents at 31 December 2008 include restricted cash of NOK 3,165 million related to trading activities. This restricted cash is related to certain collateral requirements set out by exchanges where StatoilHydro ASA is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

For reconciliation of Cash and cash equivalents reported in the statement of financial position, see Statements of cash flows.

7 Inventories

Inventories are valued at the lower of cost and net realisable value. Inventory of crude oil, refined products and non-petroleum products are determined under the first-in, first-out (FIFO) method.

(in NOK million)	At December 31 2008	2007
Crude oil	5,317	5,745
Petroleum products	1,316	1,528
Other	187	1,035
Total inventories	6,820	8,308

A write-down of inventory to net realisable value of NOK 2.8 billion have been recognised as Purchases [net of inventory variation] at year end 2008 (0 at year end 2007).

8 Investments in subsidiaries and associated companies

(in NOK million)	Subsidiaries	Associates
Investment at 1 January 2008	164,386	1,083
Net income subsidiaries and associated companies	27,763	187
Translation adjustments	30,880	0
Pension related adjustments	(707)	0
Change in paid-in equity	64,846	0
Ordinary dividend	(6,123)	(230)
Investment at 31 December 2008	281,045	1,040

Ownership in certain subsidiaries (in %)					
Name	%	Country of incorporation	Name	%	Country of incorporation
AS Eesti Statoil	100	Estonia	Statoil Nigeria Outer Shelf AS	100	Norway
Latvija Statoil SIA	100	Lativia	Statoil Norge AS	100	Norway
Statholding AS	100	Norway	Statoil North Africa Gas AS	100	Norway
Statoil AB	100	Sweden	Statoil North Africa Oil AS	100	Norway
Statoil Angola Block 15 AS	100	Norway	Statoil North America Inc.	100	United States
Statoil Angola Block 15/06 Award AS	100	Norway	Statoil Orient Inc AG	100	Switerzland
Statoil Angola Block 17 AS	100	Norway	Statoil Polen Invest AS	100	Norway
Statoil Angola AS	100	Norway	Statoil Sincor AS	100	Norway
Statoil Apsheron AS	100	Norway	Statoil SP Gas AS	100	Norway
Statoil Asia Pacific Pte. Ltd.	100	Singapore	Statoil (UK) Ltd	100	United Kingdom
Statoil Azerbaijan Alov AS	100	Norway	Statoil Venezuela AS	100	Norway
Statoil Azerbaijan AS	100	Norway	StatoilHydro Canada Ltd.	100	Canada
Statoil BTC Finance AS	100	Norway	StatoilHydro Orinoco AS	100	Norway
Statoil Coordination Center N.V.	100	Belgium	StatoilHydro Petroleum AS	100	Norway
Statoil Danmark A/S	100	Denmark	StatoilHydro Russia AS	100	Norway
Statoil Deutschland GmbH	100	Germany	StatoilHydro Venture AS	100	Norway
Statoil do Brasil Ltda	100	Brazil	Statpet Invest AS	100	Norway
Statoil Exploration Ireland Ltd	100	Ireland	UAB Lietuva Statoil	100	Lithuania
Statoil Forsikring AS	100	Norway	Statoil Metanol ANS	82	Norway
Statoil Hassi Mouina AS	100	Algeria	Mongstad Refining DA	79	Norway
Statoil Iran AS	100	Norway	Mongstad Terminal DA	65	Norway
Statoil Nigeria AS	100	Norway	Tjeldbergodden Luftgassfabrikk DA	51	Norway
Statoil Nigeria Deep Water AS	100	Norway			

Voting rights correspond to ownership interests.

Ownership in certain associated companies (in %)		
Name	%	Country of incorporation
Nova Naturgass AB	30	Sweden
Vestprosess DA	17	Norway
Etanor DA	16	Norway

9 Financial assets

Non-current financial assets

(in NOK million)	At 31 December 2008	2007
Financial investments	17	25
Financial receivables	557	274
Financial assets	574	299

Current financial investments

(in NOK million)	At 31 December 2008	2007
Money marked funds	2,616	155
Financial investments	2,616	155

All current financial investments are recorded at fair value. All balances at year end 2008 and 2007 are considered to be trading securities where unrealised gains and losses are included in income. The cost price for current financial investments at 31 December 2008 and 2007 was NOK 2,402 million and NOK 169 million respectively.

10 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	Construction in progress	Total
Cost at 31 December 2007	2,842	296,616	4,599	777	4,276	12,804	321,914
Additions from SHP AS at the acquistion cost	0	16,367	193	0	0	1,485	18,045
Additions and transfers	756	15,861	212	242	0	10,240	27,311
Disposals assets at cost	(462)	(1,504)	(13)	(29)	0	0	(2,008)
Cost at 31 December 2008	3,136	327,340	4,991	990	4,276	24,529	365,262
Accumulated depr. and impairment losses at 31 December 2007	(2,080)	(196,376)	(3,325)	(201)	(399)	0	(202,381)
Additions accumulated depreciation on assets from SHP AS	0	(8,928)	(57)	0	0	0	(8,985
Depreciation, depletion and amortisation for the year	(441)	(18,670)	(137)	(30)	(212)	0	(19,490)
Accumulated depreciation disposed assets	459	1,414	34	(1)	0	0	1,906
Accumulated depr. and impairment losses at 31 December 2008	(2,062)	(222,560)	(3,485)	(232)	(611)	0	(228,950)
Carrying amount at 31 December 2008	1,074	104,780	1,506	758	3,665	24,529	136,312
Intangible assets	-	-	-	-	-	-	5,110
Estimated useful lives (years)	3 - 10	*	15-20	20 - 33	20 - 25		

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

In 2008 StatoilHydro Petroleum AS (SHP) has transferred Property, plant and equipment to StatoilHydro ASA amounting to NOK 9.1 billion (gross values NOK 18.0 billion on Property, plant and equipment, and NOK 8.9 billion on accumulated depreciation, respectively). All StatoilHydro Petroleum licences in the "North Area" and Njord has been transferred.

The book value of vessels consists of financial leases.

In 2008 and 2007, capitalised interest amounted to NOK 0.5 billion and NOK 1.1 billion, respectively.

In addition to depreciation, amortisation and impairment losses specified above, intangible assets have been amortised by NOK 4 million in 2008.

11 Trade and other receivables

(in NOK million)	At 31 December 2008	2007
Trade receivables	38,277	38,186
Other receivables	9,001	6,100
Trade and other receivables	47,278	44,286

Other receivables consist of receivables towards joint ventures, associated companies and other related parties.

12 Financial items

(In NOK million)	2008	2007
Foreign exchange gains (losses) non-current financial liabilities	(11,252)	5,944
Foreign exchange gains (losses) derivative financial instruments	(25,001)	8,276
Other foreign exchange gains (losses)	(2,066)	1,798
Net foreign exchange gains (losses)	(38,319)	16,018
Dividends received	166	96
Gains (losses) financial investments	1,923	(250)
Interest and other financial income	8,361	4,455
Interest income and other financial items	10,450	4,301
Capitalised borrowing costs	511	1,058
Accretion expense asset retirement obligation	(1,269)	(1,345)
Interest and other financial expense	(4,683)	(5,689)
Interest and other financial expense	(5,441)	(5,976)
Net financial Items	(33,310)	14,343

Included in the Foreign exchange gains (losses) derivative financial instruments classification are changes in the fair values of currency swap contracts related to liquidity and currency risk management. The weakening of the NOK versus the USD during 2008 resulted in fair value losses on these positions recognised in the annual figures for 2008.

Increase in Gains (losses) financial investments in 2008 is mainly related to currency effects, included in Fair value changes.

Increase in Interest and other financial income current financial assets in 2008 is mainly related to interest on currency swap contracts due to increased interest rate spread and accrued interest on prepaid tax.

Capitalised borrowing costs are reduced due to more fields going into production in 2008 compared to 2007.

13 Income taxes

Income tax expense

(in NOK million)	2008	2007
Current taxes payable	84,787	62,053
Change in deferred tax	(5,478)	1,037
Income tax expense	79,309	63,090
Uplift benefits for the year	7,461	5,914

Revenue from oil and gas activities on the NCS is taxed according to the Petroleum tax law. In addition to normal corporation tax, a special tax of 50% is levied after deducting uplift, an investment tax credit. Uplift is deducted by 7.5% per year for four years, as from the year of investment. Unrecognised uplift credits amount to NOK 10.8 billion as at 31 December 2008.

Significant components of deferred tax assets and liabilities were as follows

	At 31 December	
(in NOK million)	2008	2007
Deferred tax assets on		
Inventory	948	142
Other short-term items	3,778	1,463
Pensions	9,158	10,385
Decommissioning and asset retirement obligation	18,702	17,594
Other long-term items	3,940	1,547
Total deferred tax assets	36,526	31,131
Deferred tax liabilities on		
Property, plant and equipment	57,790	51,996
Capitalized exploration expenditures and interest	12,125	9,924
Other long-term items	1,553	4,132
Total deferred tax liabilities	71,468	66,052
Net deferred tax liabilities	34,942	34,921

The movement in deferred income tax liability

(in NOK million)	2008	2007
Deferred income tax liability at 1 January	34,921	34,997
Charged to the income statement	(5,478)	1,037
Acquisition from wholly owned subsidiary StatoilHydro Petroleum AS of carrying amount in subsidiary	3,970	0
Acquisitions, sales and other	1,529	(1,113)
Deferred income tax liability at 31 December	34,942	34,921

14 Current financial liabilities

(in NOK million)	At 31 December 2008	2007
Bank loans and overdraft facilities	39	41
Collateral liabilities	10,123	2,797
Commercial paper liabilities	2,989	0
Current portion of long-term debt	5,398	1,636
Current portion of financial lease	235	184
Other	255	73
Total	19,039	4,731
Weighted average interest rate	2.38%	5.61%

Collateral liabilities relates to cash received in order to offset a portion of the group credit exposure.

Commercial paper liabilities relates to the US Commercial Paper (CP) program available for short term funding. StatoilHydro can borrow maximum USD 4 billion under the current CP programme.

As of 31 December 2008 and 2007, StatoilHydro had no committed short-term credit facilities available or drawn.

15 Non-current financial liabilities

(in NOK million)	At 31 December 2008	2007
Unsecured bonds	41,753	33,853
Unsecured bank loans	4,899	1,436
Financial lease obligation	3,932	3,194
Financial liabilities to subsidiaries	37	27
Gross financial liabilities	50,621	38,509
Less current portion	5,633	1,820
Financial liabilities	44,988	36,689
Weighted average interest rate (%)	5.97	6.47

StatoilHydro utilises currency swaps to manage foreign exchange risk on its non-current financial liabilities. The swaps are reflected in the table above, and as such substantially all non-current financial liabilities are exposed to changes in the USDNOK exchange rate. The stated interest rate on the majority of the non-current loans are fixed. Interest rate swaps are utilised to manage interest rate exposure.

