FACTS

THE NORWEGIAN PETROLEUM SECTOR

2009

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Foreword by the Minister of Petroleum and Energy Terje Riis-Johansen

The world needs energy – and over the short and medium term it is clear that much of our global energy consumption will come from fossil sources such as oil, gas and coal. Here in Norway, investments in the petroleum sector account for about one-fourth of total investments. One-third of the State's revenues come from this sector, value creation from the oil and gas industry accounted for one-fourth of the gross domestic product in 2008, and around 200,000 people are employed in petroleum-related activities. These figures highlight the importance and impact of the activity level in the oil and gas sector for the development of the Norwegian economy.

Greenhouse gas emissions are an unfortunate side-effect of these activities. We know that production of Norwegian oil and gas causes less emissions of greenhouse gases than production in other comparable countries, in part due to our strict regulations and advanced Norwegian technology. We should be proud of this, but we also need to look towards the future. The challenges on the horizon will demand even more commitment from both the authorities and the industry.

2009 will be an exciting year. The comprehensive management plan for the Norwegian Sea will facilitate value creation through sustainable use of resources, while at the same time maintaining the structure, functions and productivity of the eco-system. Our work to update the comprehensive management plan for Lofoten and the Barents Sea is also well underway.

We see the northern areas as Norway's most important strategic focus area in the years to come. The Government's goal is to strengthen Norway's sovereignty and ensure sustainable management of the rich fishery and petroleum resources in these areas. This will be accomplished by protecting the environment, settlement and industrial development in the northern areas – in cooperation with Russia and other partners. The vulnerable marine environment presents a special challenge for industrial development in the Arctic region. It is essential that we ensure coexistence between environmental considerations, safe sea transport and the petroleum activities. This will require active measures from the authorities, who must set the framework for the various activities. Both now and in the future, the authorities and the industry need to coordinate their efforts in order to develop policies, technology, systems and knowledge so that petroleum activities can take place in Arctic areas in a manner that is both safe and sustainable. Further development of our knowledge base, more research in relevant areas and close cooperation between countries and industries are key elements in achieving this goal.

We need world-class oil spill preparedness in order for the petroleum activities to earn broad legitimacy in the population. The Government will make oil spill preparedness a higher priority, it will accommodate the need for resources in the form of training and drills, and it will help promote good interaction among the responsible players. We also know that it is extremely important that oil spill preparedness is firmly rooted in local communities and regions, as well as at the national level. Our role as government authorities requires that our expectations and demands for the petroleum industry are clear.

Extracting the resources beneath our seabed is a demanding task. Norwegian oil production is falling. The latest production forecasts show a sharper production decline than we had anticipated. But these are very uncertain estimates. The Ministry of Petroleum and Energy is focusing on measures that can help stem the decline in production. Gas production is expected to increase in the years to come, with the gas segment of total production growing from 40 per cent in 2008 to 48 per cent in 2012. This illustrates the necessity of adapting to new situations. As public authorities, we pledge to take this responsibility seriously, also in the months and years to come.

2009 will be a year marked by many challenges, but also many opportunities for the petroleum sector. The financial crisis and setbacks in the world economy have had a devastating impact on oil prices. Demand for oil has dwindled, in OECD countries to its lowest level in more than 30 years. The problem in today's market situation is no longer the high price of oil. There is a risk that weaker demand, lower prices, higher costs and difficult access to credit may impede investments in new oil projects. This will mean less oil on the market in the future.

The level of activities in 2008 has been very high. I believe this vigorous activity will continue in 2009. Projects have been started and contracts have been signed. However, the fact that a lot of activity is underway does not mean that individual companies or companies in certain markets will not experience a demanding period with few new assignments. Nor does it mean that projects won't be postponed. It means only that the total demand for goods and services for the offshore activities will still be very high in 2009. Nevertheless, if the financial crisis had not occurred, analyses predicted even stronger growth in the next few years, from an already record-setting level.

Other parts of the Norwegian economy must prepare for weak development and rising unemployment in 2009. An open economy such as ours will certainly feel the effects of the international economic downturn. In spite of this, Norway is well-equipped to meet the current demanding financial climate. Thanks to the revenues we have harvested from the petroleum activities, the Norwegian State has substantial freedom to manoeuvre; to take steps to soften the effects of a shaken world economy and to help bring about changes that allow Norway to emerge from these difficult times even stronger.

We can choose to look on this period of decline as a time of new opportunities and a new framework for action that is different than before. Resources can be transferred and injected into areas where work needs to be done. One such area is climate and the environment. The companies on the Norwegian shelf have paid a CO_2 tax since 1991, and this tax has been instrumental in the work to decrease greenhouse gas emissions. Starting on 1 January 2008, the petroleum activities were included in the Norwegian quota system, and must thus purchase emission quotas. The

Government will also continue to work on large and small measures that can boost energy efficiency and cut emissions from the Norwegian shelf. The Government is also positioning the full weight of its support to stimulate development of technology for capturing and storing CO_2.

The Government is devoted to ensuring that the petroleum sector creates regional and local ripple effects. The petroleum activities can lead to greater economic growth and local and national business development. Ripple effects can include direct effects such as contract awards to national, regional or local supplier companies, or indirect effects in the form of more robust local buying power and demand for goods and services.

The ripple effects from the oil and gas activities are about much more than just the resources mobilised for individual field developments. The oil industry needs the efforts of a number of different sectors and expert communities, and it helps stimulate their further development. One shining example of this is the Norwegian supplier industry, which is now one of Norway's foremost export industries, second only to oil and gas. Another example is the relevance for Norwegian research and technology, and for the interplay between the industry and the Norwegian research community in nearly every conceivable discipline. A third example is the need for transport services, maintenance services, catering and logistics. We estimate that nearly 150,000 people have jobs that are directly linked to the Norwegian oil and gas activities. These figures do not include general subcontracts such as administrative support, accounting, IT services, canteen services and transport. If we add the number of people employed in all types of subcontracts to the number of people who work directly for the industry, we are probably talking about well over 200,000 people.

In any event, the most important effect of the petroleum activities is the combination of profitable developments and the fact that the public purse receives a large portion of the proceeds from this production. This provides us with good opportunities to pursue an active welfare policy for the benefit of the entire population. We plan to hold steady on this course.

The Minister of Petroleum and Energy

Foreword by Director General Bente Nyland

This year marks the 40th anniversary of the discovery of the Ekofisk field in the North Sea. This was the start of developments that have made petroleum activities Norway's most important industry. In January 2009 a new milestone was reached when production licence no. 500 was awarded to Det norske oljeselskap (operator) and the newcomers Skeie Energy and Spring Energy.

In addition to the petroleum activities' great importance for the Norwegian economy and for local communities where many are employed in this industry, the activities have also led to major investments in and use of technology, making Norway a major exporter of technology.

The global economy has been in crisis since the autumn of 2008. Last summer, oil prices peaked at USD 146 a barrel. By the end of the year, however, the price had fallen to USD 40 a barrel, and so far in 2009, prices have ranged between 40 and 55 dollars a barrel. In conjunction with a high cost level in the industry, plummeting oil prices have led some major oil companies to signal cutbacks and the possible postponement of projects due to a lack of capital. In this situation, the Norwegian Petroleum Directorate sees it as important that the oil industry does not make hasty decisions that might have a permanent, negative effect on resource recovery from the Norwegian continental shelf.

Gas production on the Norwegian shelf continues to increase, and in 2008 gas sales amounted to nearly 100 billion Sm^3. This figure is expected to rise to 112 billion Sm^3 over the next five years. Norway will be an important gas supplier in Europe for many decades to come.

Oil production on the Norwegian shelf is falling. This is in line with the Norwegian Petroleum Directorate's forecasts, but the forecasts for 2009 indicate a steeper decline than previously expected. This trend could deepen if the oil price remains at

its current level. While oil production in the peak year of 2001 amounted to 3.1 million barrels a day, forecasts for 2009 are 1.9 million barrels a day.

The most important measures in reducing the decline in oil production will be to discover and develop new resources and to produce more from existing fields, not least through cost efficiency measures and by approving profitable projects. By closely following the oil companies, the NPD is working to ensure that necessary measures are implemented.

Improved oil recovery

No other oil-producing country recovers more oil from its offshore fields than Norway. Nevertheless, approximately 54 per cent of the oil will remain underground when the fields are closed down according to today's plans. That is too much. The largest remaining oil resources are found in fields where oil production is declining. Over the next few years, important choices will therefore need to be made if we are to extract significantly more oil and gas. The NPD wants to increase recovery, provided it creates added value. In light of this, the NPD has revitalised enhanced recovery efforts in cooperation with FORCE, the industry's own cooperation forum for technology development. The NPD believes cooperation is the operative word if we are to progress in the qualification of technology that can boost oil recovery in the longer term. If large-scale tests could be conducted on producing fields, that would be a big step in the right direction. This is a major effort, however, requiring the backing of the industry in general. The NDP will do what it can to make this happen.

Extensive exploration activity

A total of 56 exploration wells were drilled during 2008. This is the highest number of exploration wells ever on the Norwegian continental shelf. Twenty-five new discoveries were made, mainly smaller discoveries in the vicinity of existing infrastructure. According to the plans reported to us by the oil companies in late autumn 2008, exploration activity will remain high in 2009.

The great majority of exploration wells are drilled by StatoilHydro, the biggest player on the Norwegian shelf. However, the new companies that came to the shelf after 2000 have also begun to make their mark in exploration. Altogether between 55 and 60 new companies have been prequalified as operators or licensees in the course of the last ten years.

The player scenario offshore is reflected in the number of applications for APA (Awards in Predefined Areas) and the ordinary licensing rounds. There were 47 applicants for APA 2008, with awards made in January. For the 20th licensing round, which was announced last year and will be awarded in the first half of 2009, there was also a total of 47 applicants.

The Norwegian Petroleum Directorate believes considerable oil and gas resources are still to be found on the Norwegian shelf, but there is great uncertainty concerning the estimates. On the basis of the NPD's anticipated estimates, around 25 per cent of the shelf resources remain to be discovered, with a third each in the North Sea, the Norwegian Sea and the Barents Sea.

CO_2 storage

In Norway, oil and gas production accounts for about 31 per cent (2007 values) of total CO_2 emissions. The government's ambition is a further reduction of the overall emissions of greenhouse gases. Even though significant steps have already been taken to reduce CO_2 emissions, additional cuts are needed. More efficient energy on existing fields, and power from land to new fields, are among the measures under consideration. The capture and storage of CO_2 is another area where the NPD has been and will be involved. Safe storage of CO_2 under the seabed requires knowledge of the properties and storage capacity of the different types of rocks. The NPD has extensive expertise on geological conditions on the Norwegian shelf. This expertise is now being used to survey possible storage sites for CO_2.

During the autumn of 2008, the Government launched the Climate Cure project. The purpose of the project is to identify measures that will make it possible to reach the Government's climate targets. This is a joint effort by the Norwegian Pollution Control Authority, the Norwegian Petroleum Directorate, the Norwegian Water Resources and Energy Directorate, the Norwegian Public Roads Administration and Statistics Norway. The NPD is assessing possible measures in the petroleum sector, one of them being the capture and storage of CO_2.

Coexistence

The increased activity on the Norwegian shelf has led to more conflict between the two principal users of the sea, the petroleum industry and the fisheries. The fishermen find that there is less room to manoeuvre because of the steady increase in seismic surveys. On this basis, a working group was appointed in 2007 with members from the Directorate of Fisheries and the NPD to assess measures to improve conditions. A number of measures have been implemented, e.g. mandatory courses have been established for fishery experts, the NPD has introduced an improved announcement system and the regulations have been amended. Work has also been conducted to assess the status of research into the effects of seismic surveys on fish and sea mammals, as part of the work to agree on a minimum distance between fishing in progress and seismic work.

The Norwegian Petroleum Directorate will complete the acquisition of seismic data in Nordland VII and Troms II during the summer of 2009. The data acquisition began in the summer of 2007 at the request of the Government. The purpose is to obtain knowledge of any petroleum deposits in these waters, and such knowledge will be used when the Integrated Management Plan for the Barents Sea and the waters off Lofoten and Vesterålen is revised in 2010. In connection with the acquisition of 3D seismic data in the summer of 2009, NPD has commissioned the Institute of Marine Research to research the consequences of this by studying the startle response on fish and how sound from seismic sources travels through water.

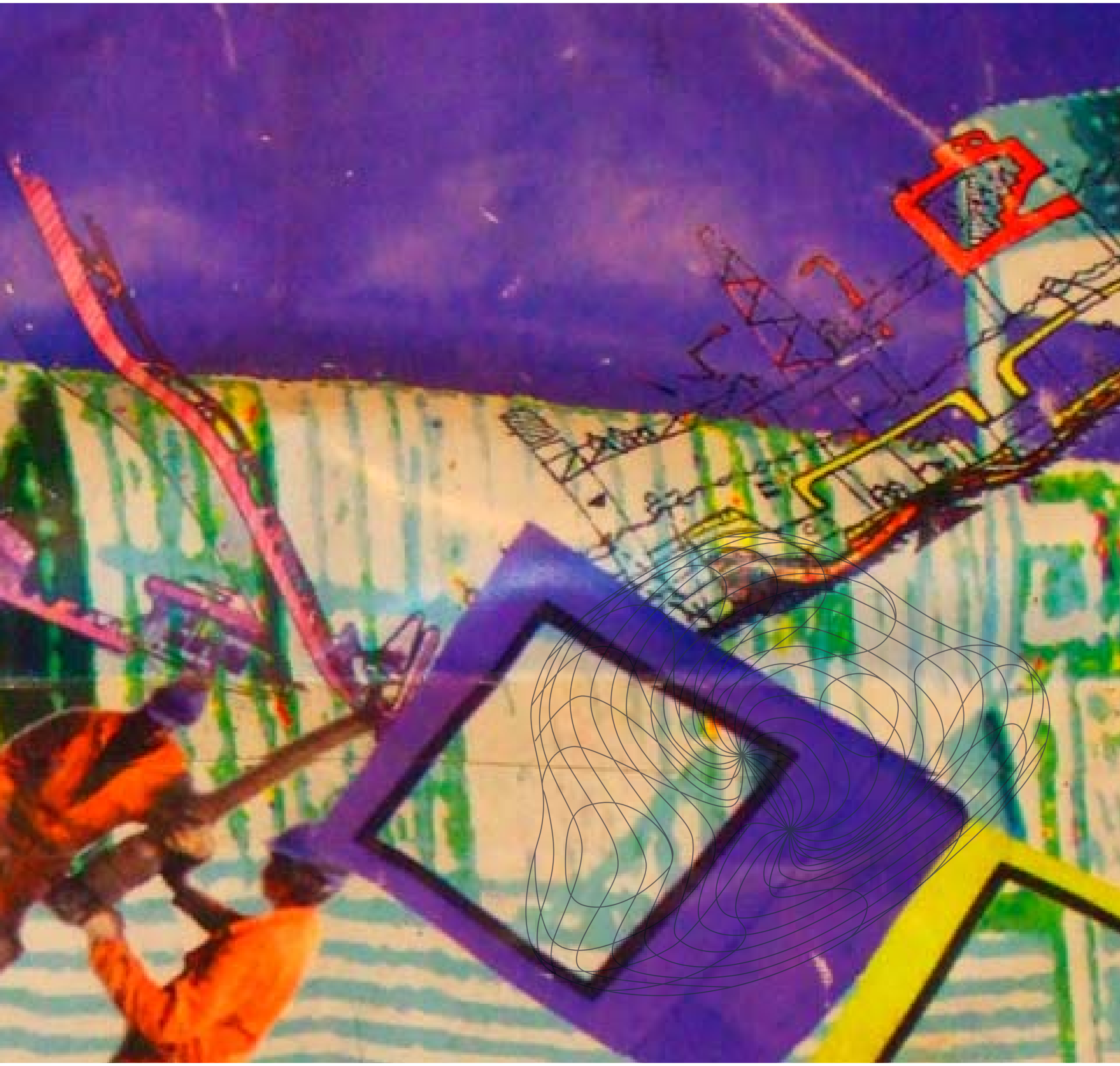
Future vision

In 2008, the Norwegian Petroleum Directorate was awarded the Norwegian Petroleum Society's prize for its importance as a technical contributor to policy formation and for its work on scenarios. We believe a crucial element in making good decisions is the ability to envisage not just one, but several future scenarios. By combining our factual knowledge of the petroleum resources on the Norwegian shelf with knowledge of the world around us, the Norwegian Petroleum Directorate hopes that our scenario work will provide input and ideas for those responsible for making decisions concerning our future.

Director General

Content

1 The petroleum sector - Norway's largest industry



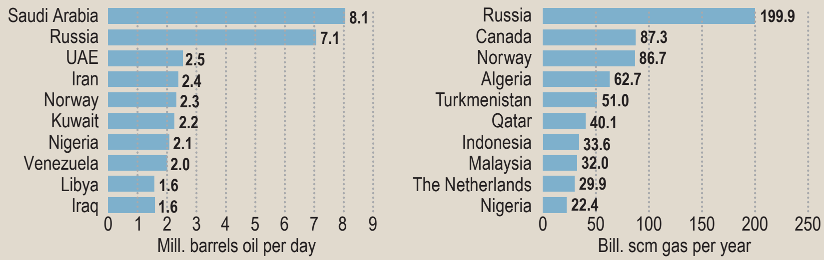


Figure 1.1 The largest oil exporters (oil includes NGL and condensate) and gas exporters in 2007

(Source: KBC Market Services)

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 started on 15 June 1971, and in the following years a number of major discoveries were made. Today, there are 60 fields in production on the Norwegian continental shelf. In 2008, these fields produced 2.5 million barrels of oil per day (including NGL and condensate) and 99.3 billion standard cubic metres (scm) of gas, for a total production of saleable petroleum of 242.2 million scm oil equivalents (o.e.). In 2007, Norway was ranked as the world's fifth largest oil exporter and the eleventh largest oil producer. In 2007, Norway was the third largest gas exporter in the world. Preliminary indications are that Norway will surpass Canada, becoming the second largest gas producer in the world in 2008.

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 7000 billion in current terms. In 2008, the petroleum sector accounted for 26 per cent of national value creation. The value created by the petroleum industry is three times higher than in land-based industries and around 23 times the total value creation of the primary industries.

Tax revenues from the production companies and direct ownership (SDFI – the State's Direct Financial Interest), ensure that the State receives much of the values created from the petroleum activities. In 2008, the State's net cash flow from the petroleum sector amounted to approximately 34 per cent of total revenues. After more than 35 years of production, the sector has generated net revenues to the State in the order of NOK 3750 billion in current terms. The State's revenues from petroleum activities are allocated to a separate fund, the Government Pension Fund – Global. By the end of 2008, the value of this fund was NOK 2275 billion.

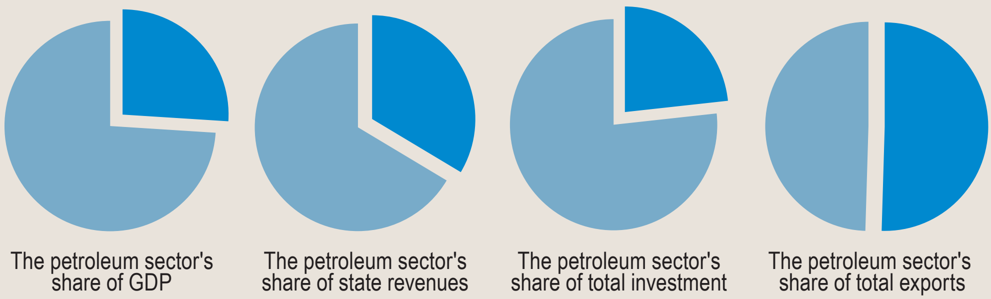


Figure 1.2 Macro-economic indicators for the petroleum sector

(Source: Statistics Norway/The Ministry of Finance)

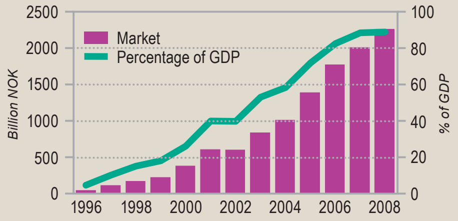


Figure 1.3 Size of the Government Pension Fund - Global - as of 31 December 2008 and as a percentage of GDP
(Source: Statistics Norway/Norges Bank)

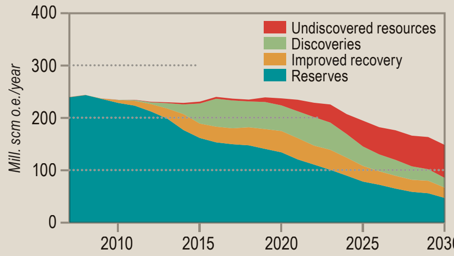


Figure 1.4 Production forecast
(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)

The petroleum revenues are gradually phased into the economy to cover the structural, oil-corrected deficit in the fiscal budget. The funds are phased in approximately in step with the development in the expected real return on the Fund.

In 2008, crude oil, natural gas and pipeline services accounted for half of the value of Norway's exports. Measured in NOK, the value of petroleum exports was 600 billion in 2008, 15 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 2008 more than NOK 2100 billion (current terms) had been invested. Investments in 2008 amounted to approximately NOK 130 billion, or 23 per cent of the country's total real investments.

Future trends

We have produced about 38 per cent of the expected total resources on the Norwegian continental shelf. The remaining resources represent a huge potential value creation for many years to come.

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

Petroleum production is expected to remain steady over the next few years. The production of oil and other liquids will fall gradually. Gas export on the other hand is expected to increase and to reach a level between 115 to 140 billion scm within the next decade. From representing approximately 40 per cent of the total Norwegian petroleum production in 2008, the share attributed to gas production will increase considerably in the future. 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 has grown considerably in recent years, and the investment level is expected to reach a record high in 2009. Recent developments in the world economy make this year's forecasts subject to more than the usual uncertainty. The robust investment activity in spite of the financial crisis is a result of the fact that 2009 investments are largely driven by decisions that have already been made and contracts that have already been signed. The effects of the negative economic trend are expected to manifest themselves in more force later on.

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, peaking at more than USD 140 per barrel in mid-2008. Since then, deterioration of the world economy has caused demand for oil to dwindle, and thus a sharp drop in prices. At the beginning of 2009, oil sold for slightly more than USD 40 per barrel. When growth in the world economy resumes, there is reason to believe that demand for oil will again start to rise. Future oil price developments will also depend on how much oil the OPEC production cartel pours into the market in the years to come.

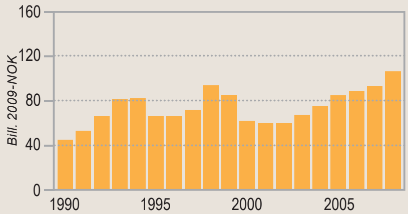
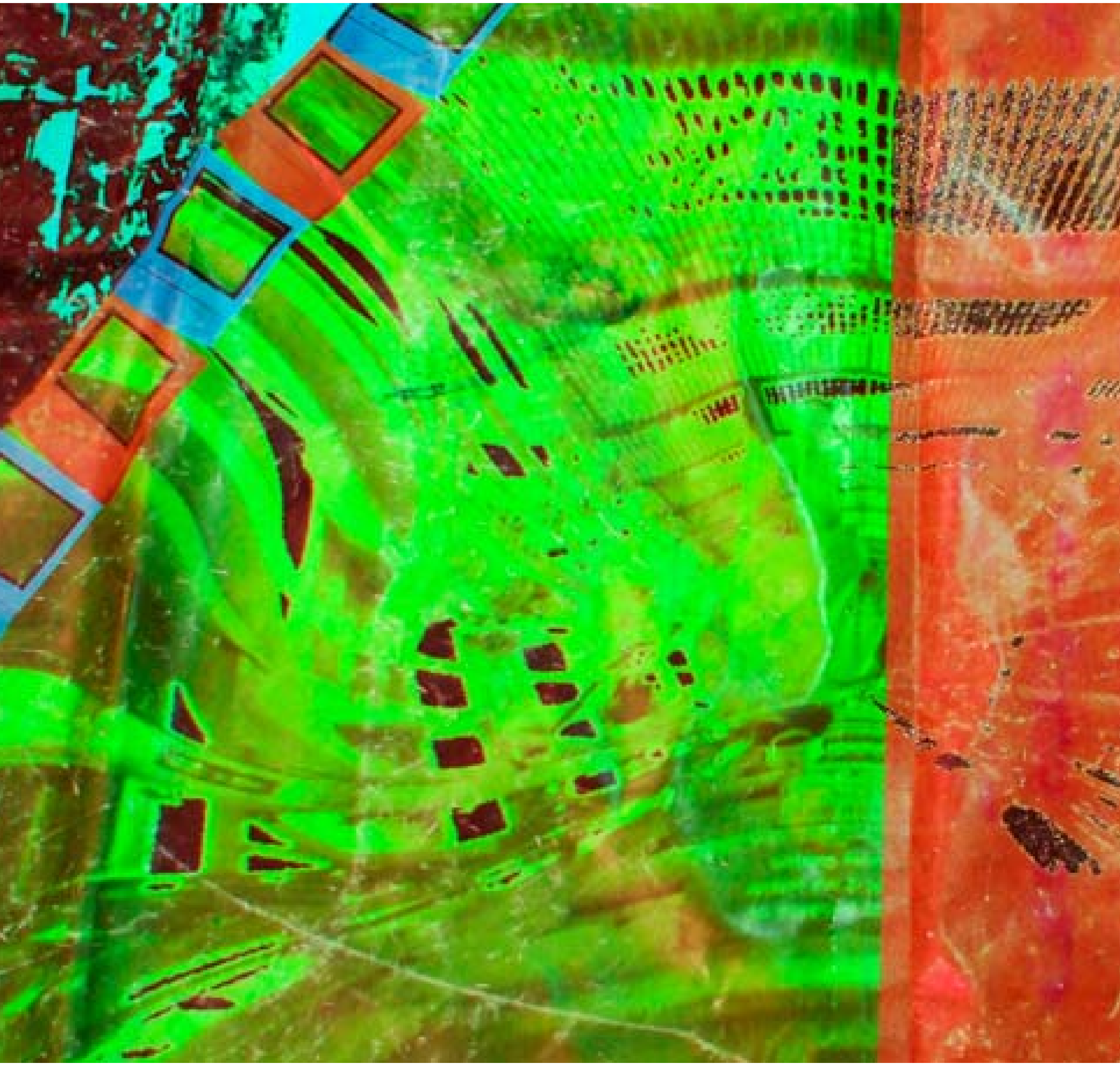


Figure 1.5 Historical investments (excluding investments in exploration)
(Source: Norwegian Petroleum Directorate/ Ministry of Petroleum and Energy)

2 Norwegian resource management



The 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, public 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. Right from the start, national administration and control over the petroleum activities on the Norwegian continental shelf have been fundamental requirements. The challenge facing Norway in developing its petroleum activities was to establish a system of managing the petroleum resources – a system that would maximise the value for Norway as a whole.

In the beginning, the Norwegian government selected a model in which foreign companies carried out the petroleum activities on the Norwegian continental shelf. Over time, the Norwegian involvement was strengthened through the participation of Norsk Hydro, and by the creation of a wholly owned state oil company, Statoil, in 1972. A private Norwegian company, Saga Petroleum, was also established, but was later acquired by Norsk Hydro. In 2007, Norsk Hydro's oil and gas activities merged with Statoil, and the new company was named StatoilHydro ASA. The cooperation and competition between the various companies on the Norwegian continental shelf have been crucial, as the companies 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 has secured substantial revenues from the sector.

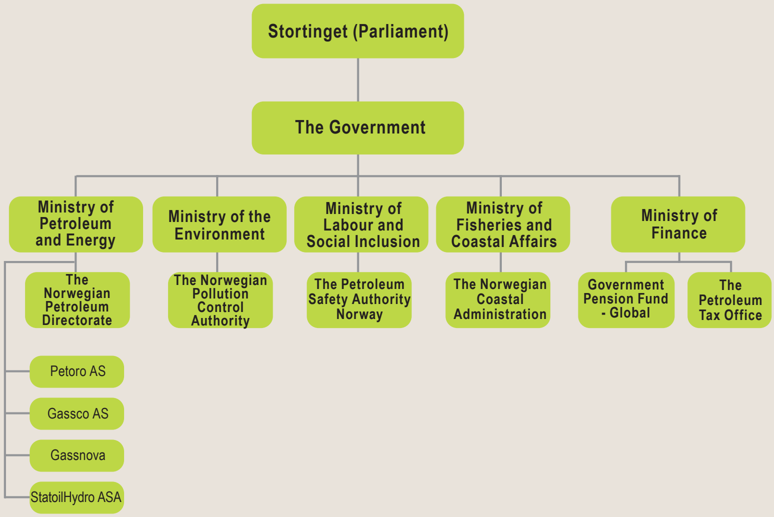


Figure 2.1 National organisation of the petroleum sector

(Source: Norwegian fiscal budget)

The current resource management model

In order for oil companies to make rational investment decisions, the framework conditions must be predictable and transparent. The organisation of the activities and the division of roles and responsibilities shall ensure that important social considerations are safeguarded and that the value created from the activities benefits society as a whole. At the same time, consideration for the external environment, health, working environment and safety plays an important role.[1]

Norwegian and international oil companies are responsible for the actual petroleum activities on the Norwegian continental 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 whereby oil companies supply the 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 activities, in connection with exploration drilling[2], plans for development and operation[3] and decommissioning plans[4] for fields.

For the oil companies to maximise 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 at the same time meeting their own goals, which is to maximise their profits. 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.[5] 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, neither will the Norwegian State. 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 main rule is that the authorities award production licences to a group of companies instead of one company alone, normally on the basis of applications from oil companies in connection with licensing rounds.[6] The most important award criteria include understanding of the geology, technical expertise, financial strength and the experience the authorities have had with the specific 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. Under this system, expertise and experience are gathered from a number of companies from all over the world. The licensee group also functions as an internal control system within the production

1 *Environmental considerations in the petroleum activities are addressed in Chapter 9.*
2 *Ref. Chapter 4.*
3 *Chapter 5 addresses development and operation, while gas management is discussed in Chapter 6..*
4 *More on decommissioning after production is concluded in Chapter 7..*
5 *Ref. Chapter 3.*
6 *A more detailed discussion of exploration policy can be found in Chapter 4.*

licence, where each licensee is responsible for monitoring the work of the operator.

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 and development. Therefore, the Norwegian authorities have established an environment that promotes technological development. Today there is close collaboration between oil companies, research institutes, the supply industry and the authorities when it comes to technology and research.[7]

National organisation of the petroleum sector

The Storting

The Storting (Norwegian parliament), establishes the framework for the 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. The opening of new areas for petroleum activities, major development projects or matters of great public importance must be discussed 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:

- The Ministry of Petroleum and Energy – responsible for resource management and for the sector as a whole
- The Ministry of Labour and Social Inclusion – responsible for health, the working environment 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.

7 See Chapter 8.

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 given by the Storting and the government. In addition, the Ministry has a particular responsibility for supervising the state-owned corporations, Petoro AS and Gassco AS, as well as the oil company in which the state holds a majority interest, StatoilHydro ASA.

The Norwegian Petroleum Directorate

The Norwegian Petroleum Directorate (NPD) is administratively subordinate to the Ministry of Petroleum and Energy. The NPD plays a key role in petroleum resource management, and is an advisory body for the Ministry of Petroleum and Energy. The NPD exercises authority in connection with exploration for and production of petroleum deposits on the Norwegian continental shelf, including statuary powers and to make decisions based on the rules regulations governing 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 company responsible for the transport of natural gas from the Norwegian continental shelf. The company is the operator of Gassled, although it has no ownership interest in the company. Gassco AS handles this operatorship in a manner that is neutral for all owners and users.

Gassnova

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

StatoilHydro ASA

In 2007, Norsk Hydro's oil and gas activities merged with Statoil, and the new company was named StatoilHydro ASA. StatoilHydro ASA is listed on the Oslo and New York stock exchanges. As of 15 March 2009, the state owned 67 per cent of the company's shares.

More on the national organisation of the petroleum sector

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 emergency preparedness measures in relation to the petroleum sector.

The Petroleum Safety Authority Norway

The Petroleum Safety Authority Norway has regulatory responsibility for safety, contingency measures and the work environment in the petroleum sector.

The Petroleum Safety Authority Norway is responsible for technical and operational safety, including emergency preparedness 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

The Ministry of Finance is responsible for managing 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 environmental protection and management of the Norwegian external environment.

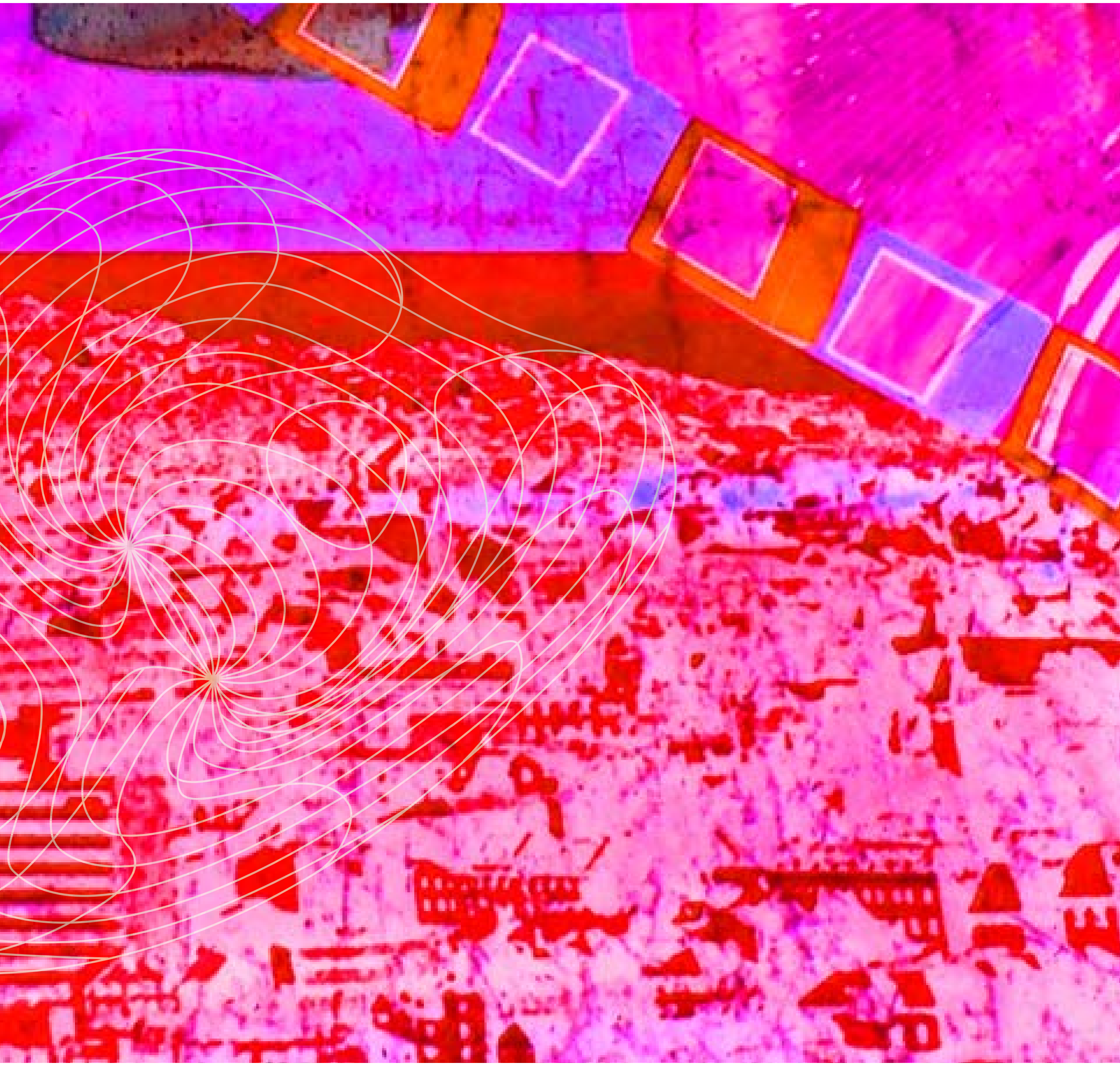
The Norwegian Pollution Control Authority

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.

The Senior Management Forum

The Senior Management Forum (Topplederforum) was established in the autumn of 2000, and is chaired by the Minister of Petroleum and Energy. The Senior Management Forum is an arena where the industry and the authorities can discuss relevant topics and key challenges for the oil and gas sector; however, no formal decisions on oil and gas policy are made in the Forum. The Senior Management Forum is organised and financed by the Ministry of Petroleum and Energy. Members of the Forum include senior managers from oil companies, the supply industry, employees' and employers' organisations, research institutes and the authorities.

