FACTS

THE NORWEGIAN PETROLEUM SECTOR 2006

Ministry of Petroleum and Energy

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Foreword by the Minister of Petroleum and Energy, Odd Roger Enoksen

Status of petroleum sector and its value for the Norwegian society

The petroleum sector is extremely important to Norway. This industry is responsible for one fourth of all value creation in the country, and more than one fourth of the state's revenues. Nearly 80,000 people are employed in petroleum-related activities, and the spillover effects to other industries are substantial. The global society is also dependent on Norwegian petroleum products, as we are the world's third largest exporter of oil and gas.

Norway has acquired knowledge and expertise in efficient recovery of petroleum resources over the course of nearly 40 years of oil and gas activities. Less than one third of our estimated petroleum resources have been produced, which indicates that the Norwegian continental shelf still has much to offer.

Some areas of the Norwegian continental shelf can be considered mature. These areas require more innovation and further development of technology. Even so, there are many opportunities to be found in mature areas. Oil companies have made significant progress in developing technology to increase recovery from fields already in production, and the recovery rate on the Norwegian continental shelf is high compared with other areas in the world. It is important that we continue this positive trend, and to facilitate this the Ministry of Petroleum and Energy has recently established regulations on use of facilities by others. The objective of these regulations is to achieve efficient use of existing platforms and pipelines to ensure more exploration for and production of petroleum. This is particularly important in mature areas of the continental shelf.

Record-high activity in 2005

The level of activity on the Norwegian continental shelf was very high in 2005. More than 250 million standard cubic metres of oil equivalents were produced, equal to the annual energy consumption of more than 100 million Norwegian households. In 2005, production commenced from the Kristin and Urd fields, bringing the total number of producing fields up to fifty.

Petroleum-related investments in the Norwegian petroleum sector were record high in the past year. More than NOK 80 billion was invested in 2005, and there are good indications that this level will be maintained in 2006. The level of investment is a major determining factor for future petroleum activities and it is thus important that the authorities support this development.

There is considerable interest in the Norwegian continental shelf. In 2005, nine new companies were prequalified as licensees or operators, and several more companies are currently being evaluated.

The authorities provide companies with access to new exploration area through annual licensing rounds. In the Awards in Predefined Areas (APA) in 2005, the companies were offered 45 new production licenses in mature areas. The interest in the 19th licensing round has also been considerable. This indicates that many players still believe there are interesting prospects on the Norwegian continental shelf.

Several significant discoveries were made in 2005, despite the fact that the exploration activity was lower than expected. 2005 also brought discoveries in less-explored areas in the Norwegian Sea. The tight rig market is the main cause of fewer exploration wells being drilled in 2005 than were expected at the beginning of the year.

The high activity level can, in part, be explained by the high price of oil, but other factors are also involved. The task of the authorities is to ensure that there are well-adapted and predictable framework conditions in place for the players in the petroleum sector. This requires close cooperation between the authorities and the other players in the industry.

Commitment areas in 2006

There are many signs that the high level of activity will continue in 2006, but this will not happen automatically. The decisions we make today determine the conditions for further development of the oil and gas activities, and are therefore important factors when it comes to shaping the future scenario. As one of the key players in this connection, it is essential that the authorities work on the basis of a long-term perspective. Ensuring constructive interaction between the players in the petroleum industry is also important.

In its “Soria Moria declaration”, the coalition government lays out the course for oil and gas sector. The government’s primary objective is to maintain high levels of value creation, employment and expertise in the industry. This will be accomplished by means including reinforcing active exploration for oil and gas, and by increasing production from fields in operation. By establishing a proactive strategy for the northern areas, the government wants to strengthen cooperation across national borders and contribute to transboundary sharing of expertise. A strengthened and long-term commitment to the northern areas will also yield positive effects for outlying regions.

The government aims for Norway to lead the world when it comes to technology and the environment. It is important that we work together to ensure that petroleum activities do not conflict with consideration for the environment. The efforts to establish a value chain for CO_2 constitute an important step in the right direction, in addition to other measures designed to reduce emissions to air and

discharges to sea. Active development of technology and introduction of the CO_2 tax resulted in a substantial reduction in emissions of greenhouse gases from the Norwegian continental shelf. With regard to discharges to sea, the authorities and the industry have established a joint objective of zero environmentally hazardous discharges, and a number of measures are now being implemented to minimise such discharges.

As we continue to develop the future of oil and gas sector in Norway, I will work to pave the way so that the players are able to carry out efficient and environmentally friendly production of Norwegian oil and gas for many, many years to come.

Minister of Petroleum and Energy

Foreword by the Director General of the Norwegian Petroleum Directorate, Gunnar Berge

There are still enormous values to be found in fields on the Norwegian continental shelf, and our goal is to ensure that as much as possible of these resources are produced. Development of technology is an important prerequisite in this connection. Today, it is possible to produce oil and gas which was previously either very difficult to recover or not profitable. Improved mapping and reservoir management, combined with extended reach horizontal wells, are examples of methods that have yielded good results. As many as eight of ten developed fields have achieved higher estimated recoverable resources after the fields started producing. This increase in resources is 60 percent on average. The value potential of a field also increases when smaller deposits around the field are developed and tied in to existing infrastructure, thus extending the life of the field.

”Five billion barrels of extra oil reserves before 2015.” This is the new target set by the authorities for the Norwegian continental shelf for the next ten-year period. This target implies that a number of projects must be realised before 2015, including measures to improve the recovery from fields already in production, as well as development of discoveries - in short, greater value creation from mature areas on the continental shelf. Proving and developing previously undiscovered resources will also help us to achieve this goal. One thing is certain: this will depend on the best efforts by all participants in the Norwegian petroleum industry.

Good stewardship of the external environment is a precondition for petroleum activities. A continuous commitment to measures to protect the environment has made it possible to produce oil and gas without harmful discharges to sea under normal operations. The Norwegian Petroleum Directorate has participated in the work on the overall management plan for the Barents Sea and ocean territory off Lofoten. The Directorate has also made an important contribution to the work to address climate challenges by studying the potential associated with injecting CO_2 in order to increase recovery on the Norwegian continental shelf.

The Norwegian Petroleum Directorate manages large volumes of information related to the activity on the Norwegian continental shelf. Each year, the oil companies report resource estimates, planned production, measures to improve recovery, environmental emissions/discharges and costs for fields and discoveries. This information constitutes an important basis for the authorities’ work on the national budget. The Norwegian Petroleum Directorate utilises these figures for studies, prognosis and analyses, as well as to prioritise follow-up of production licences. Our goal is to employ good resource management to contribute to creating the greatest possible value for the Norwegian society from the oil and gas industry.

In the autumn of 2005, the Norwegian Petroleum Directorate and the Ministry of Petroleum and Energy established a new system to follow up the operating companies on the Norwegian continental shelf. The authorities want a tool that enables better monitoring of progress and activity on the respective fields, and which indicates whether the oil companies are doing what they should in order to create value for the society at large. Among other things, the new system entails dialogue with the companies regarding key indicators such as growth in reserves, production, investments, exploration and a number of qualitative parameters.

The Norwegian Petroleum Directorate must maintain an overview of and knowledge concerning all of the resources on the entire continental shelf, and employs various work methods to map these resources. In the autumn of 2005, the Norwegian Petroleum Directorate carried out shallow drilling in the northern part of the Barents Sea to obtain more knowledge about the geology in an area to the east of Svalbard. The results will be used in the work to estimate the resources in this part of the Barents Sea.

The authorities are also key players when fields straddling the border between the Norwegian and British sectors of the North Sea are developed. Unitisation across national borders can release resources that would not otherwise be profitable - neither on the Norwegian nor the British sides. These are exacting processes that rely on flexibility and creativity - and a bit of generosity on both sides. When we succeed, the result is a win-win situation. Development of fields such as Blane and Enoch are examples that prove this is possible. As the British and Norwegian continental shelves mature, transboundary cooperation will become increasingly necessary, both for field developments and transport solutions. The important aspects here are to identify the problems and see the potential for value creation.

The initiative taken by the Norwegian Petroleum Directorate vis-à-vis the oil industry to develop the potential contained in integrated operations is also motivated by the objective of increasing value creation from the continental shelf. Estimates show that, if the industry exploits the potential of integrated operations, the recovery rate for fields could be increased by an average of two - four percentage points, in addition to the benefit of reduced operating costs. This will necessitate decisions and investments over the next three - four years. Under the direction of the e-driftforum (integrated operations forum), a study has been conducted of the consequences of integrated operations on the Norwegian continental shelf for employees in the petroleum activities, and the possibility of developing new Norwegian jobs. A working group representing a wide range of viewpoints has looked into the expertise and competence needed for broad implementation of integrated operations.

Knowledge and expertise are vital keywords for value creation. When petroleum activities began on the Norwegian continental shelf about 40 years ago, young new graduates stood in line to get jobs. Many of them are still at work, but most of this expertise from the early years of the industry will soon be retiring. It is important that we have a new generation that is ready and capable of taking over. A precondition for further value creation is that the industry is able to motivate young people to choose education and employment within this sector.

The Norwegian continental shelf may be much larger than we think. It extends outside the 200-nautical mile border in the Banana Hole in the Norwegian Sea, into the Nansen Basin in the Arctic Ocean north of Svalbard and into the Loophole on the border with Russia in the Barents Sea. The law of the sea treaty states that coastal states that have a continental shelf that extends beyond the 200-nautical mile border, must determine the border on the basis of relevant scientific data by presenting the matter to the continental shelf commission in the United Nations (UN) within a certain deadline. Geologists from the Norwegian Petroleum Directorate have obtained the necessary scientific data to enable Norway to submit its claim. When the continental shelf commission completes its deliberations, we will have a final clarification of the extent of the continental shelf. According to our estimates, the Norwegian shelf area outside the 200-nautical mile border is equivalent to an area as large as half of the Norwegian mainland.

Gunnar Berge

Director General

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1 The petroleum sector – Norway's largest industry

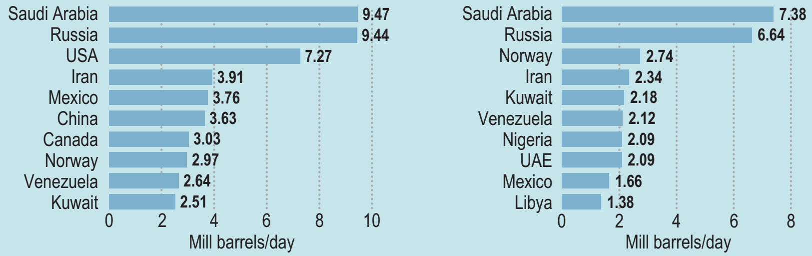


Figure 1.1 The largest oil producers and exporters in 2005 (including NGL/condensate)

(Source: Petroleum Economics Ltd.)

In the late 1950s, very few people believed that the Norwegian continental shelf might conceal rich oil and gas deposits. However, the discovery of gas at Groningen in the Netherlands in 1959 caused geologists to revise their thinking on the petroleum potential of the North Sea.

With the Ekofisk discovery in 1969, the Norwegian oil adventure really began. Production from the field began on 15 June 1971, and in the following years a number of major discoveries were made. Today, there are 50 fields in production on the Norwegian continental shelf. In 2005, these fields produced 3 million barrels of oil (including NGL and condensate) per day and 85 billion standard cubic metres (scm) gas, for a total production of saleable petroleum of 257 million scm oil equivalents (o.e.). Norway ranks as the world's third largest oil exporter and the eighth largest oil producer, see figure 1.1. In 2004, Norway was the third largest gas exporter and the seventh largest gas producer in the world.

The significance of the petroleum sector in the Norwegian society

Petroleum activities have contributed significantly to economic growth in Norway and to the financing of the Norwegian welfare state. Through nearly 40 years of operations, the industry has created values in excess of NOK 5 000 billion NOK 2005; it is today Norway's largest industry. In 2005, the petroleum sector accounted for 25 percent of value creation in the country. This equals twice the value creation of the manufacturing industry and around 17 times the total value creation of the primary industries.

Through direct and indirect taxes and direct ownership, the state is ensured a high proportion of the values created from the petroleum activities. In 2005, the state's net cash flow from the petroleum sector amounted to approximately 33 percent of total revenues. Beyond the resources used to cover the non-oil budget deficit, the state's revenues from petroleum activities are allocated to a separate fund, the Government Pension Fund – Global (formerly the Government Petroleum Fund). By the end of 2005, the value of this fund was NOK 1 399 billion.

In 2005, crude oil, natural gas and pipeline services accounted for 52 percent of the value of Norway's exports. Measured in NOK, the value of petroleum exports was 445 billion, 35 times higher than the export value of fish.

Since the petroleum industry started its activities on the Norwegian continental shelf, enormous sums have been invested in exploration, field development, transport infrastructure and land facilities; at the end of 2005 this amounted to approximately NOK 2 100 billion NOK 2005. Investments in 2005

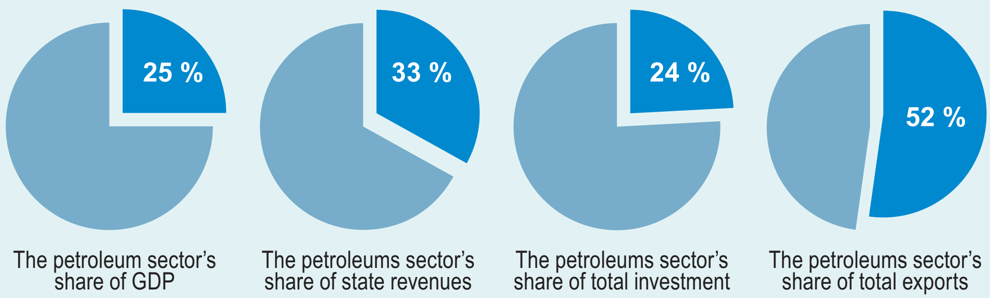


Figure 1.2 Macroeconomic indicators for the petroleum sector

(Source: Statistics Norway, Ministry of Finance)

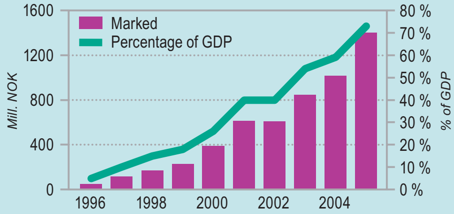


Figure 1.3 The size of the Government Pension Fund - Global at 31.12.2005 and as a share of GDP

(Source: Norwegian Public Accounts, Statistics Norway)

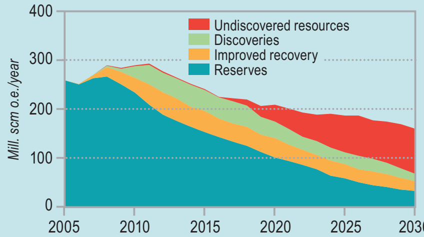


Figure 1.4 Production forecast

(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)

amounted to NOK 88 billion, or 24 percent of the country's total real investments.

Future trends

In spite of more than 30 years of production, only approximately 30 percent of the expected total resources on the Norwegian continental shelf have been produced. There is thus potential for further value creation.

Figure 1.4 shows a forecast for future production from the Norwegian continental shelf. It is based on the Norwegian Petroleum Directorate's estimate of recoverable petroleum resources on the Norwegian continental shelf and presupposes that the authorities and the industry will implement the necessary measures to recover the remaining volumes.

Petroleum production is expected to increase gradually up until 2011, and to fall gradually thereafter. Gas production is expected to increase until 2013 and could reach plateau at a level of 120 billion scm. From representing approximately 35 percent of the total Norwegian petroleum production in 2006, gas production is likely to continue to increase and may come to represent a share of more than 50 percent by 2013. In the longer term, the number and size of new discoveries will be a critical factor for the production level.

The level of activity on the Norwegian continental shelf remains high. In 2005, investments of NOK 88 billion were made in development and operations, while investments in exploration activity amounted to NOK 7 billion. In 2006, an investment level of NOK 95 billion is anticipated and approximately 20 exploration wells are scheduled for drilling. There will be investment both in measures to increase oil recovery and in developing new fields. The individual projects with the largest investments are Snøhvit, Ormen Lange and Langeled. Investments are expected to remain high until 2009, before falling to a somewhat lower level than we have today. Nevertheless, forecasts indicate that activity in the industry will remain high over the long term, see figure 1.5. In the years ahead, investments will relate primarily to modification and drilling activities. There is considerable uncertainty tied to the investment forecasts, for both the longer and the shorter terms. In addition to the investments, the forecasts also reveal a market for operations and maintenance of approximately NOK 35 billion annually for many years to come.

The oil price is a very important factor as regards the activity level and revenues to the state. The price of oil has increased substantially in recent years, averaging nearly USD 55 per barrel in 2005 (Brent quality). At the beginning of 2006, the price had risen above USD 60 per barrel. There are several reasons for the high price level. There is a steady increase in the demand for oil. At the same time, the production capacity is nearly fully exploited, and production is uncertain and unstable in many major producing countries. If the growth in the world economy continues, there are reasons to assume that oil prices will remain at a relatively high level in the next few years.

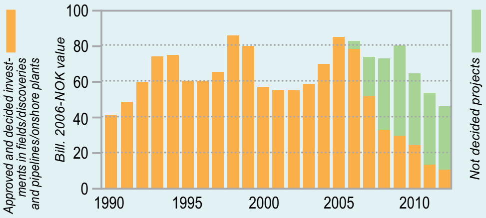


Figure 1.5 Historic investments and forecasted future investments

(Source: Norwegian Petroleum Directorate/ Ministry of Petroleum and Energy)

2 Norwegian resource management

Interest in exploring for oil on the Norwegian continental shelf began in the early 1960s. At that time there were no Norwegian oil companies, and very few Norwegian institutions, official or private, had any knowledge of petroleum-related activities. There was even a question as to whether the Norwegian continental shelf really held significant petroleum resources. From the start, national administration and control over the petroleum activities on the Norwegian continental shelf have been fundamental requirements. The challenge for Norway in developing its petroleum activities was to establish a system of managing the petroleum resources that maximised the values for the Norwegian people and the Norwegian society.

To begin with, the Norwegian government selected a model in which foreign companies carried out all petroleum activities on the Norwegian continental shelf. Over time, the Norwegian involvement was strengthened by the creation of a wholly owned state oil company, Statoil. Norsk Hydro also took part in the petroleum activities. A private Norwegian company, Saga Petroleum, was also established, but was later acquired by Norsk Hydro. The cooperation and competition between the various companies on the Norwegian continental shelf have been crucial, as they have all possessed different technical, organisational and commercial expertise. This policy has contributed to ensuring that Norway today has its own oil companies and a competitive supplier industry, and that the nation is secured substantial revenues from the sector.

The current resource management model

In order for oil companies to make rational investment decisions, the framework conditions must be predictable and transparent. This is the general

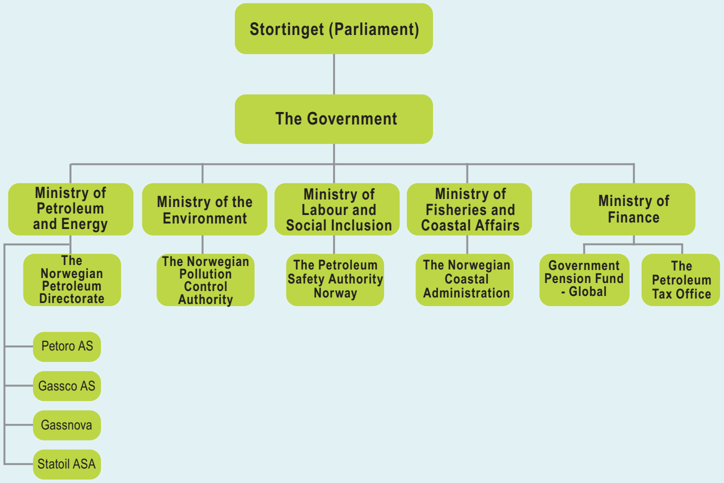


Figure 2.1 National organisation of the petroleum sector

(Source: Ministry of Petroleum and Energy)

basis for the incentive system Norway has established on the Norwegian continental shelf. Organisation of the activities and the division of roles and responsibilities shall ensure that important social considerations are safeguarded and that the value created benefits society as a whole. At the same time, consideration for the external environment, health, working environment and safety plays an important role.

Norwegian and international oil companies are responsible for the actual operation of petroleum activities on the Norwegian contintental shelf. Competition between oil companies yields the best result when it comes to maximising the value of the petroleum resources. At the same time, it is important that the authorities can understand and evaluate the decisions made by the companies. Therefore, Norway has established a system where oil companies create ideas and carry out the technical work required to recover the resources, but their activities also require approval by the authorities. The approval of the authorities is required in all stages of the petroleum activity, in connection with exploration drilling[1], plans for development[2] and decommissioning plans[3] for fields. In this system, the oil companies create the solutions necessary to recover the resources, while the Norwegian authorities ensure that these solutions concur with the goal of maximising the values for the Norwegian society as a whole.

For the oil companies to function as agents for the Norwegian society in maximising the values on the Norwegian continental shelf, a framework must be in place which provides the petroleum industry with incentives to fulfil the state's objectives while also meeting their own goals, which is to maximise their profit. Through the petroleum taxation system and the State's Direct Financial Interest (SDFI), the state receives a substantial portion of the revenues from the petroleum activities[4]. At the same time, however, tax deductions are granted for the costs associated with petroleum activities. In such a tax system, the Norwegian State functions as a passive owner in a production licence on the Norwegian continental shelf. This system implies that, if the oil companies do not make money, the Norwegian State will not collect revenues. In this manner, all players in the Norwegian petroleum sector have a common interest in ensuring that production of the Norwegian petroleum resources creates the greatest possible values.

Cooperation and competition

While competition is desirable, cooperation between the players in the petroleum industry is also beneficial. Therefore, the authorities award production licences to a group of companies instead of to just one company. Production licences are normally awarded on the basis of applications from oil companies in connection with licensing rounds[5]. The most important criteria for award include understanding the geology, technical expertise, financial strength and the experience of the oil company. Based on the applications, the Ministry of Petroleum and Energy establishes a licensee group. In this group, the oil companies exchange ideas and experience, and share the costs and revenues associated with the production licence. The companies compete, but must also cooperate to maximise the value in the production licence they have been awarded. In this system, expertise and experience from around the world are gathered together in nearly all of the

1 *Ref. Chapter 3.*
2 *Chapter 4 addresses development and operation, while gas management is discussed in Chapter 5.*
3 *More on decommissioning after production is concluded in Chapter 6.*
4 *Ref. Chapter 8.*
5 *A more detailed discussion of exploration policy can be found in Chapter 3.*

production licences on the Norwegian continental shelf. The licensee group also functions as an internal control system in the production licence, where each licensee is responsible for monitoring the operator's work.

The petroleum sector is driven by technological innovation. Maximising the values on the Norwegian continental shelf requires that oil companies constantly apply the best available technology, and that they carry out the necessary research. Therefore, the Norwegian authorities have established an environment that promotes technological development. Today there is close collaboration between oil companies, research institutes, the supplier industry and the authorities when it comes to technology and research[6].

National organisation of the petroleum sector

The Storting

The Storting, the Norwegian parliament, creates the framework for Norwegian petroleum activities. The methods used include passing legislation and adopting propositions, as well as discussing and responding to white papers concerning the petroleum activities. Major development projects or matters of great public importance must be discussed and approved by the Storting. The Storting also supervises the government and the public administration.

The government

The government holds the executive power over petroleum policy and is responsible vis-à-vis the Storting for this policy. In applying the policy, the government is supported by the ministries and subordinate directorates and agencies. The responsibility for executing the various roles within the petroleum policy is shared as follows:

6 See Chapter 7.

- The Ministry of Petroleum and Energy
  – responsible for resource management and the sector as a whole
- The Ministry of Labour and Social Inclusion
  – responsible for health, the working environ ment and safety
- The Ministry of Finance
  – responsible for state revenues
- The Ministry of Fisheries and Coastal Affairs
  – responsible for oil spill contingency measures
- The Ministry of the Environment
  – responsible for the external environment

KonKraft and the Senior Management Forum

The Ministry of Petroleum and Energy works in close dialogue with the Norwegian-based oil and gas industry to strengthen competitiveness on the Norwegian continental shelf, as well as the competitiveness of the supplier industry.

This process goes under the name of KonKraft. To ensure that KonKraft has sufficient professional clout, an arena has been set up where the industry and the authorities can discuss key challenges and proposals for concrete measures. This arena is called the Senior Management Forum (Topplederforum). The Senior Management Forum was established in the autumn of 2000 and is chaired by the Minister of Petroleum and Energy. The Forum is composed of about 40 senior managers from oil companies, the supplier industry, employee and employers' organisations, research institutes and the authorities.

More on the national organisation of the petroleum sector

THE MINISTRY OF PETROLEUM AND ENERGY

The Ministry of Petroleum and Energy holds the overall responsibility for management of petroleum resources on the Norwegian continental shelf. This includes ensuring that the petroleum activities are carried out in accordance with the guidelines drawn up by the Storting and the government. The Norwegian Petroleum Directorate is administratively subordinate to the Ministry of Petroleum and Energy. In addition, the ministry holds a particular responsibility for monitoring the state-owned corporations, Petoro AS, Gassco AS and Gassnova, and the partly state-owned Statoil ASA.

The Norwegian Petroleum Directorate

The Norwegian Petroleum Directorate plays a major role in the management of the petroleum resources, and is an important advisory body for the Ministry of Petroleum and Energy. The Norwegian Petroleum Directorate exercises management authority in connection with exploration for and exploitation of petroleum deposits on the Norwegian continental shelf. This also includes authority to issue regulations and make decisions according to rules and regulations for the petroleum activities.

Petoro AS

Petoro AS is a state-owned corporation which is responsible for the State's Direct Financial Interest (SDFI) on behalf of the state.

Gassco AS

Gassco AS is a state-owned corporation responsible for the transport of natural gas from the Norwegian continental shelf.

Gassnova

Gassnova is an administrative agency with the task of promoting and supporting innovation and development of environmentally friendly gas power technology.

Statoil ASA

Statoil ASA is listed on the Oslo and New York stock exchanges. The state owns a 70.9 percent stake in the company.

THE MINISTRY OF LABOUR AND SOCIAL INCLUSION

The Ministry of Labour and Social Inclusion holds the overall responsibility for the working environment and for safety and contingency measures in relation to the petroleum sector.

The Petroleum Safety Authority Norway

The Petroleum Safety Authority is responsible for safety, contingency measures and the working environment in the petroleum sector.

THE MINISTRY OF FINANCE

The Ministry of Finance holds the overall responsibility for ensuring that the state collects taxes, fees and other revenues from the petroleum sector.

The Petroleum Tax Office

The Petroleum Tax Office is part of the Norwegian Tax Administration, which is subordinate to the Ministry of Finance. The main function of the Petroleum Tax Office is to ensure correct assessment and collection of the taxes and fees that have been determined by the political authorities.

The Government Pension Fund – Global (formerly the Government Petroleum Fund)

The Ministry of Finance is responsible for administrating the Government Pension Fund - Global. Responsibility for operational administration has been delegated to Norges Bank.

THE MINISTRY OF FISHERIES AND COASTAL AFFAIRS

The Ministry of Fisheries and Coastal Affairs is responsible for maintaining adequate contingency measures against acute pollution in Norwegian waters.

The Norwegian Coastal Administration

The Coastal Administration is responsible for national oil spill contingency measures.

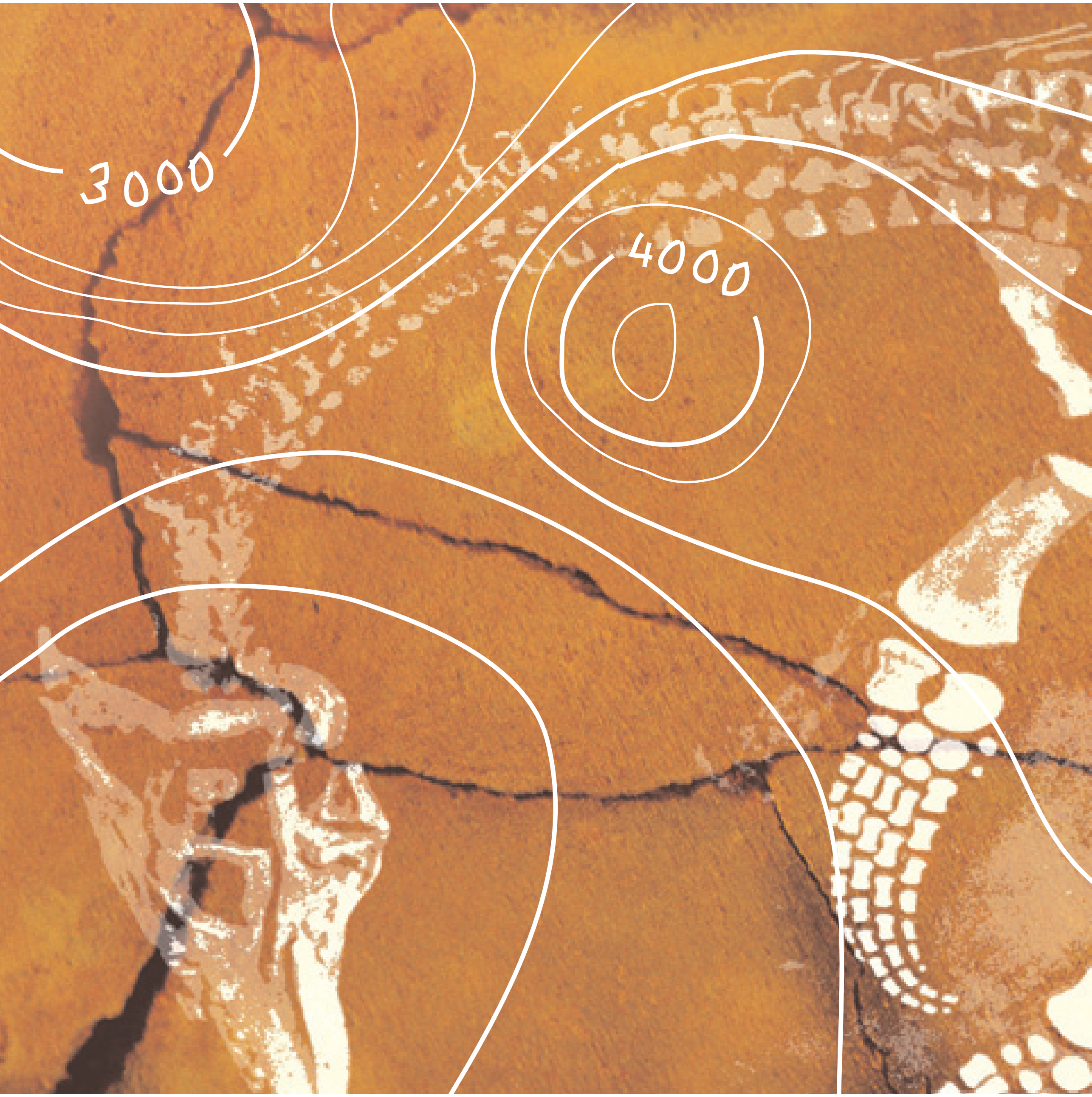
THE MINISTRY OF THE ENVIRONMENT

The Ministry of the Environment holds the overall responsibility for management of the Norwegian external environment.

The Norwegian Pollution Control Authority

The responsibilities of the Norwegian Pollution Control Authority include enforcing the Pollution Control Act. Another key task is to provide the Ministry of the Environment with advice, guidelines and technical documentation.

3 Exploration activities



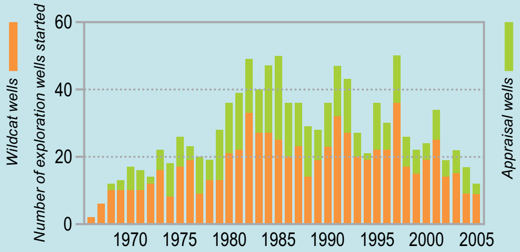


Figure 3.1 Exploration wells spudded on the NCS 1966-2005

(Source: Norwegian Petroleum Directorate)

Exploring for and proving undiscovered resources is a prerequisite for recovering the petroleum resources on the Norwegian continental shelf. Exploration activities are an important indicator of future production. Typically, it takes several years from a decision to begin exploring for resources until any discoveries can be put into production. The framing of exploration policy is hence an important aspect of Norwegian resource management.

In recent years there has been a trend towards less exploration activity on the Norwegian continental shelf than was previously the case and fewer major discoveries have been made. For the authorities, it is important that Norwegian exploration policy provides for rapid and efficient identification of new resources. It is the companies which then undertake the exploration itself and the proving of new resources. Exploration policy is therefore designed to increase the attractiveness of the Norwegian continental shelf and to help bring in new players to complement the existing ones. The authorities seek to promote a correct level of activity on the continental shelf through the structure of the licensing system and through access to and management of exploration acreage.

A fundamental precondition for petroleum activities on the Norwegian continental shelf is the coexistence of the oil industry and other users of the sea and land areas affected by such activities. This precondition is also important in licensing policy. This policy places great emphasis on safeguarding the interests of all users of the marine areas, both when opening up new areas, in the announcement of licensing rounds and in the award of production licences.

The licensing system

The Petroleum Act (Act of 29 November 1996 No. 72 relating to petroleum activities) provides the general legal basis for the licensing system which regulates Norwegian petroleum activities. The Act and its appurtenant regulations authorise the award of licences to explore for, produce and transport petroleum, etc.

The Petroleum Act establishes that the proprietary right to subsea petroleum deposits on the Norwegian continental shelf is vested in the state. Before permission for exploration drilling and production (a production licence) can be awarded, the area in question must have been opened up for petroleum activities. An impact assessment, covering such aspects as the environmental, economic and social effects of such activities on other industries and adjacent regions, must be carried out.

Production licences are normally awarded through licensing rounds. The government announces a certain number of blocks for which an application for a production licence may be made. Applicants may apply individually or in groups. Production licences are awarded on the basis of impartial, objective, non-discriminatory and published criteria. On the basis of applications received, the Ministry of Petroleum and Energy puts together a group of companies for each licence or can make adjustments to a group which has submitted a joint application. The Ministry of Petroleum and Energy appoints an operator for this partnership, who is responsible for carrying out the day to day activities under the terms of the licence.

The production licence regulates the rights and obligations of licensees in relation to the state. This document supplements the provisions of the Petroleum Act and specifies detailed terms for each licence. The licence provides an exclusive right for exploration, exploration drilling and the production of petroleum within the geographical area specified in the production licence. Ownership of the petroleum produced rests with the licensees.

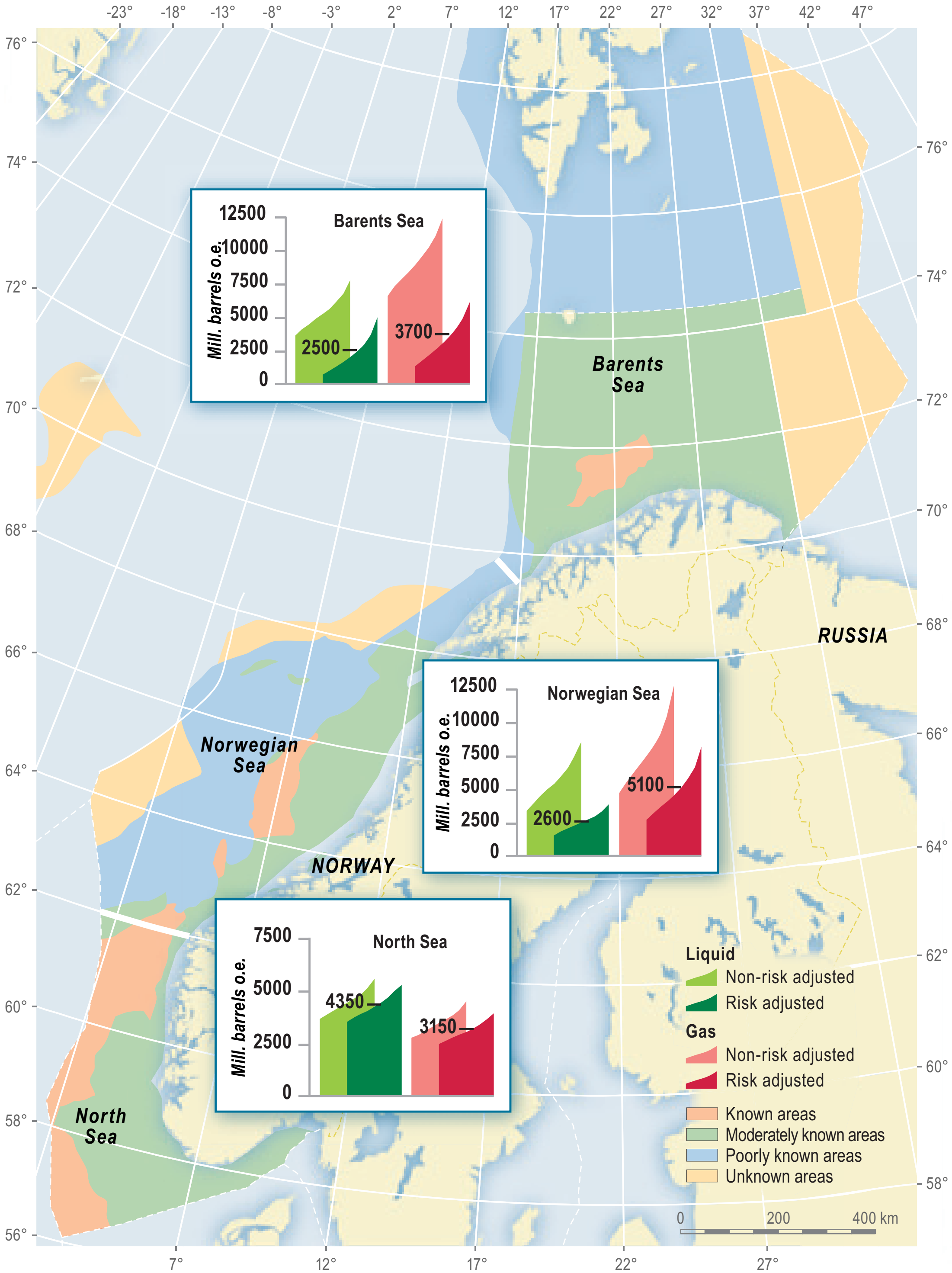


Figure 3.2 Undiscovered resources

(Source: Norwegian Petroleum Directorate)

The production licence is awarded for an initial exploration period, which can last up to ten years. A specified work obligation must be met during this period, including seismic surveys and/or exploration drilling. An area fee is charged per square kilometre, according to detailed rules. Providing that all the licensees agree, a licence can be relinquished once the work obligation has been fulfilled.

Mature and frontier areas

The parts of the Norwegian continental shelf that the Parliament has opened up for petroleum activities are the greater part of the North Sea, Norwegian Sea and the southern Barents Sea. The Norwegian Petroleum Directorate's estimate of undiscovered resources in the areas on the continental shelf totals 3.4 billion standard cubic metres (scm) of recoverable oil equivalents. This is roughly equal to the volumes that have already been produced to date on the Norwegian continental shelf and the resources are divided more or less equally between the three regions, with 35 percent in the North Sea, 36 percent in the Norwegian Sea and 29 percent in the Barents Sea (see figure 3.2). Depending on the degree of maturity of the different areas, there is some variation in the types of challenges faced in realising the commercial potential of the undiscovered resources on the Norwegian continental shelf.

Characteristics of mature areas include familiar geology, minor technical challenges and well-developed or planned infrastructure. For this reason, it is fairly likely that discoveries will be made when prospects are drilled. At the same time, however, major new discoveries are less likely. There have been petroleum activities in parts of the mature area of the continental shelf for nearly 40 years. This means that the geology in these areas is well documented, and the infrastructure is for the most part highly developed.

Frontier areas are characterised by little knowledge of the geology, significant technical challenges and a lack of infrastructure. The uncertainty surrounding exploration activity is greater here, but there is still the possibility of making substantial new discoveries in these areas. These factors lead to a smaller group of less diverse players who are capable of exploring for such resources. In addition to broad-based experience and technical and geological expertise, the players who operate in these areas must have a solid financial base.

Exploration policy in mature and frontier areas

Mature areas

Petroleum activities on the Norwegian continental shelf started in the North Sea and have gradually moved northwards based on the principle of gradual opening of areas. Consequently, large portions of the North Sea are now considered to be mature from an exploration perspective. There has also been considerable exploration of Haltenbanken in the Norwegian Sea, and many parts of this region are also considered mature. The most recent area to be considered mature is the area surrounding Snøhvit in the Barents Sea.

The infrastructure is overall highly developed in mature areas. Nevertheless, the lifetime of the existing infrastructure is limited and it is thus important to prove and recover the resources in these areas before the infrastructure is shut down. Otherwise, profitable resources may be left in the ground because the discoveries are too small to carry a stand-alone development of infrastructure.

The authorities have determined that industry access to larger parts of mature areas is important so that time-critical resources can be produced. It is also important that the areas awarded to the

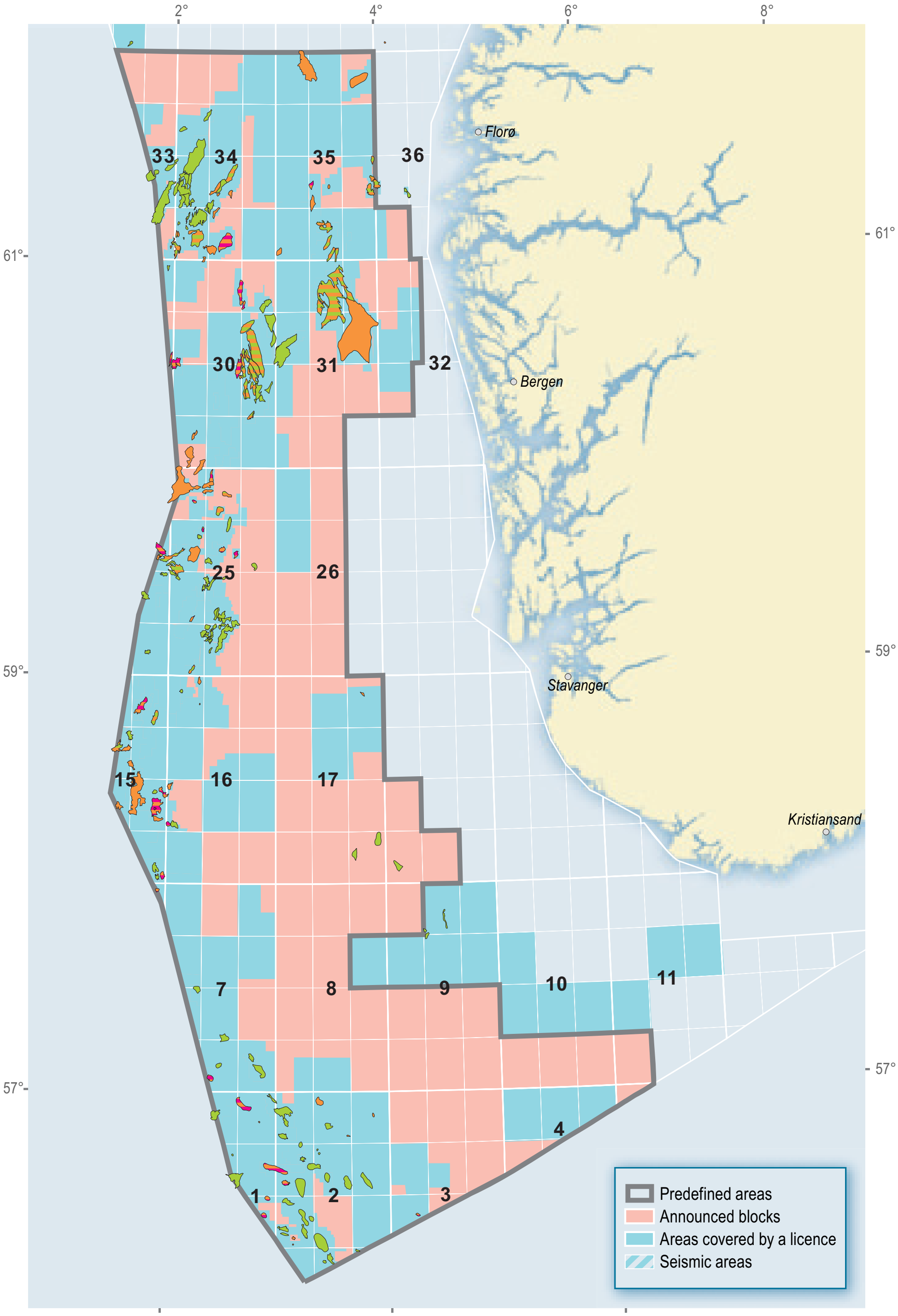


Figure 3.3 Awards in pre-defined areas - North Sea announcement 2006

(Source: Norwegian Petroleum Directorate)

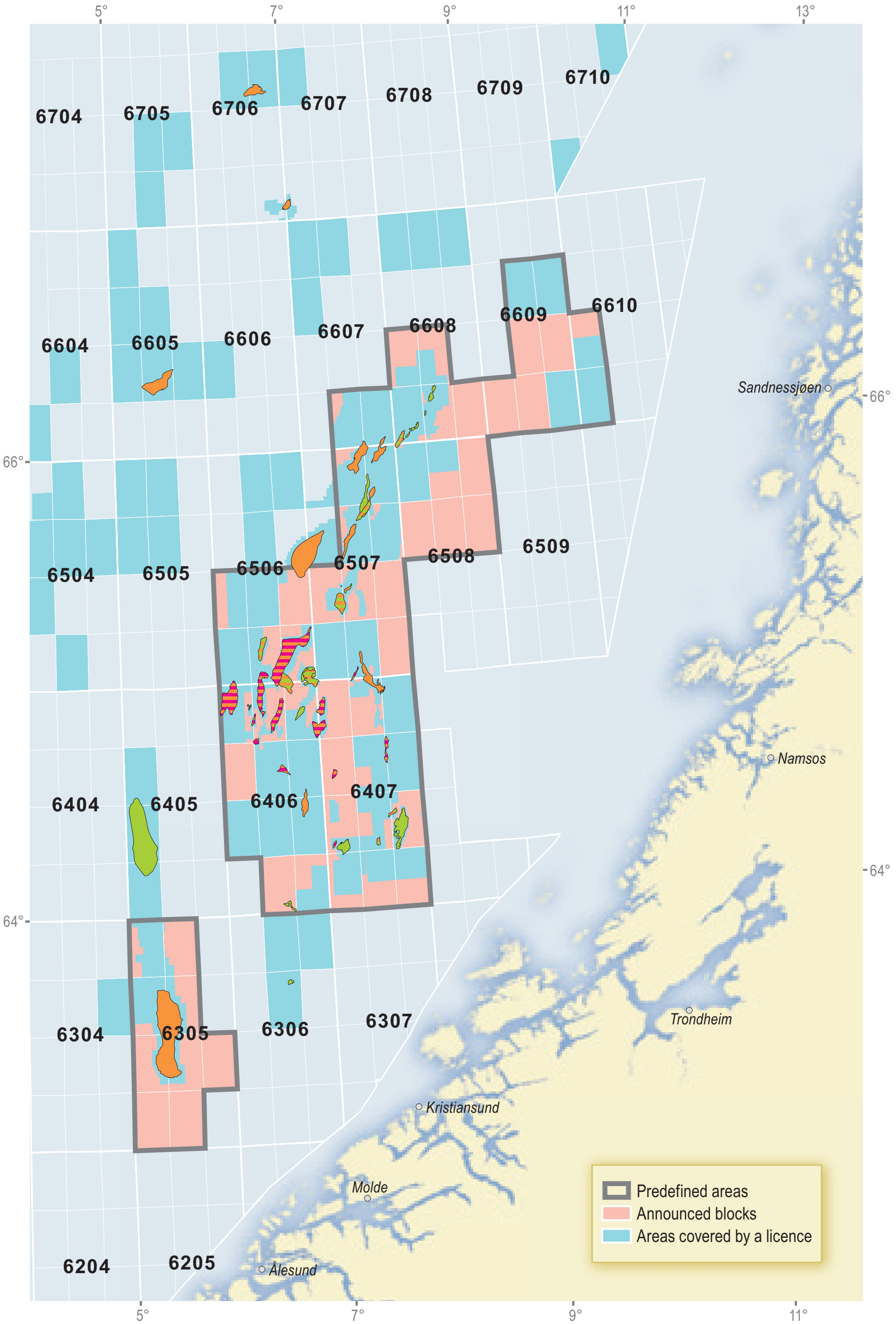


Figure 3.4 Awards in pre-defined areas - Norwegian Sea announcement 2006

(Source: Norwegian Petroleum Directorate)

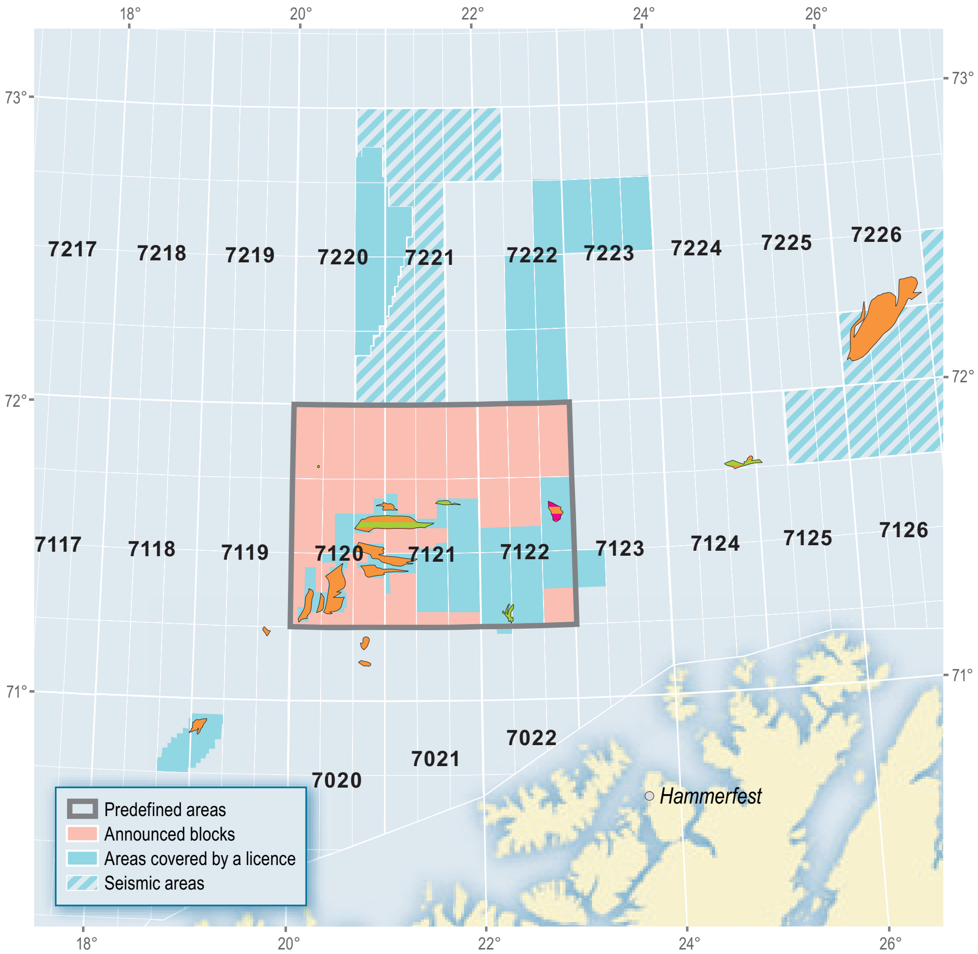


Figure 3.5 Awards in pre-defined areas - Barents Sea announcement 2006
(Source: Norwegian Petroleum Directorate)

industry is explored quickly and efficiently. For this reason, the Government has implemented a policy shift in mature areas, introducing a scheme in 2003 for award of production licences in predefined areas (APA) in mature areas of the Norwegian continental shelf. The premise of this system is the designation of large, predefined exploration areas which encompass all mature areas on the Norwegian continental shelf. This area will be expanded, never curtailed, as new areas mature. The system entails a permanent annual cycle for licensing rounds in mature areas. Three such licensing rounds have been carried out in mature areas to date: APA 2003, APA 2004 and APA 2005. Figures 3.3, 3.4 and 3.5 show the areas announced for award in APA 2006.

Acreage within the predefined area which is relinquished during the period of time from the announcement of area until the application deadline expires will be included in the announced area. This means that all acreage that is relinquished within the predefined area will automatically be included in the announced area as of the date when the relinquishment takes effect. This will provide an opportunity for other companies that may have a different opinion concerning the area's prospectivity to explore the area quickly. This will ensure more rapid circulation of acreage, and more efficient exploration of the mature areas.

Frequent awards and more announced area in each licensing round have resulted in an increase in licensed area. At the beginning of 2005, 16 percent of the area opened up to petroleum activities

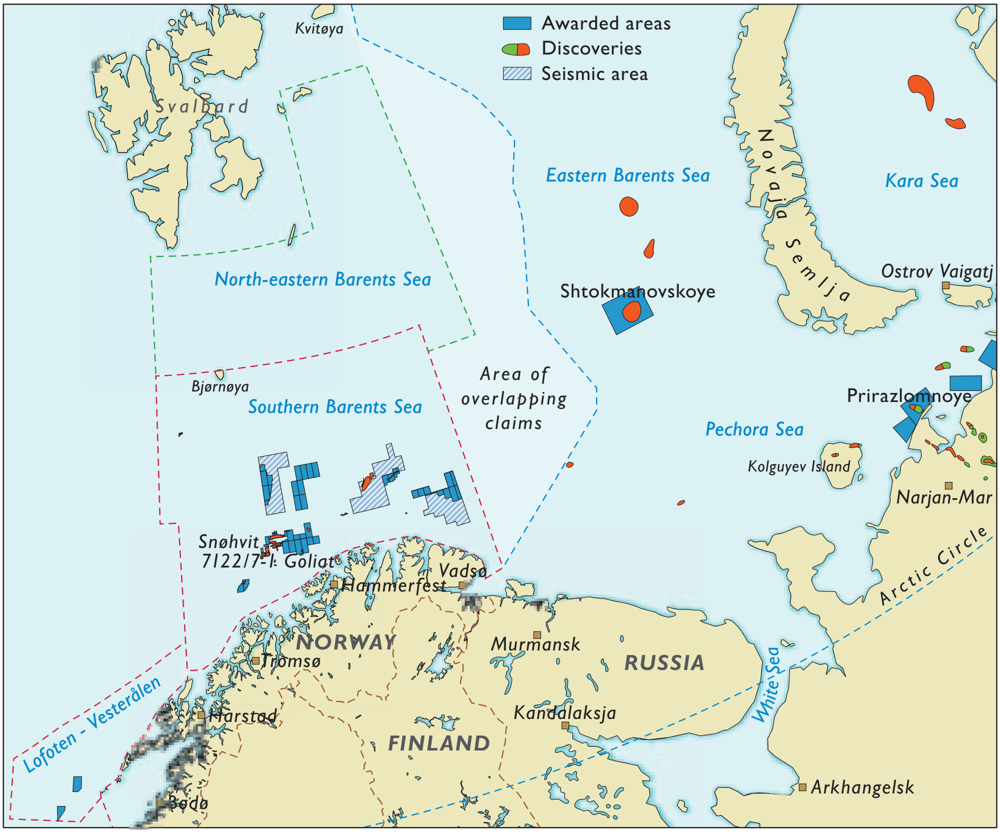


Figure 3.6 Norwegian and Russian part of the Barents Sea
(Source: Norwegian Petroleum Directorate)

on the Norwegian continental shelf was covered by production licenses, an increase from nine percent in the previous year.

Active exploration within licensed area is important to the authorities. This requires framework conditions designed to ensure that companies which have been awarded production licences do not leave the area idle, but rather actively explore it.

In the mature areas, the work obligations assumed when companies are awarded new production licences are organised as a set of activities and decisions. At each juncture, the company must decide whether it wants to implement new activities in the licence or relinquish the entire area.

Another important change is that the area of the production licence to be awarded is now “tailored” in the sense that the company is only awarded acreage for which it has concrete plans.

Changes have also been made concerning which areas the companies are allowed to retain upon expiration of the initial period. Previously, when the initial period was expired, the companies could retain as much as 50 percent of the awarded area without obligation to carry out any specific activity. Today, the basic rule is that companies can only retain areas in which they plan to start production.

Frontier areas

The areas currently considered to be frontier areas on the Norwegian continental shelf include major portions of the Barents Sea and the Norwegian Sea. In the Norwegian Sea, this applies particularly to deepwater regions and the northernmost areas. The coastal areas in the southern part of the Norwegian continental shelf are also relatively immature.

The 18th licensing round introduced a principle change in the rules for relinquishing area. The regulations that apply in mature areas will now also apply to the immature areas. However, it is not expedient for all companies that receive produc-

Aker Energy*	Dong	Lasmo*	OER	Petro-Canada
Altinex	Endeavour	Lundin	OMV	Premier Oil
Anadarko	Ener Petroleum	Marubeni	Oranje Nassau	Revus
BG Norge	Faroe-Petroleum	Mitsubishi	PA Resources	Ruhrgas
Centrica	Gaz de France	Mærsk	Paladin	Sumitomo
CNR	Hunt Oil	Nexen	Pelican*	Talisman
Discover Petroleum	Idemitsu	Noble Energy	Pertra	Wintershall
DNO	Kerr McGee	Noreco	Petoro	

* Companies that no longer exists as individual companies

Figure 3.7 Prequalified/new companies since 2000 (As of 1st Quarter 2006)

tion licenses in immature areas to submit a plan for development and operation by the end of the initial period. The main rule for relinquishment in these areas is therefore linked to delimitation of resources proven through drilling. Futhermore, the same changes apply to immature areas as for mature areas with regards to tailoring the acreage to be awarded.

The announcement of the 19th licensing round in 2005 includes blocks in both the Norwegian Sea and the Barents Sea. Representative key blocks have been selected for announcement in the Barents Sea, and exploration within these blocks will provide important information about large areas in this ocean territory.