Details of largest unsecured bonds:

Bond agreement	Fixed interest rate	Maturity (year)	Balance in NOK million at 31 December 2008	2007
USD 500 million	6.500%	2028	3,462	2,675
USD 500 million	5.125%	2014	3,498	2,704
USD 480 million	7.250%	2027	3,363	2,600
USD 375 million	5.750%	2009	2,624*	2,026*
USD 300 million	7.750%	2023	2,100	1,623
USD 300 million	6.360%	2009	2,100	1,623
EUR 500 million	5.125%	2011	4,915	3,961
EUR 300 million	6.250%	2010	2,960	2,388
GBP 225 million	6.125%	2028	2,277	2,432

* Net after buy backs of NOK 2,288 million and NOK 1,765 million in 2008 and 2007, respectively

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 bond holders and lenders.

StatoilHydro's secured bankloans in USD have been secured by mortgage in shares in a subsidiary and investments in other companies with a combined book value of NOK 2,908 million, a bank deposit with a book value of NOK 1,070 million, and StatoilHydro's pro-rata share of income from certain applicable projects.

StatoilHydro has 24 unsecured bond agreements outstanding, which contain provisions allowing StatoilHydro 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 is NOK 42,722 million at 31 December 2008 closing rate.

Non-current financial liabilities repayment profile:

(in NOK million)	
2010	3,202
2011	3,330
2012	3,860
2013	3,273
Thereafter	31,323
Total	44,988

StatoilHydro ASA has an agreement with an international bank syndicate for committed non-current revolving credit facility totalling USD 2 billion, all undrawn. Commitment fee is 0.0575% per annum.

16 Financial instruments and derivatives

Market risk management

StatoilHydro ASA operates in the worldwide crude oil, refined products, natural gas, and electricity markets and is exposed to such market risks as 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 focus on achieving the highest risk adjusted returns within the given mandate. Long-term is generally viewed as risks managed at the corporate level and (or) normally having a six months or longer time horizon for significant volumes while short term is generally viewed as risks managed at segment and lower levels according to trading strategies and pre-defined mandates.

StatoilHydro ASA has established guidelines for entering into contractual arrangements (derivatives) in order to manage the commodity price, foreign currency rate, and interest rate risk. We use both financial and commodity-based derivatives to manage the risks in our overall earnings and the future value of cash flows.

Commodity price risk
Commodity price risk constitutes StatoilHydro ASA's most important market risk and is monitored everyday against established mandates as defined by our governing policies. To manage the commodities price risk StatoilHydro ASA enters into commodity-based derivative contracts, which consist of futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity.

Derivatives associated with crude oil and petroleum products are traded mainly on the InterContinental 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, 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 usually three years or less.

Currency risk
Fluctuations in exchange rates can have significant effects on the entity's results. Foreign exchange risk is assessed on a portfolio basis in accordance with approved strategies and mandates. StatoilHydro ASA uses only well-understood, conventional derivative instruments which include futures and options traded on regulated exchanges, OTC-swaps, - options and forward contracts.

Our cash inflows are largely influenced by USD while our cash outflows, such as operating expenses and taxes payable, are to a large extent in NOK. Accordingly, a significant portion our exposure to foreign currency rates exists with USD versus Norwegian kroner. We seek to manage this currency mismatch by issuing or swapping non-current financial debt into USD.

StatoilHydro ASA further seeks to manage short-term currency mismatches by using derivative instruments both for 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 a subsequent year. This means, from time to time, we purchase substantial NOK amounts on a forward basis using derivative instruments.

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

The basic rule is that the non-current debt portfolio shall have floating rate interest payments. The modified duration (the percentage change in value for one percentage point change in yield) expresses the way we monitor interest rate risk. Generally our modified duration shall be between 0 and 1.0%. Other strategies can from time to time be approved if justified by factors such as corporate risk considerations, tax considerations, large non-recurring transactions, credit rating concerns, etc.

The following currency risk sensitivities by end of 2008 have been calculated by assuming a 20% change in the foreign currency exchange rates. For the interest rate risk sensitivity a one percentage point change has been used in the calculation. The estimated gains and losses that will impact our income statement are presented in the following table.

(in NOK million)	Gains	Losses
At 31 December 2008		
Currency risk (20% sensitivity)	29,014	(29,014)
Interest rate risk (1 percentage point sensitivity)	1,017	(1,017)
At 31 December 2007		
Currency risk (10% sensitivity)	11,726	(11,726)
Interest rate risk (1 percentage point sensitivity)	173	(173)

Credit risk
Credit risk is the risk that our customers or counterparties to financial instruments will cause us financial loss by failing to honour their obligation. Credit risk arises from credit exposures with customer accounts receivables as well as from derivate financial instruments and deposits with financial institutions.

The current financial crisis has brought into focus the need for all entities to have robust credit policies with close monitoring of associated risks. Over the years, we have established a clear credit policy which has proven especially valuable during this period of widespread financial pressure. The tools used to manage and monitor credit risk have been tested by the continuing crisis and no material credit losses have materialised for StatoilHydro ASA during 2008.

Key elements of our credit risk management approach include
- A global credit risk policy
- Credit mandates
- Internal credit rating process
- Credit risk mitigation tools
- Continuously monitoring and managing credit exposures

Prior to entering into transactions with new counterparties, the credit policy requires all counterparties to be formally identified, approved, and assigned internal credit ratings as well as exposure limits. Once established, all counterparties are re-assessed minimum annually with high risk counterparties reviewed 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. Exposure limits are determined based on assigned internal credit ratings combined with other factors, such as expected transaction and industry characteristics, as outlined in our credit policy. The mandate for setting credit limits is regularly reviewed with regard to changes in market conditions.

There are several instruments available to us to reduce or control credit risk both on an individual counterparty and portfolio level. The main tools used by StatoilHydro ASA are variations of bank and parental guarantees, prepayments and cash collateral. For bank guarantees only investment grade rated international banks are accepted.

We manage credit risk both on a portfolio and counterparty level. We have pre-defined limits regarding the minimum average credit rating allowed at any given time on the total portfolio level as well as maximum credit exposures for individual counterparties. We monitor the portfolio on a regular basis and individual exposures versus limits on a daily basis. The total credit exposure portfolio of StatoilHydro ASA is well diversified with respect to number and quality of counterparties, industries and geographically. The majority of our credit exposure is typically with investment grade counterparties.

The following table contains the fair market value of open non-exchange traded derivative assets split by our assessment of the counterparty's credit risk.

	At 31 December	
(in NOK million)	**2008**	**2007**
Counter-party rated		
Investment grade, rated A or above	1,381	1,507
Other investment grade	225	10
Non investment grade or not rated	188	635

As of 31 December 2008, collateral is received in cash to offset a certain portion of StatoilHydro ASA's credit exposure.

Consistent with our policies, commodity derivative counter-parties have been assigned credit ratings corresponding to those of their respective parent companies. If the parent company is highly rated, it may not be necessary to obtain a parent company guarantee from such a counterparty.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our obligations when due. The purpose of liquidity and short-term liability management is to make certain that StatoilHydro ASA at all times has sufficient funds available to cover financial obligations.

StatoilHydro ASA's business activities often generate, on a monthly basis, a positive cashflow 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) cashflows are typically limited.

The amount of liquid assets will, as a rule, follow a cyclical pattern and increase from month to month, with an exception for months with tax or dividends payments 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 and subsequently 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 programs or under documentation established ad hoc.

Significantly all of StatoilHydro ASA's financial liabilities related to derivative financial instruments, both exchange traded and non-exchange traded commodity based derivatives together with financial derivatives fall due within one year, based on the underlying delivery period of the contracts included in the porfolio.

Fair value of derivative financial instruments

The following table contains estimated fair values of financial and commodity based derivative instruments recognised in the balance sheet.

(in NOK million)	Fair value of assets	Fair value of liabilities	Net fair value
At 31 December 2008			
Foreign currency instruments	173	(13,565)	(13,392)
Crude Oil and Refined products	40	(5)	35
Natural Gas and Electricity	1,879	(2,309)	(430)
At 31 December 2007			
Foreign currency instruments	1,617	0	1,617
Crude Oil and Refined products	469	(1,130)	(661)
Natural Gas and Electricity	492	(2,678)	(2,186)

In addition to the fair value of financial derivative instruments recognised in the balance sheet StatoilHydro ASA has entered into interest rate swap and cross currency swap agreements that are not recognised in the balance sheet. These agreements had at 31 December 2008 a fair value of NOK 12.1 billion. By end of 2007 the fair value was NOK 4.5 billion.

The fair values of quoted financial assets and liabilities are determined by reference to bid and ask prices respectively, at the close of business on the balance sheet date. Fair values of derivative financial instruments quoted in active markets such as but not limited to commodity based futures, exchange traded option contracts and equity instruments are based on quoted market prices obtained from the relevant exchanges or clearing houses.

The following table summarises the basis for fair value estimation and the maturity of all our financial derivative instruments recognised in StatoilHydro ASA's balance sheet.

(in NOK million)	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Maturity in excess of 5 years	Total fair value
At 31 December 2008					
Fair value based on prices quoted in an active market	31	(245)	(32)	0	(246)
Fair value based on price inputs from observable market transactions	(13,455)	(85)	0	0	(13,540)
Fair value based on inputs from other sources	0	0	0	0	0
At 31 December 2007					
Fair value based on prices quoted in an active market	(447)	(866)	0	0	(1,313)
Fair value based on price inputs from observable market transactions	3	2	0	0	5
Fair value based on inputs from other sources	0	0	0	78	78

17 Employee retirement plans

Pension obligation

StatoilHydro ASA is obligated to follow the Act on Mandatory company pensions. The company's pension scheme follows the requirement as included in the Act.

StatoilHydro ASA uses the option in Norwegian Accounting Standard (NRS) 6A and recognises actuarial gains and losses directly in equity, outside the Statement of Income, in the period in which they occur. Actuarial gains and losses related to the accrual for termination benefits are recognised in the income statement in the period in which they occur.

StatoilHydro ASA's defined benefit retirement plans cover all of its 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 independent actuaries.

StatoilHydro ASA is - due to National agreements - into the "agreement-based early retirement plan" (AFP). When an employee retires through AFP the company has an obligation to pay a percentage of the benefits. This part of the plan is defined as a multi-employer plan. The administrator is not able to calculate the company's share of assets and liabilities and this plan is consequently accounted for as a defined contribution plan. The period's contributions are recognised in the income statement as the pension cost for the period. When an employee retires through AFP, the company also offers a gratuity. This is a defined benefit plan, and included in the accrued obligations related to the defined benefit plans.

The obligations related to the defined benefit plans were measured at 31 December, 2008 and 2007. 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. The discount rate for the defined benefit plans in Norway was estimated to be 4.5% at 31 December 2008 based on the long-term interest rate on Norwegian government bonds extrapolated based on a 30 year yield curve to match StatoilHydro's payment portfolio for earned benefits.

The longest duration of Norwegian government bonds are 10 years. StatoilHydro's opinion is that the most appropriate method to extrapolate the 10 years rate to a 30 year rate is based on the yield curves with reference to European and USA interest rates (equally weighted). In a long term perspective, these countries are assumed to have similar market trends and interest levels as Norway.