3 Government petroleum revenues



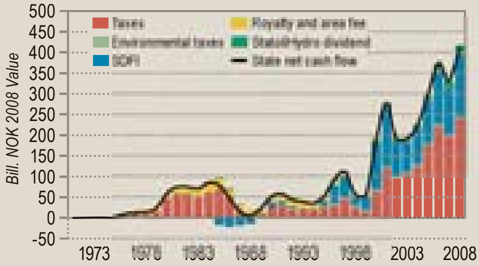


Figure 3.1 Net cash flow to the state from the petroleum activities *(Source: State Accounts and SDFI Accounts)*

Direct taxes:	239.6
Environmental taxes and area fee:	5.5
SDFI:	153.8*
Statoil dividend:	16.9**
Total:	415.8

* SDFI annual accounts 2008 (except transfer to SPFF)
** Dividend for 2007 paid in 2008

Figure 3.2 Net cash flow to the state from the petroleum activities 2008 (BNOK) *(Source: State Accounts for 2008 and SDFI Accounts)*

The government receives significant revenues from the petroleum activities. In 2008, 33.5 per cent of total state revenues came from this sector. Figure 3.1 shows that income from this sector has been consistently high in recent years, with 2006 yielding extraordinarily high income to the state. The 2009 national budget estimates the value of the remaining petroleum resources on the Norwegian continental shelf at NOK 5455 billion (2009-NOK).

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)
- Dividend from ownership in StatoilHydro

Norway has a special system designed to secure state revenues from the petroleum activities. The main rationale for the system is the extraordinary returns associated with production of the resources. The fiscal system must be viewed in light of the common ownership of the resources on the Norwegian continental shelf, and the fact 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 per cent, while the special tax rate is 50 per cent. When calculating taxable income for both ordinary and special taxes, investments are subject to depreciation on a linear basis over six years from the date the investments were made.

Companies may deduct all relevant expenses, including exploration, research and development, financial, operating and removal expenses (see Figure 3.3). Consolidation between fields is permitted. In order to shield the normal return from the special tax, an extra deduction, called the uplift, is allowed in the calculation base for special tax. This amounts to 30 per cent of the investments (7.5 per cent per annum for four years from the year the investment was 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 to be neutral, so that an investment project that is profitable for an investor before tax will also be profitable after tax. This allows us 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, the NO_x 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 2009 is NOK 0.46 per litre of petroleum or scm of gas.

Pursuant to the Gothenburg Protocol of 1999, Norway has an obligation to reduce annual emissions of nitrogen oxides (NO_x). In order to fulfil this obligation, the NO_x tax was introduced from 1 January 2007. For 2009, the tax is NOK 15.85 per kg of NO_x.

Operating income (norm price)
- Operating expenses
- Linear depreciation for investments (6 years)
- Exploration expenses, R&D and decommisioning
- CO_2-tax, NO_X-tax and area fee
- Net financial costs

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

= Special tax base (tax rate: 50 %)

Figure 3.3 Calculation of petroleum tax
(Source: Ministry of Petroleum and Energy)

The area fee is intended to be an instrument that contributes to efficient exploration of awarded acreage so that potential resources are produced as quickly as possible within a prudent financial framework, as well as to extend the lifetime of existing fields.

Norm prices

Most oil companies on the Norwegian continental shelf are parts of corporations with diversified global business portfolios. 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 associated companies are equivalent 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 set by the Petroleum Price Council (PPR), and should reflect the price paid for petroleum traded between independent parties. As a rule, the norm price is stipulated each month and for each field. The PPR 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 PPR does not find it appropriate to stipulate a norm price, the actual achieved 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)

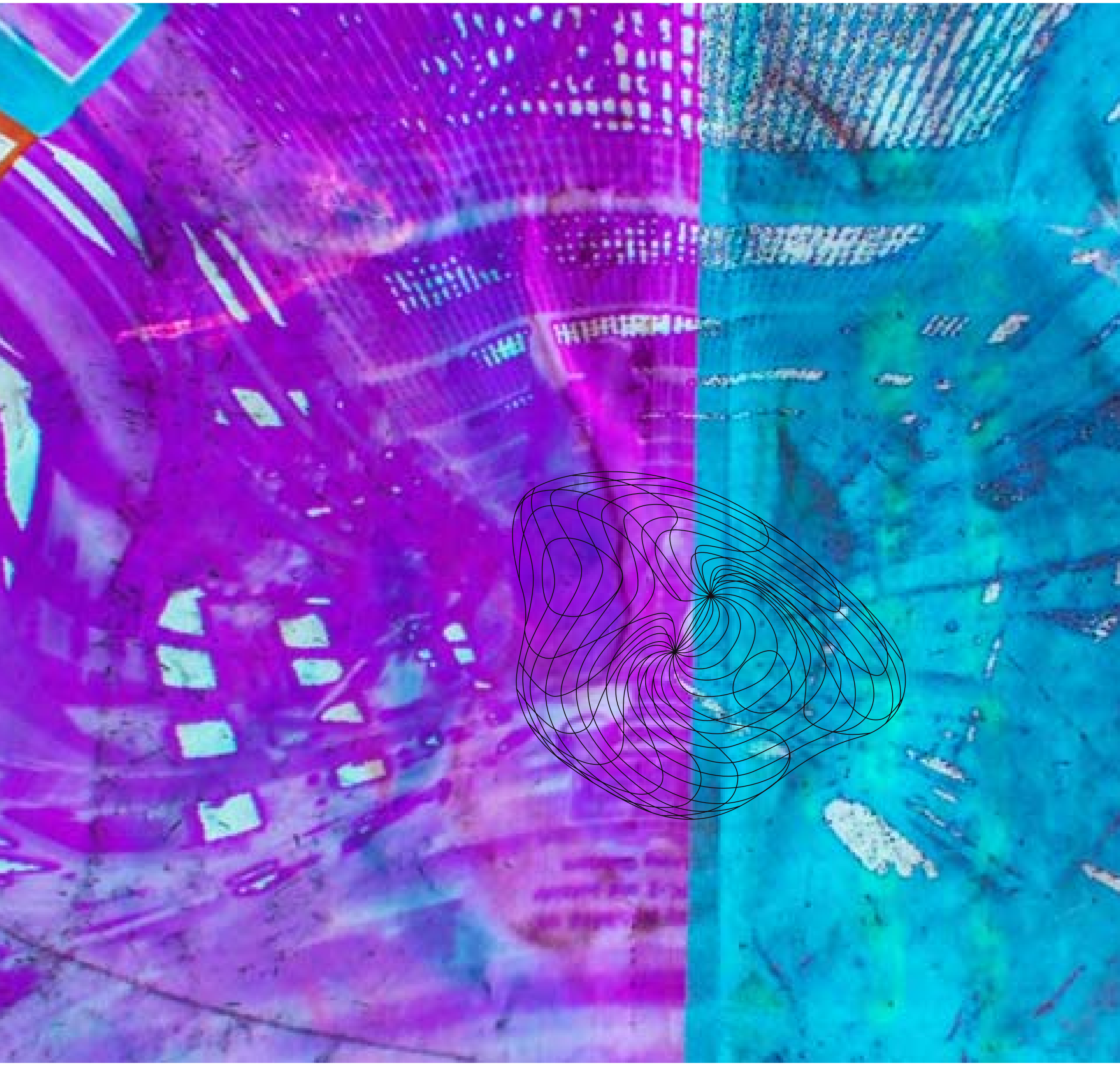
The State's Direct Financial Interest (SDFI) is an important source of state revenues, in addition to taxes, fees and dividends from its ownership in StatoilHydro. SDFI is an arrangement in which the state owns interests in a number of oil and gas fields, pipelines and onshore facilities. The government take is decided when production licences are awarded and the size of the state interest 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 partially privatised on 18 June 2001, the administration of the SDFI portfolio was transferred to the state-owned trust company, Petoro. As of 1 January 2009 the state had direct financial interests in 121 production licences and 12 joint ventures for pipelines and onshore facilities.

The SDFI arrangement is neutral in the sense that no risk is transferred from the state to the companies. This system allows the state, when awarding acreage, to determine exactly how much of the value creation shall devolve on the state. For production licences with low expected profitability, the state can decide to take a small interest, or even refrain from taking an interest, while a larger share would be appropriate for more profitable fields.

StatoilHydro dividend

As of 15 March 2009, the state owns 67 per cent of the shares in StatoilHydro. As an owner in StatoilHydro, the state receives dividends which form part of the state's revenues from the petroleum sector.

4 Exploration activities



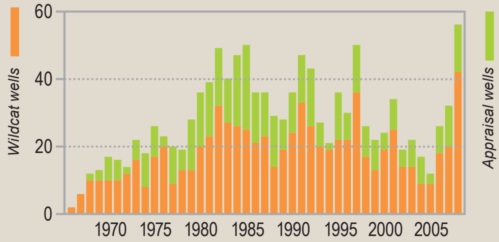


Figure 4.1 Spudded exploration wells on the Norwegian continental shelf 1966-2008

(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. 10-15 years is not unusual. The formulation of exploration policy is hence an important aspect of long-term Norwegian resource management.

Recent years have shown a rapid decline in oil production on the Norwegian shelf. For the authorities, it is important that Norwegian exploration policy provides for rapid and efficient identification of new resources to offset declining production. It is the companies that undertake the exploration and the proving of new resources. Exploration policy is therefore designed to ensure that the Norwegian continental shelf is attractive for established and new players that can contribute to efficient exploration. The government will give the companies access to attractive exploration acreage. The exploration acreage should offer possibilities in both mature and new, less explored areas which could hold resources.

The exploration activities have increased substantially in 2007 after a period of slow activity. A total of 32 exploration wells were spudded in 2007, including 20 appraisal wells. Twelve discoveries were made. A new record was set in 2008 with 56 exploration wells spudded. Of these, 42 were wildcat wells and 14 were appraisal wells. Twenty-five discoveries were made. Continued exploration drilling in frontier areas in the Norwegian Sea and the Barents Sea will be important for the mapping and evaluation of the resource potential in these areas.

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 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 Norwegian State has proprietary rights to subsea petroleum deposits on the Norwegian continental shelf. Before permission for exploration drilling and production (a production licence) can be granted, the area in question must have been opened up for petroleum activities. In connection with this, an impact assessment covering such aspects as the environmental, economic and social effects of such activities on other industries and adjacent regions, must be prepared.

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 the 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

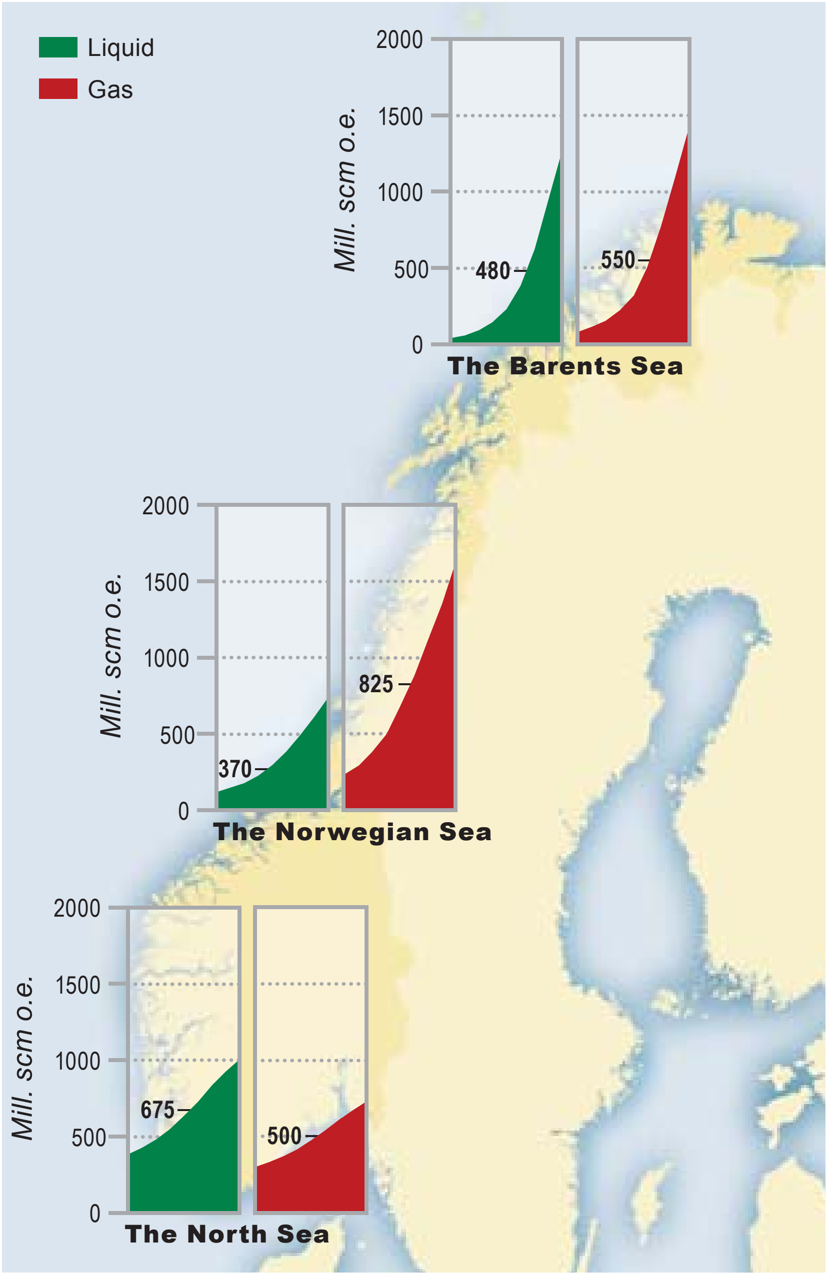


Figure 4.2 Undiscovered resources distributed by area. The number in each column indicates expected recoverable volumes while the uncertainty in the estimate is indicated by the slanted line; low estimate on the left, high estimate on the right *(Source: Norwegian Petroleum Directorate)*

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 and 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.

The production licence is awarded for an initial period (the exploration period), which can last up to ten years. A specified work commitment must be met during this period, including geological/geophysical preparatory work and/or exploration drilling. Providing that all the licensees agree, a licence can be relinquished once the work commitment has been fulfilled.

Mature and frontier areas

The parts of the Norwegian continental shelf that the Norwegian Parliament (Storting) has opened up for petroleum activities are the greater part of the North Sea, the 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. The resources are divided more or less equally between the three regions, with 35 per cent in the North Sea, 35 per cent in the Norwegian Sea and 30 per cent in the Barents Sea (see Figure 4.2). Depending on the degree of maturity of the different areas, there is some variation in the types of challenges involved in realising the commercial potential of the undiscovered resources on the Norwegian continental shelf.

Characteristics of mature areas include familiar geology, fewer technological challenges and well-developed or planned infrastructure. The discovery rate is high, but 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 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. The companies allowed to explore in these areas must have broad-based experience, technical and geological expertise, and 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 overall infrastructure is generally 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 warrant a stand-alone development of infrastructure.

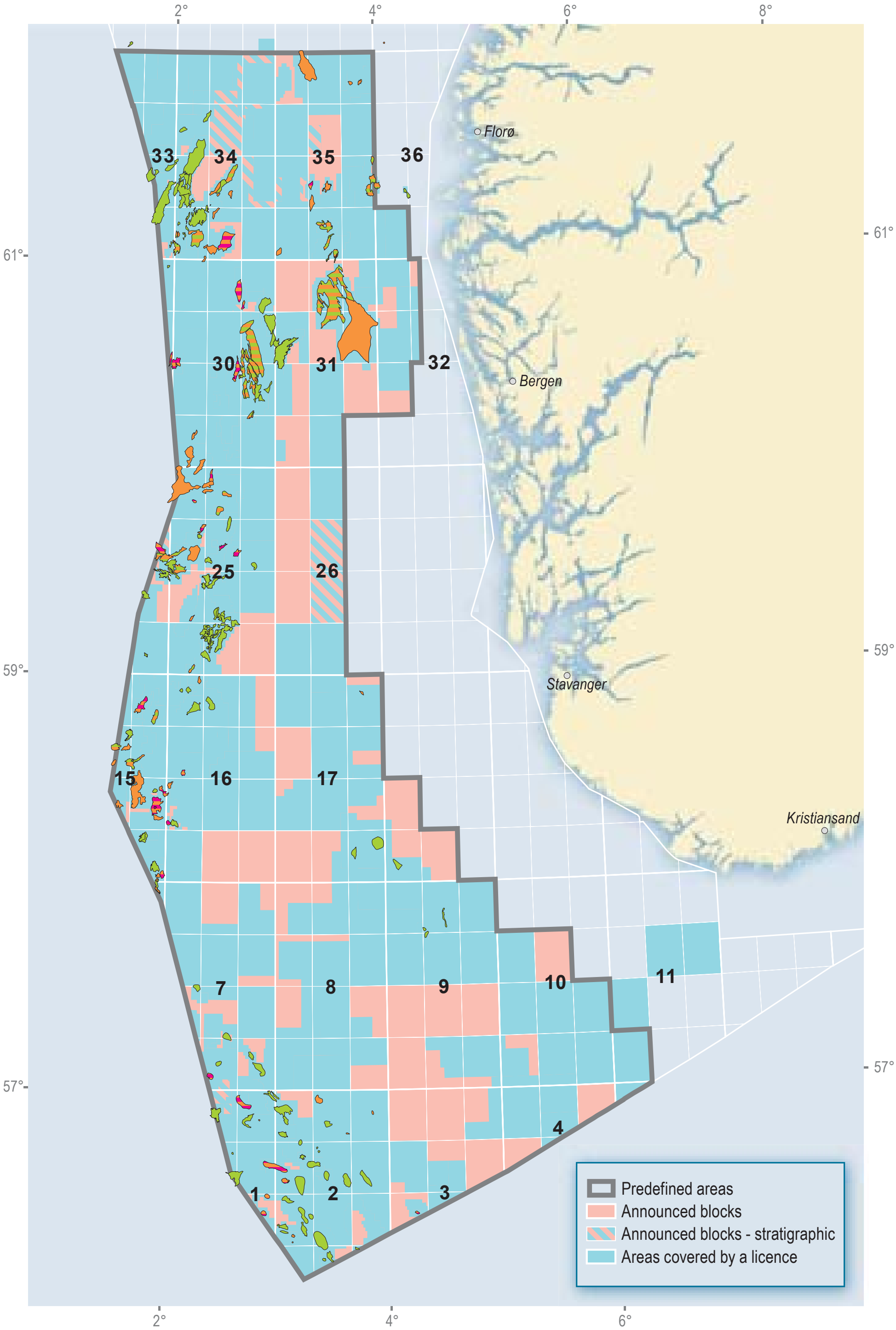


Figure 4.3 Awards in predefined areas – announcement North Sea 2009

(Source: Norwegian Petroleum Directorate)

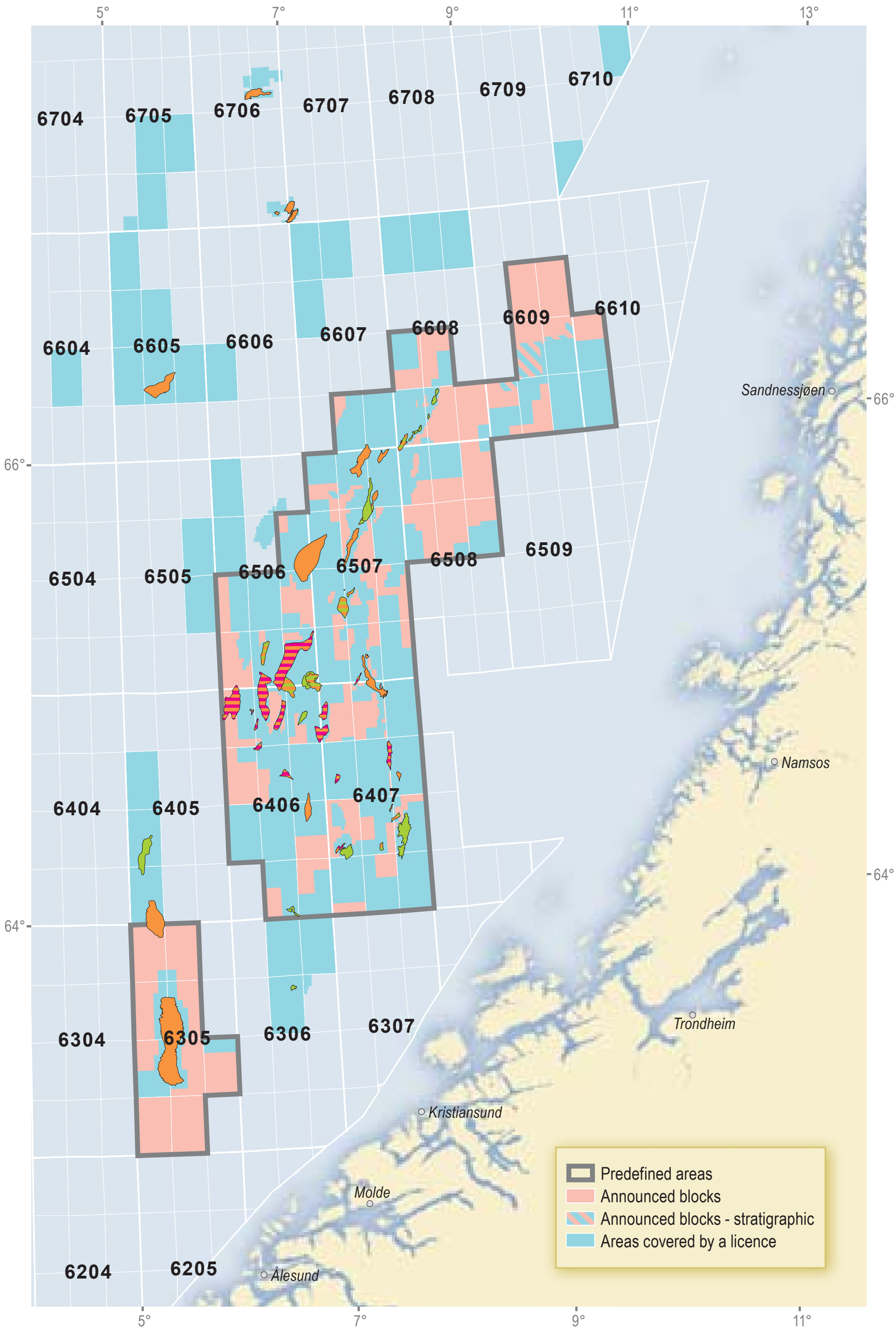


Figure 4.4 Awards in predefined areas – announcement Norwegian Sea 2009

(Source: Norwegian Petroleum Directorate)

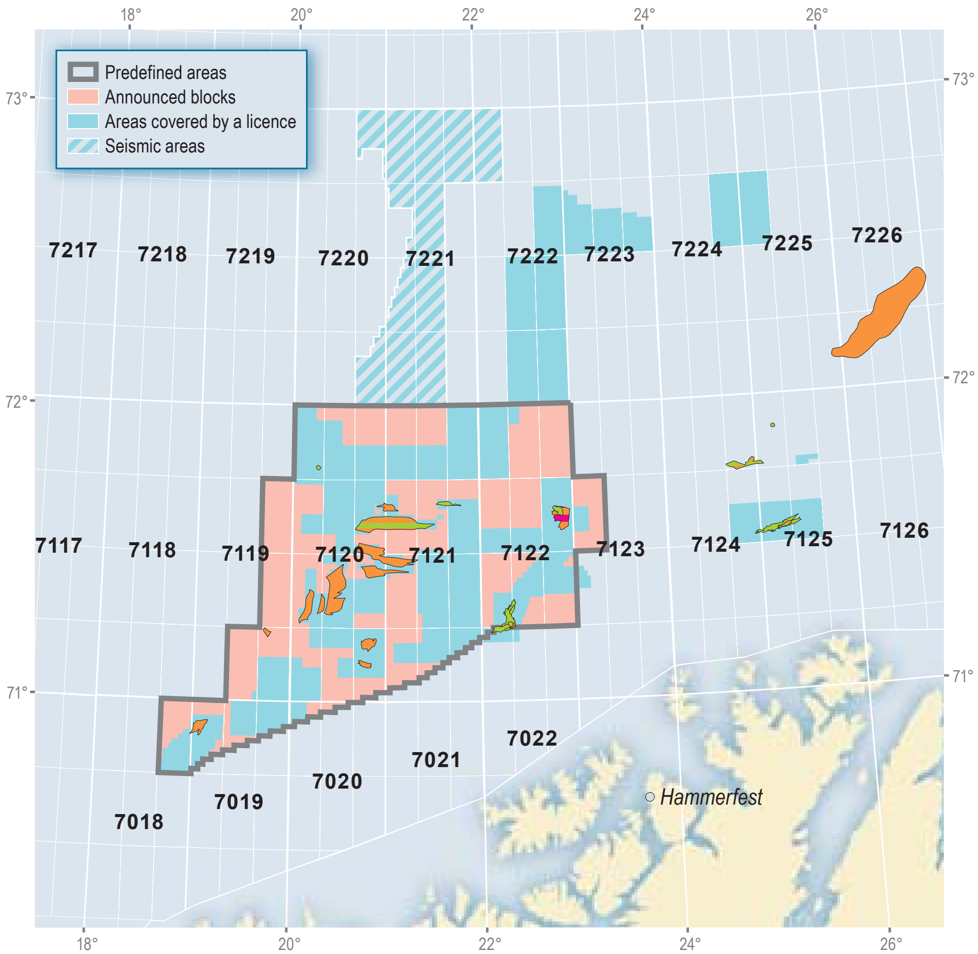


Figure 4.5 Awards in predefined areas – announcement Barents Sea 2009
(Source: Norwegian Petroleum Directorate)

The authorities have determined that industry access to larger parts of the mature areas is important so that time-critical resources can be produced. It is also important that the areas awarded to the industry are 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 (Storting White Paper No. 38 (2003-2004) On the petroleum activities. 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. Six such licensing rounds have been carried out in mature areas to date (APA 2003 - 2008). Figures 4.4 and 4.5 show the areas announced for award in APA 2009.

Active exploration within licensed areas is important to the authorities. The areas awarded are tailored so that the companies will only get acreage where they have specific plans.

The work commitment assumed when companies are awarded new production licences consists of a set of activities and decisions. At each

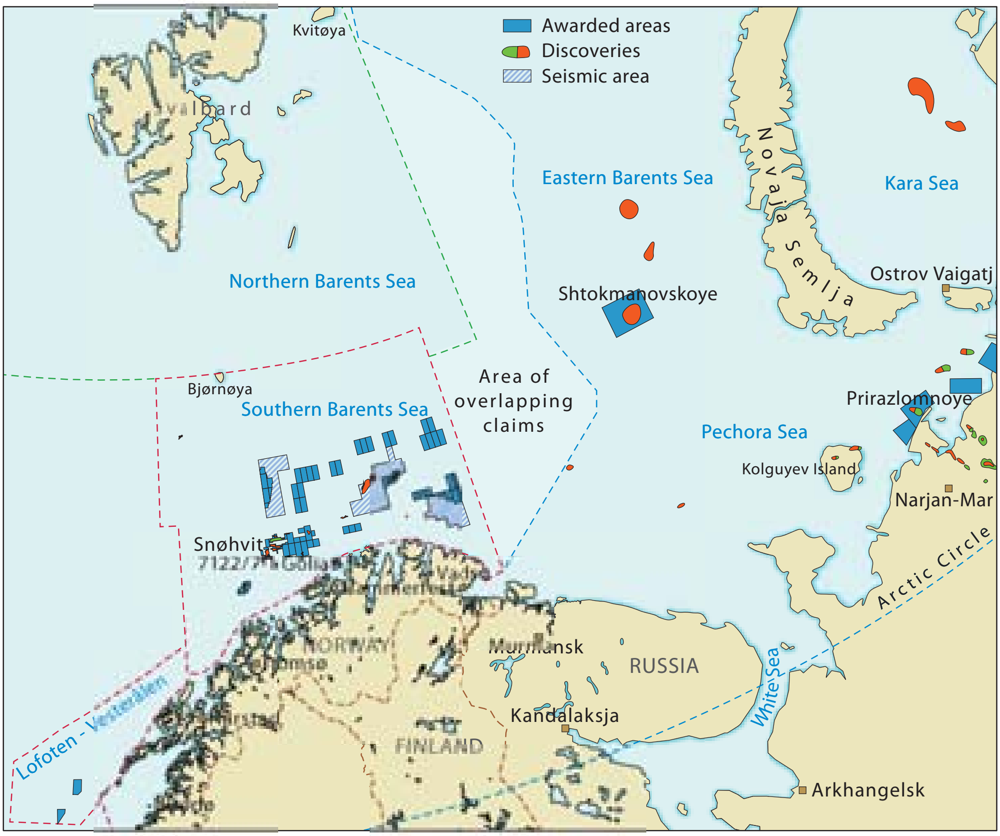


Figure 4.6 Norwegian and Russian sectors of the Barents Sea

(Source: Norwegian Petroleum Directorate)

juncture, the company must decide whether it wants to implement new activities in the licence or relinquish the entire area. New companies that may have a different view on the prospectivity can then apply for these relinquished areas. This leads to a more rapid circulation of acreage and more efficient exploration of the mature areas. Upon expiration of the initial period, companies could previously retain as much as 50 per cent of the awarded area without an obligation to carry out any specific activity. Today, the general rule is that companies can only retain areas in which they plan to start production.

The area fee is also a policy instrument intended to help increase activity in the awarded areas. The idea behind the area fee is that no area fee shall be paid for areas where production or active exploration activity is taking place. The licensees pay no area fee during the initial period, in which exploration activity proceeds according to a compulsory work program. After the initial period, the licensees shall pay an annual fee to the state for each square kilometre of the area that is covered under a production licence. As of 1 January 2007, the area fee rules were updated to reinforce the function of the fee in overall resource management. Under the new rules, the companies shall pay NOK 30 000 per square kilometre for the first year, with the rate increasing

Aker Exploration	Det Norske	GdF	Nexen	Petoro	Skeie Energy
Aker Maritime*	Discover	Genesis	Noble	Petro-Canada	Spring Energy
Altinex*	DNO	Hunt Oil	Noreco	Petrofac	Sumitomo
Anadarko	Dong	Idemitsu	North Energy	PGNiG	Talisman
BayernGas	E.ON Ruhrgas	Kerr McGee	OER*	Premier	VNG
BG Norge	Edison	Lasmo*	OMV	Repsol	Wintershall
Bridge Energy	Endeavour	Lotos	Oranje Nassau	Revus	4sea energy
Centrica	Ener*	Lundin	PA Resources	Rocksource	
CNR	Enterprise*	Marubeni	Paladin*	Sagex	
Concedo	Excel Expro	Mitsubishi	Pelican*	Serica	
Dana	Faroe	Mærsk	Perenco	Skagen 44	

* Not currently an independent company.

Figure 4.7 Prequalified/new companies since 2000 (as of 1Q 2009)

(Source: Ministry of Petroleum and Energy)

to NOK 60 000 for the second year. From and including the third year, the companies pay the maximum fee rate, which is NOK 120 000 per square kilometre. The companies can achieve an exemption from the area fee if they submit a Plan for Development and Operation, a so-called PDO, to the Ministry of Petroleum and Energy. However, area fee exemptions are granted only for the areas that comprise the geographic extent of the resources, and for which a PDO has been submitted. The regulations also provide for area fee exemptions for two years if the companies drill a wildcat well in addition to the original work commitment.

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 fundamental change in the rules for relinquishing area. The regulations that applied in mature areas were also applied to the immature areas. However, it is not expedient for all companies that receive production 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 delineation of resources proven through drilling. Furthermore, 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 had particular focus on areas in the Barents Sea and the western part of the Norwegian Sea. These awards represented an important step in the exploration of these areas. The 20th licensing round (currently in progress) was announced in the spring of 2008 with award of production licenses scheduled for the spring of 2009.

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. *Storting White Paper No. 8 (2005-2006) "Comprehensive management plan for the marine environment in the Barents Sea and the waters off Lofoten"* (Comprehensive Management Plan), was submitted to the Storting in the spring of 2006. The comprehensive management plan presents the framework for the petroleum activities in these areas and provides guidelines as to where petroleum activities are permitted. Several programs have been initiated to gather more knowledge about the ocean areas involved, before the scheduled revision of the plan in 2010. One of these is a three-year program for geological mapping and acquisition of seismic data in Nordland VII and Troms II, under the auspices of the Norwegian Petroleum Directorate. In 2007 and 2008, NOK 70 million and NOK 140 million respectively were allocated for this program, and in 2009 the budget is NOK 200 million.

The work on an integrated management plan for the Norwegian Sea commenced in the spring of 2007. The aim is, as for the above-mentioned plan, to establish framework conditions that balance the interests of the fisheries, the petroleum industry and the shipping industry, as well as protect the environment. The plan will consider the compound impact for the environment in these ocean areas and will set up the framework for regulating the different commercial interests in these areas. The integrated management plan for

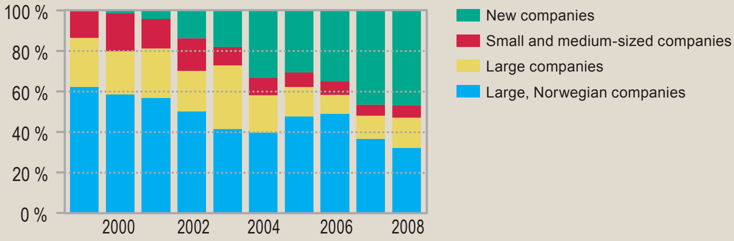


Figure 4.8 Exploration costs in production licences in the North Sea by company size
(Source: Norwegian Petroleum Directorate)

the Norwegian Sea is scheduled to be forwarded in the spring of 2009.

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 Nordland and Skagerrak.

The Storting must decide to open these areas for petroleum activities before they can be announced in a licensing round. Such a 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.

Area with overlapping claims

The border between Norway and Russia remains unclear and is currently being negotiated by Russian and Norwegian authorities. This area, approximately equivalent to the Norwegian part of the North Sea, is marked on Figure 4.6.

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.

Prequalification

In order to facilitate the entry of new players, Storting White Paper No. 39 (1999–2000) *On the oil and gas activities* introduced a system for prequalification of new operators and licensees. From the scheme's inception to January 2009, 55 new companies (at the time of writing) 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 4.7 shows prequalified and new companies since 2000.

Significant acreage and production licences have been awarded to these new players in the licensing rounds in mature areas. Over the past two years, new players have accounted for more than 40 per cent of the exploration costs in the North Sea. (See Figure 4.8).

So far most of the new companies have focussed on the mature areas in the North Sea and the Norwegian Sea. The last few rounds have, however, shown increased interest on the part of the new entrants also in the Barents Sea. It is expected that more companies will take part in the licensing rounds in frontier areas as they expand their knowledge of the shelf and establish larger organisations in Norway.

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 website: www.npd.no.

5 Development and operations

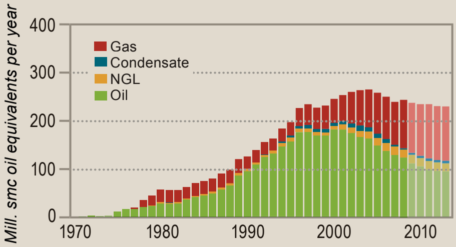


Figure 5.1 Historical production of oil and gas and production forecast for the next few years

(Source: Norwegian Petroleum Directorate)

In 2008, Norwegian oil and gas production totalled 242.1 million scm. Of this, natural gas production accounted for about 99 billion scm, an increase of nearly 10 billion scm compared to the record-breaking year 2007. While gas production grew last year, oil production fell. Gas sales are expected to reach more than 100 billion scm in 2009, with additional increases expected in the years to come. The natural gas share of total petroleum sales is expected to increase from 40 per cent in 2008 to 48 per cent in 2012. Figure 5.1 shows historical production of oil and gas, and expected production for the next few years.

High oil prices in 2008 led to a substantial increase in both cost and activity levels on the Norwegian shelf. There is considerable uncertainty as to how the dramatic drop in oil prices and the general economic situation will impact these activities in the time ahead. The volume of activity in the next few years is largely governed by decisions made a few years back. In 2008, the authorities approved the Plans for Development and Operation (PDO) of Yttergryta and Morvin in the Norwegian Sea. Several other new development plans may be submitted to the authorities for approval in 2009. Development of the Goliat and Gudrun discoveries may receive authority approval during 2009.

Historic development

Production on the Norwegian continental shelf has been dominated by a few large fields. 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 petroleum activities. The large fields have contributed to the establishment of infrastructure that subsequent fields have been able to tie into. Production from several of these fields is declining, 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. As the Norwegian petroleum industry has moved northwards, it has entered areas containing enormous gas resources. Consequently, a number of gas fields have been developed and a comprehensive gas transport infrastructure has been established, making it possible to develop additional gas resources. Development of the gas fields, combined with falling production from major oil fields, means that gas is becoming an ever more important component of Norway's petroleum production.

Effective production of petroleum resources

To protect society's interests in the 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 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 the petroleum industry framework conditions, companies are obliged to carry out prudent development and operation 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

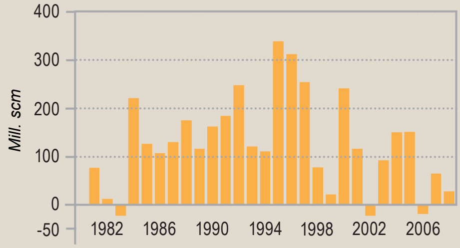


Figure 5.2 Gross reserve growth, oil 1981-2008

(Source: Norwegian Petroleum Directorate)

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 impact assessment which interested parties are invited to comment upon in a consultation process. The impact assessment describes the development's expected impact on the environment, fisheries and society in general. The authorities' 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. The Ministry has prepared new guidelines for plans for development and operation and plans for installation and operation. The main purpose of these updated guidelines is to clarify the regulations and the authorities' expectations for developments on the Norwegian shelf.