It is still possible to make large new discoveries in the immature areas of the Norwegian continental shelf. The prospects of making such discoveries help ensure that the Norwegian continental shelf remains competitive in an international perspective. The gradual expansion of petroleum activities towards the vast frontier areas in the northern parts of the Norwegian continental shelf has necessitated a clarification of the terms and conditions for petroleum activities in these areas.

In 2002, consideration for the environment and fishery industry led to the initiation of a study on the consequences of year-round petroleum activity in the Lofoten-Barents Sea area (abbreviated ULB). Based on the results of this study, the government in office resolved not to open areas for further petroleum activities in awarded areas in Nordland VI off the Lofoten coast. At the same time, the government approved a general opening for further year-round petroleum activities in previously opened areas in the southern Barents Sea, except areas with particular environmental or fishery value.

In the winter of 2003, the Ministry of Petroleum and Energy and the Ministry of Fisheries (today: the Ministry of Fisheries and Coastal Affairs) established a working group (Coexistence Group I), with the objective of assessing the possibilities of coexistence between the fisheries and the petroleum industry in the area from Lofoten and northwards, including the Barents Sea. The Ministry of Petroleum and Energy, the Ministry of Fisheries and Coastal Affairs, the Norwegian Petroleum Directorate, the Directorate of Fisheries, the Institute of Marine Research, the Norwegian Fishermen's Association and the Norwegian Oil Industry Association all participated in this work. The group proposed recommended conditions for the regulation of the relationship between petroleum activities and fishery activities in the Barents Sea. The working group summarised its findings in a report completed in July 2003.

The coexistence group resumed its work in the spring of 2005 with a continued discussion of coexistence between petroleum and fishery activities within the frame of sustainable development (Coexistence Group II). In accordance with the Storting (Norwegian Parliament) resolution, the group was expanded to include participants from the Ministry of Environment, the Norwegian Pollution Control Authority, the Directorate for Nature Management and the Norwegian Foundation for Nature Research. The Ministry of Labour and Social Inclusion and the Petroleum Safety Authority Norway were also added to the group.

The group's work is coordinated with the overall management plan for the Barents Sea and the area off Lofoten (abbreviated HFB). The report from Coexistence Group II will be published following the Storting White Paper on the management plan, expected to be submitted to the Storting before Easter 2006.

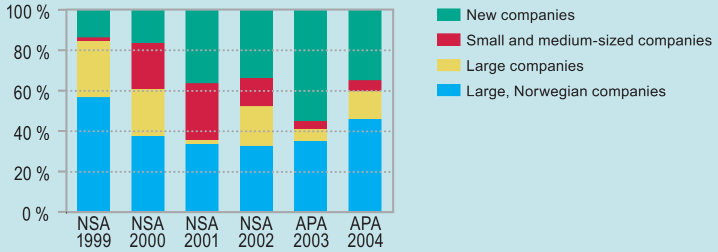


Figure 3.8 Exploration costs in production licences awarded in NSA and APA distributed according to the size of the companies *(Source: Norwegian Petroleum Directorate)*

Unopened areas

There are still large parts of the Norwegian continental shelf which the Storting has not opened up for petroleum activities, including all of the northern Barents Sea, Troms II, Nordland VII, parts of Nordland VI, coastal regions off the Nordland coast and Skagerrak.

The Storting must decide to open these areas for petroleum activities before they can be announced in a licensing round. Such decision requires preparation of an impact assessment which examines factors including the economic, social and environmental effects such activities could have on other industries and the surrounding region. The question of whether or not to open these areas must also be submitted to local authorities and stakeholder organisations that may have a special interest in this matter.

The present coalition government's position paper, the so-called "Soria Moria declaration", states that "no petroleum activities will commence in Nordland VI during the current parliamentary period. When the overall management plan is presented, it will be determined which areas will be opened in the remaining ocean areas outside of Lofoten and northwards, including the Barents Sea, and which areas will remain closed to petroleum activities. The Storting will make this decision".

Area with overlapping claims

The boundary between Norway and Russia has still not been finally drawn and is currently being discussed by Russian and Norwegian authorities. The area, approximately equivalent in size to the Norwegian part of the North Sea, is outlined in figure 3.6.

Industry structure

Industry structure refers to the number and composition of oil companies involved in petroleum activities on the Norwegian continental shelf. The largest multinational players occupy a key place on the Norwegian continental shelf, which is a natural consequence of the fact that the shelf has been characterised by tasks that are small in number, but large and complex in terms of the opportunity to realise substantial values. As the Norwegian continental shelf matures and the challenges there have changed and become more diverse, it has been important to adapt the player scenario to the altered situation. This has led to a focus in recent years on attracting competent new players onto the continental shelf. Several of these players have been smaller companies with particular expertise in mature areas and tail-end production. More information on operators and licensees in production licences and fields on the Norwegian continental shelf can be obtained on the Norwegian Petroleum Directorate's web page: www.npd.no/reports.

Prequalification

In order to facilitate the entry of new players, White Paper No. 39 (1999–2000) to the Storting introduced a system for prequalification of new operators and licensees. From the scheme's inception to March 2006, 39 companies had been prequalified, or had become licensees on the Norwegian continental shelf. Additional companies are currently being evaluated or have indicated that they wish to become prequalified.

Figure 3.7 shows prequalified companies on the Norwegian continental shelf since 2000.

Significant acreage and production licences have been awarded to these new players in the North Sea Rounds and APA. In the past four years, new players have accounted for more than 20 percent of the exploration costs associated with these rounds.

4 Development and operations

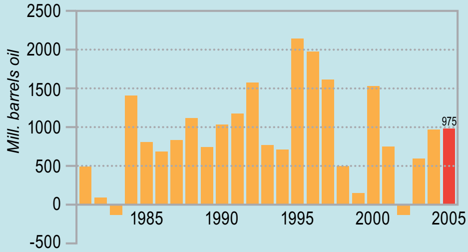


Figure 4.1 Annual gross increase in the reserves of oil 1981-2005
(Source: Norwegian Petroleum Directorate)

In 2005, Norway produced an impressive 84 billion standard cubic metres (scm) of gas, more than ever before. Total oil production was 148 million scm, a slight decline from the previous year. Total production of oil and gas is expected to remain at about these levels over the next few years, with a slight increase up to the anticipated peak year of 2008. In the future, production of oil will decrease while production of gas will increase. Ten years ago, gas made up 15 percent of total production. In 2006, this will increase to 35 percent, while in 2013, gas production is expected to account for more than 50 percent of total production.

At the end of 2005, there were 42 producing fields in the North Sea and eight producing fields in the Norwegian Sea. Two new fields came into production in 2005, Kristin and Urd, both in the Norwegian Sea. With the Snøhvit field coming on stream in 2007, petroleum will also be produced from the Norwegian sector of the Barents Sea. As the Norwegian petroleum industry has moved northwards, it has entered into areas containing enormous gas resources. Consequently, a number of gas fields have been developed and a comprehensive gas transport infrastructure has been established, which has made it possible to develop additional gas resources. Development of the gas fields, combined with falling production from major oil fields, entails that gas is becoming an ever more important component of Norway's petroleum production.

Production on the Norwegian continental shelf has been dominated by a few large fields. Production from several of these fields is on the decline, while several new, smaller fields have been developed, with the result that current production is distributed over a greater number of fields than previously. This development is to be expected. When the North Sea was opened up for petroleum activity, the most promising areas were explored first. This led to world-class discoveries which were then put into production, and were given names such as Ekofisk, Statfjord, Oseberg, Gullfaks and Troll. These fields have been, and still are, of great significance for the development of the Norwegian continental shelf. The large fields have contributed to the establishment of infrastructure that subsequent fields have been able to tie into.

Fields and infrastructure – potential for efficient exploitation

To protect society's interests in development and operation of oil and gas fields, the authorities have established frameworks for these activities, which are intended to ensure that the companies make decisions that are also beneficial to the society at large. It is important that these frameworks are predictable for the companies. Hence, the authorities have created a model that is characterised by both cooperation and competition between the players, with the intention of creating a climate for sound decisions that benefit both the companies and the rest of society.

Under petroleum industry framework conditions, companies are obliged to carry out prudent development and operations of proven petroleum resources. This means that the companies are responsible for submitting and executing new projects, whereas the authorities give the final consent for implementation. When a new deposit is to be developed, the company must submit a plan for development and operation (PDO) for approval. An important part of the development plan is an environmental impact assessment which interested parties are given the opportunity to comment upon in a hearing round. The impact assessment is to describe the development's expected impact on the environment, any transboundary environmental effects, natural resources, fisheries and society in general. The governmental consideration of this assessment and of the development plan, ensures a prudent project in terms of resources, as well as acceptable consequences for other matters of public interest.

Development of proven petroleum resources is the basis for production and value creation from the petroleum industry today. The 50 fields on the Norwegian continental shelf also provide an opportunity to better exploit the resources in the surrounding areas where the fields are located. This constitutes an enormous potential that can generate significant values for society if it is exploited prudently. The Norwegian Petroleum Directorate has assessed this potential and has arrived at an objective for reserve growth on the Norwegian continental shelf of 800 million scm (five billion barrels) oil before 2015. This is equivalent to the oil resources in approximately two Oseberg fields. With today's oil price, this volume will have a gross value[1] of approximately NOK 2 000 billion, nearly 1.5 times as much as the Government Pension Fund - Global (formerly the Petroleum Fund). This objective is a stretch target for both the industry and the authorities. If we are to realise this potential, we must increase recovery from fields in production, develop discoveries in the vicinity of existing infrastructure, prove and develop new resources and constantly operate the fields better and more cost-efficiently. Figure 4.1 shows annual growth of oil reserves in the

1 *NOK 400/barrel*

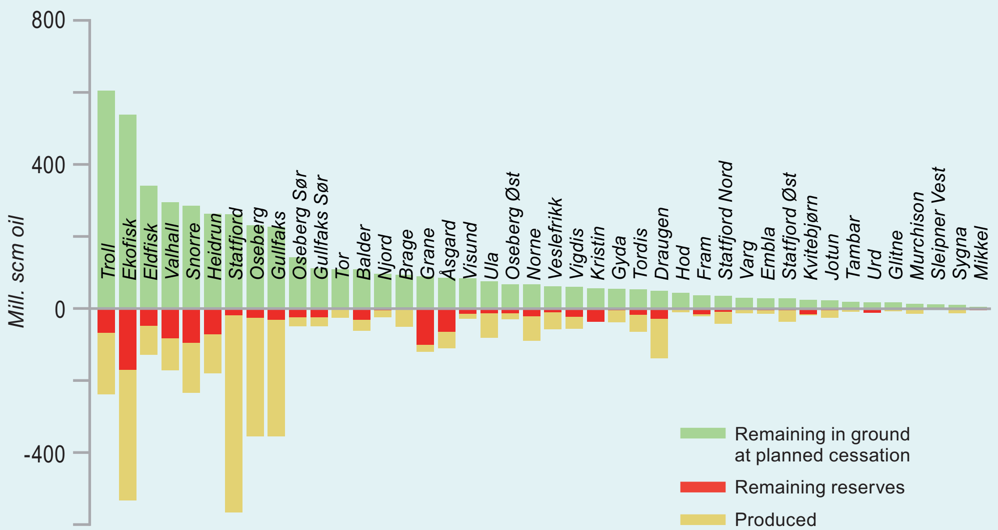
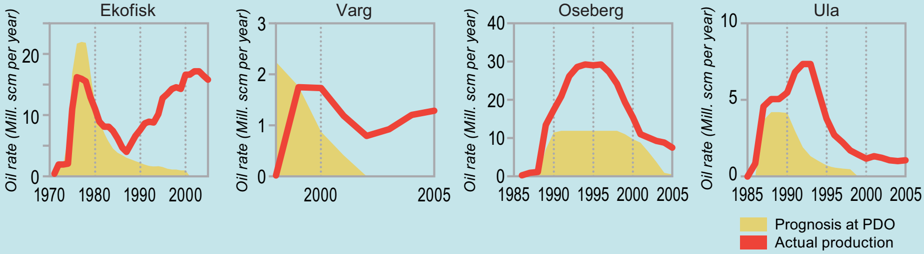


Figure 4.2 Distribution of resources - fields in production
(Source: Norwegian Petroleum Directorate)



Figur 4.3 Production trends for the Ekofisk, Varg, Oseberg and Ula fields

(Source: Norwegian Petroleum Directorate)

period 1981–2005. Since the objective for growth in reserves was launched less than one year ago, 155 million scm (approximately one billion barrels) oil has already been added. This equals nearly 20 percent of the target.

In 2006, the Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate will introduce a new, more structured monitoring of fields currently in operation. The background for this initiative is that the development towards a more mature shelf also brings about new challenges for the authorities. So far, much of the activity on the Norwegian continental shelf has been directed towards development of large, new fields. The considerable resource potential we see in fields in operation and in the area surrounding existing infrastructure means that there is a need to change the way the authorities follow up the activities in these fields. The goal is to ensure recovery of as much of the resources as possible. Based on data reported by the operators, the authorities conduct an annual analysis of development in mature areas. This analysis forms the basis for how the authorities will prioritise the follow-up of each field.

Further development of fields in operation

Parts of the Norwegian continental shelf are currently defined as mature areas. This term refers to areas that are characterised by familiar geology, well-developed infrastructure, falling production and increasing unit costs. There is still a considerable potential for value creation in these areas if we are able to increase the recovery rate in producing fields, streamline operations and explore for resources near existing infrastructure.

Figure 4.2 provides an overview of the total oil resources in producing fields. The resources can be divided into the following categories:

- Produced quantities
- Remaining reserves
- Resources that will be left in the ground after planned shutdown

The figure shows that, on the basis of present plans, significant oil resources will remain in the ground after the planned shutdown of these fields. A number of measures must be implemented if we are to produce these resources. The measures can be divided into two groups: increased recovery and efficient operations.

First and foremost, the licensees must invest in projects for improved recovery. Some examples are drilling more wells, measures to extract more from existing wells, injection into the reservoir to extract more petroleum and adaptations in processing facilities. There is significant and continuous activity underway in this area. In 2005, a number of decisions were made which will result in additional recovery of oil of nearly 155 million scm. This is equivalent to three new fields of the size of Brage, and amounts to more than the total Norwegian oil production in 2005. These types of measures contribute to increasing the average recovery rate. In 1995, the average recovery rate for oil in producing fields was approximately 40 percent - today it is 46 percent. Development and use of new technology has played a very important role in increasing recovery, and it still does. For example, new technology makes it possible to drill wells and develop fields in ways which were not technically feasible in the past.

Figure 4.3 shows production trends for the Ekofisk, Varg, Oseberg and Ula fields. The figure shows that actual production from these fields has proved to differ greatly from the estimates made when the original development plans were submitted. Based on the original plans, these fields should now have been closed down. Due to efficient operations and increased recovery these fields will, however, remain on stream for many years to come. At Ekofisk, the operator hopes to continue production until 2050.

These examples illustrate that considerable value can be created by increased recovery. Figure 4.3 also shows that increased recovery extends a field's lifetime. This is positive, because it makes it possible to implement further development measures, and implies that the infrastructure will remain in place for a longer period, thus increasing the possibility of tie-ins of other discoveries to existing infrastructure, as discussed in the following section.

Figure 4.4 shows that a field's expected lifespan changes over time. This is because throughout the production period, increased insight and knowledge is gained by the operator – which, in turn, provides the basis for implementing additional projects that were not profitable at the time of development. In addition the development and use of new technology have made it possible to implement projects that were formerly not profitable.

Increased recovery and extended lifetimes for fields provide greater value creation, however, in many cases they result in challenges as regards emissions to air and discharges to sea. Measures designed to improve recovery often require significant amounts of energy and may entail additional emissions to air. When oil production declines, this can also lead to more production of the water that occurs naturally in the reservoir. These challenges are addressed in more detail in Chapter 9.

Efficient operations help reduce production costs. Therefore, efficient operations will affect resource recovery because profitable production can be maintained longer than if the operations were less efficient. This can help ensure that resources that are not currently profitable will still be produced. Many fields are facing a situation where the cost level must be reduced in order to justify profitable operations at a lower production level.

Developments in communications technology have given rise to new working methods. This is referred to as integrated operations, eOperations or smart operations. Integrated operations entail that information technology is used to alter work processes to achieve better decisions, to remote-control equipment and processes, and to move functions and personnel onshore. Technology and

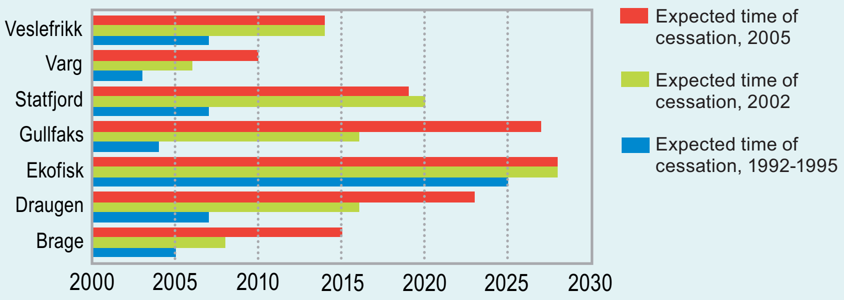


Figure 4.4 Lifetimes for selected fields
(Source: Norwegian Petroleum Directorate)

knowledge are linked in such a manner that it will change the way tasks are assigned between offshore and land, oil companies and supplier firms. Therefore, reduced costs and integrated operations are elements that help streamline operations, and thus increase recovery. See the text box on integrated operations for more information.

Tie-in of discoveries, exploration for and development of new resources

By year-end 2005, nearly NOK 1 900 billion in current monetary value has been invested on the Norwegian continental shelf. This is equivalent to more than NOK 1 billion each week over the whole period. These investments have made it possible to establish extensive infrastructure which is a condition for production and marketing of petroleum, but it also forms a basis for the development of additional resources in a cost-efficient manner.

As production from a field declines, spare capacity will often be available in the existing infrastructure. Such capacity may provide for an effective exploitation of resources that can be tied in to existing infrastructure. In some cases, the use of existing infrastructure will be a prerequisite for profitable development of new fields, because some of these deposits are too small to justify their own separate infrastructure. Exploration for and development of resources near existing infrastructure can result in significant value for the Norwegian society.

Estimates from the Norwegian Petroleum Directorate indicate that approximately two thirds of the undiscovered resources on the Norwegian continental shelf are likely to be located in the North Sea and the Norwegian Sea. These are the areas on the Norwegian continental shelf that currently have an extensive infrastructure. In order to map the prospects in these areas, and to be able to take advantage of the opportunities offered by the existing infrastructure, the authorities have established a proactive exploration policy for mature areas. Large areas are made available to oil companies in a predictable manner, while stringent requirements are set for those companies that are awarded exploration acreage. In extension of this policy, and on the basis of the fact that a number of fields are approaching decommissioning, it is important that the existing infrastructure is utilised efficiently, either by the owners themselves or by third-party users.

Large parts of the oil and gas sector on the Norwegian continental shelf have entered a more mature phase. Of a total of eleven approved development plans (PDOs) in 2005, eight are satellite developments. In order to contribute to efficient use of existing infrastructure, such as existing platforms and pipelines, the Ministry of Petroleum and Energy issued new regulations on this topic, Regulations relating to use of facilities by others, which came into effect on 1 January 2006. The purpose of these regulations is to ensure efficient use of the infrastructure, and thus give the licensees sufficient incentives to carry out exploration and production activities. This objective shall be achieved by stipulating a framework for the negotiation process and for the establishment of tariffs and other conditions in agreements on third-party use of facilities. The regulations do not entail any change in the principle whereby it is the commercial players that are responsible for negotiating solutions acceptable to both parties.

In order to ensure that the potential in and in the surroundings of producing fields is maximised, it is important that the participating interests are vested with the companies which want to make the most of them. This is why the authorities take a positive view on transfers of participating interests. In addition, the authorities have opened up for a broader range of players; reference made to the discussion of new players in Chapter 3. Other countries in which the petroleum sector has reached a mature phase have experienced that established companies do not always prioritise activities in fields where production has fallen to a low level. They would rather sell, to the benefit of companies for which such activity is a core business area. With this in mind, the Norwegian authorities believe that a diversity of players, making different assessments and priorities, constitutes a positive contribution towards realising the resource potential on the Norwegian continental shelf.

Increased recovery, increased lifetime and tie-in of resources in the vicinity of producing fields form the basis for creating substantial additional values for the society at large. However, increased recovery and longer lifetime are only relevant if this can be accomplished within prudent frameworks for the external environment, health, working environment and safety. In order to develop the resources in and around existing fields, the infrastructure already in place must oftentimes be utilised. This implies less freedom for companies compared to what is the case in new developments. For example, the selection of technical solutions must take into account the limitations associated with the equipment that is already in place, weight restrictions, etc.

In the medium term it is important to ensure that the decline in Norway's oil and gas production is minimised and that the fields' lifetimes are extended. On the basis of existing plans, we know that large volumes of oil and gas will be left behind when the fields are abandoned. Today it is not profitable to recover these resources, but they represent a considerable potential that might be unlocked in the future. Realising this potential will require work on many fronts to explore all alternatives that can help in achieving this goal.

Integrated operations on the Norwegian continental shelf

Introduction of integrated operations in the petroleum sector implied using (near) real-time data to integrate the work between organisations and technical disciplines, thus achieving more efficient and better management in all phases of the activities. With today's technology, fields will be connected to land using broadband, which will allow personnel on shore to have access to the information at the same time as the personnel on the facilities.

When field data is available in real-time for relevant professionals, the organisation on land can provide more efficient support, monitoring and guidance. This can increase safety and improve access to expertise, thus increasing efficiency. There are major financial gains associated with introducing integrated operations. Petoro has estimated the potential at NOK 150 billion, based on a two percent increase in production and a 20 percent reduction in operating costs. Others have arrived at similar figures.

Today, the petroleum sector in Norway has made great advances in the implementation of integrated operations, in an international context. One of the reasons for this is that fibre cables have been laid to many of the fields on the Norwegian continental shelf, thus providing a basis for integrated operations. Many facilities already have access to broadband communication, which is a precondition for transmitting large volumes of data. Maximum benefits from the digital infrastructure depends on predictable solutions that provide third-party access, cost sharing and adequate information security. In order to exploit all of the possibilities and realise the potential inherent in integrated operations, changes will have to be made in the way we work and in the division of tasks between offshore and onshore, and between operator and supplier. This could create new organisation structures and link people and organisations together, regardless of their physical location. With so many possibilities for interaction between organisations, standardisation is vital. For more mature fields, the challenge lies in adapting the level of ambition and timing. This way, the solutions can become cost-effective and contribute to development of new resources, thus extending field lifetime.

The greatest progress has been made in deploying the new forms of operation within drilling. Here companies have started to integrate data in real-time between the operations room on land and the facilities. Information and necessary data are now available to everyone at the same time, thus providing better and faster operational support for the personnel offshore and making it easier to place wells at optimal locations in the reservoirs. The major operators have already documented significant financial gains associated with this form of operation. Less progress has been made within operations and maintenance, but some companies have put this kind of technology and work processes to use in production management. Both operators and suppliers establish operations centres on land that are linked to the operations room on the facilities. A connection can also be established to the operations room from other locations around the world, thus ensuring improved exploitation of special expertise.

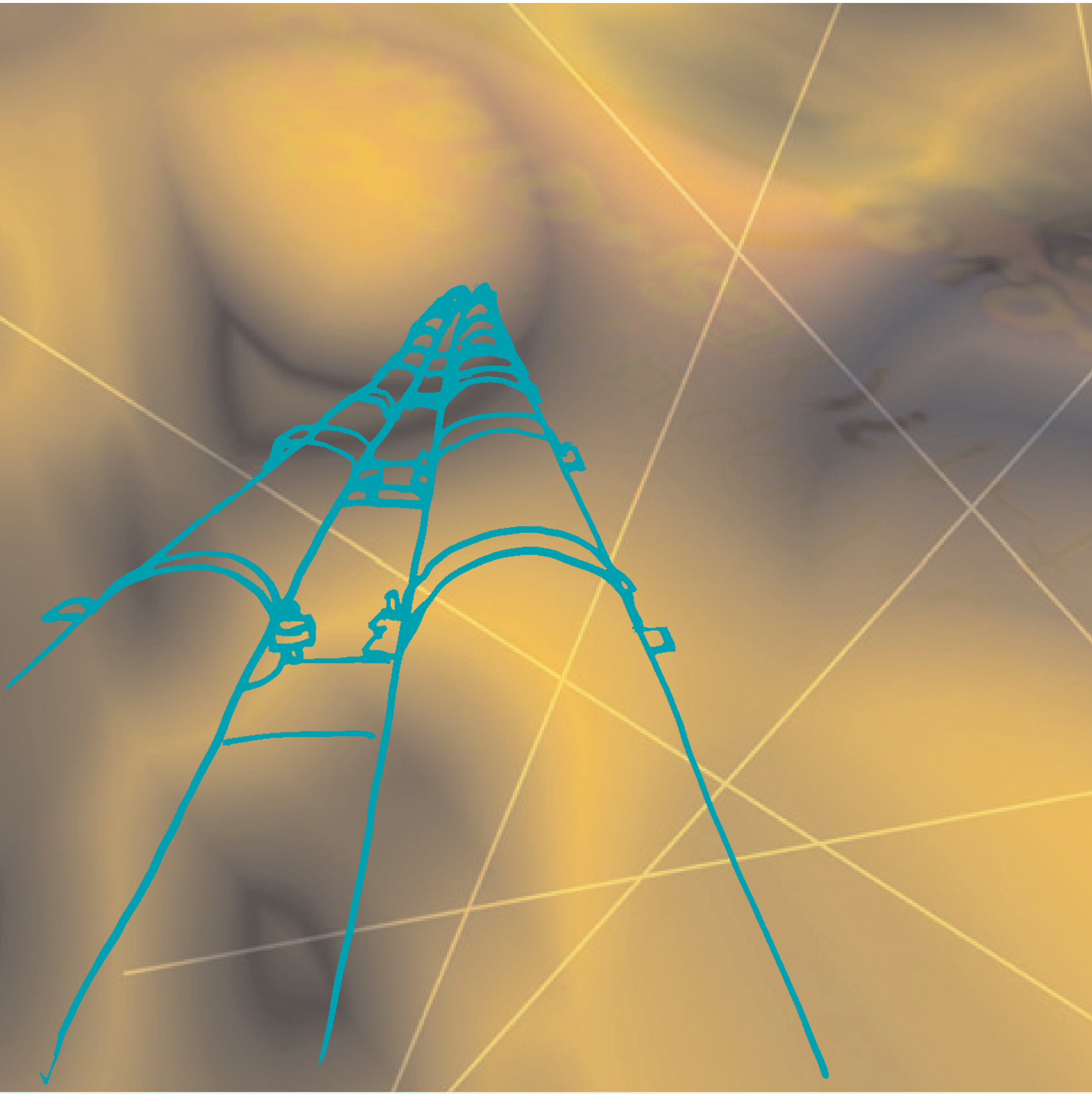
Further development

Integrated operations have already been an important element in many new developments. For example, the developments of Snøhvit and Ormen Lange include many elements of integrated operations. Where profitable, existing fields are linked to the digital infrastructure to facilitate use of the new technology.

Suppliers, oil companies and research institutions carry out research and development within these fields. Some technical solutions exist, but more research and development is needed in order to convert data into useful information and knowledge, develop advanced sensors that are reliable over time, and to develop better data transmission from the wells. Organisational solutions must also be identified to achieve the necessary integration throughout all technical disciplines, and in relation to the geographical locations of various suppliers and oil companies.

Figure 4.5 Optical fiber cables on the Norwegian continental shelf
(Source: Norwegian Petroleum Directorate)

5 Norwegian gas exports



Gas activities comprise an increasing part of the petroleum sector, and thus bring considerable revenues to the state. Norwegian gas is also important for supply of energy in Europe, and is exported to all of the major consumer countries in Western Europe. In terms of energy content, gas exports in 2005 were more than seven times larger than normal Norwegian production of electricity. Norwegian gas exports meet approximately 15 percent of the European gas consumption.[1] Most Norwegian exports go to Germany and France, where Norwegian gas supplies around 30 percent of the total consumption. When the Ormen Lange field comes on stream, Norwegian gas will have a market share of approximately 15-20 percent in the United Kingdom. Producers on the Norwegian continental shelf have entered into sales agreements with buyers in Germany, France, the UK, Belgium, the Netherlands, Italy, Spain, the Czech Republic, Austria, Poland, Denmark and Switzerland. When Snøhvit LNG commences operation in 2007, Norway will also supply gas to the USA.

Current capacity in the Norwegian pipeline system is 100 billion standard cubic metres (scm), which will increase to 120 billion scm when the Langeled pipeline has been completed. There are four receiving terminals for Norwegian gas on the Continent: two in Germany, one in Belgium and one in France. There will be two terminals in the United Kingdom when the southern part of the Langeled pipeline is completed in 2006 (see figure 5.1). The Norwegian gas transport system is extensive, totalling more than 6 600 kilometres of pipelines, or equivalent to the distance between Oslo and Chicago. Treaties have been developed to govern rights and obligations between Norway and the countries that have landing sites for gas.

1 OECD Europe

Achieving the highest possible value for Norwegian petroleum resources is a paramount goal. Most of the fields on the Norwegian continental shelf contain both oil and gas, so that attempts must be made to achieve the optimum balance between oil and gas production. At the same time, the gas management system must facilitate efficiency in all stages of the gas chain – exploration, development and transport.

All licensees on the Norwegian continental shelf are responsible for selling their own gas. Statoil sells the state's oil and gas, together with its own petroleum, in accordance with the instruction concerning marketing and sale of oil and gas.

One special feature of gas production is that it requires major investment in transport. Norwegian gas is mainly transported from the field to the consumer in pipelines. The authorities place great emphasis on evaluating a number of transport alternatives, so that the selected solution is as robust as possible. Costs involved in constructing pipelines are considerable, and there are significant economies of scale involved in investment in the transport system. In many cases, it may be appropriate to build the pipelines somewhat larger than initially needed, so that any new gas discoveries can be transported through the existing pipeline system.

Sector organisation

The general policy instruments employed in gas resource management are exploration policy, conditions for approval of development plans and production licences for oil and gas (see Chapters 3 and 4). Many fields on the Norwegian continental shelf contain both gas and oil. When awarding gas production licences, the authorities take into account optimum recovery of oil. On occasion, the authorities have awarded

Figure 5.1 Gas pipelines

(Source: Norwegian Petroleum Directorate)

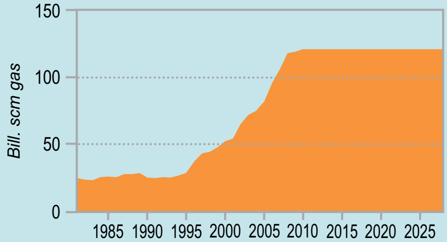


Figure 5.2 Historic and expected Norwegian gas exports

(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)

licences for production of less gas than applied for by the companies, out of consideration for the need to produce oil.

The authorities play an important part in establishing transport capacity and increasing system capacity. The authorities are responsible for studying alternative transport methods, in order to ensure that the system develops efficiently. At the same time, it is important to ensure efficient operation, including achieving economies of scale. The Ministry of Petroleum and Energy employs a number of instruments to achieve this. Three central instruments in the Norwegian gas transport system are: the operator Gassco AS, the coordinated ownership Gassled and regulated conditions for access to the transport system. Use of these instruments is assessed in connection with development of new infrastructure and when the use of the existing infrastructure is changed. Operatorship, ownership and questions reagarding regulated access can be employed independently.

Gassco

Gassco AS is the operating company for Gassled, which comprises most of the transport system on the Norwegian continental shelf. Gassco was established in 2001, and is wholly owned by the Norwegian state. Gassco is responsible for operations (planning, monitoring, coordination and administration of transport from the fields to the receiving terminals), allocation of capacity and development of the transport system.

Gassco shall contribute to holistic further development of the Norwegian gas infrastructure. In cases where major developments are considered, this means that Norwegian gas in addition to those fields that trigger transport needs must also be taken into consideration. Further development of the gas infrastructure must also take place in a manner that is expedient for the existing gas infrastructure on the Norwegian continental shelf.

A neutral company ensures that consideration is given to the submitted development alternatives for infrastructure, as well as exploitation of economics of scale. Gassco's task is to coordinate the processes for further development of the upstream network of gas pipelines, and to assess the need for such further development. Gassco recommends solutions, but does not itself invest in infrastructure.

A neutral and independent operator of the gas transport system is important to ensure that all users of the system are treated equally, both in regard to making use of the system and to the consideration of capacity increases. This is necessary to ensure efficient exploitation of the resources on the Norwegian continental shelf. Efficient exploitation of the existing gas transport system may also contribute to the reduction, or postponement, of the need for new investments.

Gassled

The transport system for Norwegian gas, i.e. the pipelines and terminals, is mainly owned by the Gassled partnership. Gassled encompasses all rich and dry gas facilities that are currently in use or are planned to be used to any significant degree, by parties other than the owners (third party use). New pipelines and transport-related facilities are intended to be included in Gassled from the time they are put to use by third parties, and are thus part of the central upstream gas transport system.

Common ownership of the transport system ensures that the gas is transported as efficiently as possible. The greatest value is created when conflicts of interest about which pipeline should be used to transport the gas can be avoided.

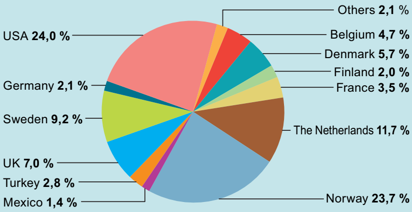


Figure 5.3 Sale of NGL/condensate 2005 by country of first destination
Total 22,7 mill. scm oe
(Source: Norwegian Petroleum Directorate)

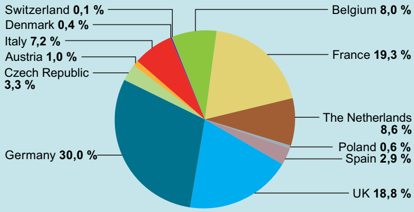


Figure 5.4 Norwegian natural gas exports 2005
Total 82,5 bill. scm
(Source: Norwegian Petroleum Directorate)

Regulated access to the transport system

The pipeline system is a natural monopoly, requiring enormous initial investments. This is why gas transport tariffs are governed by special regulations issued by the Ministry of Petroleum and Energy. This ensures that the economic returns are earned from producing fields and not from the transportation system. The oil companies' access to capacity in the system is based on their needs for gas transport. In order to secure good resource management, transport rights can be transferred between users when needs change. Gassco is responsible for allocating capacity.

Gassled – overall ownership structure for gas transport

The ownership split in Gassled:

Petoro AS*	38.63%
Statoil ASA	20.56%
Norsk Hydro Produksjon AS	11.19%
Total E&P Norge AS	8.67%
ExxonMobil Exploration and Production Norway AS	5.18%
Norske Shell Pipelines AS	4.44%
Mobil Development Norway AS	4.58%
Norsea Gas AS	3.05%
Norske ConocoPhillips AS	2.03%
Eni Norge AS	1.69%

* Petoro AS is the licensee for the state's participating interest (State's Direct Financial Interest - SDFI)

Petoro's share in Gassled will be increased by approximately 9.5 percent with effect from 1 January 2011, and the other licensees' shares will be reduced correspondingly at the same date. The SDFI share in Norsea Gas AS is 40.0 percent. When this is taken into account, the state, represented by SDFI, will have a share in Gassled of 39.5 percent in 2003-2010 and 49 percent from 2011. The licence period for relevant Gassled facilities will run until 31 December 2028.

The coordinated ownership structure for the most significant parts of the gas infrastructure has laid the foundation for a uniform access regime and will ease administration and daily operation of gas transport in the future. The ownership structure may be adjusted when new facilities and pipelines are incorporated into Gassled.

6 Decommissioning

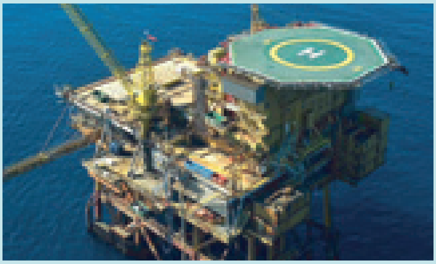


Figure 6.1 Drilling and production installation DP2, to be removed from the Frigg field *(Source: Total E&P Norge AS)*

Petroleum activities only borrow the sea, and all phases of oil and gas activities must respect the environment and other marine users. The main rule is that, when petroleum activity ceases, everything must be cleared and removed.

To date, the Ministry of Petroleum and Energy has approved more than 10 decommissioning plans. In most cases it has been decided that abandoned facilities are to be removed and taken ashore, e.g. Odin, Nordøst Frigg, Øst Frigg, Lille-Frigg, Frøy and TOGI. Following consideration of the decommissioning plans for Ekofisk I and Frigg, permission was given to leave in place the concrete substructure and protective wall on the Ekofisk Tank, as well as the concrete substructure TCP2 at the Frigg field. The work to remove the installations on the Frigg field and parts of Ekofisk commenced in 2005. The decommissioning plans for MCP- 01 and H7 are currently being considered by the Ministry.

The regulations

Both national and international regulations apply to the disposal of an installation on the Norwegian continental shelf.

Disposal or decommissioning of facilities is regulated by the Petroleum Act. In addition to this Act, Norway's obligations under the OSPAR Convention (Convention for the Protection of the Marine Environment of the North-East Atlantic) also apply. OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations, which came into force on 9 February 1999, lays down guidelines for the various disposal alternatives that are acceptable for various types of marine installations. This decision does not cover pipelines, parts of an installation that are under the seabed and concrete anchor foundations that do not present an obstacle to fisheries.

The decision means that it is prohibited to dump, or leave in place, wholly or partially disused offshore installations in the marine environment. Derogation from the prohibition may be granted for individual installations, or parts of installations, if an overall assessment of the case in question shows that there are weighty reasons for disposal at sea.

If derogation from the OSPAR decision concerning disposal on land is applied for, a consultative process must be carried out in the OSPAR system. The appropriate authorities in the individual countries make the final decision and grant permission for exemption, if applicable. There are a number of conditions that must be met if permission is to be granted. Up until today, Norway has granted two exemptions to the OSPAR decision concerning disposal on land. As mentioned, permission has been granted to leave in place the Ekofisk Tank and its protective wall, as well as the concrete substructure TCP2 at the Frigg field.

The guidelines laid down in White Paper No. 47 (1999–2000) "Decommissioning of redundant pipelines and cables" to the Storting apply to pipelines and cables. As a general rule, pipelines and cables may be left in place when they do not obstruct or present a safety risk for bottom fishing, with costs of burial, covering or removal taken into consideration.

Decommissioning plans

A principal provision of the legislation requires licensees to submit a decommissioning plan to the Ministry of Petroleum and Energy two to five years prior to expiration or relinquishment of a production licence, or the use of a facility is terminated permanently.

The decommissioning plan must consist of two main parts, a disposal plan and an impact assessment. The impact assessment provides an overview of the expected consequences of the disposal, such as environmental consequences. The disposal plan is assessed by the Ministry of Petroleum and Energy and the Ministry of Labour and Social Inclusion (safety aspects). The Ministry of Petroleum and Energy coordinates the public hearing of the impact assessment.

The Ministry of Petroleum and Energy prepares a draft Royal Decree, which is submitted to the government, based on the impact assessment and feedback from the public hearing, as well as on the disposal plan and its assessment. Applications for derogation from the OSPAR decision concerning disposal on land must be presented to the Storting.

Liability

If a decision entails abandonment, the legislation states that the licensees are liable for any damage or hindrance that may arise from the installation remaining in place, whether deliberate or negligent. However, the licensees and the state may agree that future maintenance and liability can be transferred to the state, in return for an agreed financial compensation.

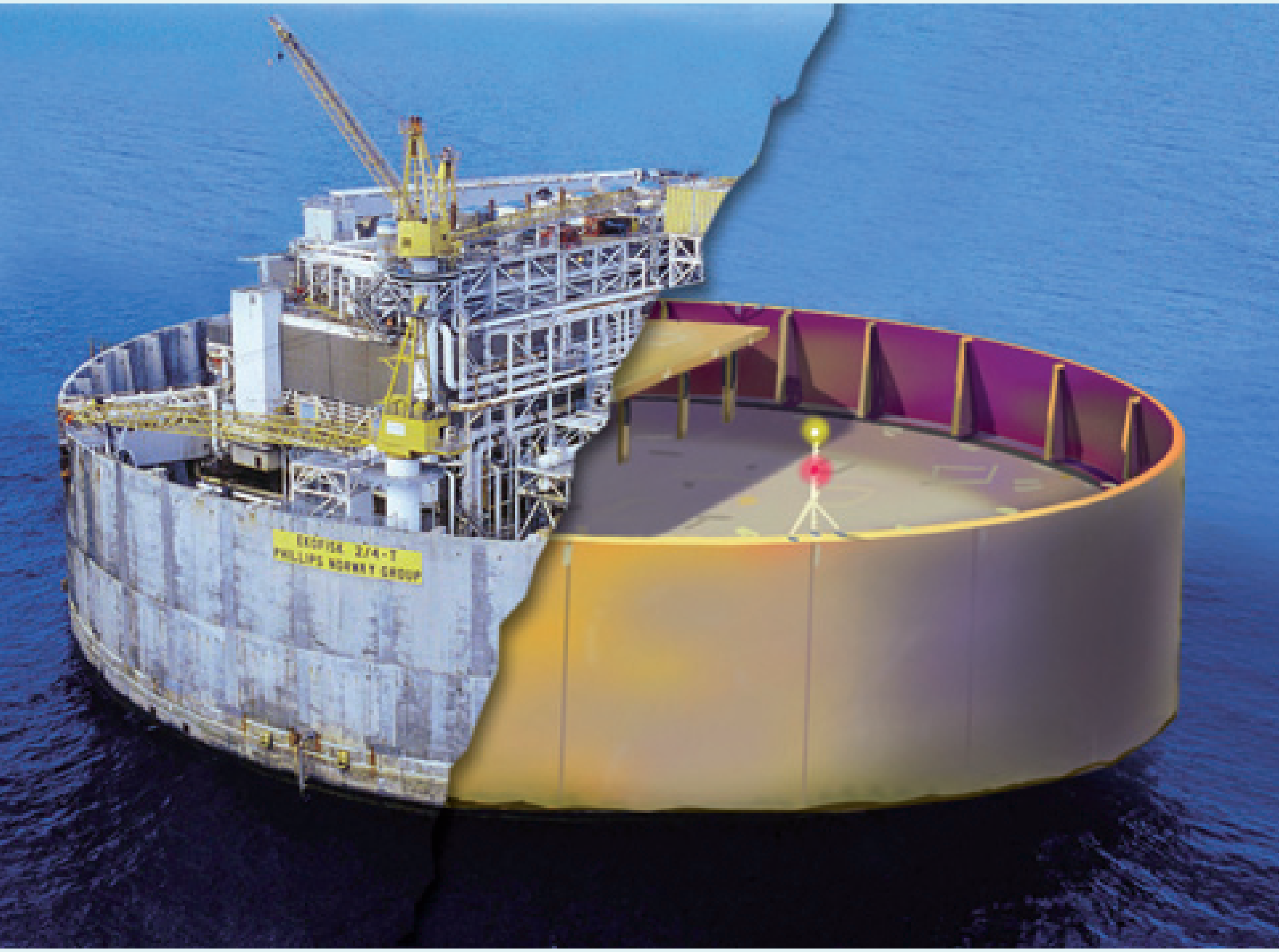


Figure 6.2 Illustration of the Ekofisk Tank before and after removal of the topsides

(Source: ConocoPhillips)

7 Research, technology and industrial development

Norwegian petroleum industry

Building Norwegian petroleum expertise has been an important part of Norwegian petroleum policy. Today, Norway has a highly developed and internationally competitive petroleum industry. This applies both to oil companies, the supply and service industry and research institutions. The petroleum sector provides valuable input to other sectors of Norwegian industry.

The supply industry in Norway is active in most steps of the value chain, from exploration and development to production and decommission. In areas such as seismic survey, drilling equipment, subsea facilities and floating production solutions, Norwegian companies are among the leading in the world. These companies are located in every county in Norway and the local and regional effects of the petroleum activities are eviden. In 2005, approximately 80,000 people were employed in the petroleum sector in Norway.

Investments by oil companies in development, operation and maintenance on the Norwegian continental shelf generate a considerable demand for products and services from the supply industry in Norway and abroad. Oil companies' international activities give the Norwegian supply and service industry new opportunities. International experience and participation in international development projects are extremely important for the further development of the supply and service industry. This international experience could also help reduce the cost level on the Norwegian continental shelf.

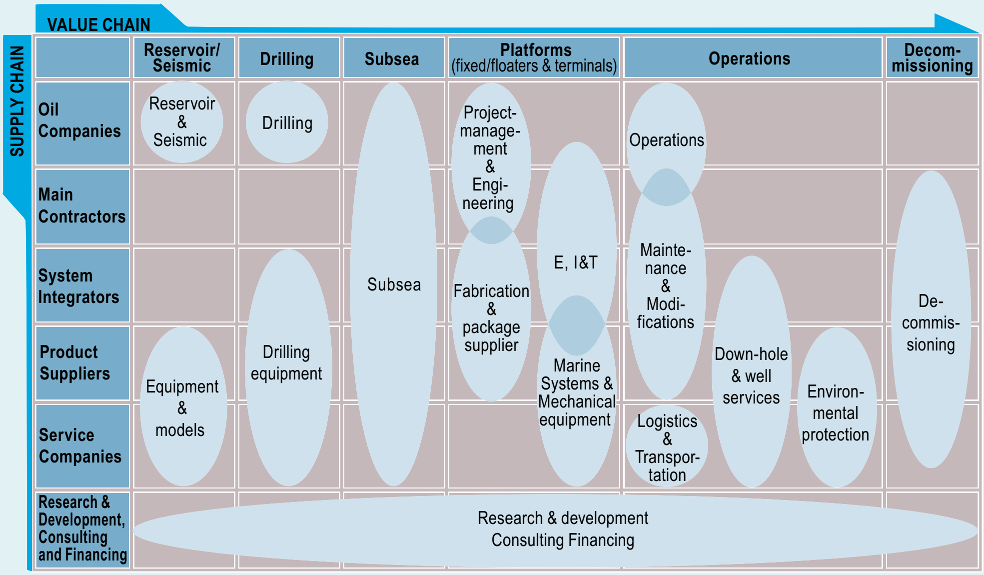


Figure 7.1 Interactive map of the Norwegian Oil & Gas "World-Class" Clusters

(Source: www.Intsok.com)

Industry and industrial cooperation linked to the petroleum industry

There are a number of arenas and meeting places which promote coordination in the petroleum industry and improve the players' wider understanding of the range of challenges that the industry faces today – be they organisational, technological or commercial. The Ministry of Petroleum and Energy considers it important to support and participate actively in these arenas.

INTSOK

In order to promote the internationalisation of Norwegian petroleum-related industry, the authorities established INTSOK – Norwegian Oil and Gas Partners – in 1997, in partnership with the Norwegian petroleum industry. INTSOK is regarded by the Norwegian authorities as an important partner. About 160 companies are members of the foundation. INTSOK aims to promote the Norwegian petroleum industry internationally. The goal is for Norwegian petroleum-related companies to increase their annual sales abroad to approximately 80 billion within 2010.

Petrad

As part of its international activities, the Ministry of Petroleum and Energy also supports Petrad. Petrad is a non-profit Norwegian government foundation established in 1989 to facilitate knowledge and experience transfer about petroleum management, administration and technology between managers and experts in governments and national oil companies.

Oil for development

The Ministry of Petroleum and Energy cooperates with the Ministry of Foreign Affairs, the Ministry of Finance and the Ministry of the Environment on a joint commitment to assist developing countries in management of petroleum resources. This effort entails financial support through an additional allocation of NOK 50 million per year, starting in 2006. This program includes:

- Reinforcing Norwegian bilateral assistance to countries requesting Norwegian petroleum expertise
- Emphasis on sound governance in petroleum management

Oil for development is a broad-based program, encompassing issues such as resource and revenue management, environmental and industrial development. Norwegian experts on technical disciplines and petroleum resource management will be involved in this work, including the Norwegian Petroleum Directorate, Petrad and INTSOK. Norad is responsible for coordinating these efforts.

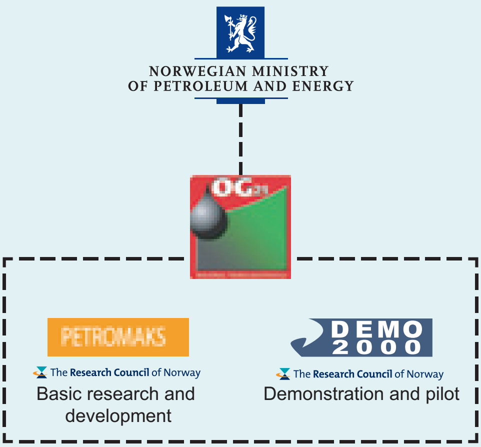


Figure 7.2 Ministry of Petroleum and Energy's involvement in petroleum research
(Source: Ministry of Petroleum and Energy)

Research and technological development in the oil and gas sector

Development of new technology and increased expertise in the oil and gas industry are important to ensure that the sector will continue to contribute to economic growth and general welfare in Norway. Several of the solutions currently used by the oil and gas industry are the result of significant investments in research and technology development in the 1970s, 1980s and 1990s. In the years to come, however, value creation on the Norwegian continental shelf will be more technologically demanding and knowledge-intensive than is the case today. For this reason, continuing efforts in research and technology development are important to ensure a competitive Norwegian oil and gas industry. Figure 7.2 illustrates the organisation of petroleum research in Norway.

In order to meet the challenges associated with efficient and prudent petroleum activities, OG21 – Oil and Gas in the 21st century - was established on the initiative of the Ministry of Petroleum and Energy in 2001. The objective was to unite the oil and gas industry in a common national technology strategy. Today, OG21 is organised in a board, whose composition is determined by the Ministry of Petroleum and Energy, and a secretariat. The link to the petroleum industry is through the OG21 Forum. The OG21 Forum is a meeting place where all parties with interest in petroleum research can participate in the OG21 strategy process.

OG21 has managed to get oil companies, universities, research institutes, the supplier industry and the authorities to join forces and support a common national technology strategy for oil and gas. In the International Energy Agency's evaluation of Norwegian energy policy in 2005, the OG21 collaboration was recognised as being unique in a global perspective.

The goal of OG21 is to:

- Increase the value creation on the Norwegian continental shelf
- Increase the export of Norwegian technology

OG21's strategy work has identified eight core areas for research and technology development:

1 Environmeltal technology for the future
2 Exploration and reservoir characterisation
3 Enhanced recovery
4 Cost effective drilling and intervention
5 Integrated operations and real time reservoir management
6 Subsea processing and transport
7 Deep water and subsea production technology
8 Gas technologies

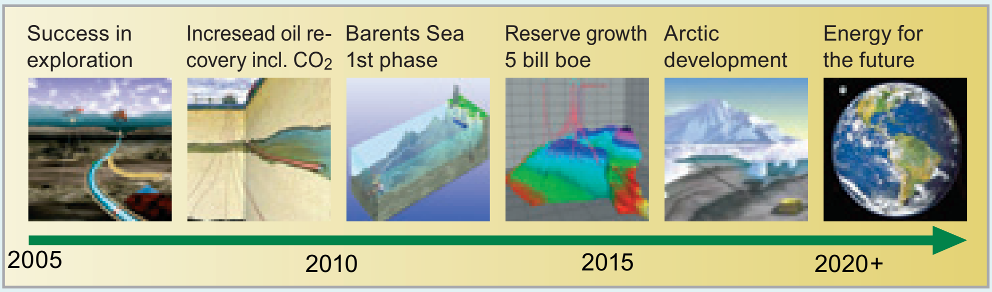


Figure 7.3 OG21's technology road map for value creation on the Norwegian continental shelf
(Source: OG21)

OG21's strategy work has laid the foundation for a road map for necessary research and technology development in the Norwegian oil and gas activities. Figure 7.3 depicts this road map.

An important objective for OG21 is to increase state funding of research and development in the petroleum-related area to NOK 600 million per year. OG21 believes that such a public research effort would be commensurate with the main technological challenges in the sector.

The authorities' contribution to petroleum research is largely organised in the PETROMAKS and DEMO 2000 research programs. These programs are intended to contribute to attaining the goals set in the national technology strategy for the petroleum industry, OG21. The funds from the authorities are channelled through the Research Council of Norway, which coordinates the programs.

PETROMAKS

PETROMAKS encompasses both strategic fundamental research and development of expertise, research use, technological development and research as a basis for formulation of the policy. The program's target groups are Norwegian companies and groups that wish to promote the build-up of knowledge and expertise in Norway, productivity, innovation and exports in the petroleum sector.

The objective of PETROMAKS is to contribute to better exploitation of fields in production and increased access to new reserves. The activities in the program are largely aimed at discovering more oil and gas, improving recovery from existing fields, streamlining transport of wellstreams over large distances and efficient transport of gas to the markets. The program also seeks to prepare a basis for development in HSE and the external environment, reducing the cost level on the Norwegian continental shelf and strengthening petroleum-related industrial development, in Norway.

The social science research program Petropol was incorporated into PETROMAKS in 2004. Establishment of a new social science program targeting the challenges faced by the authorities and the petroleum industry will be considered in 2006.

DEMO 2000

An important initiative for the promotion of new technological solutions within the petroleum industry is the DEMO 2000 partnership. This program targets projects where new technology can be demonstrated through pilot projects and field tests, and relates particularly to challenges associated with getting research-based innovations in the Norwegian petroleum sector out into the market. The pilot projects entail close cooperation with supplier firms, research institutions and oil companies; a collaboration which, in itself, helps to develop a progressive, market-oriented expertise network.

In total, the state has contributed with more than NOK 340 million to DEMO 2000 projects in the period 1999-2005. These efforts have triggered a total commitment, together with the industry, of NOK 1.5 billion.

These are DEMO 2000's main goals:

- New field developments on the Norwegian continental shelf through new and cost-effective technologies and new implementation models
- New Norwegian industrial products for sale in a global marketplace

The DEMO 2000 program has supported demonstration of new petroleum technology since 1999. Some of the technologies developed through the program are already available on a commercial basis, and have resulted in significant cost savings for the industry. DEMO 2000 believes that their ambition is a realistic one - to ensure that a greater number of new solutions can be put to commercial use within the coming years, both in Norway and abroad, including in technical disciplines such as seabed processing, gas compression on the seabed, efficient drilling and integrated operations (remote control). The value created by innovations within these areas could become enormous.

PROOF

Budget funds from the Ministry of Petroleum and Energy are also allocated to important R&D activities relating to the environment. The research program PROOF examines the long-term effects of discharges to sea from the petroleum activities, and constitutes a part of the larger program, "The Sea and the Coast", planned for the period 2006–2015.

Other strategic research

The fundamental research within the framework of priorities for petroleum-related subjects aims to establish R&D expertise of high international quality in the university and institute sector. For research institutions, the strategic institute program (SIP) is part of the basic allocation, as defined by the Ministry of Education and Research.

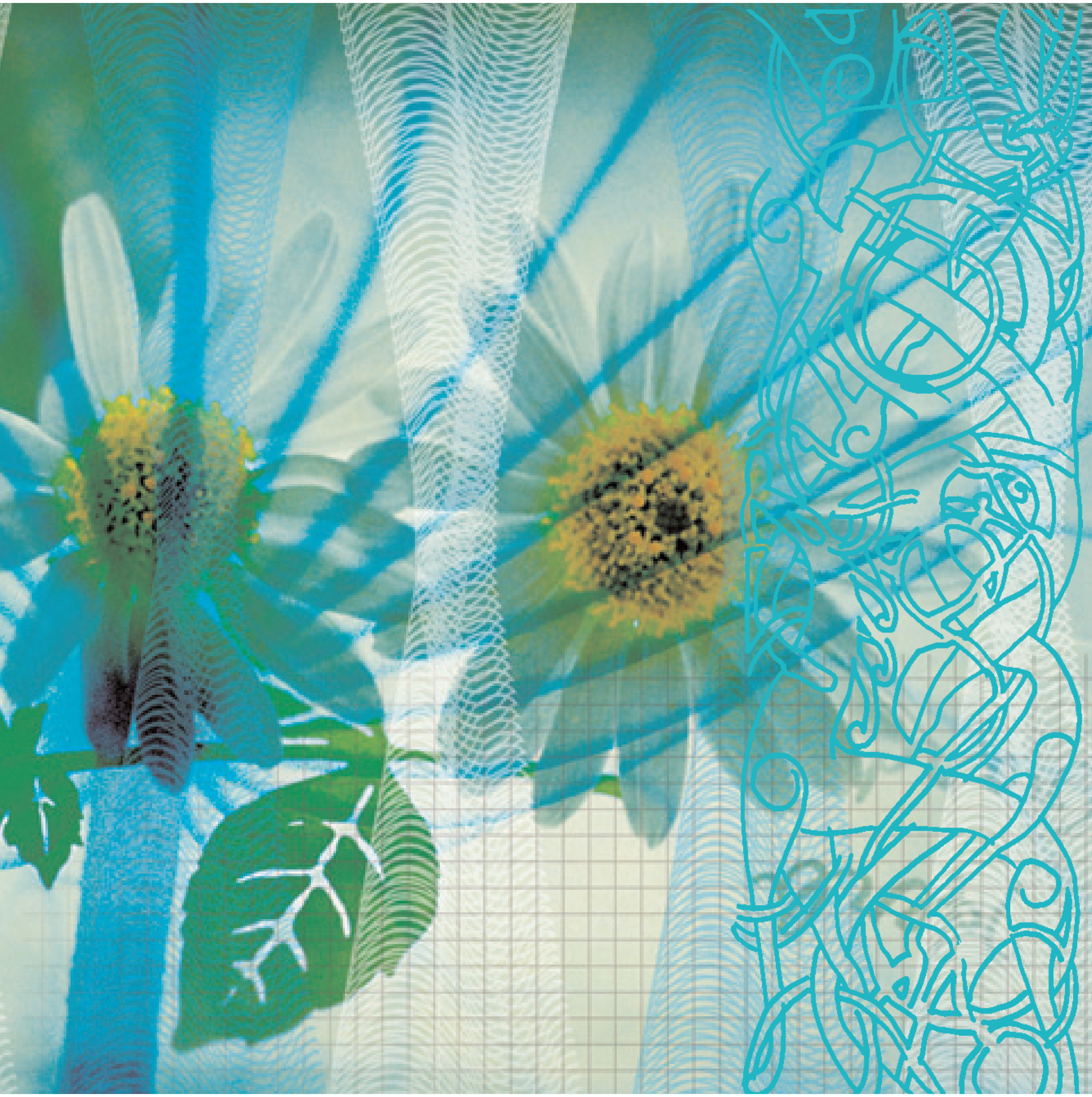
CLIMIT

CLIMIT is a cooperative program between Gassnova and the Research Council of Norway, and relates to research, development and demonstration of technology associated with gas-fired power production with carbon capture and storage. This relates to knowledge and solutions for:

- CO_2 capture before, during and after power production
- Compression of CO_2
- Transport of CO_2
- Long-term storage of CO_2, disposal or alternative uses

The CLIMIT program encompasses all phases of development and commercialisation of new solutions. The CLIMIT-program administers approximately 145 MNOK for support activities in 2006.