Payroll tax is calculated based on the pension plan's net unfundet status. Payroll tax is included in the projected benefit obligation.

Net periodic pension cost

(in NOK million)	2008	2007
Current service cost	2,248	2,420
Interest cost on prior years' benefit obligation	2,320	1,556
Expected return on plan assets	(1,948)	(1,654)
Amortisation of actuarial gain or loss related to termination benefits	(215)	0
Amortisation of past service cost	0	2,065
Losses (gains) from curtailment or settlement	73	(1,564)
Defined benefit plans	2,478	2,823
Multi-employer plans	72	42
Termination benefits	0	6,516
Total net pension cost	2,550	9,381

Pension cost includes payroll tax.

The expense related to pension cost is recognised as Operating cost or Selling, general and administrative cost based on the function of the cost. Pension cost is partly charged to partners of StatoilHydro operated licences.

In 2007, StatoilHydro ASA offered early retirement (termination benefits) to employees above the age of 58 years (contingent upon certain conditions). The expenses related to termination benefits were recognised as Operating cost and Selling, general and administration cost, NOK 4.8 billion and NOK 1.7 billion, respectively.

Change in projected benefit obligation (PBO)

(in NOK million)	2008	2007
Projected benefit obligation at January 1	46,993	27,283
Current service cost	2,248	2,420
Interest cost on prior years' benefit obligation	2,320	1,556
Actuarial loss (gain)	3,575	135
Past service cost	0	2,065
Benefits paid	(1,195)	(497)
Settlements/curtailments	132	(1,434)
Business combination	0	8,949
Termination benefits	0	6,516
Changing in receivable from subsidiary related to termination benefit costs	49	0
Projected benefit obligation at December 31	54,122	46,993

Change in pension plan assets

(in NOK million)	2008	2007
Fair value of plan assets at January 1	32,124	21,288
Expected return on plan assets	1,948	1,654
Actuarial gain (loss)	(3,791)	(320)
Company contributions (including payroll tax)	1,200	3,585
Benefits paid	(274)	(246)
Business combination	0	6,034
Settlements	24	129
Fair value of plan assets at December 31	31,231	32,124

Total provision for pensions

(in NOK million)	2008	2007
Balance sheet provision at 1 January	(14,869)	(5,995)
Net periodic pension costs defined benefit plans	(2,478)	(2,824)
Net actuarial loss (gain) recognised in SORIE	(7,582)	(455)
Less employer contributions	1,200	3,585
Less benefit paid during year	921	251
Business combination	0	(2,915)
Termination benefits	0	(6,516)
Changing in receivable from subsidiary related to termination benefit costs	(49)	0
Other changes	(34)	0
Balance sheet provision at 31 December	(22,891)	(14,869)

Surplus (deficit) at 31 December for the current and previous two periods are as follow:

(in NOK million)	2008	2007	2006
Surplus (deficit) at 31 December:	(22,891)	(14,869)	(5,995)
Represented by:			
Asset recognised as pension asset	0	1,561	2,949
Asset recognised as non-current financial receivables from subsidiary*	2,070	2,117	0
Liability recognised as non-current pension liability	(24,961)	(18,384)	(8,781)
Liability recognised as current liability	0	(163)	(163)

The defined benefit obligation may be analysed as follows:

(in NOK million)	2008	2007
Funded pension plans	34,236	29,495
Unfunded pension plans	19,886	17,498
PBO at 31 December	54,122	46,993

*Asset recognised as non-current financial receivables from subsidiary relates to termination benefit costs.

Actuarial gains and losses recognised directly in retained earnings:

(in NOK million)	2008	2007
Unrecognised actuarial losses (gains) at 1 January	0	0
Actuarial losses (gains) on plan assets occur during the year	3,791	(184)
Actuarial losses (gains) on benefit obligaion occur during the year	3,575	135
Recognised in the income statement during the year	215	0
Recognised directly to equity (SORIE) during the year	(7,581)	49
Unrecognised actuarial losses (gains) at 31 December	0	0

Actual return on plan assets

(in NOK million)	2008	2007
Actual return on plan assets	(1,843)	1,334

History of experience gains and losses for the current and previous two periods are as follow::

(in NOK million)	2008	2007	2006
Actual return less expected return on plan assets (NOK million)	(3,791)	184	1,086
As % of plan assets at beginning of year	(11.80%)	0.86%	6.13%
Experience gains/(losses) on plan liabilities (NOK million)	(3,575)	(135)	(3,835)
As % of present value of plan liabilities at beginning of year	(7.61%)	(0.49%)	(17.85%)
Total actuarial gain/(loss) (NOK million)	(7,366)	49	(2,749)
As % of present value of plan liabilities at beginning of year	(13.61%)	0.18%	(12.79%)

The cumulative amount of actuarial gains and losses recognised directly to equity amounted to NOK 13.3 billion after tax. (Negative effect on equity). NOK 12.6 million is related to actuarial gains and losses recognised in StatoilHydro ASA and 0.7 million is related to subsidiaries accounted for using the equity method.

Assumptions for the year (Profit and Loss items)

in %	2008	2007
Discount rate	5.00	4.50
Expected return on plan assets	6.25	5.75
Rate of compensation increase	4.50	4.25
Expected rate of pension increase	3.25	2.75
Expected increase of social security base amount (G-amount)	4.25	4.00
Expected inflation	2.25	2.25

Assumptions at end of year (Balance sheet items)

in %	2008	2007
Discount rate	4.50	5.00
Expected return on plan assets	5.75	6.25
Rate of compensation increase	4.00	4.50
Expected rate of pension increase	2.75	3.25
Expected increase of social security base amount (G-amount)	3.75	4.25
Expected inflation	2.00	2.25
Average remaining service period in years	15	15

Expected turnover at 31 December 2008 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 turnover at 31 December 2007 was 4.0%, 1.5%, 1.3%, 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 Agreement-based early retirement pension (AFP) is 50% for employees at 62 years and 30% for employees at 63 - 66 years.

The mortality table K 2005 plus one extra year of living 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 StatoilHydro ASA.

Below is shown a selection related to demographic assumptions used at 31 December 2008. The table shows the probability of disability or death, within one year, by age groups as well as expected lifetime.

	Disability in %		Mortality in %		Expected lifetime	
Age	Men	Women	Men	Women	Men	Women
20	0.12	0.15	0.015	0.015	81.51	85.35
40	0.21	0.35	0.083	0.046	81.83	85.60
60	1.48	1.94	0.716	0.386	83.27	86.51
80	N/A	N/A	6.550	4.142	88.97	90.74

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 2008. 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)	0.5%	-0.5%	0.5%	-0.5%	0.5%	-0.5%	0.5%	-0.5%
Changes in:								
Projected benefit obligation at								
31 December 2008	(4.7)	5.4	3.8	(3.4)	(1.5)	1.5	3.0	(2.8)
Service cost 2009	(0.3)	0.4	0.3	(0.3)	(0.1)	0.1	0.2	(0.2)

Pension assets

The plan assets related to the defined benefit plans were measured at fair value at 31 December 2008 and 2007. The long-term expected return on pension assets is based on long-term risk-free rate adjusted for the expected long-term risk premium for the respective investment classes. A risk free interest (the Norwegian Government bond with a life of 10 year included markup for estimating a longer interest rate than ten year) will be 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 give 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 a need to invest 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 %)	2008	2007
Equity securities	19.10	31.90
Debt securities	70.20	50.50
Commercial papers	3.30	8.60
Real estate	6.90	6.90
Other assets	0.50	2.10
Total	100.00	100.00

Properties owned by StatoilHydro pension fund amounted to NOK 2.2 billion of total pension assets at 31 December 2008 and are rented to companies in the Group.

StatoilHydro's pension fund invest 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 funds for 2009. The portfolio weight during a year will depend on the risk capacity.

Finance portfolio StatoilHydro's pension funds

(All figures in %)	Portfolio weight [1]		Expected rate of return
Equity securities	40.00	(+/- 5)	X + 4
Debt securities	59.50	(+/- 5)	X
Certificates	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) in percentage points.
X = Long-term rate of return on debt securities

Company contribution may either be paid in cash or be deducted from the pension premium fund. At 31 December 2008, the pension premium fund amounted to NOK 4.5 billion. The decision whether to pay in cash or deduct from the pension premium fund is made on an annual basis. In 2008, NOK 2.9 billion was deducted from the pension premium fund. NOK 1.2 billion was paid to StatoilHydro pension fund as a capital increase.

The expected company contribution related to 2009 amounts to NOK 2.4 billion.

18 Asset retirement obligation, other provisions and other liabilities

(in NOK million)	2008	2007
Asset retirement obligation at 1 January	22,723	23,289
Liabilities incurred / revision in estimates	722	(1,787)
Accretion	1,269	1,345
Disposals	(412)	0
Incurred removal cost	(234)	(124)
Asset retirement obligation at 31 December	24,068	22,723
Current portion of asset retirement obligations	286	140
Analysis of provisions and other liabilities at 31 December		
Non-current portion of asset retirement obligations	23,782	22,583
Other provisions and other liabilities	2,468	2,143
Asset retirement obligation, other provisions and other liabilities	26,250	24,726

Asset retirement obligations

A majority of expenditures related to asset retirement obligations are currently expected to be paid in the period between 2015 and 2025, and only a minor portion of expenditures are expected to be paid in the next five years. The timing depends primarily on when the production ceases at the various facilities whereas the amounts to be paid depend on future development in technologies, regulations, rates and availability of necessary support vessels. The provision for the expenditures is estimated using existing technology. Assumed vessel rates and all other input prices are estimates of rates and prices at the time of the expenditures and the calculated future expenditures have been discounted using nominal pre-tax discount rates. Input prices in other currencies than the functional currency of the individual entities have been converted into functional currency at the exchange rates ruling at the date of the estimate calculations.

Obligations related to environmental remediation and cleanup related to oil and gas producing assets are included in the estimated asset retirement obligations.

19 Research and development expenditures

Research and Development (R&D) expenditures were NOK 1,626 and NOK 1,350 million in 2008 and 2007, respectively. R&D expenditures are partly financed by partners of StatoilHydro operated licenses. StatoilHydro ASA's share of the expenditures has been recognised as expense in the Income Statement.

20 Leases

StatoilHydro ASA leases certain assets, notably vessels and drilling rigs.

StatoilHydro ASA has entered into certain operational lease contracts for a number of drilling rigs as of December 31, 2008. The remaining significant contracts' terms range from 3 months to 4 years. Certain contracts contain renewal options. Rig lease agreements are for the most part based on fixed day rates. StatoilHydro's rig leases have partly been entered into in order to ensure drilling capacity for sanctioned projects and planned wells, and partly in order to secure long term strategic capacity for future exploration and production drilling. Certain rigs have been subleased in whole or for parts of the lease term to StatoilHydro-operated licenses on the Norwegian Continental Shelf (NCS). These matters are shown gross as operating leases in the table below. However, for rig leases where the joint venture is the original lessee, StatoilHydro only includes its proportional share of the rig lease.