Development of proven petroleum resources is the basis for production and value creation from the petroleum industry today, but the importance of exploiting the resources in the known areas is increasing. This constitutes an enormous potential that can generate significant value for society if 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 of oil before 2015. This is equivalent to twice the original oil resources in the Gullfaks field. 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 5.2 shows annual growth of oil reserves in the period 1981–2008. The

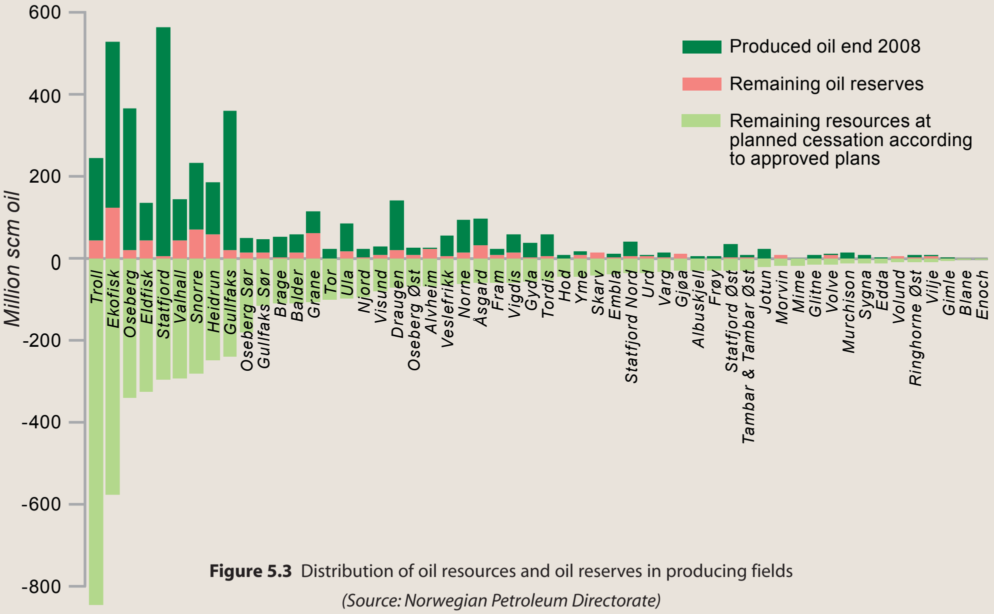


Figure 5.3 Distribution of oil resources and oil reserves in producing fields

(Source: Norwegian Petroleum Directorate)

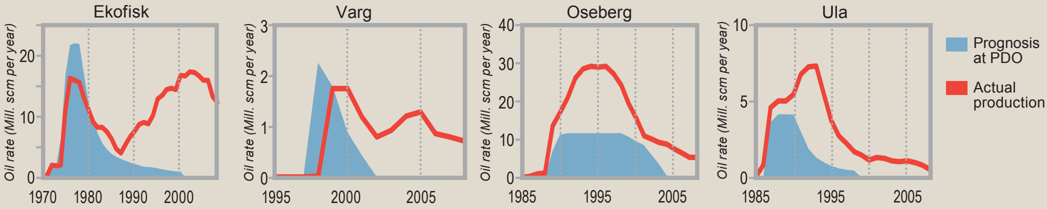


Figure 5.4 Production trends for Ekofisk, Varg, Oseberg and Ula
(Source: Norwegian Petroleum Directorate)

accounts for 2008 show a growth of 29 million scm of oil, included as new reserves. The 2007 accounts included a growth of 65 million scm of oil. The largest contribution to oil reserves in 2008 came from the Morvin, Ula and Oseberg fields.

Increased recovery in mature areas

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 5.3 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 main categories, where one covers measures to increase recovery and the other how to improve recovery through efficient operations.

Increased recovery

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 process facilities. Such measures contribute to increasing the average recovery rate. In 1995, the average recovery rate for oil in producing fields was approximately 40 per cent - today it is 46 per cent. 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 5.4 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 how considerable value can be created through increased recovery.

Extended lifetime

Figure 5.4 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 this infrastructure.

Figure 5.5 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, more efficient operation and 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

The most important parameter for extending the lifetime of a field is economically profitable production. Efficient operations help reduce production costs. Therefore, efficient operations will affect resource recovery as 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. The introduction of integrated operations (IO) in the petroleum activity, 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. The goal is reduced costs and more effective operations. In an international context, today's Norwegian petroleum industry has achieved great advances in the implementation of integrated operations. One of the reasons for this is that broadband (fibre-optic cable) has already been laid for transmission of large volumes of data to many of the fields. Integrated operations have already become an important element in many new developments and status reports from the operators indicate a committed effort towards integrated operations on many mature fields. Wherever profitable, existing fields will be linked to the digital infrastructure for implementation of the new technology.

New discoveries – effective use of infrastructure

In 2008, about NOK 130 billion was invested on the Norwegian continental shelf. Total investments on the Norwegian continental shelf have now reached

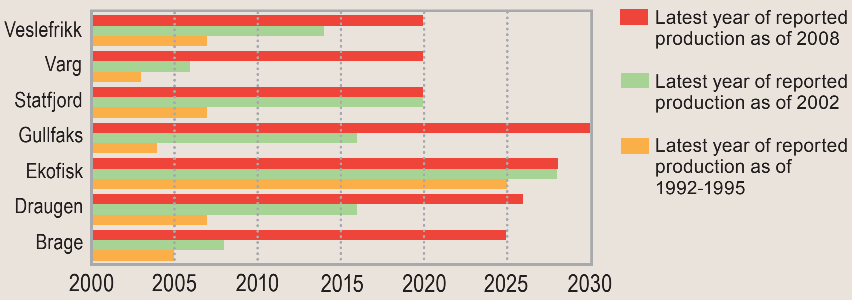


Figure 5.5 Lifetime for some fields
(Source: Norwegian Petroleum Directorate)

about NOK 2100 billion in current monetary value. These investments have made it possible to establish extensive infrastructure which is a precondition for producing and marketing 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 activities on the Norwegian continental shelf have entered a more mature phase. 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 in 2005, *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.

Future trends

In order to ensure that the potential of producing fields and their surroundings 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 of transfers of participating interests. In addition, the authorities have facilitated a broader range of players; reference is made to the discussion of new players in Chapter 4. The Norwegian authorities believe that a diversity of players, making different assessments and setting different priorities, constitutes a positive contribution towards realising the resource potential on the Norwegian continental shelf.

Increased recovery, extended 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.

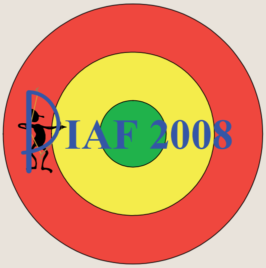
However, increased recovery and longer lifetime are only relevant if this can be accomplished within prudent frameworks for the external environment, health, working environment and safety. In order to develop the resources in and around existing fields, the infrastructure already in place must often 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.

PIAF

In 2005, the Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate started work to develop a new method to follow up the fields in production on the Norwegian continental shelf. The method was first implemented in 2006 and was called PIAF (performance indicator analysis for fields). PIAF will be carried out every year.

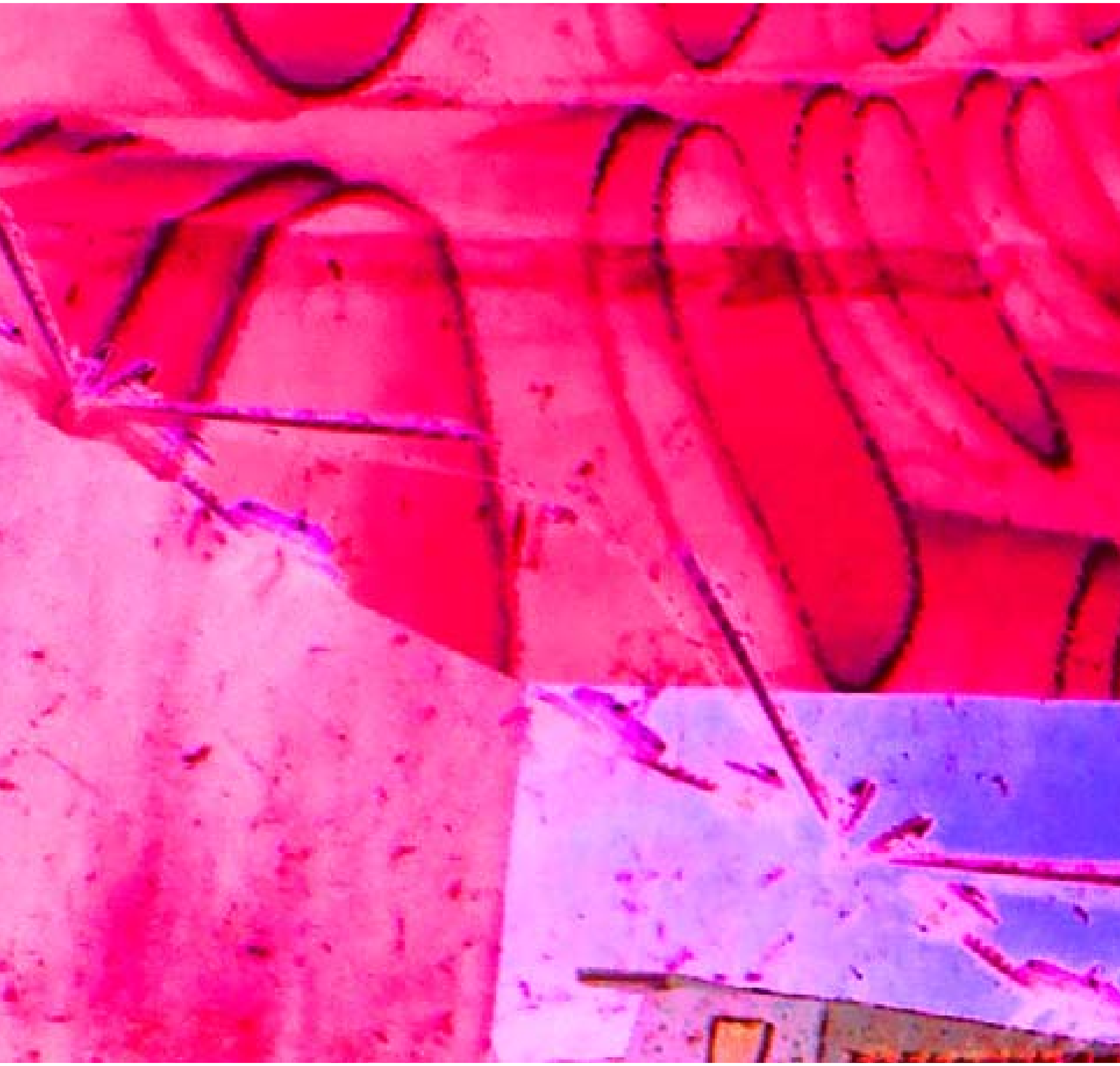
The background for this initiative was that the government wanted a more systematic and closer follow up of how the operators and the licensees work to develop the resources in and around fields in production, including increased recovery, phasing in additional resources and increasing the efficiency of operations. The operators in each of the fields work continuously on many different projects for operation and further development of the fields.



The objective of PIAF is to ensure that the authorities have a better and more systematic overview of the development of resource growth, recovery, operating costs and investments. Problems that obstruct the fields' development and possible improvement areas can be identified through PIAF. PIAF also makes it possible to distinguish between the problems concerning the entire continental shelf and the ones concerning specific fields.

Figure 5.6 Fibre-optic cable network on the Norwegian continental shelf
(Source: Norwegian Petroleum Directorate)

6 Norwegian gas exports



Gas activities comprise an increasing part of the petroleum sector, and thus generate considerable revenues for the state. Norwegian gas is also important for the energy supply in Europe, and is exported to all of the major consumer countries in Western Europe. In terms of energy content, gas exports in 2008 were about eight times larger than the average Norwegian production of electricity. Norwegian gas exports supply approximately 16 per cent of the European gas consumption.[1] Most Norwegian exports go to Germany, the UK, Belgium and France, where Norwegian gas accounts for 25 to 35 per cent of the total consumption. 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 and Denmark. With the Snøhvit field, Norway also supplies LNG (Liquefied Natural Gas) to the USA, Japan and other customers.

Current capacity in the Norwegian pipeline system is about 120 billion scm per year. There are four receiving terminals for Norwegian gas on the Continent: two in Germany, one in Belgium and one in France. There are also two terminals in the UK (see map). The Norwegian gas transport system consists of a network of more than 7800 km of pipelines. Treaties have been developed to govern rights and obligations between Norway and the countries that have landing sites for gas.

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, and achieving the optimum balance between oil and gas production is vital. The gas management system must facilitate efficiency in all stages of the gas chain – exploration, development and transport.

1 *OECD Europe.*

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

One special feature of gas production is that it requires major investments 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 investments in the transport system. In many cases, it may be appropriate to build the pipelines somewhat larger than initially needed, so that potential 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 4 and 5). Many fields on the Norwegian continental shelf contain both gas and oil. When awarding gas production permits, the authorities take into account the prospects for optimum recovery of oil. On occasion, the authorities have awarded production permits 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 efficient system development. At the same time, it is important to ensure efficient operation, including

Figure 6.1 Gas pipelines

(Source: Norwegian Petroleum Directorate)

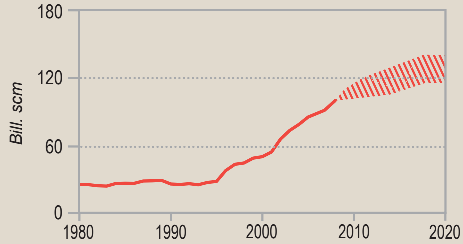


Figure 6.2 Historical and expected Norwegian gas sales. Sales of gas are expected to reach a level of 115-140 billion scm during the next decade *(Source: Norwegian Petroleum Directorate / Ministry of Petroleum and Energy)*

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. The Ministry considers the use of these instruments in connection with development of new infrastructure and when the use of the existing infrastructure is changed. Operatorship, ownership and issues regarding 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 comprehensive further development of the Norwegian gas infrastructure. In cases where major developments is considered, this means that all other Norwegian gas, not just the resources in fields that trigger a need for gas transport, must also be included in such evaluations. Further development of the gas infrastructure must 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 equal treatment of all users of the system, both as regards utilisation of the system and 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 avoiding conflicts of interest about which pipeline should be used to transport the gas.

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 transport 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*	38.46 %
StatoilHydro ASA	20.47 %
StatoilHydro Petroleum AS	11.63 %
Total E&P Norge AS	7.78 %
Exxon Mobil Exploration and Production Norway AS	5.29 %
Mobil Development Norway AS	4.14 %
Norske Shell Pipelines AS	3.97 %
Norsea Gas AS	2.73 %
ConocoPhillips Skandinavia AS	2.00 %
Eni Norge AS	1.53 %
A/S Norske Shell	1.35 %
DONG E&P Norge AS	0.66 %

* 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 8 per cent with effect from 1 January 2011, and the other licensees' shares will be adjusted correspondingly on the same date. The SDFI share in Norsea Gas AS is 40.0 per cent. When this is taken into account, the state, represented by SDFI, will have a share in Gassled of 39.4 per cent in 2003-2010 and 47.5 per cent from 2011. The licence period for most of the 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.

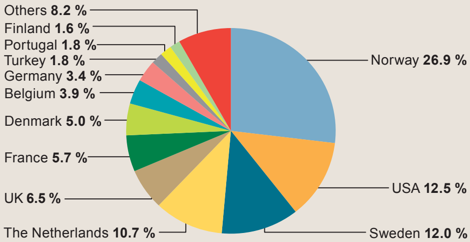


Figure 6.3 Sales of NGL/condensate 2008, distributed by first receiving country, total 19.5 million scm oe. *(Source: Norwegian Petroleum Directorate)*

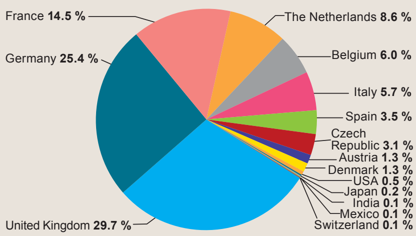


Figure 6.4 Norwegian natural gas exports 2008, total 96.1 billion scm, distributed by receiving country *(Source: Norwegian Petroleum Directorate)*

7 Decommissioning

Figure 7.1 The DP2 drilling and production facility removed from the Frigg field in 2008
(Source: Total E&P Norge AS)

Petroleum activities only borrow the sea, and all phases of the 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 ten 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 facilities on the Frigg field and parts of Ekofisk commenced in 2005. The decommissioning plan for MCP-01 is currently being considered by the Ministry. The DP2 drilling and production facility on the Frigg field was removed in July 2008 (see Figure 7.1).

The regulations

Both national and international regulations apply when the government reaches a decision regarding disposal of an installation on the Norwegian continental shelf. Disposal or decommissioning of facilities is regulated by the Petroleum Act of 1996. 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 from the OSPAR decision concerning disposal on land. As mentioned, permission has been granted to leave in place the concrete substructure of the Ekofisk Tank and its protective wall, as well as the concrete substructure TCP2 at the Frigg field.

The guidelines laid down in Storting White Paper No. 47 (1999–2000) *"Decommissioning of redundant pipelines and cables"* 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

As a main rule, the Petroleum Act 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.

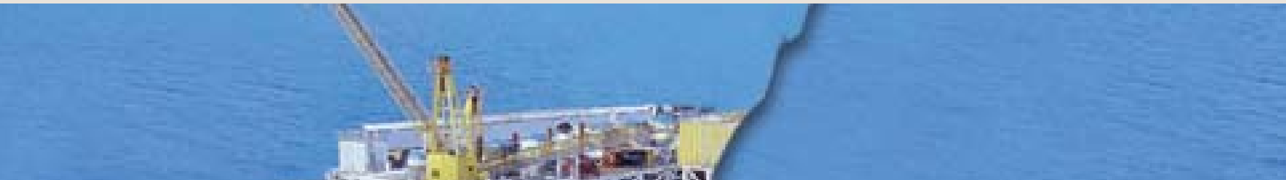
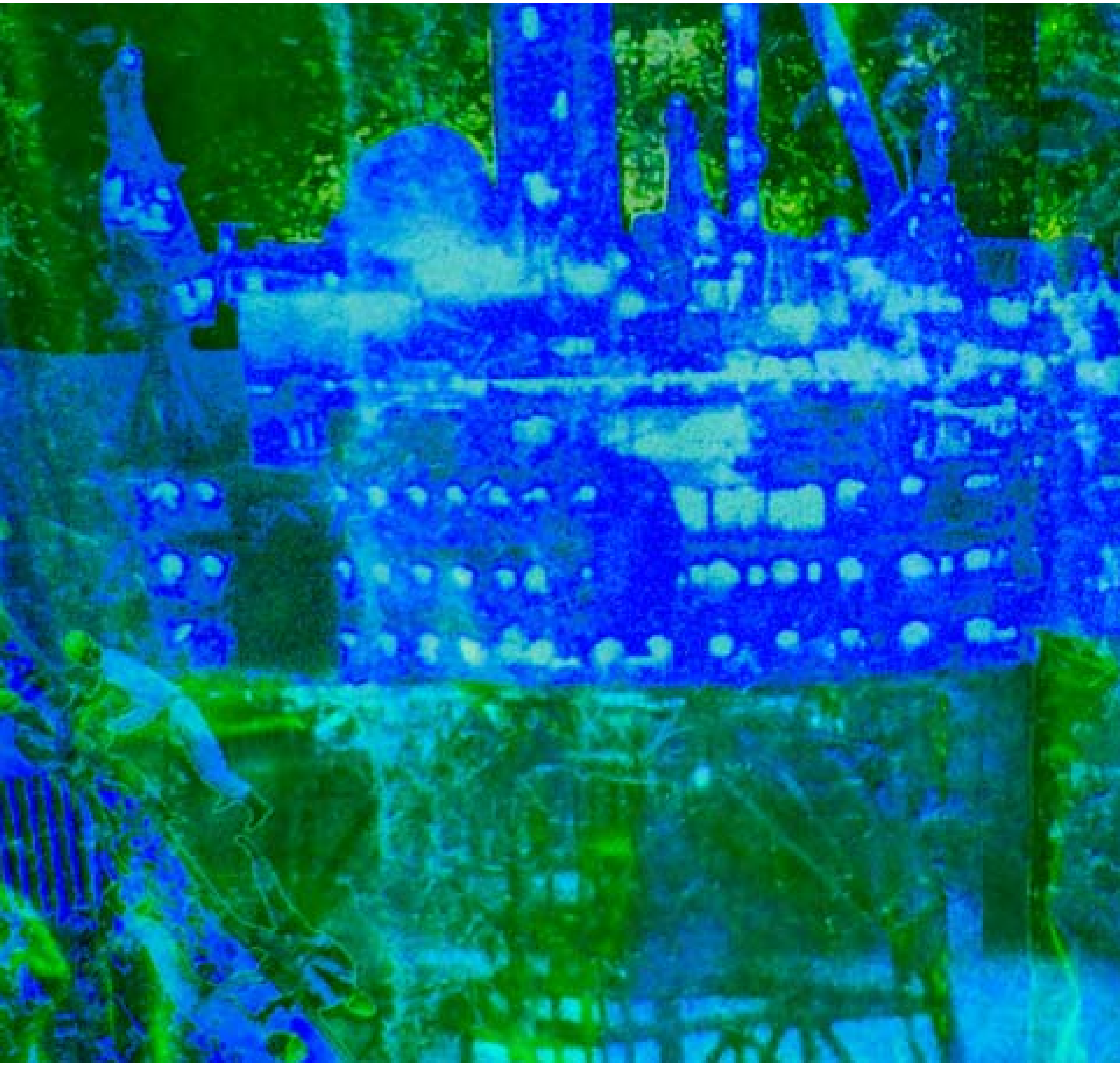


Figure 7.2 Illustration of the Ekofisk Tank, before and after removal of the superstructure
(Source: ConocoPhillips)

8 Research, technology and industrial development



Norwegian petroleum industry

Building up Norwegian and Norwegian-based petroleum expertise has been an important element in Norwegian petroleum policy. In the beginning, much of this knowledge was obtained from foreign oil companies and supplier firms. Today, however, Norway has a highly developed and internationally competitive petroleum industry. This applies both to oil companies, the supplier industry and research institutions. The sector also provides valuable input to innovation and technological development in other sectors of Norwegian business and industry.

Supplier firms in Norway are represented in most steps of the value chain, from exploration and development to production and disposal. Norwegian suppliers are among the best in the world in fields such as seismic surveys, drilling equipment, subsea facilities and floating production solutions. These supplier firms are located in every county in Norway and the local and regional ripple effects of the petroleum activities are evident even in parts of the country that would not normally be expected to have a link to this industry. A study[1] conducted by Menon Business Economics shows that the industry generates more than just tax revenues for the state. It creates jobs and stimulates local and regional business development. Increased internationalisation manifests itself as more local employment and value creation. Approximately 100,000 people are employed in the supplier industry in Norway.

Investments by oil companies in development, operation and maintenance on the Norwegian

1 *KonKraft Report 4 Internationalisation*

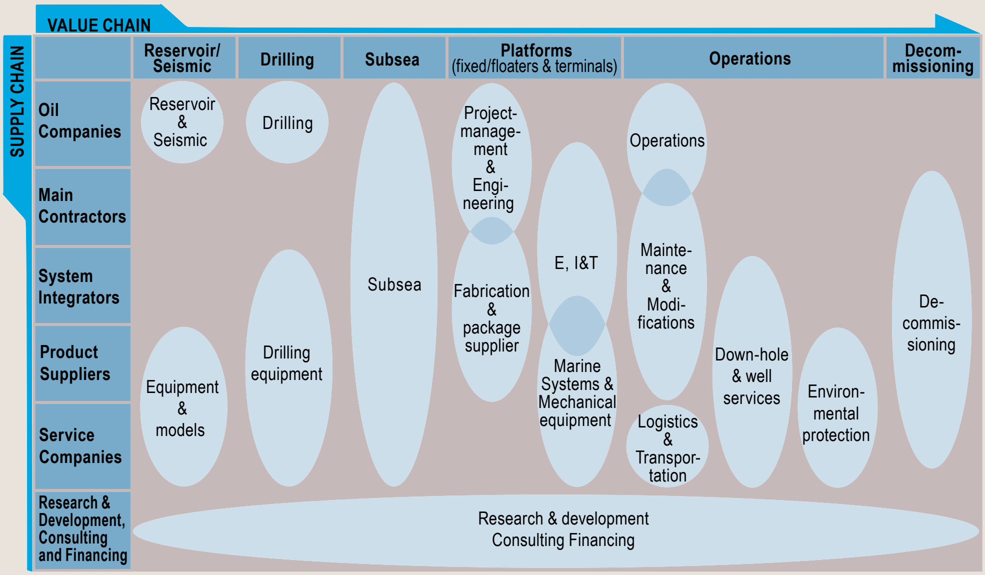


Figure 8.1 Interactive map of Norwegian oil and gas clusters

(Source: www.Intsok.com)

continental shelf generate a considerable demand for products and services from the supplier industry in Norway and abroad. In order to stimulate the continuation of this growth, the supplier firms must ensure that they continue their expansion into the international arena. International experience and participation in international development projects are extremely important for the further development of the supplier industry. This international experience could also help reduce the cost level on the Norwegian continental shelf.

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 180 companies are members of the foundation. Figures from Menon Business Economics assume that, in 2007, Norwegian petroleum-related companies had international sales of NOK 95 billion; six times as much as in 1995. The goal is to increase annual sales abroad to about NOK 120 billion in 2012.

Petrad

As part of its international activities, the Ministry of Petroleum and Energy also supports the Petrad foundation. Petrad is a Norwegian assistance agency which offers various types of knowledge transfer programs to the management of national oil companies and petroleum authorities in developing countries.

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 when it comes to petroleum administration and good management. This program includes:

- reinforcing Norwegian bilateral assistance to countries requesting Norwegian petroleum expertise
- emphasis on sound governance and insight in petroleum management

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

EITI

The Extractive Industries Transparency Initiative is an international initiative whose purpose is to strengthen good governance in resource-rich countries through the publication of revenues from oil, gas and mining companies to the state. Publication of revenue streams may contribute to greater accountability on the part of the authorities to the populace. Norway has supported the initiative since 2003.

An overriding principle in the Norwegian authorities' petroleum management, as in all parts of the administration, is that it should meet the highest standards with regard to accountability. It is an important principle in Norwegian petroleum management that there should be transparency regarding tax payments to the state, and tax figures are available to the public. The revenue streams are independently audited through the work of the Office of the Auditor General in Norway.

Norway is well-positioned to demonstrate international leadership regarding the issue of transparency of revenue streams from the petroleum industry, and this is also reinforced in the Oil for Development program. Both EITI and the Norwegian system are set up to secure transparency around payments. While EITI is intended for less mature and transparent systems than we have here, Norway nonetheless decided in the fall of 2007 to implement the EITI in Norway. This means that, even though the revenue streams are already transparent, we have undertaken the responsibility to go through a process stipulated by the EITI principles. The purpose is to make information about the revenue streams from this sector more readily available. While Norway already meets the intentions of the EITI, the purpose of Norway's undertaking to implement the EITI is to further the initiative internationally. In the winter of 2008/2009, a group was established to take responsibility for the implementation in Norway. This group included representatives from the civilian population, the industry and the authorities. Norway also applied for status as an EITI candidate.

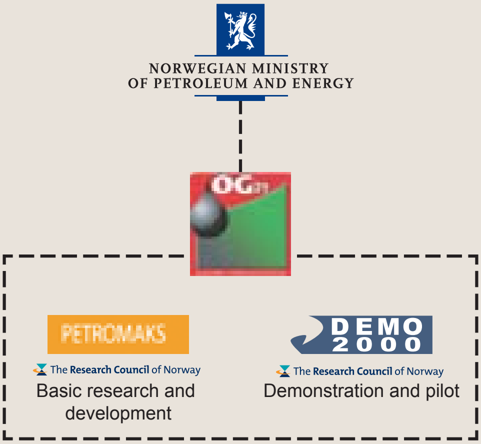


Figure 8.2 The Ministry of Petroleum and Energy's involvement in petroleum research *(Source: Ministry of Petroleum and Energy)*

The member companies in OLF, the Norwegian Oil Industry Association, share the government's ambition of greater revenue transparency in the extractive industries. On behalf of its members, the association has accepted that tax payments to the Norwegian state from oil companies present on the Norwegian continental shelf may be made public.

Norway also hosts the International Secretariat of the EITI. More information on the EITI may be found at www.eitransparency.org.

Research and technological development in the oil and gas sector

Development of new technology and increased competence 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 8.2 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. OG21 is organised in a board, whose composition is determined by the Ministry of Petroleum and Energy, and a secretariat.

OG21 has managed to encourage 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 Association's evaluation of Norwegian energy policy in 2005, the OG21 collaboration was recognised as being unique in a global perspective.

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 maintains that such a public research effort would be required to sufficiently meet 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 identified in the OG21 strategy. The funds from the authorities are channelled through the Research Council of Norway, which coordinates the programs.

The OG21 strategy was revised in 2005 to better adjust to today's challenges. The revised strategy has identified eight core technology areas which will be vital for the future development of the Norwegian petroleum activity:

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

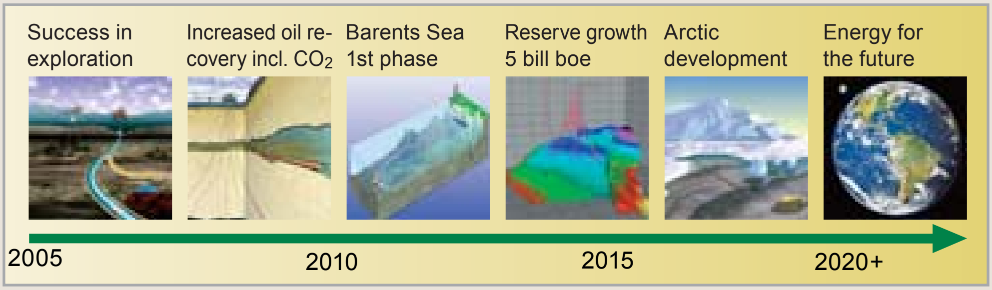


Figure 8.3 OG21's technology roadmap for value creation on the Norwegian continental shelf
(Source: OG21)

The new OG21 board was appointed in October 2007 and is chaired by StatoilHydro.

PETROMAKS

PETROMAKS (maximum exploitation of the petroleum reserves) is a petroleum research program covering strategic fundamental research and development of expertise, user-related research and technology.. The program's target groups are Norwegian companies and research communities that wish to promote the build-up of knowledge and expertise in Norway. The national technology strategy, OG21, serves to guide PETROMAKS' priorities.

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 issues and the external environment, reducing the cost level on the Norwegian continental shelf and strengthening petroleum-related industrial development, in Norway and internationally. Another important objective of PETROMAKS is to contribute to an increased level of competence in the petroleum sector as well as to improve recruitment to the industry.

The Research Council does not have dedicated programs for the northern areas. Instead, northern area research is integrated throughout all of the Research Council's activities, including the PETROMAKS program. In this context, PETROMAKS finances research on special arctic-related issues such as extreme climate, less developed infrastructure, development and production in ice-affected areas, handling of ice and transport over very long distances.

DEMO 2000

An important initiative in the promotion of new technological solutions within the petroleum industry is the DEMO 2000 program. New technology is often associated with high costs and high risk, and it can be particularly challenging to get solutions out onto the market. The objective of DEMO 2000 is to contribute to reduced costs and risk for the industry and commercialisation of new technology by supporting pilot and demonstration projects. The program is based on the national technology strategy, OG21.

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.

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 there is a great potential within technical disciplines such as seabed processing, gas compression on the seabed, efficient drilling and integrated operations (remote control). Innovations within these areas carry a substantial potential for increased value creation. The DEMO 2000 program, like PETROMAKS, emphasises developing and testing petroleum technology with particular relevance for arctic conditions.

PETROSAM

PETROSAM is a social-scientific petroleum research program. The aim of the program is to provide insight and competence regarding social conditions relevant to strategic and policy-making decisions of the government and the petroleum sector. PETROSAM will also focus on international relations, in particular the Middle East and Russia. PETROSAM was established in 2006 and will continue until 2012.

PROOF

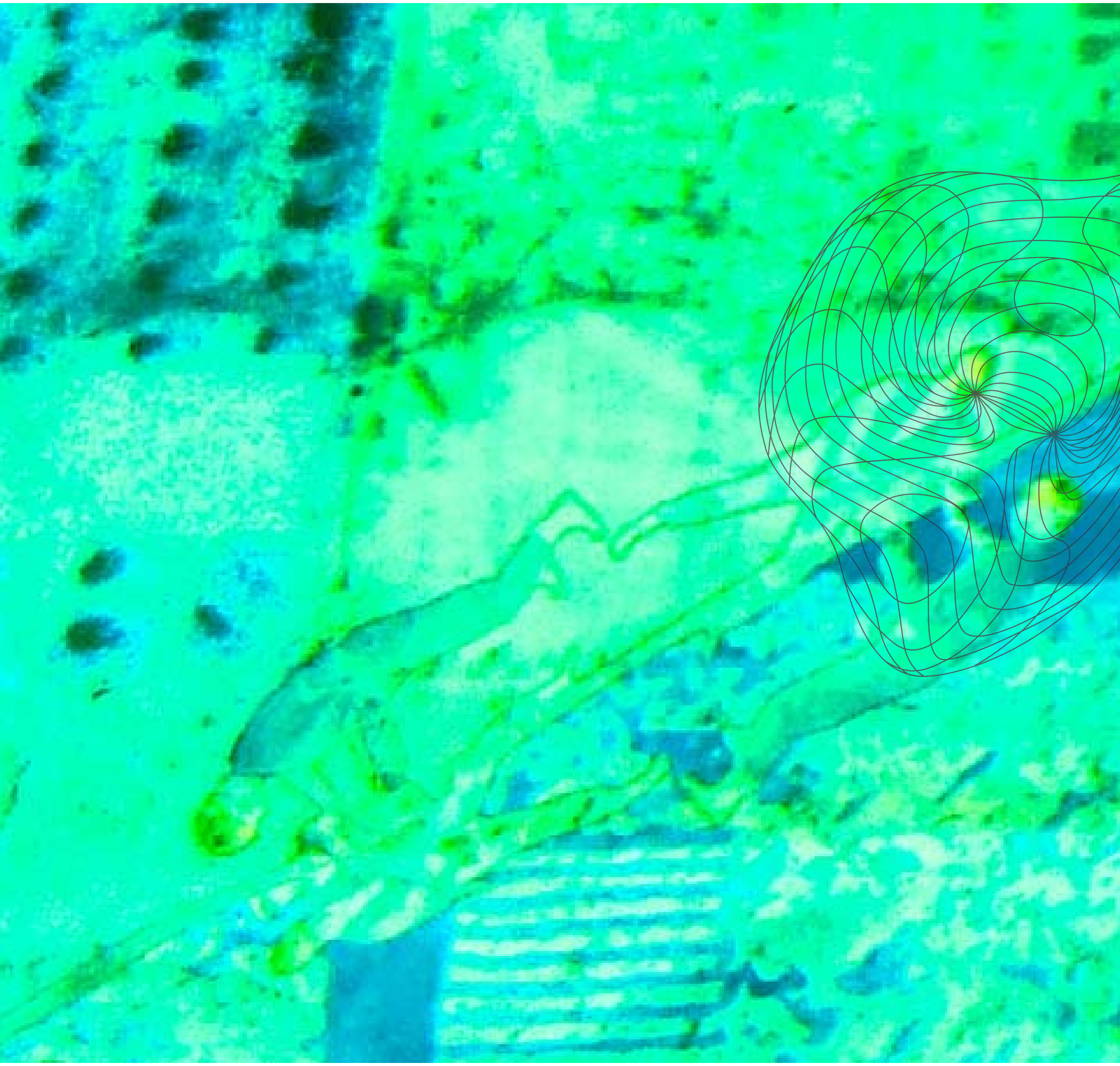
The research program PROOF examines long-term effects of discharges to sea from petroleum activities, and constitutes a part of the larger program, “The Sea and the Coast”, which is planned for the period 2006–2015.

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 environmentally friendly power generation. The program is financed partly by the Gas Technology Fund’s returns, which are managed by Gassnova, and partly by funds channelled through the Research Council.

CLIMIT’s objective is to contribute to profitable power generation with CO_2 capture. The program will cover financial support to the entire development chain, from long-term research for competence building to projects demonstrating CO_2 capture technologies. The project portfolio will mainly focus on technology solutions for cost-effective CO_2 capture. In addition, CLIMIT will prioritise development of knowledge and solutions for safe and reliable capture of CO_2 in geological formations.

9 Environmental considerations in the Norwegian petroleum sector



Introduction

Consideration for the environment has always been 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 natural environment in all phases of the activities, from licensing rounds to exploration, development, operations and decommissioning.

Norway was quick to take the climate issue seriously, and in 1991 it was one of the first countries to introduce a substantial CO_2 tax. This tax has led to development of technology and triggered initiatives that led to considerable emission reductions. The strict regulation of flaring through the Petroleum Act contributes to a low general level of flaring on the Norwegian continental shelf, compared with other countries. The authorities and the petroleum industry have worked together closely to reach the objective of zero environmentally hazardous discharges to sea from the petroleum activities (zero discharge target). As a result, the zero discharge targets are considered to be achieved as regards discharges of chemical additives. As a result of the continuous strong emphasis on the environment, the Norwegian petroleum sector maintains very high environmental standards compared with petroleum sectors in other countries.