8 Government petroleum revenues



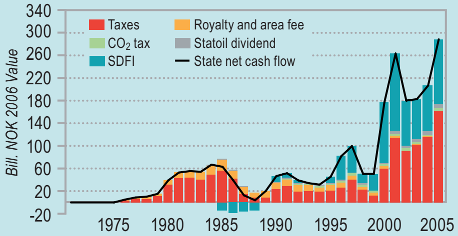


Figure 8.1 The net government cash flow from petroleum activities
(Source: Norwegian Public Accounts and National Budget)

Direct taxes:	159,3
Royalty, CO_2-tax Area fee:	4,4
SDFI:	111,2
Statoil dividend:	8,1
Total:	**283,0**

Figure 8.2 The net government cash flow from petroleum activities 2005
(Source: National Budget)

The government earns high revenues from the petroleum sector. In 2005, the sector generated 33 percent of government revenues. Figure 8.1 shows income from the sector, which has been high in recent years, and 2005 was a year with very high payments to the state, see figure 8.2. The value of the remaining petroleum reserves on the Norwegian continental shelf was estimated at NOK 4 210 billion in the National Budget for 2006.

The government receives a large share of the value created through:

- Taxation of oil and gas activities
- Charges/Fees
- Direct ownership in fields on the Norwegian continental shelf (through the State's Direct Financial Interest, SDFI)
- Dividends from ownership in Statoil

Why does Norway have a special system for government take when it comes to petroleum revenues? The main rationale for the system is the extraordinary returns associated with production of the resources. The fiscal system must be understood in connection with the common ownership of the resources on the Norwegian continental shelf, and that the oil companies are allowed to exploit a valuable, limited resource.

The petroleum tax system

Petroleum taxation is based on the Norwegian rules for ordinary corporation tax. Due to the extraordinary profitability associated with production of the Norwegian petroleum resources, a special tax is also levied on income from these activities. The ordinary tax rate is the same as for land activities, 28 percent, while the special tax rate is 50 percent. When calculating taxable income for both ordinary and special taxes, an investment is subject to depreciation on a linear basis over six years from the date it was made. Companies may deduct all relevant expenses, including exploration, research and development, net financial, operating and decommissioning expenses (see figure 8.3). Consolidation between fields is permitted. In order to shield a normal return on investment from the special tax, an extra deduction, the uplift, is allowed in the calculation base for special tax. This amounts to 30 percent of the investments (7.5 percent per annum for four years from the year the investment is made).

Companies that are not in tax position may carry forward their losses and the uplift with interest. An application may also be made for refund of the fiscal value of exploration costs in the companies' tax returns.

The petroleum tax system has been designed for neutrality, so that an investment project that is profitable for an investor before tax, will also be profitable after tax. It is, therefore, possible to harmonise the requirement for significant revenues to the society with the requirement for sufficient post-tax profitability for the companies.

Other taxes

The most important other taxes linked to petroleum activities are the carbon dioxide tax and the area fee.

The CO_2 tax was introduced in 1991 and is an instrument for reducing CO_2 emissions from the petroleum sector. CO_2 tax is levied at a rate per standard cubic metre (scm) of gas burned or directly released and per litre of petroleum burned. The rate for 2006 is NOK 0.79 per litre of petroleum or scm of gas.

The area fee accrues on all production licences after the expiry of an initial period. The fee is intended to encourage relinquisment of acreage that companies do not wish to exploit. Special rules apply for the oldest licences and licences in the Barents Sea.

Operating income (norm price)
- Operating expenses
- Linear depreciation for investments (6 years)
- Exploration expenses
- CO_2-tax and area fee
- Net financial costs (limited by the thin capitalisation rule: 20% equity)

= Corporation tax base (tax rate: 28%)
- Uplift (7,5% of investment for 4 years)

= Special tax base (tax rate: 50%)

Figure 8.3 Calculation of petroleum tax
(Source: Ministry of Petroleum and Energy)

Norm prices

Most oil companies on the Norwegian continental shelf are parts of corporations with a diversified global business portfolio. Produced petroleum is therefore largely sold to associated companies.

It can often be a very difficult task for the petroleum tax authorities to assess whether prices agreed between two parties is equal to what two independent parties would have agreed upon jointly for each individual sale. In order to avoid this problem, Section 4 of the Petroleum Tax Act states that norm prices may be stipulated and used in the calculation of taxable income. The methods for stipulation and use of norm prices are described in regulations.

The norm price is fixed by the Norm Price Board, and should be equivalent to the price paid for the petroleum had it been traded between independent parties. The norm price is stipulated each month and for each field. The Norm Price Board meets each quarter to stipulate prices for the previous quarter. The prices are based on information from and meetings with the operating companies before the final norm price is stipulated. Decisions may be appealed to the Ministry of Petroleum and Energy within 30 days. When the Norm Price Board does not find it appropriate to stipulate a norm price, the actual sales price will be used as the basis for taxation. This applies to certain crude oils and NGL. The actual sales price is used as a basis for gas.

The State's Direct Financial Interest (SDFI)

The State's Direct Financial Interest (SDFI) is an important source of state revenues in addition to taxes, fees and dividends from its ownership in Statoil. SDFI is an arrangement in which the state owns interests in a number of oil and gas fields, pipelines and onshore facilities. The State's interest is decided when production licences are awarded and the size varies from field to field. As one of several owners, the state pays its share of investments and costs, and receives a corresponding share of the income from the production licence. SDFI was established on 1 January 1985. Prior to this, Statoil alone, at the time a fully state-owned company, was responsible for the state's ownership holdings in production licences. In 1985, Statoil's participation was split into one direct financial share for the state (SDFI) and one for Statoil. When Statoil was privatised and listed on 18 June 2001, the administration of the SDFI portfolio was transferred to the state-created trust company, Petoro.

The arrangement with SDFI interests has a neutral effect, as no risk is transferred from the state to the companies. The SDFI arrangement implies that the state, when awarding acreage, can determine exactly how much of the value creation shall devolve on the state. For production licences for which profitability is expected to be low, the state can decide to take a small, or even no, interest, while a larger share would be appropriate for more profitable fields.

Statoil dividend

As of 1 March 2006, the state owns 70.9 percent of the shares in Statoil. As an owner in Statoil, the state receives dividends, which form part of the state's revenues from the petroleum sector.

9 Environmental considerations in the Norwegian petroleum sector

Norway as a pioneer in environmental solutions

Consideration for the environment is an integrated part of the Norwegian petroleum activities. In order to ensure that Norway can combine its role as a major energy producer with being a pioneer in environmental issues, a comprehensive set of policy instruments has been developed to safeguard consideration for the environment in all phases of the activities, from licensing rounds to exploration, development, operations and decommissioning. As a result of this strong emphasis on the environment, the Norwegian petroleum sector maintains very high environmental standards. This chapter provides an overview of policy instruments designed to ensure that the environment is taken into consideration, measures implemented to reduce emissions and discharges, as well as the status of emissions to air and discharges to sea from the petroleum activities.

The various phases of the petroleum activities give rise to different types of emissions and discharges. Exploration activity entails discharge of drill cuttings and emissions to air from energy production. Exploration activity also entails the danger of acute oil spills which can harm larvae, fish eggs, fish, seabirds, marine mammals and organisms in the shoreline. Fortunately, acute spills are very rare. During the operations phase there are discharges to sea and emissions to air, primarily water with residues of oil and chemicals (produced water), carbon dioxide (CO_2) and nitrogen oxides (NOx) from energy production and flaring, and non-methane volatile organic compounds (nmVOC) from storage and loading of crude oil. There is also some danger of oil spills during the operations phase.

Policy instruments

Emissions and discharges from off shore petroleum activities in Norway are to a great extent regulated by the Petroleum Act, the CO_2 Tax Act and the Pollution Control Act. Petroleum facilities on land are subject to the same types of policy instruments as other land-based industry. The processes involved in approving new development plans (PDOs/PIOs) are key elements of the petroleum legislation. Facilities located on land or at sea within the base lines are also subject to the scope and extent of the Planning and Building Act.

The authorities employ various policy instruments in the different phases of petroleum activity, from the exploration phase through the operations phase and finally, decommissioning. The policy instruments also vary according to the different types of emissions to air and discharges to sea.

International agreements and obligations

In accordance with international agreements, Norway is obliged to limit its emissions of various components. How this affects the petroleum sector will depend on how the individual agreements are worded, and how the requirements and policy instruments are distributed by sector in Norway. Air pollution agreements normally specify an emissions threshold for each country. The wording of the agreements determines whether the imposed limits must be implemented in their entirety within each country's borders, or whether reductions can also be made in other countries where the costs of such reductions may be lower. The costs of reducing emissions from the various sources, both domestic and international, will help determine the degree to which measures will be implemented in the petroleum sector.

Global climate pollution is regulated by the UN Climate Convention. According to the Kyoto

Policy instruments to reduce emissions/discharges from the petroleum activities

CO_2

The CO_2 Tax Act and the Greenhouse Gas Emission Trading Act constitute the key policy instruments designed to reduce emissions of CO_2. The authorities can also apply other policy instruments, such as terms and conditions in PDOs/PIOs, emission/discharge permits and production permits, which also cover flaring.

With effect from 1 January 1991, the use of gas, oil and diesel in association with petroleum operations on the Norwegian continental shelf is subject to CO_2 tax under the CO_2 Tax Act. As of 1 January 2006, the CO_2 tax is NOK 0.79 per litre of oil and standard cubic metre (scm) of burned gas (or approximately NOK 330/tonne CO_2). Under the Petroleum Act, burning of gas through flaring beyond what is necessary to ensure the safety of normal operations, is not permitted without consent from the Ministry of Petroleum and Energy. The Greenhouse Gas Emission Trading Act established a system of quota obligations and marketable quotas for the period 2005–2007. In the petroleum sector, only a few facilities on land, such as gas processing plants and gas terminals, are subject to quota obligations. The Greenhouse Gas Emission Trading Act and its scope will be reviewed by the end of 2007.

NOx

In the operations phase, emissions of NOx on the Norwegian continental shelf are regulated by means of terms stipulated in the PDO/PIO approval process. Emission permits covering NOx can also be granted under the Pollution Control Act.

nmVOC

Discharges of nmVOC associated with loading and storage of crude oil offshore have been regulated since 2001 by means of discharge permits issued pursuant to the Pollution Control Act.

Oil, organic compounds and chemicals

Companies must apply for discharge permits from the Norwegian Pollution Control Authority in order to discharge oil and chemicals to sea. The Norwegian Pollution Control Authority grants discharge permits pursuant to the provisions of the Pollution Act. Under the Pollution Act, the operating companies themselves are responsible for and obliged to establish the necessary contingency planning measures to counteract acute pollution. Municipal and national emergency response plans are also in place.

Protocol, Norway is obliged to ensure that average emissions for the years 2008–2012 do not increase by more than one percent compared to the emissions level in 1990. Relative to current levels, this implies a reduction of approximately eight percent. The obligation can be met through reducing domestic emissions, and through reducing emissions in other countries by the use of the Kyoto mechanisms (Emission Trading, the Green Development Mechanism and Joint Implementation). With the Greenhouse Gas Emission Trading Act, Norway has established a national quota system for greenhouse gases from 2005, as a follow-up to the Kyoto Protocol.

Emissions to air with regional environmental impact are regulated by various protocols under the Convention on Long-Range Transboundary Air Pollution (LRTAP). In 1999, together with the USA, Canada and other European countries, Norway signed the Gothenburg Protocol, which aims to solve the environmental problems of acidification, eutrophication and ground-level ozone. The Gothenburg Protocol entered into force on 17 May 2005. Under this protocol, Norway is to reduce NOx emissions to 156,000 tonnes by 2010. This implies a 27 percent reduction for Norway, compared to 1990 emission levels. The new commitment for nmVOC is virtually unchanged from the one accepted by Norway under the existing Geneva Protocol, i.e. that annual nmVOC emissions from all of the mainland and the Norwegian economic zone south of the 62nd parallel should be reduced as quickly as possible by 30 percent from the 1989 level. Under the Gothenburg Protocol, total national emissions shall not exceed 195,000 tonnes per year by 2010.

Discharges of oil and chemicals may have local impacts in the immediate vicinity of the facilities. These discharges are regulated on a national basis through a permit system pursuant to the Pollution Act. These discharges are also regulated internationally through the OSPAR Convention. For discharges to sea, an international maximum level for oil content in water has been set at 40 mg per litre and 30 mg per litre from 1 January 2007. Use and discharge of chemicals is subject to international regulation in the form of mandatory risk assessment and classification according to the properties of the chemicals.

Zero environmentally hazardous discharges to sea

The objective of zero environmentally hazardous discharges to sea from the petroleum activities was established in White Paper No 58 (1996–1997) Environmental Policy for Sustainable Development to the Storting. Since then, the authorities and the industry have worked together in a dedicated group to precisely define the objective and identify methods for achieving this goal. This objective has also been discussed in several subsequent White Papers.

The zero discharges targets constitute a goal based on a precautionary principle to help ensure that discharges to sea of oil and environmentally hazardous substances do not lead to unacceptable risks to health or the environment. No discharge of environmentally hazardous substances is the main rule; neither chemical additives nor naturally occurring chemical substances.

When selecting measures to reduce discharges from the individual fields, an overall assessment of the consequences for the environment, costs, safety and reservoir aspects must be carried out. It is therefore possible that the achievable target in practical terms on an existing field, based on such field-specific overall assessments, is minimising discharges. Operating companies on the Norwegian continental shelf are expected to be ambitious

Definitions of zero discharges and zero discharges targets

Definitions

Environmentally hazardous, environmentally hazardous compounds, environmentally hazardous chemical substances, environmentally hazardous components: Substances or groups of substances with properties including toxicity, low biodegradation, potential bioaccumulation and/or hormone disruption. The most dangerous of these substances are classified as environmental toxins.

Environmentally harmful, environmentally harmful discharges: This term refers to the damage that emissions and discharges can cause, and depends on the quantity released, the location and time of the release. An environmentally harmful discharge may be of an environmentally hazardous substance, but it may also be a substance that has no such inherent characteristics.

Zero discharge targets

Environmentally hazardous substances:

- Zero discharges, or minimisation of discharges of naturally occurring environmental toxins encompassed by end objective No. 1 for chemicals hazardous to health and the environment, ref. the priorities list in White Paper No. 25 (2002–2003) to the Storting.
- Zero discharges of chemical additives in the Norwegian Pollution Control Authority's black category (general prohibition on use and discharge) and the red category (high priority for phasing out via substitution)*.

Other chemical substances:

Zero discharges or minimisation of discharges of the following substances that can lead to harm to the environment:

- Oil (components that are not hazardous to the environment)
- Substances in the Norwegian Pollution Control Authority's yellow and green categories
- Cuttings
- Other substances that can lead to harm to the environment

(Source: White Paper No. 25 (2002–2003) The Environmental Policy of the Government and the State of the Environment in Norway to the Storting.)

White Paper No. 38 (2003–2004) On the petroleum activities to the Storting, stipulated specific conditions for petroleum activities in the Lofoten–Barents Sea area. The Lofoten–Barents Sea area is defined as a particularly vulnerable area, which is subject to more stringent discharge requirements than those in place for the rest of the Norwegian continental shelf.

*Ref. Regulations relating to conduct of activities in the petroleum activities (the Activities Regulations) of 3 September 2001.

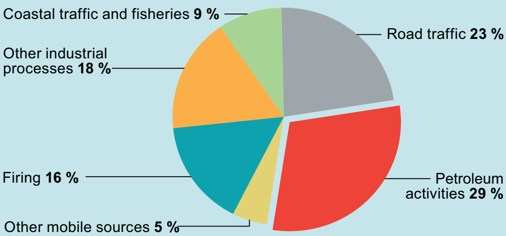


Figure 9.1 Sources of Norwegian emissions of CO_2, 2004
(Source: Statistics Norway)

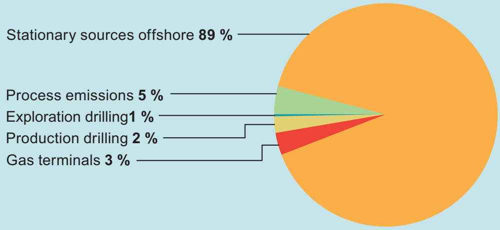


Figure 9.2 CO_2 emissions from petroleum activities 2004, by source
(Source: Norwegian Petroleum Directorate)

in their endeavours to achieve this goal, and they are also expected to work actively to develop and put to use new techniques that can contribute to achieving this goal.

As a step in their work to achieve zero environmentally hazardous discharges to sea, the operating companies have reported to the authorities concerning relevant measures, with associated costs and impact on the environment. Replacement of environmentally hazardous chemicals is, in general, a cost-effective measure. Discharges of environmentally hazardous chemical additives have been sharply reduced in recent years, and the zero discharge target will probably be achieved as regards these substances.

With regard to oil and naturally occurring substances in produced water, process optimisations, reinjection of produced water and cleaning measures appear to contribute most to reducing the risk of harm to the environment, within an acceptable cost frame.

Reports from the companies show that many measures have been implemented, and there has been a substantial improvement in the environment. Initially, the goal of zero environmentally hazardous discharges to sea should have been met in 2005. On several fields, however, the process of evaluating, testing and implementing measures has been more time-consuming than expected, and cannot be completed until 2006. Thus, full effect of the measures can not be expected until in 2007.

Emissions and discharges from the petroleum activities

Emissions to air from the petroleum sector largely consist of exhaust gases from combustion of gas in turbines, flaring and combustion of diesel. These exhaust gases contain substances such as CO_2 and NOx. Other environmentally hazardous substances released to air include nmVOC, methane (CH_4) and sulphur dioxide (SO_2). Discharges to sea from the petroleum sector contain residues of oil and chemicals used in the production processes, as well as naturally occurring chemical substances.

Measuring and reporting discharges and emissionS

In most cases, emissions to air are calculated on the basis of the volume of gas and diesel consumed on the facility. The emissions factors are based on measurements from suppliers or standard figures developed by the industry itself, through the Norwegian Oil Industry Association. On most fields, emissions are calculated using field-specific factors. Software that can calculate emissions based on measured process parameters is also available.

When calculating total oil discharges, the volume of produced water discharged to sea is measured, followed by an analysis of the oil content in the water. Discharge of chemicals is calculated based on consumption, relative to how much is recovered and/or injected.

The Norwegian Pollution Control Authority, the Norwegian Petroleum Directorate and the Norwegian Oil Industry Association have established a joint database to report discharges to sea and emissions to air from the petroleum activities. Since 2004, all operators on the Norwegian continental shelf report emission and discharge data directly in this database. This allows both the operating companies themselves and the authorities to more easily analyse historical emissions to air and discharges to sea in a more complete and consistent manner.

Emission status for CO_2

CO_2 emissions associated with the facilities on the Norwegian continental shelf largely originate from

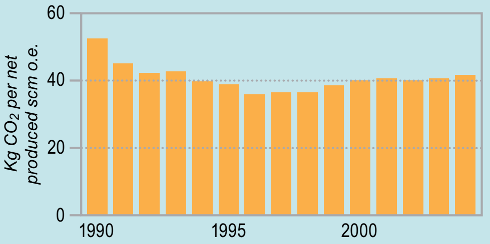


Figure 9.3 Emissions of taxable CO_2 per produced unit
(Source: Norwegian Petroleum Directorate)

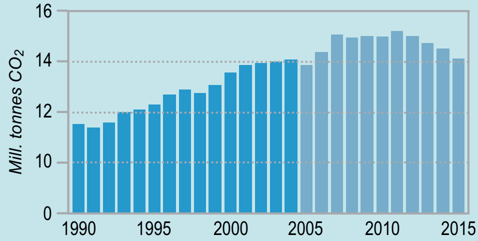


Figure 9.4 Emissions of CO_2 from the Norwegian petroleum sector
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

combustion of gas in turbines, flaring of gas and combustion of diesel. CO_2 is the most important of the greenhouse gases, and is largely derived from combustion of fossil fuels. Of all the fossil fuels, natural gas gives the lowest CO_2 emissions per energy unit.

The environmental effects of CO_2 emissions include the following:

- CO_2 contributes to the greenhouse effect, which in turn causes global warming.
- High concentrations of CO_2 in the atmosphere may result in more CO_2 dissolved in water, which can in turn lead to a reduction of the pH value in the sea.

In a national context, petroleum activities are responsible for 29 percent of CO_2 emissions (see figure 9.1). This percentage is expected to fall in the years to come. Other major emission sources in Norway include road traffic and other mobile sources, heating and emissions from industrial processes.

As shown in figure 9.2, the majority of the CO_2 emissions from the petroleum sector are linked to the offshore facilities. Other CO_2 emissions come from gas terminals on land and indirectly from VOC emissions (so-called process emissions).

Improved energy efficiency and reduced flaring have led to a reduction in CO_2 emissions per produced oil equivalent of approximately 21 percent from 1990 to 2004 (see figure 9.3). This is a result of a general improvement in technology and measures that reduce the emissions, such as the CO_2 tax introduced in 1991. However, the reduction in CO_2 emissions per produced oil equivalent has not been large enough to offset the increase in energy consumption resulting from a higher level of activity on the Norwegian continental shelf (see figure 9.4). In particular, increased gas production with subsequent gas compression for export has led to greater energy consumption, which in turn increases emissions of CO_2.

Generally speaking, emissions associated with production of a unit of oil or gas will vary between fields, as well as over the lifetime of a specific field. Reservoir conditions and transport distance to the gas market are factors that cause energy requirements, and thus emissions, to vary from field to field. The fact that emissions also vary over the lifetime of a specific field is in part due to an increasing amount of water in the wellstream as the field ages. As the energy required in the process facility largely depends on the total volume of liquid and gas (water, oil and gas), a field will have higher emissions per produced unit as it matures. This is one of the reasons for the slight increase in emissions per unit in recent years. The trend on the Norwegian continental shelf towards more mature fields and movement of activity northward reinforces the development of more emissions per produced unit. Treatment and transport of produced gas requires more energy than liquid production. Production of gas accounts for an increasing percentage of production on the Norwegian continental shelf. This has a significant impact on the development of the indicator CO_2 emissions per produced unit.

Measures for reducing CO_2 emissions

Development of combined solutions for energy production offshore (combined cycle power plants), recirculation of flare gas and injection of CO_2 separated from the produced gas at Sleipner Vest are examples of the Norwegian continental shelf's leading-edge position in terms of implementing efficient environmental solutions.

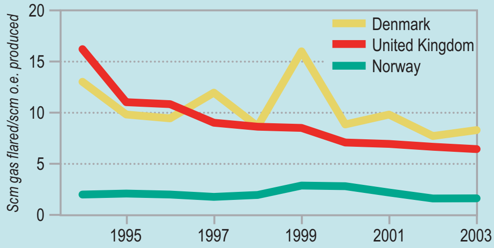


Figure 9.5 Flared gas per produced unit in Denmark, UK and Norway, 1994-2003

(Source: Norwegian Petroleum Directorate)

Combined power solutions

Combined cycle power plants are a solution whereby heat from turbine exhaust gas is used to produce steam, which in turn is used to generate electric power. Combined cycle power increases energy efficiency, and is currently in use on the Oseberg, Snorre and Eldfisk fields. These facilities are unique in a global offshore context.

Storage of CO_2

CO_2 can be injected and stored in depleted oil and gas reservoirs, or in geological formations under water or on land. Since 1996, one million tonnes of CO_2 have been stored annually in the Utsira formation in connection with processing of gas from the Sleipner field. Storing CO_2 in the Utsira formation is unique. This is the only facility in the world where large quantities of CO_2 are stored in a geological formation under the seabed. When the Snøhvit field commences production in 2007, CO_2 from the gas production will be separated out before the natural gas is cooled to liquid natural gas (LNG). The CO_2 gas will be transported via pipeline from the LNG plant on Melkøya and back to the field for reinjection into the Tubåen formation. Approximately 700,000 tonnes of CO_2 will be stored in Tubåen each year.

In the future, Norway will have excellent opportunities for storing CO_2 due to its access to large, water-filled reservoirs and depleted oil or gas reservoirs off the Norwegian coast. Storing CO_2 in depleted reservoirs is a good solution in terms of geology, because the structure is likely to be impermeable inasmuch as it has contained oil and gas for millions of years.

The Norwegian authorities work actively to ensure that such storage of CO_2 can be achieved in a safe and secure manner. Work is therefore being undertaken under the auspices of the OSPAR and London Conventions to ensure that sound international regulations for CO_2 storage are established. As a step in this work, in the autumn of 2004 the authorities organised a scientific OSPAR workshop on potential environmental impacts of long-term storage of CO_2, in which a number of international experts took part. It is important to understand the potential effects of CO_2 on the marine environment to determine whether or not large-scale, long-term CO_2 storage is possible. In a long-term perspective, storage of CO_2 could be extremely important in solving climate challenges.

Use of CO_2 to enhance oil recovery

The Norwegian Petroleum Directorate has estimated that there is a significant technical potential for improved oil recovery through the use of CO_2 in oil fields on the Norwegian continental shelf. The government has ambitious goals for realising CO_2 handling and creating a value chain for transport and injection of CO_2 for improved oil recovery. These are demanding goals with tight deadlines. The government has initiated projects to ensure progress in the work to establish a CO_2 chain and enlist relevant players in the work (see topic section on the challenges associated with establishing a CO_2 chain).

Power plants and energy efficiency

CO_2 emissions from power production account for approximately 80 percent of the total emissions from offshore activities. In 2004, the authorities and the industry worked together to carry out a study of the potential for more efficient power supply on the Norwegian continental shelf. The study concluded that a realistic, although ambitious, estimate of potential emission reductions was between five and ten percent over a period of ten years. This improvement has already been included in the forecast for CO_2 emissions from the sector.

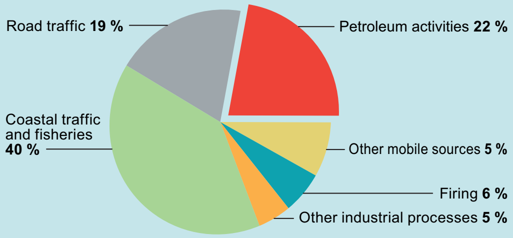


Figure 9.6 Sources of NOx emissions in Norway, 2004
(Source: Statistics Norway)

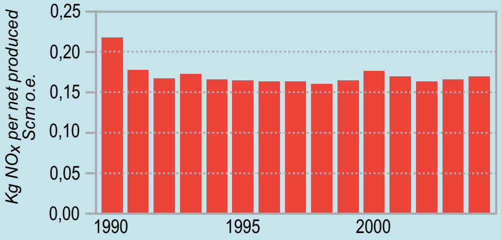


Figure 9.7 NOx emissions per produced unit
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

This can be achieved if the industry systematically implements energy management in all aspects of the operations. The industry will follow up the authorities' study. The Norwegian Oil Industry Association is working on developing common guidelines for establishing and implementing energy management.

A change in technology and energy supply concepts will be needed to ensure further increases in energy efficiency over the longer term. This calls for a long-term commitment to developing, testing and implementing new technology.

Flaring

Although flaring accounts for approximately ten percent of the CO_2 emissions from the petroleum activities, levels in Norway are low compared with other countries (see figure 9.5). The CO_2 tax and direct regulation of flaring have triggered a number of emission-reduction measures, and Norway leads the field in this area.

Emission status for NOx

Emissions of CO_2 and NOx are closely connected. As for CO_2, gas combustion in turbines, flaring of gas and diesel consumption on the facilities are key emission sources also for NOx. The volume of emissions depends both on the combustion technology and the quantity of fuel used.

The environmental effects of NOx emissions include the following:

- Impact on fish and other fauna through acidification of watercourses and the ground.
- Damage to buildings, stone and metalwork resulting from acid rain.
- Eutrophication, which may lead to a change in the composition of species in ecosystems.
- Damage to health, crops and buildings due to production of ground-level ozone.

Mobile sources account for the majority of the Norwegian NOx emissions (see figure 9.6). The petroleum sector contributes with 22 percent. Emissions of NOx per produced oil equivalent have declined by 22 percent from 1990 to 2004 (see figure 9.7). The reductions in emissions per produced oil equivalent are the result of improved technology and measures to reduce emissions. Despite the reduction in emissions per produced oil equivalent, total emissions of NOx from the sector have increased compared with 1991 (see figure 9.8). The main cause of the growth so far is increased activity which has entailed a need for more energy, which in turn means more emissions. Emissions of NOx are expected to fall from 2006.

Measures for reducing NOx emissions

Most of the measures designed to reduce CO_2 emissions also contribute to reducing NOx emissions from the petroleum sector. Other measures that can help reduce NOx emissions include introducing low-NOx burners as standard on gas turbines on new facilities. NOx emissions can be reduced by as much as 90 percent with no change in CO_2 emissions. In some cases, however, use of this technology can lead to increased CO_2 emissions.

Low-NOx burners can be retrofitted on existing turbines. Studies show that the general cost level associated with retrofitting such burners on existing facilities is considerably higher than previously assumed. Generally speaking, low-NOx technology installed on machinery running at high efficiency will result in significant environmental benefits. On machinery running at low capacity, CO_2 emissions increase, while NOx reductions are less than when the utilization of capacity is high.

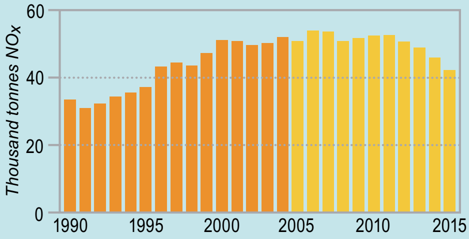


Figure 9.8 Emissions of NOx from the petroleum sector
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

Injection of steam or water in the combustion chamber can reduce NOx emissions. Steam or water will be used to reduce the combustion temperature and thus NOx emissions. This technology requires large quantities of clean water, which is a challenge offshore.

Emission status for nmVOC
nmVOC stands for non-methane volatile organic compounds, which vaporise from substances such as crude oil. In the petroleum sector, most of these emissions derive from offshore and onshore storage and loading of crude oil.

The environmental effects of nmVOC include:

- Formation of ground-level ozone, which can damage health, crops and buildings
- Direct exposure to nmVOC can cause respiratory tract damage
- nmVOC contributes indirectly to the greenhouse effect in that CO_2 and ozone are formed when nmVOC reacts with air in the atmosphere.

The petroleum sector is the main source of nmVOC emissions in Norway (see figure 9.9), accounting for approximately 54 percent of total emissions. Emissions of nmVOC largely originate from storage and loading of crude oil offshore. Minor emissions also occur at the gas terminals and in connection with small leaks. Other industrial processes and road traffic are also important sources of nmVOC emissions in Norway. The petroleum sector's share of this is shrinking due to the phase-in of emission-reducing technology.

Industry joint venture on nmVOC-reducing technology

Emission permits entail a requirement whereby oil must be stored and loaded using the best available technology (BAT). Technologies designed to meet this requirement will be implemented according to a specified timetable extending to the end of 2008.

Operators of Norwegian continental shelf fields with buoy loading have established a joint venture to coordinate phase-in of nmVOC-reducing technology and to fulfil the requirement in an expedient and cost-effective manner. The joint venture paves the way for exchange of experience with regard to operation of the facility.

The joint venture agreement was signed in 2002, and 26 companies take part in this collaboration which covers buoy loading of oil from Varg, Glitne, Jotun, Balder, Gullfaks, Statfjord, Draugen, Njord, Åsgard and Norne.

At the end of 2005, nmVOC-reducing technology had been installed on 13 buoy loaders, as well as on two ships transporting oil from Heidrun. The estimated nmVOC reduction in 2004 was 38,762 tonnes. Focus in the future will be on measures to achieve high operational regularity on existing facilities.

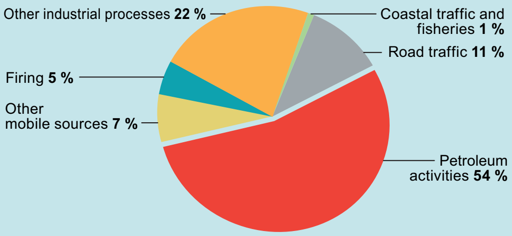


Figure 9.9 Sources of Norwegian emissions of nmVOC, 2004
(Source: Statistics Norway)

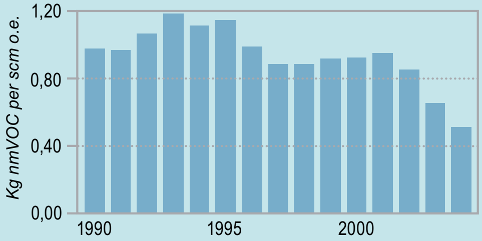


Figure 9.10 Sources of nmVOC emissions per produced unit
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

Emissions of nmVOC per produced unit of oil have also declined in recent years (see figure 9.10).

There are large differences in emissions depending on where the oil is loaded. The main reason for this is that the content of volatile gases in the oil varies from field to field.

Several of the newer fields on the Norwegian continental shelf use floating storage facilities. This type of development can result in higher emissions of nmVOC than on fields where oil storage takes place in the base of the platforms (Statfjord, Draugen and Gullfaks). This is because the use of floating storage facilities also entails emissions between production and storage.

The forecast for emissions of nmVOC from the sector shows a distinct declining trend in the years to come (see figure 9.11). Implementation of emission-reducing technology is the reason for this. Moreover, oil production is expected to reach its peak a few years from now.

Measures for reducing nmVOC emissions

For a number of years, the oil companies have worked to make technology for recovering nmVOC available to storage vessels and shuttle tankers. Today, tested technology exists that can reduce emissions from loading by approximately 70 percent. Several vessels have now installed technology to reduce emissions. The operators of fields with buoy loading on the Norwegian continental shelf have formed a joint venture (see text box).

A recovery facility for nmVOC was deployed at the crude oil terminal at Stura in 1996. This facility is the first of its kind in a crude oil terminal. In order for loading tankers to use the facility, they must be fitted with coupling equipment. From 1 January 2003, it became a requirement that all vessels must be fitted with equipment for recovering nmVOC. Ships without the necessary equipment are not normally granted access to the facility.

Discharges of chemicals

Chemicals is a generic designation for all additives and auxiliary products used in drilling and well operations and in the production of oil and gas. The main rule is that no environmentally hazardous substances may be discharged, regardless of whether the substance is an additive or occurs naturally.

More than 99 percent of the chemicals used in the Norwegian petroleum activities consist of chemicals that are believed to have little or no impact on the environment (green and yellow chemicals, ref. the Norwegian Pollution Control Authority's clas-

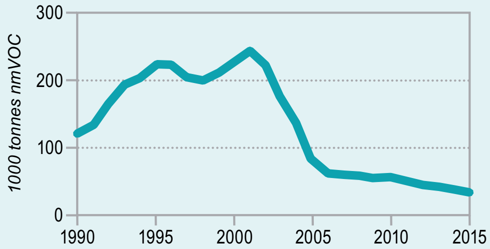


Figure 9.11 Emissions of nmVOC from petroleum activities
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

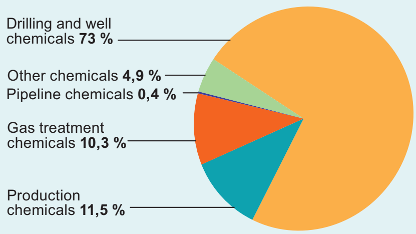


Figure 9.12 Discharges of chemicals from petroleum activities, by sources, 2004
(Source: EnvironmentWeb)

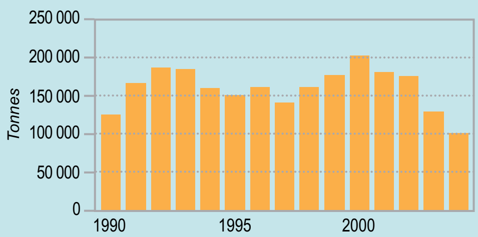


Figure 9.13 Total discharges of chemicals from petroleum activities
(Source: EnvironmentWeb)

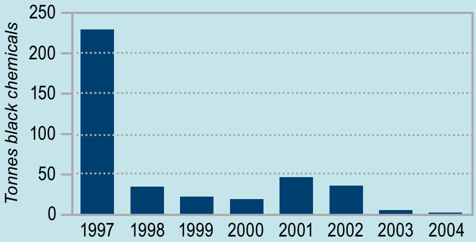


Figure 9.14 Discharges of black chemicals from petroleum activities
(Source: NOIA/EnvironmentWeb)

sification). Many of these chemicals are substances that occur naturally in seawater. The remainder are environmentally hazardous chemicals or chemicals whose potential effects have not been adequately documented.

Some of the environmental effects caused by chemicals:

- They have a certain local toxic effect, but are diluted in the water column so that the acute impact on the environment is not very significant other than in the immediate vicinity of the discharge.
- A small percentage of chemical discharges may have very serious environmental consequences, including hormone disruption or bioaccumulation.

Potential long-term effects remain uncertain, but considerable research is being done in this area.

Most chemical discharges are associated with drilling activity (see figure 9.12), and discharge volumes vary according to the level of activity taking place. Figure 9.13 shows the development in total discharges of chemicals from the petroleum activities. Discharges of environmentally hazardous production chemicals (black and red chemicals, ref. Norwegian Pollution Control Authority's classification) have been reduced by 85 percent from 2000 to 2004. Figures 9.14 and 9.15 illustrate the development in discharges of environmentally hazardous chemicals.

The chemicals that are not discharged are dissolved in the oil, deposited in the subsurface or handled as hazardous waste.

Discharges of oil and other naturally occurring chemical substances

Total discharges of oil from the Norwegian petroleum activities account for a small portion of the total discharges into the North Sea. The majority of oil discharged into the North Sea is considered to come from shipping and from the mainland via rivers. Figure 9.16 provides an overview of acute oil discharges greater than one tonne. All acute discharges from the facilities on the Norwegian continental shelf are reported to the National Coastal Administration, and the causes of the discharges are investigated.

Petroleum activities have not caused major acute spills of oil that have reached land. The environmental effects of potential acute oil spills depend on several factors, and not only the size of the spill. The location of the spill, season, wind strength, currents and the response measures are

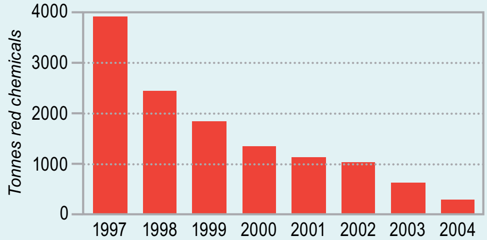


Figure 9.15 Discharges of red chemicals from petroleum activities
(Source: NOIA/EnvironmentWeb)

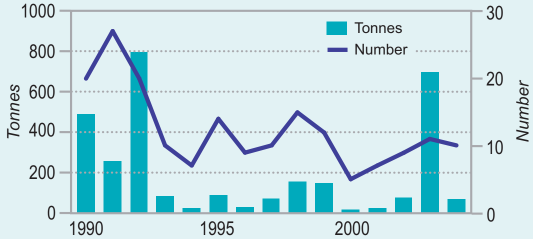


Figure 9.16 Acute oil discharges of more than one tonne
(Source: EnvironmentWeb)

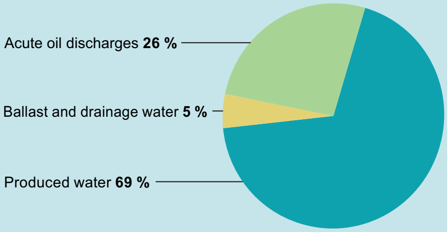


Figure 9.17 Discharges of oil from petroleum activities, by activity, 2004
(Source: EnvironmentWeb)

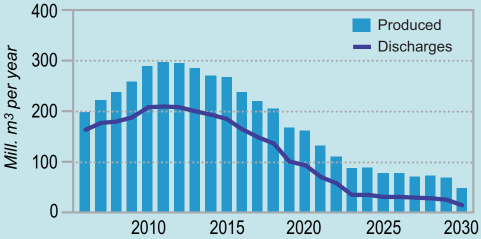


Figure 9.18 Forecast for produced water and dischages of produced water
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

all crucial for the extent of damage. Acute oil spills can harm fish, marine mammals, seabirds and shoreline. Most serious acute oil spills in Norway have originated from ship traffic near the coast.

Oil discharges from the petroleum sector largely occur in connection with ordinary operations. Water that is produced with oil and gas contains remnants of oil in the form of droplets (dispersed oil), other organic components (including dissolved oil fractions), inorganic components (heavy metals, naturally low-radioactive compounds, etc.) and residues of chemical additives. The produced water is reinjected into the subsurface or cleaned to the extent possible before it is discharged to sea. Figure 9.17 shows oil discharges distributed between activities, while figure 9.18 illustrates the development in the volume of produced water and discharges of produced water, both historical and forecast.

There is no proof of direct harm to the environment from operational discharges of oil. New research results indicate that alkyl phenol in produced water does not entail a risk to the fish populations in the North Sea. However, potential long-term effects are uncertain and substantial research is being done on this topic, including through the research program “Sea and Coast”, and its subsidiary program, PROOF.

Challenges associated with establishing a CO_2 chain

The government places great emphasis on capture and storage of CO_2 as a measure to increase oil recovery on the Norwegian continental shelf and to reduce CO_2 emissions. The government has ambitious goals for achieving CO_2 capture at gas fired power plants and for establishing a chain for transport and injection of CO_2. A CO_2 chain encompasses capture of CO_2 from emission sources, transport and storage of CO_2, and use of CO_2 to improve oil recovery.

Production of power and other use of fossil energy is the largest source of greenhouse gas emissions. Capture of CO_2 and storage of CO_2 in oil/gas reservoirs and geological formations emerges as a potential measure to reduce global emissions. The technology for capturing and storing CO_2 is still in the early stages of development. The available technology is very expensive, and there are many uncertainties linked to the costs and operation of a CO_2 chain. For many years, there has been considerable international interest in development of technology for capture and storage of CO_2, particularly from coal-based power plants. In Norway the focus has been on capture and storage of CO_2 from gas fired power plants, and Norwegian players have made great advances in this area.

Use of CO_2 to increase oil recovery can reduce costs associated with capture and storage because the CO_2 that is captured will take on an added value. This could result in a profitable value chain for CO_2, but this depends on solving several significant technological challenges.

In its Special Report on Carbon Dioxide Capture and Storage (IPCC 2005), the UN Intergovernmental Panel on Climate Change concludes that storage of CO_2 can account for as much as one-half of emission reductions in this century. However, major challenges must be solved before this potential can be realised. The IPCC report points out that by and large, the technology for capture and storage of CO_2 is not mature, and that there is as yet no experience from capture of CO_2 from large coal and gas power plants.

The government aims to implement CO_2 capture at gas power plants and to establish a value chain for transport and injection of CO_2, associated with the gas power plant being built at Kårstø.

Capture of CO_2

The costs associated with capture and storage of CO_2 derived from fossil fuel power production is a fundamental challenge, as this represents a substantial cost-driver. The costs associated with capturing CO_2 from a power plant amount to approximately two-thirds of the costs for the entire CO_2 chain, while transport and storage amount to approximately one-third. This distribution applies in general to all the various technology concepts.

The technology for capturing CO_2 from gas fired power plants can be divided into three main categories: post-combustion, pre-combustion and oxy-fuel. Post-combustion entails separating CO_2 from the exhaust gas from the power plant using chemical cleaning. Because CO_2 is separated from the exhaust gas, this technology can, in principle, be utilised in existing power plants without major modifications of the plant itself. Post-combustion is considered to be the most mature technology, although there is still significant uncertainty surrounding its use.

With the aid of pre-combustion technology, CO_2 is captured before combustion. This is accomplished by converting the natural gas to a hydrogen-rich gas mixture. This gas mixture is treated so that CO_2 is captured, and the new fuel is thus "decarbonised", which means that the exhaust gas contains very little CO_2. Pre-combustion requires modification of gas turbines and is considered to be a more complex technology than post-combustion.

With oxy-fuel, combustion takes place in the gas turbine with pure oxygen instead of air. This means that the exhaust contains water vapour and CO_2, and the CO_2 can be separated out by cooling the exhaust. Today's gas turbines suffer from very poor performance with oxygen combustion, and there has been little effort to date to develop new types of turbines that are better suited to oxygen combustion. In addition, production of oxygen is extremely energy-intensive, and the corresponding technology is quite costly. Therefore, oxy-fuel is considered to be a technology that is not very mature.

Capturing CO_2 requires a lot of energy. The IPCC report assumes that, if 90 percent of the CO_2 from a power plant is captured, fuel consumption will increase by 11–40 percent, depending on the technology and the fuel. Capturing CO_2 reduces the performance of the power plant and increases other environmentally harmful emissions. The report estimates that capture of CO_2 increases the production costs associated with power production by 20–85 percent. If the current level of research and development is maintained, the cost of capturing CO_2 could be reduced by 20–30 percent over the next ten years.

So far, none of these three technologies have been subjected to large-scale testing in gas power plants. Therefore, there is much uncertainty associated with use of the available technology for CO_2 capture, particularly with regard to costs and performance.

Transport of CO_2

CO_2 must be transported from the CO_2 source to the geological structure where the CO_2 will be stored. This transport can be accomplished by pipeline or by ship. Generally speaking, transport is the least complicated element in the CO_2 chain, both as regards technology and the possibility of evaluating realistic costs. Nevertheless, the transport link requires substantial resources in terms of energy and costs. As CO_2 behaves very differently under various pressures and temperatures, transport must take place in a controlled manner to avoid solid forms and subsequent clogging of pipes or equipment.

Transporting CO_2 by ship is more complicated than pipeline transport. In order to fit as much as possible into a single shipload, the gas is converted to liquid by pressurisation or a combination of pressurisation and cooling. Valuable experience has been gained in shipping CO_2 in connection with food production and industrial use of the gas, but at smaller volumes. Storing CO_2 in geological formations on the Norwegian continental shelf will entail transport of huge volumes, which will require ships with substantial transport capacity. Assumably, the greatest challenges lie in regularity of supply and cost-effective unloading of CO_2 from a ship to an offshore installation. One alternative to ship transport direct to an offshore installation is ship transport to an intermediate storage facility on land which is linked by pipeline to the offshore field.

Pipeline transport of CO_2 does not differ significantly from transport of hydrocarbon gas. The technologies are known, and there is extensive experience with construction and operation of major pipelines for transport of gas from the Norwegian continental shelf to the European continent. However, there is no experience with transport of large volumes of CO_2 through long pipelines on the seabed.

The most optimal means of transport depends on the needs and the individual situation, including the number of emission sources, the volume of emissions from each source, the distance from the source to the storage place and the volume of CO_2 to be transported. With current technology, pipeline transport is believed to be the simplest and most cost-effective alternative. Starting in 2007, experience will be obtained in the transport of $CO_2$by pipeline from the Snøhvit LNG plant.

Storing CO_2

Norway has extensive experience in storing CO_2 in geological structures. Since 1996, one million tonnes of CO_2 per year have been separated from gas production on the Sleipner Vest field in the North Sea for storage in Utsira, a geological formation 1000 metres below the seabed. In 2007, production of natural gas, NGL and condensate will commence from the Snøhvit field in the Barents Sea. In connection with treatment of the wellstream on Melkøya, 700,000 tonnes of CO_2 will be separated and stored in a reservoir 2 600 metres below the seabed.

There is a significant technical potential for storing CO_2 in geological formations around the world. Producing oil and gas fields, old oil and gas fields and other formations are all candidates for such storage. Storage in reservoirs that are no longer in operation is a good solution in terms of geology because these structures are likely to be impermeable after having held oil and gas for millions of years. Other formations are also considered to be secure storage alternatives for CO_2. The international SACS project has documented that the CO_2 pumped down into the enormous Utsira formation from the Sleipner field does not leak out.

The risk of leakage from geological storage is minimal. The IPCC report concludes that, if the storage is done properly, there is a 90–99 percent probability that more than 99 percent of all stored CO_2 will still be in place after one hundred years. After 1000 years, there is a 66–90 percent probability that more than 90 percent will still be in place.

Use of CO_2 to increase oil recovery

As oil fields enter into a mature phase, the pressure in the reservoir diminishes and additional pressure support is needed to maintain production levels. Water or natural gas is used as pressure support to maintain production levels on quite a few oil fields on the Norwegian continental shelf. Injection of CO_2 can be an alternative or supplement to use of water or natural gas as pressure support. In some cases, CO_2 is miscible with the reservoir oil, and can thus contribute to enhancing production beyond what can be achieved through water or gas injection.

Significant challenges are associated with using CO_2 to increase oil production from fields on the Norwegian continental shelf. Particularly costly are modifications of existing installations and equipment for injection and treatment of reproduced CO_2. Several of the relevant candidates for CO_2 injection contain large volumes of gas, and reproduced CO_2 must be separated from the gas in accordance with sales gas specifications. These processes require considerable space, and in many cases a new installation will have to be built in order to make room for the equipment.

An oil field needs CO_2 deliveries for a much shorter period of time than the anticipated lifetime of a gas fired power plant. In addition, the need for added CO_2 will diminish as more and more CO_2 is produced with the process stream. There is not necessarily concurrence between access to CO_2 from a gas fired power plant and the CO_2 needed by an oil field. Therefore an infrastructure for CO_2 transport must be developed that makes it possible to store CO_2 as the need for CO_2 to improve oil recovery on a field is reduced and oil production is shut down.

Larger volumes of CO_2 are needed when CO_2 is to be used to increase oil recovery. CO_2 from a single point source (such as Kårstø) will probably not provide sufficient volumes for optimal injection into an oil field. It may therefore be necessary to obtain CO_2 from other sources in Norway or from abroad.

Projects to ensure progress in the work to establish a CO_2 chain

The government has initiated three projects to ensure progress in the work to establish a CO_2 chain and to involve relevant players in this work.

Subproject 1 covers the entire CO_2 chain with capture, transport and injection of the gas to increase oil recovery or for storage. Through preliminay negotiations between gas fired power plants and other major point sources of CO_2 and oil companies, revenues and costs in all stages of the CO_2 chain can be quality assured. Mapping these players' willingness to pay will provide an overview of potential revenues in the chain, and thus also the framework for the state's involvement.

Subproject 2 will clarify the time perspective and costs of establishing a carbon capture facility connected to the gas fired power plant which is under construction at Kårstø. The goal is to establish such a facility by 2009. This work requires close cooperation with relevant suppliers of CO_2 capture technology. A legally liable entity must also be established to be responsible for the facility as regards supply and procurement, construction, operation and ownership.

In Subproject 3, the Ministry of Petroleum and Energy will cooperate with relevant ministries to clarify the organisational and legal framework for the state's involvement in the CO_2 chain.

Cooperation between the authorities and the industry

The challenges associated with capture and storage of CO_2 must be met through international cooperation and efforts on all levels - between industry players, research institutions and at the governmental authority level. If capture and storage of CO_2 is to become an important measure for reducing the global emissions of greenhouse gases, technological solutions must be identified that can make capture and storage of CO_2 a competitive alternative to other energy solutions in a global perspective.

Norwegian authorities are active in international research and technology cooperation. Important arenas for cooperation and coordination on the authority level include the Carbon Sequestration Leadership Forum, cooperation under the direction of the International Energy Agency and various research programs in the EU, in addition to bilateral cooperation.

Norwegian authorities prioritise participation by Norwegian players. Several key Norwegian research institutions and companies participate in international cooperation projects where both energy and supplier companies and governmental authorities in several countries are working together. Such projects ensure that both necessary technology developers and technology buyers take part in developing technology.

The government has also included capture and storage of CO_2 as an important topic in the energy dialogue with the EU Commission, and will consider potential areas of cooperation with a view towards promoting use of CO_2 to increase oil recovery. The common effort will also include capture and storage of CO_2.

In 2005, the Norwegian Minister of Petroleum and Energy and the British Minister of Energy signed a joint declaration on geological storage of CO_2 in the North Sea, and established a working group for the North Sea Basin. The objective is to develop common principles as a basis for regulating CO_2 storage in the North Sea.

Gassnova

Gassnova, the state's centre for environmentally friendly gas technology, was established in 2005. Gassnova's objective is to promote development of progressive, environmentally friendly and cost-effective gas power technology. Gassnova supports projects whose development is between the research stage and commercial facilities, such as pilot and demo facilities. In cooperation with the Research Council of Norway, Gassnova manages the state program CLIMIT, which supports development and demonstration of solutions for gas fired power plants with CO_2 capture and storage.

Just Catch

In cooperation with Aker Kværner Engineering & Technology, Gassnova has launched the project Just Catch for technology to capture CO_2 from gas fired power plants. Gassnova provides financial support to the project. Aker Kværner Engineering & Technology is joined in this project with leading Norwegian and international companies in the energy industry: Gassco, Fortum, Norsk Hydro, Lyse Energi, Petoro, Shell, Skagerak Energi, Statkraft, Statoil and Østfold Energi. GASSTek is involved as the main supplier. The objective of the project is to:

- Reduce the technical and financial risk associated with building full-scale facilities for capturing CO_2 from gas fired power plants.
- Establish a cost-effective design for a demonstration facility for CO_2 capture based on technology that will be available in 2010.
- Develop descriptions and technical specifications and set up cost estimates for recommended facilities. The level of quality and degree of detail shall be sufficient to provide a basis for decisions on proceeding with engineering and construction of a demo facility.

The project will run for two years, with two phases and a total cost frame of NOK 32 million. Phase 1 will deal with theoretical estimates, qualifications and verifications, further development of technology and laboratory-scale tests. Such tests can be carried out by research institutions such as Sintef. The budget for Phase 1 is NOK 18.5 million. Phase 2 will include testing of equipment and chemicals in pilot facilities, probably in the rig at Kårstø.

The technology concept selected in the Just Catch project is based on absorption of CO_2 from the exhaust of a gas fired power plant in a chemical solution (amine), i.e. post-combustion technology. The capture concept selected in the project has the following properties:

- The concept does not require entirely new technology elements in order to function, but the technology must be developed further so that it is cost-effective.
- The technology can be used and installed in the near future (2010).
- The concept can be used for conventional gas fired power plants and can also be retrofitted on existing power plants and for industrial emissions.
- Power production is independent of the capture facilities.
- The greatest challenges are the low concentrations of CO_2 in the exhaust (3-4 percent), necessitating the handling of large volumes of exhaust gas.
- Similar technology is being used to separate CO_2 in natural gas. In these types of facilities (such as on the Sleipner platform), the natural gas to be exported is cleaned to achieve sales quality. The CO_2 cleaning process is also used industrially as a pre-treatment for LNG production (liquid natural gas).
- The method can also be adapted for coal power plants.

10 Petroleum resources

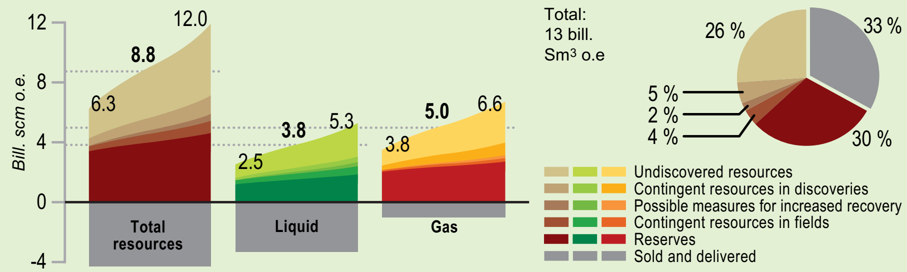


Figure 10.1 Petroleum resources and uncertainty in the estimates at 31.12.2005
(Source: Norwegian Petroleum Directorate)

The Norwegian Petroleum Directorate's estimates of total discovered and undiscovered petroleum resources on the Norwegian continental shelf are approximately 13 billion standard cubic metres of oil equivalents (scm o.e.). Around 4.3 billion scm o.e. have been recovered, 33 percent of the total resources. The remaining total recoverable resources amount to 8.8 billion scm o.e., 5.4 billion scm of which are proven resources, with an estimated 3.4 billion scm o.e. undiscovered.

There was encouraging resource growth from exploration activity in 2005. Six new discoveries have been made; two oil discoveries and four gas discoveries. The total recoverable resources stemming from exploration activity are 3-15 million scm oil and 40-120 billion scm gas. Some of the discoveries are still being evaluated and the estimates are thus very uncertain.

Since petroleum production began on the Norwegian continental shelf in 1971, 4.3 billion scm o.e. has been produced from 63 fields. In 2005, the Kristin and Urd fields started production. 42 fields in the North Sea and 8 in the Norwegian Sea were on stream at the end of the year. The PDOs for five new fields, Enoch, Blane, Ringhorne Øst, Vilje and Volve, were approved in 2005. In addition, plans for development and operation (PDO) were approved for Fram Øst, Njord Gas Export, Skinfaks/Rimfaks IOR, Statfjord Late Life (including Tampen Link) and Oseberg Delta, and amended PDOs were approved for Tordis, Norne and Gullfaks. A PDO exemption was granted for Tune Sør. A plan for development of Tyrihans was presented to the Storting for approval.

Figure 10.1 depicts the total recoverable potential on the Norwegian continental shelf. The volumes are divided according to the Norwegian Petroleum Directorate's resource classification, and show total resources, liquid and gas.