As a member of the Snøhvit Sellers' group StatoilHydro ASA has entered into leasing arrangements for three LNG vessels on behalf of StatoilHydro ASA and the SDFI (the State's direct financial interest) respectively. StatoilHydro ASA accounts for the combined StatoilHydro and SDFI share of these agreements as finance leases in the balance sheet, and further accounts for the SDFI related portion as operating sub-leases. The finance leases included in the balance sheet reflect a firm leasing term of 20 years. In addition, StatoilHydro has the option to extend the leases for two additional periods of five years each.

In 2008, net rental expense was NOK 7,1 billion (NOK 4,2 billion in 2007) of which minimum lease payments were NOK 8,7 billion (NOK 5,1 billion in 2007) and sublease payments received were NOK 1,6 billion (NOK 0,9 billion in 2007). No material contingent rents expensed in 2008 or 2007.

The information in the table below shows future minimum lease payments under non-cancellable leases at 31 December 2008.

Amounts related to financial leases include future minimum lease payments for assets recorded in the financial statements at year-end 2008.

			Financial lease		
(in NOK million)	**Operating Leases**	**Operating sublease**	**Minimum lease payments**	**Interest**	**Net present value minimum lease payments**
2009	10,235	(2,202)	336	(15)	321
2010	9,151	(1,435)	336	(28)	308
2011	5,492	(131)	336	(42)	294
2012	3,422	(131)	336	(55)	281
2013	2,240	(131)	336	(66)	270
Thereafter	1,395	(1,203)	4,030	(1,572)	2,458
Total future minimum lease payments	31,935	(5,233)	5,710	(1,778)	3,932

Property, plant and equipment include the following amounts for leases that have been capitalised at 31 December 2008 and 2007.

(in NOK million)	**2008**	**2007**
Vessels	4,276	4,276
Accumulated depreciation	(611)	(399)
Capitalised amounts	3,665	3,877

21 Other commitments and contingencies

Contractual commitments

(in NOK million)	2009	2010	Thereafter	Total
Joint Venture related:				
Construction in progress	2,826	533	292	3,651
Other investments and property, plant and equipment	1,295	334	110	1,739
Subtotal joint venture related commitments	4,121	867	402	5,390
Non Joint Venture related:				
Construction in progress	476	1,989	263	2,728
Total	4,597	2,856	665	8,118

The contractual commitments reflect StatoilHydro ASAs share and mainly comprise construction and acquisition of property, plant and equipment.

Other long term commitments

StatoilHydro ASA has entered into agreements for pipeline transportation for most of its prospective gas sales contracts. These agreements ensure the right to transport the production of gas through the pipelines, but also impose an obligation to pay for booked capacity. In addition, the Company has entered into certain obligations for other forms of transport capacity as well as terminal, processing, storage and entry capacity commitments. The following table outlines nominal minimum obligations for future years.

StatoilHydro ASA has entered into a number of general or field specific long-term frame agreements mainly related to crude oil loading and transport capacity availability. The main contracts run up until the end of the respective field lives. Such contracts have not been included in the below table of contractual commitments unless they entail specific minimum payment obligations.

Obligations payable by the Company to associated companies are included gross in the table below. Where the Company reflects both ownership interests and transport capacity cost for a pipeline in the accounts, the amounts in the table include the net transport commitment payable for StatoilHydro ASA.

Nominal minimum commitments at 31 December 2008:

(in NOK million)	
2009	4,427
2010	4,367
2011	4,849
2012	4,421
2013	3,573
Thereafter	13,019
Total	34,656

Guarantees

The Company has provided parent company guarantees covering liabilities of subsidiaries with operations in Algeria, Angola, Belgium, Brazil, Canada, Cuba, Germany, Great Britain, Iran, Ireland, Libya, Mozambique, Netherlands, Singapore, Sweden, the Faroe Islands, USA and Venezuela. The Company has also counter-guaranteed certain bank guarantees covering liabilities of subsidiaries in Algeria, Angola, Brazil, Canada, Egypt, Great Britain, Indonesia, Iran, Ireland, Nigeria, the Netherlands and Venezuela.

Under the Norwegian public limited companies act section 14-11, StatoilHydro 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 StatoilHydro is jointly liable for is approximately NOK 6.6 billion with terms extending until 2050. As of the current date, the probability that these guarantee commitments will impact StatoilHydro is deemed to be remote. No liability has been recognised in the accounts at year end 2008.

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 2008, StatoilHydro ASA was committed to participating in 17 wells off Norway, with an average ownership interest of approximately 41%. StatoilHydro ASA's share of estimated expenditures to drill these wells amounts to approximately NOK 3.1 billion. Additional wells that StatoilHydro may become committed to participating in depending on future discoveries in certain licenses are not included in these numbers.

StatoilHydro ASA issued a declaration to the Norwegian Ministry of Petroleum and Energy (MPE) in 1999 in connection with a dispute between four Åsgard partners and StatoilHydro related to the construction of new facilities for the Åsgard development at the Kårstø Terminal. The declaration confirmed that the MPE will receive similar treatment as the four Åsgard partners with respect to the disputed issues. On the basis of the declaration, the MPE on 29 April 2008 issued a writ involving a multi-component compensation claim, the aggregate principal exposure of which for StatoilHydro approximates between NOK 4 and 7 billion after tax. In November 2008 ExxonMobil, the final Åsgard partner at the time of the original dispute, has issued a similar writ with a compensation claim approximating an estimated exposure of up to NOK 1 billion after tax. StatoilHydro rejects both claims.

StatoilHydro ASA has offered early retirement packages to employees above the age of 58 years (contingent upon certain conditions). The offer is divided into two phases; employees working onshore (first phase) and employees working offshore and on onshore plants and terminals (second phase). A settlement concerning restructuring cost charges related to the first phase has been reached in 2008 between StatoilHydro and the partners on the Norwegian continental shelf. Based on the settlement, StatoilHydro ASA has recognized NOK 1.0 billion before tax as a cost reduction in 2008. Contingent receivables related to the second phase remain unrecorded.

StatoilHydro was informed on 26 September 2007 of possible consultancy agreements and transactions associated with Hydro's petroleum activities in Libya, which were transferred to StatoilHydro as of 1 October 2007 as part of the merger with Hydro Petroleum, and which could be in conflict with applicable Norwegian and US anti-corruption legislation. Following a preliminary assessment by StatoilHydro, an external review of the relevant aspects was initiated. The external US and Norwegian legal counsels that have conducted the review delivered their report to StatoilHydro ASA's CEO on 6 October 2008. The report has also been delivered to the National Authority for Investigation and Prosecution of Economic and Environmental Crime in Norway (Økokrim), the US Department of Justice, the US Securities and Exchange Commission and Libyan authorities. The report does not draw any legal conclusions. In accordance with the mandate for the review, the report entails the facts relevant to applicable Norwegian and US anti-corruption legislation to which StatoilHydro ASA may be subject as a result of the merger.

During the normal course of its business StatoilHydro is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset, respectively, in respect of such litigation and claims cannot be determined at this time. StatoilHydro has provided in its accounts for probable liabilities related to litigation and claims based on the Company's best judgement. StatoilHydro does not expect that the financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings.

22 Related parties

The Norwegian State is the majority shareholder of StatoilHydro ASA and also holds major investments in other entities. This ownership structure means that StatoilHydro 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 a normal arms-length basis.

The ownership interests of the Norwegian State in StatoilHydro ASA are held by the Norwegian Ministry of Petroleum and Energy (MPE). The following transactions with SDFI volumes were made between StatoilHydro and MPE for the years presented:

Total purchases of oil and natural gas liquid from the Norwegian State amounted to NOK 112.7 billion, (223 million barrels oil equivalents) and NOK 98.5 billion, (237 million barrels oil equivalents) in 2008 and 2007, respectively. Purchases of natural gas from the Norwegian State (excluding purchases from licenses and sales on behalf of the Norwegian State) amounted to NOK 0.4 billion and NOK 0.3 billion in 2008 and 2007, respectively.

The State's natural gas production, which StatoilHydro ASA is selling, in its own name, but for the Norwegian State's account and risk as well as related expenditures refunded by the State, are presented net in StatoilHydro ASA's financial statements.

In relation to its ordinary business operations such as pipeline transport, gas storage and processing of petroleum products, StatoilHydro ASA also has regular transactions with certain unconsolidated affiliated entities. Such transactions are carried out on an arm's length basis, and are included within the applicable captions in the Statements of income.

23 Equity and shareholders

Change in equity

(in NOK million)	2008	2007
Shareholders' equity 1 January	143,724	103,700
Effect of the merger with Hydro Petroleum	0	35,420
Net income	40,637	43,869
Ordinary dividend	(23,090)	(27,085)
Actuarial gain employee retirement benefit plans	(9,535)	211
Effectuation annulment program, see information below	0	(2,465)
Treasury shares bought	(230)	(182)
Value of stock compensation plan	80	112
Foreign currency translation adjustment	30,880	(9,856)
Total equity 31 December	182,466	143,724

Common stock

	Number of shares	Par value	Common stock
Authorized and issued	3,188,647,103	2.50	7,971,617,757.50
Treasury shares	3,781,209	2.50	9,453,022.50
Total outstanding shares	3,184,865,894	2.50	7,962,164,735.00

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

The annual General Meeting in 2006 authorised the Board of Directors to acquire own shares for subsequent annulment. Under an agreement with the Norwegian State a proportion of the State's shares should later be redeemed and annulled, so that the State's ownership interest remained unchanged. The extraordinary General Meeting on 5 July 2007 approved to reduce the Share capital by NOK 50,397,120 by annulment of 5,867,000 acquired Treasury shares, and redemption and annulment of 14,291,848 shares held by the State through the payment of NOK 2,441,899,894 to the State, represented by the Ministry of Petroleum and Energy. The amount corresponds to the average volume-weighted price of the company's buyback of own shares in the market with the addition of interest.

The board of directors is authorised on behalf of the company to acquire StatoilHydro shares in the market. The authorisation may be used to acquire StatoilHydro shares with an overall nominal value of up to NOK 15 million. The board decides the manner in which the acquisition of Statoil shares in the market will take place. Such shares acquired in accordance with the authorisation may only be used for sale and transfer to employees of the StatoilHydro group as part of the group's share saving plan approved by the board. The lowest amount which may be paid per share is NOK 50; the highest amount which may be paid per share is a maximum NOK 500. The authorisation is valid until the next ordinary general meeting.