This chapter provides an overview of emissions and discharges from the petroleum activities, as well as policy instruments and measures designed to ensure consideration for the environment.

Acts and legislation that regulate emissions and discharges from the petroleum sector

Emissions and discharges from petroleum activities in Norway are largely regulated by the Petroleum Act, the CO_2 Tax Act, the Special Tax Act, the Greenhouse Gas Emission Trading 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 evaluating consequences and approving new development plans (PDOs/PIOs) are key elements of the petroleum legislation. Facilities located on land or at sea within the baseline are also subject to the scope and extent of the Planning and Building Act (see Chapter 6).

In addition to the aforementioned statutes, the petroleum sector has committed to reducing emissions and discharges under various agreements. In accordance with international agreements, Norway has pledged to limit its discharges of various components. How this affects the petroleum sector depends on the wording of the respective agreements, and how the requirements and policy instruments are allocated to the various sectors in Norway.

Various types of emissions and discharges from the petroleum activities

The different phases of the petroleum activities lead to different types of discharges and emissions. With exploration activity come discharges of drill cuttings and emission from generating energy. The operations phase brings discharges to sea, primarily in the form of water containing residues of oil and chemicals (produced water); and emissions to air in the form of carbon dioxide (CO_2) and nitrogen oxides (NO_x) from generating energy and flaring, as well as non-methane volatile organic compounds (nmVOC) from storage and loading of crude oil. Both exploration activity and production entail the risk of acute spills.

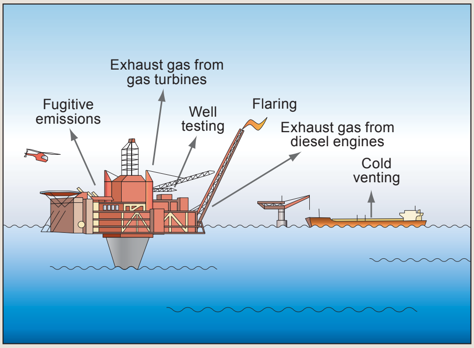
Emissions to air

The agreements regarding emissions to air usually specify emission limits for each country. The wording of the agreement determines whether the imposed limits must be implemented completely within the borders of each country, or whether reductions can also be implemented in other countries where the costs of such reductions may be lower. The costs associated with reducing emissions from the various sources, both national and international, have an impact on the types of measures implemented vis-à-vis the petroleum sector.

After the Kyoto Protocol, Norway has an emissions target which entails that the country's average greenhouse gas emissions for the years 2008–2012 shall not increase more than one per cent compared with the emission level in 1990. Compared with today's level, this would mean a reduction of greenhouse gas emissions by about 7 per cent. The requirement will be met by reducing emissions both nationally and in other countries using the Kyoto mechanisms "Clean Development Mechanism (CDM)" and "Joint Implementation (JI)".

The Climate White Paper presented in June 2007, entails that Norway should exceed the Kyoto target by 10 percentage points. The climate compromise of January 2008 suggested that Norway would become carbon-neutral in 2030. In addition, a reduction of Norwegian greenhouse gas emissions of 15–17 million tonnes of CO_2-equivalents by 2020 has been assumed, including forestry. This means that about 2/3 of our total emission reductions must come from national sources.

With the Greenhouse Gas Emission Trading Act, Norway established a national quota system for greenhouse gases starting in 2005 as a follow-up of the Kyoto Protocol. The Greenhouse Gas Emission Trading Act was revised in 2007 and in February 2009. Norway implemented the EU's



Overview of emission/discharge sources

directive on emission trading in the fall of 2007, and the Norwegian quota system is linked to the EU's quota system for the period 2008–2012. In December 2008, the EU agreed on an emissions trading directive for the period 2013–2020. This directive is now being considered by the EEA//EFTA countries.

Emissions that have regional environmental consequences are regulated in the protocols under the Convention on Long-Range Transboundary Air Pollution (the LRTAP Convention). Together with the USA, Canada and other European countries, Norway signed the Gothenburg Protocol in 1999. This protocol seeks to solve the environmental issues of acidification, over-fertilization and ground-level ozone. The Gothenburg Protocol took effect on 17 May 2005. Under this Protocol, Norway is to reduce NO_x emissions to 156,000 tonnes by 2010. This means a 27 per cent reduction compared with the 1990 emission levels. As regards nmVOC, the new commitment is approximately the same as Norway assumed under the prevailing Geneva Protocol, which requires annual nmVOC emissions from the entire mainland and the Norwegian economic zone south of the 62nd parallel to be reduced as soon as possible by 30 per cent compared with the 1989 level. Under the Gothenburg Protocol,

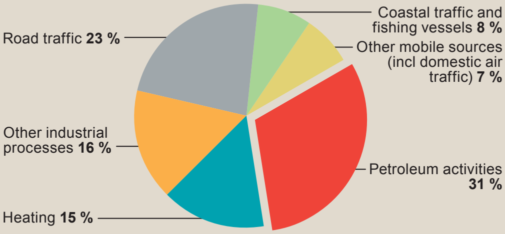


Figure 9.1 Sources of Norwegian CO_2 emissions, 2007
(Source: Statistics Norway)

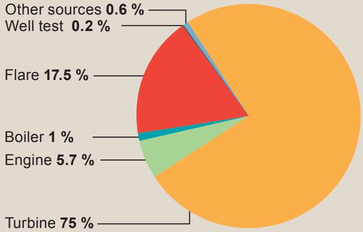


Figure 9.2 CO_2 emissions from the petroleum activities, 2007, by source
(Source: Norwegian Petroleum Directorate)

total national emissions shall not exceed 195,000 tonnes per year by 2010.

Discharges to sea

Discharges to sea mainly include produced water, drill cuttings and residues of chemicals and cement from drilling operations.

Discharges of oil and chemicals can have local effects in the area near the facilities, and such discharges are regulated at the national level through discharge permits based on the Pollution Act. These discharges are also subject to international regulation through the Oslo-Paris Convention on discharges to sea (the OSPAR Convention). For discharges to sea, the stipulated international maximum level for oil content in water was reduced to 30 mg per litre starting from 2007. Use and discharge of chemicals are regulated at the international level in the form of risk assessment requirements and categorisation according to the properties of the chemicals.

The objective of zero hazardous discharges to sea from the petroleum activities was confirmed in Storting White Paper No. 58 (1996–1997) *Environmental protection policy for sustainable development*. This objective has also been raised in several subsequent white papers, including in Storting White Paper No. 12 (2001–2002) Clean and rich seas, Storting White Paper No. 25 (2002–2003) *The Government's environmental protection policy and the state of the environment in Norway* and Storting White Paper No. 26 (2006-2007) *The Government's environmental protection policy and the state of the environment in Norway.*

The zero discharge target is a precautionary target intended to contribute to ensuring that discharges to sea of oil and environmentally hazardous substances do not lead to unacceptable damage to human health or the external environment. The main rule is that no environmentally hazardous substances may be discharged, neither chemical additives nor chemical substances that naturally occur in the environment. After the objective of zero discharges to sea was confirmed, the authorities and the industry have worked together to find solutions aimed at achieving this goal.

The oil industry has invested billions in reducing discharges to sea, and the implemented measures have significantly reduced these discharges. Discharges of environmentally hazardous substances on the priority list from produced water and drill cuttings account for less than 3 per cent of the national discharges of the specific substances. Discharges of environmentally hazardous chemical additives (red and black categories) have been reduced by more than 99 per cent during the period 1997 to 2007, and the zero discharge target is considered to be achieved as regards chemical additives. The Norwegian Pollution Control Authority (SFT) has provided an account of the progress in the zero discharge work in reports to the Ministry of the Environment in 2002, 2003, 2005 and 2006.

The target for environmentally hazardous natural substances in produced water has not been achieved to the same extent as for chemical additives. Produced water contains residues of oil and chemical substances, both chemicals added in the process and naturally occurring chemical substances. For oil and naturally occurring substances in produced water, the greatest contributions towards reducing the risk of environmental damage within an acceptable cost framework are provided by process optimisations, reinjection of produced water and cleaning measures.

Many fields have implemented measures to reduce discharges, with a view towards the zero discharge target. However, several of the planned measures have proven to be more time-consuming

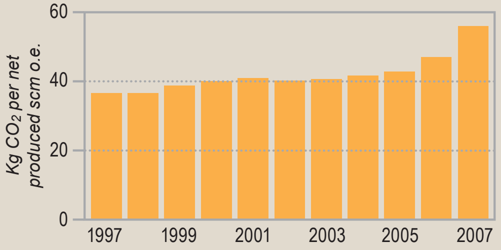


Figure 9.3 Emissions of taxable CO_2 per produced unit
(Source: Norwegian Petroleum Directorate)

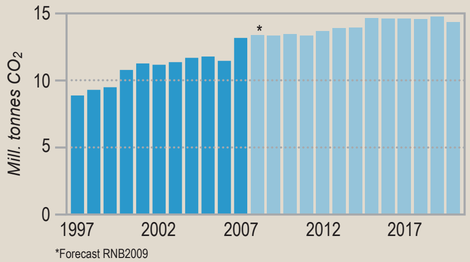


Figure 9.4 CO_2 emissions from the petroleum sector in Norway
(Source: Norwegian Petroleum Directorate)

than expected. Thus, the final achieved objective for existing fields cannot be evaluated until 2009, at the earliest. In 2009, the government will assess the progress made, and determine whether additional measures are needed to ensure that the zero discharge target is achieved.

Emissions from the petroleum activities

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

Measuring and reportin g discharges and emissions

In most cases, emissions to air are calculated on the basis of the volume of fuel gas and diesel consumed on the facility. The emission factors are based on measurements from suppliers or standard figures developed by the industry itself, through the Norwegian Oil Industry Association, or using field-specific measurements and calculations.

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/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

In a national context, the petroleum activities account for 31 per cent of the CO_2 emissions (see Figure 9.1). The other major sources of CO_2 emissions in Norway are road traffic, heating and emission from industrial processes. CO_2 emissions from the facilities largely come from combustion of gas and diesel in turbines and flaring of gas (see Figure 9.2).

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 lakes and the sea.

The development on the Norwegian continental shelf towards more mature fields, movement of activities towards the north and longer distances for gas transport all reinforce the trend of higher emissions per produced unit (see Figure 9.3). Treatment and transport of produced gas requires more energy than production of liquid. Gas accounts for an increasing share of production on the Norwegian continental shelf. At the same time, reservoir pressure in the production wells is declining, thus increasing the need for gas compression and, in turn, the need for energy.

Reservoir conditions are another factor which causes an increase in the need for power. As field

CO_2 emissions from production in Norway compared with the international average

Emissions on the Norwegian shelf are low compared with most other countries in the world. The figure below shows Norway's emissions compared with the international average.

The figure shows CO_2 emissions per produced unit of petroleum. The figure shows developments for Norway and for the world. In 2006, Norway's emissions per produced unit were about 47 kg per scm o.e., while the international average in 2006 was about 120 kg per scm.[1]

There has been a slight increase in emissions per produced unit on the Norwegian continental shelf in recent years, largely due to more energy-intensive production from mature fields.

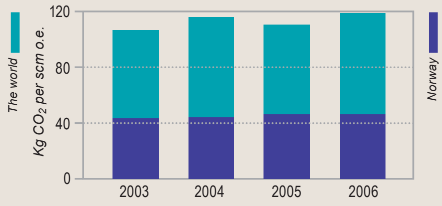


Figure 9.5 CO_2 emissions per produced unit in Norway and international average (2003-2006)
(Source: Norwegian Petroleum Directorate)

1 *Source: International Association of Oil and Gas Producers, www.ogp.org.uk.*

lifetime progresses, more water is produced in the well stream. Since the total volume of liquid and gas (water, oil and gas) largely determines the energy need in the process facilities, a field will have higher emissions per produced unit as it matures.

In the next few years, CO_2 emissions from the petroleum activities will be about 14 million tonnes of CO_2 per year, most likely peaking in 2019.

Measures aimed at reducing CO_2-emissions

Norway is well in the forefront when it comes to using efficient environmental solutions, and the country utilises both policy instruments and technical measures in the work to reduce CO_2 emissions. The CO_2 tax and the Greenhouse Gas Emission Trading Act are central policy instruments in the efforts to reduce these emissions. The authorities can also use other measures, such as the conditions in PDOs/PIOs, emission permits and production permits, which cover factors such as flaring.

CO_2 Tax

Under the CO_2 Tax Act which took effect on 1 January 1991, all use of gas, oil and diesel in connection with petroleum activity on the continental shelf is subject to CO_2 tax. As of 1 January 2008, the CO_2 tax is 45 øre per litre of oil and per standard cubic metre (scm) of gas (equivalent to approximately NOK 184 per tonne of CO_2).

Greenhouse Gas Emission Trading Act

The Greenhouse Gas Emission Trading Act was revised in 2007 and in February 2009. Offshore petroleum facilities were included in the Norwegian quota system starting from 2008, together with the companies that had quota obligations in the first period of the quota system, 2005–2007.

Petroleum facilities must purchase all necessary quotas. At present, several fields receive all or part of their power supply from land. The facilities on Troll A and Ormen Lange use electricity from the power grid, and decisions have been made to use power from land for the Valhall Redevelopment project and development of the Gjøa field.

Conditions and permits

Under the Petroleum Act, companies may not flare any more gas than is necessary to ensure normal operations, without the approval of the Ministry of Petroleum and Energy. Although flaring accounts for about 7 per cent of the CO_2 emissions from the petroleum sector, the level of flaring in Norway is low compared with other countries (see Figure 9.5). The CO_2 tax and direct regulation of flaring have triggered a number of emission-reducing measures, which have put Norway in the forefront in this area.

All plans for development and operation of oil and gas fields (PDOs/PIOs) must contain an analysis of potential power supply from land. This applies both to new field developments and major modifications to existing installations.

Examples of measures aimed at reducing CO_2 emissions

In addition to the overarching policy instruments, there are also concrete, practical measures on the shelf. The authorities and the oil companies have a strong commitment to research and development of technology to find good technical solutions that can contribute to reducing emissions which can harm the environment. Much is being done to develop environmental competence and environmental technology, and the Norwegian oil industry leads the way when it comes to applying environmentally friendly solutions. This has yielded results, and many of the solutions first applied in Norway have become export commodities.

Combined power

Combined power is a solution which utilises heat from the exhaust gas in the turbines to produce steam, which is in turn used to generate electricity. Combined power boosts energy efficiency, and it 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. On the Snøhvit field, starting in April 2008, CO_2 from the gas production was separated out and stored before the natural gas is cooled to liquid natural gas (LNG). The CO_2 gas is transported via pipeline from the LNG plant on Melkøya and back to the field for reinjection and storage in the Tubåen formation, 2600 metres below the seabed. When the Snøhvit field is operating at full capacity, approximately 700,000 tonnes of CO_2 will be stored 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 environmentally 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. In the autumn of 2006, it was agreed under the London Convention that injection and storage of CO_2 in geological formations under the seabed would be allowed. This change entered into force on 10 February 2007. Similar changes were made to the OSPAR Convention in the summer of 2007. The changes will enter into force when at least seven of the parties to the convention have ratified the change resolution. Norway ratified the changes on 9 November 2007.

The Ministry of Petroleum and Energy has given Gassco, Gassnova, the Norwegian Petroleum Directorate and the Norwegian Water Resources and Energy Directorate the task of evaluating different solutions for transport and storage of CO_2 from the CO_2 capture plants, including Kårstø and Mongstad. The first reports were made in the summer of 2007 and the group is to make a recommendation on the best transport and storage solution for CO_2, taking into consideration costs, reservoir conditions and technological risk. According to the plan, an investment decision will be made in 2009.

A new state-owned enterprise, Gassnova SF, was established in June 2007. The enterprise is responsible for the state's interests in the technology centre at Mongstad, the work on CO_2 capture at Kårstø, as well as the projects to study transport and storage of CO_2.

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 injection in oil fields on the Norwegian continental shelf. New studies have shown negative profitability with current assumptions regarding development costs and oil prices (for example use of CO_2 to improve oil recovery from the Draugen field). The great potential, as well as focus on emissions, implies that the Norwegian Petroleum Directorate still will have a special focus on use of CO_2 to enhance oil recovery.

Energy management and energy efficiency

Emissions of CO_2 from power production on the continental shelf account for about 90 per cent of the total emissions from the offshore activities. In 2004, the authorities cooperated with the industry to produce a report on the possibilities of achieving more efficient energy supply on the Norwegian continental shelf. The study concluded that a realistic, but ambitious estimate of potential emission reductions is about 5–10 per cent over a period of 10 years. This improvement has already been incorporated in the projected CO_2 emissions from the sector. This can be achieved if the industry systematically implements energy management in all aspects of the activities. The industry followed up the authorities' study, and in the spring of 2006, the Norwegian Oil Industry Association (OLF) published guidelines to assist the companies in achieving a formalised, systematic approach to the work on energy management, based on the same principles as in approved standards for environmental management, such as ISO 1400 and EMAS. Under the Pollution Act, emission permits issued by the SFT stipulate requirements for energy management (an energy management system), and companies are to be audited on this requirement.

Many energy efficiency measures were implemented when the CO_2 tax was introduced in 1991. A fundamental shift in technology and energy supply concepts is needed to ensure even better energy efficiency over the long term. This demands a long-term commitment to development, testing and implementation of new technology.

Electrification by means of power from land

On 4 January 2008, the Norwegian Petroleum Directorate (NPD), the Norwegian Water Resources and Energy Directorate (NVE), the Norwegian Pollution Control Authority (SFT) and the Petroleum Safety Authority Norway (PSA)

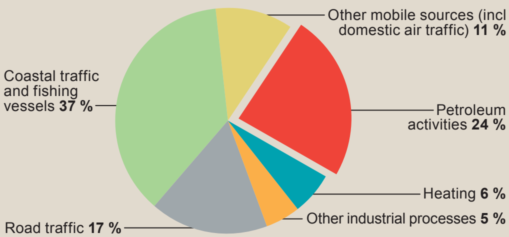


Figure 9.6 Sources of Norwegian emissions of NO_x, 2007
(Source: Statistics Norway)

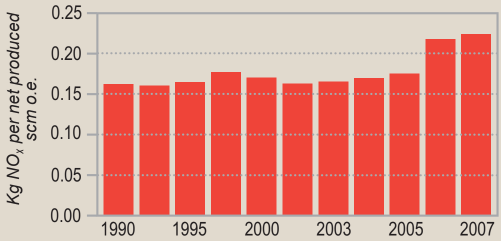


Figure 9.7 NO_x emissions per produced unit
(Source: Norwegian Petroleum Directorate)

submitted a report to the government. The report was a new review of the costs associated with supplying the petroleum activities on the shelf with power from land; a report that was presaged in Storting White Paper No. 34 (2006–2007) Norwegian climate policy. The new calculations show that the costs of measures needed to electrify an area with existing facilities was in the range of NOK 1600 to 5000 per tonne of CO_2. These costs are mainly related to significantly higher construction costs offshore, greater complexity in the modification processes and shorter field lifetime than previously assumed. At the same time, the report showed that nearly 45 per cent of the emissions from the sector cannot be replaced by electricity from land (such as emissions from floating facilities and emissions linked to gas flaring as a safety measure). In the agreement on the Climate White Paper (the climate compromise), the parties agreed that the work on emission-free power in the petroleum sector must be intensified. Based on technical, financial and supply-related factors, power from land and emission-free power shall be considered in connection with new developments and major modification projects. Electrification must be viewed in light of the fact that there are considerable variations between the facilities as regards technical properties, costs and, not least, the effect on other power consumers through connection to the general power supply. The economics of solutions involving power from land depend particularly on the need for heat and power, distance to land and facility design.

As of today, several fields already receive all or parts of their power supply from land. For example, the Troll A and Ormen Lange facilities use power from the grid, while Valhall Redevelopment and the Gjøa field will be developed using power from land.

Emission status for NO_x

Emissions of CO_2 and NO_x 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 NO_x. The volume of emissions depends both on the combustion technology and the quantity of fuel used. For example, combustion in gas turbines yields lower emissions of NO_x than combustion in diesel motors.

NO_x is a nitrogen compound which contributes to acidification. The environmental effects of NO_x 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
- damage to health, crops and buildings due to production of ground-level ozone

Mobile sources account for the majority of the Norwegian NO_x emissions (see Figure 9.6). The petroleum sector contributes 24 per cent. Emissions of NO_x per produced oil equivalent have risen slightly since 1997 (see Figure 9.7). Total emissions of NO_x from the sector have also increased from 1991 (see Figure 9.8). The main cause of the growth to date is increased activity, which has entailed a need for more energy, and in turn, more emissions.

Measures for reducing NO_x emissions

PDOs/PIOs

In the operations phase, emissions of scm on the continental shelf are regulated by conditions that may be set in connection with consideration of the PDO/PIO. Emission permits may also be issued pursuant to the Pollution Act, which includes NO_x.

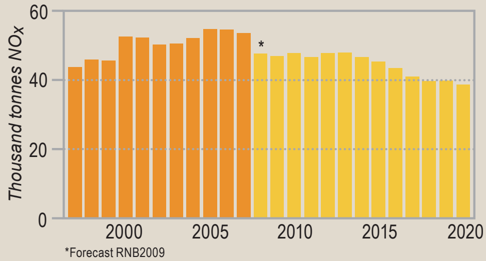


Figure 9.8 NO_x emissions from the petroleum activities
(Source: Norwegian Petroleum Directorate)

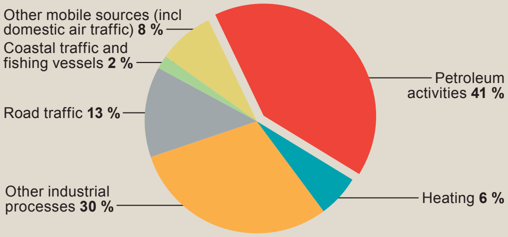


Figure 9.9 Sources of Norwegian emissions of nmVOC, 2007
(Source: Statistics Norway)

The SFT is currently working on updating the emission permits.

NO_x tax and the Gothenburg Protocol
On 28 November 2006, the Storting adopted a tax on emissions of NO_x. The legal basis for this is found in the amendment (1 January 2007) of the Regulations relating to special tax. The tax applies to all emissions from the petroleum activities from turbines with a gross added energy greater than 10 MW and machinery larger than 750 hp, as well as emissions from flaring. The tax is currently set at NOK 15 per kg of NO_x.

The purpose of the tax is to reduce annual emissions of NO_x in Norway to 156,000 tonnes by 2010, in accordance with our commitment under the Gothenburg Protocol from 1999 (ratified by Norway on 30 January 2002). The tax largely targets emissions from domestic activities, and includes emissions from major within the maritime and aviation sectors, land-based activities, as well as on the continental shelf. Shipping companies and owners of vessels, owners of land-based activities and operators of activities on the continental shelf are all subject to the tax.

In connection with the Storting's consideration of the NO_x tax, a decision was made to grant an exemption for emission sources which were part of environmental agreements with the State on introduction of measures to reduce NO_x in accordance with stipulated environmental targets. The Norwegian State (represented by the Ministry of the Environment) and the industry organisations have now entered into an environmental agreement on reduction of NO_x emissions. Emissions from these industry organisations shall not exceed 98,000 tonnes in the geographical area covered by Norway's commitments under the Gothenburg Protocol.

The industry organisations have established a dedicated NO_x fund that will be used to fulfill the commitments under this agreement. On behalf of the industry organisations, the fund collects payments per kilogram of NO_x emissions from enterprises that have endorsed the agreement. The fund also provides subsidies for cost-effective measures aimed at reducing NO_x emissions.

Examples of measures for reducing NO_x emissions

Low-NO_x burners
In addition to the regulations mentioned above, practical measures are also being implemented to reduce emissions of NO_x. Low-NO_x burners are one such measure. These burners can be

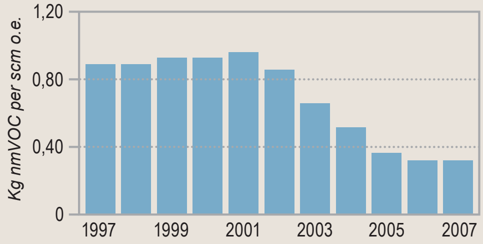


Figure 9.10 nmVOC emissions per produced unit
(Source: Norwegian Petroleum Directorate)

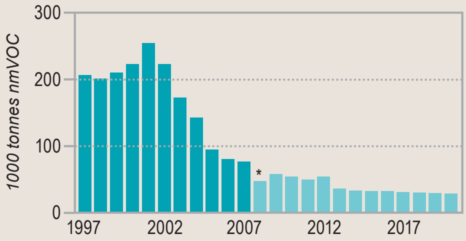


Figure 9.11 Emissions of nmVOC from the petroleum activities
(Source: Norwegian Petroleum Directorate)

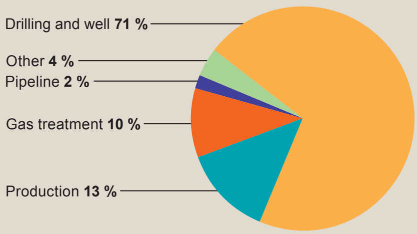


Figure 9.12. Discharges of chemicals from the Norwegian petroleum activities, by source, 2007
(Source: Norwegian Petroleum Directorate)

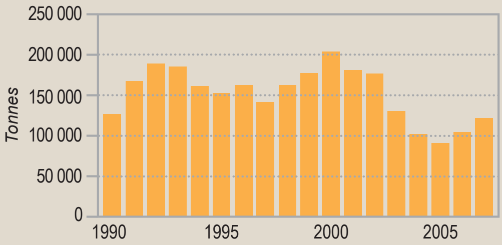


Figure 9.13 Total discharges of chemicals from the Norwegian petroleum activities
(Source: Norwegian Petroleum Directorate)

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-NO_x 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 NO_x reductions are less when the utilization of capacity is high.

Injection of steam or water is a technology that can reduce NO_x emissions by reducing the combustion temperature in the combustion chamber. This technology is not in use today because steam and water injection is not qualified to be used offshore. Among other things, there are great challenges related to the fact that the technology requires great amounts of clean water. However, in the future, this technology could contribute to reducing NO_x emissions from the petroleum sector even more.

Emission status for nmVOC

nmVOC stands for non-methane volatile organic compounds, which are vapours from substances such as crude oil. In the petroleum sector, most of these emissions come from storage and loading of crude oil offshore and from the land terminals.

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 41 per cent of total emissions. Emissions of nmVOC largely originate from storage and loading of crude oil offshore.

Industry collaboration

Emission permits entail a requirement whereby oil must be stored and loaded using the best available emission-reducing 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 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 facilities.

The joint venture agreement was signed in 2002, and 29 companies take part in this collaboration which covers buoy loading of oil from Varg, Glitne, Jotun, Balder, Gullfaks, Statfjord, Draugen, Njord, Åsgard, Norne, Volve and Alvheim.

At the end of 2008, nmVOC-reducing technology had been installed on 16 buoy loaders, as well as on three ships transporting oil from Heidrun. The estimated nmVOC reduction from 2007 to 2008 was approximately 25,778 tonnes. In 2009, the focus will be on measures to achieve continued good, safe operations of the facilities and high operational regularity.

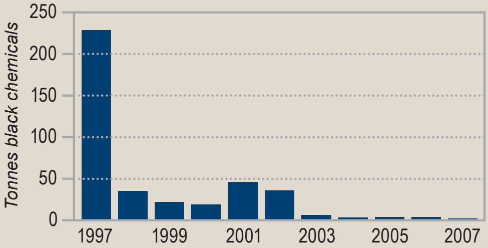


Figure 9.14 Discharges of black chemicals from the petroleum activities *(Source: Norwegian Petroleum Directorate)*

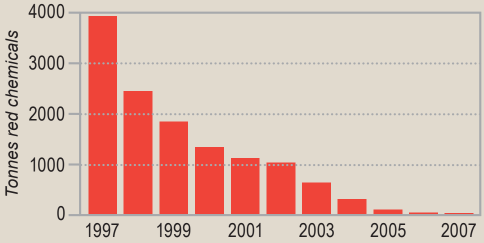


Figure 9.15 Discharge of red chemicals from the petroleum activities *(Source: Norwegian Petroleum Directorate)*

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. 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 main reason for this.

Measures and instruments for reducing nmVOC emissions

Starting from 2001, emissions of nmVOC linked to offshore loading and storage of crude oil have been governed under the emission permit system, pursuant to the Pollution Act.

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 per cent. 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 Sture 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.

Discharge status for chemicals

Chemicals are 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.

The contribution from the petroleum sector to national discharges to sea is less than 3 per cent of the environmental toxins on SFT's list.

More than 99 per cent of the chemicals used in the Norwegian petroleum activities consist of chemicals which are believed to have little or no impact on the environment (green and yellow chemicals, ref. the Norwegian Pollution Control Authority's (SFT's) classification). 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.

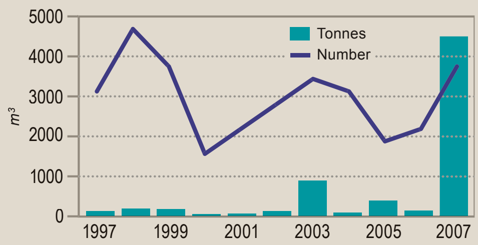


Figure 9.16. Acute oil spills larger than one cubic metre *(Source: Norwegian Petroleum Directorate)*

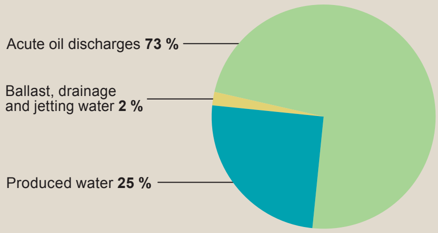


Figure 9.17 Discharges of oil from the petroleum activities distributed by activities, 2007 *(Source: Norwegian Petroleum Directorate)*

- 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 added environmentally hazardous production chemicals (black and red chemicals, ref. Norwegian Pollution Control Authority's classification) have been reduced by 94 per cent for black chemicals and 98 per cent for red chemicals since 2000. 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 are handled as hazardous waste.

Measures for reducing discharge of chemicals

Companies must apply for discharge permits from the SFT in order to discharge chemicals to the sea. The SFT issues discharge permits pursuant to the rules of the Pollution Act. Under the Pollution Act, the operating companies themselves are responsible for and obliged to establish the necessary emergency preparedness to deal with acute pollution, in addition to municipal and national emergency preparedness.

Discharges of oil

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 comes from shipping and from the mainland via rivers. Figure 9.16 provides an overview of acute oil discharges greater than one cubic meter (m^3). 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.

During 40 years of oil and gas activities the operations have not caused major acute oil spills that have led to damage to the environment.
In 2006, the total volume of acute discharges to sea was 122 m^3 (see Figure 9.16). Unfortunately, in December 2007, there was an incident on the Statfjord field in the North Sea involving discharge

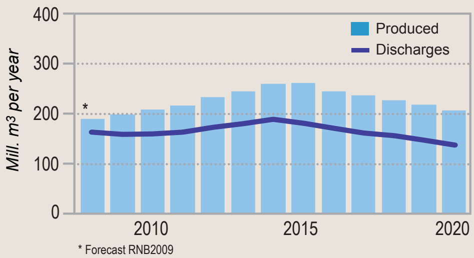


Figure 9.18 Forecasts for produced water and for discharge of produced water *(Source: Norwegian Petroleum Directorate)*

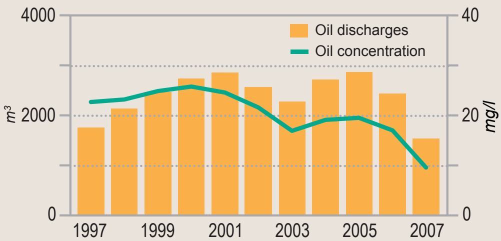


Figure 9.19 Discharges of oil in produced water and appurtenant oil concentration *(Source: Norwegian Petroleum Directorate)*

of approximately 4408 m^3 of oil – the second largest acute oil discharge from production on the Norwegian continental shelf. This meant that the total acute discharges to sea in 2007 were 4408 m^3. The objective for the industry and the authorities is to continue to reduce the risk of oil spills from future operations on the Norwegian continental shelf.

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 effectiveness of the response measures are all crucial for the extent of damage. Acute oil spills can harm fish, marine mammals, seabirds and beach zones. 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, natural 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. Oily cuttings and drilling fluid that previously accounted for a large share of the oil discharged from the petroleum activity, are now reinjected into suitable reservoirs or taken to land for further treatment. Figure 9.17 shows oil discharges distributed by activities, while Figure 9.18 illustrates the predicted development in the

Oil spill preparedness

In Norway, the preparedness for acute pollution consists of private sector preparedness, municipal preparedness and state preparedness. The Ministry of Fisheries and Coastal Affairs and the Norwegian Coastal Administration are responsible for coordinating the total national oil spill preparedness, as well as the government's preparedness for acute pollution. The Ministry of the Environment is responsible for setting preparedness requirements for acute pollution in municipalities and for private enterprises. The Norwegian Pollution Control Authority approves the emergency preparedness plans and ensures that the demands are complied with.

On behalf of the oil companies, the operators are responsible for handling acute incidents that are a result of their own activities, using preparedness resources that are designed for this purpose. The Norwegian Clean Seas Association for Operating Companies (NOFO), which consists of a number of companies that are licensees on the Norwegian continental shelf, has also established regional plans which take into consideration reinforcement of ocean-going preparedness, coastal preparedness and beach zone preparedness. NOFO manages and maintains preparedness which includes personnel, equipment and vessels. NOFO has five bases along the coast – Stavanger, Mongstad, Kristiansund, Træna and Hammerfest, in addition to some fields where NOFO equipment is permanently located. NOFO has a total of 16 oil spill preparedness systems and carries out at least two joint training exercises each year.

volume of produced water and discharges of produced water. Implemented measures have led to considerable reductions in the discharge of oil per unit of produced water. However, the measures implemented so far do not exceed the increase in discharges as a result of the fact that water production increases as the fields mature, although the discharges have been stabilized at the current level. Figure 9.19 shows the total oil discharges and the average concentration of dispersed oil in water (mg/litre).

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. To increase this knowledge, the Ministry of Petroleum and Energy, the Ministry of the Environment and the petroleum industry have cooperated to finance the research program "Long-term effects of discharges to sea from the petroleum activity (PROOF)", which was initiated in the autumn of 2002 under the Research Council of Norway. The program has now been continued as a subsidiary program (PROOFNy) under the research program "Sea and Coast". The main areas included in PROOFNy are effects in the water column, special research assignments in the Arctic region, the link between research and monitoring, long-term effects of acute spills and the discharge of cuttings. The program also hopes to focus on projects in the area of synergetic effects on the ecosystem.

Measures for reducing discharges of oil

The companies must apply for discharge permits from the Norwegian Pollution Control Authority (SFT) in order to discharge oil to the sea, following the same procedure as for chemicals. The SFT grants discharge permits pursuant to the rules in the Pollution Act. Under the Pollution Act, the operating companies themselves are responsible for and obliged to establish the necessary emergency preparedness to deal with acute pollution, in addition to municipal and national emergency preparedness.

Some of the environmental statistics in the figures have not been updated since last year as they were not ready when Facts 2009 went to print. The Norwegian Petroleum Directorate and Statistics Norway have updated figures for some of the environmental indicators.

Definitions

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 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 for environmentally hazardous substances:
Zero discharges, or minimisation of discharges of naturally occurring environmental toxins encompassed by the end objective for chemicals hazardous to health and the environment, ref. the priorities list in Storting White Paper No. 25 (2002–2003).

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 that can lead to harm to the environment, including oil (components that are not hazardous to the environment), substances in the Norwegian Pollution Control Authority's yellow and green categories, cuttings and other substances that can lead to harm to the environment *

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

Storting White Paper No. 38 (2003–2004) On the petroleum activities, 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.