Resources

Resources is a collective term that covers technically recoverable quantities of petroleum. The resources are classified according to maturity, see figure 10.2. The classification shows the petroleum volumes that the licensees have decided to develop, or that are approved for development (reserves), the volumes that depend on clarification and decision (contingent resources) and the volumes that are expected to be discovered (undiscovered resources). The main classifications are reserves, contingent resources and undiscovered resources.

The detailed resource accounts as at 31.12.2005 are to be found in table 10.1 and in Appendix 2.

Reserves

Reserves cover remaining recoverable, saleable petroleum resources in petroleum deposits that the licensees have decided to develop, and for which the authorities have approved the PDO or granted a PDO exemption. Reserves also include petroleum resources in deposits that the licensees have decided to develop, but for which the plan has not been processed by the authorities in the form of a PDO approval or a PDO exemption. The reserves are estimated at 4 billion scm o.e., and has been reduced by 32 million scm over the past year. Gross reserves increased significantly in 2005, by 248 million scm o.e. Reserves in approved and submitted development plans account for approximately 159 million scm o.e. The remaining volumes, 89 million scm o.e., are derived from increases in the reserves on several fields, in part because measures for recovering contingent resources in fields have been approved, and the resources have thus been entered as reserves. With 280 million scm o.e. produced in 2005 (including historical production of TOGI gas), the resource accounts show a net reduction in remaining reserves of 32 million scm o.e.

Out of the authorities' new goal of maturing 800 million scm of oil as reserves before 2015, 157 million scm oil were entered as reserves in 2005, which amounts to 19 percent of this goal. The 2005 increase is the largest in five years.

Contingent resources

Contingent resources means discovered quantities of petroleum for which no development decision has yet been made. Contingent resources in fields, not including resources from potential measures to improve recovery, were reduced by 36 million scm o.e. in 2005. The reason for the reduction is that there has been substantial maturing of contingent resources in fields in 2005. Projects such as Statfjord Late Life, Ringhorne Øst, Smørbukk Sør Q Phase 2 and Tune Sør have been decided by the licensees and the resources are entered as reserves. There has also been a maturing of resources to reserves from the Brage, Gungne, Gullfaks, Huldra and Ula fields.

The estimate for contingent resources in discoveries has been adjusted downward by 20 million scm o.e. to 727 million scm o.e. This reduction is the result of the Blane, Volve and Oseberg Delta and Tyrihans[1] deposits, which were in the planning phase last year, having had their PDOs approved in 2005, and are thus entered as reserves.

The potential for resources from future measures to improve recovery of oil are now estimated at 137 million scm o.e. The estimate has been increased by 12 million scm o.e. compared to last year. The estimate for gas is unchanged from the previous year.

Undiscovered resources

Undiscovered resources are petroleum volumes which are expected to be present in defined exploration models, confirmed and unconfirmed, but which have not yet been proven through drilling (resource categories 8 and 9). The estimate of total undiscovered resources is 3.4 billion scm o.e., unchanged from last year.

The North Sea

A total of 7.2 billion scm o.e. has been proven in the North Sea, of which 3.9 billion scm o.e. has been produced. Remaining reserves are 2.7 billion scm o.e., of which 36 percent is oil. Production from the North Sea in the past year was 230 million scm o.e. (including historical production of TOGI gas). The remaining reserves in the North Sea has been reduced by 96 million scm o.e. Two oil discoveries and one gas discovery were made in the North Sea in 2005. Nevertheless, there are no major changes in the estimates for contingent resources and undiscovered resources. Undiscovered resources in the North Sea are expected to amount to approximately 1.2 billion scm o.e.

1 *The PDO for Tyrihans was presented to the Storting for approval in December 2005 and was approved by the Storting in February 2006*

The Norwegian Sea

In the Norwegian Sea, a total of 2.0 billion scm o.e. has been proven, of which 0.4 billion scm o.e. has been produced. Remaining reserves amount to approximately 1.1 billion scm o.e., of which 62 percent is gas. Production in 2005 totalled 50 million scm o.e. The estimate for remaining reserves has increased because the licensees have submitted a PDO for Tyrihans, and because the reserves in several fields in the Norwegian Sea have increased. Three new gas discoveries were made in the Norwegian Sea in 2005, however, there has been little change in the estimate for contingent resources in discoveries. This is because a PDO has been submitted for Tyrihans, and the resources have thus been entered as reserves. The estimate for undiscovered resources in the Norwegian Sea is unchanged.

The Barents Sea

0.2 billion scm o.e. have been proven in the Barents Sea. Production from the Snøhvit field will commence in 2007. There has been little change in the estimate for contingent resources in fields and discoveries in the Barents Sea over the past year. The estimate for undiscovered resources in the Barents Sea is unchanged..

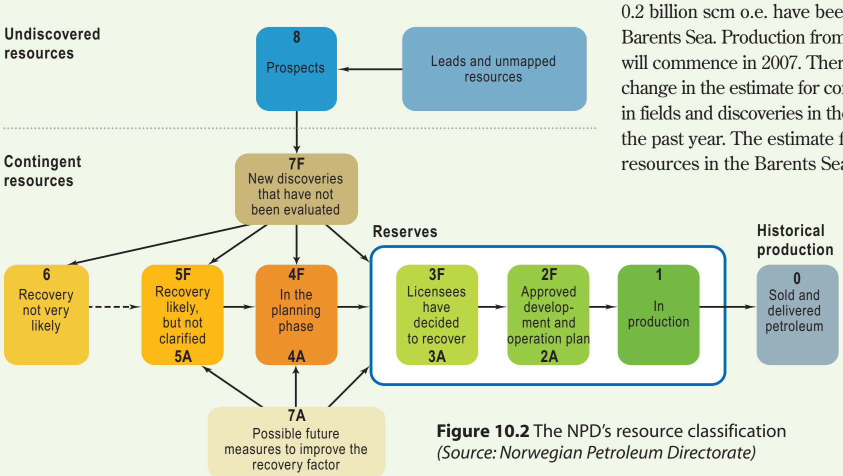


Figure 10.2 The NPD's resource classification *(Source: Norwegian Petroleum Directorate)*

Table 10.1 Resource accounts at 31.12.2005

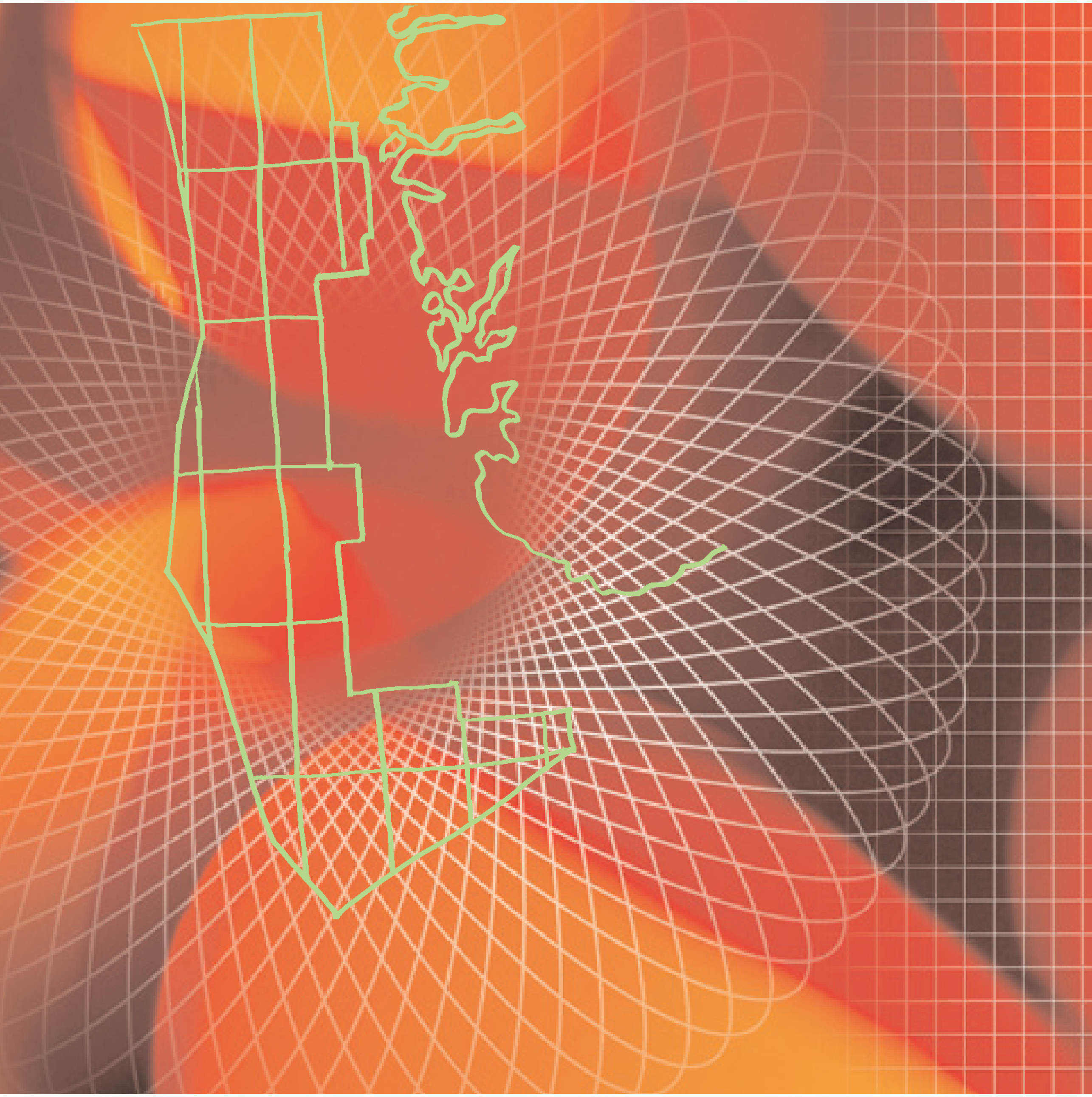
Total recoverable potential	Resource accounts per 31.12.2005					Changes from 2004				
	Oil	Gas	NGL	Cond	Total	Oil	Gas	NGL	Cond	Total
Project status category	mill scm	bill scm	mill tonnes	mill scm	mill scm oe	mill scm	bill scm	mill tonnes	mill scm	mill scm oe
Produced	3018	1055	90	81	4324	148	107	9	8	280
Remaining reserves'	1230	2358	138	47	3898	5	-28	16	-40	-32
Contingent resources in fields	310	156	17	4	503	32	-34	-14	-9	-36
Contingent resources in discoveries	138	494	30	37	727	-41	11	9	-7	-20
Potential from improved recovery*	137	100			237	12	0	0	0	12
Undiscovered	1160	1900		340	3400	0	0	0	0	0
Total	**5994**	**6062**	**275**	**509**	**13089**	**157**	**56**	**20**	**-47**	**204**
North Sea										
Produced	2668	995	79	64	3877	122	93	6	4	230
Remaining reserves'	957	1577	75	4	2627	-57	-56	10	-2	-96
Contingent resources in fields	262	118	10	4	404	42	-18	-14	-2	-5
Contingent resources in discoveries	87	161	15	18	293	-16	-7	6	-8	-19
Undiscovered	615	500		75	1190	0	0	0	0	0
Total	**4589**	**3297**	**179**	**165**	**8391**	**91**	**11**	**9**	**-8**	**110**
Norwegian Sea										
Produced	350	60	11	17	447	26	14	3	4	50
Remaining reserves'	273	675	57	24	1080	63	28	4	-38	61
Contingent resources in fields	48	38	7	0	99	-3	-12	0	-6	-20
Contingent resources in discoveries	45	325	16	19	418	-21	16	3	1	1
Undiscovered	235	810		175	1220	0	0	0	0	0
Total	**951**	**1907**	**90**	**235**	**3264**	**65**	**47**	**10**	**-39**	**92**
Barents Sea										
Produced	0	0	0	0	0	0	0	0	0	0
Remaining reserves'	0	161	6	18	191	0	0	1	0	3
Contingent resources in fields	0	0	0	0	0	-7	-4	0	-1	-12
Contingent resources in discoveries	7	8	0	1	16	-3	1	0	0	-1
Undiscovered	310	590		90	990	0	0	0	0	0
Total	**317**	**759**	**6**	**109**	**1197**	**-10**	**-3**	**1**	**0**	**-10**

' Includes resource categories 1, 2 and 3

*Resources from future measures for improved recovery are calculated for the total recoverable potential and have not been broken down by area

(Source: Norwegian Petroleum Directorate)

11 Fields in production



Keys to tables in Chapters 11–13

Participating interests in fields do not necessarily correspond with interests in the individual production licences (unitised fields or fields for which the sliding scale has been exercised have a different composition of interests than the production licence).

Because interests are quoted with only two decimal places, licensee holdings in some of the fields may not add up to 100 percent. Participating interests are shown as of 1 January 2006.

"Recoverable reserves originally in place" refers to reserves in resource categories 0, 1, 2 and 3 in the Norwegian Petroleum Directorate's classification system.

See figure 10.2 Norwegian Petroleum Directorate's resource classification

"Recoverable reserves remaining at 31 December 2005" refers to reserves in resource categories 1, 2 and 3 in the Norwegian Petroleum Directorate's resource classification.

Resource Category 0: Petroleum sold and delivered
Resource Category 1: Reserves in production
Resource Category 2: Reserves with an approved plan for development and operation
Resource Category 3: Reserves which the licensees have decided to develop

Expected production of oil is listed in barrels per day, while gas, NGL and condensate are listed in annual values.

Southern North Sea

The southern part of the North Sea sector became important for the country at an early stage, with Ekofisk as the first Norwegian offshore field to come on stream in 1971. Today, 15 fields are producing in the Southern North Sea, and three fields are currently being developed. Seven fields have been shut down after production has ceased, although some of these may play a role in new production later on. Ekofisk serves as a hub for petroleum operations in this area, with several fields utilising the infrastructure for further transport in the Norpipe system. From Ekofisk, oil is exported by pipeline to Teesside in the UK, while gas is sent by pipeline to Emden in Germany. North of Ekofisk are the Sleipner fields, which produce gas and condensate. Sleipner Øst and Sleipner Vest came on stream in the 1990s. These fields serve as an important hub for the gas transport system on the Norwegian continental shelf.

Although there has been production from the Southern North Sea for many years, remaining resources in the region are substantial, particularly in the large chalk fields in the very south of the area. Production of oil and gas is expected to continue from this area for at least another three decades.

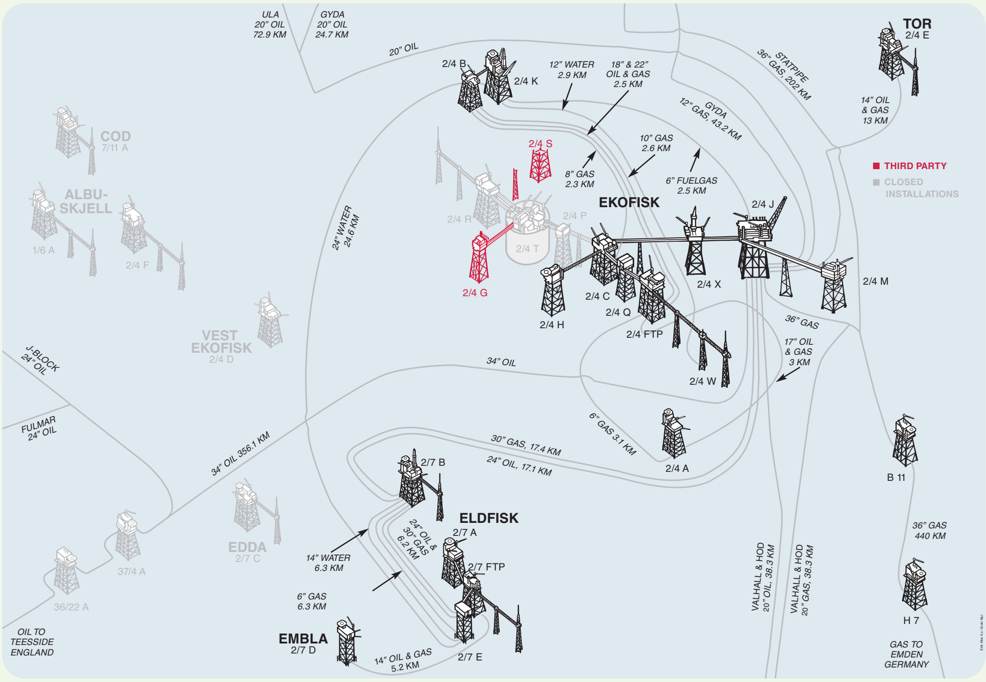


Figure 11.1 Facilites in the Ekofisk area
(Source: ConocoPhillips)

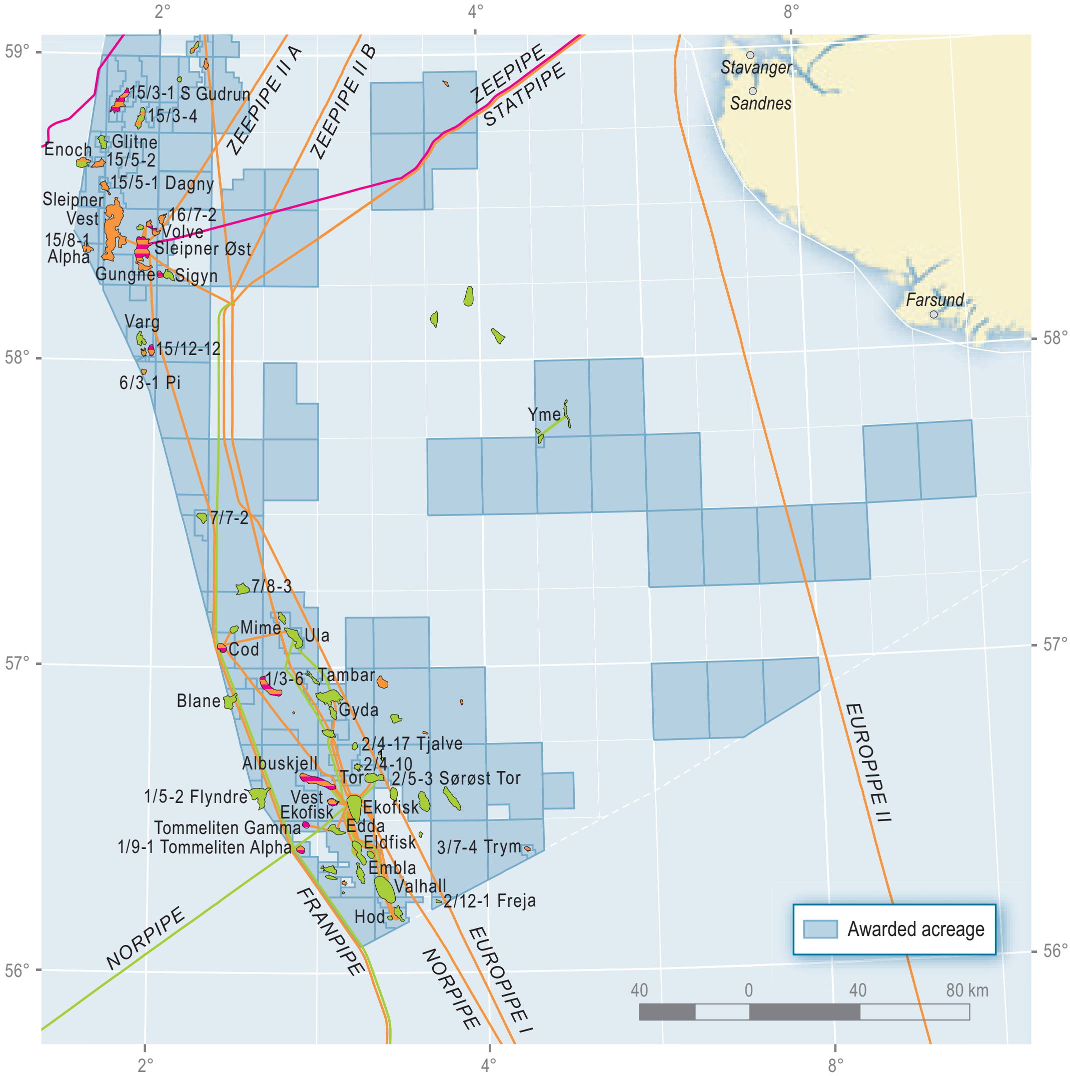


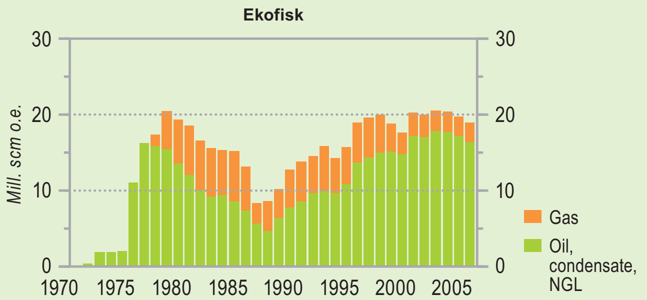
Figure 11.2 Southern North Sea
(Source: Norwegian Petroleum Directorate)

Ekofisk

Block and production licence	Block 2/4 – production licence 018. Awarded 1965.	
Discovery	1969	
Development approval	01.03.1972	
On stream	15.06.1971	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11%
	Eni Norge AS	2.39%
	Norsk Hydro Produksjon AS	6.65%
	Petoro AS	5,00%
	Statoil ASA	0.95%
	Total E&P Norge AS	39.90%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	531.2 million scm oil	169.6 million scm oil
	155.0 billion scm gas	26,3 billion scm gas
	14.2 million tonnes NGL	2.7 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 290,000 barrels/day Gas: 3.14 billion scm NGL: 0.28 million tonnes	
Investment	Total investment is expected to be NOK 148.3 billion (2006 values)	
	NOK 112.2 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
The sea depth in the area is between 70-75 metres. Production at Ekofisk began in 1971 from the jack-up facility Gulftide. During the first years, the field produced to tankers from four wells, until the concrete tank was in place in 1973. Since then, the field has been populated by many facilities, including riser facilities for associated fields and export pipelines. Several of these have been decommissioned and are awaiting disposal. Today, the operative parts of the Ekofisk Centre consist of the accommodation facilities, Ekofisk H and Ekofisk Q, the production facility Ekofisk C, the drilling and production facility Ekofisk X and the processing facility Ekofisk J. Ekofisk W is a wellhead facility for water injection. In the fall of 2005, a new facility, Ekofisk M, was put into service. This facility gives the field 30 new well slots, more risers and greater process capacity. From the wellhead facilities Ekofisk A and B on the south and north of the field, production goes to the riser facility Ekofisk FTP at the Ekofisk Centre. Ekofisk B is connected by bridge to Ekofisk K, which is the main facility for water injection.

Production from the Ekofisk field was formally started in 1971. Approval in principle of the technical system for development of the Ekofisk field was granted in 1972. Water injection was approved on 20.12.1983, Ekofisk II was approved on 09.11.1994, Ekofisk Growth was approved on 06.06.2003.



Reservoir:
The Ekofisk field produces from the Ekofisk and Tor chalk formations in the Upper Paleocene and Lower Cretaceous Ages. The reservoir rocks are fine-grained and dense, but pervasive fractures increase flow.

Recovery strategy:
Ekofisk was originally developed with pressure depletion as the drive mechanism. Since then, limited gas injection and comprehensive water injection have contributed to a substantial increase in oil recovery. Large scale water injection started in 1987, and in subsequent years the water injection area has been extended in several phases. Experience has proven that water displacement of the oil is more effective than expected, and the estimated reserves have been adjusted upwards correspondingly. In addition to the water injection, compaction of the soft chalk provides extra force to drainage of the field. This effect is reinforced because the injected water contributes to weakening the chalk.

Transport:
Oil and gas are routed to the export pipelines via the processing facility on Ekofisk J. Gas from the Ekofisk area is sent via pipeline to Emden, while the oil, which also contains the NGL fractions, is sent via pipeline to Teesside.

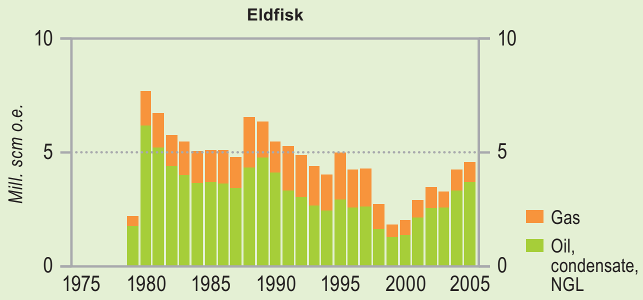
Status:
Production from Ekofisk is expected to maintain its current high level, and increase somewhat for a few more years. This is mainly due to increased numbers of wells and increased processing capacity from the new facility Ekofisk M. In relation to current plans, there are good chances for further increase in the reserves when water injection is optimised. High activity is expected to continue at the field over the coming years. A possible transfer of production from Ekofisk A and Ekofisk B is being evaluated. Two new facilities on the field are being evaluated. In the summer of 2006, the licence may decide to build a new accommodation facility and a new production facility is in the early conceptual stage. Continual drilling is, under the current strategy, the key to high recovery levels. In addition to efforts to optimise short and long-term production, work on cleaning and disposal of disused facilities is in progress.

Eldfisk

Block and production licence	Block 2/7 - production licence 018. Awarded 1965.	
Discovered	1970	
Development approval	25.04.1975	
On stream	08.08.1979	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11%
	Eni Norge AS	12.39%
	Norsk Hydro Produksjon AS	6.65%
	Petoro AS	5.00%
	Statoil ASA	0.95%
	Total E&P Norge AS	39.90%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	128.4 million scm oil	47.8 million scm oil
	51.1 billion scm gas	15.2 billion scm gas
	4.5 million tonnes NGL	1.0 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 66,000 barrels/day Gas: 0.71 billion scm NGL: 0.07 million tonnes	
Investment	Total investment is expected to be NOK 63.5 billion (2006 values)	
	NOK 44.8 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
The sea depth in the area is 70-75 metres. The original Eldfisk development consisted of three facilities. Eldfisk B is a combined drilling, wellhead and process facility, while Eldfisk A and FTP are wellhead and process facilities connected by a bridge. Eldfisk A also has drilling facilities. Oil and gas are transported in two pipelines to the Ekofisk Centre for onward transport to Teesside and Emden. Modifications have been made to Eldfisk and Ekofisk to enable the oil from Eldfisk to be piped directly to the export pumps on Ekofisk J. In 1999, a new water injection facility, Ekofisk E, was installed. The facility also supplies the Ekofisk field with some injection water through a pipeline from Eldfisk to Ekofisk K. Eldfisk water injection was approved on 12.12.1997. Upgrading of the capacity of Eldfisk was approved on 06.06.2003, as part of the plan for Ekofisk Growth.

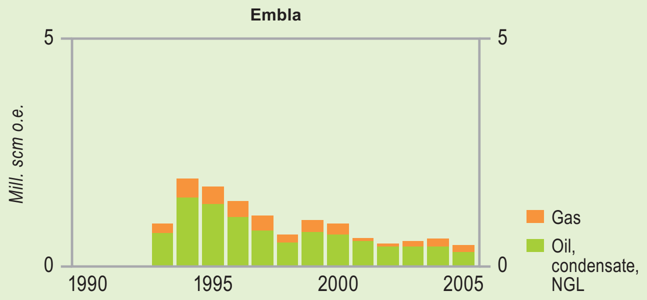
Reservoir:
The Eldfisk field produces from the Ekofisk, Tor and Hod chalk formations from the Lower Paleocene and Upper Cretaceous Ages. The reservoir rock is fine-grained and dense, but pervasive fractures increase flow. The field consists of three structures: Alpha, Bravo and Øst Eldfisk.



Recovery strategy:
Eldfisk was originally developed with pressure depletion as the drive mechanism. In 1999, water injection began at the field, based on horizontal injection wells. Gas is also injected in certain periods.

Transport:
Oil and gas are sent to the export pipelines through the Ekofisk Centre. Gas from the Ekofisk area is sent by pipeline to Emden, while the oil, which also contains the NGL fractions, is routed by pipeline to Teesside.

Status:
Eldfisk production is expected to remain constant over the next years. In relation to current plans, there is a great potential for increase in the reserves by increasing the number of wells and by optimising water injection. A study is in progress to determine measures to increase recovery from Eldfisk. These measures may imply new facilities.



Embla

Block and production licence	Block 2/7 - production licence 018. Awarded 1965.	
Discovered	1988	
Development approval	14.12.1990	
On stream	12.05.1993	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11%
	Eni Norge AS	12.39%
	Norsk Hydro Produksjon AS	6.65%
	Petoro AS	5.00%
	Statoil ASA	0.95%
	Total E&P Norge AS	39.90%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	14.5 million scm oil	5.6 million scm oil
	6.2 billion scm gas	3.3 billion scm gas
	0.6 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 11,000 barrels/day Gas: 0.26 billion scm NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 4.0 billion (2006 values)	
	NOK 4.0 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

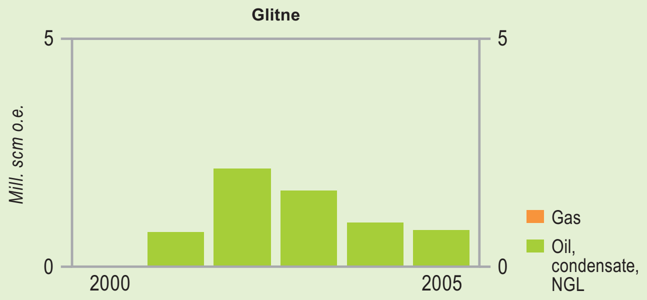
Development:
Embla has been developed with an unmanned wellhead facility which is remotely controlled from Eldfisk. The sea is 70-75 metres deep in the area. The amended PDO for Embla was approved on 25.04.1995.

Reservoir:
The Embla field produces from a segmented sandstone reservoir from the Devonian and Permian Ages. The reservoir is more than 4 000 metres beneath the seabed.

Recovery strategy:
Embla uses pressure depletion as the drive mechanism.

Transport:
Oil and gas are transported to Eldfisk and on to the Ekofisk Centre for export. Gas from the Ekofisk area is transported by pipeline to Emden, while the oil, which also contains the NGL fractions, is routed via pipeline to Teesside.

Status:
One additional well was drilled on Embla in 2005, and another is planned for 2006. Additional wells will be evaluated, based on the results of these wells. Without drilling more wells, production from Embla will decrease in the future.



Glitne

Blocks and production licences	Block 15/5 - production licence 048 B. Awarded 2001. Block 15/6 - production licence 029 B. Awarded 2001.	
Discovered	1995	
Development approval	08.09.2000 by the Crown Prince Regent in Council	
On stream	29.08.2001	
Operator	Statoil ASA	
Licensees	DONG Norge AS	9.30%
	Det Norske Oljeselskap AS	10.00%
	Statoil ASA	58.90%
	Total E&P Norge AS	21.80%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	7.6 million scm oil	1.2 million scm oil
Production	**Estimated production in 2006:** Oil: 10,000 barrels/day	
Investment	Total investment is expected to be NOK 1.7 billion (2006 values) NOK 1.7 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

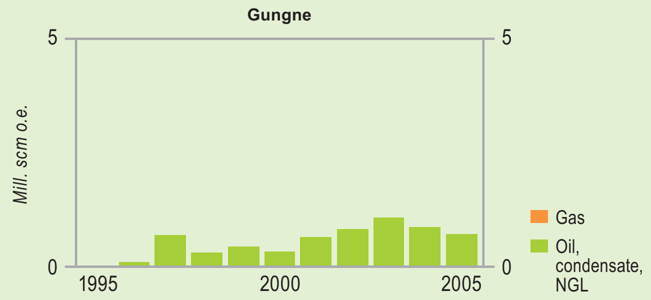
Development:
Glitne is an oilfield that lies 40 kilometres northeast of the Sleipner area. The sea depth in the area is 110 metres. The development consists of four production wells and a water injection well tied back to the floating production, storage and offloading vessel, Petrojarl 1.

Reservoir:
The reservoir consists of several separate sand sheets of deep-marine fan deposits in the upper Heimdal formation.

Recovery strategy:
Associated gas is used for gas lift in the wells, while excess gas is reinjected into the reservoir.

Transport:
Oil from Glitne is processed and stored on board the production vessel. The oil is exported using shuttle tankers.

Status:
Consideration is being given to drilling two new wells on the Glitne flanks. Increased reserves from these wells could extend production through 2009. Interpretation of reprocessed seismics will provide the basis for new well targets and possible deposits in the area.



Gungne

Block and production licence	Block 15/9 - production licence 046. Awarded 1976.	
Discovered	1982	
Development approval	29.08.1995 by the King in Council	
On stream	21.04.1996	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and Production Norway AS	28.00%
	Norsk Hydro Produksjon AS	9.40%
	Statoil ASA	52.60%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.20051**
	12.2 billion scm gas	12.2 billion scm gas
	1.6 million tonnes NGL	0.4 million tonnes NGL
	4.3 million scm condensate	0.6 million scm condensate
Production	**Estimated production in 2006:**	
	Gas: 1.16 billion scm NGL: 0.20 million tonnes Condensate: 0.48 million scm	
Investment	Total investment is expected to be NOK 1.3 billion (2006 values)	
	NOK 1.3 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

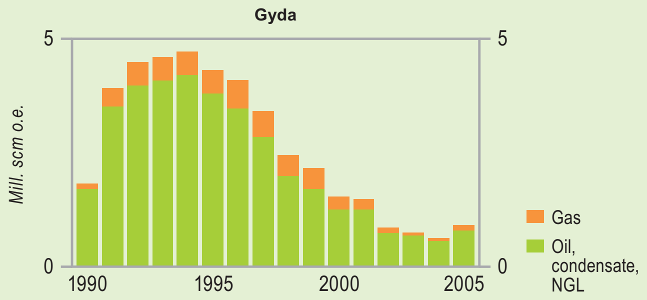
The remaining gas reserves are shown as equal to the original, because gas production from Gungne, Sleipner Vest and Sleipner Øst are measured together.

Development:
Gungne is a gas field and the sea depth in the area is 83 metres. Gungne produces via two wells drilled from Sleipner A.

Reservoir:
Gungne produces gas and condensate mainly from sandstone reservoirs in the Skagerrak formation from the Triassic Age. The reservoir characteristics are generally good, but the reservoir is segmented and lateral, continuous shale layers act as barriers.

Recovery strategy:
Gungne produces using pressure depletion as the drive mechanism.

Transport:
Gas and condensate from Sleipner Øst and Gungne are processed on Sleipner A. Processed gas from Sleipner A is mixed with gas from Troll and exported in pipeline via Draupner to Zeebrugge.



Gyda

Block and production licence	Block 2/1 - production licence 019 B. Awarded 1977.	
Discovered	1980	
Development approval	02.06.1987 by the Storting	
On stream	21.06.1990	
Operator	Talisman Energy Norge AS	
Licensees	DONG Norge AS	34.00%
	Norske AEDC A/S	5.00%
	Talisman Energy Norge AS	61.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	37.8 million scm oil	4.9 million scm oil
	6.2 billion scm gas	0.7 billion scm gas
	1.9 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 14,000 barrels/day Gas: 0.17 billion scm NGL: 0.03 million tonnes	
Investment	Total investment is expected to be NOK 15.2 billion (2006 values)	
	NOK 14.4 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

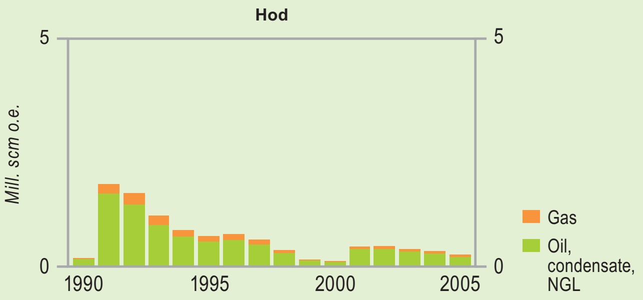
Development:
The Gyda field has been developed with a combined drilling, accommodation and processing facility with a steel jacket. The sea depth in the area is 66 metres.

Reservoir:
The reservoir consists of Upper Jurassic sandstones.

Recovery strategy:
The field produces with water injection as the drive mechanism. Starting in 2006, also produced water will be reinjected into the reservoir for pressure support.

Transport:
The oil is transported to Ekofisk via the oil pipeline from Ula and on to Teesside. The gas is transported in a dedicated pipeline to Ekofisk for onward transport to Emden.

Status:
Water production is increasing and new wells are being drilled to extract as much as possible of the remaining reserves.



Hod

Block and production licence	Block 2/11 - production licence 033. Awarded 1969.
Discovered	1974
Development approval	26.06.1988 by the Storting
On stream	30.09.1990
Operator	BP Norge AS
Licensees	Amerada Hess Norge AS 25.00% BP Norge AS 25.00% Enterprise Oil Norge AS 25.00% Total E&P Norge AS 25.00%
Recoverable reserves	**Original:** 10.0 million scm oil, 1.7 billion scm gas, 0.4 million tonnes NGL **Remaining as of 31.12.2005:** 1.9 million scm oil, 0.3 billion scm gas, 0.2 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 7,000 barrels/day Gas: 0.07 billion scm NGL: 0.01 million tonnes
Investment	Total investment is expected to be NOK 2.4 billion (2006 values) NOK 2.3 billion had been invested as of 31.12.05 (2006 values)
Operating organisation	Stavanger
Main supply base	Tananger

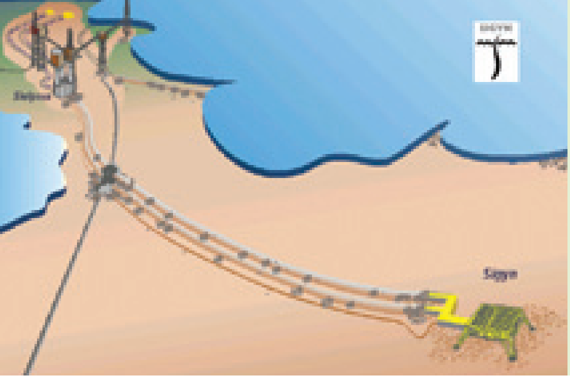
Development:
Hod is an oil field and the sea depth in the area is 72 metres. The field is developed with an unmanned production facility, which is remotely controlled from the Valhall field 13 kilometres farther north. The PDO for the Hod Sadel area was approved on 20.06.1994.

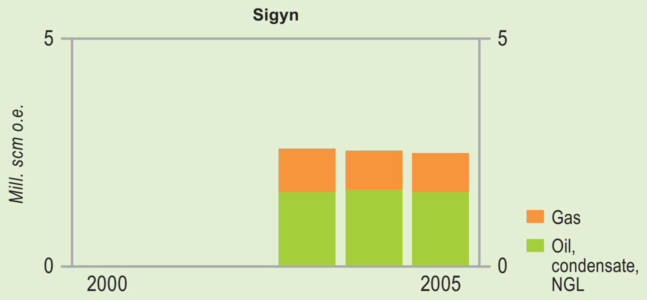
Reservoir:
The field produces from chalk in the Ekofisk, Tor and Hod formations. The field consists of the three structures Hod Vest, Hod Øst and Hod Sadel.

Recovery strategy:
Recovery takes place through pressure depletion. Since 2001, gas lift has been used in the most important well in the field to increase production.

Transport:
Oil and gas are transported in a shared pipeline to Valhall for further processing. The transport systems to Teesside and Emden are used for onward transport.

Status:
Production from Hod Øst and Hod Vest is stable at a low level. The field is in a late phase with the current recovery strategy. Water injection is being evaluated to improve the recovery from the Hod Øst structure. A well was drilled into the Sadel area in 2005 from the facility south on Valhall. Several additional wells are planned to increase production from Hod. A water injection pilot started in early 2006.





Sigyn

Block and production licence	Block 16/7 - production licence 072. Awarded 1981.	
Discovered	1982	
Development approval	31.08.2001 by the King in Council	
On stream	22.12.2002	
Operator	ExxonMobil Exploration and Production Norway AS	
Licensees	ExxonMobil Exploration and Production Norway AS	40.00%
	Norsk Hydro Produksjon AS	10.00%
	Statoil ASA	50.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	6.9 billion scm gas	4.3 billion scm gas
	2.9 million tonnes NGL	1.9 million tonnes NGL
	5.5 million scm condensate	2.5 million scm condensate
Production	**Estimated production in 2006:**	
	Gas: 0.77 billion scm NGL: 0.25 million tonnes Condensate: 0.59 million scm	
Investment	Total investment is expected to be NOK 2.3 billion (2006 values)	
	NOK 2.2 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
Sigyn is located in the Sleipner area and the sea depth in the area is around 70 metres. The field has been developed with a subsea template as a satellite of Sleipner Øst. The wellstream is controlled from Sleipner Øst and is sent through two pipelines to the Sleipner A facility.

Reservoir:
The field consists of the Sigyn Vest deposits, which contain gas/condensate, and Sigyn Øst, which contains light oil. The main reservoir is located in the Skagerrak formation of the Triassic Age.

Recovery strategy:
The field is produced with pressure depletion as the drive mechanism.

Transport:
The gas is exported using the dry gas system at Sleipner. Condensate is transported via the condensate pipeline from Sleipner A to Kårstø.

Sleipner Vest

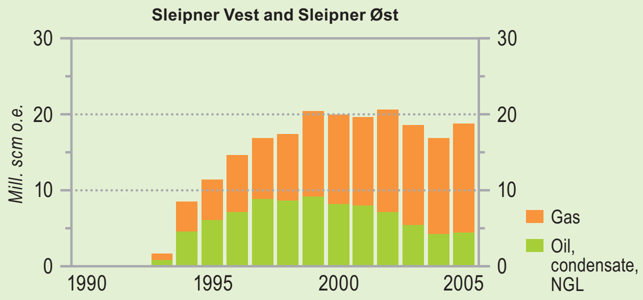
Blocks and production licences	Block 15/6 - production licence 029. Awarded 1969. Block 15/9 - production licence 046. Awarded 1976.	
Discovered	1974	
Development approval	14.12.1992 by the Storting	
On stream	29.08.1996	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and Produksjon Norway AS	32.24%
	Norsk Hydro Produksjon AS	8.85%
	Statoil ASA	49.50%
	Total E&P Norge AS	9.41%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005***
	107.8 billion scm gas	51.6 billion scm gas
	8.1 million tonnes NGL	4.4 million tonnes NGL
	28.1 million scm condensate	3.9 million scm condensate
Production	**Estimated production in 2006:** Gas: 9.82 billion scm NGL: 0.45 million tonnes Condensate: 1.59 million scm	
Investment	Total investment is expected to be NOK 24.0 billion (2006 values) NOK 23.0 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

** Gas production from Gungne, Sleipner Vest and Sleipner Øst is measured collectively. The remaining reserves show Sleipner Øst and Sleipner Vest in total.*

Development:
Sleipner Vest is a gas field and the sea depth in the area is 110 metres. The field is developed with a wellhead facility, Sleipner B, and a processing facility, Sleipner T. The Alpha Nord segment has been developed with a subsea template and four production wells. The subsea template is tied back to Sleipner T.

Reservoir:
Sleipner Vest produces from the Middle Jurassic Sleipner and Hugin formations. Most of the reserves are found in the Hugin formation, which consists of a sequence of beach deposits. The underlying Sleipner formation has fluvial deposits. The faults in the field are generally not sealing, and communication between the geological sand accumulations is generally good.

Recovery strategy:
Sleipner Vest production is driven by pressure depletion.



The figure shows total production from Sleipner Vest and Sleipner Øst

Transport:
Gas and condensate from Sleipner Vest are processed at Sleipner T, where CO_2 is also removed from the gas. Processed gas from Sleipner Vest is injected into the Ty formation at Sleipner Øst. The gas that is not injected goes to Sleipner A for export. CO_2 is injected in the Utsira formation via a dedicated injection well from Sleipner A. Unstable condensate from Sleipner Vest and Sleipner Øst is combined at Sleipner A and sent to Kårstø for processing to stable condensate and NGL products.

Status:
By reducing the inlet pressure on Sleipner T, the process capacity has been 110 percent of the design basis. To maintain production when the field comes off plateau in 2007, evaluation is being given to further decreasing the inlet pressure by installing a new compressor. Drilling of nearby deposits is also being evaluated.

Sleipner Øst

Block and production licence	Block 15/9 - production licence 046. Awarded 1976.	
Discovered	1981	
Development approval	15.12.1986 by the Storting	
On stream	24.08.1993	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and Production Norway AS	30.40%
	Norsk Hydro Produksjon AS	10.00%
	Statoil ASA	49.60%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005***
	66.3 billion scm gas	51.6 billion scm gas
	12.8 million tonnes NGL	4.4 million tonnes NGL
	27.5 million scm condensate	3.9 million scm condensate
Production	**Estimated production in 2006:**	
	Gas: 2.38 billion scm NGL: 0.23 million tonnes Condensate: 0.42 million scm	
Investment	Total investment is expected to be NOK 36.9 billion (2006 values)	
	NOK 32.5 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

** Gas production from Gungne, Sleipner Vest and Sleipner Øst is measured collectively. The remaining reserves show Sleipner Øst and Sleipner Vest in total.*

Development:
Sleipner Øst is a gas and condensate field. The sea depth in the area is 82 metres. The field has been developed with an integrated processing, drilling and accommodation facility with a concrete jacket, Sleipner A. A separate riser facility has also been built, Sleipner R, which is bridge connected to Sleipner A. Sleipner R also connects Sleipner A to the pipelines for gas transport, two subsea templates and the flare stack Sleipner F. A subsea template has been installed for production from the northern part of Sleipner Øst and one for production at Loke. Three Sigyn wells are also tied back to Sleipner A.

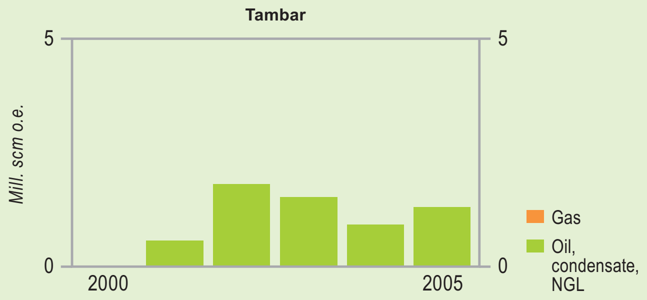
The PDO for Loke was approved in 1991 and production started in 1993. Development of Loke Triassic was approved on 29.08.1995 and production started on 19.06.1998.

Reservoir:
The Sleipner Øst and Loke resources are mainly found in sandstones in the Ty formation from the Tertiary Age and sandstones in the Hugin formations from the Middle Jurassic Age. There is no pressure communication between the two reservoir zones. The Hugin formation consists of shallow marine deposits and coastal, land-deposited sediments. The Ty reservoir consists of shallow marine fan deposits. Below the Hugin formation is the Triassic Skagerrak formation. The Skagerrak formation makes up the main reservoir at Loke and consists of alluvial deposits with moderate to poor reservoir characteristics.

Recovery strategy:
The Hugin reservoir produces with pressure depletion. The Ty reservoir has received pressure support from gas injection, but this was concluded in 2005. To optimise production, the wells are now produced with a reduced inlet pressure in separator B. The wellstream from Sleipner Øst is processed on Sleipner A, together with production from Gungne and Sigyn.

Transport:
Unstable condensate from Sleipner Vest and Sleipner Øst is mixed and sent to Kårstø for processing into stable condensate and NGL products. Processed gas is mixed with gas from Troll and exported via Draupner to Zeebrugge. Starting in 2007, gas from Ormen Lange will be exported through the Langeled pipeline from Nyhamna via Sleipner A to the UK.

Status:
Sleipner Øst came off plateau in December 2005. Two new wells were drilled in 2005 to increase the well potential, and more wells are planned in 2006. A project has been initiated to evaluate the possible benefit of lowering the inlet pressure even more.



Tambar

Blocks and production licences	Block 1/3 - production licence 065. Awarded 1981. Block 2/1 - production licence 019 B. Awarded 1977.	
Discovered	1983	
Development approval	03.04.2000 by the King in Council	
On stream	15.07.2001	
Operator	BP Norge AS	
Licensees	BP Norge AS DONG Norge AS	55.00% 45.00%
Recoverable reserves	**Original:** 8.3 million scm oil 2.6 billion scm gas 0.2 million tonnes NGL	**Remaining as of 31.12.2005** 2.4 million scm oil 2.6 billion scm gas 0.1 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 15,000 barrels/day Gas: 0.39 billion scm NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 2.2 billion (2006 values) NOK 1.6 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

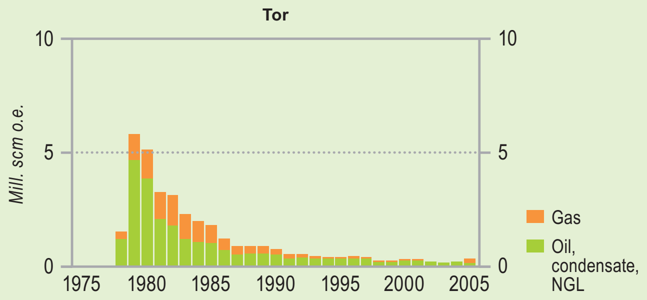
Development:
Tambar is an oilfield located southeast of the Ula field. The sea depth in the area is 68 metres. The field has been developed with an unmanned wellhead facility.

Reservoir:
The reservoir consists of Upper Jurassic sandstones deposited in a shallow marine environment. The reservoir quality varies, and the reservoir is divided into zones according to the quality of the sand.

Recovery strategy:
Three wells have been drilled that produce with pressure depletion as the drive mechanism.

Transport:
Production is transported to Ula through the Ula Gyda Interconnector Pipeline (UGIP) for processing. UGIP is an interim solution until a new pipeline is in place by 1 September 2007. Oil is exported in the existing pipeline system to Teesside via Ekofisk. The gas is injected into the Ula reservoir to contribute to increased oil recovery.

Status:
Installation of a multiphase pump is planned to increase oil recovery. A study will be conducted in 2006 to evaluate water injection and well requirements.



Tor

Blocks and production licences	Block 2/4 - production licence 018. Awarded 1965. Block 2/5 - production licence 006. Awarded 1965.	
Discovered	1970	
Development approval	04.05.1973	
On stream	28.06.1978	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	30.66%
	Eni Norge AS	10.82%
	Norsk Hydro Produksjon AS	5.81%
	Petoro AS	3.69%
	Statoil ASA	0.83%
	Total E&P Norge AS	48.20%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	25.3 million scm oil	3.2 million scm oil
	11.5 billion scm gas	0.8 billion scm gas
	1.2 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 6,000 barrels/day Gas: 0.08 billion scm NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 8.6 billion (2006 values) NOK 8.3 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

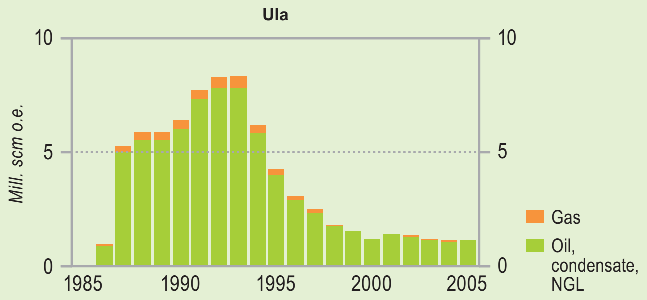
Development:
Tor is an oil field that has been developed with a combined wellhead and processing facility. The Tor field development was approved as part of the Ekofisk development. The sea depth in the area is 70 metres.

Reservoir:
The main reservoir at Tor is at a depth of around 3 200 metres and consists of fractured chalk belonging to the Tor formation. The Ekofisk formation also contains oil, but has poor production characteristics.

Recovery strategy:
Tor was originally produced by pressure depletion. In 1992, limited water injection commenced. The facility has subsequently been upgraded and the scope of water injection has been expanded.

Transport:
Oil and gas are exported via the processing facility at Ekofisk J. Gas from the Ekofisk area is transported by pipeline to Emden, while the oil, which also contains NGL fractions, is sent via pipeline to Teesside.

Status:
A study is currently evaluating the future of Tor. A new production well will be drilled in 2006 as part of this work.



Ula

Blocks and production licences	Block 7/12 - production licence 019. Awarded 1965. Block 7/12 - production licence 019 B. Awarded 1977.	
Discovered	1976	
Development approval	30.05.1980 by the Storting	
On stream	06.10.1986	
Operator	BP Norge AS	
Licensees	BP Norge AS DONG Norge AS Svenska Petroleum Exploration AS	80.00% 5.00% 15.00%
Recoverable reserves	**Original:** 80.0 million scm oil 3.8 billion scm gas 3.1 million tonnes NGL	**Remaining as of 31.12.2005** 13.2 million scm oil 0.6 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 25,000 barrels/day NGL: 0.04 million tonnes	
Investment	Total investment is expected to be NOK 21.1 billion (2006 values) NOK 20.2 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Ula is an oilfield and the sea depth in the area is 70 metres. The development consists of three conventional steel facilities for production, drilling and accommodation. The facilities are connected by bridges.

Reservoir:
The main reservoir is in Upper Jurassic sandstones. The sand was deposited in a shallow marine environment. Permeability varies from good to very good, but deteriorates towards the flanks.

Recovery strategy:
Initially, oil was recovered by pressure depletion, but after some years water injection was implemented to increase recovery. WAG (water/alternating gas injection) started in 1998. As access to gas increased by processing production from Tambar at Ula, the WAG programme has been extended.

Transport:
The oil is transported by pipeline via Ekofisk to Teesside. All gas is reinjected into the reservoir in order to increase oil recovery.

Status:
The Blane field will be tied back to the Ula field for processing. Gas from Blane will be used for injection in Ula. At the same time, Ula gas capacity will be upgraded. Based on the good effect on oil recovery, evaluation is ongoing to expand the WAG program by drilling additional wells and importing more gas for injection.

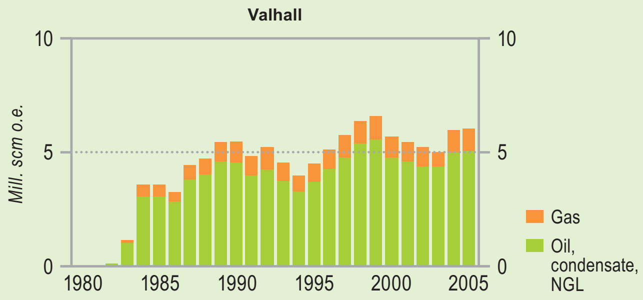
Valhall

Blocks and production licences	Block 2/11 - production licence 033 B. Awarded 2001. Block 2/8 - production licence 006 B. Awarded 2000.	
Discovered	1975	
Development approval	02.06.1977 by the Storting	
On stream	02.10.1982	
Operator	BP Norge AS	
Licensees	Amerada Hess Norge AS	28.09%
	BP Norge AS	28.09%
	Enterprise Oil Norge AS	28.09%
	Total E&P Norge AS	15.72%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	170.9 million scm oil	82.3 million scm oil
	31.9 billion scm gas	14.3 billion scm gas
	5.9 million tonnes NGL	3.0 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 87,000 barrels/day Gas: 1.05 billion scm NGL: 0.12 million tonnes	
Investment	Total investment is expected to be NOK 59.0 billion (2006 values) NOK 44.5 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Valhall is an oilfield located in an area with a sea depth of 70 metres. The field was originally developed with three facilities, for accommodation, drilling and production. In 1996, a riser facility (Valhall WP) with slots for 19 additional wells was installed. The four facilities are connected by bridges. A water injection facility was installed centrally in the field in the summer of 2003 and connected by bridge to Valhall WP. The drilling rig on this facility will also be used by Valhall WP. The flank development consists of two wellhead facilities positioned in the north and south of the field. The southern facility came on stream in 2003 and the northern facility came on stream in 2004. Valhall processes production from Hod, and delivers gas for gas lift in Hod's wells. The PDO for Valhall WP was approved on 02.06.1995. The PDO for Valhall water injection was approved on 03.11.2000. The PDO for Valhall flank development was approved on 09.11.2001.

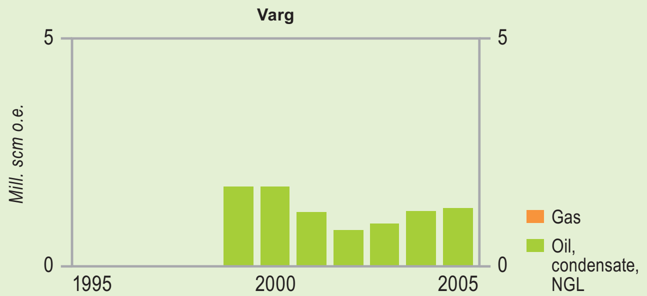
Reservoir:
The Valhall field produces from chalk in the Tor and Hod formations from the Upper Cretaceous Age. The chalk in the Tor formation is fine-grained and soft, with continuous fractures that allow oil and water to flow more easily. As a result of the production, the chalk has compacted, causing subsidence of the seabed at Valhall.

Recovery strategy:
Recovery originally took place using pressure depletion with compaction. Water injection in the centre of the field started in January 2004.



Transport:
Oil and NGL are routed via pipeline to Ekofisk for onward transport to Teesside. Gas is sent via pipeline to Norpipe for onward transport to Emden.

Status:
Production from Valhall is expected to increase from current rates as a consequence of the increased number of wells and the effect of water injection. In relation to current planning, there are significant possibilities for further increases in reserves by using all well slots and optimising water injection. As the seabed has subsided, and the original facilities have aged, the licensees are planning a new facility with processing plant and accommodation. A decision has been made to supply electric power to this facility from land. A PDO is expected in 2006.



Varg

Block and production licence	Block 15/12 - production licence 038. Awarded 1975.	
Discovered	1984	
Development approval	03.05.1996 by the King in Council	
On stream	22.12.1998	
Operator	Talisman Energy Norge AS	
Licensees	Pertra AS	5.00%
	Petoro AS	30.00%
	Talisman Energy Norge AS	65.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	12.6 million scm oil	3.7 million scm oil
Production	**Estimated production in 2006:**	
	Oil: 26,000 barrels/day	
Investment	Total investment is expected to be NOK 6.8 billion (2006 values)	
	NOK 6.6 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Trondheim	
Main supply base	Tananger	

Development:
Varg is an oilfield to the south of Sleipner Øst. The the sea depth in the area is 84 metres. The field has been developed with a production vessel (Petrojarl Varg) with integrated oil storage, and a connected wellhead facility (Varg A).