The 20 largest shareholders at 31 December 2008 (in %)		
1	THE NORWEGIAN STATE (Ministry of Petroleum and Energy)	66.42
2	FOLKETRYGDFONDET (Norwegian national insurance fund)	3.42
3	BANK OF NEW YORK, ADR DEPARTEMENT*	2.67
4	STATE STREET BANK*	1.40
5	CLEARSTREAM BANKING S.A.*	1.39
6	STATE STREET BANK*	1.27
7	JP MORGAN CHASE BANK*	1.21
8	BANK OF NEW YORK, MELLON BANK*	0.83
9	THE NORTHERN TRUST*	0.65
10	JP MORGAN CHASE BANK*	0.51
11	BANK OF NEW YORK, MELLON BANK*	0.49
12	THE NORTHERN TRUST*	0.46
13	INVESTORS BANK*	0.43
14	THE NORTHERN TRUST*	0.41
15	DNB NOR NORGE	0.33
16	THE NORTHERN TRUST*	0.33
17	SVENSKA HANDELSBANKEN	0.31
18	STATE STREET BANK*	0.30
19	DNB NOR NORGE	0.27
20	RBC DEXIA INVESTORS*	0.27

* Client account and similar

Members of the Board of Directors, Corporate Executive Committee and Corporate Assembly holding shares as of 31 December 2008:

Board of directors	
Svein Rennemo	10,000
Marit Arnstad	0
Elisabeth Grieg	33,108
Grace Reksten Skaugen	400
Roy Franklin	0
Kjell Bjørndalen	0
Kurt Anker Nilsen	0
Lill-Heidi Bakkerud	330
Claus Clausen	165
Morten Svaan	933

Corporate Executive Committee	
Helge Lund (Chief Executive Officer)	13,857
Rune Bjørnson	4,351
Jon Arnt Jacobsen	7,164
Peter Mellbye	7,906
Margareth Øvrum	7,977
Gunnar Myrebøe	2,726
Eldar Sætre	6,057
Øystein Michelsen	2,040
Helga Nes	1,397
Corporate Assembly (in total)	5,665

24 Share-based compensation

StatoilHydro's Share Saving Plan provides employees with the option to purchase StatoilHydro shares through monthly salary deductions, and a contribution by StatoilHydro ASA. 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 StatoilHydro for purchased shares, amount vested for bonus shares granted and related social security tax was NOK 307 million and NOK 220 million related to 2008 and 2007, respectively. For the 2009 program (granted in 2008) the estimated compensation expense is NOK 338 million. At 31 December 2008 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 623 million.

25 Business developments

In 2008 StatoilHydro ASA acquired certain oil and gas production assets, with a carrying amount of NOK 9.1 billion, and related deferred tax liabilites, with a carrying amount of NOK 4.0 billion, from the wholly owned subsidiary StatoilHydro Petroleum AS. The acquired net assets were transferred at their carrying amounts. The same assets were transferred from StatoilHydro ASA to StatoilHydro Petroleum AS effective 1 January 2009 as part of a larger reorganisation, see note 26 Subsequent events.

In 2008 StatoilHydro ASA sold certain shares in subsidiaries to other entities, wholly owned, directly or indirectly by StatoilHydro ASA. These shares were transferred at their carrying amounts.

26 Subsequent events

Effective 1 January 2009, StatoilHydro ASA transferred the activities and assets of the Norwegian offshore operations, excluding employees, to StatoilHydro Petroleum AS. The transfer was made in the form of a non-cash asset contribution accounted for at the carrying amounts of the assets given up, with no gain or loss recognition. Following these reorganisations the operations of StatoilHydro ASA is no longer subject to the special petroleum tax on the Norwegian Continental Shelf. As a consequence, the tax assets related to pension liabilities in StatoilHydro ASA have, effective 31 December 2008, been recognised at 28%, which is the tax rate expected to be in effect at the realisation date. Previously the estimated tax rate was 56%, based on assumed amounts expected to be realised under the petroleum tax regime and the general tax regime, respectively. The effect is a reduction of the deferred tax assets on pensions and retained earnings by NOK 5.4 billion as of 31 December 2008.

The transfer of activities and assets has also resulted in a change of functional currency from NOK to USD in StatoilHydro ASA effective from 1 January 2009 and with prospective effect. This change has no impact on the financial statements for 2008. The presentation currency will remain NOK.

On 4th March 2009 StatoilHydro ASA issued a GBP 0.8 billion bond with a 22 year tenure, a EUR 1.2 billion bond with a 12 year tenure and a EUR 1.3 billion bond with a six year tenure. All three bonds were fully subscribed. The bonds are issued under StatoilHydro ASA's Euro Medium Term Note Programme and will be listed on London Stock Exchange. The bonds have been guaranteed by StatoilHydro Petroleum AS.

Stavanger, 17 March 2008

THE BOARD OF DIRECTORS OF STATOILHYDRO ASA

SVEIN RENNEMO
CHAIR

MARIT ARNSTAD
DEPUTY CHAIR

LILL-HEIDI BAKKERUD

KJELL BJØRNDALEN

CLAUS CLAUSEN

ROY FRANKLIN

KURT ANKER NIELSEN

ELISABETH GRIEG

GRACE REKSTEN SKAUGEN

MORTEN SVAAN

HELGE LUND
PRESIDENT AND CEO

Auditor's report

To the Annual Shareholders' Meeting of
StatoilHydro ASA

Auditor's report for 2008

We have audited the annual financial statements of StatoilHydro ASA as of 31 December 2008, showing a profit of NOK 40,637 million for the Parent Company and a profit of NOK 43,270 million for the Group. We have also audited the information in the Directors' report concerning the financial statements, the going concern assumption, and the proposal for the allocation of the profit. The financial statements comprise the financial statements for the Parent Company and the Group. The financial statements of the Parent Company comprise the balance sheet, the statements of income and cash flows and the accompanying notes. The financial statements of the Group comprise the balance sheet, the statements of income and cash flows, the statement of changes in equity and the accompanying notes. The regulations of the Norwegian Accounting Act and accounting standards, principles and practices generally accepted in Norway have been applied in the preparation of the financial statements of the Parent Company. IFRSs as adopted by the EU and as issued by the International Accounting Standards Board have been applied in the preparation of the financial statements of the Group. These financial statements and the Directors' report are the responsibility of the Company's Board of Directors and President and Chief Executive Officer. Our responsibility is to express an opinion on these financial statements and on other information according to the requirements of the Norwegian Act on Auditing and Auditors.

We conducted our audit in accordance with laws, regulations and auditing standards and practices generally accepted in Norway, including the auditing standards adopted by the Norwegian Institute of Public Accountants. These auditing 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. To the extent required by law and auditing standards, an audit also comprises a review of the management of the Company's financial affairs and its accounting and internal control systems. We believe that our audit provides a reasonable basis for our opinion.

In our opinion,
- the financial statements of the Parent Company are prepared in accordance with laws and regulations and present fairly, in all material respects the financial position of the Company as of 31 December 2008, and the results of its operations and its cash flows for the year then ended, in accordance with accounting standards, principles and practices generally accepted in Norway
- the financial statements of the Group are prepared in accordance with laws and regulations and present fairly, in all material respects, the financial position of the Group as of 31 December 2008, and the results of its operations and its cash flows and the changes in equity for the year then ended, in accordance with IFRSs as adopted by the EU and as issued by the International Accounting Standards Board
- the Company's management has fulfilled its duty to properly record and document the Company's accounting information as required by law and bookkeeping practice generally accepted in Norway
- the information in the Directors' report concerning the financial statements, the going concern assumption, and the proposal for the allocation of the profit is consistent with the financial statements and complies with law and regulations.

Stavanger, 17 March 2009
Ernst & Young AS
Erik Mamelund
State Authorised Public Accountant (Norway)
(sign)

Note: The translation to English has been prepared for information purposes only.

HSE accounting

StatoilHydro's objective is to operate with zero harm to people and the environment, in accordance with the principles for sustainable development. We support the Kyoto protocol and apply the precautionary principle in the conduct of our business.

Our HSE management system is an integrated part of our total management system, and is described in our governing documents.

Our management system relating to overall management and control, and many of the main operational units, have been certified in accordance with the ISO 9001 and ISO 14001 standards. An overview of certified units can be found at www.statoilhydro.com/sertifisering.

A key element in our HSE management system is recording, reporting and assessment of HSE data. HSE performance indicators have been established to provide information on historical trends. The intention is to document quantitative developments over time and use the information in decision-making for systematic and purposeful improvement efforts.

HSE data are compiled by the business units and reported to the corporate executive committee, which evaluates trends and decides whether improvement measures are required. The chief executive submits the HSE results and associated assessments to the board of directors. These results are posted on our intranet and internet sites. Quarterly HSE statistics are compiled and made accessible on our website through the performance report.

Our three group-wide performance indicators for safety are the total recordable injury frequency (TRIF), the lost-time injury frequency (LTIF) and the serious incident frequency (SIF). These are reported quarterly at corporate level for StatoilHydro employees and contractors. Statistics on our employees' sickness absence are reported annually.

The group-wide environmental indicators are reported annually at corporate level, with the exception of oil spills, which are also reported quarterly. The environmental indicators - oil spills, emissions of CO_2 and NO_X, energy consumption and the recovery rate for non-hazardous waste - are reported for StatoilHydro-operated activities. This includes the Gassled facilities at Kårstø and Kollsnes, for which Gassco is operator, while StatoilHydro is responsible for the technical operation (technical service provider).

Historical data include figures relating to acquired operations from the acquisition date. Correspondingly, figures relating to divested operations are included up to the divestment date.

Results
We suffered two fatal accidents in 2008. At a team-building gathering, during a canoeing trip, one person drowned. The second fatality occurred when a boat was casting off from the production platform South Pars No 9 in the Persian Gulf. A mooring line broke and struck a crew member on board the vessel *Interservice*.

StatoilHydro had three other serious incidents during 2008: air intrusion in a cracker at the Mongstad refinery with a risk of explosion, a large gas leak at the Oseberg C offshore platform and an oil leak in the Statfjord A offshore platform shaft. All three incidents had the potential to develop into a major accident.

The HSE accounting shows the development of the HSE performance indicators over the past five years. Use of resources, emissions and waste volumes for selected StatoilHydro-operated land-based plants, and for StatoilHydro-operated activities on the Norwegian continental shelf are shown in separate environmental overviews. See also the information on health, safety and the environment in the review of StatoilHydro's operations and the directors' report.

During 2008, our operations account for more than 143 million working hours (including contractors). These hours form the basis for the frequency indicators in the HSE accounting. Contractors handle a large proportion of the assignments for which StatoilHydro is responsible as operator or principal enterprise

StatoilHydro's safety results with respect to serious incidents have been at a stable level the last years. The overall SIF indicator increased from 2007 (2.1) to 2008 (2.2) and is now at the same level as in 2006 (2.2).

There has been an increase in the number of total recordable injuries per million working hours (TRIF) in 2008 (5.4) compared with 2007 (5.0). Contractor TRIF at year end 2008 was 6.6, and StatoilHydro employee TRIF was 3.4. The LTIF (injuries leading to absence from work) was 2.1 in 2008, an increase from 2007 (2.0).