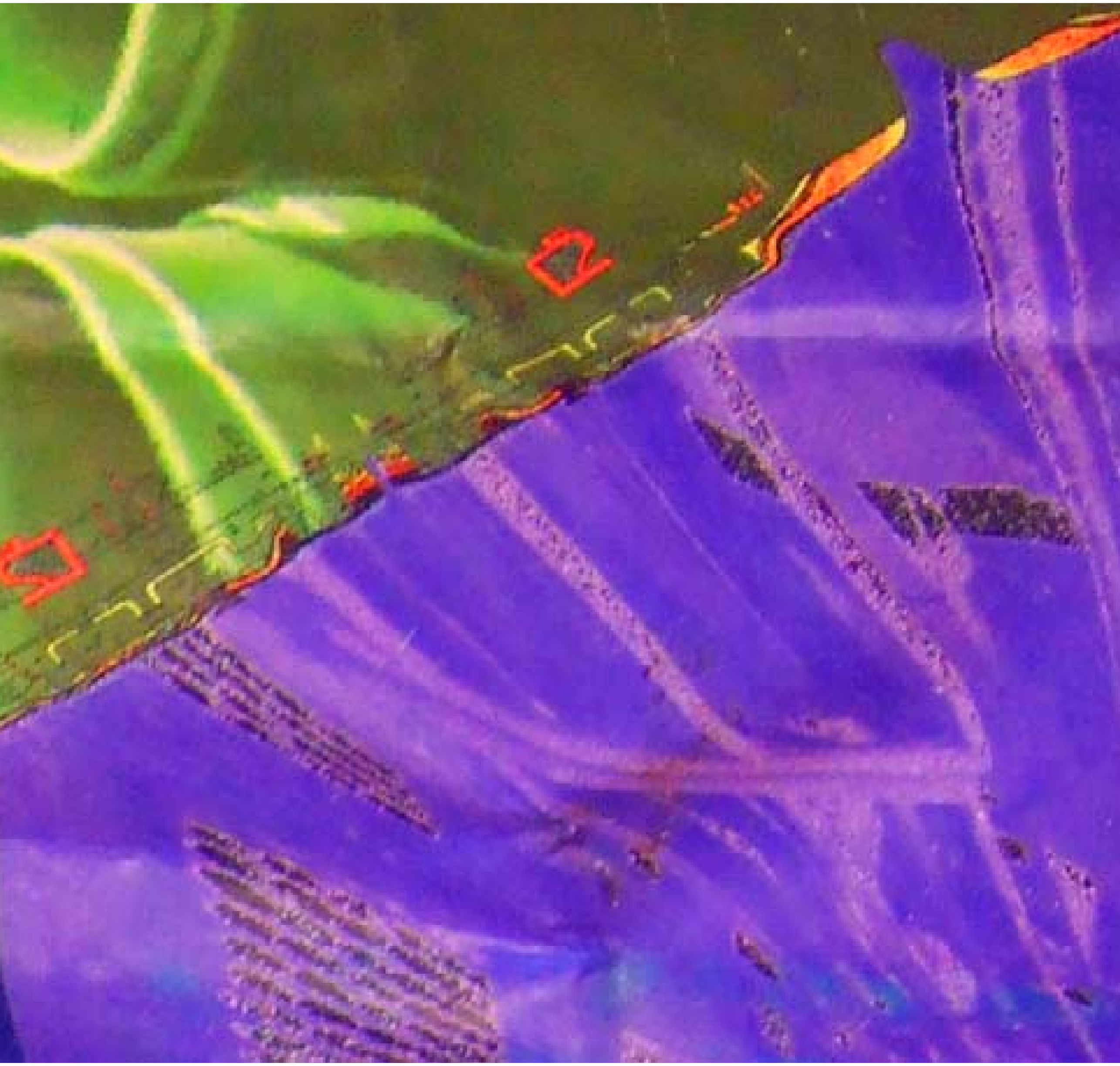
No discharge of produced water. Injection of produced water is the assumed basis, or use of other technology that prevents discharge of produced water. In case of operational deviation, maximum 5 per cent of the produced water can be released to sea if it is cleaned (before discharge to sea).

No discharge of drill cuttings or drilling fluids. Drill cuttings and drilling fluids will be reinjected or taken to land for disposal. Drill cuttings from the top hole section may normally be discharged under the condition that the discharge does not contain substances with unacceptable environmental effects, and only in areas where the potential for damage to vulnerable environmental components is considered to be low.

No discharge to sea from well testing.

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

10 Petroleum resources



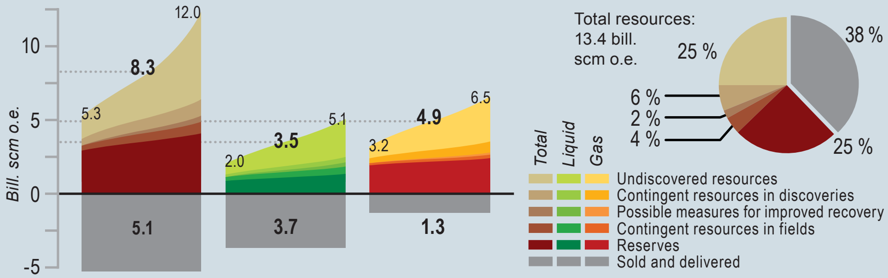


Figure 10.1 Petroleum resources and uncertainty in the estimates per 31.12.2008
(Source: Norwegian Petroleum Directorate)

The Norwegian Petroleum Directorate (NPD) estimates that the total discovered and undiscovered petroleum resources on the Norwegian continental shelf amount to approximately 13 billion standard cubic meters of oil equivalents (scm o.e.). Of this, a total of 5.1 billion scm o.e., corresponding to 38 per cent of the total resources, have been produced. The total remaining recoverable resources amount to 8.4 billion scm o.e. Of this volume, 5.0 billion scm o.e. are proven resources, while the estimate for undiscovered resources is 3.4 billion scm o.e.

The resource growth from exploration activity in 2008 was good. 25 new discoveries were made from a total of 56 exploration wells. The total growth of recoverable resources from exploration activity is 50 million scm oil and 72 billion scm gas. Several of the discoveries are still being evaluated and the estimates are thus very uncertain.

Since production started on the Norwegian continental shelf in 1971, petroleum has been produced from a total of 73 fields. In 2008, three new fields, Alvheim, Vilje and Volve, came on stream. At the end of 2008, 51 of the producing fields are located in the North Sea, nine in the Norwegian Sea and one in the Barents Sea. PDOs for two new fields, Morvin and Yttergryta, were approved in 2008, and a PDO for 3/7-4 Trym is under consideration at the Ministry of Petroleum and Energy. In addition, amended PDOs for Ekofisk, Urd and Norne were approved by the authorities, and PDO exemptions were granted for Varg and 30/9-14 G Sentral.

Figure 10.1 shows the total recoverable resource potential on the Norwegian continental shelf. The volumes are divided according to the NPD'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 magnitude of petroleum volumes decided by the licensees for development or approved by the authorities for development (reserves), volumes dependent on clarification and decisions (contingent resources) and volumes expected to be discovered in the future (undiscovered resources). The main resource classes are thus reserves, contingent resources and undiscovered resources.

The detailed resource accounts as of 31 December 2008 are shown in Table 10.1 and in tables in Appendix 2.

Reserves

Reserves include remaining recoverable petroleum resources in deposits 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 authorities have not as yet completed processing of either a PDO approval or a PDO exemption.

Gross gas and liquid reserves increased by 39 million scm o.e. in 2008. The reason is an increase in gross reserves on several fields, among others, Tyrihans, Ula and Alvheim. In addition, approved plans for development and operation of Morvin and Yttergryta and a development decision for 3/7-4 Trym, have led to that resources now have been entered as reserves. Since 243 million scm o.e. were produced in 2008, the resource accounts show a net reduction in remaining reserves of 204 million scm o.e., corresponding to approximately six per cent.

With regard to the authorities' goal of maturing 800 million scm of oil to reserves before 2015, 29 million scm of oil matured to reserves in 2008. In the period 2005 to 2008 the total reserves growth has been 232 million scm o.e.

Contingent resources

Contingent resources include discovered quantities of petroleum for which a development decision has yet to be made. Contingent resources in fields, excluding resources from possible future measures to improve recovery (resource category 7A), were increased by 34 million scm o.e. The reason for this increase is a general maturing of resources in projects on fields in 2008, and that many new projects for improved recovery have been realised.

The estimate for contingent resources in discoveries has increased by 129 million scm o.e. to 775 million scm o.e. This reflects the good resource growth from exploration in 2008, and that six discoveries where development was considered to be not very likely (resource category 6), now are being evaluated by a new operator.

There are no changes in the resource potential for possible future measures to improve oil recovery (resource category 7A) compared to last year. Oil is estimated at 145 million scm o.e. and gas is estimated at 77 million scm o.e.

Undiscovered resources

Undiscovered resources include petroleum volumes expected to be present in defined plays, confirmed and unconfirmed, but which have not yet been proven by 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

Production from the North Sea in 2008 totalled 176 million scm o.e., and the growth in gross reserves was 16 million scm o.e. The remaining reserves in the North Sea were thus reduced by 160 million scm o.e. Contingent resources in fields increased by 32 million scm o.e. due, i.a. to that several projects for improved recovery were realised. Contingent resources in discoveries increased by 42 million scm o.e due to a relatively good resource growth from exploration and increased resource estimates from, amongst others, 15/3-1 Gudrun and the discovery 16/1-8. Twelve new discoveries were made in the North Sea in 2008, eight oil discoveries, three oil/gas discoveries and one gas discovery.

The Norwegian Sea

Production from the Norwegian Sea in 2008 was 64 million scm o.e. In spite of increased reserves in some fields in production and additional new reserves from Morvin and Yttergryta, remaining reserves were reduced by 41 million scm o.e. compared to last year. Nine new discoveries were made in the Norwegian Sea in 2008, one oil discovery, seven gas discoveries and one gas/condensate discovery. In spite of this, the estimate for contingent resources in discoveries has been reduced by 21 million scm o.e. compared to the accounts for last year. The reason is, among others, that some of the resources have matured to reserves and that the discoveries 6605/8-1 and 6706/6-1 have been moved to resource category 6 where recovery is not very likely.

The Barents Sea

Production from the Barents Sea in 2008 was 3 million scm o.e. There are no changes in contingent resources in fields, but the estimate for contingent resources in discoveries has increased the past year. The increase of 108 million scm o.e. is due to four new discoveries in the Barents Sea in 2008, one oil/gas discovery and three gas discoveries. In addition, there are three discoveries located in re-awarded production licences. The new operator is re-evaluating these discoveries.

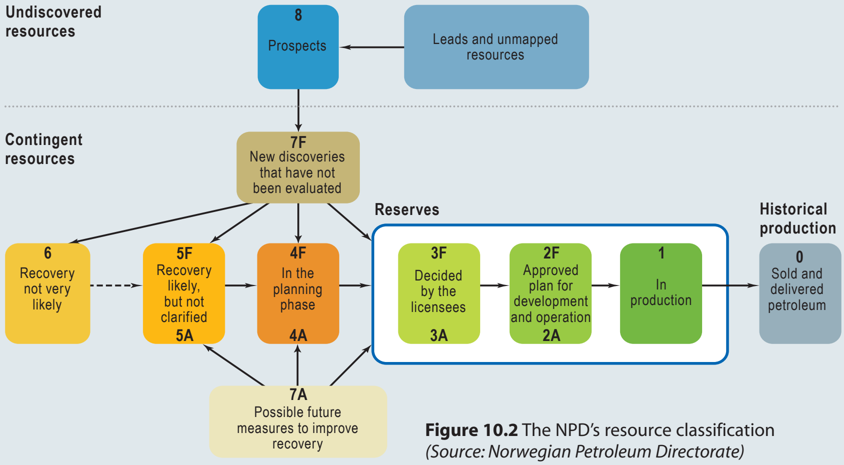


Figure 10.2 The NPD's resource classification
(Source: Norwegian Petroleum Directorate)

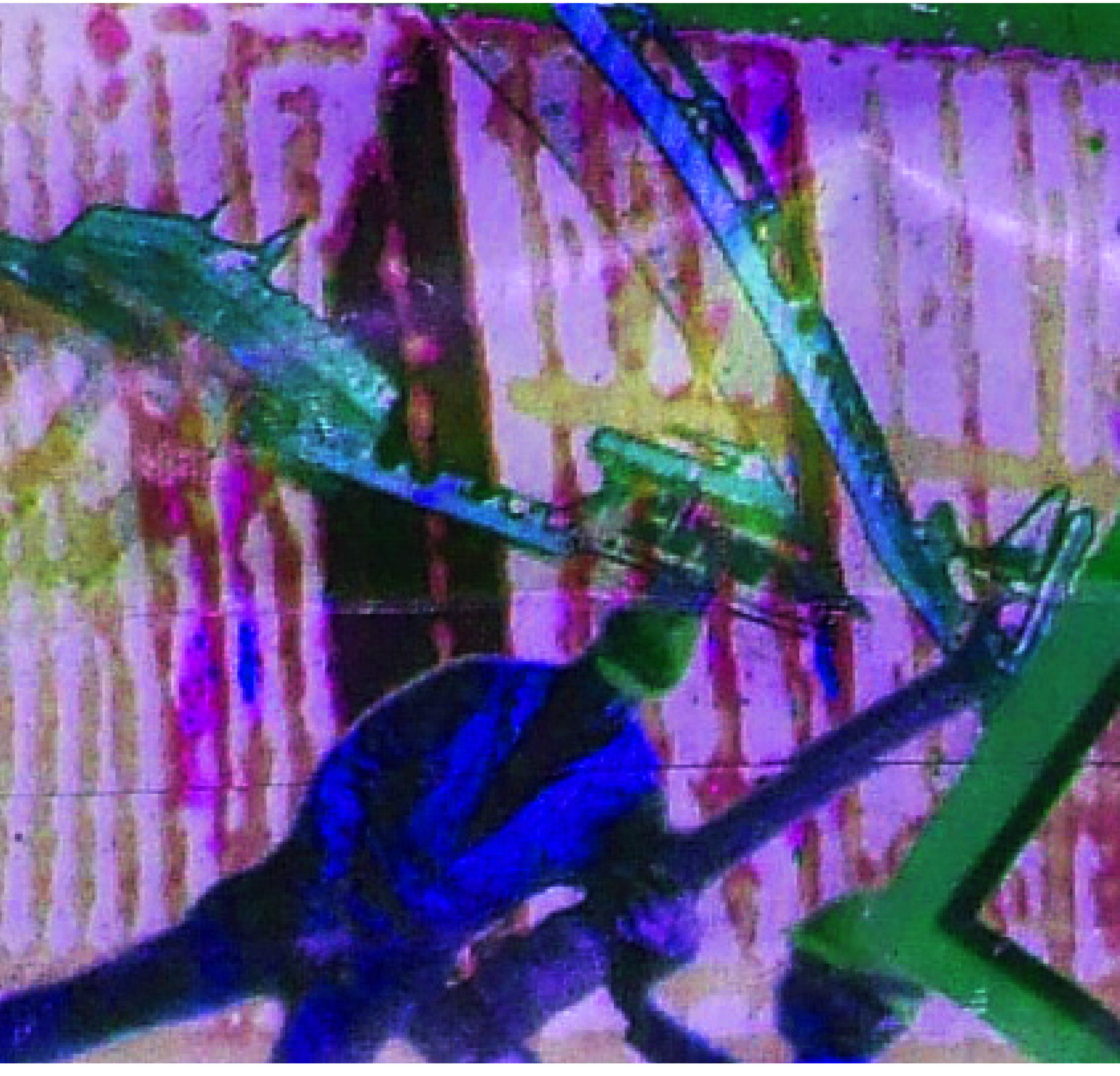
Table 10.1 Resource accounts per 31.12.2008

	Resource accounts per 31.12.2008					Changes from 2007				
Total recoverable potential	**Oil**	**Gas**	**NGL**	**Cond**	**Total**	**Oil**	**Gas**	**NGL**	**Cond**	**Total**
Project status category	mill scm	bill scm	mill tonnes	mill scm	mill scm o.e.	mill scm	bill scm	mill tonnes	mill scm	mill scm o.e.
Produced	3405	1333	116	96	5055	122	101	8	4	243
Remaining reserves*	919	2215	120	43	3407	-93	-97	-3	-8	-204
Contingent resources in fields	333	181	28	5	572	15	15	3	-2	34
Contingent resources in discoveries	210	512	14	27	775	41	107	-2	-15	129
Potential from improved recovery**	145	77			222	0	0	0	0	0
Undiscovered	1260	1875		265	3400	0	0	0	0	0
Total	**6273**	**6193**	**277**	**437**	**13431**	**86**	**126**	**6**	**-20**	**202**
North Sea										
Produced	2975	1202	95	73	4430	97	67	5	3	176
Remaining reserves*	708	1405	65	0	2237	-76	-74	-4	-3	-160
Contingent resources in fields	286	108	13	3	422	23	10	0	-2	32
Contingent resources in discoveries	130	170	4	16	325	25	31	-5	-4	42
Undiscovered	620	500		55	1175	0	0	0	0	0
Total	**4720**	**3385**	**177**	**147**	**8589**	**69**	**34**	**-4**	**-6**	**90**
Norwegian Sea										
Produced	431	128	21	23	621	25	31	3	1	64
Remaining reserves*	211	652	49	26	983	-17	-21	1	-4	-41
Contingent resources in fields	47	65	15	1	141	-8	5	3	0	2
Contingent resources in discoveries	21	226	9	9	273	1	-16	3	-11	-21
Undiscovered	220	825		150	1195	0	0	0	0	0
Total	**930**	**1896**	**93**	**209**	**3212**	**1**	**-1**	**9**	**-14**	**4**
Barents Sea										
Produced		2	0	1	3	0	2	0	1	3
Remaining reserves*	0	158	6	17	187	0	-2	0	-1	-3
Contingent resources in fields	0	8	0	1	10	0	0	0	0	0
Contingent resources in discoveries	59	116	0	2	177	15	92	0	0	108
Undiscovered	420	550		60	1030	0	0	0	0	0
Total	**479**	**835**	**7**	**81**	**1408**	**15**	**92**	**0**	**0**	**108**

* *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*

11 Fields in production



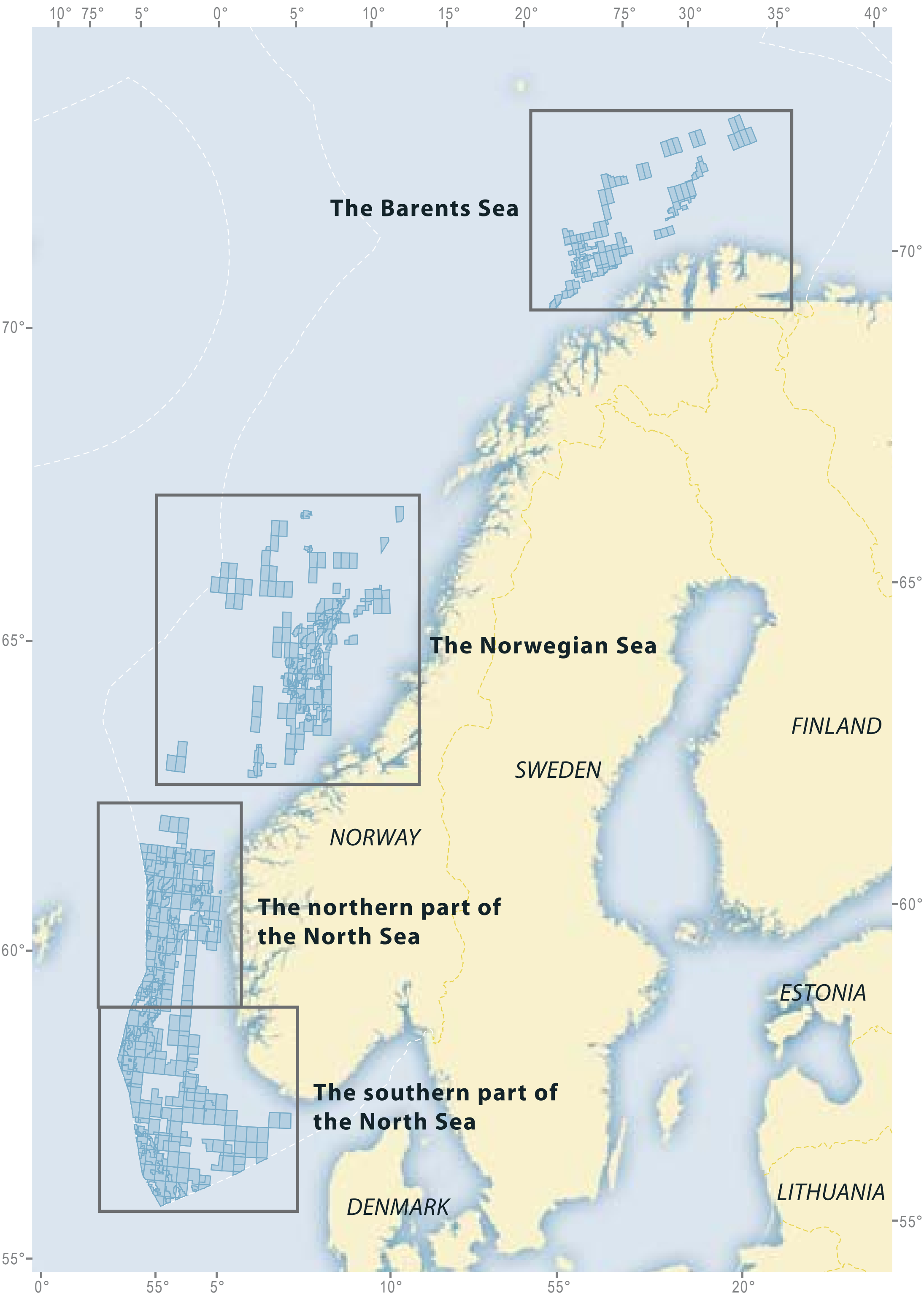


Figure 11.1 Areas on the Norwegian continental shelf

The southern part of the North Sea

The southern part of the North Sea became important for Norway when Ekofisk came on stream in 1971 as the first Norwegian offshore field. At present 28 fields are located in the area, 20 of these are now in production. Rev came on stream early 2009. Seven fields have been shut down after production has ceased and some of these are now being prepared for redevelopment. Yme is being redeveloped and production will start in the autumn of 2009. There is also high activity in the area in connection with disused facilities. 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 United Kingdom, while gas is sent by pipeline to Emden in Germany. The Sleipner fields, north of the Ekofisk area, serve as an important hub for the gas transport system on the Norwegian continental shelf. Although there has been production from the southern part of the North Sea for many years, remaining resources in the area 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.

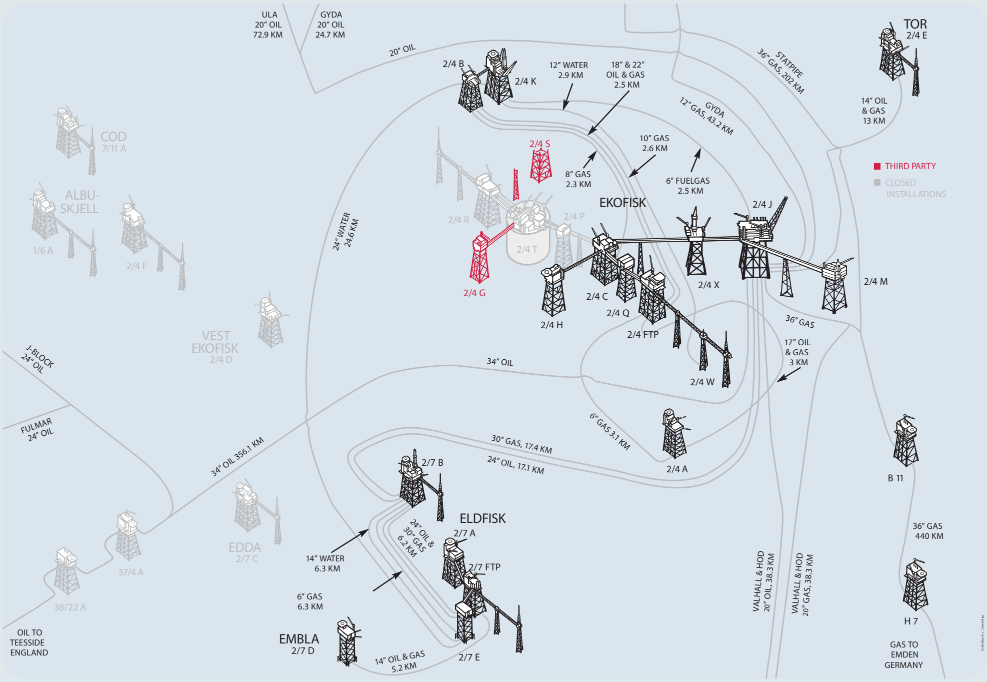


Figure 11.2 Facilities in the Ekofisk area

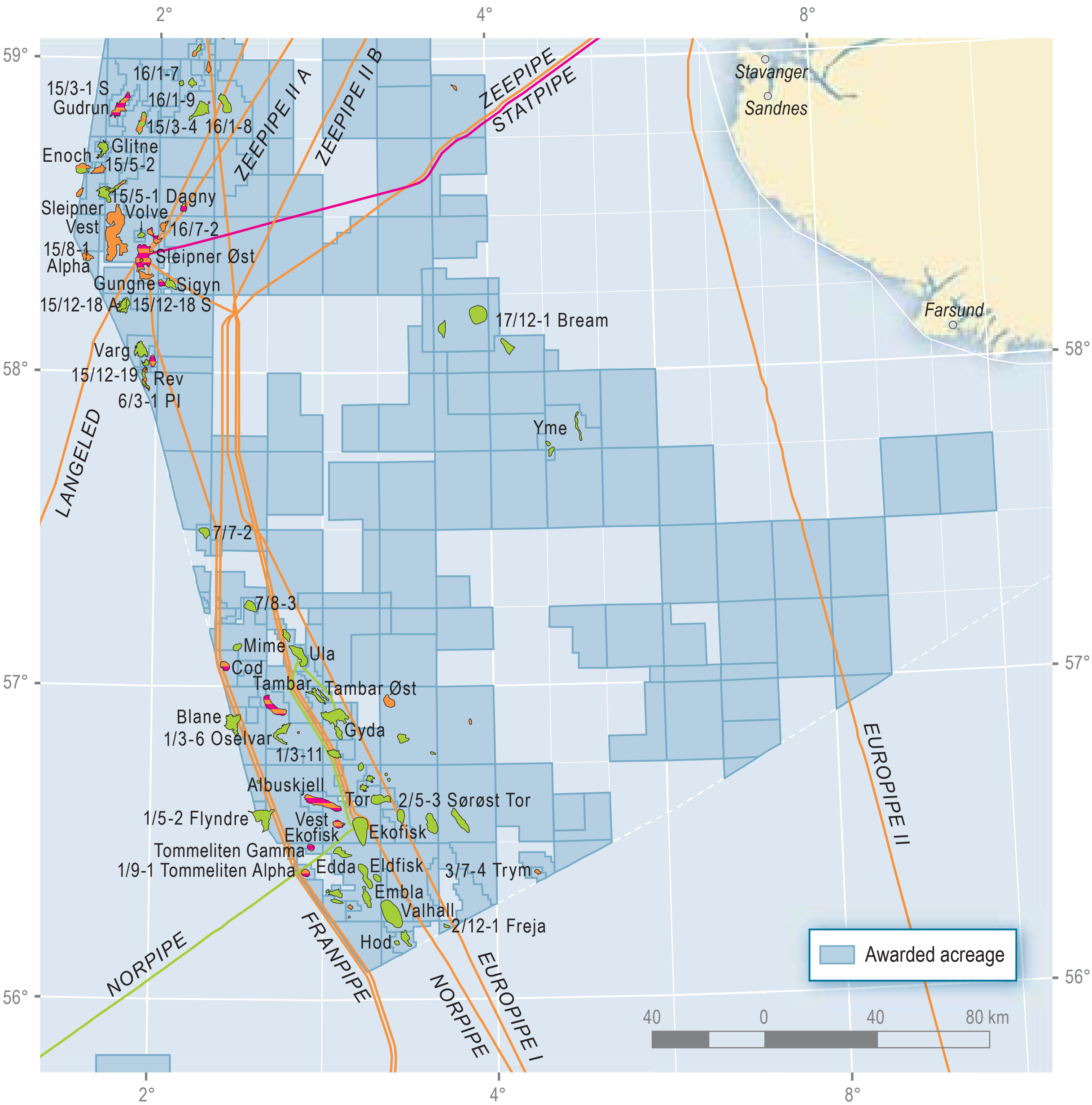


Figure 11.3 Fields and discoveries in the southern part of the North Sea

The northern part of the North Sea

The northern part of the North Sea encompasses the three main areas Tampen, Oseberg /Troll and Balder /Heimdal. At present 31 fields are in production in this part of the North Sea, and more will be developed over the next years. The gas fields in the Frigg area have been shut down after ceased production, but some of these may be redeveloped at a later stage. 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 major 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 is mainly a gas hub with processing services for other fields. Oil and gas from fields in the northern part of the North Sea are transported by tankers or by pipeline to land facilities in Norway and the United Kingdom.

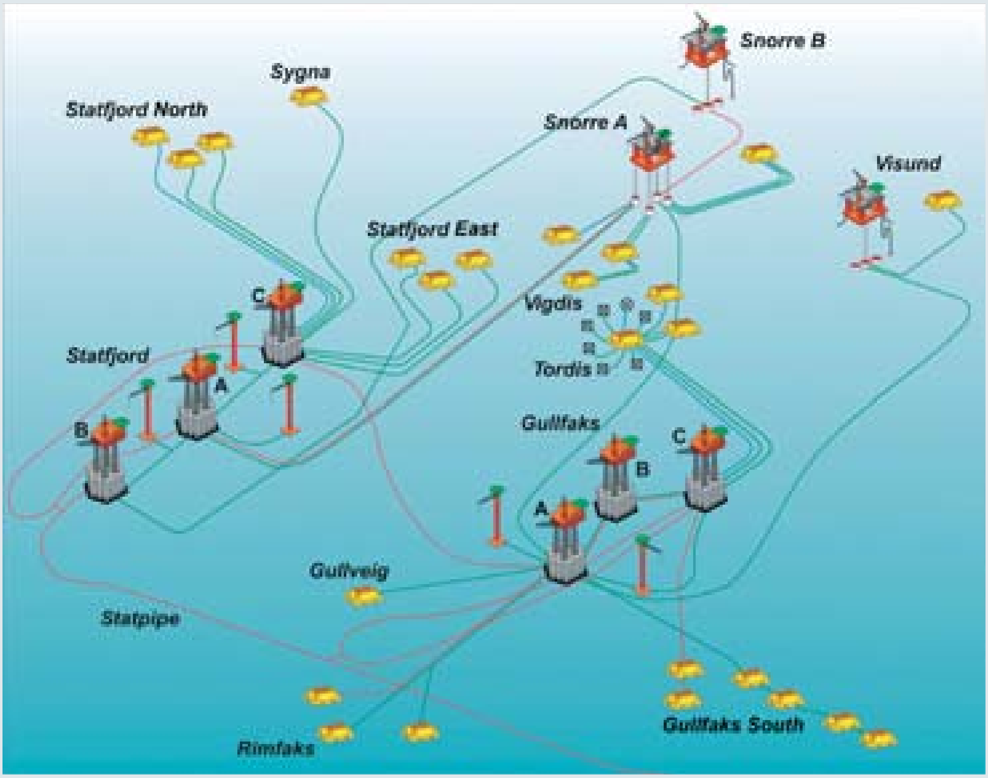


Figure 11.4 Facilities in the Tampen area
(Source: Statoil)

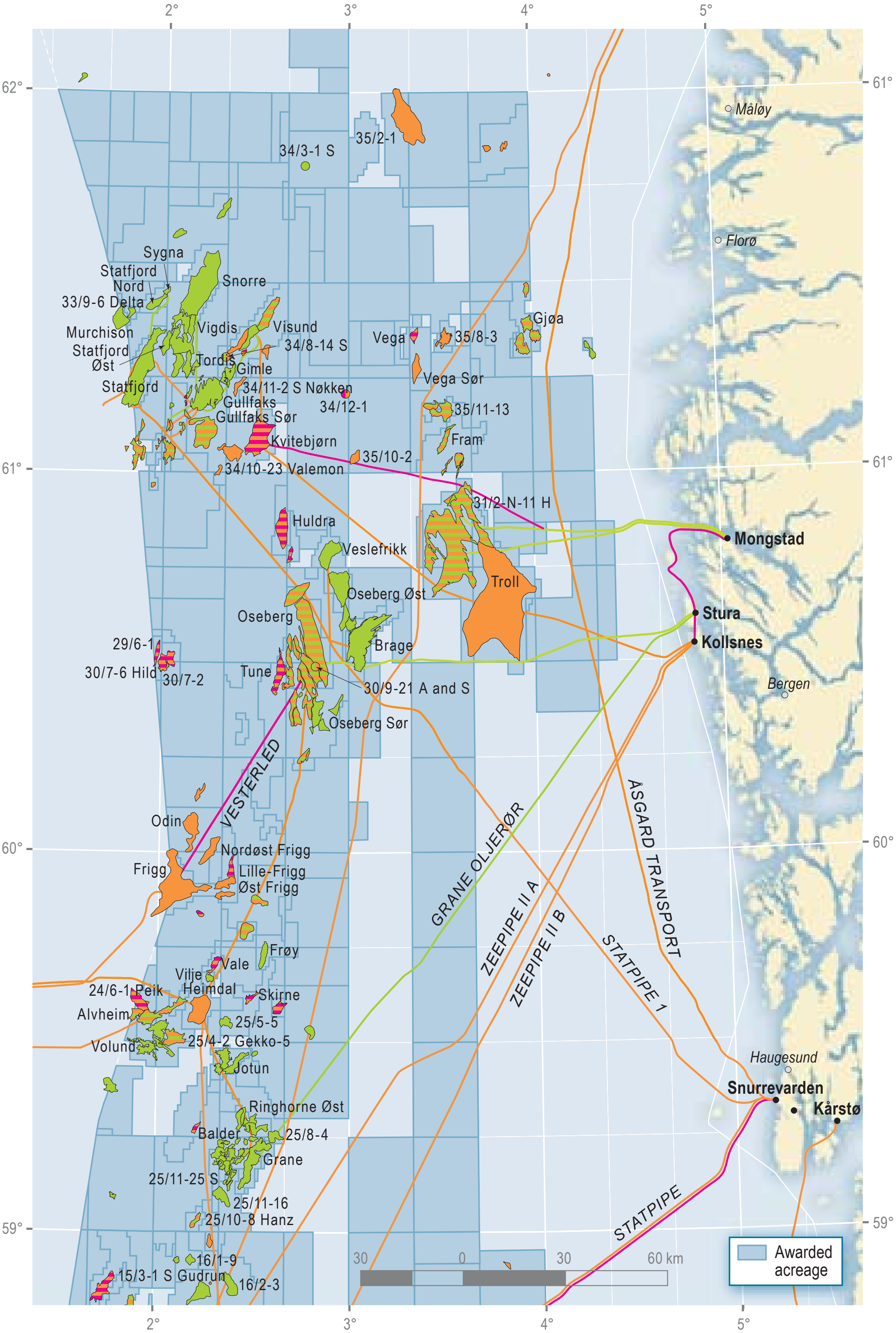


Figure 11.5 Fields and discoveries in the northern part of the North Sea

The Norwegian Sea

The Norwegian Sea is a less mature petroleum province than the North Sea. At present 10 fields are in production in the area and 4 fields are under development. No fields have ceased production. Draugen was the first field to come on stream, in 1993. There are significant gas reserves in the Norwegian Sea. The Åsgard field and the Åsgard Transport represent the key processing and gas export infrastructure for the Norwegian Sea. The gas from Åsgard, Kristin, Mikkel, Norne and Draugen is transported in the Åsgard Transport pipeline to Kårstø in Rogaland, and gas from Heidrun is transported in Haltenpipe to Tjeldbergodden in Møre og Romsdal. Gas production from Ormen Lange started in 2007. The gas is transported in a new pipeline to Nyhamna, and from there on to Easington in the United Kingdom. Oil from the fields in the Norwegian Sea is transported by tankers.

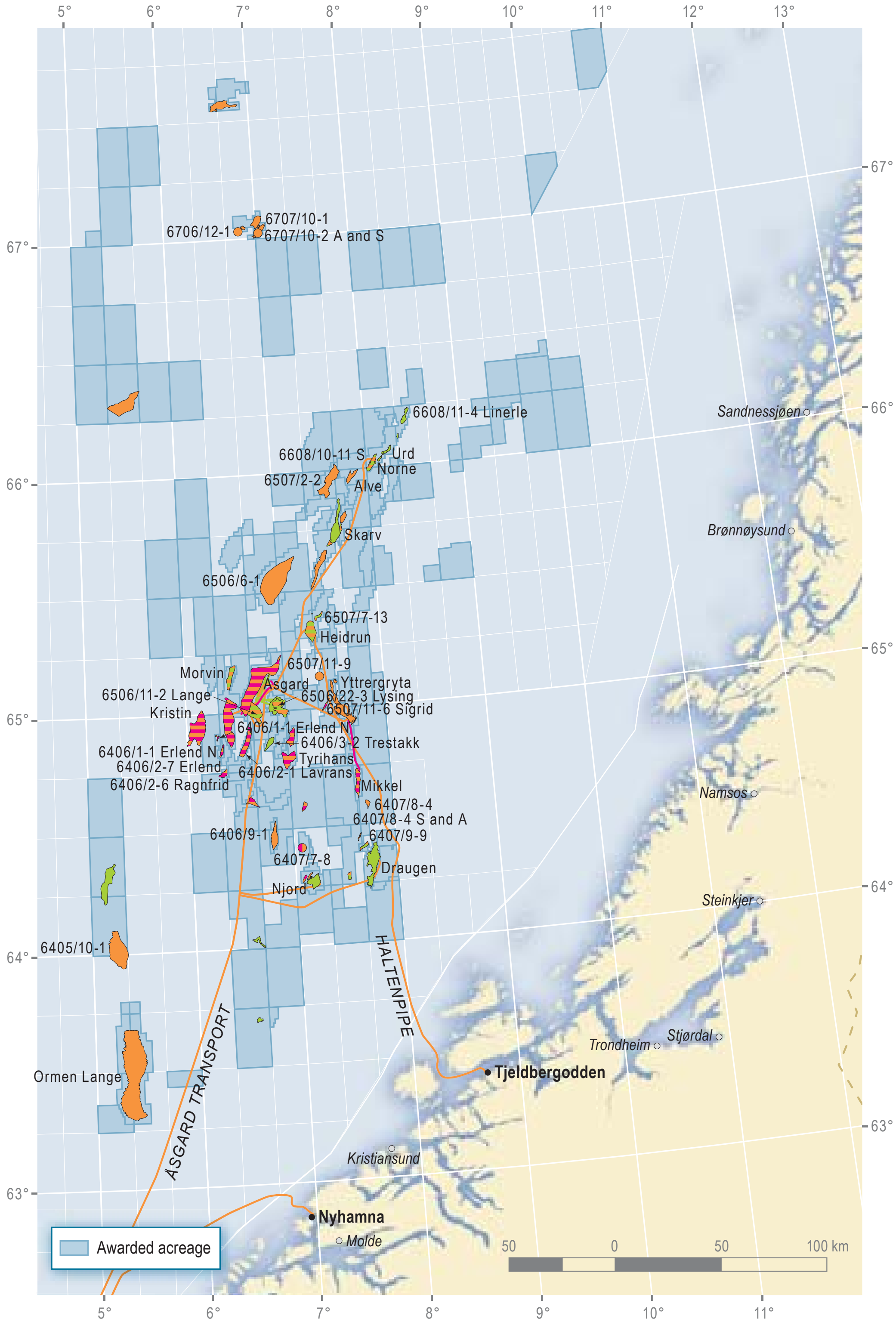


Figure 11.6 Fields and discoveries in the Norwegian Sea

The Barents Sea

The Barents Sea is an immature petroleum province. Snøhvit is the only field developed so far. The field came on stream in 2007. Several discoveries in the area are being considered tied to Snøhvit in connection with a possible further development at Melkøya. The gas from Snøhvit is transported in pipeline to Melkøya and further processed and liquefied to LNG which is transported by tankers to the market. A plan for development and operation (PDO) for 7122/7-1 Goliat was sent to the authorities in February 2009. The development concept is a floating production and storage facility tied to subsea wells.