Reservoir:
The field contains oil in Upper Jurassic sandstone reservoirs. The structure is segmented by faults.

Recovery strategy:
Recovery currently takes place by means of water and gas injection. The decommissioning plan for the field was approved in 2001, and the plan was to produce until the summer of 2002. However, the operator has succeeded in increasing the reserves on the field, and has proven and developed additional resources. Production from the Varg Vest segment, which started in 2004, has been instrumental in extending the life of the Varg field.

Transport:
Oil is offloaded from the production vessel onto shuttle tankers.

Northern North Sea

The northern part of the North Sea encompasses the three main areas Tampen, Troll/Oseberg and Heimdal/Balder. 28 fields are currently producing in the Northern North Sea, and three fields are being developed. The Tampen area holds many of the largest oil fields on the Norwegian continental shelf, such as Statfjord, Snorre and Gullfaks. Although Tampen is a mature petroleum province, there is still a substantial resource potential, and production from this area is expected to continue for at least another 20 years.

Troll plays a very important role for gas supplies from the Norwegian continental shelf, and it will remain the main source of Norwegian gas exports throughout this century. Significant oil production has also developed on the Troll field. The Oseberg area includes Brage and Veslefrikk, in addition to the Oseberg fields. Oil production from the Oseberg area is declining, but will remain important for many years to come. Heimdal has become a gas centre, carrying out processing services for other fields.

In recent years, there have been many developments in the Northern North Sea, as well as decisions to develop many new discoveries. Some of these fields border on the British continental shelf and are tied back to fields on the British side. Oil and gas from fields in the Northern North Sea are transported by tankers or by pipeline to land facilities in Norway and the UK.

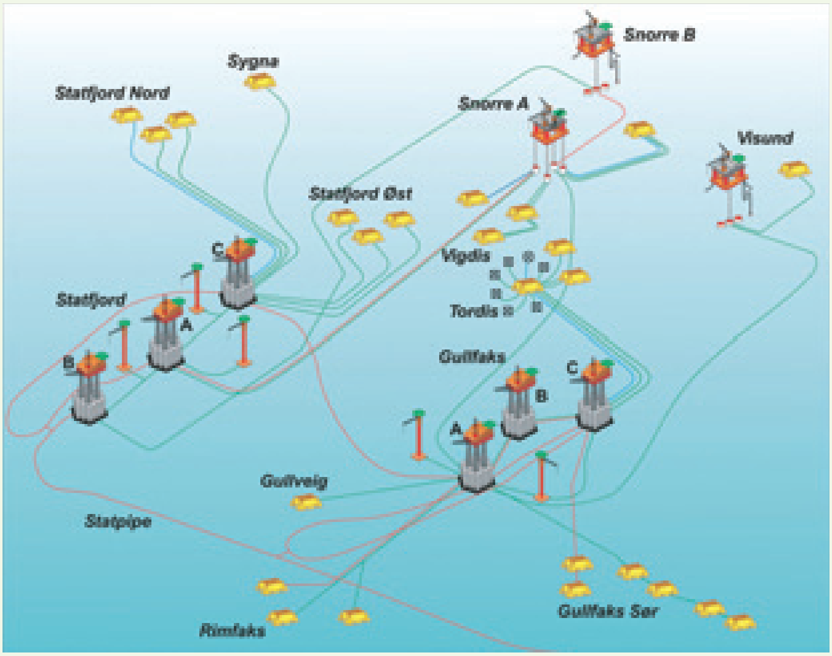


Figure 11.3 The Tampen area
(Source: Statoil)

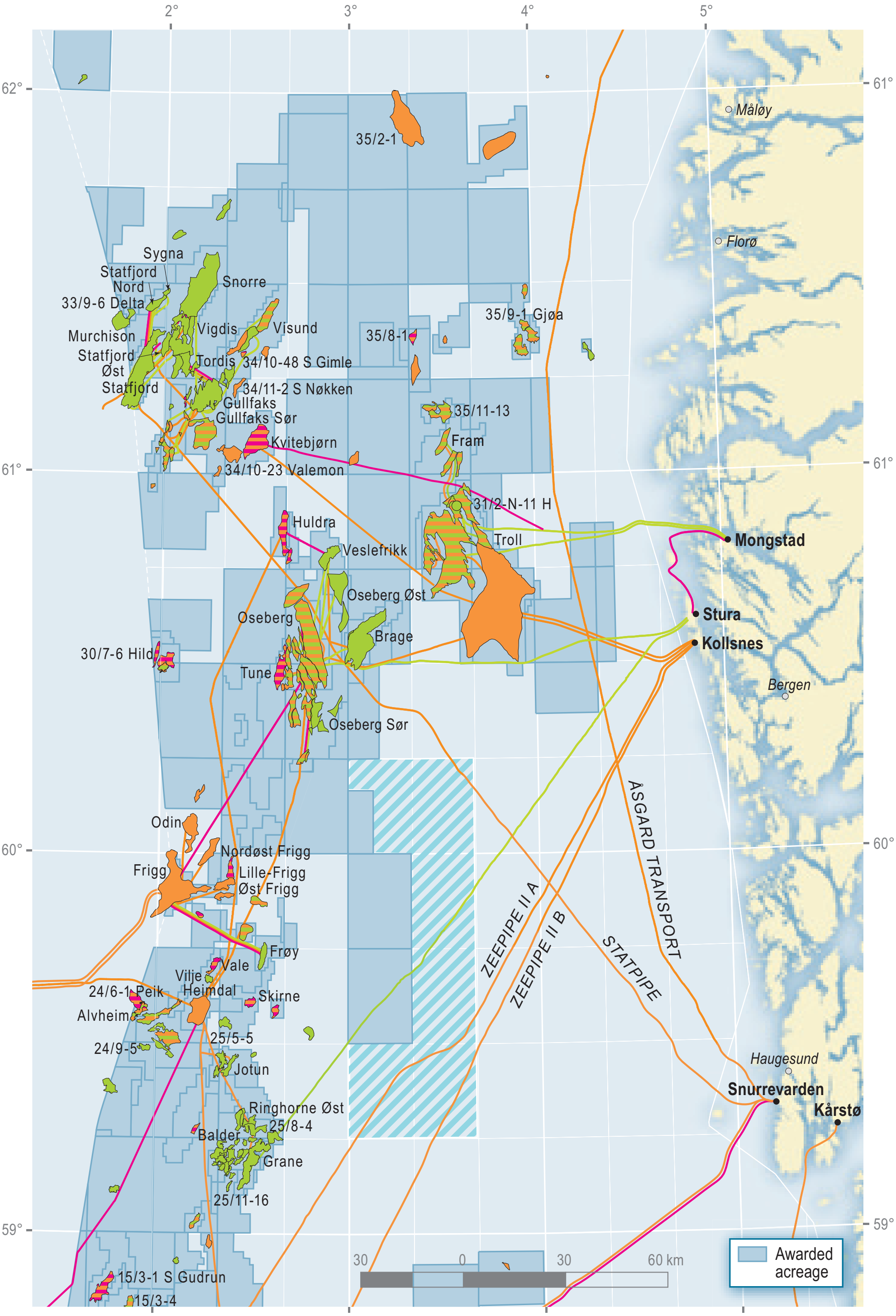
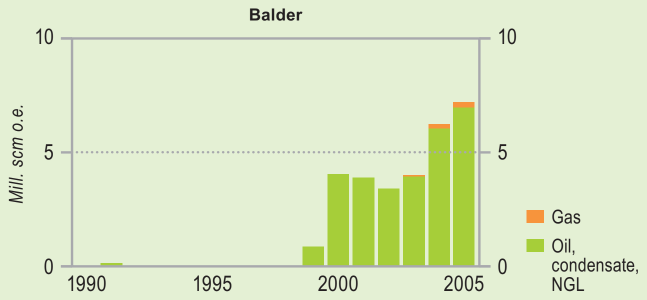


Figure 11.4 Northern North Sea
(Source: Norwegian Petroleum Directorate)



Balder

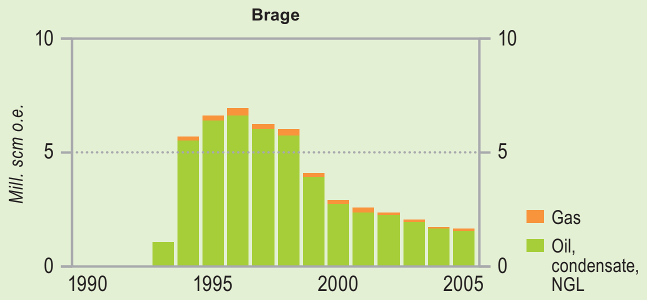
Blocks and production licences	Block 25/10 - production licence 028. Awarded 1969. Block 25/11 - production licence 001. Awarded 1965. Block 25/8 - production licence 027. Awarded 1969. Block 25/8 - production licence 027 C. Awarded 2000. Block 25/8 - production licence 169. Awarded 1991.	
Discovered	1967	
Development approval	02.02.1996 by the King in Council	
On stream	02.10.1999	
Operator	ExxonMobil Exploration and Production Norway AS	
Licensees	ExxonMobil Exploration and Production Norway AS	100.00%
Recoverable reserves	**Original:** 61.6 million scm oil 1.6 billion scm gas	**Remaining as of 31.12.2005** 32.3 million scm oil 1.1 billion scm gas
Production	**Estimated production in 2006:** Oil: 108,000 barrels/day Gas: 0.29 billion scm	
Investment	Total investment is expected to be NOK 26.4 billion (2006 values) NOK 23.4 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
Balder is an oil field 190 kilometres west of Stavanger. The sea depth in the area is 125 metres. The field has been developed with subsea wells tied back to the accommodation, production and storage vessel, Balder FPU, where oil and gas are processed. The Ringhorne discovery, which is part of the Balder field, has been developed with a combined accommodation, drilling and wellhead facility, which is also tied back to Balder FPU, and a subsea template with one oil production well and one water injection well. The PDO for Ringhorne was approved on 11.05.2000 and production started on 21.05.2001. An amended PDO for Ringhorne was approved on 14.02.2003.

Reservoir:
Balder contains several separate structures of Tertiary sandstones. Ringhorne includes several Tertiary sand structures and a main reservoir of Jurassic sandstones.

Recovery strategy:
Balder is recovered by aquifer drive, as well as water injection and gas injection.

Transport:
Oil and gas from the Jurassic reservoir at Ringhorne are transported to Jotun for processing, while oil from the Tertiary reservoirs is routed to Balder. Excess gas from Balder is in part reinjected into the reservoir, while the rest goes to Jotun for export via Statpipe.



Brage

Blocks and production licences	Block 30/6 - production licence 053 B. Awarded 1998. Block 31/4 - production licence 055. Awarded 1979. Block 31/7 - production licence 185. Awarded 1991.	
Discovered	1980	
Development approval	29.03.1990 by the Storting	
On stream	23.09.1993	
Operator	Norsk Hydro Produksjon AS	
Licensees	Endeavour Energy Norge AS	4.44%
	Eni Norge AS	12.26%
	Norsk Hydro Produksjon AS	20.00%
	Paladin Resources Norge AS	20.00%
	Petoro AS	14.26%
	Revus Energy AS	2.50%
	Statoil ASA	12.70%
	Talisman Energy Norge AS	13.84%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	49.8 million scm oil	3.6 million scm oil
	2.4 billion scm gas	0.3 billion scm gas
	0.8 million tonnes NGL	
Production	**Estimated production in 2006:** Oil: 19,000 barrels/day Gas: 0.08 billion scm	
Investment	Total investment is expected to be NOK 17.9 billion (2006 values) NOK 17.3 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

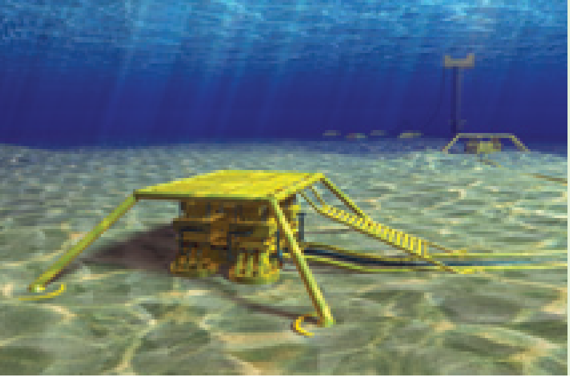
Development:
The Brage field is an oilfield and has been developed with a fixed integrated production, drilling and accommodation facility with a steel jacket. Test production from the Sognefjord formation took place in 1997, and this deposit was approved for development on 20.10.1998. The sea depth in the area is 140 metres.

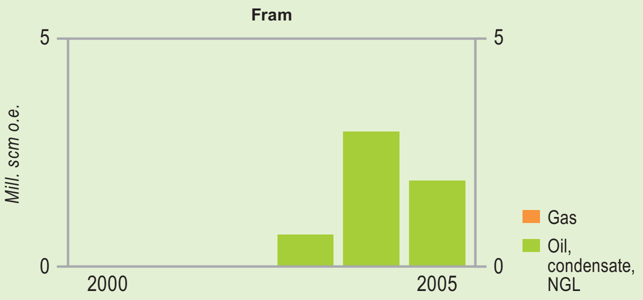
Reservoir:
The Brage field consists of sandstone reservoirs in the Lower Jurassic Statfjord formation, the Middle Jurassic Fensfjord formation and Upper Jurassic Sognefjord formation.

Recovery strategy:
The recovery mechanism in the Statfjord formation is water injection, and in the Fensfjord formation both water and gas injection. The Sognefjord formation is recovered with pressure depletion.

Transport:
The oil is sent by pipeline to Oseberg and on through the pipeline in the Oseberg Transport System (OTS) to the Sture terminal. A gas pipeline is tied back to Statpipe.

Status:
Brage is in tail production, and work is proceeding to find new ways of increasing recovery from the field. Development of the Sognefjord reservoir with a new subsea template in the northern part of the field was planned, but the results of drilling carried out in 2005 indicated that the resources were less than expected. Adding chemicals to the injection water to improve water flow is one of the methods being evaluated.





Fram

Block and production licence	Block 35/11 - production licence 090. Awarded 1984.	
Discovered	1992	
Development approval	23.03.2001 by the King in Council	
On stream	02.10.2003	
Operator	Norsk Hydro Produksjon AS	
Licensees	Gaz de France Norge AS	15.00%
	Idemitsu Petroleum Norge AS	15.00%
	Mobil Development Norway AS	25.00%
	Norsk Hydro Produksjon AS	25.00%
	Statoil ASA	20.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	21.0 million scm oil	15.5 million scm oil
	10.2 billion scm gas	10.2 billion scm gas
	0.2 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 23,000 barrels/day Gas: 0.12 billion scm	
Investment	Total investment is expected to be NOK 8.7 billion (2006 values)	
	NOK 4.9 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

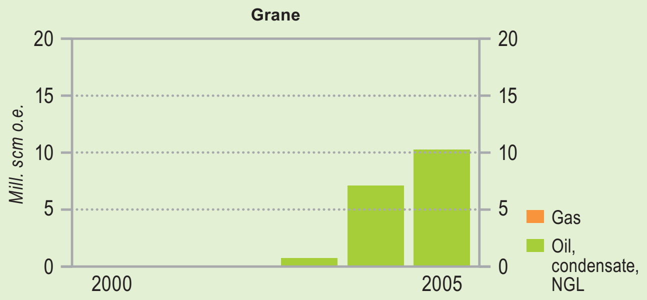
Development:
Fram is an oilfield located about 22 kilometres north of Troll. The sea depth in the area is 350 metres. The Fram Vest development consists of two subsea templates tied back to Troll C. The gas is separated from the liquid on Troll C and reinjected into the Fram Vest reservoir. Development of Fram Øst was approved on 22.04.2005. The development includes two new subsea templates tied back to Troll C. Planned production start-up is October 2006.

Reservoir:
The Fram Vest and Fram Øst reservoirs consist of Upper Jurassic sandstones in rotated fault blocks.

Recovery strategy:
Production takes place with gas injection as pressure support.

Transport:
The Fram wellstream is transported by pipeline to Troll C for processing. The oil is then transported to Mongstad through the Troll Oljerør II pipeline. When gas injection ceases, the gas will be exported via Troll A to Kollsnes.

Status:
Fram's lifetime is dependent on the lifetime of Troll C. Consideration is being given to drilling additional wells on Fram to increase production.



Grane

Blocks and production licences	Block 25/11 - production licence 001. Awarded 1965. Block 25/11 - production licence 169 B1. Awarded 2000. Block 25/11 - production licence 169 B2. Awarded 2000.	
Discovered	1991	
Development approval	14.06.2000 by the Storting	
On stream	23.09.2003	
Operator	Norsk Hydro Produksjon AS	
Licensees	ExxonMobil Exploration and Production Norway AS	25.60%
	Norsk Hydro Produksjon AS	38.00%
	Norske ConocoPhillips AS	6.40%
	Petoro AS	30.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	120.0 million scm oil	101.9 million scm oil
Production	**Estimated production in 2006:**	
	Oil: 204,000 barrels/day	
Investment	Total investment is expected to be NOK 19.6 billion (2006 values) NOK 14.6 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
The Grane oil field is located to the east of the Balder field, and has been developed with an integrated accommodation, drilling and processing facility with a fixed steel jacket. The facility has 40 well slots. The sea depth in the area is 127 metres.

Reservoir:
The field consists of one main reservoir structure and some additional segments. The reservoir consists of Tertiary sandstones in the Heimdal formation with good reservoir characteristics. The oil has high viscosity. Smaller amounts of oil are also found in the Lista formation above the main structure.

Recovery strategy:
The recovery mechanism is gas injection at the top of the structure, and long-range horizontal production wells at the bottom of the oil zone. Water is also injected into the reservoir. The oil in the Lista reservoir will probably be drained as a result of the gas injection in the Heimdal formation.

Transport:
Oil from Grane is sent by pipeline to the Sture terminal where it is stored and shipped. Injection gas is imported through a pipeline from the Heimdal facility.

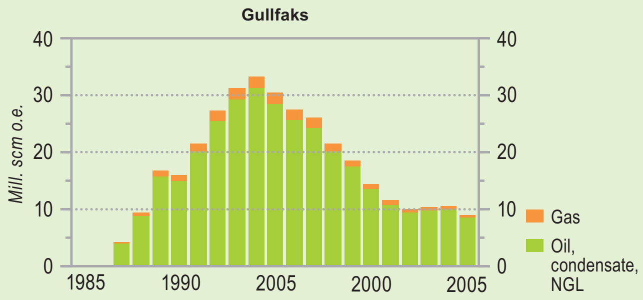
Status:
Additional wells are planned to be drilled on Grane. They will be drilled as multi-branch wells. A study is also being conducted on the use of polymers to improve the effect of water injection.

Gullfaks

Blocks and production licences	Block 34/10 - production licence 050. Awarded 1978. Block 34/10 - production licence 050 B. Awarded 1995.	
Discovered	1978	
Development approval	09.10.1981 by the Storting	
On stream	22.12.1986	
Operator	Statoil ASA	
Licensees	Norsk Hydro Produksjon AS	9.00%
	Petoro AS	30.00%
	Statoil ASA	61.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	354.6 million scm oil	31.9 million scm oil
	24.6 billion scm gas	2.9 billion scm gas
	2.7 million tonnes NGL	0.4 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 127,000 barrels/day Gas: 0.48 billion scm NGL: 0.06 million tonnes	
Investment	Total investment is expected to be NOK 113.0 billion (2006 values) NOK 106.7 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply bases	Ågotnes and Florø	

Development:
Gullfaks is an oilfield located in an area with a sea depth of 130 to 220 metres. The field has been developed with three integrated processing, drilling and accommodation facilities with concrete bases and steel topsides, Gullfaks A, B and C. Gullfaks B has a simplified processing plant with only first-stage separation. Gullfaks A and C receive and process oil and gas from Gullfaks Sør. The facilities are also involved in production and transport from Tordis, Vigdis and Visund. The Tordis production is processed in a separate facility on Gullfaks C. The original PDO for the Gullfaks field included the Gullfaks A and Gullfaks B facilities. A PDO for the eastern section (Gullfaks C) was approved on 01.06.1985. The PDO for Gullfaks Vest was approved on 15.01.1993, and recovery from the Lunde formation was approved on 03.11.1995. In December 2005, an amended PDO for the Gullfaks field was approved. This plan covers prospects and small discoveries in the area around Gullfaks which can be drilled and produced from existing facilities. With this plan, recovery of the resources in the area can be accomplished more efficiently in the future.

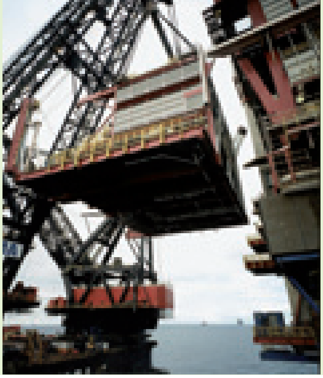
Reservoir:
The Gullfaks reservoirs consist of Middle Jurassic sandstones in the Brent group, and Lower Jurassic and Upper Triassic sandstones in the Cook, Statfjord and Lunde formations. The reservoirs are 2 800-3 400 m below the seabed. The Gullfaks reservoirs are located in rotated fault blocks in the west and a structural horst in the east, with an intermediate highly faulted area.



Recovery strategy:
Gullfaks is an oil field, and the drive mechanism for recovery is mainly pressure support using water injection, gas injection or water/alternating gas injection (WAG). The drive mechanism varies between the various drainage areas in the field, but water injection constitutes the main strategy.

Transport:
Oil is exported from Gullfaks A and Gullfaks C via loading buoys to shuttle tankers. The part of the rich gas that is not reinjected is sent through the export pipeline to Statpipe for further processing at Kårstø and export to the Continent as dry gas.

Status:
Production from Gullfaks is in the decline phase. Efforts are being made to increase recovery, partly by locating and draining pockets of remaining oil in water-flooded areas, and partly through massive water circulation. Comprehensive analysis has also been carried out to calculate the potential for injecting CO_2 into the reservoir. There are a number of small deposits in the flank areas around Gullfaks that can be drilled and recovered using extended reach wells. Test production has taken place in 2005 from such an extended reach well from Gullfaks C. This well also extends into the neighbouring block, 34/8.

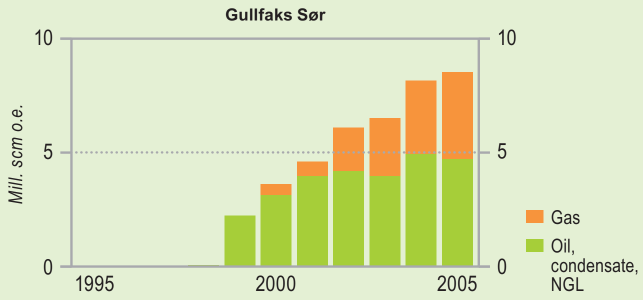


Gullfaks Sør

Blocks and production licences	Block 33/12 - production licence 037 B. Awarded 1998. Block 33/12 - production licence 037 E. Awarded 2004. Block 33/12 - production licence 152. Awarded 1988. Block 34/10 - production licence 050. Awarded 1978. Block 34/10 - production licence 050 B. Awarded 1995.	
Discovered	1978	
Development approval	29.03.1996 by the King in Council	
On stream	10.10.1998	
Operator	Statoil ASA	
Licensees	Norsk Hydro Produksjon AS Petoro AS Statoil ASA	9.00% 30.00% 61.00%
Recoverable reserves	**Original:** 48.3 million scm oil 43.4 billion scm gas 5.3 million tonnes NGL	**Remaining as of 31.12.2005** 24.0 million scm oil 30.9 billion scm gas 3.9 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 70,000 barrels/day Gas: 3.2 billion scm NGL: 0.41 million tonnes	
Investment	Total investment is expected to be NOK 30.4 billion (2006 values) NOK 25.4 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply bases	Ågotnes and Florø	

Development:
Gullfaks Sør has been developed with a total of ten subsea templates tied back to the Gullfaks A and Gullfaks C facilities. The Gullfaks Sør deposits have been developed in two phases. The PDO for Phase 1 included production of oil and condensate from the 34/10-2 Gullfaks Sør, 34/10-17 Rimfaks and 34/10-37 Gullveig deposits. The PDO for Phase 2 was approved on 08.06.1998 and covered production of gas from the Brent group in the Gullfaks Sør deposit. 34/10-47 Gulltopp was discovered in 2002 and included in Gullfaks Sør in 2004. Gulltopp will be produced through an extended reach production well from Gullfaks A. A PDO for Rimfaks IOR and the 33/12-8 A Skinfaks discovery was approved on 11.02.2005. This project includes a new subsea template and a satellite well. The Skinfaks discovery is now included in Gullfaks Sør and production will commence in 2007.

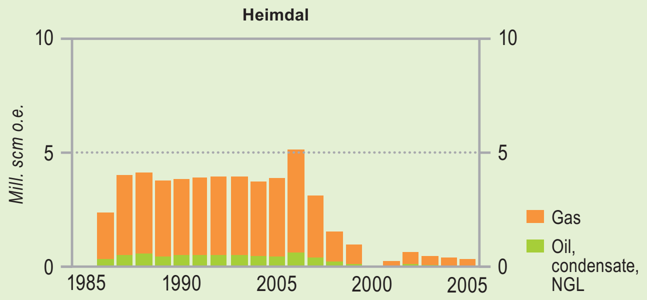
Reservoir:
The Gullfaks Sør reservoirs consist of Middle Jurassic sandstones in the Brent group and Lower Jurassic and Upper Triassic Statfjord formations. The reservoirs lie 2 400-3 400 metres below the seabed, in rotated fault blocks. The reservoirs in the Gullfaks Sør deposit are heavily segmented, with many internal faults, and the Statfjord formation has poor flow characteristics. The Skinfaks, Rimfaks, Gullveig and Gulltopp deposits however show good reservoir characteristics.



Recovery strategy:
Recovery of oil and condensate from Gullfaks Sør is partly driven by pressure support from gas injection in the Brent group, and by pressure depletion in the Statfjord formation. Rimfaks is produced using full pressure maintenance by gas injection. Recovery of oil from Gullveig is by pressure depletion, and the production is also affected by the production at Tordis and Gullfaks. Gulltopp and Skinfaks will be produced using gas lift.

Transport:
The oil is transported to Gullfaks A for processing, storage and further transport by shuttle tankers. Gas is processed on Gullfaks C and rich gas is then exported through Statpipe to Kårstø for further processing and export to the Continent as dry gas.

Status:
New production wells in recent years have shown that more reserves can be recovered from the Gullfaks Sør deposits. Additional wells are being planned.



Heimdal

Block and production licence	Block 25/4 - production licence 036 BS. Awarded 2003.	
Discovered	1972	
Development approval	10.06.1981 by the Storting	
On stream	13.12.1985	
Operator	Norsk Hydro Produksjon AS	
Licensees	Marathon Petroleum Norge AS	23.80%
	Norsk Hydro Produksjon AS	19.44%
	Petoro AS	20.00%
	Statoil ASA	20.00%
	Total E&P Norge AS	16.76%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	7.2 million scm oil	0.8 million scm oil
	42.3 billion scm gas	
Production	**Estimated production in 2006:**	
	Gas: 0.16 billion scm	
Investment	Total investment is expected to be NOK 19.0 billion (2006 values)	
	NOK 19.0 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

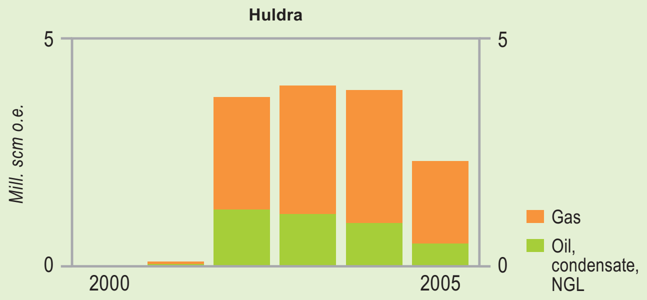
Development:
Heimdal is a gas field located in an area with a sea depth of 120 metres. The field has been developed with an integrated drilling, production and accommodation facility with a steel base (HMP1). The Heimdal Jurassic development was approved on 02.10.1992 and the PDO for Heimdal Gas Centre (HGS) was approved on 15.01.1999. The plan involves a new riser facility (HRP), bridge connected to HMP1.

Reservoir:
The reservoir consists of Tertiary sandstones in the Heimdal formation deposited as deep-marine turbidites.

Recovery strategy:
Heimdal is developed with pressure depletion.

Transport:
Originally, gas was sent by pipeline from Heimdal to Statpipe, but may also now be transported by other pipelines. Condensates are transported by pipeline to Brae in the British sector. After HGS was installed, a new gas pipeline (Vesterled) has been connected to the existing gas pipeline from Frigg to St. Fergus. A gas pipeline has also been laid from HRP to Grane for gas injection. Huldra, Vale and Skirne are tied to Heimdal for processing via a joint pipeline.

Status:
The Heimdal production facilities are now mainly used for processing the gas from Huldra, Vale and Skirne. When the facility has spare capacity, gas is also produced from the Heimdal reservoir.



Huldra

Blocks and production licences	Block 30/2 - production licence 051. Awarded 1979. Block 30/3 - production licence 052 B. Awarded 2001.	
Discovered	1982	
Development approval	02.02.1999 by the Storting	
On stream	21.11.2001	
Operator	Statoil ASA	
Licensees	Norske ConocoPhillips AS	23.34%
	Paladin Resources Norge AS	0.50%
	Petoro AS	31.96%
	Statoil ASA	19.88%
	Total E&P Norge AS	24.33%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	5.0 million scm oil	1.1 million scm oil
	15.8 billion scm gas	5.1 billion scm gas
	0.1 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 4,000 barrels/day Gas: 0.93 billion scm NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 8.0 billion (2006 values) NOK 7.5 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply bases	Ågotnes and Florø	

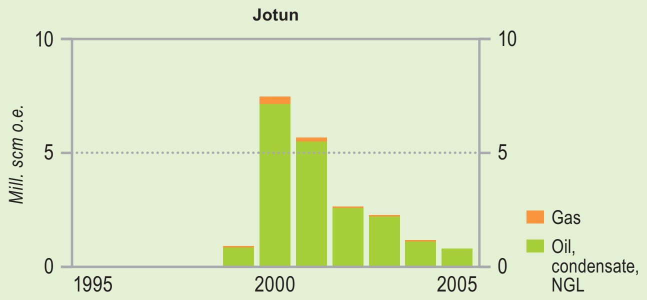
Development:
Huldra is a gas field developed with a steel wellhead facility with a simple process plant. Gas and condensate are transported in separate pipelines. The facility is remotely operated from Veslefrikk B, 16 kilometres away. The sea depth in the area is 125 metres.

Reservoir:
The Huldra reservoir is in a rotated fault block and consists of Jurassic sandstones in the Brent group. The reservoir has high pressure and high temperature. Reservoir communication is uncertain, but the production history indicates two main segments without pressure communication. There are many small faults in the field.

Recovery strategy:
A compressor will be installed on Huldra in 2006, and be operational from January 2007, to increase recovery at reduced wellhead pressure.

Transport:
Following first stage separation, the wet gas is transported to Heimdal for further processing, whereas the condensate is transported to Veslefrikk for processing.

Status:
The field produces gas and condensate from a total of six production wells. The field is expected to remain at plateau for slightly less than three years.



Jotun

Blocks and production licences	Block 25/7 - production licence 103 B. Awarded 1998. Block 25/8 - production licence 027 B. Awarded 1999.	
Discovered	1994	
Development approval	10.06.1997 by the Storting	
On stream	25.10.1999	
Operator	ExxonMobil Exploration and Production Norway AS	
Licensees	Enterprise Oil Norge AS ExxonMobil Exploration and Production Norway AS Lundin Norway AS Petoro AS	45.00% 45.00% 7.00% 3.00%
Recoverable reserves	**Original:** 25.1 million scm oil 1.0 billion scm gas	**Remaining as of 31.12.2005** 4.9 million scm oil 0.2 billion scm gas
Production	**Estimated production in 2006:** Oil: 12,000 barrels/day Gas: 0.03 billion scm	
Investment	Total investment is expected to be NOK 11.3 billion (2006 values) NOK 10.7 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

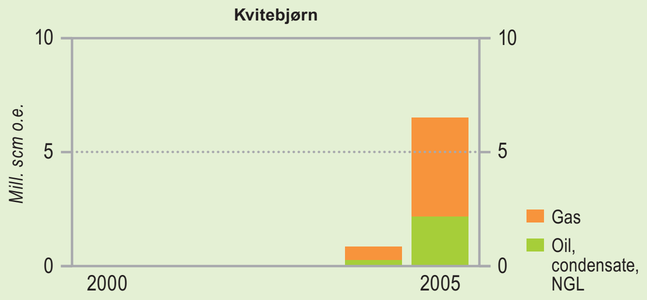
Development:
Jotun is an oil field located 25 kilometres north of Balder. The sea depth in the area is 126 metres. The field has been developed with a combined accommodation, production and storage vessel, Jotun A, and a wellhead facility, Jotun B. Jotun also processes gas from Balder and oil from the Jurassic reservoir in the Ringhorne deposit in Balder.

Reservoir:
The Jotun field comprises three oil filled structures. The eastern structure also has a gas cap. The reservoirs were deposited in a submarine fan system. The three structures are relatively flat and only separated by minor depressions. To the west the sand has good reservoir quality, while the shale content increases towards the east.

Recovery strategy:
Recovery is driven by pressure support from reinjection of produced water.

Transport:
The oil is exported via loading buoys to tankers. The processed rich gas is exported via Statpipe to the Kårstø plant.

Status:
Jotun production fell off plateau earlier than estimated, and the production decline has been steeper than previously estimated.



Kvitebjørn

Block and production licence	Block 34/11 - production licence 193. Awarded 1993.
Discovered	1994
Development approval	14.06.2000 by the Storting
On stream	26.09.2004
Operator	Statoil ASA
Licensees	Enterprise Oil Norge AS 6.45% Norsk Hydro Produksjon AS 15.00% Petoro AS 30.00% Statoil ASA 43.55% Total E&P Norge AS 5.00%
Recoverable reserves	**Original:** 18.0 million scm oil, 51.9 billion scm gas, 2.3 million tonnes NGL **Remaining as of 31.12.2005.** 15.5 million scm oil, 47.0 billion scm gas, 1.9 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 54,000 barrels/day Gas: 6.7 billion scm NGL: 0.31 million tonnes
Investment	Total investment is expected to be NOK 11.2 billion (2006 values) NOK 9.8 billion had been invested as of 31.12.05 (2006 values)
Operating organisation	Bergen
Main supply base	Florø

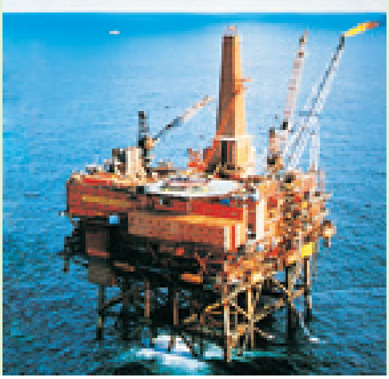
Development:
Kvitebjørn is a gas condensate field developed with an integrated accommodation, drilling and processing facility with a steel jacket. Sea depth in the area is approximately 190 metres. 11 production wells will be drilled in the reservoir. Drill cuttings and produced water are injected in a dedicated disposal well.

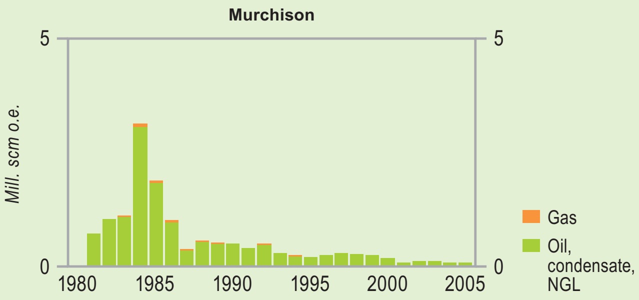
Reservoir:
The reservoir consists of sandstones in the Middle Jurassic Brent group. The reservoir lies at approximately 4 000 metres depth, and has high temperature and pressure.

Recovery strategy:
Recovery is driven by pressure depletion.

Transport:
Rich gas is transported in a dedicated pipeline to Kollsnes, while condensate is transported in a pipeline tied to the Troll Oil Pipeline II for onward transport to Mongstad.

Status:
Production from Kvitebjørn was higher than expected in 2005. Recent reservoir evaluations show that the reserves will be adjusted upwards by about 50 percent compared with the PDO estimate. One of the production wells is being drilled to the 34/10-23 Valemon discovery to delimit this in relation to Kvitebjørn.





Murchison

Block and production licence	Block 33/9 - production licence 037 C. Awarded 2000. The Norwegian part of the field is 22.2%, the British part is 77.8%.	
Discovered	1975	
Development approval	15.12.1976	
On stream	28.09.1980	
Operator	CNR International (UK) Limited	
Licensees	Revus Energy AS	10.68%
	Statoil ASA	11.52%
	CNR International (UK) Limited	68.72%
	Ranger Oil (UK) Ltd	9.08%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
(Norwegian part)	13.8 million scm oil	0.4 million scm oil
	0.4 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2006:**	
(Norwegian part)	Oil: 2,000 barrels/day	
Investment	Total investment is expected to be NOK 7.4 billion (2006 values) NOK 7.3 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Aberdeen, Scotland	
Main supply base	Peterhead, Scotland	

Development:
Murchison has been developed with a combined drilling, accommodation and production facility with a steel jacket, located in the British sector. The British and Norwegian licensees entered into an agreement in 1979 concerning common exploitation of the resources in the Murchison field. The agreement also involves British and Norwegian authorities.

Transport:
Both the Norwegian and British licensees' share of the oil and NGL is piped through the Brent system to Sullom Voe in the Shetlands.

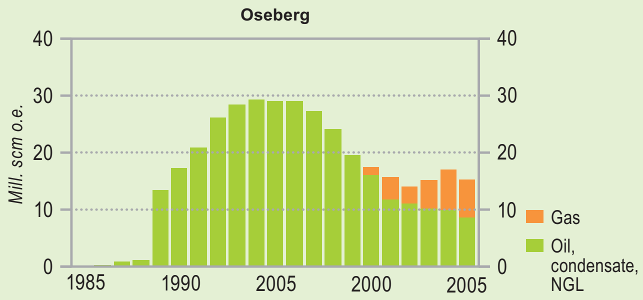
Status:
In 2006, there are plans to drill from Murchison into a deposit on the Norwegian side of the border. The new agreement on transboundary cooperation facilitates this type of cost-effective solution.

Oseberg

Blocks and production licences	Block 30/6 - production licence 053. Awarded 1979. Block 30/9 - production licence 079. Awarded 1982.	
Discovered	1979	
Development approval	05.06.1984 by the Storting	
On stream	01.12.1988	
Operator	Norsk Hydro Produksjon AS	
Licensees	Mobil Development Norway AS	4.70%
	Norsk Hydro Produksjon AS	34.00%
	Norske ConocoPhillips AS	2.40%
	Petoro AS	33.60%
	Statoil ASA	15.30%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	354.7 million scm oil	26.2 million scm oil
	111.1 billion scm gas	84.4 billion scm gas
	7.2 million tonnes NGL	3.6 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 112,000 barrels/day Gas: 3.86 billion scm NGL: 0.57 million tonnes	
Investment	Total investment is expected to be NOK 89.6 billion (2006 values) NOK 79.9 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Oseberg is an oilfield with a gas cap. The sea depth in the area is 100 metres. Oseberg is developed in multiple phases. The field centre in the south consists of two facilities, the process and accommodation facility Oseberg A and the drilling and water injection facility Oseberg B. The Oseberg C facility, an integrated production, drilling and accommodation facility (PDQ), lies in the northern part of the field. Oseberg D is a facility for gas processing tied to the Oseberg Field Centre. Oseberg Vestflanke has been developed with a subsea template tied back to Oseberg B. Oseberg Delta will be developed with a subsea template tied back to Oseberg D. The facilities at the field centre process oil and gas from the Oseberg Øst, Oseberg Sør and Tune fields. The PDO for the northern part of the field was approved on 19.01.1988. The PDO for Oseberg D was approved on 13.12.1996. The PDO for Oseberg Vestflanke was approved on 19.12.2003, and the PDO for Oseberg Delta was approved on 23.09.2005.

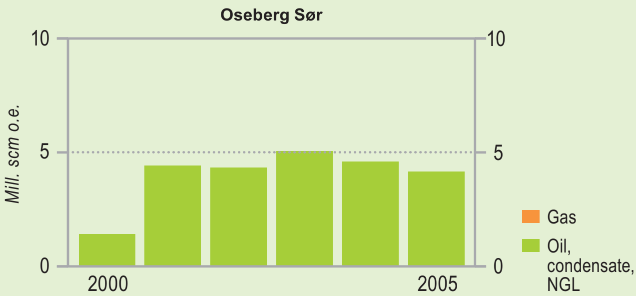
Reservoir:
The field consists of several sandstone reservoirs in the Middle Jurassic Brent group, and is divided into several structures. The main reservoir is located in the Oseberg and Tarbert formations, but production also takes place from the Etive and Ness formations. The field has generally good reservoir characteristics.



Recovery strategy:
The Oseberg field produces through pressure maintenance with the injection of both gas and water, and with WAG (water alternating gas) injection. Massive upflank gas injection has provided extremely good oil displacement, and a large gas cap has now developed that will be recovered in the future. Formerly, injection gas was imported from Troll Øst and Oseberg Vest.

Transport:
The oil is sent through the Oseberg Transport System (OTS) to the Sture terminal. Gas export began in 2000 through a new pipeline, Oseberg Gas Transport (OGT), to the Statpipe system via the Heimdal facility.

Status:
Most production wells are now drilled horizontally. The challenge in the future will be to produce the oil that remains under the gas cap, and to balance the gas and oil production from the field. Oseberg Delta will commence production in the fall of 2007. There are plans for test production from an overlying chalk reservoir on the Oseberg field.



Oseberg Sør

Blocks and production licences	Block 30/12 - production licence 171 B. Awarded 2000. Block 30/9 - production licence 079. Awarded 1982 Block 30/9 - production licence 104. Awarded 1985.	
Discovered	1984	
Development approval	10.06.1997 by the Storting	
On stream	05.02.2000	
Operator	Norsk Hydro Produksjon AS	
Licensees	Mobil Development Norway AS	4.70%
	Norsk Hydro Produksjon AS	34.00%
	Norske ConocoPhillips AS	2.40%
	Petoro AS	33.60%
	Statoil ASA	15.30%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005***
	49.2 million scm oil	25.1 million scm oil
	10.5 billion scm gas	10.5 billion scm gas
Production	**Estimated production in 2006:** Oil: 61,000 barrels/day Gas: 0.83 billion scm	
Investment	Total investment is expected to be NOK 17.0 billion (2006 values) NOK 15.4 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

** Remaining gas reserves are set equal to the original because gas from Oseberg Sør is not reallocated from Oseberg.*

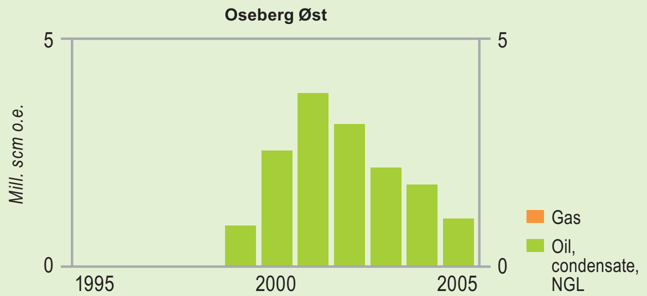
Development:
Oseberg Sør is an oil field located in an area with a sea depth of approximately 100 metres. The field has been developed with an integrated steel facility with accommodation, drilling module and first stage separation of oil and gas. Additional deposits included in the Oseberg Sør field have been developed with subsea templates tied back to the Oseberg Sør facility. Final processing of oil and gas takes place on the Oseberg Field Centre. An amended PDO for the Oseberg Sør J deposit was approved on 15.05.2003.

Reservoir:
The Oseberg Sør reservoirs consist of Jurassic sandstones in several separate structures.

Recovery strategy:
Recovery mainly takes place using water injection, but there is also WAG (water alternating gas) injection in parts of the field.

Transport:
The oil is transported by pipeline to the Oseberg Field Centre. Following final processing, the oil is routed to the Sture terminal whereas gas is transported via Oseberg Gas Transport into Statpipe via the Heimdal facility.

Status:
Several small discoveries surrounding the field are being evaluated for tie-in to the Oseberg Sør facility.



Oseberg Øst

Block and production licence	Block 30/6 - production licence 053. Awarded 1979.	
Discovered	1981	
Development approval	11.10.1996 by the King in Council	
On stream	03.05.1999	
Operator	Norsk Hydro Produksjon AS	
Licensees	Mobil Development Norway AS	4.70%
	Norsk Hydro Produksjon AS	34.00%
	Norske ConocoPhillips AS	2.40%
	Petoro AS	33.60%
	Statoil ASA	15.30%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005***
	29.2 million scm oil	13.8 million scm oil
	0.5 billion scm gas	0.5 billion scm gas
Production	**Estimated production in 2006:**	
	Oil: 16,000 barrels/day Gas: 0.03 billion scm	
Investment	Total investment is expected to be NOK 10.2 billion (2006 values)	
	NOK 7.6 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

** Remaining gas reserves are set equal to the original because gas from Oseberg Øst is not reallocated from Oseberg.*

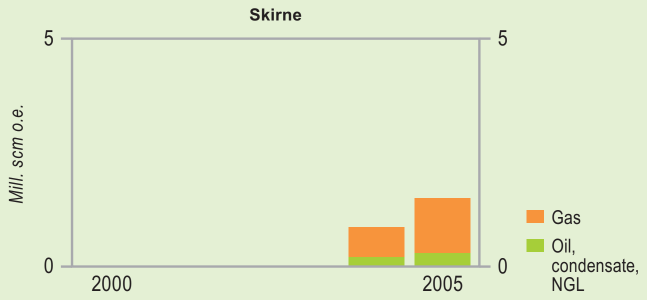
Development:
Oseberg Øst is an oil field developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The sea depth in the area is 160 metres.

Reservoir:
The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oil-bearing layers of varying reservoir characteristics within the Middle Jurassic Brent group.

Recovery strategy:
The field is produced with pressure maintenance using both water injection and WAG (water alternating gas) injection.

Transport:
The oil is sent by pipeline to the Oseberg Field Centre for further processing and transport through the Oseberg Transport System (OTS) to the Sture terminal. The gas is mainly used for injection, gas lift and fuel.

Status:
The field has a relatively low rate of recovery, although various measures for increasing oil recovery are being evaluated in an ongoing process. A new drilling campaign is expected to yield increased production from 2007.



Skirne

Block and production licence	Block 25/5 - production licence 102. Awarded 1985.	
Discovered	1990	
Development approval	05.07.2002 by the Crown Prince Regent in Council	
On stream	03.03.2004	
Operator	Total E&P Norge AS	
Licensees	Marathon Petroleum Norge AS	20.00%
	Norsk Hydro Produksjon AS	10.00%
	Petoro AS	30.00%
	Total E&P Norge AS	40.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	1.6 million scm oil	1.1 million scm oil
	6.7 billion scm gas	4.8 billion scm gas
Production	**Estimated production in 2006:**	
	Oil: 6,000 barrels/day Gas: 1.26 billion scm	
Investment	Total investment is expected to be NOK 2.5 billion (2006 values)	
	NOK 2.4 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	

Development:
Skirne is located east of the Heimdal field. The sea depth in the area is 120 metres. The production wells are connected by pipeline to Heimdal for processing. The Byggve deposit is part of the Skirne field.

Reservoir:
The reservoir consists of sandstone in the Middle Jurassic Brent Group.

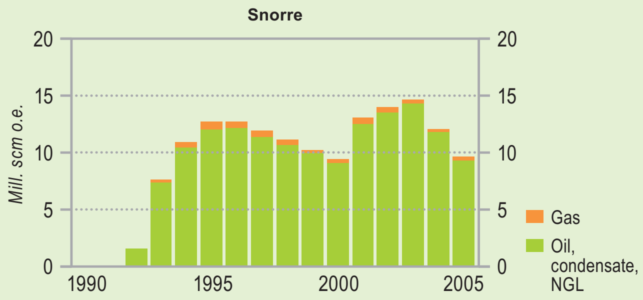
Recovery strategy:
The recovery mechanism is pressure depletion.

Snorre

Blocks and production licences	Block 34/4 - production licence 057. Awarded 1979. Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1979	
Development approval	27.05.1988 by the Storting	
On stream	03.08.1992	
Operator	Statoil ASA	
Licensees	Amerada Hess Norge AS	1.18%
	ExxonMobil Exploration and Production Norway AS	11.16%
	Idemitsu Petroleum Norge AS	9.60%
	Norsk Hydro Produksjon AS	17.65%
	Petoro AS	30.00%
	RWE Dea Norge AS	8.88%
	Statoil ASA	15.58%
	Total E&P Norge AS	5.95%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	234.0 million scm oil	95.7 million scm oil
	6.6 billion scm gas	1.2 billion scm gas
	4.8 million tonnes NGL	0.6 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 126,000 barrels/day Gas: 0.02 billion scm NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 85.4 billion (2006 values) NOK 62.2 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

Development:
Snorre is an oil field located in an area with sea depth of 300-350 meters. Snorre A in the south is a floating steel facility (TLP) for accommodation, drilling and processing. A subsea template with ten well slots, Snorre UPA, is located centrally in the field and connected to Snorre A. Snorre A has also installed processing facility for production from the Vigdis field. Snorre B is located in the northern part of the field and is a semi-submersible integrated drilling, processing and accommodation steel facility. Amended PDO for Snorre, including a processing module for Vigdis on Snorre A, was approved on 16.12.1994. The PDO for Snorre B was approved on 08.06.1998. Snorre B came on stream in June 2001.

Reservoir:
The Snorre field consists of several large slightly tilted fault blocks. The reservoir sandstones belong to the Lower Jurassic and Triassic Statfjord and Lunde formations, and has been deposited on a flood plain. The reservoir has a complex structure with many channels and internal flow barriers.



Recovery strategy:
Snorre is produced with pressure maintenance by water injection, gas injection and WAG (water alternating gas) injection. Foam assisted injection (FAWAG) has also been used in parts of the reservoir.

Transport:
Oil and gas are separated in two stages on Snorre A before transport in separate pipelines to Statfjord A for final processing and export. The oil is loaded onto shuttle tankers at Statfjord and the gas is sent through the Statpipe pipeline to Kårstø. Processed oil from Snorre B is routed by pipeline to Statfjord B for storage and loading to shuttle tankers. All gas from Snorre B is reinjected into the reservoir, but can, when required, also be sent by pipeline to Snorre A.

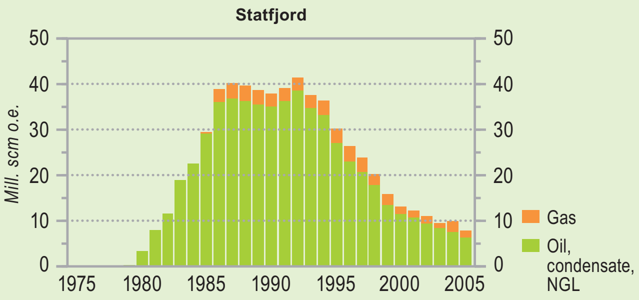
Status:
Snorre had lower production than expected in 2005. Significant resources remain in the field, and several measures are being evaluated to increase recovery. There are plans to modify the processing plant at Snorre A in order to increase the capacity for production and injection of water and gas. Increased capacity is also being evaluated for Snorre B. Additional wells are required, and the measures being evaluated include installing an additional subsea template in the north.

Statfjord

Blocks and production licences	Block 33/12 - production licence 037. Awarded 1973. Block 33/9 - production licence 037. Awarded 1973. Norwegian part of the field is 85.47%, British part is 14.53%.	
Discovered	1974	
Development approval	16.06.1976 by the Storting	
On stream	24.11.1979	
Operator	Statoil ASA	
Licensees	A/S Norske Shell	8.55%
	Enterprise Oil Norge AS	0.89%
	ExxonMobil Exploration and Production Norway AS	21.37%
	Norske ConocoPhillips AS	10.33%
	Statoil ASA	44.34%
	BP Petroleum Development Ltd	4.84%
	Centrica Resources Limited	4.84%
	ConocoPhillips UK Ltd.	4.84%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
(Norwegian part)	565.6 million scm oil	18.4 million scm oil
	78.6 billion scm gas	26.9 billion scm gas
	25.5 million tonnes NGL	11.8 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 86,000 barrels/day Gas: 1.43 billion scm NGL: 0.68 million tonnes	
Investment	Total investment is expected to be NOK 123.6 billion (2006 values) NOK 112.7 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply bases	Ågotnes and Florø	

Development:
Statfjord is an oil field straddling the border between the Norwegian and British sectors of the continental shelf. The sea depth in the area is 150 metres. The field has been developed with three fully integrated facilities; Statfjord A, Statfjord B and Statfjord C. Statfjord A is centrally positioned on the Statfjord field, and came on stream in 1979. Statfjord B is located on the southern part of the field, and came on stream in 1982. Statfjord C is situated in the northern part of the field, and came on stream in 1985. Statfjord B and Statfjord C have the same construction. The satellite fields Statfjord Øst, Statfjord Nord and Sygna have a separate inlet separator on Statfjord C. The northern flank of the Statfjord field has been developed with two subsea facilities, one for production and one for injection, both tied back to Statfjord C. The PDO for Statfjord late life was approved on 08.06.2005.

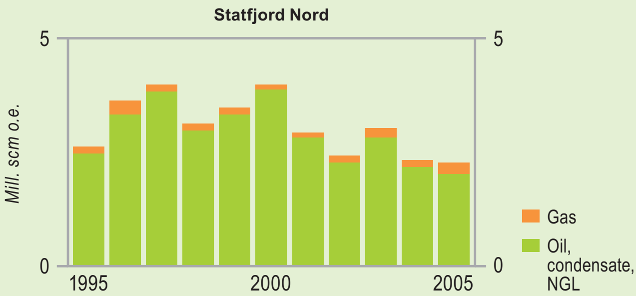
Reservoir:
The Statfjord field consists of one large fault block, tilted towards the west, as well as a number of smaller fault compartments along the east flank. The field extends into the British sector. The reservoirs in the Statfjord field consist of sandstones belonging to the Brent group, the Cook formation and the Statfjord formation.



Recovery strategy:
The Brent reservoir produces with pressure support from WAG (water alternating gas) injection. The Statfjord formation produces with pressure support from upflank water injection and supplemental gas injection, and WAG injection in the lower flank. The oil in the Cook formation is recovered by phasing in wells penetrating the reservoir, or by deepening existing wells. Statfjord late life will entail that all injection will cease in 2007 and the injection wells will be converted to water producers.

Transport:
Stabilised oil is stored in storage cells at each facility. Oil is loaded to tankers from one of the three oil loading systems at the field. The gas is sent through Statpipe to Kårstø, where NGL is separated before dry gas is transported on to Emden. The UK licencees route their share of the gas through the FLAGS (Far North Liquids and Gas System) pipeline from Statfjord B to St. Fergus in Scotland. Tampen Link is a new pipeline for export of the gas from Statfjord late life to the UK via FLAGS.

Status:
The plan for blowdown of the reservoirs in the Statfjord field (Statfjord late life) will extend the lifetime of the field by at least 10 years and provide significant extra recovery of gas and oil. The comprehensive work with modification of the facilities is ongoing. The lifetime of Statfjord A and the Snorre connection are now being evaluated together with the licensees in the Snorre field. Work is in progress to optimise oil recovery before the blowdown starts. Plans include test of nitrate injection (AMIOR).



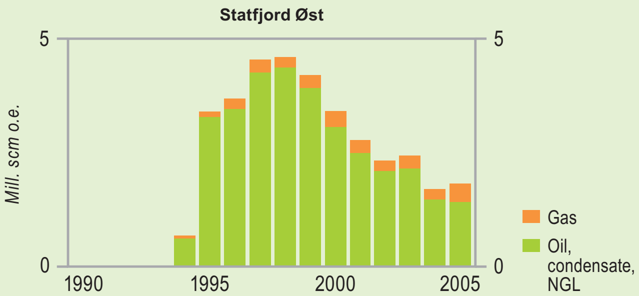
Statfjord Nord

Block and production licence	Block 33/9 - production licence 037. Awarded 1973.	
Discovered	1977	
Development approval	11.12.1990 by the Storting	
On stream	23.01.1995	
Operator	Statoil ASA	
Licensees	A/S Norske Shell	10.00%
	Enterprise Oil Norge AS	1.04%
	ExxonMobil Exploration and Production Norway AS	25.00%
	Norske ConocoPhillips AS	12.08%
	Petoro AS	30.00%
	Statoil ASA	21.88%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	41.8 million scm oil	9.6 million scm oil
	2.7 billion scm gas	0.8 billion scm gas
	0.9 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 26,000 barrels/day Gas: 0.19 billion scm NGL: 0.07 million tonnes	
Investment	Total investment is expected to be NOK 8.2 billion (2006 values)	
	NOK 7.4 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Ågotnes	

Development:
Statfjord Nord is an oil field located approximately 17 kilometres north of Statfjord. The sea depth in the area is 250-290 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two templates are for production and one is for water injection. One well slot is used for an injection well at the Sygna field.

Reservoir:
The Statfjord Nord reservoir consists of Middle Jurassic sandstones belonging to the Brent group, and Upper Jurassic sandstones of the Munin formation.

Recovery strategy:
The field produces with pressure support from water injection. The wellstream is routed through two pipelines to Statfjord C for processing, storage and export. Statfjord Nord, Sygna and Statfjord Øst use the same process equipment on Statfjord C.