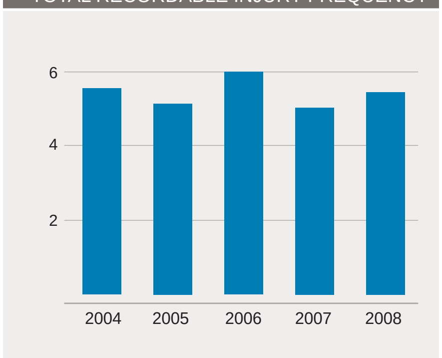
In addition to our HSE accounting at group level, the business units prepare more specific HSE statistics and analyses for use in their own improvement efforts. We have for instance implemented an indicator used to follow up status on observations and actions from monitoring of our facilities technical safety condition.

In 2008, StatoilHydro was fined NOK 2 million for an accident that occurred on 26 April 2005 on Oseberg B, where a drilling worker was seriously injured. StatoilHydro also accepted some minor fines for breach of regulations at service stations.

HSE performance indicators

Here we present charts and statistics for our HSE performance indicators.

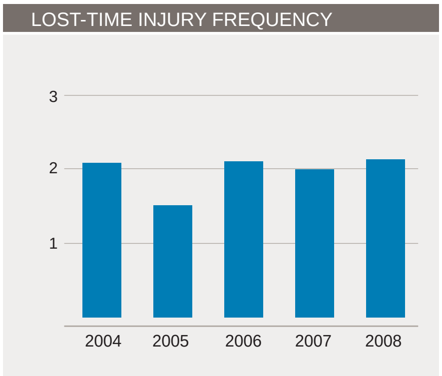
TOTAL RECORDABLE INJURY FREQUENCY



Definition: The number of fatalities, lost-time injuries, cases of alternative work necessitated by an injury and other recordable injuries, excluding first-aid injuries per million working hours.

Developments: The total recordable injury frequency (including both StatoilHydro employees and contractors) increased from 5.0 in 2007 to 5.4 in 2008. The frequency for StatoilHydro employees decreased from 3.5 in 2007 to 3.4 in 2008, while the frequency for our contractors increased from 6.1 in 2007 to 6.6 in 2008.

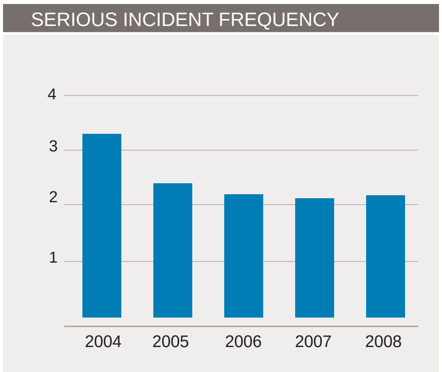
LOST-TIME INJURY FREQUENCY



Definition: The number of lost-time injuries and fatal accidents per million working hours.

Developments: The lost-time injury frequency (including both StatoilHydro employees and contractors) increased from 2.0 in 2007 to 2.1 in 2008. The frequency for StatoilHydro employees was 1.7 in 2008, the same as in 2007, and for our contractors the lost-time injury frequency increased from 2.2 in 2007 to 2.3 in 2008.

SERIOUS INCIDENT FREQUENCY

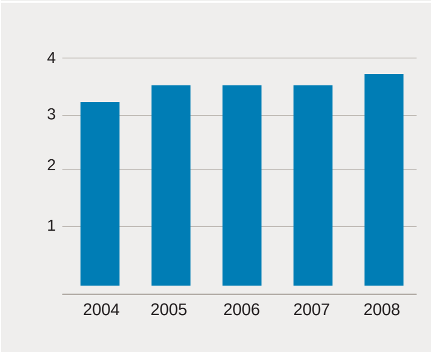


Definition: The number of incidents of a very serious nature per million working hours (1).

Developments: The serious incident frequency (including StatoilHydro employees and contractors) increased from 2.1 in 2007 to 2.2 in 2008 and is now at the same level as in 2006.

(1) An incident is an event or chain of events that has caused or could have caused injury, illness and/or damage to/loss of property, the environment or a third party. Matrices for categorisation have been established where all undesirable incidents are categorised according to the degree of seriousness, and this forms the basis for follow-up in the form of notification, investigation, reporting, analysis, experience transfer and improvement.

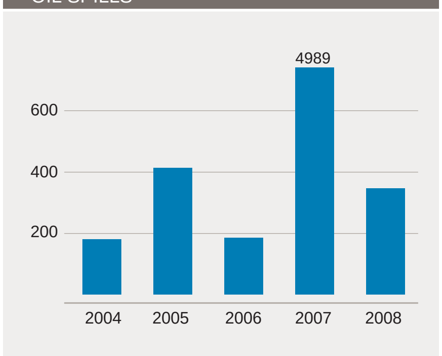
SICK LEAVE



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

Developments: Sickness absence in StatoilHydro has been stable at 3.5% for the last three years, but increased in 2008 to 3.7%. It is still low compared with similar industries, and it is closely followed up by managers at all levels.

OIL SPILLS

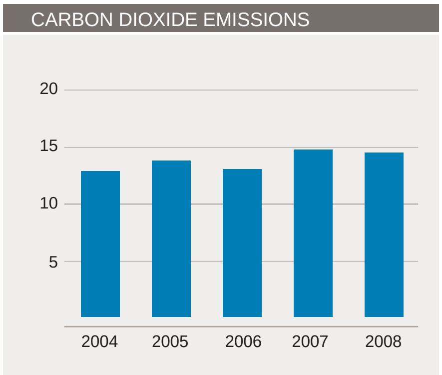


Definition: Accidental oil spills to the natural environment from StatoilHydro operations (in cubic metres) (2).

Developments: The number of accidental oil spills was 401 in 2008 as against 387 in 2007. The volume of accidental spills has decreased from 4,989 cubic metres in 2007 to 342 cubic metres in 2008. The figure shows the volume of oil spills in cubic metres.

(2) All accidental oil spills reaching the natural environment from StatoilHydro operations are included in the figure.

CARBON DIOXIDE EMISSIONS

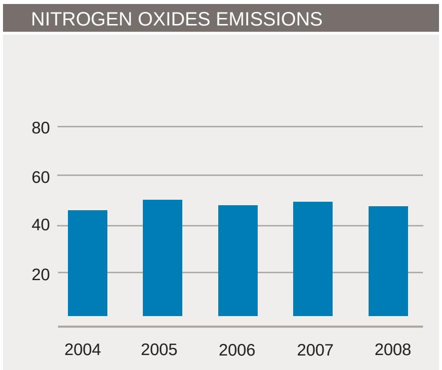


Definition: Total emissions of carbon dioxide in million tonnes from StatoilHydro-operated activities (3)

Developments: Carbon dioxide emissions in 2008 have been as expected and approximately the same in 2007. Carbon dioxide emissions decreased from 14.6 million tonnes in 2007 to 14.4 million tonnes in 2008. Entering the production phase at Snøhvit at the beginning of the year caused increased emissions, while planned maintenance during the summer at several EPN installations reduced emissions. There has been a small increase in CO2 emissions in NG and a small decrease in CO2 emissions in M&M due to planned maintenance and closure of plants.

(3) Carbon dioxide emissions include carbon dioxide from energy and heat production in own plants, flaring, residual emissions from carbon dioxide capture and treatment plants, process emissions, emissions of carbon dioxide as a consequence of gross energy (electric power and heat) imported from a third party (indirect emission), emissions of carbon dioxide as a consequence of exported energy to a third party.

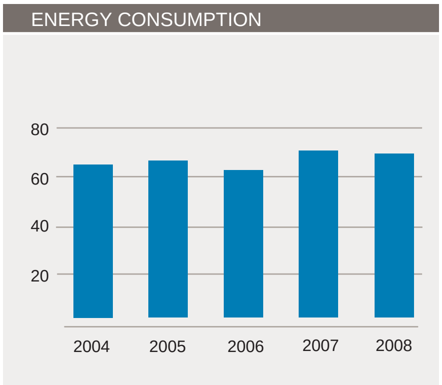
NITROGEN OXIDES EMISSIONS



Definition: Total emissions of nitrogen oxides in thousand tonnes from StatoilHydro-operated activities (4)

Developments: Emissions of NOx in 2008 have been as expected and slightly lower than in 2007. Nitrogen oxides emissions have decreased from 49.4 thousand tonnes in 2007 to 46.7 thousand tonnes in 2008. There has been a minor reduction in the overall EPN NOx emissions due to the use of a lower NOx emission factor. The new NOx factor has been decided in an agreement between the authorities and the petroleum industry as a result of the introduction of NOx tax. There has been a small increase in NOx emissions in NG and a small decrease in NOx emissions in M&M due to planned maintenance and closure of plants.

(4) Nitrogen oxide emissions include all emission sources and include nitrogen oxides from energy and heat production in own plant, transportation of products, flaring and treatment plants.

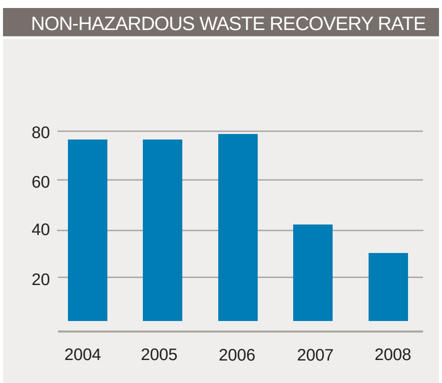


Definition: Total energy consumption in terawatt-hours (TWh) for StatoilHydro-operated activities (5)

Developments: Energy consumption in 2008 has been as expected and approximately the same as for the year 2007. Energy consumption has decreased from 69.8 TWh in 2007 to 69.6 TWh in 2008. Energy consumption and the CO2 emissions basically follow the same pattern. There has been an increase in energy consumption in NG due to non-utilised energy from the VOC incinerator at Kårstø. There has been a small decrease in energy consumption in M&M due to planned maintenance and closure of plants.

(5) Energy consumption includes energy consumed in producing the facility's deliveries or by performing an activity, that is the sum of imported energy, energy generated by own activity and unused energy minus delivered/sold energy.

This includes energy from power and heat production based on combustion, unused energy from flaring (including well testing/well work-over and venting), energy sold/delivered to third party, net energy (heat and electricity) imported from contractor, gross energy (heat and electricity) imported from contractor.



Definition: The recovery rate for non-hazardous waste comprises non-hazardous waste from StatoilHydro operated activities and represents the amount of non-hazardous waste for recovery as a proportion of the total quantity of non-hazardous waste (6)

Developments: The recovery rate for non-hazardous waste has decreased from 41% in 2007 to 29% in 2008. The non hazardous waste recovery rate shows a negative trend compared to previous years. The main change is within M&M, but there are uncertainties in data. During 2009, there will be focus on quality assurance of data from all parts of M&M.