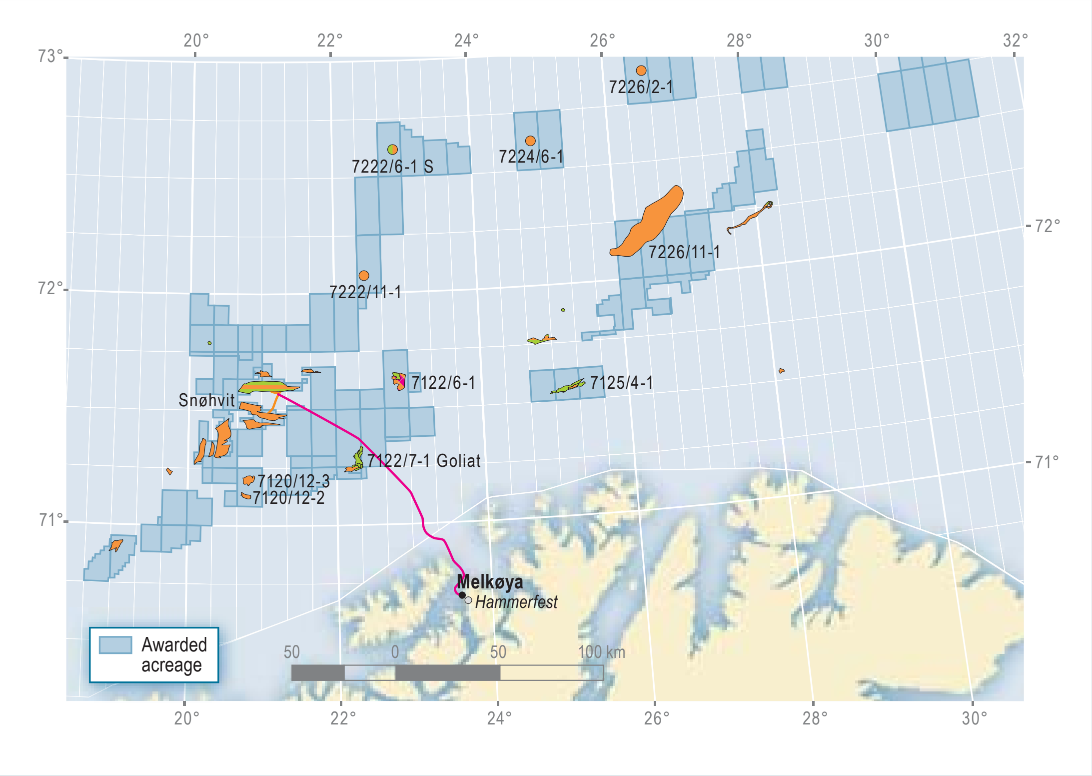


Figure 11.7 Fields and discoveries in the Barents Sea

Keys to tables in Chapters 11–13:

Participating interests in fields do not necessarily correspond with interests in the individual production licences since 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 per cent. Participating interests are shown as of 31 December 2008.

"Original recoverable reserves" refers to reserves in resource categories 0, 1, 2 and 3 in the Norwegian Petroleum Directorate's resource classification. See figure 10.2 The Norwegian Petroleum Directorate's resource classification.

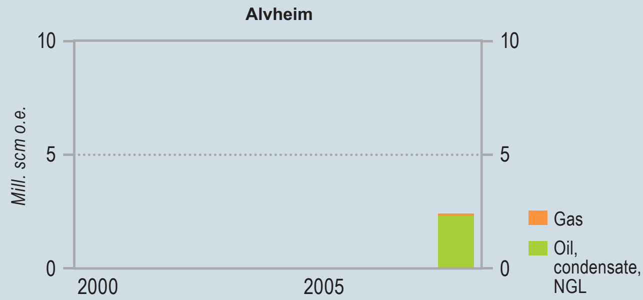
"Recoverable reserves remaining at 31 December 2008" refers to reserves in resource categories 1, 2 and 3 in the Norwegian Petroleum Directorate's resource classification.

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

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

Pictures and illustrations in Chapters 11 – 14:

Thanks to A/S Norske Shell, BP Norge AS, ConocoPhillips Skandinavia AS, ExxonMobil Exploration and Production Norway A/S, Marathon Petroleum Norge AS, StatoilHydro ASA, Talisman Energy Norge AS og Total E&P Norge AS for use of pictures and illustrations of facilities.



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	
On stream	08.06.2008	
Operator	Marathon Petroleum Norge AS	
Licensees	ConocoPhillips Skandinavia AS	20.00 %
	Lundin Norway AS	15.00 %
	Marathon Petroleum Norge AS	65.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008**
	27.5 million scm oil	25.2 million scm oil
	8.1 billion scm gas	7.9 billion scm gas
Production	**Estimated production in 2009:**	
	Oil: 80 000 barrels/day, Gas: 0.57 billion scm	
Investment	Total investment is expected to be NOK 18.5 billion (2009 values)	
	NOK 15.7 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	

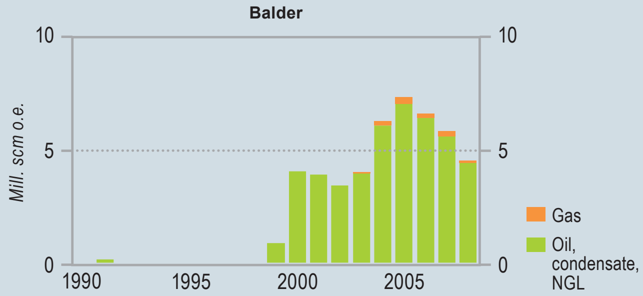
Development:
Alvheim is an oil and gas field in the northern part of the North Sea near the border to the British sector. The field comprises three deposits, 24/6-2, 24/6-4 Boa and 25/4-7. The deposit 24/6-4 Boa lies partly in the British sector. The sea depth in the area is 120-130 metres. The field is developed with a production vessel and subsea wells. The oil is stabilised and stored in the production vessel.

Reservoir:
The reservoir consists of sandstones deposited as turbidites in the Heimdal Formation of Paleocene age. The reservoir depth is approximately 2 100 metres.

Recovery strategy:
Alvheim is produced by natural aquifer drive. There are plans for water injection later in the production period.

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

Status:
Alvheim came on stream in July 2008.



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 & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS	100.00 %
Recoverable reserves	**Original:** 60.0 million scm oil 1.9 billion scm gas	**Remaining as of 31.12.2008:** 14.2 million scm oil 0.9 billion scm gas
Production	**Estimated production in 2009:** Oil: 56 000 barrels/day, Gas: 0.13 billion scm	
Investment	Total investment is expected to be NOK 28.6 billion (2009 values) NOK 26 billion have been invested as of 31.12.2008 (2009 values)	
Operating organization	Stavanger	
Main supply base	Dusavik	

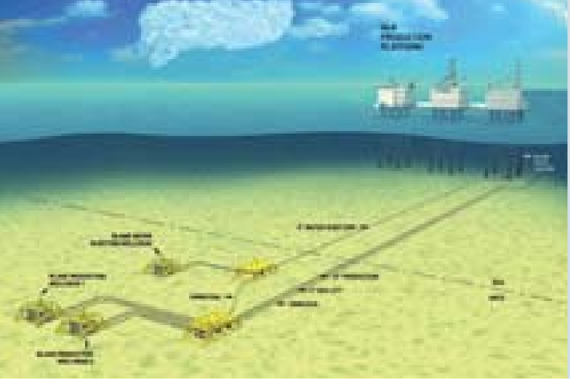
Development:
Balder is an oil field in the northern part of the North Sea. The sea depth in the area is 125 metres. The field has been developed with subsea wells tied back to the accommodation, production and storage vessel, Balder FPSO, where oil and gas are processed. The Ringhorne discovery, included in the Balder field, is developed with a combined accommodation, drilling and wellhead facility, tied back to the Balder FPSO. 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.

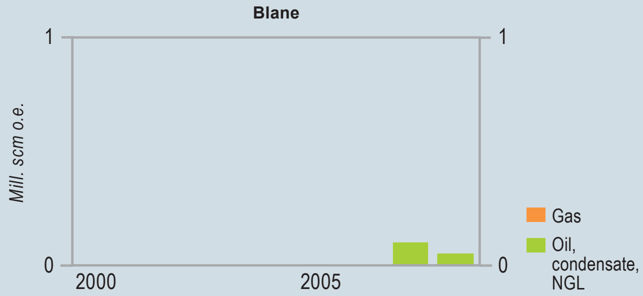
Reservoir:
The field contains several separate oil deposits in Eocene and Paleocene sandstones. The main reservoirs are in the Rogaland Group and belong to the Heimdal, Hermod and Ty formations at a depth of about 1 700 metres. The Ringhorne development comprises several reservoirs of the same type as in Balder and a main reservoir of Jurassic age containing oil and associated gas.

Recovery strategy:
Balder and the Ringhorne deposit are recovered by natural aquifer drive and partly by gas injection.

Transport:
Oil and gas from the Jurassic reservoir at the Ringhorne deposit are transported to Jotun for processing, while oil from the Paleocene reservoirs is routed to Balder. Gas from Balder FPSO is transported to Jotun FPSO for gas lift and final processing and then exported via Statpipe. In periods with reduced gas export excess gas may be injected in Balder.

Status:
New seismic (4D) analysis will be used to evaluate new well locations.





Blane

Blocks and production licences	Block 1/2 - production licence 143 BS, awarded 2003 The Norwegian part of the field is 18%, the British part is 82%	
Discovered	1989	
Development approval	01.07.2005	
On stream	12.09.2007	
Operator	Talisman Energy Norge AS	
Licensees	Talisman Energy Norge AS	18.00 %
	Bow Valley Petroleum (UK) Limited	12.50 %
	Eni UK Limited	13.90 %
	Eni ULX Limited	4.11 %
	Moc Exploration (U.K.) Limited	13.99 %
	Roc Oil (GB) Limited	12.50 %
	Talisman North Sea Limited	25.00 %
Recoverable reserves (Norwegian part)	**Original:** 0.9 million scm oil	**Remaining as of 31.12.2008:** 0.7 million scm oil
Production	**Estimated production in 2009:** Oil: 2 000 barrels/day	
Investment	Total investment is expected to be NOK 0.6 billion (2009 values) NOK 0.6 billion have been invested as of 31.12.2008 (2009 values)	

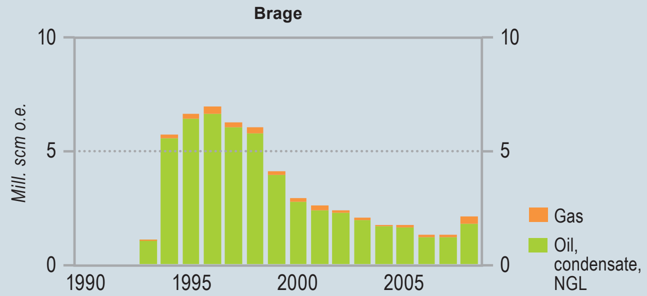
Development:
Blane is an oil field located in the southern part of the North Sea on the border to the British sector southwest of Ula. The water depth in the area is about 70 metres. The field has been developed with a subsea facility tied to the Ula field. The facilities on the seabed are located on the British continental shelf.

Reservoir:
The reservoir is in marine Paleocene sandstones of the Forties Formation at a depth of approximately 3 000 metres.

Recovery strategy:
Blane will be produced by pressure support from injection of produced water from Blane, Tambar and Ula. In addition gas lift will be used in the wells.

Transport:
The wellstream is transported in pipeline to Ula for processing and metering. The oil is exported in existing pipeline to Teesside while the gas is sold to Ula for injection in the Ula reservoir.

Status:
A water injection well was drilled in 2008. The water injection has been delayed due to risk of scaling since the injection water from Ula contains much sea water.



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	StatoilHydro Petroleum AS	
Licensees	Altinex Oil Norway AS	12.26 %
	Endeavour Energy Norge AS	4.44 %
	Petoro AS	14.26 %
	Wintershall Norge ASA	2.50 %
	StatoilHydro ASA	12.70 %
	StatoilHydro Petroleum AS	20.00 %
	Talisman Energy Norge AS	33.84 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	55.1 million scm oil	5.0 million scm oil
	3.9 billion scm gas	1.2 billion gas
	1.3 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 20 000 barrels/day, Gas: 0.15 billion scm, NGL: 0.05 million tonnes	
Investment	Total investment is expected to be NOK 23.4 billion (2009 values) NOK 21.2 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

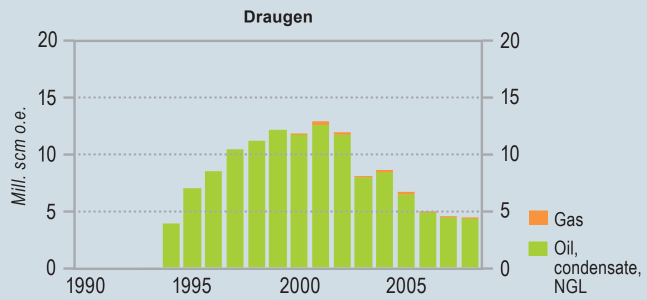
Development:
Brage is an oil field east of Oseberg in the northern part of the North Sea. The sea depth in the area is 140 metres. Brage has been developed with a fixed integrated production, drilling and accommodation facility with a steel jacket.

Reservoir:
The reservoir contains oil in sandstones of the Statfjord Formation of Early Jurassic age, and in the Brent Group and the Fensfjord Formation of Middle Jurassic age. There is also oil and gas in the Sognefjord Formation of Late Jurassic age. The reservoirs are at a depth of 2 000 – 2 300 metres. The reservoir quality varies from poor to excellent.

Recovery strategy:
The recovery mechanism in the Statfjord and Fensfjord formations is water injection. The wells in the Fensfjord Formation are also recovered by gas lift. The Sognefjord Formation has been recovered by pressure depletion, but gas injection will start in February 2009.

Transport:
The oil is sent by pipeline to Oseberg and on through 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 in progress to find new ways of increasing recovery from the field. The water injection capacity is being increased and produced water is reinjected into parts of the field. New wells have been drilled in 2007 and more wells are planned for the coming years. Adding chemicals to the injection water to improve water flow is also being evaluated. Production from the Brent reservoir started in 2008 and a water injection well will be drilled during 2009.



Draugen

Blocks and production licences	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 %
	Chevron Norge AS	7.56 %
	Petoro AS	47.88 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	143.1 million scm oil	21.2 million scm oil
	1.5 billion scm gas	0.1 billion scm gas
	2.4 million tonnes NGL	0.4 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 54 000 barrels/day, Gas: 0.07 billion scm, NGL: 0.11 million tonnes	
Investment	Total investment is expected to be NOK 33.7 billion (2009 values)	
	NOK 30.6 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

Development:
Draugen is an oil field in the Norwegian Sea at 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 pipelines transport the oil from 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 also has six subsea water injection wells, of these only two are being used.

Reservoir:
The main reservoir is in sandstones belonging to the Rogn Formation of Late Jurassic age. The Garn Formation of Middle Jurassic age in the western part of the field is also producing. The reservoirs lie at a depth of about 1 600 metres and are relatively homogenous, with good reservoir characteristics.

Recovery strategy:
The field is produced by pressure maintenance through water injection. Water injection north on the field ceased in 2005 due to technical reasons. Production data show that the field has sufficient natural pressure support in this area. Two new subsea wells started production in 2008.

Transport:
The oil is exported by tankers via a floating loading buoy. The associated gas is sent through the Åsgard Transport pipeline to Kårstø.

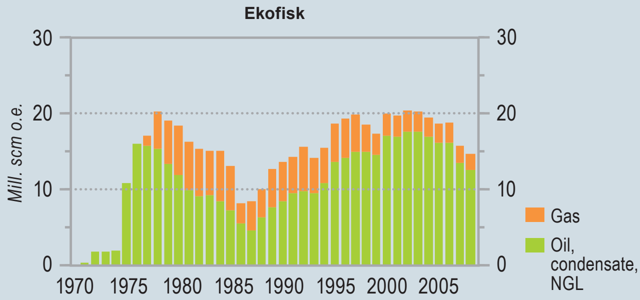
Status:
Several measures to increase oil recovery have been evaluated. The licensees have evaluated both gas injection and CO_2 injection, but both have been rejected. Additional wells are being evaluated for increased oil recovery. There are plans to tie the discovery 6407/9-9 to Draugen. Gas from this deposit will be used for power generation at Draugen.


Ekofisk

Blocks and production licences	Block 2/4 - production licence 018, awarded 1965	
Discovered	1969	
Development approval	01.03.1972	
On stream	15.06.1971	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11 %
	Eni Norge AS	12.39 %
	Petoro AS	5.00 %
	StatoilHydro ASA	0.95 %
	StatoilHydro Petroleum AS	6.65 %
	Total E&P Norge AS	39.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	528.5 million scm oil	125.7 million scm oil
	156.1 billion scm gas	20.4 billion scm gas
	14.5 million tonnes NGL	2.2 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 212 000 barrels/day, Gas: 2.50 billion scm, NGL: 0.24 million tonnes	
Investment	Total investment is expected to be NOK 185.7 billion (2009 values)	
	NOK 139.5 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Ekofisk is an oil field located in the southern part of the North Sea. 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 further developed with 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 wellhead facility for water injection Ekofisk W, the drilling and production facility Ekofisk X, the processing facility Ekofisk J and the production and processing facility Ekofisk M. From the wellhead facility Ekofisk A south on the field, production goes to the riser facility Ekofisk FTP for processing at the Ekofisk Centre. In 2007 the pipeline from Ekofisk B in the northern part of the field was rerouted to Ekofisk M. Ekofisk B is connected by bridge to Ekofisk K, which is a facility for water injection. A plan for water injection was approved on 20.12.1983, a PDO for Ekofisk II was approved on 09.11.1994 and Ekofisk Growth was approved on 06.06.2003.

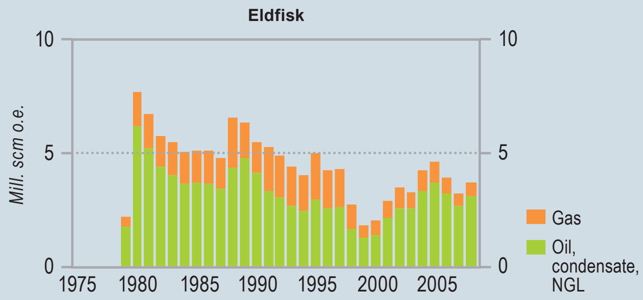
Reservoir:
The Ekofisk field produces from fractured chalk of the Ekofisk and Tor formations of Early Paleocene and Late Cretaceous ages. The reservoir rocks have high porosity, but low permeability. The reservoir has an oil column of more than 300 metres and lies 2 900 - 3 250 metres below sea level.



Recovery strategy:
Ekofisk was originally developed by pressure depletion and had an expected recovery factor of 17 per cent. 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 expected recovery factor for Ekofisk is now approximately 50 per cent. In addition to the water injection, compaction of the soft chalk provides extra force to the drainage of the field. The reservoir compaction has resulted in subsidence of the seabed, now more than 9 metres, centrally on the field. It is expected that the subsidence will continue for many years, but at a lower rate.

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 Norpipe Gas pipeline to Emden, while the oil, which also contains the NGL fractions, is sent via Norpipe Oil pipeline to Teesside.

Status:
Production from Ekofisk is maintained at a high level. This is mainly due to increased number of water injection wells and production from new facilities on the field. There are plans for new facilities and new drilling targets for extended water injection in the southern parts of the field. In addition to efforts to optimise short and long-term production, work on disposal of disused facilities is in progress.



Eldfisk

Blocks and production licences	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 %
	Petoro AS	5.00 %
	StatoilHydro ASA	0.95 %
	StatoilHydro Petroleum AS	6.65 %
	Total E&P Norge AS	39.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	135.1 million scm oil	45.9 million scm oil
	43.5 billion scm gas	5.9 billion scm gas
	4.0 million tonnes NGL	0.4 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 38 000 barrels/day, Gas: 0.45 billion scm, NGL: 0.05 million tonnes	
Investment	Total investment is expected to be NOK 96.8 billion (2009 values)	
	NOK 54.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

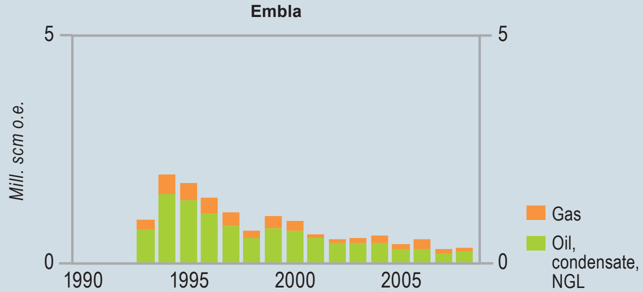
Development:
Eldfisk is an oil field located near Ekofisk in the southern part of the North Sea. The sea depth in the area is 70 - 75 metres. The original Eldfisk development consisted of three facilities. Eldfisk B is a combined drilling, wellhead and process facility, while Eldfisk A and FTP are wellhead and process facilities connected by a bridge. Eldfisk A also has drilling facilities. 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.

Reservoir:
The Eldfisk field produces from the Ekofisk, Tor and Hod chalk formations from the Early Paleocene and Late Cretaceous ages. The reservoir lies at a depth of 2 700 - 2 900 metres. The reservoir rock is finegrained and dense, but with high porosity. The field consists of three structures: Alpha, Bravo and Øst Eldfisk.

Recovery strategy:
Eldfisk was originally developed by pressure depletion. In 1999, water injection began at the field, based on horizontal injection wells. Gas is also injected in periods when export is not possible. Pressure depletion has caused compaction in the reservoir, which has resulted in several metres of seabed subsidence.

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:
The original facilities, Eldfisk A, B and FTP have a short remaining operating lifetime and must be upgraded or replaced if production from Eldfisk shall continue in the future. A major project has been initiated to find the best solution for a long-term development of the field.



Embla

Blocks and production licences	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 %
	Petoro AS	5.00 %
	StatoilHydro ASA	0.95 %
	StatoilHydro Petroleum AS	6.65 %
	Total E&P Norge AS	39.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	12.0 million scm oil	2.4 million scm oil
	5.6 billion scm gas	2.2 billion scm gas
	0.6 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 3 000 barrels/day, Gas: 0.10 billion scm, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 5 billion (2009 values)	
	NOK 4.4 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

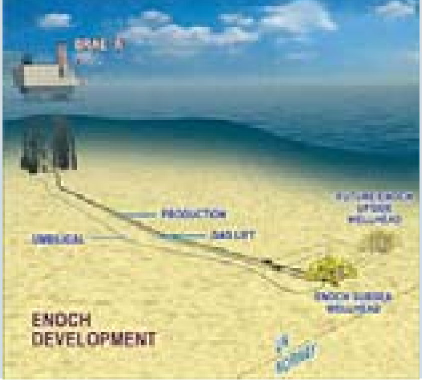
Development:
Embla is located close to Eldfisk in the southern part of the North Sea. The field has been developed with an unmanned wellhead facility which is remotely controlled from Eldfisk. The sea depth in the area is 70-75 metres. The amended PDO for Embla was approved on 25.04.1995.

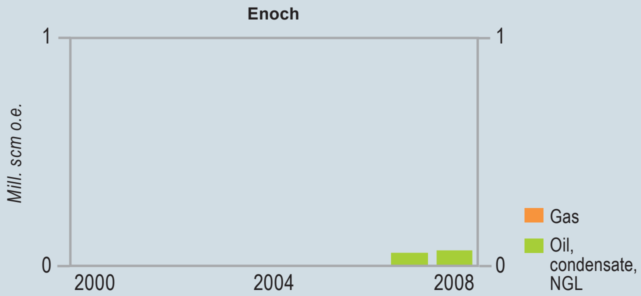
Reservoir:
The Embla field produces from a segmented sandstone reservoir of Devonian and Permian ages. The reservoir is complex and lies at a depth of more than 4 000 metres. Embla is the first field with high pressure and high temperature developed in the area.

Recovery strategy:
Embla is produced by pressure depletion.

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 by pipeline to Teesside.

Status:
In the long-term, new wells may be drilled at Embla if the lifetime of Eldfisk is extended.





Enoch

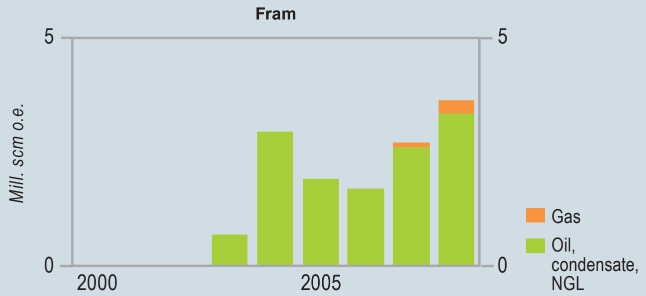
Blocks and production licences	Block 15/5 - production licence 048 B, awarded 2001 The Norwegian part of the field is 20%, the British part is 80%	
Discovered	1991	
Development approval	01.07.2005	
On stream	31.05.2007	
Operator	Talisman North Sea Limited	
Licensees	Altinex Oil Norway AS	4.36 %
	DONG E&P Norge AS	1.86 %
	Det norske oljeselskap ASA	2.00 %
	StatoilHydro ASA	11.78 %
	Bow Valley Petroleum (UK) Limited	12.00 %
	Dana Petroleum (E & P) Limited	8.80 %
	Dyas UK Limited	14.00 %
	Endeavour Energy (UK) Limited	8.00 %
	Roc Oil (GB) Limited	12.00 %
	Talisman LNS Limited	1.20 %
	Talisman North Sea Limited	24.00 %
Recoverable reserves (Norwegian part)	**Original:** 0.4 million scm oil	**Remaining as of 31.12.2008:** 0.3 million scm oil
Production	**Estimated production in 2009:** Oil: 1 000 barrels/day	
Investment	Total investment is expected to be NOK 0.2 billion (2009 values) NOK 0.2 billion have been invested as of 31.12.2008 (2009 values)	

Development:
Enoch is located in the southern part of the North Sea on the border to the British sector, northwest of Sleipner. The field has been developed with a subsea facility on the UK continental shelf and is tied to the British field Brae.

Reservoir:
The reservoir is in sandstones in a submarine fan system of Paleocene age at a depth of approximately 2 100 metres. The reservoir quality is varying.

Recovery strategy:
The field is recovered by pressure depletion. Water injection may be implemented at a later stage.

Transport:
The wellstream from Enoch is transported to the Brae A facility for processing and further transport in pipeline to Cruden Bay. The gas is sold to Brae.



Fram

Blocks and production licences	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	StatoilHydro Petroleum AS	
Licensees	ExxonMobil Exploration & Production Norway AS	25.00 %
	GDF SUEZ E&P Norge AS	15.00 %
	Idemitsu Petroleum Norge AS	15.00 %
	StatoilHydro ASA	20.00 %
	StatoilHydro Petroleum AS	25.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	23.9 million scm oil	10.8 million scm oil
	8.4 billion scm gas	8.0 billion scm gas
	0.1 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 42 000 barrels/day, Gas: 0.38 billion scm, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 11.7 billion (2009 values)	
	NOK 10.8 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

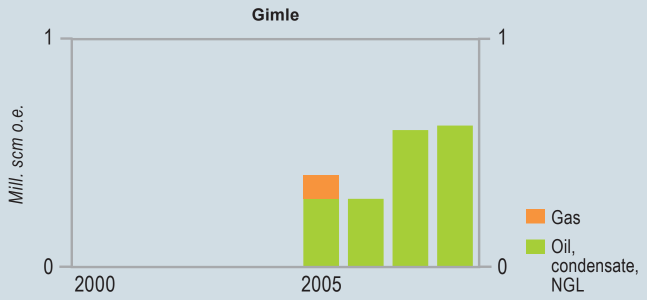
Development:
Fram is an oil field located in the northern part of the North Sea, about 20 kilometres north of Troll. The sea depth in the area is 350 metres. The field comprises two deposits, Fram Vest and Fram Øst. The Fram Vest deposit is developed by two subsea templates tied back to Troll C. The gas is separated from the liquid on Troll C and reinjected into the Fram Vest reservoir. The development of the Fram Øst deposit was approved on 22.04.2005. The development includes two subsea templates tied back to Troll C. Production from Fram Øst started in October 2006.

Reservoir:
The reservoirs in Fram Vest and Fram Øst consist partly of Upper Jurassic turbidity sandstones of the Draupne Formation and shallow marine sandstones in the Sognefjord Formation, and partly sandstones of the Brent Group of Middle Jurassic age. The reservoirs are in several isolated rotated fault blocks and contain oil with an overlying gas cap. The reservoir depth is 2 300 - 2 500 metres. The reservoir in the Fram Vest deposit is complex while the reservoirs in the Fram Øst deposit are generally of good quality.

Recovery strategy:
Production from the Fram Vest deposit takes place with gas injection as pressure support. Gas export from Fram started in the autumn of 2007. From the beginning of 2009, the Fram Øst deposit of the Sognefjord Formation is produced by injection of produced water as pressure support, in addition to natural aquifer drive. The Brent reservoir in the Fram Øst deposit is recovered by pressure depletion. Gas lift will also be used in the wells.

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. Gas which is not injected is exported via Troll A to Kollsnes.

Status:
The oil production is dependent on the gas production capacity at Troll C. Several production wells were drilled on the Fram Øst deposit in 2008, among them a multibranch well. Additional resources from new deposits in the area near the field are being considered for a Phase 3 development of Fram. Several exploration wells may be drilled in the area in the coming years.



Gimle

Blocks and production licences	Block 34/10 - production licence 050 DS, awarded 2006	
Discovered	2004	
Development approval	18.05.2006	
On stream	19.05.2006	
Operator	StatoilHydro ASA	
Licensees	ConocoPhillips Skandinavia AS	5.79 %
	Petoro AS	24.19 %
	StatoilHydro ASA	47.23 %
	StatoilHydro Petroleum AS	17.90 %
	Total E&P Norge AS	4.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	4.0 million scm oil	2.3 million scm oil
	1.1 billion scm gas	1.0 billion scm gas
	0.2 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 8 000 barrels/day	
Investment	Total investment is expected to be NOK 1.0 billion (2009 values)	
	NOK 0.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	

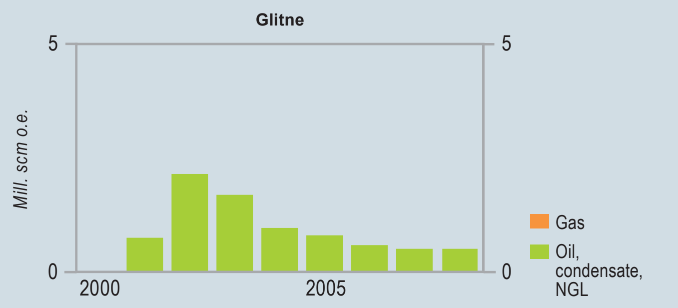
Development:
Gimle is a small oil field in the northern part of the North Sea. The sea depth in the area is about 220 metres. The field is tied to the Gullfaks C facility by three wells.

Reservoir:
The reservoir consists of sandstones of the Tarbert Formation of Middle Jurassic age, in a downfaulted structure north-east of Gullfaks. The reservoir depth is about 2 900 metres. The reservoir characteristics are good with a few minor faults.

Recovery strategy:
The field is recovered by water injection from an injection well giving pressure support to the reservoir.

Transport:
The production from Gimle is processed on the Gullfaks C facility and transported together with oil and gas from Gullfaks.

Status:
Drilling of the second and last production well started in November 2007 and the well was completed and came on stream in the summer of 2008. The well also had exploration targets in two prospects, but did not reach the targets.



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	StatoilHydro ASA	
Licensees	DONG E&P Norge AS	9.30 %
	Det norske oljeselskap ASA	10.00 %
	StatoilHydro ASA	58.90 %
	Total E&P Norge AS	21.80 %
Recoverable reserves	**Original:** 8.3 million scm oil	**Remaining as of 31.12.2008:** 0.3 million scm oil
Production	**Estimated production in 2009:** Oil: 5 000 barrels/day	
Investment	Total investment is expected to be NOK 2.8 billion (2009 values) NOK 2.8 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

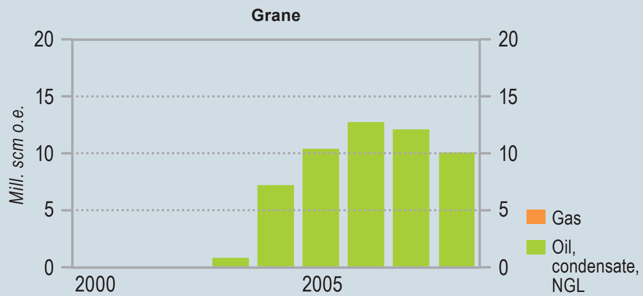
Development:
Glitne is an oil field in the southern part of the North Sea, 40 kilometres north of the Sleipner area. The sea depth in the area is about 110 metres. The development consists of six production wells and a water injection well tied back to the floating production, storage and offloading vessel, Petrojarl 1.

Reservoir:
The reservoir consists of several separate sand sheets of deepmarine fan deposits in the upper part of the Heimdal Formation of Paleocene age. The reservoir lies at a depth of approximately 2 150 metres.

Recovery strategy:
Glitne is recovered by pressure support partly from reinjection of produced water in one well and partly from a large aquifer. In addition associated gas is used for gas lift in the horizontal wells.

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

Status:
The last well was drilled and came on stream in 2007. It is expected that the production from the field will cease in 2010, but various measures to increase the lifetime of the field are still being considered. Seismic data acquired in 2008, will be interpreted in order to find possible remaining resources which may be produced with a new well.



Grane

Blocks and production licences	Block 25/11 - production licence 001, awarded 1965 Block 25/11 - production licence 169 B1, awarded 2000	
Discovered	1991	
Development approval	14.06.2000 by the Storting	
On stream	23.09.2003	
Operator	StatoilHydro Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	6.40 %
	ExxonMobil Exploration & Production Norway AS	25.60 %
	Petoro AS	30.00 %
	StatoilHydro Petroleum AS	38.00 %
Recoverable reserves	**Original:** 116.2 million scm oil	**Remaining as of 31.12.2008:** 63.4 million scm oil
Production	**Estimated production in 2009:** Oil: 148 000 barrels/day	
Investment	Total investment is expected to be NOK 26.1 billion (2009 values) NOK 19.1 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Grane is an oil field located to the east of the Balder field in the northern part of the North Sea. The sea depth is 128 metres. The field has been developed with an integrated accommodation, drilling and processing facility with a fixed steel jacket. The facility has 40 well slots.

Reservoir:
The field consists of one main reservoir structure and some additional segments. The reservoir consists of sandstones of the Heimdal Formation of Paleocene age with good reservoir characteristics and lies at a depth of approximately 1 700 metres. The oil has high viscosity. Oil is also present in a reservoir in the Lista Formation.

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. The oil in the Lista Formation will probably be recovered with support from the gas injection in the Heimdal Formation. Four water injection wells are planned later in the production period.

Transport:
Oil from Grane is sent by pipeline to the Sture terminal for storage and export. Injection gas is imported to Grane through a pipeline from the Heimdal facility.

Status:
Several new wells are being planned, most of them as multilateral wells. The first water injection well is planned to be drilled in 2010.