Statfjord Øst

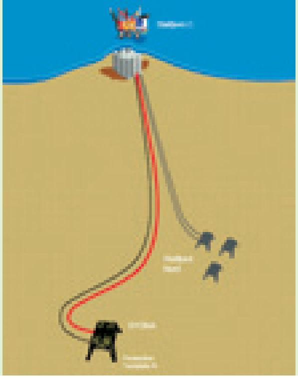
Blocks and production licences	Block 33/9 - production licence 037. Awarded 1973. Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1976	
Development approval	11.12.1990 by the Storting	
On stream	24.09.1994	
Operator	Statoil ASA	
Licensees	A/S Norske Shell	5.00%
	Enterprise Oil Norge AS	0.52%
	ExxonMobil Exploration and Production Norway AS	17.75%
	Idemitsu Petroleum Norge AS	4.80%
	Norsk Hydro Produksjon AS	6.64%
	Norske ConocoPhillips AS	6.04%
	Petoro AS	30.00%
	RWE Dea Norge AS	1.40%
	Statoil ASA	25.05%
	Total E&P Norge AS	2.80%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	36.4 million scm oil	5.6 million scm oil
	3.9 billion scm gas	1.0 billion scm gas
	1.4 million tonnes NGL	0.4 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 14,000 barrels/day Gas: 0.37 billion scm NGL: 0.15 million tonnes	
Investment	Total investment is expected to be NOK 7.4 billion (2006 values) NOK 6.6 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Ågotnes	

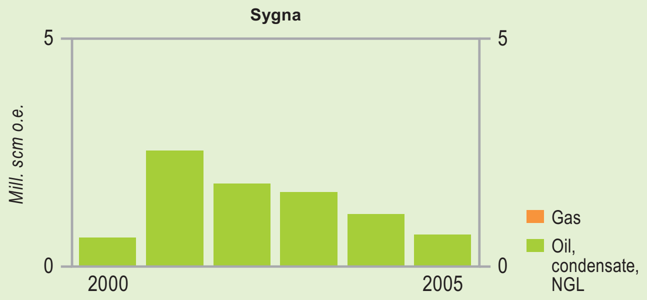
Development:
Statfjord Øst is an oil field located approximately 7 kilometres northeast of the Statfjord field. The sea depth in the area is 150-190 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two of the templates are for production and one for water injection.

Reservoir:
The Statfjord Øst reservoir consists of Middle Jurassic sandstones in the upper and lower parts of the Brent group.

Recovery strategy:
The field is produced with pressure support from water injection. When blowdown of the Statfjord field commences, pressure will also decrease in Statfjord Øst. Measures to offset this include drilling a production well from Statfjord C to accelerate recovery. In 2005, a project was initiated to increase oil recovery by MIOR (Microbiological Improved Oil Recovery).

Transport:
The wellstream is routed through two pipelines to Statfjord C for processing, storage and further transport. Statfjord Øst, Sygna and Statfjord Nord use the same processing equipment on Statfjord C.





Sygna

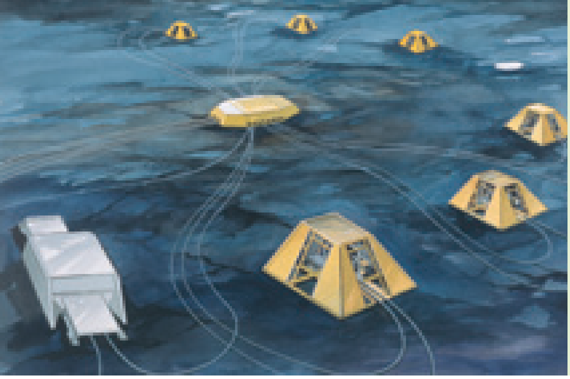
Blocks and production licences	Block 33/9 - production licence 037. Awarded 1973. Block 34/7 - production licence 089. Awarded 1984.
Discovered	1996
Development approval	30.04.1999 by the King in Council
On stream	01.08.2000
Operator	Statoil ASA
Licensees	A/S Norske Shell 5.50% Enterprise Oil Norge AS 0.57% ExxonMobil Exploration and Production Norway AS 18.48% Idemitsu Petroleum Norge AS 4.32% Norsk Hydro Produksjon AS 5.98% Norske ConocoPhillips AS 6.65% Petoro AS 30.00% RWE Dea Norge AS 1.26% Statoil ASA 24.73% Total E&P Norge AS 2.52%
Recoverable reserves	**Original:** 12.2 million scm oil **Remaining as of 31.12.2005** 3.8 million scm oil
Production	**Estimated production in 2006:** Oil: 9,000 barrels/day
Investment	Total investment is expected to be NOK 2.6 billion (2006 values) NOK 2.2 billion had been invested as of 31.12.05 (2006 values)
Operating organisation	Stavanger
Main supply base	Florø

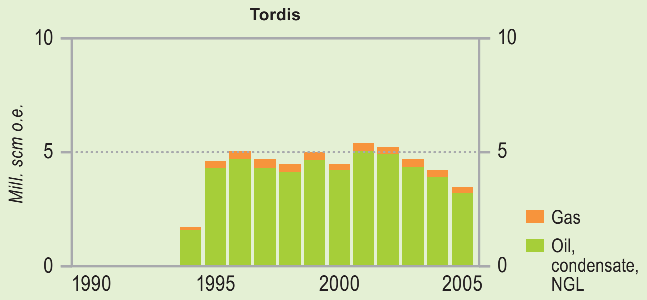
Development:
The Sygna oil field is situated just north of the Statfjord Nord field. The sea depth in the area is 300 metres. The field has been developed with one subsea template with four well slots, connected to Statfjord C.

Reservoir:
The Sygna reservoir consists of Middle Jurassic Brent group sandstones.

Recovery strategy:
The field is produced using water injection from Statfjord Nord.

Transport:
The wellstream is sent by pipeline to Statfjord C for processing, storage and further transport. Statfjord Nord, Statfjord Øst and Sygna share processing equipment on Statfjord C.





Tordis

Block and production licence	Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1987	
Development approval	14.05.1991 by the Storting	
On stream	03.06.1994	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and Production Norway AS	10.50%
	Idemitsu Petroleum Norge AS	9.60%
	Norsk Hydro Produksjon AS	13.28%
	Petoro AS	30.00%
	RWE Dea Norge AS	2.80%
	Statoil ASA	28.22%
	Total E&P Norge AS	5.60%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	64.0 million scm oil	17.1 million scm oil
	5.6 billion scm gas	2.0 billion scm gas
	1.8 million tonnes NGL	0.5 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 41,000 barrels/day Gas: 0.20 billion scm NGL: 0.08 million tonnes	
Investment	Total investment is expected to be NOK 10.9 billion (2006 values)	
	NOK 9.1 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

Development:
Tordis is an oil field located between the Snorre and Gullfaks fields. The sea depth in the area is approximately 200 metres. The field has been developed with a central subsea manifold tied back to Gullfaks C. Seven separate satellite wells and two subsea templates are tied back to the subsea manifold. The wellstream is transferred to Gullfaks C through two pipelines. Injection water is piped to Tordis from Gullfaks C. Tordis consists of four discoveries: Tordis, Tordis Øst, Borg and 34/7-25 S. The PDO for Tordis Øst was approved on 13.10.1995. The PDO for Borg was approved on 29.06.1999. An amended PDO for Tordis (Tordis IOR) was approved on 16.12.2005.

Reservoir:
The reservoirs in Tordis and Tordis Øst consist of Middle Jurassic sandstones in the Brent group. The reservoir in Borg consists of Upper Jurassic sandstones, and the reservoir in 34/7-25 S consists of sandstones from the Brent group and sandstones equivalent to Upper Jurassic. The Tordis reservoirs lie at a depth of 2 000 – 2 500 m.

Recovery strategy:
Production from the Tordis and 34/7-25 S deposits is partially accomplished with pressure maintenance by water injection and aquifer drive. Pressure at Borg is fully maintained using water injection. Recovery at Tordis Øst takes place with pressure support from aquifer drive. Tordis IOR entails improved oil recovery through low pressure production.

Transport:
Oil from Tordis is transported to Gullfaks C and exported by tankers. The export gas is sent through Statpipe to Kårstø.

Status:
Tordis IOR includes new wells, installation of a subsea separator with injection of produced water, and modifications on Gullfaks C for low pressure separation. The subsea separator represents a step forward technology which may contribute to improved recovery from other small fields in deep waters and reservoirs remote from infrastructure.

Troll

Troll lies about 65 kilometres west of Kollsnes and comprises two main structures: Troll Øst and Troll Vest. Troll Øst primarily occupies blocks 31/3 and 31/6, while most of Troll Vest is found in block 31/2. Roughly two-thirds of the field's recoverable gas reserves are estimated to lie in Troll Øst. A phased development has been pursued, with Phase I covering gas reserves in Troll Øst. Phase II focused on the oil reserves in Troll Vest. The Troll licensees are now conducting studies to evaluate further development of the field. A thin oil zone underlies the gas throughout the Troll field, but is only sufficiently thick for commercial recovery in the Troll Vest region. The oil in Troll Vest is located in two provinces. In the oil province, the thickness of the oil zone is 22-27 metres. In the gas province there is a thin oil zone of 11-14 metres. Test production from the two provinces in 1990 and 1991 yielded positive results. The field has huge gas resources and one of the largest oil volumes remaining on the Norwegian continental shelf.

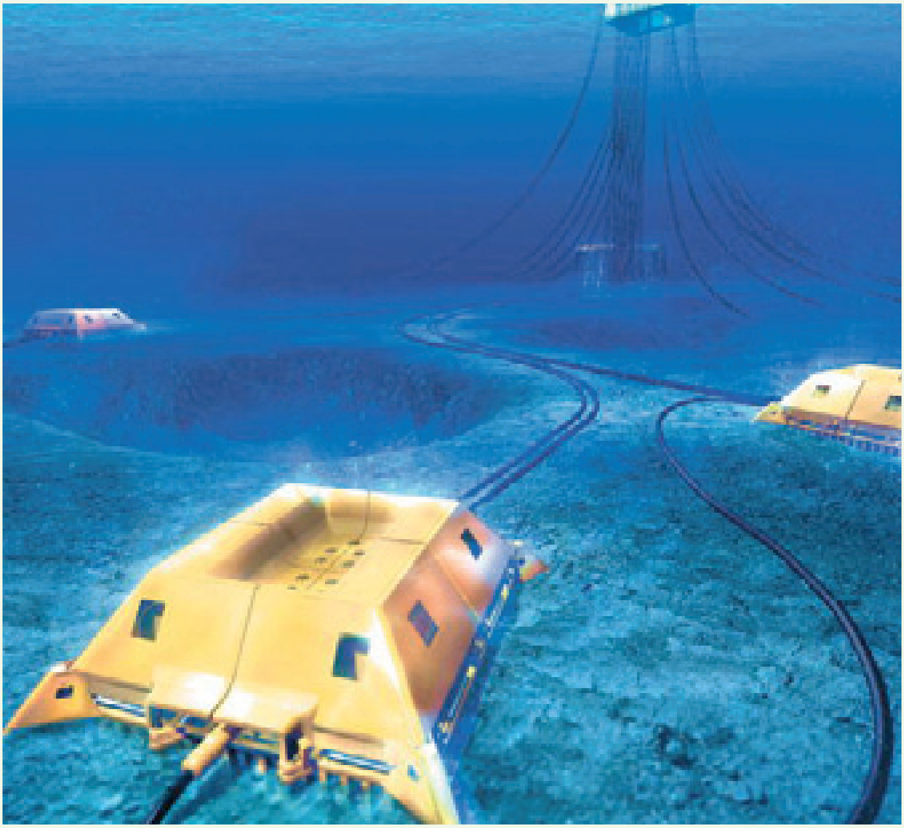
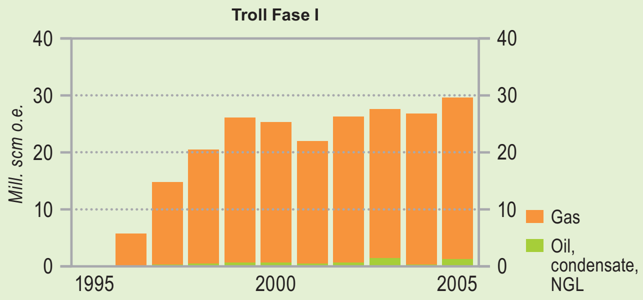


Figure 11.5 Troll pilot
(Source: Norsk Hydro)

Troll I

Blocks and production licences	Block 31/2 - production licence 054. Awarded 1979. Block 31/3 - production licence 085. Awarded 1983. Block 31/3 - production licence 085C. Awarded 2002. Block 31/3 - production licence 085 D. Awarded 2006. Block 31/5 - production licence 085. Awarded 1983. Block 31/6 - production licence 085. Awarded 1983. Block 31/6 - production licence 085C Awarded 2002.	
Discovered	1983	
Development approval	15.12.1986 by the Storting	
On stream	09.02.1996	
Operator	Statoil ASA	
Licensees	A/S Norske Shell	8.10%
	Norsk Hydro Produksjon AS	9.78%
	Norske ConocoPhillips AS	1.62%
	Petoro AS	56.00%
	Statoil ASA	20.80%
	Total E&P Norge AS	3.69%
Recoverable reserves	**Original:** 1324.9 billion scm gas 30.5 million tonnes NGL 1.6 million scm condensate	**Remaining as of 31.12.2005** 1085.4 billion scm gas 29.4 million tonnes NGL
Production	**Estimated production in 2006:** Gas: 30.00 billion scm NGL: 0.57 million tonnes	
Investment	Total investment is expected to be NOK 73.0 billion (2006 values) NOK 53.9 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Ågotnes	

Development:
Troll Phase I has been developed with Troll A, in which the gas from Troll Øst has been recovered by Statoil as operator. Troll A is a fixed wellhead facility with a concrete substructure. The Troll Oseberg Gas Injection (TOGI) subsea template has also been installed at Troll Øst. The gas has been exported to Oseberg for injection. The sea in the Troll area is more than 300 metres deep. An updated plan for processing in a land-based facility (Kollsnes), was approved in 1990. The decommissioning plan for TOGI, which entails removal of the seabed facilities, was approved in 2005.



Reservoir:
The reservoirs in Troll Øst and Troll Vest are mainly shallow marine Upper Jurassic sandstones in the Sognefjord formation. Part of the reservoir is also belonging to the underlying Middle Jurassic Fensfjord formation. The field consists of three relatively large rotated fault blocks.

Recovery strategy:
The gas in Troll Øst is recovered by pressure depletion.

Transport:
The gas from Troll Øst and Troll Vest is transported through two multiphase pipelines to the gas processing plant at Kollsnes. The condensate is separated from the gas, and transported by pipeline partly to the Sture terminal, and partly to Mongstad. The dry gas is transported in Zeepipe II A and II B.

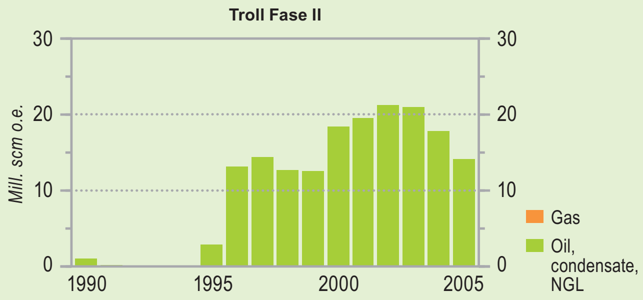
Status:
Compression capacity for gas was increased at Troll A in 2004/2005. Kollsnes was separated from the unitised Troll field in 2004, and Gassco now operates the Kollsnes terminal, as part of Gassled.

Troll Phase II

Blocks and production licences	Block 31/2 - production licence 054. Awarded 1979. Block 31/3 - production licence 085. Awarded 1983. Block 31/3 - production licence 085C. Awarded 2002. Block 31/3 - production licence 085D. Awarded 2006. Block 31/5 - production licence 085. Awarded 1983. Block 31/6 - production licence 085. Awarded 1983. Block 31/6 - production licence 085C Awarded 2002.	
Discovered	1979	
Development approval	18.05.1992 by the Storting	
On stream	19.09.1995	
Operator	Norsk Hydro Produksjon AS	
Licensees	A/S Norske Shell	8.10%
	Norsk Hydro Produksjon AS	9.78%
	Norske ConocoPhillips AS	1.62%
	Petoro AS	56.00%
	Statoil ASA	20.80%
	Total E&P Norge AS	3.69%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	238.0 million scm oil	67.7 million scm oil
Production	**Estimated production in 2006:**	
	Oil: 197,000 barrels/day	
Investment	Total investment is expected to be NOK 72.4 billion (2006 values) NOK 67.0 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Troll Phase II has been developed with Troll B and Troll C, producing oil from Troll Vest with Norsk Hydro as operator. Troll B is a floating concrete facility, while Troll C is a semi-submersible steel facility. Oil from Troll Vest is produced from several subsea templates tied back to Troll B and Troll C by flowlines. Troll Pilot, which is tied back to one of the subsea templates, is a plant for subsea separation and reinjection of produced water. The Troll C processing facility is also used for production from the Fram field. Development of Troll C was approved in 1997. There have been several PDO approvals concerning subsea templates at Troll Vest.

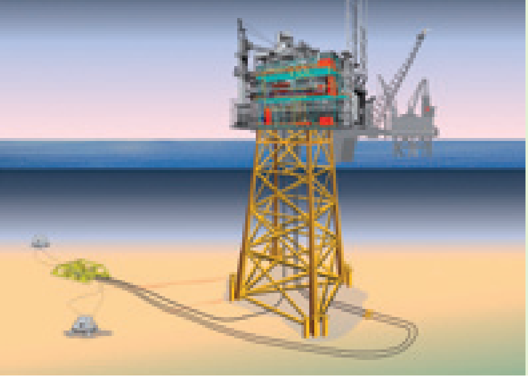
Reservoir:
The gas and oil is found mainly in the Sognefjord formation, which consists of shallow marine sandstones of Upper Jurassic Age.. Part of the reservoir is also in the underlying Fensfjord formation. The field consists of three relatively large rotated fault blocks. The oil in the Troll Vest province is formed as a 22-26 metre thick oil column under a small gas cap. In the Troll Vest gas province there is an oil column of around 12-14 metres and a gas column of up to 200 metres. A small oil discovery was made in 2005 in the Brent formation, which lies deeper than the oil in the main reservoir.

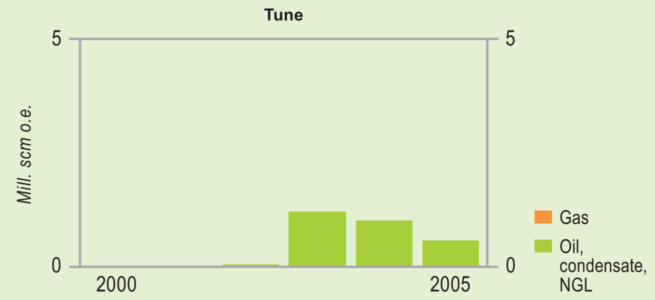


Recovery strategy:
Oil production at Troll Vest takes place through horizontal wells drilled right above the oil/water contact in the thin oil zone. The main recovery strategy is pressure depletion, but there will be simultaneous expansion of the gas cap above and the water zone below the oil. In the Troll Vest oil province, some of the gas produced has been injected back into the reservoir to optimise the oil production. One important aspect of the strategy is to recover the oil quickly, because less oil can be extracted when the pressure declines in Troll Øst. For this reason, limits have also been placed on gas extraction from Troll Øst.

Transport:
Gas from Troll Øst and Troll Vest is transported through two multiphase pipelines to the gas processing plant at Kollsnes. Condensate is separated from the gas and transported on by pipeline, partly to the Sture terminal, partly to Mongstad. The dry gas is sent through Zeepipe II A and Zeepipe II B. The oil from Troll B and Troll C is transported in the Troll Oil Pipelines I and II, respectively, to the oil terminal at Mongstad.

Status:
Drilling on Troll Vest with horizontal production wells from subsea templates continues with up to three mobile drilling facilities in activity. In total, more than 100 oil production wells have now been drilled at Troll Vest. Over the last few years, decisions have been made each year in favour of drilling new production wells that contribute to increasing oil reserves from Troll, and there are still a number of wells in the drilling plan. Several multi-branch wells have been drilled, with up to six branches in one well.





Tune

Blocks and production licences	Block 30/5 - production licence 034. Awarded 1969. Block 30/6 - production licence 053. Awarded 1979. Block 30/8 - production licence 190. Awarded 1993.	
Discovered	1996	
Development approval	17.12.1999 by the King in Council	
On stream	28.11.2002	
Operator	Norsk Hydro Produksjon AS	
Licensees	Norsk Hydro Produksjon AS Petoro AS Statoil ASA Total E&P Norge AS	40.00% 40.00% 10.00% 10.00%
Recoverable reserves	**Original:** 3.0 million scm oil 14.1 billion scm gas 0.1 million tonnes NGL	**Remaining as of 31.12.2005*** 0.4 million scm oil 14.1 billion scm gas
Production	**Estimated production in 2006:** Oil: 3,000 barrels/day Gas: 1.69 billion scm	
Investment	Total investment is expected to be NOK 5.0 billion (2006 values) NOK 4.2 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

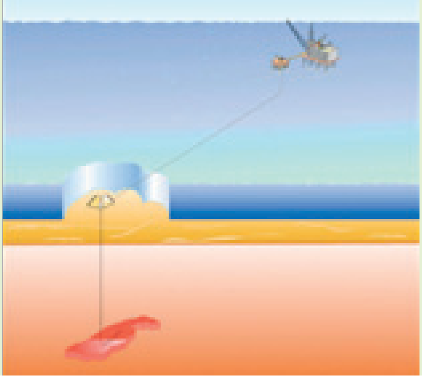
* *Remaining gas reserves are equal to the original because Tune gas is not reallocated from Oseberg.*

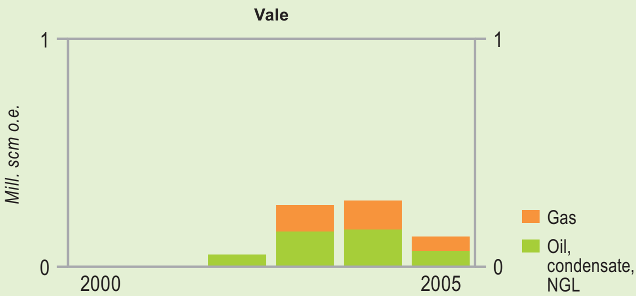
Development:
The Tune field is a gas and gas condensate field located around 10 kilometres west of the Oseberg Field Centre. The sea depth in the area is approximately 95 metres. The field has been developed with a subsea facility with four production wells in the centre of the field. A new subsea template was planned for the northern part of Tune, but as the well to Tune Nord was dry, the licensees decided to move the template to the southern part of the field (Tune Phase 3). In March 2004, a PDO exemption was granted for development of the northern part of the field, while a similar exemption was granted for the southern part of the field in May 2005.

Reservoir:
The reservoir consists of Middle Jurassic sandstones and is divided into several inclined fault blocks.

Recovery strategy:
Recovery is driven by pressure depletion.

Transport:
The Tune subsea facility is connected to the Oseberg D facility by two flowlines. An inlet module for Tune production is installed at Oseberg D. Condensate from Tune is stabilised at the Oseberg Field Centre and transported to the Sture terminal through the Oseberg Transport System (OTS). Gas from Tune is injected into the Oseberg field, while the field's licensees receive sales gas from the Oseberg field.





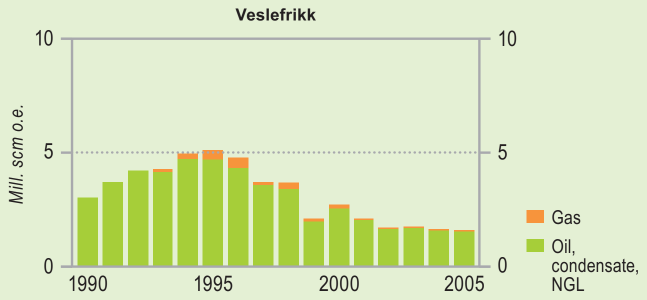
Vale

Block and production licence	Block 25/4 - production licence 036. Awarded 1971.
Discovered	1991
Development approval	23.03.2001 by the Crown Prince Regent in Council
On stream	31.05.2002
Operator	Norsk Hydro Produksjon AS
Licensees	Marathon Petroleum Norge AS 46.90% Norsk Hydro Produksjon AS 28.85% Total E&P Norge AS 24.24%
Recoverable reserves	**Original:** 1.7 million scm oil, 2.1 billion scm gas **Remaining as of 31.12.2005:** 1.2 million scm oil, 1.8 billion scm gas
Production	**Estimated production in 2006:** Oil: 7,000 barrels/day Gas: 0.53 billion scm
Investment	Total investment is expected to be NOK 2.3 billion (2006 values) NOK 2.1 billion had been invested as of 31.12.05 (2006 values)
Operating organisation	Bergen

Development:
Vale is located 16 kilometres north of Heimdal and has been developed with a subsea facility tied back to Heimdal. Water depths in the area are approximately 115 metres.

Reservoir:
The reservoir consists of Middle Jurassic sandstone in the Brent group.

Recovery strategy:
Recovery is driven by pressure depletion.



Veslefrikk

Blocks and production licences	Block 30/3 - production licence 052. Awarded 1979. Block 30/6 - production licence 053. Awarded 1979.	
Discovered	1981	
Development approval	02.06.1987 by the Storting	
On stream	26.12.1989	
Operator	Statoil ASA	
Licensees	Paladin Resources Norge AS	27.00%
	Petoro AS	37.00%
	RWE Dea Norge AS	13.50%
	Revus Energy ASA	4.50%
	Statoil ASA	18.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	56.7 million scm oil	10.0 million scm oil
	2.8 billion scm gas	0.6 billion scm gas
	1.1 million tonnes NGL	
Production	**Estimated production in 2006:** Oil: 28,000 barrels/day	
Investment	Total investment is expected to be NOK 18.1 billion (2006 values) NOK 17.1 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply bases	Ågotnes and Florø	

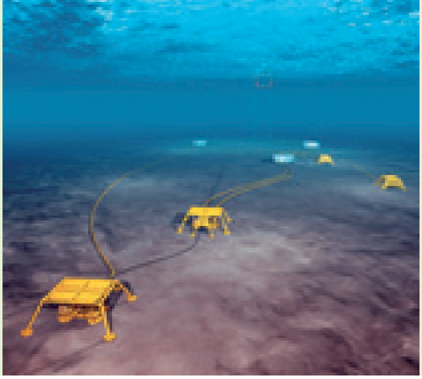
Development:
Veslefrikk is an oil field developed with two facilities. Sea depths around the facilities are about 185 metres. Veslefrikk A is a steel facility with a drilling rig and bridge connection to Veslefrikk B, where the wellstream is processed. Veslefrikk B is a converted drilling facility for processing and accommodation. Veslefrikk B was upgraded in 1999 to receive condensate from the Huldra field. The PDO for the Statfjord formation was approved on 11.06.1994. The PDO for the reservoirs in Upper Brent and I-areas was approved on 16.12.1994.

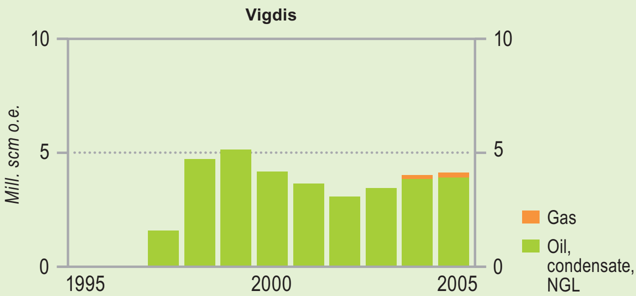
Reservoir:
The main reservoir consists of Jurassic sandstones in the Brent group, and is an uplifted fault block (horst). There are also reservoirs in the Intra Dunlin Sand and in the Statfjord formation.

Recovery strategy:
Production takes place with pressure support from injection of water and gas.

Transport:
An oil pipeline is connected to the Oseberg Transport System (OTS) for transport to the Sture terminal.

Status:
Production from Veslefrikk is in the decline phase. Continual efforts are ongoing to increase recovery from the field. Gas produced from Veslefrikk is injected back into the reservoir. A new recovery method is to use the gas for alternating WAG (water alternating gas) in the Statfjord and Brent formations. Other recovery methods include water shut-in, injection by zones and increased gas lift in the wells.





Vigdis

Block and production licence	Block 34/7 - production licence 089. Awarded 1984.	
Discovered	1986	
Development approval	16.12.1994 by the King in Council	
On stream	28.01.1997	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration and Production Norway AS	10.50%
	Idemitsu Petroleum Norge AS	9.60%
	Norsk Hydro Produksjon AS	13.28%
	Petoro AS	30.00%
	RWE Dea Norge AS	2.80%
	Statoil ASA	28.22%
	Total E&P Norge AS	5.60%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	55.4 million scm oil	22.4 million scm oil
	1.7 billion scm gas	1.3 billion scm gas
	1.2 million tonnes NGL	0.9 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 65,000 barrels/day Gas: 0.23 billion scm NGL: 0.16 million tonnes	
Investment	Total investment is expected to be NOK 12.5 billion (2006 values)	
	NOK 10.9 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

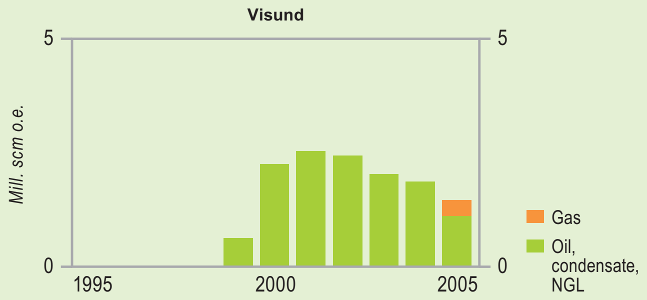
Development:
Vigdis is an oil field located between the Snorre and Gullfaks fields. The sea depth in the area is 280 metres. The field has been developed with subsea templates connected to Snorre A. The wellstream is routed to Snorre A through two flowlines. Injection water is transported by pipeline from Snorre A. Oil from Vigdis is processed in a dedicated processing module on Snorre A. The PDO for Vigdis Extension, including the discoveries 34/7-23 S, 34/7-29 S and 34/7-31, and a number of adjoining deposits, was approved on 20.12.2002.

Reservoir:
The reservoirs consist of Middle Jurassic sandstones in the Brent group. The field also contains reservoirs that consist of Lower Jurassic and Upper Triassic sandstones in the Statfjord formation and sandstone reservoirs equivalent in time to the Upper Jurassic Draupne formation. The reservoirs are at a depth of 2 200 - 2 600 metres.

Recovery strategy:
Production is based on partial pressure maintenance using water injection.

Transport:
Stabilised oil from Vigdis is sent from the Vigdis module on Snorre A to Gullfaks A for storage and export. Gas from Vigdis is used for injection at Snorre.

Status:
New wells to reach new deposits in the Vigdis area (Vigdis Extension Phase 2) have been approved. A decision has also been made to install a subsea template on the Vigdis Øst deposit, for production and water injection.



Visund

Block and production licence	Block 34/8 - production licence 120. Awarded 1985.	
Discovered	1986	
Development approval	29.03.1996 by the Storting	
On stream	21.04.1999	
Operator	Statoil ASA	
Licensees	Norsk Hydro Produksjon AS	20.30%
	Norske ConocoPhillips AS	9.10%
	Petoro AS	30.00%
	Statoil ASA	32.90%
	Total E&P Norge AS	7.70%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	27.3 million scm oil	14.4 million scm oil
	52.9 billion scm gas	52.6 billion scm gas
	6.8 million tonnes NGL	6.8 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 32,000 barrels/day Gas: 1.64 billion scm NGL: 0.25 million tonnes	
Investment	Total investment is expected to be NOK 24.9 billion (2006 values)	
	NOK 18.8 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Bergen	
Main supply base	Florø	

Development:
Visund is an oil field to the east of the Snorre field. The sea depth in the area is 335 metres. The development includes a semi-submersible integrated accommodation, drilling and processing steel facility (Visund A). The northern section of Visund has also been developed with a subsea facility about 10 kilometres to the north of Visund A. The PDO for gas export was approved on 04.10.2002.

Reservoir:
Visund contains oil and gas in several tilted fault blocks with separate pressure and liquid systems. The reservoirs are in Jurassic and Triassic sandstones in the Brent group and the Statfjord Formation.

Recovery strategy:
Oil production is driven by gas injection. Produced water is also reinjected into one of the reservoirs. Limited gas export started in 2005.

Transport:
The oil is sent by pipeline to Gullfaks A for storage and export. Gas is exported to the Kvitebjørn gas pipeline and on to Kollsnes. At Kollsnes, NGL is separated for further export to the market.

Status:
Gas export commenced on 01.10.2005. Work is in progress to optimise oil recovery before gas export levels increase. One of the measures being evaluated is to access more water to increase water injection.

Norwegian Sea

The Norwegian Sea is a less mature petroleum province. Draugen was the first field to come on stream, in 1993. Today, eight fields are producing in this area, after Kristin and Urd came on stream in 2005. One field, Ormen Lange, is under development, and the licensees have decided to develop another, Tyrihans. There are significant gas reserves in the Norwegian Sea. The produced gas is currently transported by pipeline to Tjeldbergodden in Møre og Romsdal and to Kårstø in Rogaland. The gas from Ormen Lange will be routed through a new pipeline to Nyhamna, and from there on to the United Kingdom.

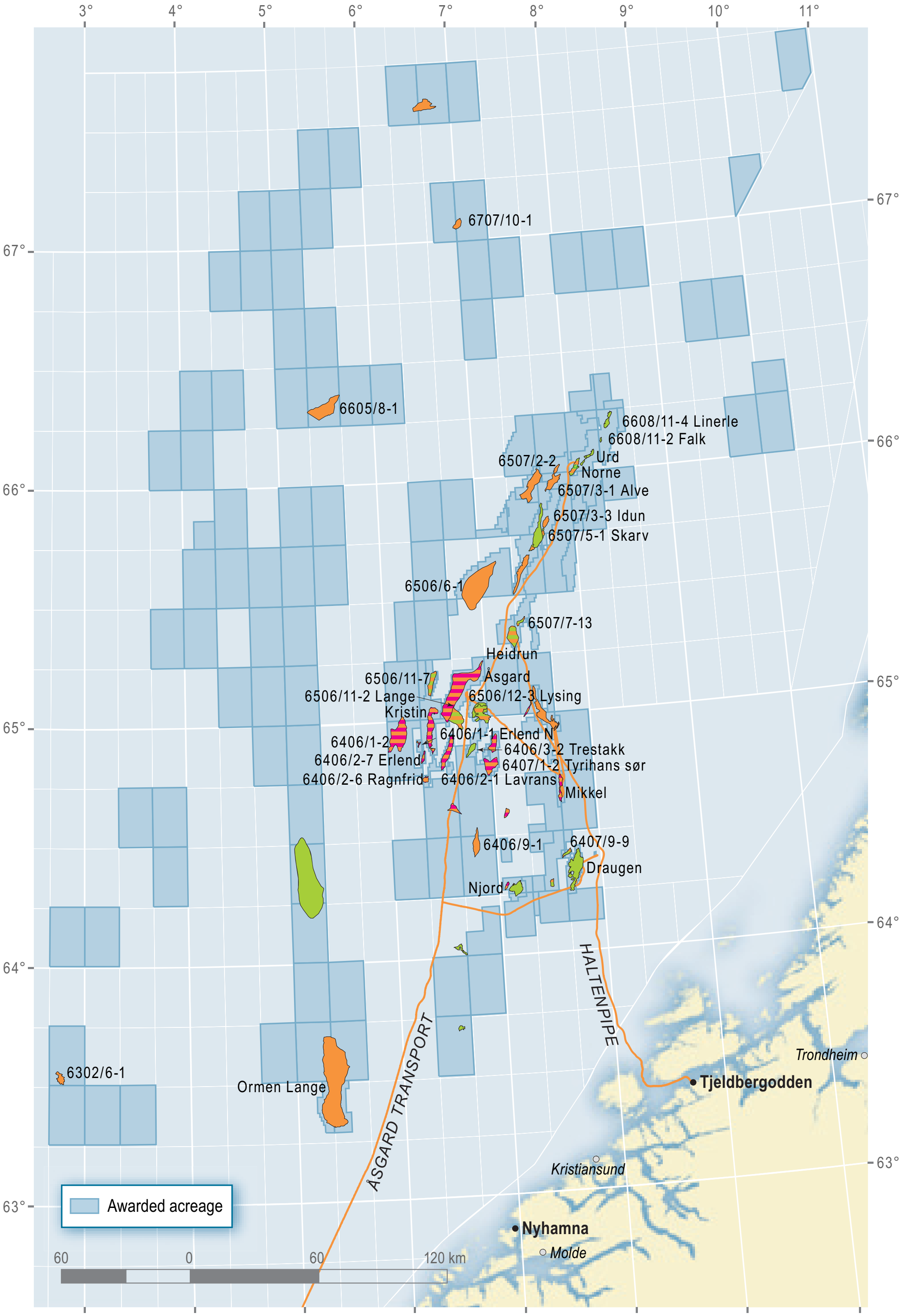
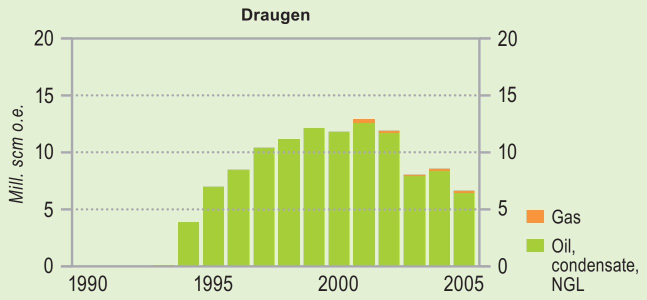


Figure 11.6 Norwegian Sea
(Source: Norwegian Petroleum Directorate)



Draugen

Block and production licence	Block 6407/9 - production licence 093. Awarded 1984.	
Discovered	1984	
Development approval	19.12.1988 by the Storting	
On stream	19.10.1993	
Operator	A/S Norske Shell	
Licensees	A/S Norske Shell	26.20%
	BP Norge AS	18.36%
	ChevronTexaco Norge AS	7.56%
	Petoro AS	47.88%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	137.9 million scm oil	28.8 million scm oil
	1.2 billion scm gas	0.2 billion scm gas
	2.2 million tonnes NGL	0.7 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 81,000 barrels/day Gas: 0.12 billion scm NGL: 0.17 million tonnes	
Investment	Total investment is expected to be NOK 26.6 billion (2006 values)	
	NOK 25.8 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

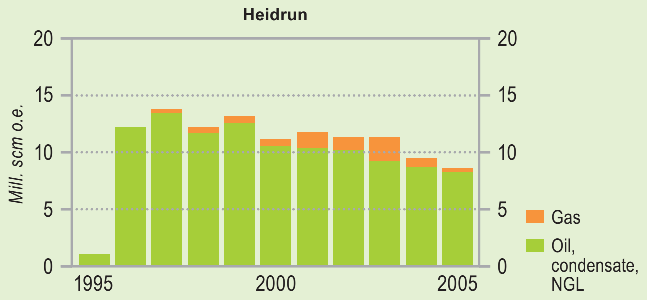
Development:
Draugen is an oil field located in an area with a sea depth of 250 metres. The field has been developed with a concrete fixed facility and integrated topside. Stabilised oil is stored in tanks in the base of the facility. Two flowlines connect the facility to a floating loading buoy. The Garn Vest and Rogn Sør deposits have been developed with a total of five subsea wells connected to the main facility at Draugen. The field has six subsea water injection wells. Additional resources in the Garn Vest structure came on stream in December 2001, while development of additional resources at the Rogn Sør structure were approved in the spring of 2001, coming on stream in January 2003.

Reservoir:
The main reservoir consists of Upper Jurassic sandstones in the Rogn formation. In addition, the Garn formation in the west of the field is producing. The reservoirs are relatively homogenous, with good reservoir characteristics.

Recovery strategy:
The field is produced with pressure maintenance through water injection.

Transport:
The oil is exported by tankers. The associated gas is sent through the Åsgard Transport pipeline to Kårstø.

Status:
Oil production came off plateau around 2003, and the quantity of produced water is increasing. Various measures to increase recovery are being evaluated. A pilot project for reinjection of the produced water is underway, and permanent full-scale reinjection will be evaluated. There are also plans for new wells and possibly gas/CO_2-injection.



Heidrun

Blocks and production licences	Block 6507/8 - production licence 124. Awarded 1986. Block 6707/7 - production licence 095. Awarded 1984.	
Discovered	1985	
Development approval	14.05.1991 by the Storting	
On stream	18.10.1995	
Operator	Statoil ASA	
Licensees	Eni Norge AS	5.12%
	Norske ConocoPhillips AS	24.31%
	Petoro AS	58.16%
	Statoil ASA	12.41%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	180.0 million scm oil	72.4 million scm oil
	42.7 billion scm gas	34.9 billion scm gas
	1.6 million tonnes NGL	1.2 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 145,000 barrels/day Gas: 0.3 billion scm NGL: 0.03 million tonnes	
Investment	Total investment is expected to be NOK 67.8 billion (2006 values) NOK 56.1 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

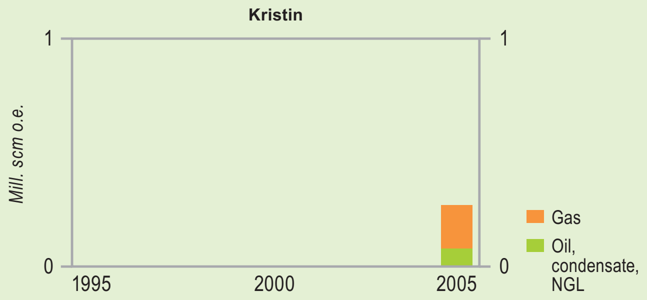
Development:
The Heidrun field is located on Haltenbanken off mid-Norway. The sea depth in the area is 350 metres. The field has been developed with a floating concrete tension leg platform, installed over a subsea template with 56 well slots. The northern part of the field is developed with subsea facilities. The PDO for the Heidrun north flank was approved on 12.05.2000.

Reservoir:
The reservoir consists of Lower and Middle Jurassic sandstones. The structure is heavily faulted.

Recovery strategy:
The recovery strategy for the field is pressure maintenance using water injection and injection of excess gas.

Transport:
Heidrun oil is transferred to tankers at the field. The oil is shipped to Mongstad and Tetney (UK) , while the gas is sent through a separate pipeline to Tjeldbergodden and in Åsgard Transport to Kårstø.

Status:
Injection of low-sulphate seawater commenced in November 2003. Efforts are being made to find methods to increase oil recovery and proving new deposits.



Kristin

Blocks and production licences	Block 6406/2 - production licence 199. Awarded 1993.	
	Block 6506/11 - production licence 134 B. Awarded 2000.	
Discovered	1997	
Development approval	17.12.2001 by the Storting	
On stream	03.11.2005	
Operator	Statoil ASA	
Licensees	Eni Norge AS	9.00%
	Mobil Development Norway AS	10.50%
	Norsk Hydro Produksjon a.s	14.00%
	Petoro AS	18.90%
	Statoil ASA	41.60%
	Total E&P Norge AS	6.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	37.2 million scm oil	37.2 million scm oil
	43.2 billion scm gas	43.0 billion scm gas
	7.8 million tonnes NGL	7.8 million tonnes NGL
	1.0 million scm condensate	0.8 million scm condensate
Production	**Estimated production in 2006:**	
	Oil: 47,000 barrels/day Gas: 2.96 billion scm NGL: 0.68 million tonnes	
Investment	Total investment is expected to be NOK 23.7 billion (2006 values)	
	NOK 20.1 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

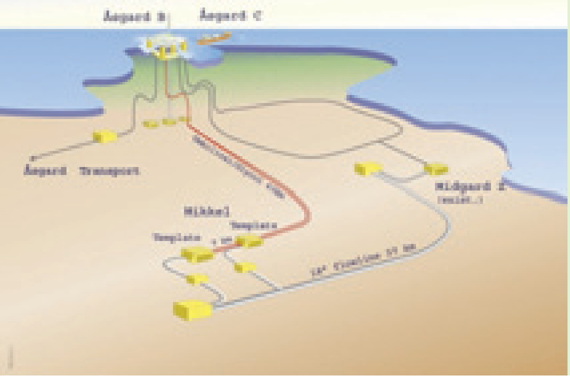
Development:
Kristin is a gas field developed with a subsea facility and a semi-submersible production facility for processing. The sea depth in the area is about 370 metres. Provision has been made for tie-in of other discoveries in the area when Kristin comes off plateau. A decision has already been made for tie back of Tyrihans to Kristin.

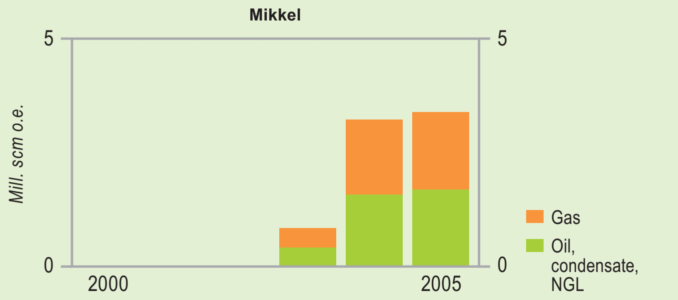
Reservoir:
The reservoir is in sandstone from the Middle Jurassic at a depth of 4 600 metres. The reservoir is in the Garn, Ile and Tofte formations and contains gas and condensate under very high pressure and with very high temperatures.

Recovery strategy:
Production is accomplished by pressure depletion.

Transport:
The rich gas from Kristin is transported in a dedicated pipeline to Åsgard Transport. The gas is sent to the Kårstø facility, where ethane and NGL are separated out. The sales gas is transported on to the Continent. Light oil is separated and stabilised on Kristin and transferred to a storage ship tied to the Åsgard C loading buoy for storage and shipping. From 01.07.2006, condensate from Kristin will be sold as oil (Halten Blend).

Status:
The Tofte formation reserves are now included in Kristin. Drilling of production wells has taken longer than planned, and production is therefore lower than expected.





Mikkel

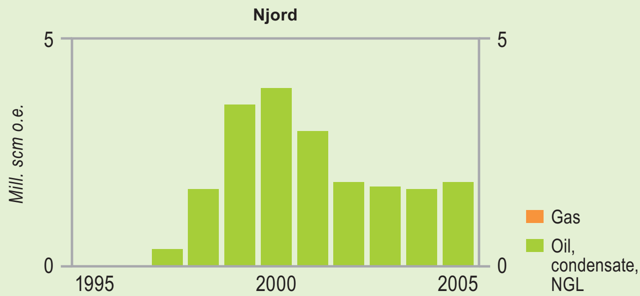
Blocks and production licences	Block 6407/5 - production licence 121. Awarded 1986. Block 6407/6 - production licence 092. Awarded 1984.	
Discovered	1987	
Development approval	14.09.2001 by the King in Council	
On stream	01.08.2003	
Operator	Statoil ASA	
Licensees	Eni Norge AS Mobil Development Norway AS Norsk Hydro Produksjon AS Statoil ASA Total E&P Norge AS	14.90% 33.48% 10.00% 33.97% 7.65%
Recoverable reserves	**Original:** 4.7 million scm oil 24.0 billion scm gas 5.9 million tonnes NGL 2.0 million scm condensate	**Remaining as of 31.12.2005** 4.7 million scm oil 20.1 billion scm gas 4.9 million tonnes NGL 0.3 million scm condensate
Production	**Estimated production in 2006:** Oil: 5000 barrels/day Gas: 1.75 billion scm NGL: 0.42 million tonnes Condensate: 0.34 million scm	
Investment	Total investment is expected to be NOK 2.2 billion (2006 values) NOK 2.0 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

Development:
Mikkel is a gas and condensate field with a 300 metres thick gas column and a 17 metres thick underlying oil column. The field is located in the eastern part of Haltenbanken, and the sea depth in the area is 220 metres. The field has been developed with two subsea templates. The wellstream from the Mikkel field is piped to Åsgard B, where it is processed.

Reservoir:
The reservoir consists of Middle Jurassic sandstones in six structures separated by faults.

Recovery strategy:
Production is accomplished by pressure depletion.

Transport:
Condensate is separated from the gas and stabilised on Åsgard B before it is exported from the field together with Åsgard's own condensate. The rich gas is sent through the Åsgard Transport pipeline to Kårstø for separation of the wet gas components. The dry gas is transported on from Kårstø to the Continent through the Europipe II pipeline.



Njord

Blocks and production licences	Block 6407/10 - production licence 132. Awarded 1987. Block 6407/7 - production licence 107. Awarded 1985.	
Discovered	1986	
Development approval	12.06.1995 by the Storting	
On stream	30.09.1997	
Operator	Norsk Hydro Produksjon AS	
Licensees	E.ON Ruhrgas Norge AS	30.00%
	Endeavour Energy Norge AS	2.50%
	Gaz de France Norge AS	20.00%
	Mobil Development Norway AS	20.00%
	Norsk Hydro Produksjon AS	20.00%
	Petoro AS	7.50%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	24.2 million scm oil	4.6 million scm oil
	8.7 billion scm gas	8.7 billion scm gas
	1.4 million tonnes NGL	1.4 million tonnes NGL
Production	**Estimated production in 2006:** Oil: 22,000 barrels/day	
Investment	Total investment is expected to be NOK 12.9 billion (2006 values) NOK 11.6 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

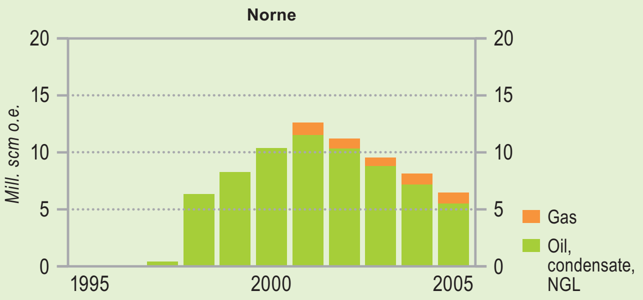
Development:
Njord is an oil field located around 30 kilometres west of Draugen. The sea depth in the area is 330 metres. The field has been developed with a steel semi-submersible drilling, accommodation and production facility, Njord A, and a storage vessel, Njord B. Njord A is located over subsea completed wells connected to the facility through flexible risers. The PDO for Njord gas export was approved on 21.01.2005.

Reservoir:
The reservoir consists of Jurassic sandstones in the Tilje and Ile formations. The field has a complicated fault pattern with only partial communication between the segments.

Recovery strategy:
Most of the gas produced at Njord is reinjected on the east flank for pressure support and increased oil recovery. The western and northern segments produce with pressure depletion.

Transport:
The oil is offloaded from the storage vessel, Njord B, to tankers for transport to the market.

Status:
Gas export from the field is scheduled to begin in October 2007. The licensees have decided to submit a PDO for the northwest flank in the summer of 2006.



Norne

Blocks and production licences	Block 6508/1 - production licence 128 B. Awarded 1998.	
	Block 6608/10 - production licence 128. Awarded 1986.	
Discovered	1992	
Development approval	09.03.1995 by the Storting	
On stream	06.11.1997	
Operator	Statoil ASA	
Licensees	Eni Norge AS	6.90%
	Norsk Hydro Produksjon AS	8.10%
	Petoro AS	54.00%
	Statoil ASA	31.00%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	89.2 million scm oil	21.4 million scm oil
	14.0 billion scm gas	9.4 billion scm gas
	1.7 million tonnes NGL	1.2 million tonnes NGL
Production	**Estimated production in 2006:**	
	Oil: 76,000 barrels/day Gas: 1.2 billion scm NGL: 0.16 million tonnes	
Investment	Total investment is expected to be NOK 22.7 billion (2006 values)	
	NOK 18.6 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Harstad	
Main supply base	Sandnessjøen	

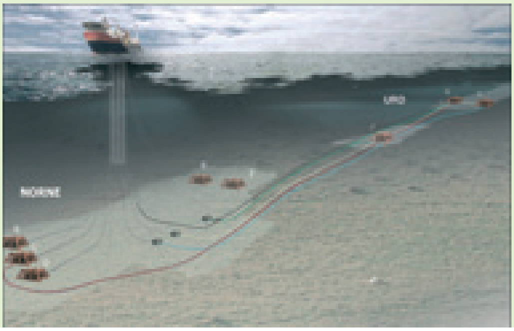
Development:
Norne is an oil field located around 80 kilometres north of the Heidrun field. The sea depth in the area is 380 metres. The field has been developed with a production and storage vessel, Norne FPSO, connected to five wellhead templates. Flexible risers carry the wellstream up to the vessel.

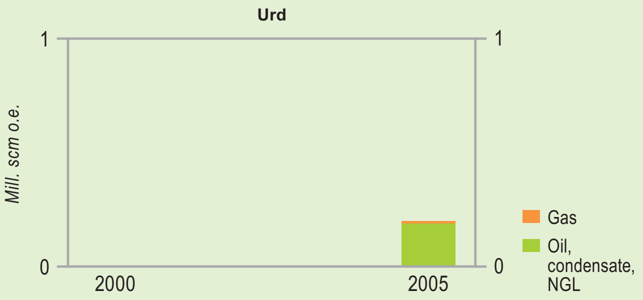
Reservoir:
The Norne field consists of two separate fault segments. The oil and gas at Norne is contained in Jurassic sandstones. Oil is mainly found in the Ile and Tofte formations, gas in the Garn formation. The reservoir is 2 525 metres deep at its shallowest.

Recovery strategy:
The oil is produced with water injection. Gas injection ceased in 2005.

Transport:
The oil is transferred to tankers for transport. Gas export started in February 2001 through a dedicated pipeline to Åsgard and on through the Åsgard Transport pipeline to Kårstø.

Status:
Various measures to increase recovery have been implemented on Norne, including Microbial Enhanced Oil Recovery (MEOR), and use of new well technology.





Urd

Blocks and production licences	Block 6608/10 - production licence 128. Awarded 1986.	
Discovered	2000	
Development approval	02.07.2004 by the Crown Prince Regent in Council	
On stream	08.11.2005	
Operator	Statoil ASA	
Licensees	Eni Norge AS	11.50%
	Norsk Hydro Produksjon AS	13.50%
	Petoro AS	24.55%
	Statoil ASA	50.45%
Recoverable reserves	**Original:**	**Remaining as of 31.12.2005**
	11.3 million scm oil	11.1 million scm oil
	0.1 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2006:**	
	Oil: 47,000 barrels/day Gas: 0.11 billion scm	
Investment	Total investment is expected to be NOK 3.8 billion (2006 values)	
	NOK 3.1 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Harstad	

Development:
Urd encompasses the 6608/10-6 Svale, 6608/10-8 Stær and 6608/10-9 Lerke discoveries, which are located northeast of Norne. Urd has been developed with subsea templates tied back to the Norne vessel. Sea depths in the area are approximately 380 metres. A total of five oil producers and three water injectors are planned. The well templates have available slots for additional wells or phase-in of additional resources.

Reservoir:
The deposits lie in rotated fault blocks in the northern part of the Dønn Terrace. The reservoir is from the Lower to Middle Jurassic Ages, and consists of sandstone in the Åre, Tilje and Ile formations.

Recovery strategy:
The oil in Svale is heavy, viscous and under-saturated, while the oil in Stær is lighter and more like the oil in Norne. Svale and Stær are drained using water injection. The wells are also equipped with gas lift to handle low pressure and high water cut.

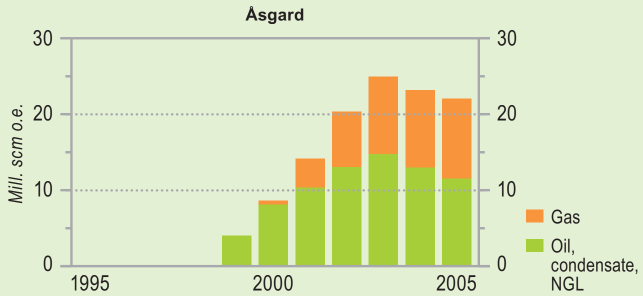
Transport:
The wellstream is processed on the Norne vessel, and oil/condensate are stabilised and offloaded together with oil or condensate from the Norne field. The rich gas is exported together with gas from the Norne field in Åsgard Transport for treatment at Kårstø.

Status:
Three wells were drilled and completed prior to start-up of production in November 2005. The plan calls for the five last wells to be completed in the first half of 2006.

Åsgard

Blocks and production licences	Block 6406/3 - production licence 094 B. Awarded 2002. Block 6407/2 - production licence 074. Awarded 1982. Block 6407/3 - production licence 237. Awarded 1998. Block 6506/11 - production licence 134. Awarded 1987. Block 6506/12 - production licence 094. Awarded 1984. Block 6507/11 - production licence 062. Awarded 1981.	
Discovered	1981	
Development approval	14.06.1996 by the Storting	
On stream	19.05.1999	
Operator	Statoil ASA	
Licensees	Eni Norge AS Mobil Development Norway AS Norsk Hydro Produksjon AS Petoro AS Statoil ASA Total E&P Norge AS	14.90% 7.35% 9.60% 35.50% 25.00% 7.65%
Recoverable reserves	**Original:** 109.7 million scm oil 196.2 billion scm gas 41.1 million tonnes NGL 16.1 million scm condensate	**Remaining as of 31.12.2005** 64.2 million scm oil 153.8 billion scm gas 33.9 million tonnes NGL 1.2 million scm condensate
Production	**Estimated production in 2006:** Oil: 109,000 barrels/day Gas: 9.98 billion NGL: 2.08 million tonnes Condensate: 1.41 million scm	
Investment	Total investment is expected to be NOK 66.5 billion (2006 values) NOK 58.9 billion had been invested as of 31.12.05 (2006 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

Development:
Åsgard is located in an area with a sea depth of 240-300 metres. The field has been developed with subsea completed wells linked to a production and storage vessel, Åsgard A, and a floating, semi-submersible facility, Åsgard B, for gas and condensate processing. The gas centre is connected to a storage vessel for condensate, Åsgard C. The Åsgard facilities are an important part of the Norwegian Sea infrastructure. In addition to processing Åsgard production, gas from Mikkel is processed. The Åsgard field has been developed in two phases. The liquid phase came on stream in 1999 and the gas export phase from 01.10.2000. Åsgard includes the discoveries 6506/12-1 Smørbukk, 6506/12-3 Smørbukk Sør and 6507/11-1 Midgard.