(6) The quantity of non-hazardous waste for recovery is the total quantity of non-hazardous waste from the plant's operations which has been delivered for re-use, recycled or incinerated with energy recovery

Environmental data

EXPLORATION & PRODUCTION NORWAY NOT INCLUDED MELKØYA [1]

ENERGY

Diesel	2,170 GWh
Electricity	49 GWh
Fuel gas	34,900 GWh
Flare gas	3,730 GWh

RAW MATERIALS [2]

Oil/condensate	101 mill scm
Gas [3]	122 bn scm
Produced water	141 mill m^3

UTILITIES

Chemicals process/prodn	69,500 tonnes
Chemicals drilling/well	403,000 tonnes

OTHER

Fresh water consumption	194,000 m^3

[1] Includes British part of Statfjord.
[2] Includes third party processing of the Sigyn and Skirne production.
[3] Includes fuel (3.1 bill. Sm3), flare (0.3 bill. Sm^3) and gas injection (33.3 bill. Sm^3).
[4] Includes offshore loading.
[5] Includes one leak of 7,969 kg dry gas from subsea template.
[6] Includes oil from produced water, drain water, ballast water and jetting.
[7] Includes 78,900 tonnes of water and green chemicals/ingredients.
[8] Includes waste from onshore bases. Waste from drilling represents 115,000 tonnes.
[9] History shows dispersed oil from 2004 to 2006 and oil index from 2007 and reflects changes in Norwegian authorities' reporting requirements.

PRODUCTS

Oil/condensate	101 mill scm
Gas for sale	85 bn scm

EMISSIONS TO AIR

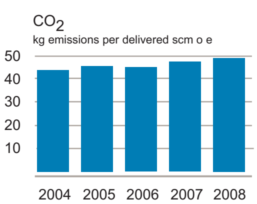
CO_2	9.1 mill tonnes
nmVOC [4]	34,300 tonnes
Methane [4]	22,800 tonnes
NO_x	39,600 tonnes
SO_2	210 tonnes
Unintentional emissions HC gas [5]	8.44 tonnes

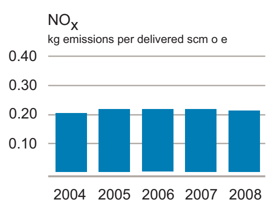
DISCHARGES TO WATER

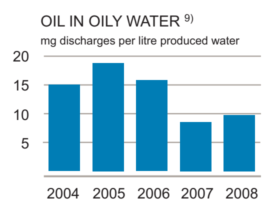
Produced water	124 mill scm
Oil in oily water[6]	1,290 tonnes
Unintentional oil spills	194 m^3
Produced water injected into the ground	23 mill m^3
Chemicals: [7]	
Process/production	31,600 tonnes
Drilling/well	57,200 tonnes
Other unintentional spills	351 m^3

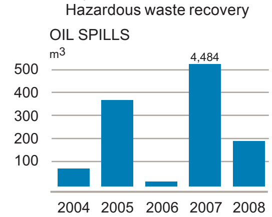
WASTE [8]

Non-hazardous waste for deposition	5,800 tonnes
Non-hazardous waste for recovery	13,400 tonnes
Non-hazardous waste recovery rate	70 %
Hazardous waste for deposition	4,720 tonnes
Hazardous waste recovery	124,000 tonnes









SNØHVIT LNG INSTALLATION

ENERGY

Electricity	69.7 GWh
Flare gas	3,580 GWh
Fuel gas	2,620 GWh
Diesel	13.9 GWh

RAW MATERIALS

Gas Snøhvit	3,250 mill scm
Condensate Snøhvit	0.5 mill scm

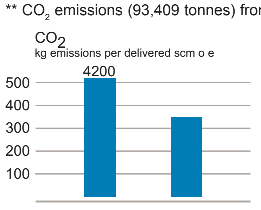
UTILITIES

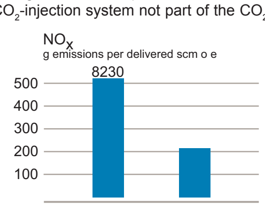
Amine	77.5 m^3
Hydraulic fluids	1.43 m^3
Caustics	8,830 m^3
Monoethylene glycol	1,400 m^3
Other chemicals	39 m^3

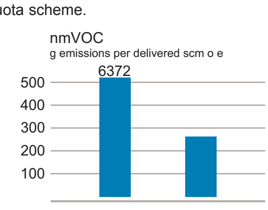
WATER CONSUMPTION

Fresh water	111,000 m^3

Calculation of OE for produced LNG/LPG is done by using OLF factor for NGL; 1 tonn NGL = 1.9 scm o e.
Environmental data reflects that Snøhvit LNG installation in 2008 has produced LNG, LPG and condensate throughout the year (from project fase to producing fase).
* 2,500 litres of purified water from the biological treatment plant were not neutralised, and were discharged to sea with ph 10.3.
** CO_2 emissions (93,409 tonnes) from CO_2-injection system not part of the CO_2 quota scheme.







PRODUCTS

LNG	3.76 mill scm
LPG	0.19 mill scm
Condensate	0.46 mill scm

EMISSIONS TO AIR

CO_2**	1,360,000 tonnes
NO_x	832 tonnes
CO	0 tonnes
SO_2	3.8 tonnes
nmVOC	1,020 tonnes
Methane	1,280 tonnes

DISCHARGES TO WATER

Treated water and open drain water	73,200 m^3
Amine	0.18 tonnes
Ammonium	0.23 tonnes
BTEX	0.08 tonnes
Phenol	0.02 tonnes
Hydrocarbons	0.04 tonnes
TOC	1.46 tonnes
Heavy metals	0.01 tonnes
Unintentional oil spills	0 m^3
Other unintentional spills*	2.92 m^3

WASTE

Non-hazardous waste for deposition	640 tonnes
Non-hazardous waste for recovery	437 tonnes
Non-hazardous waste recovery rate	41 %
Hazardous waste for deposition	33 tonnes
Hazardous waste for recovery	930 tonnes
Hazardous waste recovery rate	97 %

TJELDBERGODDEN

ENERGY

Diesel	0.1 GWh
Electricity	264 GWh
Fuel gas	1,720 GWh
Flare gas	84 GWh

RAW MATERIALS

Rich gas	520,000 tonnes

UTILITIES

Caustics	267 tonnes
Acids	64 tonnes
Other chemicals	21 tonnes

WATER CONSUMPTION

Fresh water	602,000 m³

PRODUCTS

Methanol	914,000 tonnes
Oxygen	19,200 tonnes
Nitrogen	39,900 tonnes
Argon	15,800 tonnes
LNG	12,100 tonnes

EMISSIONS TO AIR 1) 2)

CO_2	354,000 tonnes
nmVOC	251 tonnes
Methane	581 tonnes
NO_x	238 tonnes
SO_2	0.86 tonnes
Unintentional emissions HC-gas	3.61 tonnes

DISCHARGES TO WATER

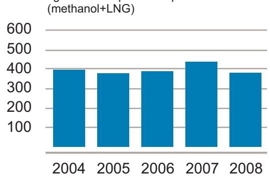
Cooling water	193 mill m³
Total organic carbon (TOC)	0.88 tonnes
Suspended matter	0.54 tonnes
Total-N	0.77 tonnes
Unintentional oil spills	0.00 m³
Other unintentional spills	0.03 m³

WASTE 3)

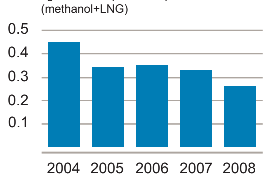
Non-hazardous waste for deposition	45 tonnes
Non-hazardous waste for recovery	81 tonnes
Non-hazardous waste recovery rate	64 %
Hazardous waste for deposition	117 tonnes
Hazardous waste for recovery	39 tonnes
Hazardous waste recovery rate	25 %

1) Figures for nmVOC/methane now include emissions from flaring.
2) Unintentional emissions are not included in nmVOC/methane figures.
3) Hazardous waste for deposition is sludge from the waste water treatment plant.

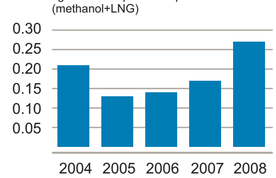
CO_2
kg emissions per tonne product (methanol+LNG)



NO_x
kg emissions per tonne product (methanol+LNG)



nmVOC
kg emissions per tonne product (methanol+LNG)



MONGSTAD 1)

ENERGY

Electricity	441 GWh
Fuel gas and steam	6,160 GWh
Flare gas	264 GWh

RAW MATERIALS

Crude oil	7,760,000 tonnes
Other process raw materials	2,780,000 tonnes
Blending components	116,000 tonnes

UTILITIES

Acids	322 tonnes
Caustics	2,480 tonnes
Additives	1,610 tonnes
Process chemicals	3,550 tonnes

WATER CONSUMPTION

Fresh water	4,350,000 m³

PRODUCTS 2) 9,830,000 tonnes

Propane	Butane
Naphtha	Gas oil
Petrol	Petcoke/sulphur
Jet fuel	

EMISSIONS TO AIR 3)

CO_2	1,440,000 tonnes
SO_2	579 tonnes
NO_x	1,590 tonnes
nmVOC refinery	7,650 tonnes
nmVOC terminal 4)	1,870 tonnes
Methan	2,720 tonnes
Unintentional emissions of HC gas 5)	8 tonnes

DISCHARGES TO WATER 6)

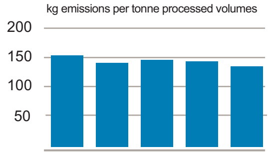
Oil in oily water	7.3 tonnes
Phenol	1.7 tonnes
Total Nitrogen	58 tonnes
Unintentional oil spills	3 m³
Other unintentional spills	31 m³

WASTE 7)

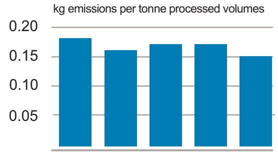
Non-hazardous waste for deposition	1,450 tonnes
Non-hazardous waste for recovery	3,040 tonnes
Non-hazardous waste recovery rate	68 %
Hazardous waste for deposition 8)	1,880 tonnes
Hazardous waste for recovery	13,000 tonnes
Hazardous waste recovery rate	87 %

1) Included data for the refinery, crude oil terminal and Vestprosess facilities.
2) Products delivered from the jetties.
3) Air emissions from refinery are reduced due to turnaround RS08.
4) Emission reduced due to nmVOC recovery unit at the crude oil terminal.
5) RUH 1058065 1 t and RUH 1033289 6.5 t (investigation not completed as of 26/1-09), 0.5 t sum other reported oil/gas leakages Included in nmVOC refinery.
6) Increased discharge of oil and total nitrogen mainly due to cleanup of basin in water treatment plant.
7) Increase in generated waste in 2008 due to turnaround and projects.
8) Hazardous waste for deposition consists mainly of polluted gravel.