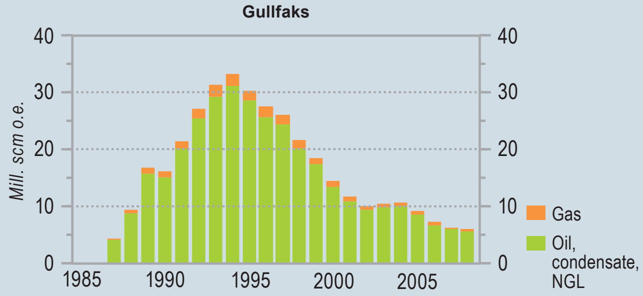
Gullfaks

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	StatoilHydro ASA	
Licensees	Petoro AS	30.00 %
	StatoilHydro ASA	61.00 %
	StatoilHydro Petroleum AS	9.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	360.1 million scm oil	20.1 million scm oil
	24.2 billion scm gas	1.5 billion scm gas
	3.0 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 88 000 barrels/day, Gas: 0.39 billion scm, NGL: 0.09 million tonnes	
Investment	Total investment is expected to be NOK 135.2 billion (2009 values) NOK 122.1 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

Development:
Gullfaks is located in the Tampen area in the northern part of the North Sea. The sea depth in the area is 130 - 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 and Gimle. 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.

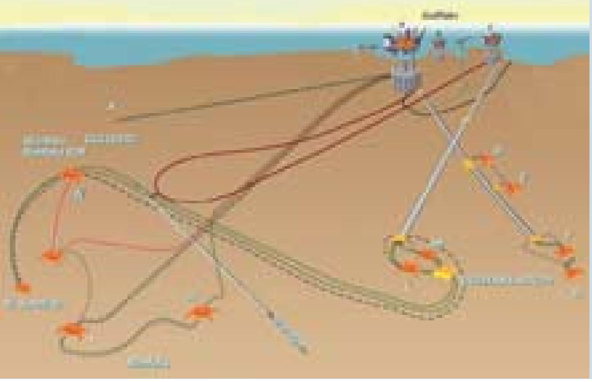
Reservoir:
The Gullfaks reservoirs consist of Middle Jurassic sandstones of the Brent Group, and Lower Jurassic and Upper Triassic sandstones of the Cook, Statfjord and Lunde formations. The reservoirs are 1 700 - 2 000 metres below the sea level. The Gullfaks reservoirs are located in rotated fault blocks in the west and a structural horst in the east, with an intermediate highly faulted area.

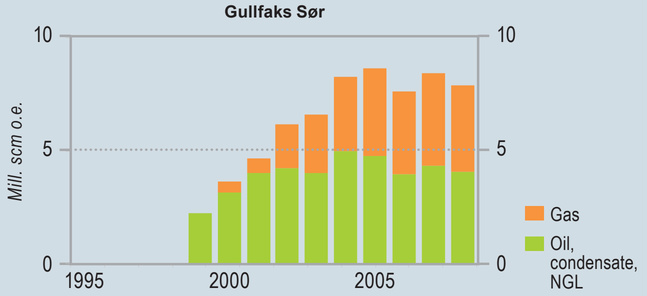
Recovery strategy:
The drive mechanisms are water injection, gas injection or water/alternating gas injection (WAG). The drive mechanism varies between the drainage areas in the field, but water injection constitutes the main strategy.



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 waterflooded areas, and partly through continued massive water circulation. Implementation of a chemical flooding pilot will be considered in 2010. A new project has also been initiated to evaluate necessary facility upgrades for lifetime extension of the field towards 2030.





Gullfaks Sør

Blocks and production licences	Block 32/12 - production licence 152, awarded 1988 Block 33/12 - production licence 037 B, awarded 1998 Block 33/12 - production licence 037 E, awarded 2004 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	StatoilHydro ASA
Licensees	Petoro AS 30.00 % StatoilHydro ASA 61.00 % StatoilHydro Petroleum AS 9.00 %
Recoverable reserves	**Original:** 47.9 million scm oil, 45.7 billion scm gas, 6.1 million tonnes NGL **Remaining as of 31.12.2008:** 14.3 million scm oil, 21.7 billion scm gas, 3.2 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 48 000 barrels/day, Gas: 2.41 billion scm, NGL: 0.32 million tonnes
Investment	Total investment is expected to be NOK 40.2 billion (2009 values) NOK 32.8 billion have been invested as of 31.12.2008 (2009 values)
Operating organisation	Bergen
Main supply base	Sotra and Florø

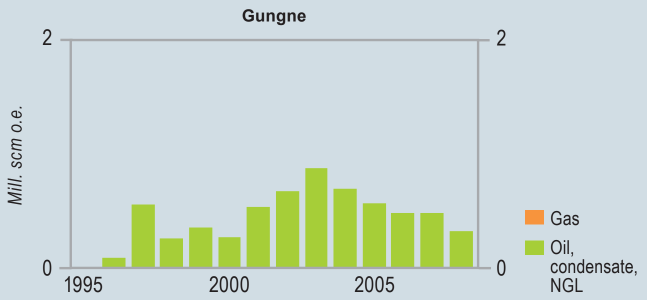
Development:
Gullfaks Sør is located to the south of Gullfaks in the northern part of the North Sea. It has been developed with a total of eleven subsea templates tied back to the Gullfaks A and Gullfaks C facilities. The Gullfaks Sør deposits have been developed in two phases. The PDO for Phase 1 included 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. The Gulltopp deposit is 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 started in January 2007.

Reservoir:
The Gullfaks Sør reservoirs consist of Middle Jurassic sandstones of the Brent Group and Lower Jurassic and Upper Triassic sandstones of the Cook, Statfjord and Lunde formations. Only the Brent and Statfjord reservoirs are currently developed. The reservoirs lie 2 400 - 3 400 metres below the sea level, 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 the Gullfaks Sør deposits is partly driven by pressure support from gas injection, and partly by pressure depletion. The Rimfaks deposit in the Brent Group is produced using full pressure maintenance by gas injection whereas Gullfaks Sør and the Rimfaks deposit in the Statfjord Formation have partial gas injection. The deposits Gullveig, Skinfaks and Gulltopp are recovered by pressure depletion, and the production is also affected by the production from Tordis and Gullfaks.

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

Status:
The Gulltopp deposit came on stream in April 2008. Plans are being made for a future gas phase for the deposits now mainly producing oil. After evaluation in 2008, the gas injection period was prolonged by two years. As part of the project, Gullfaks towards 2030, future low pressure production from Gullfaks Sør is being considered.



Gungne

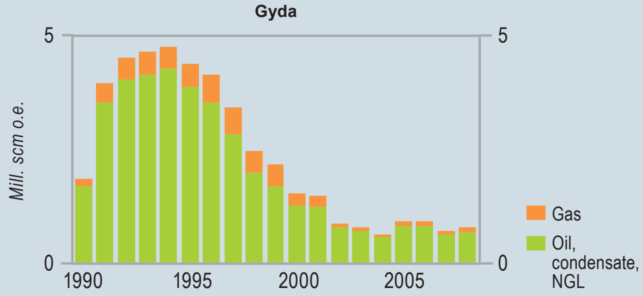
Blocks and production licences	Block 15/9 - production licence 046, awarded 1976	
Discovered	1982	
Development approval	29.08.1995 by the King in Council	
On stream	21.04.1996	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	28.00 %
	StatoilHydro ASA	52.60 %
	StatoilHydro Petroleum AS	9.40 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	14.6 billion scm gas	2.4 billion scm gas
	1.9 million tonnes NGL	0.3 million tonnes NGL
	4.0 million scm condensate	
Production	**Estimated production in 2009:**	
	Gas: 1.13 billion scm, NGL: 0.08 million tonnes	
Investment	Total investment is expected to be NOK 2.2 billion (2009 values)	
	NOK 1.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
Gungne is a gas condensate field located in the Sleipner area in the southern part of the North Sea. The sea depth in the area is 83 metres. Gungne produces via three wells drilled from Sleipner A.

Reservoir:
The reservoir consists of sandstones of the Skagerrak Formation of Triassic age. The reservoir depth is about 2 800 metres. The reservoir quality is generally good, but the reservoir is segmented and lateral, continuous shale layers act as barriers.

Recovery strategy:
Gungne is recovered by pressure depletion.

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 Zeepipe to Zeebrugge.



Gyda

Blocks and production licences	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 E&P Norge AS	34.00 %
	Norske AEDC A/S	5.00 %
	Talisman Energy Norge AS	61.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	38.8 million scm oil	4.1 million scm oil
	6.2 billion scm gas	0.3 billion scm gas
	1.9 million tonnes NGL	
Production	**Estimated production in 2009:**	
	Oil: 10 000 barrels/day, Gas: 0.13 billion scm	
Investment	Total investment is expected to be NOK 19.1 billion (2009 values)	
	NOK 16.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

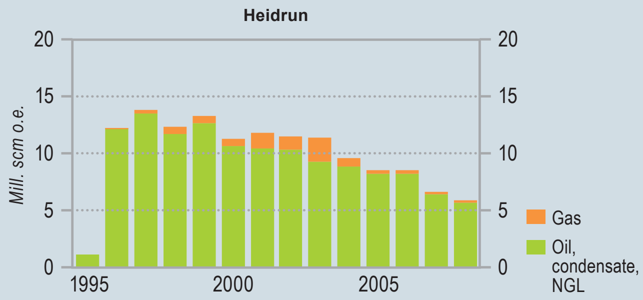
Development:
The Gyda field is located between Ula and Ekofisk in the southern part of the North Sea. It has been developed with a combined drilling, accommodation and processing facility with a steel jacket. The sea depth in the area is 66 metres.

Reservoir:
The field consists of three reservoir areas in Upper Jurassic sandstones of the Ula Formation. The reservoir depth is about 4 000 metres.

Recovery strategy:
The field produces with water injection as drive mechanism for the main part of the field. Pressure support from the gas cap and the aquifer are drive mechanisms for other parts of the field.

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

Status:
Gyda is in its tail phase and experiences increasing water production and challenges in maintaining the oil production. The production licence period has been extended to 2018 and work is ongoing to prolong the lifetime of the field correspondingly. Several new wells are being drilled on the field. A compressor was installed in 2007 for a gas lift pilot. This has resulted in increased production from the wells. Improved recovery by means of gas injection is being considered. Full gas lift is also being considered. In addition it is considered to tie-in other deposits in the area to Gyda.



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	StatoilHydro ASA	
Licensees	ConocoPhillips Skandinavia AS	24.31 %
	Eni Norge AS	5.12 %
	Petoro AS	58.16 %
	StatoilHydro ASA	12.41 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	186.0 million scm oil	58.7 million scm oil
	41.6 billion scm gas	30.1 billion scm gas
	1.7 million tonnes NGL	1.2 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 75 000 barrels/day, Gas: 0.24 billion scm, NGL: 0.03 million tonnes	
Investment	Total investment is expected to be NOK 83.1 billion (2009 values) NOK 66.7 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

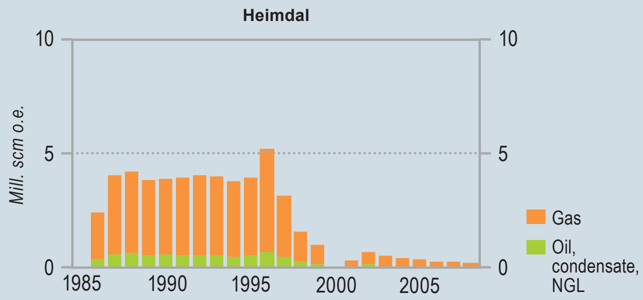
Development:
The Heidrun field is located on Haltenbanken in the Norwegian Sea. The sea depth in the area is 350 metres. The field has been developed with a floating concrete tension leg platform, installed over a subsea template with 56 well slots. The northern part of the field is developed with subsea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

Reservoir:
The reservoir consists of sandstones of the Garn, Ile, Tilje and Åre formations of Early and Middle Jurassic age. The reservoir is heavily faulted. The Garn and Ile formations have good reservoir quality, while the Tilje and Åre formations are more complex. The reservoir depth is about 2 300 metres.

Recovery strategy:
The recovery strategy for the field is pressure maintenance using water and gas injection in the Garn and Ile formations. In the more complex part of the reservoir, in the Tilje and Åre formations, the main recovery strategy is water injection.

Transport:
The oil is transferred to tankers at the field and shipped to Mongstad and Tetney (UK). The gas is transported in a pipeline to Tjeldbergodden and in Åsgard Transport to Kårstø.

Status:
Continuous efforts are being made to find new methods to increase oil recovery. Several wells have been drilled over the past years and new well targets are continuously being considered. CO_2 injection has also been considered, but for the time being this is not an option. An extension of the gas treatment capacity and different pilots to improve recovery from the reservoir are being considered.



Heimdal

Blocks and production licences	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	StatoilHydro Petroleum AS	
Licensees	Centrica Resources (Norge) AS	23.80 %
	Petoro AS	20.00 %
	StatoilHydro ASA	20.00 %
	StatoilHydro Petroleum AS	19.44 %
	Total E&P Norge AS	16.76 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	7.1 million scm oil	0.7 million scm oil
	44.6 billion scm gas	0.3 billion scm gas
Production	**Estimated production in 2009:**	
	Gas: 0.17 billion scm	
Investment	Total investment is expected to be NOK 22.4 billion (2009 values)	
	NOK 21.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

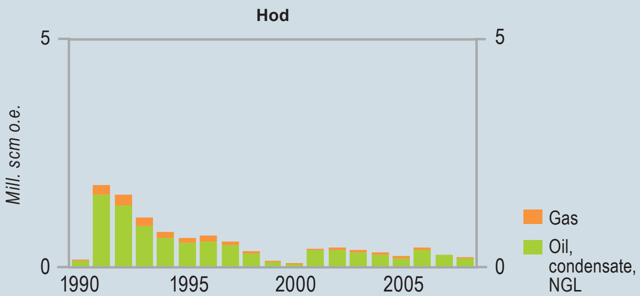
Development:
Heimdal is a gas field located in the northern part of the North Sea. The sea depth in the area is 120 metres. The field has been developed with an integrated drilling, production and accommodation facility with a steel jacket (HMP1). The Heimdal Jurassic development was approved on 02.10.1992. PDO for Heimdal Gas Centre (HGS) was approved on 15.01.1999. This included a new riser facility (HRP), bridge-connected to HMP1. Heimdal is now mainly a processing centre for other fields. Huldra, Skirne and Vale deliver gas to Heimdal, and in addition, gas from Oseberg is transported via Heimdal.

Reservoir:
The reservoir consists of sandstones of the Heimdal Formation of Paleocene age, deposited as deepmarine turbidity currents. The reservoir depth is about 2 100 metres.

Recovery strategy:
The field has been recovered by pressure depletion and has now more or less ceased producing.

Transport:
Originally, gas from Heimdal was sent in Statpipe to Kårstø and on to the Continent, but can now also be sent in Vesterled to St. Fergus in the United Kingdom. After Heimdal Gas centre was established, a new gas pipeline was connected to the existing gas pipeline from Frigg to St. Fergus. A gas pipeline has also been laid from Heimdal to Grane for gas injection. Condensate is transported by pipeline to Brae in the British sector.

Status:
The licensees are searching for new gas resources that can be tied to Heimdal to prolong the lifetime of the gas centre.



Hod

Blocks and production licences	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	BP Norge AS	25.00 %
	Enterprise Oil Norge AS	25.00 %
	Hess Norge AS	25.00 %
	Total E&P Norge AS	25.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	10.2 million scm oil	1.2 million scm oil
	1.8 billion scm gas	0.2 billion scm gas
	0.4 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 3 000 barrels/day, Gas: 0.03 billion scm	
Investment	Total investment is expected to be NOK 3.3 billion (2009 values)	
	NOK 2.8 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

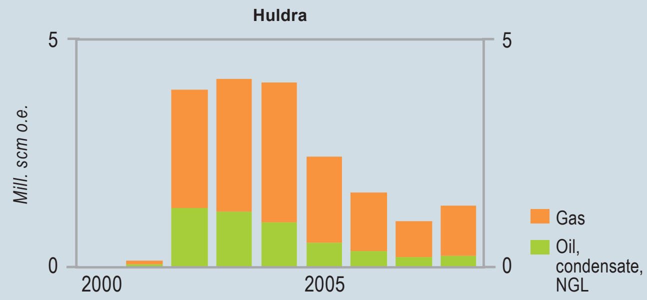
Development:
Hod is an oil field located 13 kilometres south of the Valhall field in the southern part of the North Sea. The sea depth is 72 metres. The field is developed with an unmanned production facility, which is remotely controlled from the Valhall field. The PDO for the Hod Sadel area was approved on 20.06.1994.

Reservoir:
The reservoir consists of chalk in the Ekofisk, Tor and Hod formations of Early Paleocene and Late Cretaceous age. The reservoir depth is approximately 2 700 metres. The field consists of the three structures, Hod Vest, Hod Øst and Hod Sadel. Hod Sadel is connected to Valhall and is producing through four wells drilled from Valhall.

Recovery strategy:
Recovery takes place through pressure depletion. Five wells are in production and gas lift is used in two wells to increase production. There are plans to start a water injection pilot at Hod.

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. An injection pump will be installed in 2009 to start water injection in one well.



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	StatoilHydro ASA	
Licensees	ConocoPhillips Skandinavia AS	23.34 %
	Petoro AS	31.96 %
	StatoilHydro ASA	19.88 %
	Talisman Energy Norge AS	0.50 %
	Total E&P Norge AS	24.33 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	4.9 million scm oil	0.3 million scm oil
	15.9 billion scm gas	2.1 billion scm gas
	0.1 million tonnes NGL	
Production	**Estimated production in 2009:** Oil: 3 000 barrels/day, Gas: 0.83 billion scm	
Investment	Total investment is expected to be NOK 9.0 billion (2009 values) NOK 9.0 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

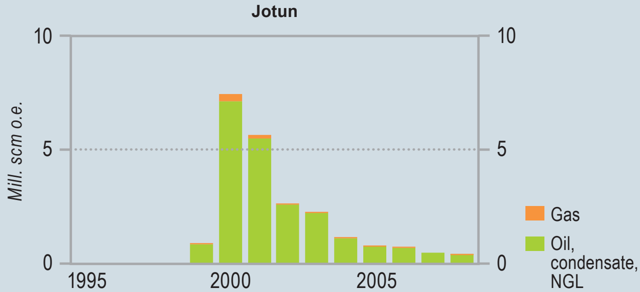
Development:
Huldra is a gas condensate field located north of Oseberg in the northern part of the North Sea. The field is developed with a steel wellhead facility with a simple process plant. The facility is remotely operated from Veslefrikk B, 16 kilometres away. The sea depth in the area is 125 metres.

Reservoir:
The reservoir is in Jurassic sandstones of the Brent Group in a rotated fault block. The reservoir has high pressure and high temperature and lies at a depth of 3 500 – 3 900 metres. 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:
Huldra is recovered by pressure depletion. The field went off plateau in the autumn of 2004.

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:
After installation of a gas compressor on the field, the low pressure production started in June 2007. The compressor will increase the recovery at reduced wellhead pressure and prolong the lifetime of the field with five years. A well was drilled in the summer of 2008 to prove resources in deeper layers, but the well was dry.



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 & Production Norway AS	
Licensees	Dana Petroleum Norway AS	45.00 %
	ExxonMobil Exploration & Production Norway AS	45.00 %
	Lundin Norway AS	7.00 %
	Petoro AS	3.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	23.6 million scm oil	1.8 million scm oil
	0.8 billion scm gas	
Production	**Estimated production in 2009:**	
	Oil: 6 000 barrels/day	
Investment	Total investment is expected to be NOK 12.3 billion (2009 values) NOK 12.3 billion have been invested as of 31.12.2008 (2009 values	
Operating organisation	Stavanger	
Main supply base	Dusavik	

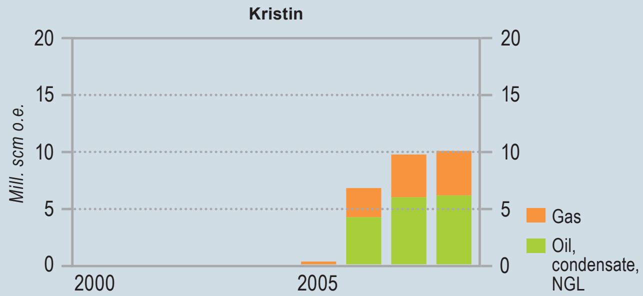
Development:
Jotun is an oil field located 25 kilometres north of Balder in the northern part of the North Sea. The sea depth in the area is 126 metres. The field has been developed with a combined accommodation, production and storage vessel (FPSO), Jotun A, and a wellhead facility, Jotun B. Jotun is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

Reservoir:
The Jotun field comprises three structures and the eastern structure has a gas cap. The reservoirs consist of sandstones of the Heimdal Formation of Paleocene age. The reservoirs are deposited in a submarine fan system and lie at a depth of about 2 000 metres. To the west the sand has good reservoir quality, while the shale content increases towards the east.

Recovery strategy:
The field is recovered by pressure support from the aquifer, combined with reinjection of produced water. Gas lift is used in all wells.

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

Status:
The field is in the decline phase and is now producing more than 90 per cent water. There are no plans for measures to improve recovery, but exploration drilling will be carried out near Jotun the coming years, which may prove new resources to the field.



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	StatoilHydro ASA	
Licensees	Eni Norge AS	8.25 %
	ExxonMobil Exploration & Production Norway AS	10.88 %
	Petoro AS	19.58 %
	StatoilHydro ASA	55.30 %
	Total E&P Norge AS	6.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	23.9 million scm oil	14.1 million scm oil
	26.0 billion scm gas	15.5 billion scm gas
	5.7 million tonnes NGL	3.5 million tonnes NGL
	2.1 million scm condensate	
Production	**Estimated production in 2009:** Oil: 49 000 barrels/day, Gas: 2.73 billion scm, NGL: 0.59 million tonnes	
Investment	Total investment is expected to be NOK 27.6 billion (2009 values) NOK 26.3 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

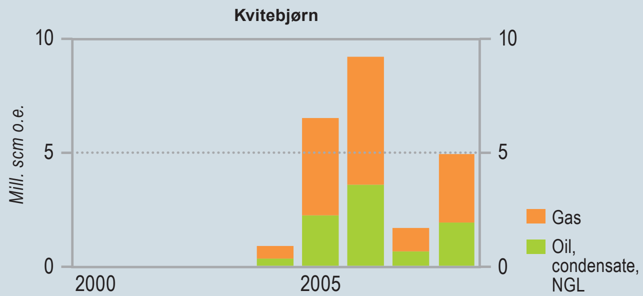
Development:
Kristin is a gas condensate field in the Norwegian Sea. The field is developed with four subsea templates tied back to a semi-submersible production facility. The sea depth in the area is about 370 metres. Provision has been made for tie-in and processing of other deposits in the area when Kristin comes off plateau. Tyrihans is now being tied back to Kristin.

Reservoir:
The reservoirs are in Jurassic sandstones of the Garn, Ile and Tofte formations and contain gas and condensate under very high pressure and with very high temperatures. The reservoirs lie at a depth of 4 600 metres. The reservoir quality is good.

Recovery strategy:
Kristin is recovered by pressure depletion.

Transport:
The rich gas from Kristin is transported in a dedicated pipeline to Åsgard Transport and further to Kårstø. Light oil is separated and stabilised on Kristin and transferred to Åsgard for storage and export. Condensate from Kristin is sold as oil (Halten Blend).

Status:
The reservoir pressure at Kristin is decreasing faster than expected. Work is ongoing to find solutions to production and drilling challenges related to pressure decrease and water breakthrough in wells. There are plans to drill infill wells to improve recovery. Extension of the lifetime for the semi submersible production facility is also a central element with regard to resource exploitation in the area.



Kvitebjørn

Blocks and production licences	Block 34/11 - production licence 193, awarded 1993	
Discovered	1994	
Development approval	14.06.2000 by the Storting	
On stream	26.09.2004	
Operator	StatoilHydro ASA	
Licensees	Enterprise Oil Norge AS	6.45 %
	Petoro AS	30.00 %
	StatoilHydro ASA	43.55 %
	StatoilHydro Petroleum AS	15.00 %
	Total E&P Norge AS	5.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	27.4 million scm oil	20.1 million scm oil
	74.0 billion scm gas	59.4 billion scm gas
	3.0 million tonnes NGL	1.7 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 41 000 barrels/day, Gas: 5.41 billion scm, NGL: 0.23 million tonnes	
Investment	Total investment is expected to be NOK 17.3 billion (2009 values)	
	NOK 13.3 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Florø	

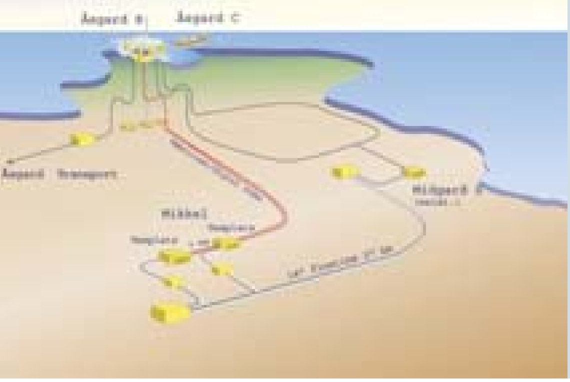
Development:
Kvitebjørn is a gas condensate field located east in the Tampen area in the northern part of the North Sea. The field is developed with an integrated accommodation, drilling and processing facility with a steel jacket. Sea depth in the area is about 190 metres. 10 production wells have been drilled in the reservoir. Drill cuttings and produced water are injected in a dedicated disposal well. Revised PDO for Kvitebjørn was approved in December 2006.

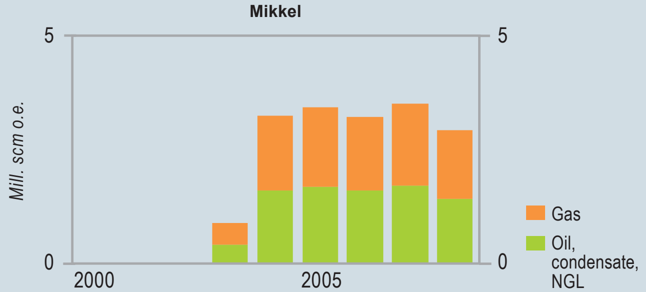
Reservoir:
The reservoir consists of Middle Jurassic sandstones of the Brent Group. The reservoir lies at approximately 4 000 metres depth, and has high temperature and high pressure. The reservoir quality is good.

Recovery strategy:
The field is recovered by pressure depletion. In 2008, the licensees decided to install a compressor to be able to further decrease the reservoir pressure and improve recovery.

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:
The production from Kvitebjørn has been temporarily reduced in 2008 to make it possible to drill additional wells before the reservoir pressure becomes too low. The production has also been closed down due to the gas pipeline having a leakage at the sea bottom. The damage was caused by a ship anchor. The production was resumed in January 2009.





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	StatoilHydro ASA	
Licensees	Eni Norge AS	14.90 %
	ExxonMobil Exploration & Production Norway AS	33.48 %
	StatoilHydro ASA	43.97 %
	Total E&P Norge AS	7.65 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	4.6 million scm oil	3.1 million scm oil
	21.9 billion scm gas	13.0 billion scm gas
	6.0 million tonnes NGL	3.6 million tonnes NGL
	2.3 million scm condensate	
Production	**Estimated production in 2009:** Oil: 9 000 barrels/day, Gas: 1.75 billion scm, NGL: 0.47 million tonnes	
Investment	Total investment is expected to be NOK 2.4 billion (2009 values) NOK 2.2 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

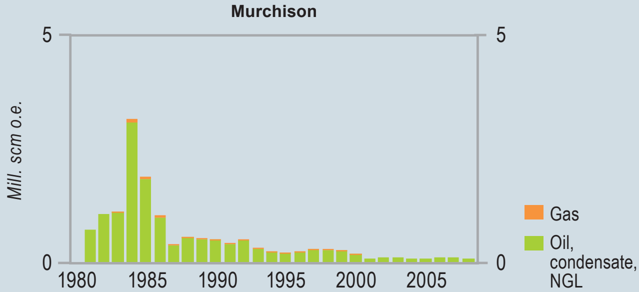
Development:
Mikkel is a gas condensate field located east in the Norwegian Sea, about 30 kilometres north of Draugen. The sea depth in the area is 220 metres. The field has been developed with two subsea templates tied back to Åsgard B.

Reservoir:
The field has a 300 metres thick gas condensate column and a thin underlying oil rim. The reservoir consists of Jurassic sandstones in the Garn, Ile and Tofte formations in six structures separated by faults, all with good reservoir quality. The reservoir depth is approximately 2 500 metres.

Recovery strategy:
Mikkel is recovered by pressure depletion.

Transport:
Produced gas and condensate are mixed with the wellstream from the Midgard deposit and routed to Åsgard B for processing. The condensate is separated from the gas and stabilised before it is shipped together with condensate from Åsgard. The condensate is sold as oil (Åsgard Blend). The rich gas is sent through the Åsgard Transport pipeline to Kårstø for separation of NGL. The dry gas is transported on from Kårstø to the Continent through the Europipe II pipeline.

Status:
An additional compressor is planned to be installed to maintain the pressure in the pipeline from Mikkel.



Murchison

Blocks and production licences	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	Wintershall Norge ASA	22.20 %
	CNR International (UK) Limited	77.80 %
Recoverable reserves (Norwegian part)	**Original:**	**Remaining as of 31.12.2008:**
	14.6 million scm oil	0.9 million scm oil
	0.4 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2009:** Oil: 1 000 barrels/day	
Investment	Total investment is expected to be NOK 8.2 billion (2009 values) NOK 8.1 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Aberdeen, Scotland	
Main supply base	Peterhead, Scotland	

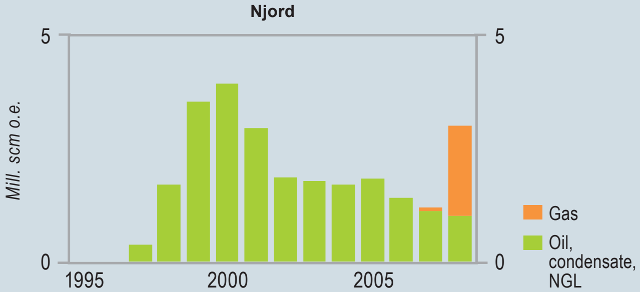
Development:
Murchison straddles the border between the Norwegian and British sector in the northern part of the North Sea. The field has been developed with a combined drilling, accommodation and production facility with a steel jacket in the British sector. The British and Norwegian licensees entered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

Reservoir:
The reservoirs are in Jurassic sandstones.

Recovery strategy:
The field is recovered by pressure support from water injection.

Transport:
The production is sent through the Brent system to Sullom Voe in the Shetlands.

Status:
Murchison is in tail production.



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	StatoilHydro Petroleum AS	
Licensees	E.ON Ruhrgas Norge AS	30.00 %
	Endeavour Energy Norge AS	2.50 %
	ExxonMobil Exploration & Production Norway AS	20.00 %
	GDF SUEZ E&P Norge AS	20.00 %
	Petoro AS	7.50 %
	StatoilHydro ASA	20.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	25.2 million scm oil	2.3 million scm oil
	10.7 billion scm gas	8.6 billion scm gas
	2.1 million tonnes NGL	2.1 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 15 000 barrels/day, Gas: 1.79 billion scm, NGL: 0.36 million tonnes	
Investment	Total investment is expected to be NOK 18 billion (2009 values) NOK 15.3 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

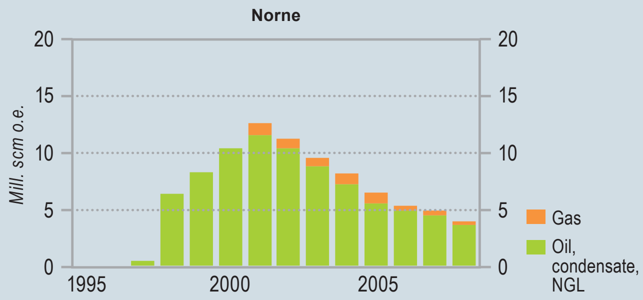
Development:
Njord is an oil field located about 30 kilometres west of Draugen in the Norwegian Sea. The sea depth in the area is 330 metres. The field has been developed with a semi-submersible drilling, accommodation and production facility and a storage vessel, Njord B. The facility is located over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

Reservoir:
The reservoir consists of Jurassic sandstones of the Tilje and Ile formations. The field has a complicated fault pattern with only partial communication between the segments. The reservoir depth is approximately 2 850 metres.

Recovery strategy:
Most of the gas produced at Njord has been reinjected in four wells for pressure support and increased oil recovery from parts of the field. Gas export from the field started in December 2007, and only minor volumes of gas are now being injected. A total of 15 production wells have been drilled during several drilling campaigns. The ambitions of the licensees are to drill further 9 – 15 well targets to improve recovery from the field. Due to the complex reservoir with many faults, the field has a relatively low recovery factor.

Transport:
The oil is off-loaded from the storage vessel to tankers for transport to the market. The gas is transported through Åsgard Transport to Kårstø.

Status:
A new drilling campaign to improve oil recovery started in the autumn of 2008. Two wells were drilled to the northwestern flank of the field in 2007 and 2008. These segments are planned to be tied in to Njord, with expected production start in 2010/2011.



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	StatoilHydro ASA	
Licensees	Eni Norge AS	6.90 %
	Petoro AS	54.00 %
	StatoilHydro ASA	39.10 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	94.9 million scm oil	14.4 million scm oil
	11.0 billion scm gas	5.2 billion scm gas
	1.7 million tonnes NGL	1.0 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 53 000 barrels/day, Gas: 0.26 billion scm, NGL: 0.04 million tonnes	
Investment	Total investment is expected to be NOK 32.8 billion (2009 values) NOK 24.4 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Harstad	
Main supply base	Sandnessjøen	

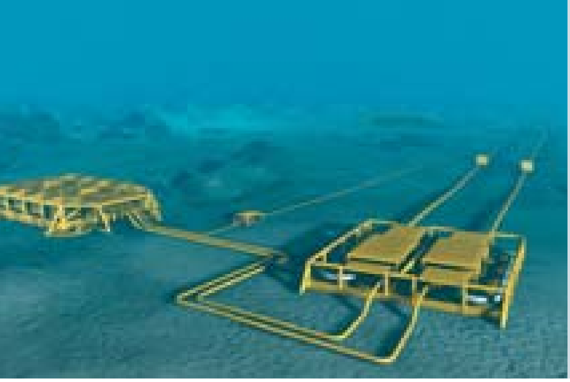
Development:
Norne is an oil field located about 80 kilometres north of the Heidrun field in the Norwegian Sea. The sea depth in the area is 380 metres. The field has been developed with a production and storage vessel, connected to six subsea templates. Flexible risers carry the wellstream up to the vessel. In April 2008, an amended PDO for Norne and Urd was approved. The plan encompasses 6608/10-11 S Trost and several prospects in the area around Norne and Urd.

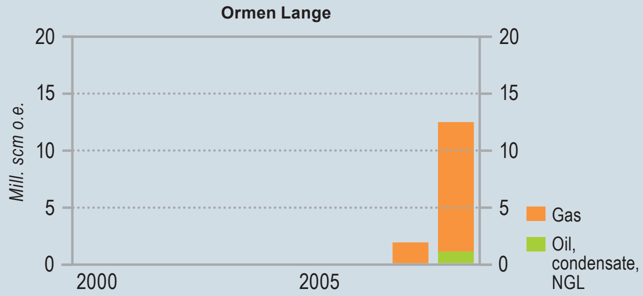
Reservoir:
The reservoir is in Jurassic sandstones. Oil is mainly found in the Ile and Tofte formations, and gas in the Garn Formation. The reservoir depth is about 2 500 metres. The reservoir quality is good.

Recovery strategy:
The oil is produced by water injection as drive mechanism. Gas injection ceased in 2005 and all gas is now being exported.

Transport:
The oil is loaded to tankers for export. Gas is transported through a dedicated pipeline to Åsgard and on through the Åsgard Transport pipeline to Kårstø.

Status:
Various measures to improve recovery are being considered, including use of new well technology. A new subsea template will also be installed in the southern part of the field.





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	
On stream	13.09.2007	
Operator	A/S Norske Shell	
Licensees	A/S Norske Shell	17.04 %
	DONG E&P Norge AS	10.34 %
	ExxonMobil Exploration & Production Norway AS	7.23 %
	Petoro AS	36.48 %
	StatoilHydro ASA	10.84 %
	StatoilHydro Petroleum AS	18.07 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	394.7 billion scm gas	381.6 billion scm gas
	28.5 million scm condensate	27.4 million scm condensate
Production	**Estimated production in 2009:** Gas: 16.93 billion scm, Condensate: 1.53 million scm	
Investment	Total investment is expected to be NOK 64.3 billion (2009 values)* NOK 21.4 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Kristiansund	

**Total investment, including the land facilities, is expected to be 88.6 billion (2009 values).*

Development:
Ormen Lange is a gas field located in the Møre Basin in the southern part of the Norwegian Sea. The sea depth in the area varies from 800 - 1 100 metres. The great sea depth has made the development very challenging and has resulted in development of new technology. The field is being developed in several phases with 24 wells from three subsea templates.

Reservoir:
The main reservoir consists of sandstones of Paleocene age in the Egga Formation, about 2 700 - 2 900 metres below sea level.

Recovery strategy:
The field is recovered by pressure depletion and, at a later stage, gas compression.

Transport:
The wellstream, which contains gas and condensate, is transported in two multiphase pipelines to the onshore facility at Nyhamna, where gas is dried and compressed before it is sent in the gas export pipeline, Langeled, via Sleipner R to Great Britain.