Reservoir:
6506/12-1 Smørbukk is a rotated fault block, bordered by faults in the west and north and structurally deeper areas to the south and east. The reservoir formations Garn, Ile, Tofte, Tilje and Åre are from the Jurassic Age and contain gas, condensate and oil. The reservoir is located at depths down to 4 850 metres. 6506/12-3 Smørbukk Sør, with reservoir rocks in the Garn, Ile and Tilje formations, is from the Lower to Middle Jurassic Ages and contains oil, gas and condensate. The Midgard discovery is divided into four structural segments with the main reservoir in the Middle Jurassic Garn and Ile formations.

Recovery strategy:
The Smørbukk and Smørbukk Sør deposits are produced with gas injection. The Midgard deposit is produced by pressure depletion. There is a thin oil zone (11.5 m) below the gas cap in Midgard, but there are no plans to produce the oil at this time.

Transport:
Oil and condensate are temporarily stored at the field and shipped to shore by tankers. The gas is exported through Åsgard Transport to Kårstø. Starting on 01.07.2006, condensate from Åsgard will be sold as oil (Halten Blend).

Status:
Most of the production wells have been drilled, and active efforts are being made to increase recovery from the field. An oil zone recently proven in the Ile reservoir on Smørbukk Sør could provide a basis for gas injection. The production properties are better than expected.

Fields where production has ceased

The fields in this summary were no longer producing as of 31 December 2005. Plans for new development are in progress for some of these fields.

Albuskjell

Block	1/6 and 2/4
Development approval	25.04.1975
Cessation plan/ Decommissioning	The cessation plan was approved by Royal Decree on 21.12. 2001, and in Storting White Paper No. 47 (1999–2000)
On stream	26.05.1979
Production ceased	26.08.1998
Total production over field lifetime	Oil: 7.4 million scm Gas: 15.5 billion scm NGL: 1.0 million tonnes

Status: There are no specific plans to recover the remaining resources. Final disposal is planned for 2007/ 2008.

Cod

Block	7/11
Development approval	04.05.1973
Cessation plan/ Decommissioning	The cessation plan was approved by Royal Decree on 21.12.2001, and in Storting White Paper No. 47 (1999–2000)
On stream	26.12.1977
Production ceased	05.08.1998
Total production over field lifetime	Oil: 2.9 million scm Gas: 7.3 billion scm NGL: 0.5 million tonnes

Status: There are no specific plans to recover the remaining resources. Final disposal is planned for 2007.

Edda

Block	2/7
Development approval	25.04.1975
Cessation plan/ Decommissioning	The cessation plan was approved by Royal Decree on 21.12.2001, and in Storting White Paper No. 47 (1999–2000)
On stream	02.12.1979
Production ceased	05.08.1998
Total production over field lifetime	Oil: 4.8 million scm Gas: 2.0 billion scm NGL: 0.2 million tonnes

Status: There are no specific plans to recover the remaining resources. Final disposal is planned for 2006 and in 2013.

Frigg

Block	25/1
Development approval	13.06.1974
Cessation plan/ Decommissioning	The cessation plan was approved by Royal Decree on 26.09.2003, and in Storting Proposition No. 38 (2003–2004)
On stream	13.09.1977
Production ceased	26.10.2004
Total production over field lifetime	Gas: 116.2 billion scm Condensate: 0.5 million scm

Status: Final disposal of the facilities is ongoing.

Frøy

Block	25/2 and 25/5
Development approval	18.05.1992
Cessation plan/ Decommissioning	The cessation plan was approved by Royal Decree on 29.05.2001, and in Storting White Paper No. 47 (1999–2000)
On stream	15.05.1995
Production ceased	05.03.2001
Total production over field lifetime	Oil: 5.6 million scm Gas: 1.6 billion scm Condensate: 0.1 million scm

Status: No activity.

Lille-Frigg

Block	25/2
Development approval	06.09.1991
Cessation plan/ Decommissioning	Storting Proposition No. 53 (1999–2000) and White Paper No. 47 (1999-2000)
On stream	13.05.1994
Production ceased	25.03.1999
Total production over field lifetime	Oil: 1.3 million scm Gas: 2.2 billion scm

Status: No activity.

Mime

Block	7/11
Development approval	06.11.1992
Cessation plan/ Decommissioning	Storting Proposition No. 15 (1996–1997) and White Paper No. 47 (1999–2000)
On stream	25.10.1990
Production ceased	04.11.1993
Total production over field lifetime	Oil: 0.4 million scm Gas: 0.1 billion scm

Status: Recovery of remaining resources is being evaluated. The plan calls for drilling an appraisal well first.

Nordøst Frigg

Block	25/1 and 30/10
Development approval	12.09.1980
Cessation plan/ Decommissioning	Storting Proposition No. 36 (1994–1995)
On stream	01.12.1983
Production ceased	08.05.1993
Total production over field lifetime	Gas: 11.6 billion scm Condensate: 0.1 million scm

Status: No activity.

Odin

Block	30/10
Development approval	18.07.1980
Cessation plan/ Decommissioning	Storting Proposition No. 50 (1995–1996) and White Paper No. 47 (1999–2000)
On stream	01.04.1984
Production ceased	01.08.1994
Total production over field lifetime	Gas: 27.3 billion scm Condensate: 0.2 million scm

Status: No activity.

Tommeliten Gamma

Block	1/9
Development approval	12.06.1986
Cessation plan/ Decommissioning	Storting Proposition No. 53 (1999–2000) and White Paper No. 47 (1999–2000)
On stream	03.10.1988
Production ceased	05.08.1998
Total production over field lifetime	Oil: 3.9 million scm Gas: 9.7 billion scm NGL: 0.6 million tonnes

Status: There are no specific plans to recover the remaining resources.

Vest Ekofisk

Block	2/4
Development approval	04.05.1973
Cessation plan/ Decommissioning	The cessation plan was approved by Royal Decree on 21.12.2001, and Storting White Paper No. 47 (1999-2000)
On stream	31.05.1977
Production ceased	25.08.1998
Total production over field lifetime	Oil: 12.2 million scm Gas: 26.0 billion scm NGL: 1.4 million tonnes

Status: There are specific plans to recover the remaining resources by means of a new subsea development tied back to Ekofisk.

Yme

Block	9/2 and 9/5
Development approval	06.01.1995
Cessation plan/ Decommissioning	The cessation plan was approved by Royal Decree on 04.05.2001
On stream	27.02.1996
Production ceased	17.04.2001
Total production over field lifetime	Oil: 7.9 million scm

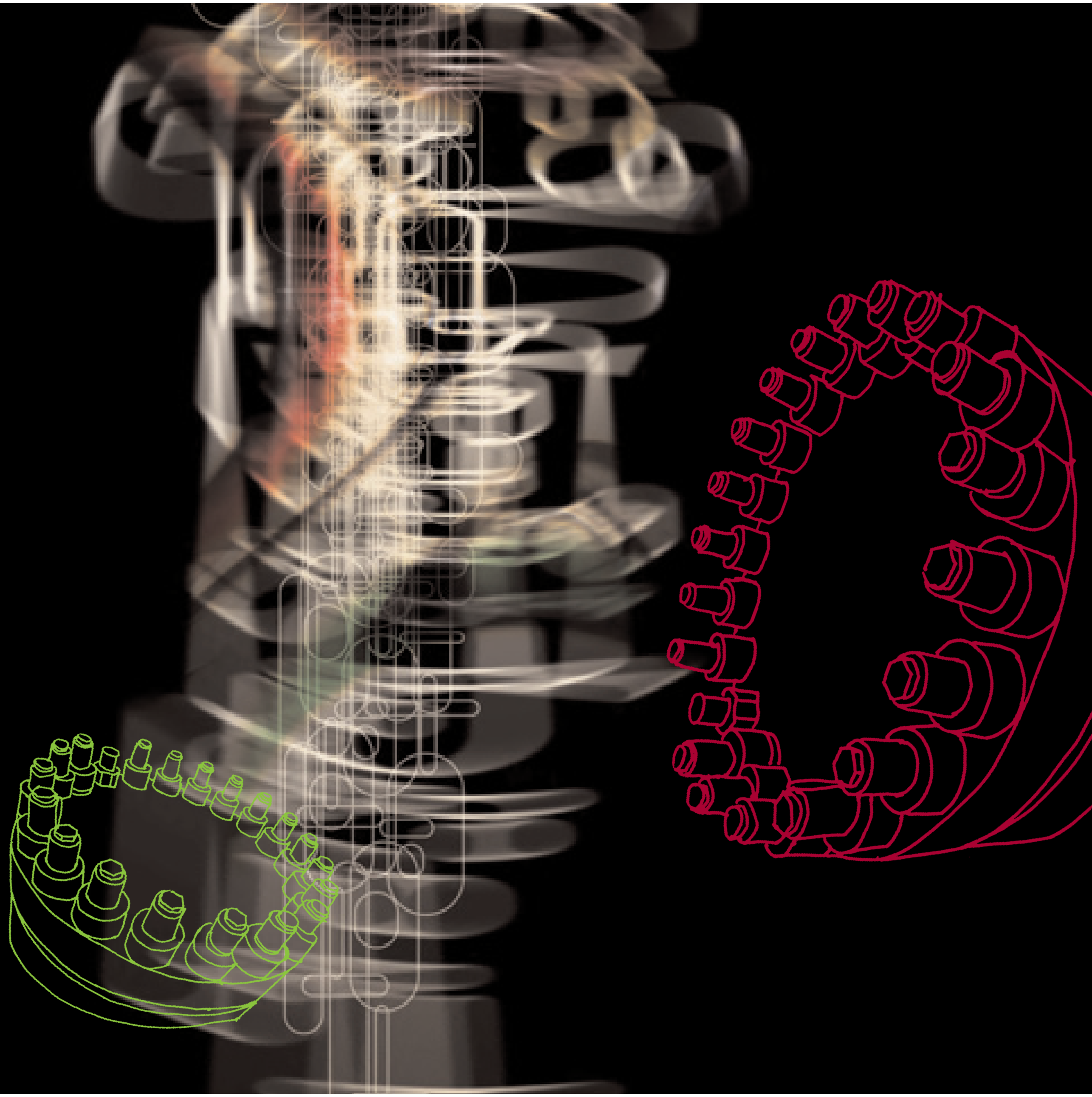
Status: There are specific plans to recover the remaining resources by means of a new subsea development and a production vessel, or a wellhead facility linked to an existing field. A decision on the development concept is expected in early 2006.

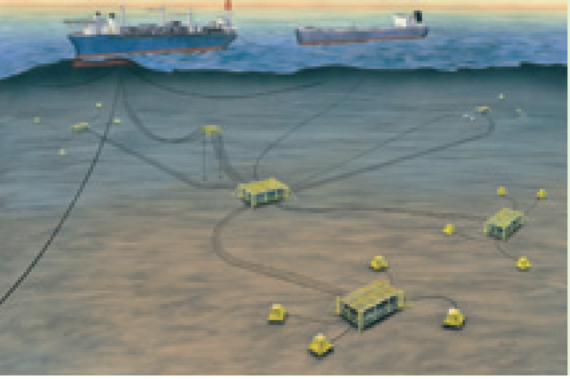
Øst Frigg

Block	25/1 and 25/2
Development approval	14.12.1984
Cessation plan/ Decommissioning	Storting Proposition No. 8 (1998–1999) and White Paper No. 47 (1999–2000)
On stream	01.10.1988
Production ceased	22.12.1997
Total production over field lifetime	Gas: 9.2 billion scm Condensate: 0.1 million scm

Status: No activity.

12 Fields under development





Alvheim

Blocks and production licences	Block 24/6 - production licence 088 BS. Awarded 2003. Block 24/6 - production licence 203. Awarded 1996. Block 25/4 - production licence 036 C. Awarded 2003. Block 25/4 - production licence 203. Awarded 1996.
Discovered	1998
Development approval	06.10.2004 by the King in Council
Operator	Marathon Petroleum Norge AS
Licensees	Lundin Norway AS 15.00% Marathon Petroleum Norge AS 65.00% Norske ConocoPhillips AS 20.00%
Recoverable reserves	**Original:** 23.7 million scm oil 5.7 billion scm gas
Investment	Total investment is expected to be NOK 9.1 billion (2006 values) NOK 3.8 billion had been invested at 31.12.05 (2006 values)

Development:
Alvheim is an oil and gas field comprising the three discoveries 24/6-2, 24/6-4 and 25/4-7. The sea in the area is 120-130 metres deep. The field will be developed using a production vessel and subsea wells. The oil will be stabilised and stored for export in the production vessel.

Reservoir:
The Alvheim reservoir consists of sandstones deposited as turbidites from the Shetland Platform in the Lower Tertiary.

Recovery strategy:
Alvheim will be produced with aquifer drive.

Transport:
The oil will be exported by tankers. Processed rich gas from Alvheim will be transported in a new pipeline from Alvheim to the SAGE system on the UK continental shelf.

Status:
A small part of Alvheim, 24/6-4 Boa, extends into the British sector. The licensees on the two sides are currently clarifying the allocation of resources and costs for this deposit. Production start-up for Alvheim is planned for February 2007.

Blane

Blocks and production licences	Block 1/2 - production licence 143 BS. Awarded 2003. The Norwegian part of the field is 18.00%, the British part is 82.00%.	
Discovered	1989	
Development approval	01.07.2005	
Operator	Paladin Expro Limited	
Licensees	Paladin Resources Norge AS	11.70%
	Talisman Energy Norge AS	6.30%
	Bow Valley Petroleum (UK) Limited	12.50%
	Eni UK Limited	13.90%
	Eni ULX Limited	4.11%
	Mox Exploration (U.K.) Limited	13.99%
	Paladin Expro Limited	25.00%
	Roc Oil (GB) Limited	12.50%
Recoverable reserves (the Norwegian part)	**Original:** 0.8 million scm oil	
Investment	Total investment is expected to be NOK 0.3 billion (2006 values) NOK 0.1 billion had been invested at 31.12.2005 (2006 values)	

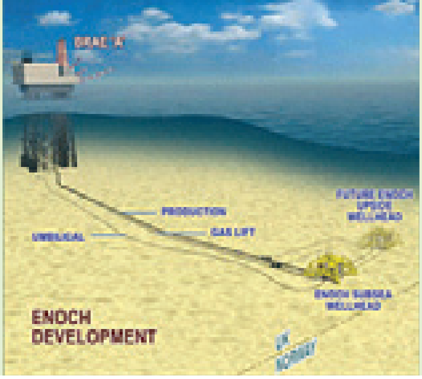
Development:
The field will be developed with subsea facilities connected to the Ula field. The subsea installations will be placed on the British continental shelf. The sea in the area is approximately 70 metres deep.

Reservoir:
The reservoir consists of Paleocene marine sandstones. Mapping and reservoir studies anticipate that the majority of the resources lie on the UK side of the boundary.

Recovery strategy:
Produced water from Blane, Ula and Tambar will be mixed on Ula and used as injection water for maintaining the pressure on Blane. Gas lift could also be an alternative after upgrading of the gas process capacity on Ula in 2007.

Transport:
The well stream will be transported in a pipeline to Ula for processing and metering. The oil will then be exported in the existing pipeline to Teesside, while the gas will be sold to Ula for injection in the Ula reservoir.

Status:
The development plan was approved by Norwegian and British authorities on 01.07.2005. Drilling will commence late in the first quarter of 2006, and production start-up is planned for early 2007.



Enoch

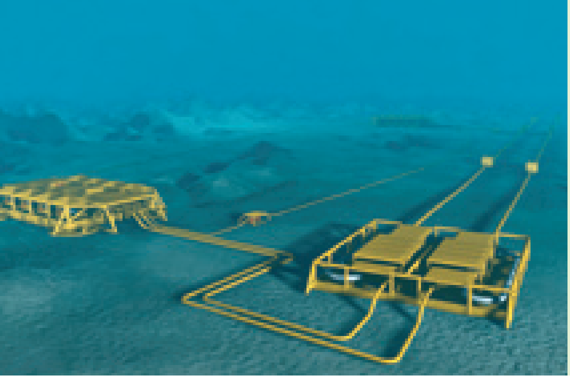
Blocks and production licences	Block 15/5 - production licence 048 B. Awarded 2001. The Norwegian part of the field is 20.00%, the British part is 80.00%.	
Discovered	1985	
Development approval	01.07.2005	
Operator	Paladin Expro Limited	
Licensees	DONG Norge AS	1.86%
	Det Norske Oljeselskap AS	2.00%
	Statoil ASA	11.78%
	Total E&P Norge	4.36%
	Bow Valley Petroleum (UK) Limited	12.00%
	Dana Petroleum (E & P) Limited	8.80%
	Dyas UK Limited	14.00%
	Lundin North Sea Limited	1.20%
	Paladin Expro Limited	24.00%
	Petro-Canada UK Limited	8.00%
	Roc Oil (GB) Limited	12.00%
Recoverable reserves (the Norwegian part)	**Original:** 0.3 mill. scm oil 0.1 billion scm gas	
Investment	Total investment is expected to be NOK 0.2 billion (2006 values) NOK 0.1 billion had been invested at 31.12.2005 (2006 values)	

Development:
The field will be developed with subsea facilities placed on the British continental shelf and connected to the British Brae field.

Recovery strategy:
The field will be produced by pressure depletion, but water injection may be implemented later if necessary.

Transport:
The well stream from Enoch will be transported to Brae A for processing before the oil is transported onwards in the existing pipeline to Cruden Bay. The gas will be sold to Brae.

Status:
The development plan was approved by Norwegian and British authorities on 01.07.2005. Production start-up is planned for late 2006.



Ormen Lange

Blocks and production licences	Block 6305/4 - production licence 209. Awarded 1996.	
	Block 6305/5 - production licence 209. Awarded 1996.	
	Block 6305/7 - production licence 208. Awarded 1996.	
	Block 6305/8 - production licence 250. Awarded 1999.	
Discovered	1997	
Development approval	02.04.2004 by the Storting	
Operator	Norsk Hydro Produksjon AS	
Licensees	A/S Norske Shell	17.04%
	DONG Norge AS	10.34%
	ExxonMobil Exploration and Production Norway AS	7.23%
	Norsk Hydro Produksjon AS	18.07%
	Petoro AS	36.48%
	Statoil ASA	10.84%
Recoverable reserves	**Original:**	
	375.2 billion scm gas	
	22.1 million scm condensate	
Investment	Total investment is expected to be NOK 33.0 billion (2006 values)	
	NOK 6.5 billion had been invested at 31.12.05 (2006 values)	

Development:
Ormen Lange lies in the Møre basin in the southern part of the Norwegian Sea. The field contains gas and some condensate. Water depth in the area varies from 800 to 1 100 metres. Ormen Lange will be developed using 24 wells drilled from four subsea templates. Four of the production wells will be ready for production start-up on 01.10.2007. Because the development area is in the Storegga slide depression, formed some 8 200 years ago, there are great challenges related to the installation of templates and pipelines on the rough seabed. The great water depths also make the development complicated and require development of new technology.

Reservoir:
The main reservoir is in sandstone from the Early Tertiary, about 2 700-2 900 metres deep.

Recovery strategy:
The recovery strategy is based on production by pressure depletion and subsequent gas compression.

Transport:
The unprocessed well stream, consisting of gas and condensate, will be routed through two multi-phase pipelines to a land installation at Nyhamna in Aukra in Møre og Romsdal. At the plant at Nyhamna, the gas will be dried and compressed before being transported through a gas export pipe, Langeled, south via the Sleipner area and onward to the UK.

Status:
Gas production from Ormen Lange is planned to begin in October 2007.

Ringhorne Øst

Blocks and production licences	Block 25/8 - production licence 027. Awarded 1969. Block 25/8 - production licence 169. Awarded 1991.	
Discovered	2003	
Development approval	25.11.2005 by the King in Council	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS	77.38%
	Norsk Hydro Produksjon AS	11.70%
	Petoro AS	7.80%
	Statoil ASA	3.12%
Recoverable reserves	**Original:** 8.0 million scm oil 0.3 billion scm gas	
Investment	Total investment is expected to be NOK 0.9 billion (2006 values)	

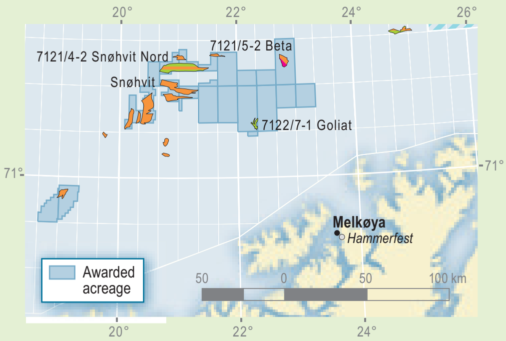
Development:
Ringhorne Øst will be produced through four production wells drilled from the Ringhorne facility. The sea depth is approximately 130 metres.

Reservoir:
The reservoir contains oil with associated gas and is equivalent to the Jurassic reservoir at the Ringhorne deposit.

Recovery strategy:
Aquifer drive is expected to be the production mechanism. If more pressure support is required, two water injection wells could be used.

Transport:
The production from Ringhorne Øst will be transported to the Ringhorne installation and the Balder vessel for processing and export.

Status:
Production start-up is planned for spring 2006.



Snøhvit

Blocks and production licences	Block 7120/6 - production licence 097. Awarded 1984.	
	Block 7120/7 - production licence 077. Awarded 1982.	
	Block 7120/8 - production licence 064. Awarded 1981.	
	Block 7120/9 - production licence 078. Awarded 1982.	
	Block 7121/4 - production licence 099. Awarded 1984.	
	Block 7121/5 - production licence 110. Awarded 1985.	
	Block 7121/7 - production licence 100. Awarded 1984.	
Discovered	1984	
Development approval	07.03.2002 by the Storting	
Operator	Statoil ASA	
Licensees	Amerada Hess Norge AS	3.26%
	Gaz de France Norge AS	12.00%
	Petoro AS	30.00%
	RWE Dea Norge AS	2.81%
	Statoil ASA	33.53%
	Total E&P Norge AS	18.40%
Recoverable reserves	**Original:**	
	160.6 billion scm gas	
	6.3 million tonnes NGL	
	18.1 million scm condensate	
Investment	Total investment is expected to be NOK 17.8 billion (2006 values)*	
	NOK 7.6 billion had been invested at 31.12.05 (2006 values)	

**Total investments, including the land facilities, is expected to be NOK 57.3 billion (2006 values)*

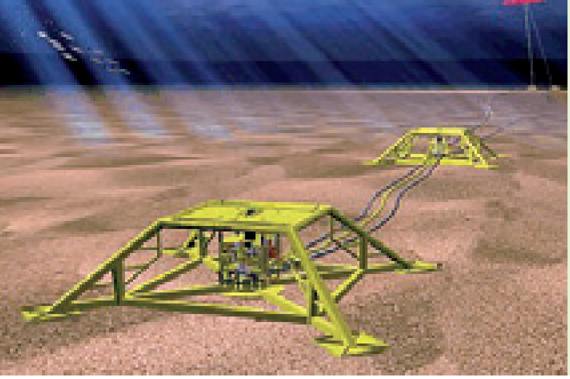
Development:
Snøhvit is a gas field with condensate and an underlying oil zone. The field lies in the central section of the Hammerfest basin at a sea depth of between 310 and 340 metres. Approved development comprises the gas resources. The production facility will consist of subsea templates for 19 production wells and a CO_2 injection well. Production start-up is planned for the 2nd quarter of 2007 with full production from the 4th quarter of 2007.

Reservoir:
The Snøhvit field consists of seven structures with gas, condensate and oil in Lower and Middle Jurassic sandstones.

Recovery strategy:
Snøhvit will be produced by pressure depletion. The approved development plan does not include recovery of the oil zone. Higher oil prices and delays in the gas development have made it more interesting to evaluate production from the thin oil zone. A conclusion is expected in 2006.

Transport:
The unprocessed well stream, comprising natural gas incorporating CO_2, NGL and condensate, will be transported through a 160 kilometres long pipeline to the Melkøya plant for processing. At Melkøya the gas will be processed and cooled to liquefy it (LNG). The CO_2 content in the gas will be separated at the Melkøya plant and returned to the field for injection in a formation below the oil and gas. Transport to the market will be by ship.

Status:
The costs have increased and the production start-up is delayed compared to the development plan.



Vilje

Blocks and production licences	Block 25/4 - production licence 036. Awarded 1971.
Discovered	2003
Development approval	18.03.2005 by the King in Council
Operator	Norsk Hydro Produksjon AS
Licensees	Marathon Petroleum Norge AS 46.90% Norsk Hydro Produksjon AS 28.85% Total E&P Norge AS 24.24%
Recoverable reserves	**Original:** 8.3 million scm oil
Investment	Total investment is expected to be NOK 2.4 billion (2006 values) NOK 0.6 billion had been invested at 31.12.05 (2006 values)

Development:
Vilje is an oil field located approximately 11 kilometres north northeast of the Heimdal field and 5 kilometres southwest of Vale. The sea depth in the area is approximately 120 metres. The field will be developed with two subsea wells connected to the Alvheim installation.

Reservoir:
The reservoir consists of Paleocene sandstones deposited as turbidites and is located approximately 2 150 metres below sea level. A 65 metres thick oil column in the Heimdal formation was proven in the discovery well.

Recovery strategy:
Production will be accomplished by aquifer drive.

Transport:
The well stream will be transported via pipeline to Alvheim, where the oil will be buoy-loaded to tankers.

Status:
Production start-up is planned for February 2007.

Volve

Blocks and production licences	Block 15/9 - production licence 046. Awarded 1976.	
Discovered	1993	
Development approval	22.04.2005 by the Crown Prince Regent in Council	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	30.40%
	Norsk Hydro Produksjon AS	10.00%
	Statoil ASA	49.60%
	Total E&P Norge AS	10.00%
Recoverable reserves	**Original:**	
	11.9 million scm oil	
	1.3 billion scm gas	
	0.2 million tonnes NGL	
	0.1 million scm condensate	
Investment	Total investment is expected to be NOK 2.0 billion (2006 values)	
	NOK 0.1 billion had been invested at 31.12.2005 (2006 values)	

Development:
Volve is located approximately 8 kilometres north of the Sleiper A installation on Sleiper Øst, at a sea depth of approximately 80 metres. The development concept is a jack-up processing and drilling facility and a vessel for storing stabilized oil.

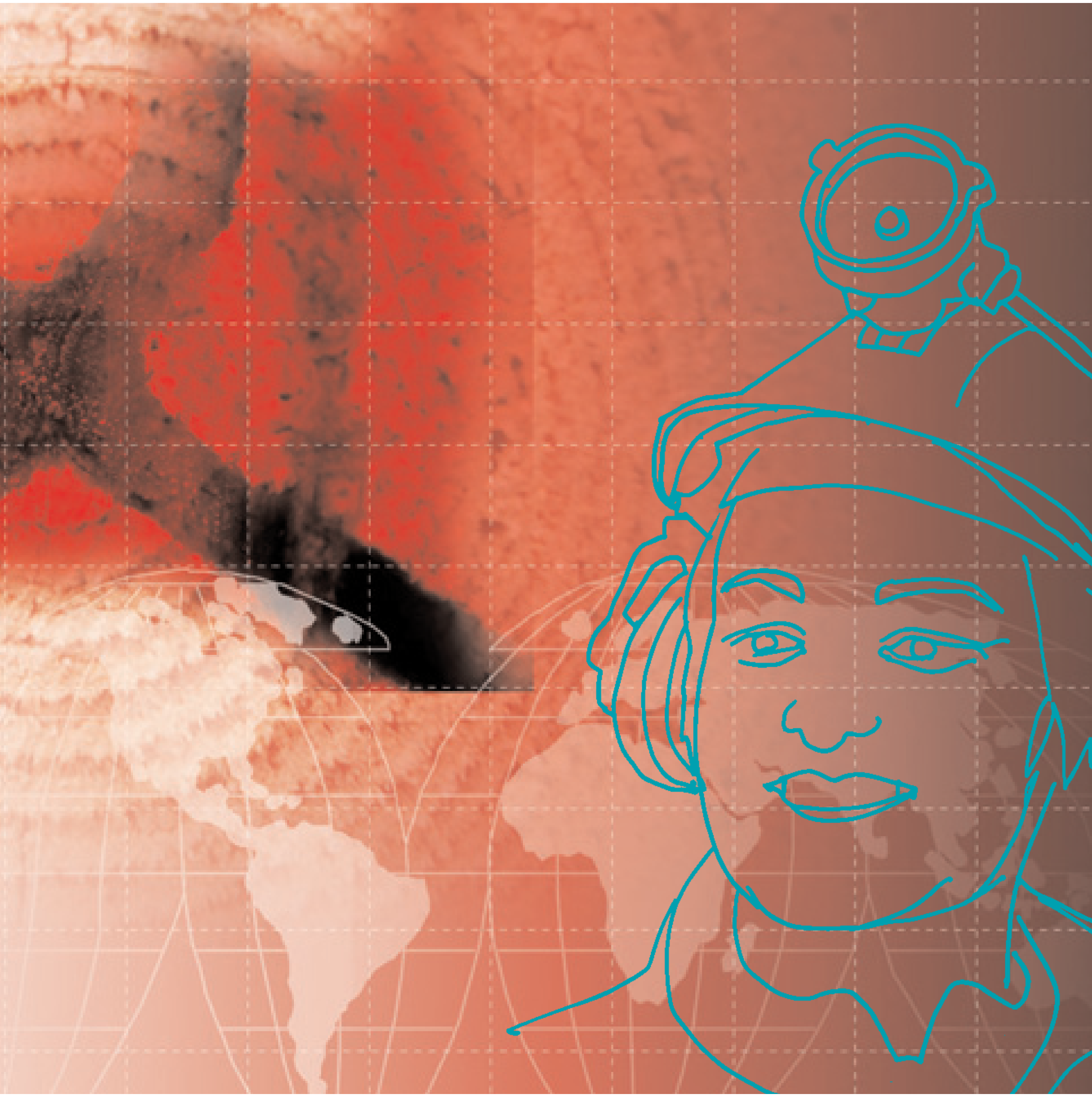
Reservoir:
The reservoir contains oil in a combined stratigraphic and structural trap with Jurrassic and Triassic sandstones in the Hugin formation. The western part of the structure is heavily faulted and it is uncertain whether there is communication across the faults.

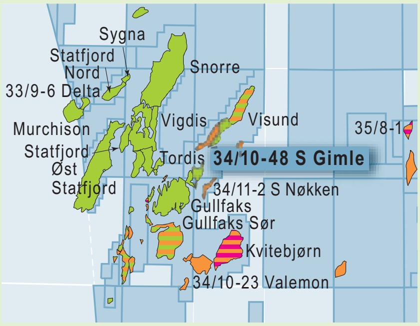
Recovery strategy:
Volve has been considered as a potential candidate for CO_2 injection.

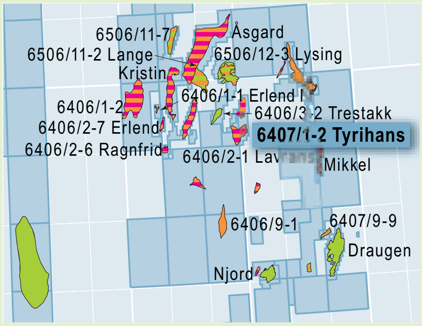
Transport:
The rich gas will be transported to Sleipner A and exported onwards from there.

Status:
A decision regarding potential CO_2 injection is expected in 2006.

13 Future developments







Development decided by the licensees

34/10-48 S Gimle	Production licence 050, 120. Operator: Statoil ASA
Resources	Oil: 4.1 million scm. Gas: 0.9 billion scm. NGL: 0.1 million tonnes. Condensate: 0.3 million scm.

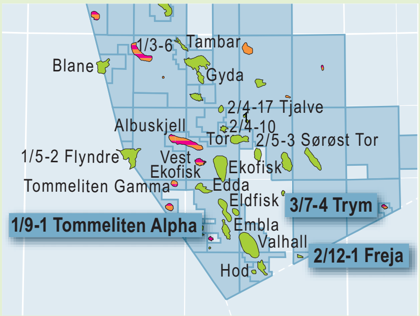
34/10-48 S Gimle was proven in 2004. The well was drilled from the Gullfaks C installation. The discovery has been in test production in 2005. The east flank of the deposit was previously proven by well 34/8-12 S. The licensees applied for an exemption from the Plan for Development and Operation (PDO) for Gimle in January 2006. Production and injection will take place from Gullfaks C. One water injection well is planned in 2006 and possibly a new production well in 2007.

Gimle is divided between production licences 050 and 120.

6407/1-2 Tyrihans	Production licence 073, 091. Operator: Statoil ASA
Resources	Oil: 29.9 million scm. Gas: 29.5 billion scm. NGL: 5.5 million tonnes.

Tyrihans encompasses the discoveries 6407/1-2 Tyrihans Sør and 6407/1-3 Tyrihans Nord. These two discoveries were made in 1982 and 1983 and are located about 25 kilometres southeast of the Åsgard field. In addition to the wildcat wells, an appraisal well has been drilled in each discovery. Tyrihans Sør has an oil column with a condensate rich gas cap. Tyrihans Nord contains gas condensate with an underlying oil column. The Garn formation is the main reservoir for both.

The licensees have selected tie-in to Kristin and processing there as the development solution. The PDO was approved by the Storting on 16 February 2006. Recovery is based on gas injection from Åsgard B into Tyrihans Sør in the first years. In addition, subsea pumps will be used to inject seawater to further increase recovery. A decision has also been made to develop the oil zone in Tyrihans Nord.



Discoveries in the planning phase

This list does not include discoveries that fall under new resources in existing fields.

1/9-1 Tommeliten Alpha	Production licence 044. Operator: ConocoPhillips Skandinavia AS
Resources	Oil: 7.9 million scm. Gas: 12.9 billion scm.

1/9-1 Tommeliten Alpha was proven in 1976. The sea depth in the area is approximately 80 metres. The discovery is located about 20 kilometres southwest of the Ekofisk field, near the border to the British sector. The discovery contains gas and condensate in Cretaceous chalk at a depth of 3 500 metres. Three appraisal wells have been drilled on the discovery, with the most recent being 1/9-7 in 2003. The licensees are evaluating the resource base and alternative development concepts. The most likely development solution is a subsea development connected to Ekofisk J. Concept selection is expected in 2006.

2/12-1 Freja	Production licence 113. Operator: Amerada Hess Norge AS
Resources	Oil: 2.9 million scm. Gas: 0.6 billion scm.

2/12-1 Freja was proven in 1986, close to the border between the Danish and Norwegian sectors. The sea depth in the area is 70 metres. The reservoir is in Upper Jurassic sandstones. The reservoir is located at a depth of about 4 900 metres, and contains oil and associated gas. 2/12-1 Freja is situated in a complex geological area between Fedagraben in the west and Gertrudgraben in the east. It is assumed that the reservoir is divided into separate fault blocks. Oil has also been proven in the Gert deposit on the Danish side of the border. The deposit will most likely be developed with a simple solution based on existing infrastructure in the area.

3/7-4 Trym	Production licence 147. Operator: A/S Norske Shell
Resources	Gas: 3.4 billion scm. Condensate: 0.8 million scm.

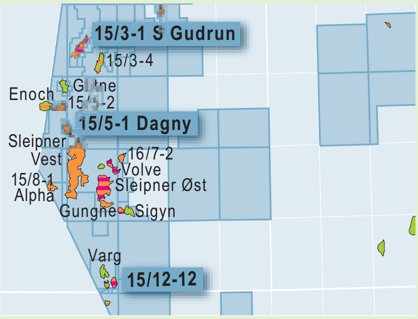
3/7-4 Trym is situated near the border between the Norwegian and Danish sectors. The sea depth in the area is 67 metres. 3/7-4 Trym was drilled in 1989, and proved gas and condensate in Upper and Middle Jurassic sandstones. The discovery is located on the same salt-induced structure as the Danish field Lulita. It is assumed that the deposits are separated by a fault zone on the Norwegian side of the border, but there may be pressure communication through the water zone.

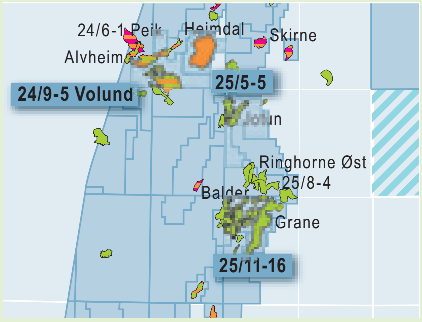
The licensees submitted a PDO to the authorities on 27 January 2006. The development solution is based on tie back to the Harald field in the Danish sector.

15/3-1 S Gudrun	Production licence 025, 187. Operator: Statoil ASA
Resources	Oil: 15.2 million scm. Gas: 8.5 billion scm. NGL: 5.4 million tonnes.

15/3-1 S Gudrun is situated about 40 kilometres north of the Sleipner area. The sea depth in the area is approximately 110 metres. The discovery was made in 1975. It contains oil and gas in Upper Jurassic sandstones, at a depth of 4 000–4 500 metres. Drilling of a new appraisal well started late in 2005. According to the plan, 15/3-1 Gudrun will be developed together with the 15/3-4 discovery, which is located ten kilometres further to the southeast.

This development will most likely be accomplished with subsea facilities tied back to existing infrastructure in Norway and/or the United Kingdom. A PDO is planned to be submitted to the authorities in December 2007. 15/3-1 Gudrun could commence production in 2010 and 15/3-4 in 2012.





15/5-1 Dagny	Production licence 029, 048. Operator: Statoil ASA
Resources	Gas: 3.8 billion scm. NGL: 0.2 million tonnes. Condensate: 1.2 million scm.

15/5-1 Dagny is located directly northwest of Sleipner Vest. This is a small discovery containing gas and condensate, made in 1977. The discovery is divided between two production licences, 048 and 029. The reservoir is made up of Middle Jurassic sandstones in the Hugin formation.

The development will most likely be based on a subsea facility connected to existing infrastructure on Sleipner A or to Sleipner T via the Alfa Nord segment. 15/5-1 Dagny is expected to come on stream during the period 2008–2010, when capacity becomes available on the Sleipner field.

15/12-12	Production licence 038. Operator: Talisman Energy Norge AS
Resources	Gas: 4.1 billion scm. Condensate: 0.7 million scm.

The 15/12-12 discovery was made in 2000 near the border between the Norwegian and British sectors and four kilometres south of the Varg field. The sea depth in the area is 90–110 metres. The reservoir is situated around a salt structure at a depth of about 3 000 metres, and is made up of Upper Jurassic sandstones. The discovery has an oil zone with gas cap. Pressure measurements indicate that the reservoir is in pressure communication with the Varg field.

Development will be based on subsea facilities tied back to existing infrastructure in the Norwegian or in the British sector.

An appraisal well will be drilled in early 2006, which will be converted into a production well when the field comes on stream. The plan calls for a PDO to be submitted to the authorities in the first half of 2006.

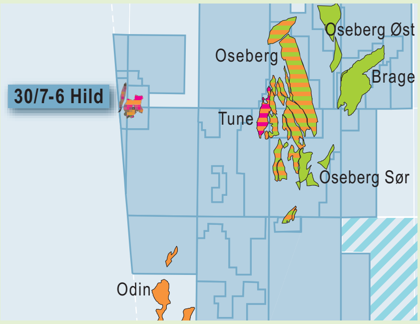
24/9-5 Volund	Production licence 150. Operator: Marathon Petroleum Norge AS
Resources	Oil: 7.0 million scm. Gas: 0.8 billion scm.

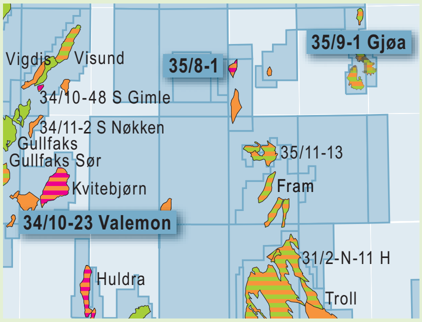
The plan is to develop this discovery with subsea wells (three production wells and one water injection well) tied back to the Alvheim facility (FPSO), which is currently being built. A PDO is expected to be submitted to the authorities in the fall of 2006, and production will commence in the winter of 2008.

25/5-5	Production licence 102. Operator: Total E&P Norge AS
Resources	Oil: 3.5 million scm. Gas: 0.1 billion scm.

The 25/5-5 discovery was made in 1995, eight kilometres east of the Heimdal field. The sea depths in the area is approximately 120 metres. The reservoir is in Paleocene sandstones, deposited as turbidity currents from the west. The discovery well proved an oil column of 18 metres about 2 130 metres below the sea surface.

The discovery is situated close to existing infrastructure in an area with several other discoveries, and may be developed later on.





25/11-16	Production licence 169. Operator: Norsk Hydro Produksjon AS
Resources	Oil: 3.6 million scm

The 25/11-16 discovery was made in 1992 directly west of the Grane field. The sea depth in the area is 120 metres. The well proved oil and associated gas at a depth of about 1 750 metres, in Paleocene Heimdal formation sandstones. The discovery is located in an area with extensive sandstone reservoirs in a submarine fan system.

The most likely development solution is subsea templates tied back to Grane, alternatively extended reach wells from Grane.

30/7-6 Hild	Production licence 40, 43. Operator: Total E&P Norge AS
Resources	Gas: 14.7 billion scm. Condensate: 1.9 million scm.

30/7-6 Hild was proven in 1979, near the border between the Norwegian and the British sectors. The sea depth in the area is 100–120 metres. The reservoir is complex, with gas and condensate at high temperatures and high pressure. The licensees are evaluating development in several phases.

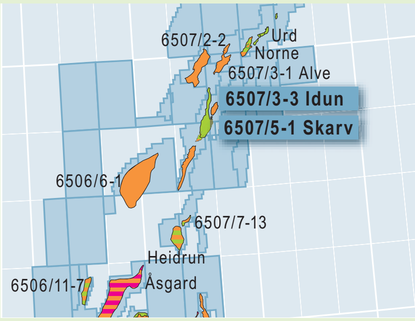
The development solution for Phase 1 will be a subsea well tied back to the nearest infrastructure. According to the plan, a PDO for Phase 1 will be submitted to the authorities in the winter of 2006. There are several alternative development solutions for Phase 2.

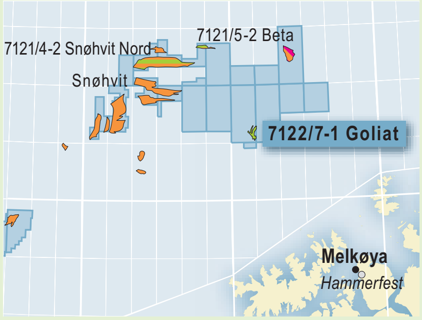
34/10-23 Valemon	Production licence 050, 193. Operator: Statoil ASA
Resources	Gas: 18.1 billion scm. NGL: 0.8 million tonnes. Condensate: 5.7 million scm.

34/10-23 Valemon is located in blocks 34/11 and 34/10 in an area with sea depth of about 135 metres. Four exploration wells have been drilled on the discovery, the first in 1985, and gas has been proven in three of them. The discovery has a complex structure with many faults. The reservoir consists of Middle Jurassic sandstones in the Brent group and the Cook formation. The reservoir lies at a depth of approximately 4 000 metres, with high pressure and high temperatures. The plan calls for development with a subsea template tied back to existing infrastructure, most likely to Kvitebjørn. In addition, the licence is evaluating use of extended reach production wells from Kvitebjørn. An appraisal well is currently being drilled from Kvitebjørn.

35/8-1	Production licence 090C, 248. Operator: Norsk Hydro Produksjon AS
Resources	Gas: 16.1 billion scm. NGL: 0.9 million tonnes. Condensate: 4.1 million scm.

35/8-1 encompasses three discoveries in an area where the sea depth is approximately 370 metres. Two of the discoveries were proven in 1981 and are situated to the north of the Fram field. 35/8-1 also includes the 35/11-2 discovery, which was drilled in 1987 and appraised in 1992. This discovery is located close to the Fram field. All of the discoveries contain gas and condensate. The plan calls for development of the discoveries as a subsea development tied back to the planned facility on Gjøa. The licensees will select the concept in the first quarter of 2006 and will submit a PDO to the authorities in the fall of 2006.





35/9-1 Gjøa	Production licence 153. Operator: Statoil ASA
Resources	Oil: 9.1 million scm. Gas: 37.1 billion scm. NGL: 6.0 million tonnes.

35/9-1 Gjøa was proven in 1989 and is situated about 40 kilometres north of the Fram field. The sea depth in the area is approximately 360 metres. The reservoir is in sandstones in the Fensfjord formation, and is made up of several segments with somewhat uncertain communication. The discovery contains gas with a relatively thin oil zone.

Statoil is operator in the development phase, while Gaz de France will take over operator responsibility when the field comes on stream. Several development alternatives have been evaluated. The licensees have chosen to proceed with a semi-submersible facility as the concept. According to the plan, a PDO will be submitted to the authorities in the fall of 2006.

6507/3-3 Idun	Production licence 159. Operator: Statoil ASA
Resources	Gas: 11.8 billion scm. NGL: 1.5 million tonnes. Condensate: 0.2 million scm.

6507/3-3 Idun was proven in 1998. The sea depth in the area is 390 metres. The discovery is located between Heidrun and Norne. The reservoir contains gas and is made up of Middle Jurassic sandstones. The deposit is situated in a structurally faulted area in the Nordland II region, with the top of the reservoir at about 3 330 metres.

The licensees in 6507/3-3 Idun and 6507/5-1 Skarv have opted to continue work on a development solution based on a production vessel. Idun will be developed with a subsea facility connected to this production vessel. The plan calls for a PDO to be submitted to the authorities in December 2006.

6507/5-1 Skarv	Production licence 159, 212, 212 B, 262. Operator: BP Norge AS
Resources	Oil: 14.3 million scm. Gas: 35.8 billion scm. NGL: 5.8 million tonnes. Condensate: 4.0 million scm.

6507/5-1 Skarv was proven in 1998 and contains oil and gas in Jurassic and Cretaceous sandstones in three fault segments. The discovery is located about 30 kilometres southwest of the Norne field and 40 kilometres north of Heidrun, mainly in production licence 212, but also in production licences 262 and 159. The sea depth in the area is approximately 400 metres.

The licensees plan a development based on a production vessel and gas export through Åsgard Transport. Injection of gas is planned in the first years to increase liquid recovery. According to the plan, a PDO will be submitted to the authorities in the fourth quarter of 2006.

7122/7-1 Goliat	Production licence 229. Operator: Eni Norge AS
Resources	Oil: 6.7 million scm.

7122/7-1 Goliat was proven in 2000 and is situated 50 kilometres southeast of the Snøhvit field and 85 kilometres northwest of Hammerfest. The sea depth in the area is about 380 metres. The first well proved oil in sandstones from the Upper Triassic to Lower Jurassic Ages, about 1 100 metres under the sea surface. Well 7122/7-3, completed early in 2006, proved more oil and gas. The well also proved oil and probably some gas in Middle Triassic sandstones, about 1 800 metres below the sea surface. Additional appraisal drilling is planned in the fall of 2006.

14 Pipelines and onshore facilities

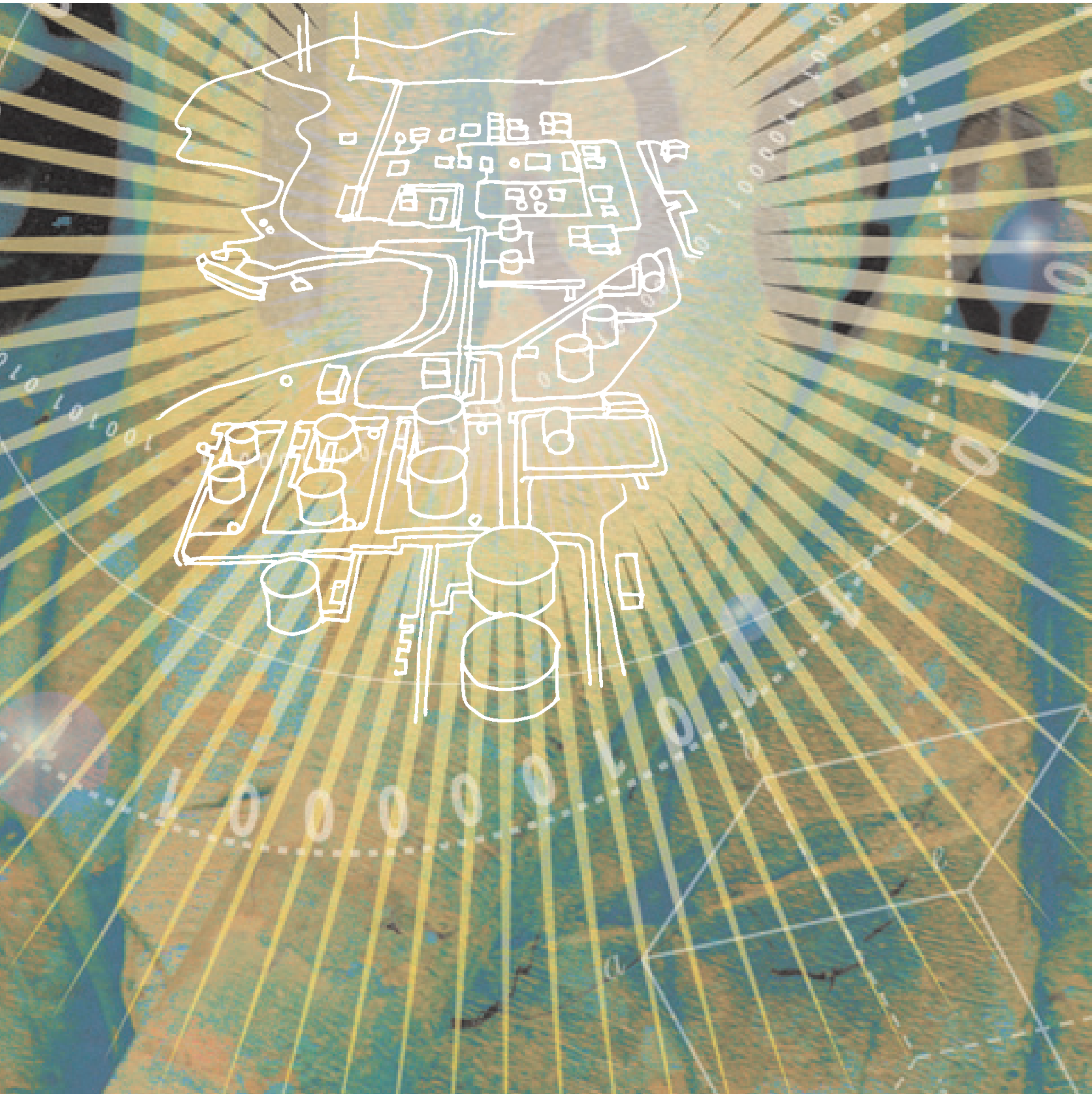


Figure 14.1 Existing and projected pipelines
(Source: Norwegian Petroleum Directorate)

The transport capacities quoted are based on standard assumptions for pressure, gas energy content, maintenance downtime and operational flexibility.

Gassled pipelines

Operator: Gassco AS

Licensees:

Petoro AS[1]	38.63%
Statoil ASA	20.56%
Norsk Hydro Produksjon AS	11.19%
Total E&P Norge AS	8.67%
ExxonMobil Exploration and Production Norway AS	5.18%
Norske Shell Pipelines AS	4.44%
Mobil Development Norway AS	4.58%
Norsea Gas AS	3.05%
Norske ConocoPhillips AS	2.03%
Eni Norge AS	1.69%

[1] Petoro is the licensee representing the State's Direct Financial Interest (SDFI). Petoro's participating interest in Gassled will be increased by approximately 9.5 percent with effect from 1 January 2011, and the other parties' participating interests will be reduced proportionally with effect from the same date.

In the spring of 2001, the government asked the relevant companies to commence negotiations with the objective of creating a unified ownership structure for gas export. Gassled represents the merger of nine gas transport facilities into a single partnership. The Gassled ownership agreement was signed on 20 December 2002, and came into effect on 1 January 2003. Gassled's licence runs to 2028.

Gassled encompasses the following pipelines: Europipe I, Europipe II, Franpipe, Norpipe, Oseberg Gas Transport, Statpipe (including the transport-related facilities at Kårstø), Vesterled, Zeepipe and Åsgard Transport. The Kollsnes gas processing facility also became part of Gassled on 1 February 2004. Gassled is organised into various zones for access and tariffs. Gassco coordinates and controls the flow of gas through a network of pipelines about 6 600 kilometres long, and manages all transport of Norwegian gas to the markets.

Europipe I

This 40-inch pipeline starts at the Draupner E riser facility and runs for 660 kilometres, terminating at Emden in Germany. Europipe I came into service in 1995. It has a capacity of about 46-54 million scm per day, depending on operating mode. The pipeline has been built for an operating life of 50 years and total investment at start-up was approximately NOK 21.3 billion (2006 value). In addition to the pipeline, investments also include the terminal at Dornum and the Europipe Metering Station in Emden.

(Agreement between Norway and Germany concerning the transmission of gas from the Norwegian continental shelf and other areas through a pipeline to the Federal Republic of Germany. (The Europipe Agreement), ref. Storting Proposition No. 60 (1992-1993) and Recommendation No. 164 (1992–1993).)

Europipe II

This 42-inch pipeline runs for 650 kilometres from Kårstø to Dornum in Germany, and became operational in 1999. With a capacity of about 71 million scm per day, Europipe II has been built for an operating life of 50 years. Total investment at start-up was approximately NOK 9.6 billion (2006 value).

(Supplementary agreement of 19 May 1999 to the Europipe agreement (see Storting Proposition No. 60 (1992-1993) and Recommendation No. 164 (1992–1993)) concerning the transmission of gas from Norway through a new pipeline (Europipe II) to Germany, ratified by Royal Decree of 14 September 2001.)

Franpipe

This 42-inch gas pipeline runs for 840 kilometres from the Draupner E riser facility in the North Sea to a receiving terminal at Dunkirk in France. The Gassled partnership owns 65 percent of the terminal, while Gaz de France owns 35 percent. The pipeline became operational in 1998.

Franpipe has a capacity of about 52 million scm per day. It has been built for an operating life of 50 years, with the total investment at start-up was approximately NOK 9.9 billion (2006 value).

(Agreement between Norway and France concerning the transmission of gas from the Norwegian continental shelf and other areas through a pipeline to France. See Storting Proposition No. 44 (1996–1997) and Recommendation No. 172 (1996–1997).)

Norpipe Gas pipeline

This 36-inch line starts at Ekofisk and runs for 440 kilometres to the Norsea Gas terminal in Emden, Germany. Also owned by Gassled, the Emden terminal cleans and meters the gas prior to onward distribution. The line became operational in 1977. Two riser facilities, H7 and B11, each with three compressors, are positioned on the German continental shelf to pump the gas southwards. The compressors on one of these installations have now been shut down. The transport capacity is approximately 35 million scm per day without using the compressor capacity on the B11 riser facility. Capacity will increase to 42–43 million scm per day if the B11 compressors are used. Norpipe has been built for an operating life of at least 30 years. Its technical life is under constant review. Total investment at start-up was approximately NOK 26.4 billion (2006 value).

(Agreement between Norway and Germany concerning the transmission of petroleum through a pipeline from the Ekofisk field and adjacent areas to Germany. See Storting Proposition No. 88 (1973-1974) and Recommendation No. 250 (1973-1974).)

Oseberg Gas Transport (OGT)

This 36-inch line starts at Oseberg and runs for roughly 109 kilometres to the riser facility at Heimdal. The pipeline became operational in 2000 and has a capacity of approximately 40 million scm per day. OGT has been built for an operating life of 50 years, and total investment at start-up was approximately NOK 1.9 billion (2006 value).

Statpipe

This 880-kilometres pipeline system includes a riser facility and a gas processing plant at Kårstø. The pipeline became operational in 1985. Statpipe Rich Gas, with a diameter of 30 inches, starts at Statfjord and runs for 308 kilometres to Kårstø, with a capacity of about 25 million scm per day. Statpipe Dry Gas has three components. One of these comprises a 28-inch pipeline running for about 228 kilometres from Kårstø to the Draupner S riser facility, with a capacity of roughly 20 million scm per day, depending on operating mode. The second component is a 36-inch pipeline running for about 155 kilometres from the Heimdal riser facility to Draupner S, with a capacity of about 30 million scm per day. The third section is a 36-inch pipeline running for roughly 203 kilometres from Draupner S to Ekofisk, with a capacity of about 30 million scm per day. The Heimdal-Draupner S and Kårstø-Draupner S pipelines can also be used for reversed flow. Total investment at start-up was approximately NOK 45.7 billion (2006 value), excluding the gas processing plant at Kårstø.

Zeepipe

Zeepipe I comprises a 40-inch pipeline running for about 814 kilometres from Sleipner to the receiving terminal in Zeebrugge, Belgium. The terminal in Zeebrugge belongs to a separate partnership, with the Gassled partners holding 49 percent and the Belgian Fluxys company holding 51 percent. Zeepipe I became operational in 1993 and has a capacity of roughly 41 million scm per day. Zeepipe I also includes a 30-inch pipeline between Sleipner and Draupner S. Zeepipe II A starts at the Kollsnes gas processing plant and ends at the Sleipner riser facility. This pipeline became operational in 1996.

Zeepipe II A is a 40-inch pipeline which is 303 kilometres long and has a capacity of 72 million scm per day. Zeepipe II B is a 40-inch pipeline running for about 300 kilometres, starting at the Kollsnes gas treatment plant and ending at Draupner E. The pipeline became operational in 1997. Zeepipe II B has a capacity of 71 million scm per day. The Zeepipe system has been built for an operating life of 50 years. Total investment at start-up is approximately NOK 24.2 billion (2006 value).

(Agreement between Norway and Belgium concerning the transmission of gas from the Norwegian continental shelf and other areas through a pipeline to Belgium. See Storting Proposition No. 148 (1987–1988) and Recommendation No. 21 (1988–1989).)