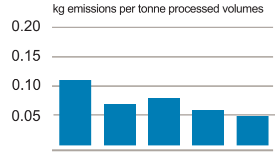
CO_2
kg emissions per tonne processed volumes



NO_x
kg emissions per tonne processed volumes



SO_2
kg emissions per tonne processed volumes



STURE PROCESSING PLANT

ENERGY

Electricity	153 GWh
Flare gas	0.02 GWh
Fuel gas	378 GWh
Diesel	0.27 GWh

RAW MATERIALS

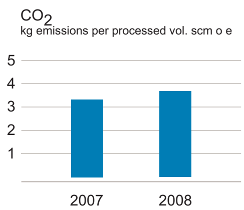
Crude oil	23.7 mill scm

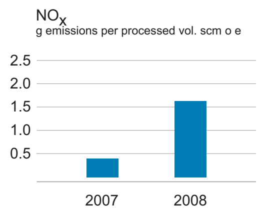
UTILITIES

Hydrochloric acid	18.5 tonnes
Sodium hydroxide	10.4 tonnes
Methanol	345 m³

WATER CONSUMPTION

Fresh water	443,000 m³





PRODUCTS

LPG	873,000 scm
Naphta	327,000 scm

CRUDE OIL EXPORT

Crude oil export	21.6 mill scm

EMISSIONS TO AIR

CO_2	86,700 tonnes
NO_x	38.5 tonnes
Unintentional HC-gas emissions	0 tonnes
nmVOC	2,250 tonnes
Methane	305 tonnes

DISCHARGES TO WATER

Treated water and open drain water	692,000 m³
TOC	58.3 tonnes
Hydrocarbons	2.05 tonnes
Unintentional oil spills	0.09 m³
Other unintentional spills	0 m³

WASTE

Non-hazardous waste for deposition	79.3 tonnes
Non-hazardous waste for recovery	160 tonnes
Non-hazardous waste recovery rate	66.9 %
Hazardous waste for deposition	0.00 tonnes
Hazardous waste for recovery	53.5 tonnes
Hazardous waste recovery rate	100.0 %

KALUNDBORG

ENERGY

Electricity	180 GWh
Steam	163 GWh
Fuel gas and oil	2,230 GWh
Flare gas	101 GWh

RAW MATERIALS

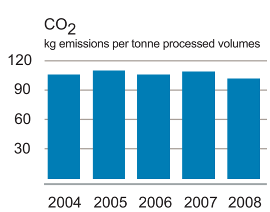
Crude oil	4,880,000 tonnes
Other process raw materials	830 tonnes
Blending components	247,000 tonnes

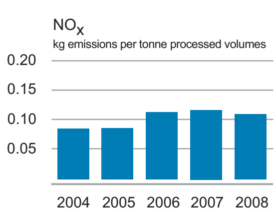
UTILITIES

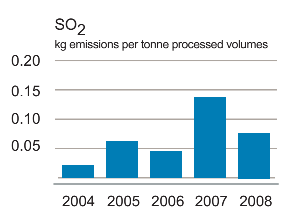
Acids	594 tonnes
Caustics	638 tonnes
Additives	535 tonnes
Process chemicals	606 tonnes
Ammonia (liquid)	2,050 tonnes

WATER CONSUMPTION

Fresh water	1,710,000 m³







PRODUCTS

PRODUCTS	4,920,000 tonnes
Naphta	108,000 tonnes
Petrol	1,380,000 tonnes
Jet fuel	251,000 tonnes
LPG (butane, propane)	53,600 tonnes
Gas oil	1,700,000 tonnes
Fuel oil	409,000 tonnes
ATS (fertiliser)	5,700 tonnes
Fuel	1,020,000 tonnes

EMISSIONS TO AIR

CO_2	498,000 tonnes
SO_2	386 tonnes
NO_x	545 tonnes
Methane	2,090 tonnes
nmVOC	4,790 tonnes
Unintentional emissions of HC gas	0.00 tonnes

DISCHARGES TO WATER

Oil in oily water	2.1 tonnes
Unintentional oil spills	0.14 m³
Other unintentional spills	0.05 m³
Phenol	0.0 tonnes
Suspended matter	9.7 tonnes
Nitrogen	6 tonnes

WASTE

Non-hazardous waste for deposition	750 tonnes
Non-hazardous waste for recovery	5,570 tonnes
Non-hazardous waste recovery rate	88.1 %
Hazardous waste for deposition	11 tonnes
Hazardous waste for recovery	4,890 tonnes
Hazardous waste recovery rate	99.8 %

KOLLSNES PROCESSING PLANT [1) >

ENERGY

Electricity	1,230 GWh
Flare gas	224 GWh
Fuel gas	181 GWh
Diesel	0.37 GWh

RAW MATERIALS

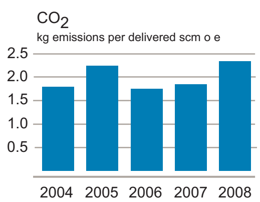
Rich gas Troll A	25 bn scm
Rich gas Troll B	2.2 bn scm
Rich gas Troll C	2.6 bn scm
Rich gas Kvitebjørn	3.1 bn scm
Rich gas Visund	0.8 bn scm

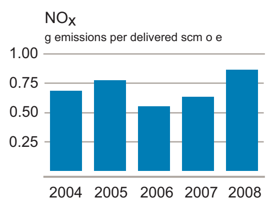
UTILITIES

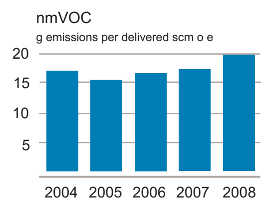
Monoethylene glycol	133 m^3
Caustics	45 m^3
Other chemicals	140 m^3

WATER CONSUMPTION

Fresh water	44,300 m^3







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PRODUCTS

Gas	33.8 bn scm
NGL	1.6 mill scm

EMISSIONS TO AIR

CO_2	83,500 tonnes
NO_x	31 tonnes
CO	44 tonnes
nmVOC	709 tonnes
Methane	1,040 tonnes

DISCHARGES TO WATER

Treated water and open drain water	133,000 m^3
Total organic carbon (TOC)	1.16 tonnes
Monoethylene glycol	1.87 tonnes
Methanol	0.42 tonnes
Hydrocarbons	0.02 tonnes
Ammonium	0.01 tonnes
Phenol	0.01 tonnes
Unintentional oil spills	0,00 m^3
Other unintentional spills	0.00 m^3

WASTE

Non-hazardous waste for deposition	213 tonnes
Non-hazardous waste for recovery	367 tonnes
Non-hazardous waste recovery rate	63 %
Hazardous waste for deposition	30 tonnes
Hazardous waste for recovery	1,670 tonnes
Hazardous waste recovery rate	98 %

[1] Gassco is the operator for the plant, but StatoilHydro is the technical service provider (TSP).

KÅRSTØ GAS PROCESSING PLANT AND TRANSPORT SYSTEMS[1)

ENERGY [11)

Fuel gas	5,770 GWh
Electricity bought	668 GWh
Diesel	4 GWh
Flare gas	165 GWh

RAW MATERIALS [2)

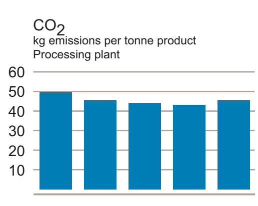
Rich gas	22.40 mill tonnes
Condensate	3.00 mill tonnes

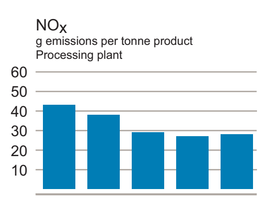
UTILITIES

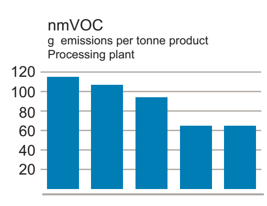
Hydrochloric acid	242 tonnes
Sodium hydroxide	99 tonnes
Ammonia	74.3 tonnes
Methanol	11.5 m^3
Other chemicals	6.6 tonnes

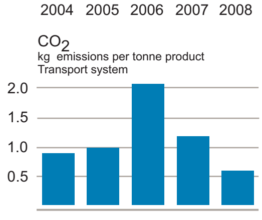
WATER CONSUMPTION

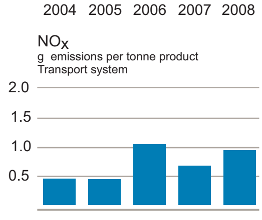
Fresh water (PP)	0.8 mill m^3

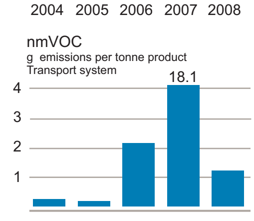












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PRODUCTS (PP)

Lean gas	18.9 mill tonnes
Propane	2.72 mill tonnes
I-butane	0.57 mill tonnes
N-butane	1.04 mill tonnes
Naphtha	0.73 mill tonnes
Condensate	1.67 mill tonnes
Ethane	0.81 mill tonnes
Electricity sold	12 GWh

EMISSIONS TO AIR [3) 4) 5) 6) 7)

CO_2	1,210,000 tonnes
SO_2	6.20 tonnes
NO_x	767 tonnes
nmVOC	1,750 tonnes
Methane	1,310 tonnes
Unintentional HC-gas emissions	4 tonnes

DISCHARGES TO WATER [8)

Cooling water	404 mill m^3
Treated water	1.04 mill m^3
Oil in oily water	0.24 tonnes
Total organic carbon (TOC)	6.8 tonnes
Unintentional oil spills	0.3 m^3
Other unintentional spills	0 m^3

WASTE [9)10)

Non-haz. waste for deposition	118 tonnes
Non-haz. waste for recovery	2,070 tonnes
Non-haz. waste recovery rate	94.6 %
Haz. waste for deposition	51 tonnes
Haz. waste for recovery	292 tonnes
Haz. waste recovery rate	85.1 %

[1)] Gassco AS is operator for the plant, but StatoilHydro is the technical service provider (TSP)

[2)] Except gas transport from TN: 24 mill tonnes.

[3), 4), 5), 6), 7)] Included emissions from Draupner, SO_2: 0,20 tonnes, NO_x: 22 tonnes, nmVOC: 29 tonnes, CH4: 144 tonnes, CO_2: 13,903 tonnes

[8)] Non-hazardous waste included from Draupner: 8 tonnes for deposition and 68 tonnes for recovery.

[9)] Hazardous waste included from Draupner; 4 tonnes for deposition and 71 tonnes for recovery.

[10)] Emissions from the terminals in Germany, Belgium and France are not included in the emissions due to that Gassco is the operator for the terminals.

[11)] Included fuel gas from TN: 67 GWh, Draupner 2.1 GWh.

Recommendation of the corporate assembly

Resolution:
At its meeting of 31 March 2009 the corporate assembly discussed the 2008 annual accounts of StatoilHydro ASA and the StatoilHydro group, and the board of directors' proposal for the allocation of net income.

The corporate assembly recommends that the annual accounts and the allocation of net income proposed by the board of directors are approved.

Oslo, 31 March 2009

Olaug Svarva
Chair of the corporate assembly

Corporate assembly
Olaug Svarva, Idar Kreutzer, Karin Aslaksen, Greger Mannsverk, Steinar Olsen, Benedicte Berg Schilbred, Ingvald Strømmen, Inger Østensjø, Rune Bjerke, Gro Brækken, Kåre Rommetveit, Tore Ulstein, Anne Synnøve Hebnes, Per Helge Ødegård, Arvid Færaas, Einar Arne Iversen, Tore Amund Fredriksen, Per Martin Labråthen, Jan-Eirik Feste, Anne K. S. Horneland