Åsgard Transport

This 42-inch pipeline runs for about 707 kilometres from the Åsgard field to Kårstø. It became operational in 2000, with a capacity of about 69 million scm per day. Åsgard Transport is built for an operating life of 50 years, with total investment at start-up of approximately NOK 10.5 billion (2006 value).

Kollsnes gas processing plant

The gas processing plant at Kollsnes in the municipality of Øygarden in Hordaland County forms part of Gassled. Wellstreams are separated at Kollsnes into gas and condensate. The gas is dried and compressed before being sent to the Continent via a pipeline to Sleipner and Draupner.

Kollsnes also delivers a small amount of gas to the LNG plant at the Gasnor-Kollsnes Industrial Park. Following a stabilisation process, the condensate is sent on to the Vestprosess plant at Mongstad. This plant was upgraded in 2004 with an NGL extraction plant to treat gas from Kvitebjørn and Visund. After the upgrade, the capacity is 143 million scm dry gas per day and 9 780 scm condensate per day. In order to ensure that the plant can deliver 143 million scm dry gas per day, a new export compressor will be put into operation from 1 October 2006.

Kårstø gas and condensate processing plant

Rich gas is processed at the Kårstø gas processing facility and the products, which are dry gas, ethane, propane, isobutane and naphtha, are separated. The dry gas, which largely contains methane and ethane, is transported by pipeline from Kårstø. The Kårstø condensate facility receives unstabilised condensate from the Sleipner field. The condensate is stabilised by separating out the lightest components. Ethane, iso-butane and normal butane are stored in refrigerated tanks, while naphtha and condensate are held in tanks at ambient temperature. Propane is stored in large refrigerated rock caverns. These products are exported from Kårstø in liquid form by ship.

Processing facilities at Kårstø comprise four extraction/fractionation lines for methane, ethane, propane, butanes and naphtha, plus a fractionation line for stabilising condensate. The capacity of the gas processing facilities prior to the latest expansion in 2005 was 70 million scm rich gas per day. The condensate plant has a capacity of approximately 5.5 million tonnes of unstabilised condensate per year. After the last expansion, the KEP-2005 project, the capacity for recovering ethane at Kårstø has increased from 620,000 tonnes to 950,000 tonnes per year. At the same time, the gas processing facility was upgraded to handle 88 million scm rich gas per day.

Other pipelines

Draugen Gas Export

Operator	A/S Norske Shell	
Licensees	Petoro AS[1]	47.88%
	BP Norge AS	18.36%
	A/S Norske Shell	26.20%
	ChevronTexaco Norge AS	7.56%
Investment	Total investment at start-up was approximately NOK 1.1 billion (2006 value)	
Operating lifetime	The technical operating lifetime is 50 years	
Capacity	Approximately 2 billion scm per year	

[1] Petoro's participating interest in Gassled will be increased by around 9.5 percent with effect from 1 January 2011, and the other parties' participating interest will be reduced correspondingly with effect from the same date.

This 16-inch pipeline links the Draugen field to Åsgard Transport, and provides opportunities for possible tie-ins of other fields in the area. The pipeline is 78 kilometres long and commenced operation in November 2000.

Grane Gas Pipeline

Operator	Norsk Hydro Produksjon AS
Licensees	As for the Grane field
Investment	Total investment at start-up was approximately NOK 0.3 billion (2006 value)
Operating lifetime	The technical operating life is 30 years
Capacity	Approximately NOK 3.6 billion scm per year

The pipeline commenced operation in September 2003. Gas injection is required in order to produce the oil from the Grane field. This gas is transported to the field through the Grane Gas Pipeline. The 50 kilometres long pipeline runs from the Heimdal riser facility to Grane. The diameter of the pipeline is 18 inches.

Grane Oil Pipeline

Operator	Norsk Hydro Produksjon AS	
Licensees	Petoro AS	43.60%
	ExxonMobil Exploration and Production Norway AS	25.60%
	Norsk Hydro Produksjon AS	24.40%
	Norske ConocoPhillips AS	6.40%
Investment	Total investment at start-up was approximately NOK 1.6 billion (2006 value)	
Operating lifetime	The technical operating lifetime is 30 years	
Capacity	34,000 scm oil per day	

This pipeline became operational at the same time as the Grane field, in September 2003. The pipeline links the Grane field to the Sture terminal. It is 220 kilometres long and has a diameter of 29 inches.

Haltenpipe

Operator	Gassco AS	
Licensees	Petoro AS	57.81%
	Statoil ASA	19.06%
	Norske ConocoPhillips AS	18.13%
	Eni Norge AS	5.00%
Investment	Total investment at start-up was approximately NOK 2.8 billion (2006 value) in pipelines and the terminal	
Operating lifetime	The licence expires on 31 December 2020	
Capacity	2.2 billion scm gas per year	

This 16-inch gas pipeline runs for 250 kilometres from the Heidrun field on Haltenbanken in the Norwegian Sea to Tjeldbergodden in the municipality of Aure in Møre og Romsdal county, where Statoil ASA and Norske ConocoPhillips AS have built a methanol plant close to the receiving terminal. This plant uses Heidrun gas to produce methanol. Gas deliveries to the methanol plant amount to approximately 0.7 billion scm per year.

Heidrun Gas Export

Operator	Statoil ASA[1]	
Licensees	Petoro AS	58.16%
	Norske ConocoPhillips AS	24.31%
	Statoil ASA	12.41%
	Eni Norge AS	5.12%
Investment	Total investment at start-up was approximately NOK 0.9 billion (2006 value)	
Operating lifetime	The technical operating lifetime is 50 years	
Capacity	Approximately 4.0 billion scm per year	

[1] *The operatorship is due to be transferred to Gassco AS.*

This 16-inch pipeline runs roughly 37 kilometres from the Heidrun field to the Åsgard Transport system. It became operational in February 2001.

Kvitebjørn Oil Pipeline (KOR)

Operator	Statoil ASA	
Licensees	Statoil ASA	50.00%
	Petoro AS	30.00%
	Norsk Hydro Produksjon AS	15.00%
	Total E&P Norge AS	5.00%
Investment	Total investment at start-up was approximately NOK 0.5 billion (2006 value)	
Operating lifetime	The technical operating lifetime is 25 years	
Capacity	Approximately 10,000 scm per year	

Kvitebjørn Oil Pipeline (KOR) transports condensate from Kvitebjørn to the Mongstad oil terminal. This 16-inch line runs for about 90 kilometres to tie in to an existing Y-connection on Troll Oil Pipeline II. The pipeline became operational in the second half of 2004.

Langeled

Operator	Norsk Hydro Produksjon AS	
Licensees	Petoro AS	32.95%
	Norsk Hydro Produksjon AS	17.61%
	A/S Norske Shell	16.50%
	Statoil ASA	14.99%
	DONG Norge AS	10.22%
	ExxonMobil Exploration and Production Norway AS	6.95%
	Norske ConocoPhillips AS	0.78%

The plan for installation and operation estimates start-up costs at around NOK 20.9 billion (2006 value). The ownership in Langeled will be determined before it becomes operational, on the basis of updated cost estimates.

The Langeled system will transport gas from the land facilities for Ormen Lange at Nyhamna via a tie-in at the Sleipner riser facility to a new receiving terminal at Easington on the eastern coast of the UK. This system will comprise a 42-inch pipeline from Nyhamna to the Sleipner riser (northern leg) and a 44-inch line from Sleipner to Easington (southern leg). Capacity will be just over 80 million scm per day in the northern leg and about 70 million scm per day in the southern leg. The system will have an overall length of roughly 1 200 kilometres. The southern leg is due to become operational in October 2006, with the northern following in October 2007. Norsk Hydro will be the operator for the development phase, while Gassco AS will be the operator for the operating phase. The plan calls for this pipeline to be incorporated into Gassled in the autumn of 2006.

Norne Gas Transport System (NGTS)

Operator	Gassco AS	
Licensees	Petoro AS	54.00%
	Statoil ASA	31.00%
	Norsk Hydro Produksjon AS	8.10%
	Eni Norge AS	6.90%
Investment	Total investment at start-up was approximately NOK 1.2 billion. (2006 value).	
Operating lifetime	Technical operating lifetime is 50 years	
Capacity	Approximately 3.6 billion scm per year	

This 16-inch pipeline runs 126 kilometres from Norne to the Åsgard Transport system. It became operational in February 2001.

Tampen Link

Operator	Statoil ASA	
Licensees	Statoil ASA	43.9 %
	ExxonMobil Exploration and Production Norway AS	18.2 %
	A/S Norske Shell	12.2 %
	Norsk Hydro Produksjon AS	10.5 %
	Norske ConocoPhillips AS	8.2 %
	Petoro AS	7.0%
Investment	Total investment at start-up is estimated at approximately NOK 1.6 billion (2006 value). This figure also includes necessary modifications on Statfjord B.	
Capacity	Approximately NOK 11 billion scm per year	

As part of the Statfjord Late Phase Project, a new 23.2 kilometres long, 32-inch gas pipeline will be laid between the Statfjord field and a point on the FLAGS pipeline, 1.4 kilometres south of the Brent Alpha facility. About 15.5 kilometres of the new gas export pipeline will be on the British side of the border. In addition to having capacity to transport all gas produced on Statfjord, this pipeline will be designed to enable export of gas volumes up to the capacity in the FLAGS pipeline. The date for completing Tampen Link coincides with production start-up of the Statfjord late life, currently planned for October 2007. The plan for installation and operation) was approved in 2005.

Norpipe Oil Pipeline

Owner	Norpipe Oil AS	
Operator	ConocoPhillips Skandinavia AS	
Ownership in Norpipe Oil AS	ConocoPhillips Skandinavia AS	35.05%
	Total E&P Norge AS	34.93%
	Statoil ASA	15.00%
	Eni Norge AS	6.52%
	Norsk Hydro Produksjon AS	3.50%
	SDFI	5.00%
Investment	Total investment at start-up was approximately NOK 16.3 billion (2006 value)	
Operating lifetime	The pipeline has been designed for an operating lifetime of at least 30 years The technical lifetime is under constant review	
Capacity	Design capacity for the oil pipeline is about 53 million scm per year (900,000 bbls/day), including the use of friction-inhibiting chemicals. The receiving facilities restrict capacity to about 810,000 bbls per day.	

The Norpipe Oil Pipeline crosses the British continental shelf, with landfall at Teesside in the UK. The 34-inch Norpipe oil pipeline is about 354 kilometres long and starts at the Ekofisk Centre, where three pumps have been placed. A tie-in point for UK fields is located about 50 kilometres downstream of Ekofisk. Two riser facilities, each with three pumps, were previously tied to the pipeline, but were bypassed in 1991 and 1994 respectively.

Two British-registered companies, Norsea Pipeline Ltd and Norpipe Petroleum UK Ltd, own the oil export port and fractionation plant for extracting NGL in Teesside. The pipeline carries crude from the four Ekofisk fields (Ekofisk, Eldfisk, Embla and Tor) as well as from Valhall, Hod, Ula, Gyda and Tambar, and from several British fields.

(Agreement between Norway and the UK concerning the transmission of petroleum through a pipeline from the Ekofisk field and adjacent areas to the UK. See Storting Proposition No. 110 (1972–1973) and Recommendation No. 262 (1972–1973).)

Oseberg Transport System (OTS)

Operator	Norsk Hydro Produksjon AS	
Licensees	Petoro AS	48.38%
	Norsk Hydro Produksjon AS	22.24%
	Statoil ASA	14.00%
	Total E&P Norge AS	8.65%
	Mobil Development AS	4.33%
	Norske ConocoPhillips AS	2.40%
Investment	Total investment at start-up was approximately NOK 9.8 billion. (2006 value)	
Operating lifetime	The pipeline is designed for a lifetime of 40 years	
Capacity	121,000 scm per day (technical), 990,000 scm (storage)	

Oil from the Oseberg field is transported in a 115 kilometres long, 28-inch line from the Oseberg A facility to the crude oil terminal at Stura in Øygarden municipality. The Oseberg licensees have established a separate partnership to operate this pipeline.

Sleipner Øst Condensate pipeline

Operator	Statoil ASA	
Licensees	Statoil ASA	49.60%
	ExxonMobil Exploration and Production Norway AS	30.40%
	Norsk Hydro Produksjon AS	10.00%
	Total E&P Norge AS	10.00%
Investment	Total investment at start-up was approximately NOK 1.6 billion. (2006 value)	
Capacity	200,000 bbls per day	

This 20-inch pipeline transports unstabilised condensate from Sleipner A to Kårstø.

Troll Oil Pipeline I

Operator	Statoil ASA	
Licensees	Petoro AS	55.77%
	Statoil ASA	20.85%
	Norsk Hydro Produksjon AS	9.73%
	A/S Norske Shell	8.29%
	Total E&P Norge AS	3.70%
	Norske ConocoPhillips AS	1.66%
Investment	Total investment at start-up was approximately NOK 1.12 billion. (2006 value)	
Operating lifetime	Troll Oil Pipeline I is designed to operate for 35 years	
Capacity	42,500 scm per day of oil with use of friction inhibitors	

Troll Oil Pipeline I was built to transport oil from Troll B to the oil terminal at Mongstad. The pipeline has a diameter of 16 inches and a length of 85 kilometres. The Troll licensees have established a separate partnership to handle operation of the line. Troll Oil Pipeline I was in place and ready to receive oil production from Troll B, which started in September 1995.

Troll Oil Pipeline II

Operator	Statoil ASA	
Licensees	Petoro AS	55.77%
	Statoil ASA	20.85 %
	Norsk Hydro Produksjon AS	9.73%
	A/S Norske Shell	8.29%
	Total E&P Norge AS	3.70%
	Norske ConocoPhillips AS	1.66%
Investment	Total investment at start up was approximately NOK 1.0 billion.(2006 value)	
Operating lifetime	Troll Oil Pipeline II is designed for a lifetime of 35 years	
Capacity	Current capacity is 40,000 scm per day. The hydraulic capacity is 47,500 scm per day (without use of friction inhibitors)	

This 20-inch pipeline has been built to carry oil over the 80 kilometres from Troll C to the terminal at Mongstad. The plan for installation and operation received government approval in March 1998, and Troll Oil Pipeline II was ready to begin operation when Troll C started production on 1 November 1999. Oil from Fram and Kvitebjørn is transported through Troll Oil Pipeline II. The license period for the pipeline lasts to 2023.

Other land facilities

Mongstad crude oil terminal

Owner	Statoil ASA	65.00%
	Petoro AS	35.00%

The terminal at Mongstad incorporates three jetties able to receive vessels up to 440,000 tonnes, as well as six caverns blasted in the bedrock 50 metres below ground. These caverns have a total storage capacity of 1.5 million m^3 of crude oil.

This facility was constructed to support the marketing of crude oil loaded offshore. Crude oil from fields with buoy loading (including Gullfaks, Statfjord, Draugen, Norne, Åsgard and Heidrun) is loaded offshore onto buoy loader shuttle tankers, which have a sailing range confined to northwest Europe. By storing and transhipping crude at Mongstad, however, Statoil can sell the oil to more distant destinations. Mongstad is also the receiving terminal for the oil pipelines from Troll B, Troll C, Troll Blend (Fram) and Kvitebjørn fields, as well as shuttle tankers from Heidrun.

Sture terminal

Owner	The Sture terminal forms part of the joint venture for the Oseberg Transport System (OTS), with the same ownership interests. The exception is the LPG export facilities, which are owned by Norsk Hydro Produksjon AS (the refrigerated LPG storage and transfer system to ships) and Vestprosess DA (export facility to Vestprosess).

The Sture oil terminal at Stura in Øygarden municipality near Bergen receives oil and condensate via the pipeline from the Oseberg A facility as well as from the Oseberg, Veslefrikk, Brage, Oseberg Sør, Oseberg Øst, Tune and Huldra fields. The terminal also receives Grane oil through the Grane Oil Pipeline. The terminal began operating in December 1988. It incorporates two jetties able to berth oil tankers up to 300,000 tonnes, five rock caverns for storing crude oil with a combined capacity of 1 million scm, a 60,000 m^3 rock cavern storage for LPG and a 200,000 m^3 ballast water cavern. A separate unit for recovering volatile organic compounds (VOC) has been installed.

The Ministry of Petroleum and Energy approved an upgrading of the facility in March 1998. A fractionation plant which came on line in December 1999 processes unstabilised crude from Oseberg into stabilised oil and an LPG blend. The produced LPG blend can either be exported by ship from the terminal or sent through the Vestprosess pipeline between Kollsnes, Stura and Mongstad.

Tjeldbergodden

Owner:	Statoil Metanol ANS:	
Owners in Statoil Metanol ANS:	Statoil ASA	81.70%
	Norske ConocoPhillips AS	18.30%

Plans to utilise gas from Heidrun as feedstock for methanol production at Tjeldbergodden in the municipality of Aure in Nordmøre were approved by the Storting in 1992. The methanol plant began production on 5 June 1997. Gas deliveries through the Haltenpipe line total 0.7 billion scm per year, which yield 830,000 tonnes of methanol.

An air separation plant, Tjeldbergodden Luftgassfabrikk DA, has been built in association with the methanol facility. This partnership has also constructed a small gas fractionation and liquefaction plant with an annual capacity of 35 million scm.

Vestprosess

Ownership	Petoro AS	41.00%
	Statoil ASA	17.00%
	Norsk Hydro Produksjon AS	17.00%
	Mobil Exploration Norway Inc.	10.00%
	A/S Norske Shell	8.00%
	Total E&P Norge AS	5.00%
	Norske ConocoPhillips AS	2.00%

The Vestprosess DA partnership owns and operates a system to transport and process NGL (wet gas). These facilities came on stream in December 1999. A 56 kilometres pipeline carries unstabilised NGL from the Kollsnes gas terminal, via the oil terminal at Stura, to Mongstad.

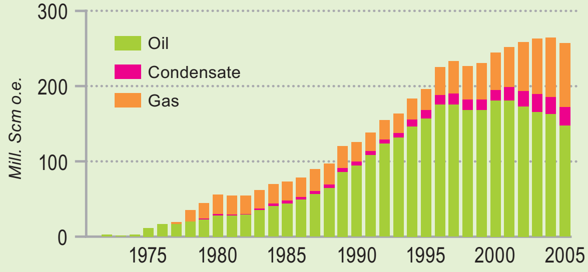
At Mongstad, processing starts by separating out naphtha and LPG. The naphtha serves as refinery feedstock, while the LPG is fractionated in a dedicated process into propane and butane. These products are stored in rock caverns before export. The Vestprosess plant utilises surplus energy and utilities from the refinery.

Appendix 1 Historical statistics

Table 1.1 The state's revenues from petroleum activities (MNOK)

Year	Ordinary tax	Special tax	Production fee	Area fee	CO_2 tax	Net cash flow SDFI	Dividend Statoil
1971			14				
1972			42				
1973			69				
1974			121				
1975			208				
1976	1143	4	712	99			
1977	1694	725	646	57			
1978	1828	727	1213	51			
1979	3399	1492	1608	53			
1980	9912	4955	3639	63			
1981	13804	8062	5308	69			0,057
1982	15036	9014	5757	76			368
1983	14232	8870	7663	75			353
1984	18333	11078	9718	84			795
1985	21809	13013	11626	219		-8343	709
1986	17308	9996	8172	198		-11960	1245
1987	7137	3184	7517	243		-10711	871
1988	5129	1072	5481	184		-9133	0
1989	4832	1547	7288	223		755	0
1990	12366	4963	8471	258		7344	800
1991	15021	6739	8940	582	810	5879	1500
1992	7558	7265	8129	614	1916	3623	1400
1993	6411	9528	7852	553	2271	159	1250
1994	6238	8967	6595	139	2557	5	1075
1995	7854	10789	5884	552	2559	9259	1614
1996	9940	12890	6301	1159	2787	34959	1850
1997	15489	19582	6220	617	3043	40404	1600
1998	9089	11001	3755	527	3229	14572	2940
1999	5540	6151	3222	561	3261	25769	135
2000	21921	32901	3463	122	3047	98219	1702
2001	41464	64316	2481	983	2862	125439	5746
2002	32512	52410	1320	447	3012	74785	5045
2003	36819	60280	765	460	3056	84713	5133
2004	43177	70443	717	496	3309	80166	5222
2005*	59800	99500	400	500	3500	111151	8139

(Source: State accounts, 2005 from the National Budget for 2006)*



Total petroleum production

(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)

Table 1.2 Petroleum production on the Norwegian continental shelf, millions of standard cubic metres oil equivalents

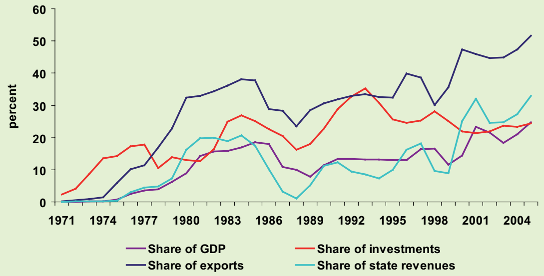
Year	Oil	Gas	Condensate	NGL	Total production
1971	0.357	0.000	0.000	0.000	0.357
1972	1.927	0.000	0.000	0.000	1.927
1973	1.870	0.000	0.000	0.000	1.870
1974	2.014	0.000	0.000	0.000	2.014
1975	10.995	0.000	0.000	0.000	10.995
1976	16.227	0.000	0.000	0.000	16.227
1977	16.643	2.655	0.002	0.000	19.300
1978	20.644	14.201	0.021	0.000	34.866
1979	22.478	20.670	0.044	1.128	44.319
1980	28.221	25.088	0.048	2.440	55.798
1981	27.485	24.951	0.048	2.168	54.652
1982	28.528	23.960	0.043	2.286	54.817
1983	35.645	23.613	0.041	2.680	61.979
1984	41.093	25.963	0.064	2.642	69.762
1985	44.758	26.186	0.076	2.968	73.987
1986	48.771	26.090	0.061	3.845	78.767
1987	56.959	28.151	0.055	4.117	89.281
1988	64.723	28.330	0.047	4.846	97.945
1989	85.983	28.738	0.053	4.898	119.672
1990	94.542	25.479	0.048	5.011	125.081
1991	108.510	25.027	0.057	4.897	138.492
1992	123.999	25.834	0.054	4.959	154.846
1993	131.843	24.804	0.554	5.518	162.720
1994	146.282	26.842	2.830	7.122	183.075
1995	156.776	27.814	3.726	7.942	196.257
1996	175.422	37.407	4.442	8.232	225.503
1997	175.914	42.950	6.401	8.074	233.338
1998	168.744	44.190	5.999	7.390	226.322
1999	168.690	48.479	6.497	6.992	230.658
2000	181.181	49.748	6.277	7.225	244.431
2001	180.884	53.895	6.561	10.924	252.264
2002	173.649	65.501	8.020	11.798	258.968
2003	165.475	73.124	11.060	12.878	262.537
2004	162.777	78.465	9.142	13.621	264.006
2005	148.126	84.964	8.422	15.736	257.247

(Source: The Norwegian Petroleum Directorate)

Table 1.3 Value creation, exports, employment, investment and exploration costs

Year	Gross product (MNOK)	Export value (MNOK)	Number of employees	Investments incl. exploration costs (MNOK)	Exploration costs (MNOK)
1971	12	36	NA	691	
1972	209	244	200	1 192	
1973	260	393	300	2 326	
1974	1 068	845	900	5 138	
1975	4 256	3 622	2 200	7 291	
1976	6 957	7 092	2 700	9 270	
1977	8 697	8 600	4 000	10 589	
1978	14 984	14 838	6 100	9 228	
1979	23 738	23 964	7 900	9 061	
1980	44 749	43 884	9 700	10 119	
1981	55 834	51 139	12 200	14 462	4 133
1982	62 735	56 492	13 100	15 909	5 519
1983	74 334	66 727	13 900	27 028	5 884
1984	91 177	81 173	15 800	32 244	7 491
1985	98 454	88 579	17 700	32 839	7 830
1986	60 936	55 894	18 000	33 155	6 654
1987	60 728	56 653	17 800	35 247	4 951
1988	50 908	50 141	18 700	29 680	4 151
1989	78 088	74 933	18 600	31 957	5 008
1990	96 962	89 894	19 200	32 223	5 137
1991	102 908	98 325	19 700	43 065	8 137
1992	104 212	98 666	20 900	49 512	7 680
1993	109 244	105 731	22 300	57 579	5 433
1994	114 174	108 573	22 500	54 653	5 011
1995	121 602	115 476	21 700	48 583	4 647
1996	167 515	167 200	22 100	47 878	5 455
1997	183 129	177 825	24 100	62 494	8 300
1998	131 630	128 807	24 900	79 216	7 577
1999	178 605	173 428	24 700	69 096	4 993
2000	341 552	325 382	23 600	53 589	5 274
2001	327 778	320 052	26 700	57 144	6 815
2002	283 029	281 158	28 400	54 000	4 476
2003	296 087	289 891	29 000	64 362	4 134
2004	359 739	346 457	29 100	71 473	4 010
2005	470 015	444 529	30 000	88 453	7 511

(Source: Statistics Norway)



Macroeconomic indicators for the petroleum sector

(Source: Statistics Norway, Ministry of Finance)

Table 1.4 The petroleum sector's percentage share of the gross national product, exports, real investments and the state's total revenues

Year	Share of gross national product	Share of exports	Share of real investments	Share of the state's total revenues
1971	0.01	0.10	2.33	0.05
1972	0.19	0.61	4.03	0.12
1973	0.20	0.81	8.65	0.16
1974	0.72	1.42	13.58	0.25
1975	2.51	5.86	14.18	0.38
1976	3.59	10.09	17.21	3.07
1977	3.98	11.40	17.88	4.38
1978	6.24	16.99	10.49	4.77
1979	8.96	22.79	13.92	7.31
1980	14.23	32.39	13.06	16.27
1981	15.59	32.91	12.60	19.76
1982	15.83	34.31	16.33	19.90
1983	16.83	36.16	25.00	18.86
1984	18.44	38.11	26.88	20.74
1985	17.99	37.69	25.13	17.50
1986	10.85	28.80	22.69	10.13
1987	9.90	28.36	20.43	3.21
1988	7.91	23.45	16.14	1.02
1989	11.38	28.53	17.92	5.20
1990	13.34	30.60	22.87	11.14
1991	13.37	31.92	28.86	12.25
1992	13.19	32.88	32.68	9.49
1993	13.16	33.46	35.22	8.50
1994	13.07	32.59	30.76	7.24
1995	12.97	32.44	25.70	10.06
1996	16.31	39.87	24.59	16.14
1997	16.48	38.59	25.14	18.15
1998	11.63	30.16	27.62	9.56
1999	14.48	35.67	25.77	8.93
2000	23.25	47.44	20.31	25.07
2001	21.48	45.90	20.27	32.07
2002	18.63	45.03	19.44	23.84
2003	18.78	45.48	22.99	24.81
2004	20.94	47.19	22.95	27.3
2005	24.70	51.60	24.40	32.8

(Source: Statistics Norway/ Ministry of Finance (National Budget for 2006)/ Ministry of Petroleum and Energy)

Appendix 2 The petroleum resources

Table 2.1 Historical production from fields no longer producing and fields currently in production

Field	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill. scm	Year of discovery[2]
Albuskjell	7.4	15.5	1.0	0.0	24.8	1972
Cod	2.9	7.3	0.5	0.0	11.2	1968
Edda	4.8	2.0	0.2	0.0	7.2	1972
Frigg	0.0	116.2	0.0	0.5	116.7	1971
Frøy	5.6	1.6	0.0	0.1	7.3	1987
Lille-Frigg	1.3	2.2	0.0	0.0	3.5	1975
Mime	0.4	0.1	0.0	0.0	0.5	1982
Nordøst Frigg	0.0	11.6	0.0	0.1	11.7	1974
Odin	0.0	27.3	0.0	0.2	27.5	1974
Tommeliten Gamma	3.9	9.7	0.6	0.0	14.7	1978
Vest Ekofisk	12.2	26.0	1.4	0.0	40.9	1970
Yme	7.9	0.0	0.0	0.0	7.9	1987
Øst Frigg	0.0	9.2	0.0	0.1	9.3	1973
Historical production	**46.3**	**228.6**	**3.7**	**0.9**	**282.9**	
34/10-48 S Gimle	0.3				0.3	2004
Balder[a)]	29.3	0.5			29.8	1967
Brage	46.2	2.2	0.9		50.0	1980
Draugen	109.1	1.1	1.6		113.2	1984
Ekofisk	361.6	128.7	11.5		512.2	1969
Eldfisk	80.6	35.9	3.5		123.1	1970
Embla	8.9	2.9	0.3		12.5	1988
Fram	5.5				5.5	1992
Glitne	6.4				6.4	1995
Grane	18.1				18.1	1991
Gullfaks[b)]	322.7	21.7	2.4		348.9	1978
Gullfaks Sør[c)]	24.3	12.5	1.4		39.6	1978
Gungne[3]			1.2	3.7	6.0	1982
Gyda[d)]	32.9	5.5	1.8		41.8	1980
Heidrun	107.7	7.8	0.4		116.2	1985
Heimdal	6.4	44.3			50.7	1972
Hod	8.1	1.5	0.2		10.0	1974
Huldra	3.9	10.7	0.1		14.7	1982
Jotun	20.2	0.7			20.9	1994
Kristin		0.2	0.0	0.2	0.5	1997
Kvitebjørn	2.5	4.9	0.4		8.1	1994
Mikkel		3.9	1.0	1.7	7.5	1987

Murchison	13.4	0.3	0.3		14.3	1975
Njord	19.6				19.6	1986
Norne	67.8	4.5	0.5		73.3	1992
Oseberg[e)]	328.5	26.7	3.5		361.9	1979
Oseberg Sør	24.1				24.1	1984
Oseberg Øst	15.4				15.4	1981
Sigyn		2.6	1.0	3.0	7.6	1982
Skirne	0.5	1.9			2.4	1990
Sleipner Vest and Sleipner Øst[3) f)]		122.5	16.5	51.7	205.5	1974
Snorre	138.3	5.5	4.2		151.8	1979
Statfjord	547.2	51.7	13.7	0.1	625.1	1974
Statfjord Nord	32.2	1.9	0.7		35.4	1977
Statfjord Øst	30.8	2.9	1.0		35.5	1976
Sygna	8.5				8.5	1996
Tambar	5.8		0.1		6.1	1983
Tor	22.1	10.7	1.1		35.0	1970
Tordis[g)]	46.9	3.6	1.3		53.0	1987
Troll[h)]	170.3	239.5	1.0	4.3	416.0	1979
Tune	2.6		0.1		2.8	1996
Ula	66.8	3.8	2.5		75.4	1976
Urd	0.2	0.0	0.0		0.2	2000
Vale	0.4	0.3			0.8	1991
Valhall	88.7	17.6	2.9		111.7	1975
Varg	8.9				8.9	1984
Veslefrikk	46.7	2.1	1.2		51.1	1981
Vigdis	33.0	0.4	0.3		33.9	1986
Visund	12.9	0.3	0.0		13.3	1986
Åsgard	45.5	42.5	7.2	14.9	116.6	1981
Producing fields	**2971.9**	**826.2**	**85.9**	**79.7**	**4041.0**	
Total sold and delivered	**3018.2**	**1054.8**	**89.6**	**80.7**	**4323.9**	

1) The conversion factor for NGL tonnes to scm is 1.9.
2) The year the first discovery well was drilled
3) Gas production from Gungne, Sleipner Vest and Sleipner Øst are metered collectively.
a) Balder also includes Ringhorne
b) Gullfaks also includes Gullfaks Vest
c) Gullfaks Sør also include Gulltopp, Gullveig, Rimfaks and Skinfaks
d) Gyda also includes Gyda Sør
e) Oseberg also includes Oseberg Vest
f) Sleipner Øst also includes Loke
g) Tordis also includes Tordis Øst and Borg
h) Troll also includes TOGI

(Source: The Norwegian Petroleum Directorate)

Table 2.2 Reserves in fields in production or fields with approved plans for development and operation

Field	Reserves mill. scm. o.e.	Year of discovery[5)]	Operator at 31.12.2005	Production licence/ Unit area
Alvheim[1)]	29.4	1998	Marathon Petroleum Norge AS	036 C. 088 BS. 203
Balder	63.2	1967	ExxonMobil Exploration and Production Norway AS	001
Blane[1)]	0.9	1989	Paladin Expro Limited	Blane
Brage	53.8	1980	Norsk Hydro Produksjon AS	Brage
Draugen	143.4	1984	A/S Norske Shell	093
Ekofisk	713.3	1969	ConocoPhillips Skandinavia AS	018
Eldfisk	188.1	1970	ConocoPhillips Skandinavia AS	018
Embla	21.9	1988	ConocoPhillips Skandinavia AS	018
Enoch[1)]	0.5	1991	Paladin Expro Limited	Enoch
Fram	31.6	1992	Norsk Hydro Produksjon AS	090
Glitne	7.6	1995	Statoil ASA	048 B
Grane	120.0	1991	Norsk Hydro Produksjon AS	Grane
Gullfaks	384.4	1978	Statoil ASA	050
Gullfaks Sør	101.8	1978	Statoil ASA	050
Gungne	19.5	1982	Statoil ASA	046
Gyda	47.6	1980	Talisman Energy Norge AS	019 B
Heidrun	225.8	1985	Statoil ASA	Heidrun
Heimdal	49.4	1972	Norsk Hydro Produksjon AS	036 BS
Hod	12.5	1974	BP Norge AS	033
Huldra	21.0	1982	Statoil ASA	Huldra
Jotun	26.1	1994	ExxonMobil Exploration and Production Norway AS	Jotun
Kristin	96.3	1997	Statoil ASA	Haltenbanken Vest
Kvitebjørn	74.1	1994	Statoil ASA	193
Mikkel	41.9	1987	Statoil ASA	Mikkel
Murchison	14.2	1975	CNR International (UK) Limited	Murchison
Njord	35.6	1986	Norsk Hydro Produksjon AS	Njord
Norne	106.4	1992	Statoil ASA	Norne
Ormen Lange[1)]	397.3	1997	Norsk Hydro Produksjon AS	Ormen Lange
Oseberg[2)]	479.4	1979	Norsk Hydro Produksjon AS	Oseberg
Oseberg Sør	59.6	1984	Norsk Hydro Produksjon AS	Oseberg Sør
Oseberg Øst	29.7	1981	Norsk Hydro Produksjon AS	053
Ringhorne Øst[1)]	8.2	2003	ExxonMobil Exploration and Production Norway AS	Ringhorne Øst

Sigyn	18.0	1982	ExxonMobil Exploration and Production Norway AS	072
Skirne	8.3	1990	Total E&P Norge AS	102
Sleipner Vest	151.3	1974	Statoil ASA	Sleipner Vest
Sleipner Øst	118.1	1981	Statoil ASA	Sleipner Øst
Snorre	249.7	1979	Statoil ASA	Snorre
Snøhvit[1)]	190.7	1984	Statoil ASA	Snøhvit
Statfjord	692.5	1974	Statoil ASA	Statfjord
Statfjord Nord	46.3	1977	Statoil ASA	037
Statfjord Øst	42.9	1976	Statoil ASA	Statfjord Øst
Sygna	12.2	1996	Statoil ASA	Sygna
Tambar	11.3	1983	BP Norge AS	065
Tor	39.1	1970	ConocoPhillips Skandinavia AS	Tor
Tordis	73.1	1987	Statoil ASA	089
Troll[3)]	1622.4	1979	Norsk Hydro Produksjon AS	Troll
Troll[4)]		1983	Statoil ASA	Troll
Tune	17.3	1996	Norsk Hydro Produksjon AS	190
Ula	89.7	1976	BP Norge AS	019
Urd	11.5	2000	Statoil ASA	128
Vale	3.8	1991	Norsk Hydro Produksjon AS	036
Valhall	214.0	1975	BP Norge AS	Valhall
Varg	12.6	1984	Pertra AS	038
Veslefrikk	61.5	1981	Statoil ASA	052
Vigdis	59.4	1986	Statoil ASA	089
Vilje[1)]	8.3	2003	Norsk Hydro Produksjon AS	36
Visund	93.1	1986	Statoil ASA	Visund
Volve[1)]	13.7	1993	Statoil ASA	Sleipner Øst
Åsgard	400.2	1981	Statoil ASA	Åsgard

1) Fields with approved development plans where production had not commenced at 31.12.2005
2) Resources in Oseberg also include Oseberg Vest
3) The resources include the total resources for Troll, including the section operated by Statoil ASA
4) The resources are included in the row above
5) The year the first discovery well was drilled

(Source: The Norwegian Petroleum Directorate)

Table 2.3 Original recoverable reserves and remaining reserves in fields in production

	Originally saleable[1)]					Remaining reserves[4)]				
	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[2)] mill. scm	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[2)] mill. scm
34/10-48 S Gimle	4.1	0.4	0.1	0.0	4.6	3.8	0.4	0.1	0.0	4.4
Alvheim[3)]	23.7	5.7	0.0	0.0	29.4	23.7	5.7	0.0	0.0	29.4
Balder[a)]	61.6	1.6	0.0	0.0	63.2	32.3	1.1	0.0	0.0	33.4
Blane[3)]	0.8	0.0	0.0	0.0	0.9	0.8	0.0	0.0	0.0	0.9
Brage	49.8	2.4	0.8	0.0	53.8	3.6	0.3	0.0	0.0	3.9
Draugen	137.9	1.2	2.2	0.0	143.4	28.8	0.2	0.7	0.0	30.2
Ekofisk	531.2	155.0	14.2	0.0	713.3	169.6	26.3	2.7	0.0	201.1
Eldfisk	128.4	51.1	4.5	0.0	188.1	47.8	15.2	1.0	0.0	65.0
Embla	14.5	6.2	0.6	0.0	21.9	5.6	3.3	0.3	0.0	9.5
Enoch[3)]	0.3	0.1	0.0	0.0	0.5	0.3	0.1	0.0	0.0	0.5
Fram	21.0	10.2	0.2	0.0	31.6	15.5	10.2	0.2	0.0	26.1
Glitne	7.6	0.0	0.0	0.0	7.6	1.2	0.0	0.0	0.0	1.2
Grane	120.0	0.0	0.0	0.0	120.0	101.9	0.0	0.0	0.0	101.9
Gullfaks[b)]	354.6	24.6	2.7	0.0	384.4	31.9	2.9	0.4	0.0	35.4
Gullfaks Sør[c)]	48.3	43.4	5.3	0.0	101.8	24.0	30.9	3.9	0.0	62.2
Gungne	0.0	12.2	1.6	4.3	19.5	0.0	12.2	0.4	0.6	13.5
Gyda[d)]	37.8	6.2	1.9	0.0	47.6	4.9	0.7	0.1	0.0	5.8
Heidrun	180.0	42.7	1.6	0.0	225.8	72.4	34.9	1.2	0.0	109.6
Heimdal	7.2	42.3	0.0	0.0	49.4	0.8	0.0	0.0	0.0	0.8
Hod	10.0	1.7	0.4	0.0	12.5	1.9	0.3	0.2	0.0	2.5
Huldra	5.0	15.8	0.1	0.0	21.0	1.1	5.1	0.1	0.0	6.3
Jotun	25.1	1.0	0.0	0.0	26.1	4.9	0.2	0.0	0.0	5.1
Kristin	37.2	43.2	7.9	1.0	96.3	37.2	43.0	7.8	0.8	95.8
Kvitebjørn	18.0	51.9	2.3	0.0	74.1	15.5	47.0	1.9	0.0	66.0
Mikkel	4.7	24.0	5.9	2.0	41.9	4.7	20.1	4.9	0.3	34.4
Murchison	13.8	0.4	0.0	0.0	14.2	0.4	0.1	0.0	0.0	0.5
Njord	24.2	8.7	1.4	0.0	35.6	4.6	8.7	1.4	0.0	16.0
Norne	89.2	14.0	1.7	0.0	106.4	21.4	9.4	1.2	0.0	33.1
Ormen Lange[3)]	0.0	375.2	0.0	22.1	397.3	0.0	375.2	0.0	22.1	397.3
Oseberg[e)]	354.7	111.1	7.2	0.0	479.4	26.2	84.4	3.6	0.0	117.5
Oseberg Sør	49.2	10.5	0.0	0.0	59.6	25.1	10.5	0.0	0.0	35.5
Oseberg Øst	29.2	0.5	0.0	0.0	29.7	13.8	0.5	0.0	0.0	14.2
Ringhorne Øst[3)]	8.0	0.3	0.0	0.0	8.2	8.0	0.3	0.0	0.0	8.2
Sigyn	0.0	6.9	2.9	5.5	18.0	0.0	4.3	1.9	2.5	10.4
Skirne	1.6	6.7	0.0	0.0	8.3	1.1	4.8	0.0	0.0	5.9
Sleipner Vest	0.0	107.8	8.1	28.1	151.3					
Sleipner Øst[f)]	0.0	66.3	12.8	27.5	118.1					

Sleipner Vest and Sleipner Øst[5)]						0.0	51.5	4.4	3.9	63.8
Snorre	234.0	6.6	4.8	0.0	249.7	95.7	1.2	0.6	0.0	98.0
Snøhvit[3)]	0.0	160.6	6.3	18.1	190.7	0.0	160.6	6.3	18.1	190.7
Statfjord	565.6	78.6	25.5	0.0	692.5	18.4	26.9	11.8	0.0	67.7
Statfjord Nord	41.8	2.7	0.9	0.0	46.3	9.6	0.8	0.3	0.0	10.9
Statfjord Øst	36.4	3.9	1.4	0.0	42.9	5.6	1.0	0.4	0.0	7.4
Sygna	12.2	0.0	0.0	0.0	12.2	3.8	0.0	0.0	0.0	3.8
Tambar	8.3	2.6	0.2	0.0	11.3	2.4	2.6	0.1	0.0	5.2
Tor	25.3	11.5	1.2	0.0	39.1	3.2	0.8	0.1	0.0	4.2
Tordis[g)]	64.0	5.6	1.8	0.0	73.1	17.1	2.0	0.5	0.0	20.1
Troll[h)4)]	238.0	1324.9	30.5	1.6	1622.4	67.7	1085.4	29.4	-2.7	1206.4
Tune[6)]	3.0	14.1	0.1	0.0	17.3	0.4	14.1	0.0	0.0	14.6
Ula	80.0	3.8	3.1	0.0	89.7	13.2	0.0	0.6	0.0	14.3
Urd	11.3	0.1	0.0	0.0	11.5	11.1	0.1	0.0	0.0	11.3
Vale	1.7	2.1	0.0	0.0	3.8	1.2	1.8	0.0	0.0	3.1
Valhall	170.9	31.9	5.9	0.0	214.0	82.3	14.3	3.0	0.0	102.2
Varg	12.6	0.0	0.0	0.0	12.6	3.7	0.0	0.0	0.0	3.7
Veslefrikk	56.7	2.8	1.1	0.0	61.5	10.0	0.6	0.0	0.0	10.6
Vigdis	55.4	1.7	1.2	0.0	59.4	22.4	1.3	0.9	0.0	25.5
Vilje[3)]	8.3	0.0	0.0	0.0	8.3	8.3	0.0	0.0	0.0	8.3
Visund	27.3	52.9	6.8	0.0	93.1	14.4	52.6	6.8	0.0	79.8
Volve[3)]	11.9	1.3	0.2	0.1	13.7	11.9	1.3	0.2	0.1	13.7
Åsgard	109.7	196.2	41.1	16.1	400.2	64.2	153.8	33.9	1.2	283.6
Total	**4173.0**	**3155.2**	**218.7**	**126.5**	**7870.1**	**1201.1**	**2331.0**	**133.3**	**46.8**	**3832.4**

1) The table shows expected value. The estimates are subject to uncertainty.

2) The conversion factor for NGL tonnes to scm is 1.9

3) Fields with approved development plans where production had not commenced at 31.12.2005

4) A negative remaining reserves figure for a field is the results of the product not being reported under original sellable volumes. This applies to produced NGL and condensate.

5) Measurements of gas production for Gungne, Sleipner Vest and Øst are combined

6) Tune gas is not reallocated back from Oseberg. Consequently the remaining gas reserves equal the original reserves

a) Balder also includes Ringhorne

b) Gullfaks also includes Gullfaks Vest

c) Gullfaks Sør also includes Gulltopp, Gullveig, Rimfaks and Skinfaks

d) Gyda also includes Gyda Sør

e) Oseberg also includes Oseberg Vest

f) Sleipner Øst also includes Loke

g) Tordis also includes Tordis Øst and Borg

h) Troll also includes TOGI

(Source: The Norwegian Petroleum Directorate)

Table 2.4 Reserves in discoveries the licensees have decided to develop

Discovery	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv. [1] mill. scm o.e.	Year of discovery[2]
34/10-48 S Gimle	4.1	0.4	0.1	0.0	4.6	2004
6407/1-2 Tyrihans Sør	29.0	29.3	5.5	0.0	68.8	1983
Total	**33.1**	**29.7**	**5.6**	**0.0**	**73.4**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the first discovery well was drilled

(Source: The Norwegian Petroleum Directorate)

Table 2.5 Resources in discoveries in the planning phase

Discovery	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv. [1] mill. scm o.e.	Year of discovery[2]
1/9-1 Tommeliten Alpha	7.9	12.9	0.0	0.0	20.8	1977
15/12-12	0.0	4.1	0.0	0.7	4.8	2001
15/3-1 S Gudrun	15.2	8.4	5.4	0.0	33.8	1975
15/5-1 Dagny	0.0	3.8	0.2	1.2	5.3	1978
2/12-1 Freja	2.9	0.6	0.0	0.0	3.5	1987
24/9-5	7.0	0.8	0.0	0.0	7.8	1994
25/11-16	3.60	0.00	0.0	0.0	3.60	1992
25/5-5	3.53	0.09	0.0	0.0	3.62	1995
3/7-4 Trym	0.00	3.44	0.0	0.75	4.19	1990
30/7-6 Hild[3]	0.00	14.72	0.0	1.89	16.61	1978
34/10-23 Valemon[4]	0.00	18.14	0.8	5.65	25.21	1985
35/8-1	0.0	16.1	0.9	4.1	21.8	1981
35/9-1 Gjøa	9.1	37.1	6.0	0.0	57.5	1989
6507/3-3 Idun	0.0	11.7	1.5	0.2	14.9	1999
6507/5-1 Skarv[5]	14.3	35.7	5.8	3.6	64.6	1998
7122/7-1 Goliat	6.7	0.0	0.0	0.0	6.7	2000
Total	**70.2**	**167.6**	**20.5**	**18.1**	**294.7**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the first discovery well was drilled
3) 30/7-6 Hild has resources in categories 4 and 5
4) 34/10-23 Valemon has resources in categories 4 and 5
5) 6507/5-1 Skarv has resources in categories 4 and 5

(Source: The Norwegian Petroleum Directorate)

Table 2.6 Resources in discoveries where development is likely but not clarified

Discovery	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv. [1] mill. scm o.e.	Year of discovery[2]
1/3-6	3.2	2.8	0.0	0.0	6.0	1991
1/5-2 Flyndre	5.1	1.6	0.0	0.0	6.6	1974
15/3-4	3.7	1.6	0.5	0.0	6.2	1982
15/5-2	0.0	4.9	0.0	0.4	5.3	1978
15/8-1 Alpha	0.0	4.1	0.5	1.0	6.0	1982
16/7-2	0.0	1.8	0.3	0.5	2.9	1982
2/4-10	1.0	0.0	0.0	0.0	1.0	1973
2/4-17 Tjalve	1.0	1.4	0.1	0.0	2.5	1992
2/5-3 Sørøst Tor	3.1	0.0	0.0	0.0	3.1	1972
24/6-1 Peik	0.0	2.0	0.0	0.3	2.3	1985
25/8-4	1.0	0.0	0.0	0.0	1.0	1992
33/9-6 Delta	1.2	0.2	0.0	0.0	1.3	1976
34/10-48 S Gimle	0.0	0.6	0.0	0.3	0.9	2004
34/11-2 S Nøkken	0.0	2.7	0.0	1.2	3.9	1996
6/3-1 Pi	0.4	0.9	0.0	0.0	1.3	1985
6406/1-1 Erlend Nord	0.0	1.1	0.0	0.3	1.4	2001
6406/1-2	0.0	12.1	2.0	4.6	20.6	2003
6406/2-1 Lavrans	0.0	12.7	3.2	5.0	23.7	1995
6406/2-6 Ragnfrid	0.0	2.6	0.0	1.8	4.4	1998
6406/2-7 Erlend	0.0	1.0	0.0	0.6	1.6	1999
6406/3-2 Trestakk	8.1	1.8	0.5	0.0	10.9	1986
6406/9-1	0.0	33.3	0.0	0.0	33.3	2005
6407/1-2 Tyrihans Sør	0.9	0.2	0.0	0.0	1.1	1983
6407/9-9	0.2	1.2	0.0	0.2	1.5	1999
6506/11-2 Lange	0.4	0.2	0.0	0.0	0.6	1991
6506/11-7	3.7	1.9	0.0	0.0	5.6	2001
6506/12-3 Lysing	1.5	0.3	0.0	0.0	1.8	1985
6506/6-1	0.0	118.0	0.0	0.0	118.0	2000
6507/2-2	0.0	15.3	2.5	1.2	21.3	1992
6507/3-1 Alve	0.0	6.2	0.0	1.2	7.4	1990
6507/7-13	0.9	0.0	0.0	0.0	1.0	2001
6608/11-2 Falk	1.6	0.1	0.0	0.0	1.7	2000
6608/11-4 Linerle	13.5	0.2	0.0	0.0	13.7	2004
6707/10-1	0.0	38.3	0.0	0.0	38.3	1997
7/7-2	3.4	0.0	0.0	0.0	3.4	1992
7/8-3	6.0	0.1	0.0	0.0	6.1	1983

7121/4-2 Snøhvit Nord	0.0	4.7	0.2	0.6	5.6	1985
7121/5-2 Beta	0.0	3.3	0.0	0.2	3.5	1986
Total	**59.7**	**279.1**	**9.8**	**19.4**	**376.8**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the first discovery well was drilled

(Source: The Norwegian Petroleum Directorate)

Table 2.7 Resources in new, unevaluated discoveries

Discovery	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv. 1) mill .scm o.e.	Year of discovery 2)
31/2-N -11 H	6	0	0	0	6	2005
35/11-13	2.45	0	0	0	2.45	2005
35/2-1	0	16.0	0.0	0.0	16.0	2005
6605/8-1	0	29.0	0.0	0.0	29.0	2005
6302/6-1		1.8			1.8	2005
Total	**8.45**	**46.8**	**0.0**	**0.0**	**55.3**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the first discovery well was drilled

(Source: The Norwegian Petroleum Directorate)

Appendix 3 Operators and licensees

The table below lists the operators and licensees in production licences and fields on the Norwegian continental shelf. There are 289 active production licences but 291 operatorships. Both Statoil ASA and Norsk Hydro Produksjon AS are operators in production licences 085 and 085B. In addition, Gassco AS is the operator for large parts of the gas pipeline network. For more facts about the petroleum activities, please visit the Norwegian Petroleum Directorate's web site: www.npd.no. Various reports relating to production licences and licensees can be downloaded from www.npd.no/reports.

Table 3.1 Operators and licensees

	Operatorship	Production licence	Field
A/S Norske Shell	11	24	7
Amerada Hess Norge AS	1	10	4
BG Norge AS	8	15	
BP Norge AS	12	16	5
Chevron Norge AS	1	6	1
CNR International (Norway) AS	1	1	
ConocoPhillips Scandinavia AS	8	10	9
DONG Norge AS	6	34	7
Det Norske Oljeselskap AS	8	22	2
Endeavour Energy Norge AS	1	12	2
Eni Norge AS	11	50	16
Enterprise Oil Norge AS	1	12	8
ExxonMobil Exploration and Production Norway AS	11	27	17
Idemitsu Petroleum Norge AS	1	9	6
Lundin Norway AS	6	16	2
Marathon Petroleum Norge AS	11	19	5
Mobil Development Norway AS	1	24	8
Mærsk Oil Exploration Norway AS	1	2	
Mærsk Oil Norway AS	1	1	
Norsk Hydro Produksjon AS	66	124	45
Norske ConocoPhillips AS	1	23	13
Paladin Resources Norge AS	5	24	5
Pertra ASA	4	10	3
Petro-Canada UK Limited	2	5	
Revus Energy ASA	1	26	4
RWE Dea Norge AS	2	22	7
Statoil ASA	88	163	48
Talisman Energy Norge AS	10	26	6
Total E&P Norge AS	11	66	39

Other licensees:	Production licence	Field
Altinex Oil AS	5	
E.ON Ruhrgas Norge AS	7	1
Gaz de France Norge AS	25	3
Noble Energy Limited	1	
Norske AEDC A/S	1	1
Norwegian Energy Company AS	3	
Petoro AS	100	41
Premier Oil Norge AS	5	
Svenska Petroleum Exploration AS	3	1
Wintershall Norge AS	3	

(Source: The Norwegian Petroleum Directorate)

Appendix 4 List of addresses

GOVERNMENT BODIES

The Ministry of Petroleum and Energy
P.O. Box 8148 Dep, N-0033 Oslo
Tel. +47 22 24 90 90, Fax +47 22 24 95 65
www.oed.dep.no

The Norwegian Petroleum Directorate
P.O. Box 600, N-4003 Stavanger
Tel. +47 51 87 60 00, Fax +47 51 55 15 71
www.npd.no

The Harstad office:
P.O. Box 787, N-9488 Harstad
Tel. +47 77 01 83 50, Fax +47 77 06 38 95

The Ministry of Labour and Social Inclusion
P.O. Box 8019 Dep, N-0030 Oslo
Tel. +47 22 24 90 90, Fax +47 22 24 95 76
www.aid.dep.no

The Petroleum Safety Authority Norway
P.O. Box 599, N-4003 Stavanger
Tel. +47 51 87 60 50, Fax +47 51 87 60 80
www.ptil.no

The Ministry of Finance
P.O. box 8008 Dep, N-0030 Oslo
Tel. +47 22 24 90 90, Fax +47 22 24 95 10
www.finans.dep.no

The Ministry of the Environment
P.O. Box 8013 Dep, N-0030 Oslo
Tel. +47 22 24 90 90, Fax +47 +47 22 24 95 60
www.md.dep.no

OPERATORS

Amerada Hess Norge AS
C.J. Hambros plass 2C, N-0164 Oslo
Tel. +47 22 94 00 00, Fax +47 22 42 63 27
www.hess.com

A/S Norske Shell
P.O. Box 40, N-4098 Tananger
Tel. +47 51 69 30 00, Fax +47 51 69 30 30
www.shell.com

BG Norge AS
P.O. Box 780 Sentrum, N-4004 Stavanger
Tel. +47 51 20 59 00, Fax +47 51 20 59 90
www.bg-group.com

BP Norge AS
P.O. Box 197 Forus, N-4065 Stavanger
Tel. +47 52 01 30 00, Fax +47 52 01 30 01
www.bp.no

Chevron Norge AS
P.O. Box 97 Skøyen, N-0212 Oslo
Tel. +47 22 13 56 60, Fax +47 22 13 56 90
www.chevrontexaco.com

CNR International (Norway) AS
c/o Wikborg, Rein & Co.
P.O. Box 1315 Vika, N-0117 Oslo
Tel. +47 22 82 75 00, Fax +47 22 82 75 01
www.cnrl.com

ConocoPhillips Skandinavia AS
P.O. Box 220, N-4098 Tananger
Tel. +47 52 02 00 00, Fax +47 52 02 66 00
www.conocophillips.com

Det Norske Oljeselskap AS
P.O. Box 1345 Vika, N-0113 Oslo
Tel. +47 23 23 84 80, Fax +47 23 23 84 81
www.dno.no

DONG Norge AS
P.O. Box 450 Sentrum, N-4002 Stavanger
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www.dong.no

Endeavour Energy Norge AS
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www.endeavourcorp.com

Eni Norge AS
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www.eninorge.no

Enterprise Oil Norge AS
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ExxonMobil Exploration and Production Norway AS
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Gassco AS
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Idemitsu Petroleum Norge AS
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www.idemitsu.no

Lundin Norway AS
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Marathon Petroleum Norge AS
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www.marathon.com

Mobil Development Norway AS
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Maersk Oil Exploration Norway AS
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Norske ConocoPhillips AS
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Pertra ASA
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Revus Energy ASA
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RWE Dea Norge AS
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Talisman Energy Norge AS
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Total E&P Norge AS
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Gaz de France Norge AS
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Norwegian Energy Company AS
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Petoro AS
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www.petoro.no

Premier Oil Norge AS
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www.premieroil.co.uk

Svenska Petroleum Exploration AS
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Wintershall Norge AS
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0106 Oslo
Tlf: 23 31 59 90, faks 23 31 59 99
www.wintershall.biz

Appendix 5 Conversion factors

Oil, condensate and gas volumes are stated in standard cubic metres (scm) and NGL volumes in tonnes. A measure of total resources can be obtained by adding up the energy content in the various types of petroleum. The total is calculated in standard cubic metre oil equivalents (scm o.e.).

1 scm oil	=	1,0 scm o.e.
1 scm condensate	=	1,0 scm o.e.
1000 scm gas	=	1,0 scm o.e.
1 tonne NGL	=	1,9 scm o.e.

Gas	1 cubic foot	1 000,00	Btu
	1 cubic metre	9 000,00	kcal
	1 cubic metre	35,30	cubic feet

Crude oil	1 scm	6,29	barrels
	1 scm	0,84	toe
	1 tonne	7,49	barrels
	1 barrel	159,00	litre
	1 barrel per day	48,80	tonnes per year
	1 barrel per day	58,00	scm per year

Approximate energy content

		MJ
1	scm natural gas	40
1	scm crude oil	35 500
1	tonne coal equivalent	29 300

Conversion factors for volume

1	scm crude oil	=	6,29 barrels
1	scm crude oil	=	0.84 tonnes crude oil (average for oil from the Norwegian continental shelf)
1	scm gas	=	35,314 cubic feet

Conversion factors between various units of energy

			MJ	kWh	BTU
1	MJ	Megajoule	1	0,2778	947,80
1	kWh	kilowatt hour	3,6	1	3412,10
1	BTU	British thermal unit	0,001055	0,000293	1

Appendix 6 The Geological Timescale