Status
The gas production started from three wells in September 2007. A/S Norske Shell took over the operatorship from StatoilHydro 1 November 2007. The field is being produced with six wells, of these, three new wells were completed in 3rd quarter 2008. The onshore facility at Nyhamna can now produce at full capacity. A third subsea template will be installed in 2009.

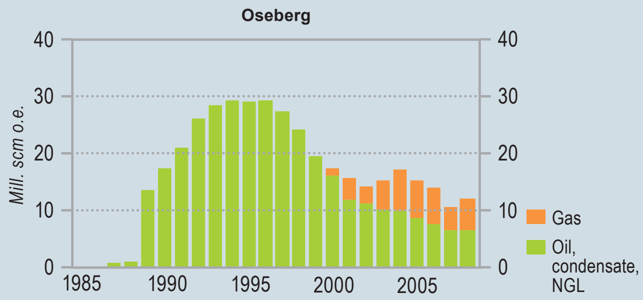
Oseberg

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	StatoilHydro Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	2.40 %
	ExxonMobil Exploration & Production Norway AS	4.70 %
	Petoro AS	33.60 %
	StatoilHydro ASA	15.30 %
	StatoilHydro Petroleum AS	34.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	366.4 million scm oil	21.1 million scm oil
	107.0 billion scm gas	85.6 billion scm gas
	9.3 million tonnes NGL	3.5 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 75 000 barrels/day, Gas: 3.23 billion scm, NGL: 0.50 million tonnes	
Investment	Total investment is expected to be NOK 101.1 billion (2009 values) NOK 94.6 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Oseberg is an oil field with a gas cap. The field is located in the northern part of the North Sea. 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. Production from the Gamma Main structure in the Statfjord Formation started in the spring of 2008 with two wells from the Oseberg Field Center. The facilities at the field centre process oil and gas from the fields Oseberg Øst, Oseberg Sør and Tune. 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.

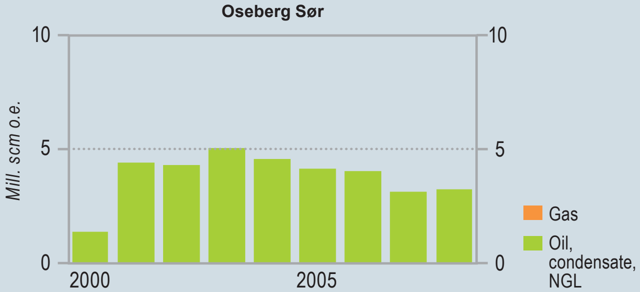
Reservoir:
The field consists of several Middle Jurassic sandstone reservoirs of the Brent Group, and is divided into several structures. The main reservoir is in the Oseberg and Tarbert formations, but production also takes place from the Etive and Ness formations. The reservoirs lie at a depth of 2 300 - 2 700 metres and have generally good reservoir characteristics.

Recovery strategy:
The Oseberg field produces by pressure maintenance with the injection of both gas and water, and by water alternating gas injection (WAG). Massive upflank gas injection on the main field has provided extremely good oil displacement, and a large gas cap has now developed which will be recovered in the future. Injection gas was previously imported from Troll Øst (TOGI) and Oseberg Vest. Small parts of the field produce by pressure depletion.



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

Status:
The challenge on Oseberg will be to produce the oil that remains under the gas cap, and to balance the gas offtake to maintain oil recovery from the field. A postponed start of the gas blowdown has been decided by the licensees. A module for low pressure production has been decided for the Oseberg Field Centre. Test production has started from an overlying chalk reservoir in the Shetland Group on the Oseberg field to evaluate the flow characteristics.



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	StatoilHydro Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	2.40 %
	ExxonMobil Exploration & Production Norway AS	4.70 %
	Petoro AS	33.60 %
	StatoilHydro ASA	15.30 %
	StatoilHydro Petroleum AS	34.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	50.6 million scm oil	16.0 million scm oil
	10.8 billion scm gas	5.4 billion scm gas
	0.4 million tonnes NGL	0.4 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 40 000 barrels/day, Gas: 0.47 billion scm, NGL: 0.04 million tonnes	
Investment	Total investment is expected to be NOK 24.3 billion (2009 values) NOK 19.8 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

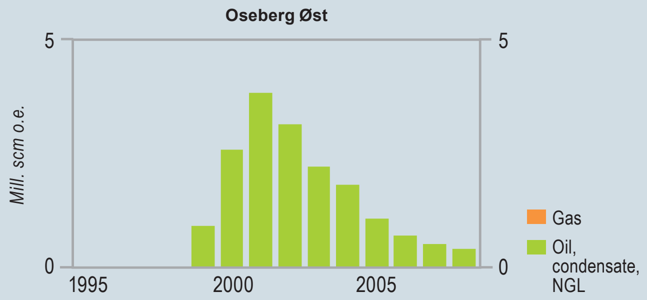
Development:
Oseberg Sør is an oil field located south of Oseberg in the northern part of the North Sea. The sea depth in the area is approximately 100 metres. The field has been developed with an integrated steel facility with accommodation, drilling module and first-stage separation of oil and gas. 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. The development of the Oseberg Sør J structure was approved on 15.05.2003 and production started in November 2006.

Reservoir:
Oseberg Sør consists of ten deposits with Jurassic sandstone reservoirs in separate structures. The reservoir depth is between 2 200 - 2 800 metres. The main reservoirs are in the Tarbert and Heather formations of Jurassic age. The reservoir quality is moderate.

Recovery strategy:
Recovery mainly takes place by water injection. In parts of the field water alternating gas injection (WAG) is being used.

Transport:
The oil is transported by pipeline to the Oseberg Field Centre where it is being processed and transported through Oseberg Transport System (OTS) to the Sture terminal. The gas is transported via Oseberg Gas Transport (OGT) into Statpipe.

Status:
The Oseberg Sør G Sentral deposit will be developed by wells drilled from the Oseberg Sør facility in 2009.



Oseberg Øst

Blocks and production licences	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	StatoilHydro Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	2.40 %
	ExxonMobil Exploration & Production Norway AS	4.70 %
	Petoro AS	33.60 %
	StatoilHydro ASA	15.30 %
	StatoilHydro Petroleum AS	34.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	27.4 million scm oil	10.3 million scm oil
	0.4 billion scm gas	0.1 billion scm gas
	0.1 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 13 000 barrels/day, Gas: 0.01 billion scm, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 11.9 billion (2009 values)	
	NOK 9.5 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

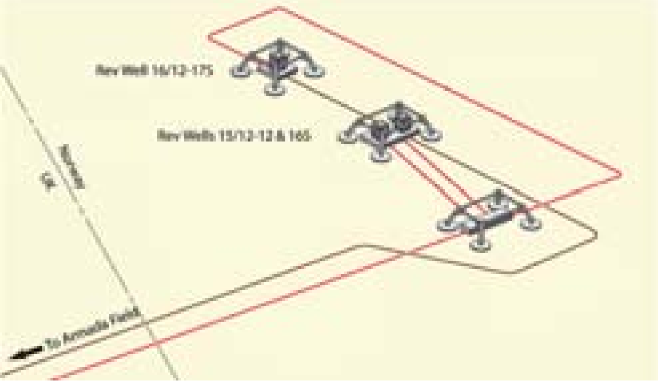
Development:
Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The sea depth in the area is about 160 metres.

Reservoir:
The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oilbearing layers of the Middle Jurassic Brent Group with varying reservoir characteristics. The reservoir lies at a depth of 2 700 - 3 100 metres.

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

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 drilling equipment on the Oseberg Øst facility has been upgraded and a drilling campaign of seven wells has started.



Rev

Blocks and production licences	Block 15/12 - production licence 038 C, awarded 2006	
Discovered	2001	
Development approval	15.06.2007 by the King in Council	
On stream	24.01.2009	
Operator	Talisman Energy Norge AS	
Licensees	Petoro AS	30.00 %
	Talisman Energy Norge AS	70.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	4.7 billion scm gas	4.7 billion scm gas
	0.3 million tonnes NGL	0.3 million tonnes NGL
	0.8 million scm condensate	0.8 million scm condensate
Production	**Estimated production in 2009:**	
	Gas: 0.98 billion scm, NGL: 0.07 million tonnes, Condensate: 0.26 million scm	
Investment	Total investment is expected to be NOK 3.9 billion (2009 values)	
	NOK 3.7 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	

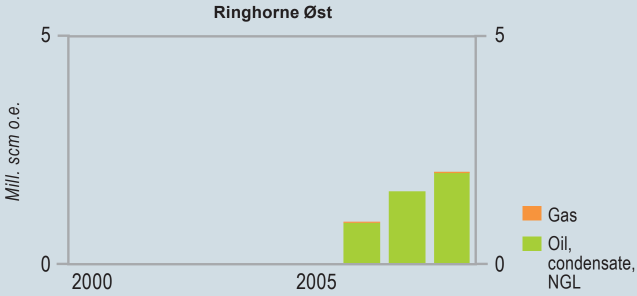
Development:
Rev is located close to the border between Norwegian and British sector, four kilometres south of the Varg field. The development concept is subsea templates connected to the Armada complex on the British continental shelf. The sea depth in the area is 90 - 110 metres.

Reservoir:
The reservoir has an oil zone with a gas cap and is in Upper Jurassic sandstones surrounding a salt structure at about 3 000 metres depth. Pressure measurements have shown that the reservoir is in communication with the Varg field.

Recovery strategy:
The field is produced by pressure depletion.

Transport:
The wellstream is routed through a 9 kilometres long pipeline to the Armada complex for processing and further export to the UK.

Status:
An appraisal well drilled on the east flank in 2007 proved additional resources. The well will be used as a production well in 2009. Rev came on stream in January 2009.



Ringhorne Øst

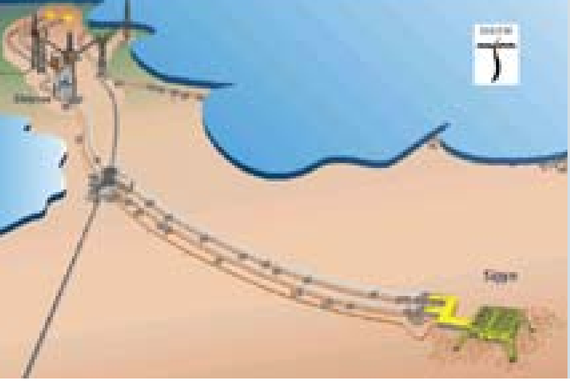
Blocks and production licences	Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 169, awarded 1991	
Discovered	2003	
Development approval	10.11.2005 by the King in Council	
On stream	19.03.2006	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS Petoro AS StatoilHydro ASA StatoilHydro Petroleum AS	77.38 % 7.80 % 3.12 % 11.70 %
Recoverable reserves	**Original:** 8.8 million scm oil 0.2 billion scm gas	**Remaining as of 31.12.2008:** 4.3 million scm oil 0.1 billion scm gas
Production	**Estimated production in 2009:** Oil: 24 000 barrels/day, Gas: 0.06 billion scm	
Investment	Total investment is expected to be NOK 1.1 billion (2009 values) NOK 0.6 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	

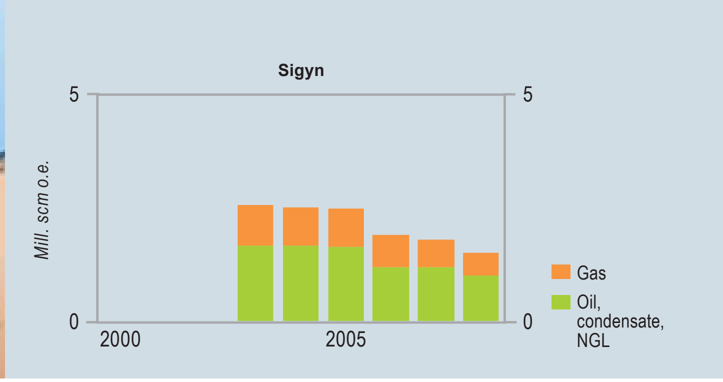
Development:
Ringhorne Øst is an oil field located north of Balder in the northern part of the North Sea. The sea depth in the area is about 130 meters. The field is developed by three production wells drilled from the Ringhorne facility on the Balder field.

Reservoir:
The reservoir contains oil with associated gas and is in Jurassic sandstones of the Statfjord Formation. The reservoir lies at a depth of approximately 1 940 metres and has good quality.

Recovery strategy:
The field is recovered by natural aquifer drive from a regional aquifer to the north and east of the structure.

Transport:
The production from Ringhorne Øst is transported to the Balder and Jotun facilities for processing, storage and export.





Sigyn

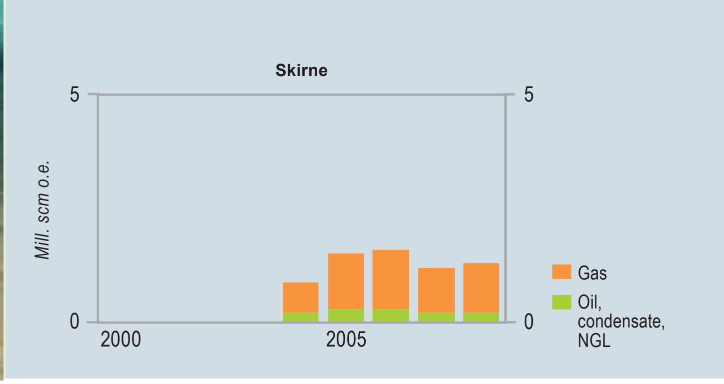
Blocks and production licences	Block 16/7 - production licence 072, awarded 1981	
Discovered	1982	
Development approval	31.08.2001 by the King in Council	
On stream	22.12.2002	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS	40.00 %
	StatoilHydro ASA	50.00 %
	StatoilHydro Petroleum AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	6.6 billion scm gas	2.1 billion scm gas
	2.9 million tonnes NGL	1.1 million tonnes NGL
	3.9 million scm condensate	
Production	**Estimated production in 2009:**	
	Gas: 0.5 billion scm, NGL: 0.21 million tonnes	
Investment	Total investment is expected to be NOK 2.5 billion (2009 values)	
	NOK 2.5 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
Sigyn is located in the Sleipner area in the southern part of the North Sea. The sea depth in the area is around 70 metres. The field comprises the deposits Sigyn Vest, which contains gas and condensate, and Sigyn Øst, which contains light oil. 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 12 kilometres long pipelines to the Sleipner A facility.

Reservoir:
The main reservoir lies in the Triassic Skagerrak Formation at a depth of approximately 2 700 metres and the reservoir quality is good.

Recovery strategy:
The field is produced by pressure depletion.

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



Skirne

Blocks and production licences	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	Centrica Resources (Norge) AS	20.00 %
	Petoro AS	30.00 %
	StatoilHydro Petroleum AS	10.00 %
	Total E&P Norge AS	40.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	2.1 million scm oil	0.9 million scm oil
	8.2 billion scm gas	3.0 billion scm gas
Production	**Estimated production in 2009:**	
	Oil: 4 000 barrels/day, Gas: 0.93 billion scm	
Investment	Total investment is expected to be NOK 3 billion (2009 values)	
	NOK 2.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	

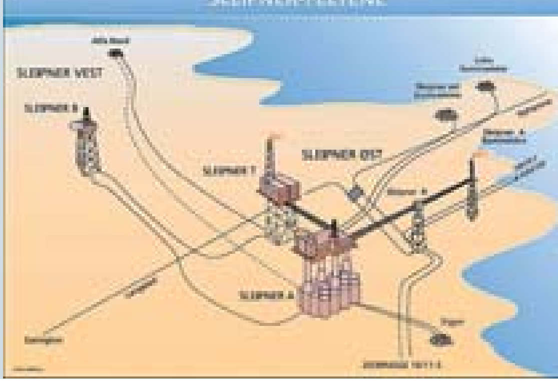
Development:
Skirne, which includes the Byggve deposit, contains gas and condensate and is located east of Heimdal in the northern part of the North Sea. The sea depth in the area is about 120 metres. The field has been developed with two subsea templates tied to Heimdal by pipeline.

Reservoir:
The reservoir consists of Middle Jurassic sandstones of the Brent Group. The Skirne deposit lies at a depth of approximately 2 370 metres and the Byggve deposit at approximately 2 900 metres. The reservoir quality is good.

Recovery strategy:
The field is recovered by pressure depletion.

Transport:
The wellstream from Skirne is transported in pipeline to the Heimdal facility for processing. Gas is exported in Vesterled and Statpipe, whereas condensate is transported to Brae in the British sector.

Status:
The lifetime for Skirne is dependent on the lifetime of the Heimdal facility.



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	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	32.24 %
	StatoilHydro ASA	49.50 %
	StatoilHydro Petroleum AS	8.85 %
	Total E&P Norge AS	9.41 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	117.7 billion scm gas	36.8 billion scm gas
	8.3 million tonnes NGL	3.0 million tonnes NGL
	29.1 million scm condensate	
Production	**Estimated production in 2009:** Gas: 6.64 billion scm, NGL: 0.39 million tonnes, Condensate: 1.22 million scm	
Investment	Total investment is expected to be NOK 28.8 billion (2009 values) NOK 27.6 billion have been invested as of 31.12.2008 (2009 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.*

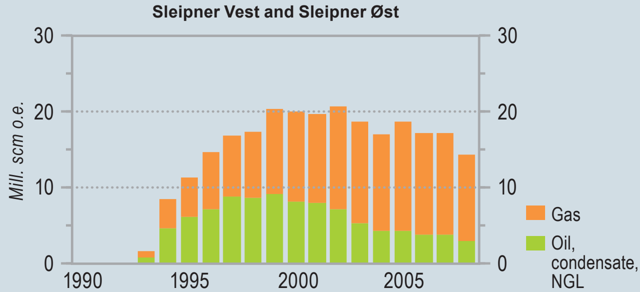
Development:
Sleipner Vest is a gas field in the southern part of the North Sea. The sea depth in the area is 110 metres. The field is developed with a wellhead facility, Sleipner B, which is remotely operated from Sleipner A on the Sleipner Øst field, and a processing facility, Sleipner T, which is bridge connected to Sleipner A. The Alpha Nord segment was developed in 2004 with a subsea template tied back to Sleipner T through an 18 kilometres pipeline.

Reservoir:
Sleipner Vest produces from the Middle Jurassic Sleipner and Hugin formations. The reservoir depth is approximately 3 450 metres. Most of the reserves are found in the Hugin Formation. The faults in the field are generally not sealing, and communication between the sand bodies is good.

Recovery strategy:
Sleipner Vest is recovered by pressure depletion.

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 goes to Sleipner A for further export. CO_2 is injected into the Utsira Formation via a dedicated injection well from Sleipner A. Unstable condensate from Sleipner Vest and Sleipner Øst is mixed at Sleipner A and sent to Kårstø for processing to stable condensate and NGL products.

Status:
To maintain production, a new compressor on Sleipner B will be started early 2009. Drilling and development of several deposits nearby will also be evaluated in the coming years. A drilling program over several years with a contracted drilling rig is expected to start in 2009.



Sleipner Øst includes total production from Sleipner Vest and Sleipner Øst, and gas production from Gungne.

Sleipner Øst

Blocks and production licences	Block 15/9 - production licence 046, awarded 1976	
Discovered	1981	
Development approval	15.12.1986 by the Storting	
On stream	24.08.1993	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	30.40 %
	StatoilHydro ASA	49.60 %
	StatoilHydro Petroleum AS	10.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	67.4 billion scm gas	36.8 billion scm gas
	13.4 million tonnes NGL	3.0 million tonnes NGL
	26.9 million scm condensate	
Production	**Estimated production in 2009:**	
	Gas: 2.12 billion scm, NGL: 0.27 million tonnes, Condensate: 0.36 million scm	
Investment	Total investment is expected to be NOK 41.6 billion (2009 values)	
	NOK 40.1 billion have been invested as of 31.12.2008 (2009 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 condensate field in the southern part of the North Sea. 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 gravity base structure, Sleipner A. A riser facility, Sleipner R, connects Sleipner A to the pipelines for gas transport and to the flare stack Sleipner F. Two subsea templates have also been installed, one for production from the northern part of Sleipner Øst and one for production of the Loke deposit. 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 reservoirs are mainly in sandstones of the Ty Formation of Paleocene age and sandstones of the Hugin Formation of Middle Jurassic age. The reservoir depth is approximately 2 300 metres. There is no pressure communication between the two reservoir zones. The underlying Triassic Skagerrak Formation is the main reservoir at Loke and has moderate to poor reservoir characteristics.

Recovery strategy:
The Hugin reservoir produces by pressure depletion. The Ty reservoir has been produced by dry gas recycling until October 2005. To optimise production, the wells are now produced with a reduced inlet pressure in separator B. Sleipner Øst went off plateau in December 2005 and the «low pressure» production started in June 2006.

Transport:
The wellstream from Sleipner Øst is processed on Sleipner A together with the production from Gungne and Sigyn. 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.

Status:
A new well came on stream in 2008. Two new well targets are planned for production in 2009. Improved recovery through reduced inlet pressure is planned to start in 2010.

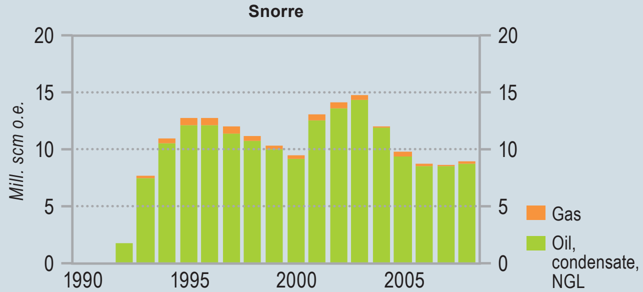
Snorre

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	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	11.58 %
	Hess Norge AS	1.04 %
	Idemitsu Petroleum Norge AS	9.60 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	8.28 %
	StatoilHydro ASA	15.55 %
	StatoilHydro Petroleum AS	17.77 %
	Total E&P Norge AS	6.18 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	234.3 million scm oil	70.8 million scm oil
	6.5 billion scm gas	0.6 billion scm gas
	4.6 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 125 000 barrels/day, Gas: 0.02 billion scm, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 107.8 billion (2009 values) NOK 76.5 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

Development:
Snorre is an oil field in the Tampen area in the northern part of the North Sea. The sea depth in the area is 300 - 350 metres. Snorre A in the south is a floating steel facility (TLP) for accommodation, drilling and processing. Snorre A has also a separate process module for production from the Vigdis field. A subsea template with ten well slots, Snorre UPA, is located centrally on the field and connected to Snorre A. Snorre B is located in the northern part of the field and is a semi-submersible integrated drilling, processing and accommodation 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.

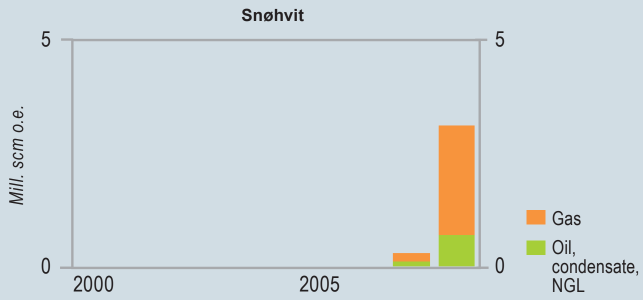
Reservoir:
The Snorre field consists of several large fault blocks. The reservoir contains Lower Jurassic and Triassic sandstones of the Statfjord and Lunde formations. The reservoir depth is 2 000 - 2 700 metres. The reservoir has a complex structure with many channels and internal flow barriers.

Recovery strategy:
Snorre is produced with pressure maintenance by water injection, gas injection and water alternating gas injection (WAG). Foam assisted injection (FAWAG) has also been tested 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 may also be sent by pipeline to Snorre A.

Status:
In 2007 it was decided to increase the processing capacities for production and injection of water. Several measures are being evaluated to increase recovery on Snorre, among others extended gas injection by gas import to the field. The existing drilling facilities on Snorre will be upgraded. Concept selection for Snorre Future Development, which constitutes a long-term solution for Snorre when the oil export via Statfjord has ceased, has been postponed until 2009. There are negotiations with the Statfjord licensees concerning further use of the Statfjord A and B facilities until Snorre has the new long-term recovery plan in place.



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	
On stream	21.08.2007	
Operator	StatoilHydro ASA	
Licensees	GDF SUEZ E&P Norge AS	12.00 %
	Hess Norge AS	3.26 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	2.81 %
	StatoilHydro ASA	33.53 %
	Total E&P Norge AS	18.40 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	160.6 billion scm gas	158.1 billion scm gas
	6.3 million tonnes NGL	6.2 million tonnes NGL
	18.1 million scm condensate	17.5 million scm condensate
Production	**Estimated production in 2009:** Gas: 3.59 billion scm, NGL: 0.19 million tonnes, Condensate: 0.6 million scm	
Investment	Total investment is expected to be NOK 21.9 billion (2009 values)* NOK 9.0 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Harstad and Stjørdal	

** Total investment, including the land facilities, is expected to be 77.3 billion (2009 values).*

Development:
Snøhvit is located in the Barents Sea in the central part of the Hammerfest basin, at a sea depth of 310 - 340 metres. Snøhvit is a gas field with condensate and an underlying thin oil zone. The field comprises several discoveries and deposits in the Askeladd and Albatross structures in addition to Snøhvit. The approved PDO for the gas resources includes subsea templates for 19 production wells and one injection well for CO_2.

Reservoir:
The reservoirs contain gas, condensate and oil in Lower and Middle Jurassic sandstones of the Stø and Nordmela formations. The reservoir depth is approximately 2 300 meters.

Recovery strategy:
The recovery strategy is pressure depletion. The development does not comprise recovery of the oil zone.

Transport:

The unprocessed wellstream, containing natural gas inclusive CO_2, NGL and condensate, is transported through a 160 kilometres long pipeline to the facility at Melkøya for processing and export. The gas is processed and cooled down to liquid form (LNG) at Melkøya. The CO_2 content in the gas is separated at Melkøya and sent back to the field and reinjected in a deeper formation. LNG is shipped to the market.

Status:

In the summer of 2007, an appraisal well was drilled in the western part of the field in order to collect more information from the oil zone. The well results showed that there was no basis for development of the oil zone. The production at Snøhvit started in the autumn of 2007. The LNG facility at Melkøya was closed down from November 2007 to January 2008 due to technical problems. An approximately eight weeks audit shut-down was carried out in the summer of 2008. The Melkøya facility is now producing at some reduced capacity.

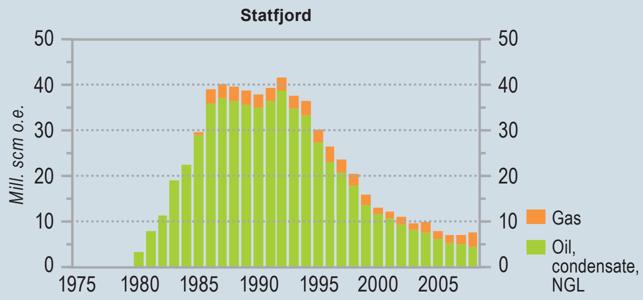
Statfjord

Blocks and production licences	Block 33/12 - production licence 037, awarded 1973 Block 33/9 - production licence 037, awarded 1973 The Norwegian part of the field is 85.47 %, the British part is 14.53 %	
Discovered	1974	
Development approval	16.06.1976 by the Storting	
On stream	24.11.1979	
Operator	StatoilHydro ASA	
Licensees	A/S Norske Shell	8.55 %
	ConocoPhillips Skandinavia AS	10.33 %
	Enterprise Oil Norge AS	0.89 %
	ExxonMobil Exploration & Production Norway AS	21.37 %
	StatoilHydro ASA	44.34 %
	Centrica Resources Limited	9.69 %
	ConocoPhillips (U.K.) Limited.	4.84 %
Recoverable reserves (Norwegian part)	**Original:**	**Remaining as of 31.12.2008:**
	565.2 million scm oil	6.6 million scm oil
	76.7 billion scm gas	18.1 billion scm gas
	24.0 million tonnes NGL	8.5 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 32 000 barrels/day, Gas: 1.92 billion scm, NGL: 1.05 million tonnes	
Investment	Total investment is expected to be NOK 144.8 billion (2009 values) NOK 132.6 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Sotra and Florø	

Development:
Statfjord is an oil field straddling the border between the Norwegian and British sectors in the Tampen area in the northern part of the North Sea. 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 field, and came on stream in 1979. Statfjord B is located in 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 similar construction. The satellite fields Statfjord Øst, Statfjord Nord and Sygna have a separate inlet separator on Statfjord C. The PDO for Statfjord Late Life was approved on 08.06.2005.

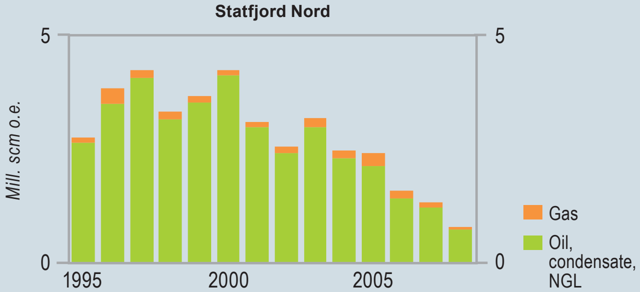
Reservoir:
The Statfjord reservoirs lie at a depth of 2 500-3 000 metres in a large fault block tilted towards the west, and in a number of smaller fault compartments along the east flank. The reservoirs are in Jurassic sandstones of the Brent Group and the Cook and Statfjord formations. The Brent Group and Statfjord Formation have excellent reservoir quality.

Recovery strategy:
The Brent reservoir was originally produced with pressure support from water alternating gas injection (WAG). The Statfjord Formation has been produced with pressure support from water injection and supplemental gas injection in the upper part, and WAG injection in the lower part. Statfjord Late Life entails that all injection now has ceased and the injection wells are converted to water producers. This will prolong the lifetime of the field by ten years and increase the recovery of both oil and gas.



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 the Statpipe pipeline to Kårstø, where NGL is separated before dry gas is transported on to Emden. The UK licensees route their share of the gas through the Far North Liquids and Gas System (FLAGS) 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. The gas export through Tampen Link started in October 2007.

Status:
The facilities are being modified as part of Statfjord Late Life, and wells were drilled and repaired in 2008. Blowdown of the reservoir pressure in the Brent Formation started in the autumn of 2008. The lifetime of Statfjord A, B and C, and further tie-in of Snorre to Statfjord A and B for some additional years are now being evaluated in cooperation with the licensees in the Snorre field.



Statfjord Nord

Blocks and production licences	Block 33/9 - production licence 037, awarded 1973	
Discovered	1977	
Development approval	11.12.1990 by the Storting	
On stream	23.01.1995	
Operator	StatoilHydro ASA	
Licensees	A/S Norske Shell	10.00 %
	ConocoPhillips Skandinavia AS	12.08 %
	Enterprise Oil Norge AS	1.04 %
	ExxonMobil Exploration & Production Norway AS	25.00 %
	Petoro AS	30.00 %
	StatoilHydro ASA	21.88 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	40.9 million scm oil	5.5 million scm oil
	2.6 billion scm gas	0.4 billion scm gas
	0.9 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 4 000 barrels/day, Gas: 0.01 billion scm, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 8.5 billion (2009 values)	
	NOK 8.3 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

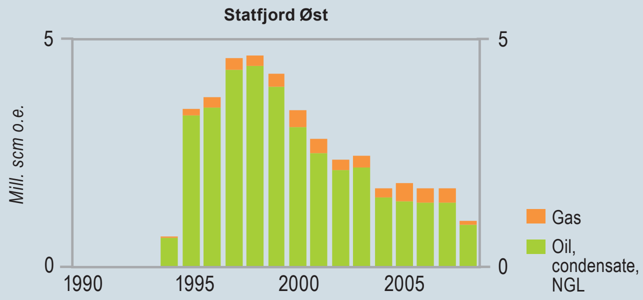
Development:
Statfjord Nord is an oil field located approximately 17 kilometres north of Statfjord in the Tampen area. The sea depth in the area is 250 - 290 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two templates are for production and one is for water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

Reservoir:
The Statfjord Nord reservoirs consist of Middle Jurassic sandstones of the Brent Group (Tarbert, Etive and Rannoch formations), and Upper Jurassic sandstones. The reservoirs lie at a depth of approximately 2 600 metres and are of good quality.

Recovery strategy:
The field produces with pressure support from water injection.

Transport:
The wellstream is routed through two pipelines to Statfjord C for processing, storage and export. Statfjord Nord, Sygna and Statfjord Øst have a shared process module on Statfjord C.

Status:
It is being considered if water alternating gas injection (WAG) can be a method for improved oil recovery on Statfjord Nord. Final decision is expected in 2009.



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	StatoilHydro ASA	
Licensees	A/S Norske Shell	5.00 %
	ConocoPhillips Skandinavia AS	6.04 %
	Enterprise Oil Norge AS	0.52 %
	ExxonMobil Exploration & Production Norway AS	17.75 %
	Idemitsu Petroleum Norge AS	4.80 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	1.40 %
	StatoilHydro ASA	25.05 %
	StatoilHydro Petroleum AS	6.64 %
	Total E&P Norge AS	2.80 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	37.0 million scm oil	3.2 million scm oil
	4.0 billion scm gas	0.4 billion scm gas
	1.5 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 13 000 barrels/day, Gas: 0.08 billion scm, NGL: 0.04 million tonnes	
Investment	Total investment is expected to be NOK 8.2 billion (2009 values) NOK 7.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

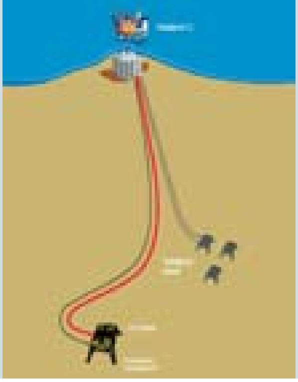
Development:
Statfjord Øst is an oil field located approximately 7 kilometres northeast of the Statfjord field in the Tampen area. The sea depth in the area is 150 - 190 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two of the templates are for production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

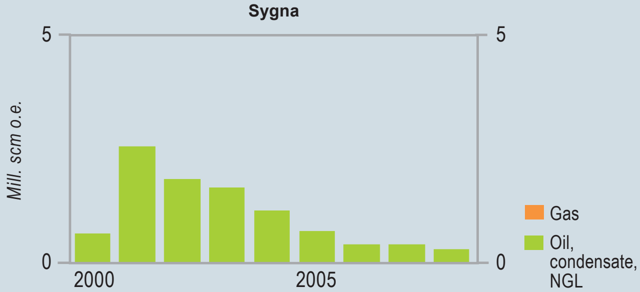
Reservoir:
The Statfjord Øst reservoir consists of Middle Jurassic sandstones of the Brent Group. The reservoir depth is approximately 2 400 metres.

Recovery strategy:
The field is produced with pressure support from water injection.

Transport:
The wellstream is routed through two pipelines to Statfjord C for processing, storage and further transport. Statfjord Øst, Sygna and Statfjord Nord have a shared process module on Statfjord C.

Status:
Through Tubing Rotary Drilling (TTRD) is being evaluated as a method for improved oil recovery on Statfjord Øst. Gas lift in the wells may also be implemented.





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	StatoilHydro ASA	
Licensees	A/S Norske Shell	5.50 %
	ConocoPhillips Skandinavia AS	6.65 %
	Enterprise Oil Norge AS	0.57 %
	ExxonMobil Exploration & Production Norway AS	18.48 %
	Idemitsu Petroleum Norge AS	4.32 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	1.26 %
	StatoilHydro ASA	24.73 %
	StatoilHydro Petroleum AS	5.98 %
	Total E&P Norge AS	2.52 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	10.8 million scm oil	1.2 million scm oil
Production	**Estimated production in 2009:**	
	Oil: 4 000 barrels/day	
Investment	Total investment is expected to be NOK 2.5 billion (2009 values) NOK 2.5 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

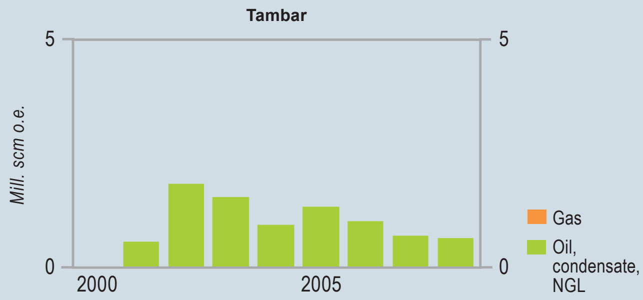
Development:
Sygna is an oil field located just north of the Statfjord Nord field in the Tampen area. The sea depth in the area is about 300 metres. The field has been developed with one subsea template with four well slots, connected to Statfjord C.

Reservoir:
The Sygna reservoir consists of Middle Jurassic sandstones of the Brent Group. The reservoir depth is approximately 2 650 metres. The reservoir quality is good.

Recovery strategy:
The field is produced by water injection with water supplied 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 have a shared process module on Statfjord C.

Status:
The plan is to sidetrack wells to new areas and maintain reservoir pressure by water injection. Alternative recovery methods are also being evaluated.



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	55.00 %
	DONG E&P Norge AS	45.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	9.7 million scm oil	1.7 million scm oil
	2.6 billion scm gas	2.6 billion scm gas
	0.3 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 8 000 barrels/day, Gas: 0.12 billion scm, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 2.8 billion (2009 values) NOK 2.5 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Tambar is an oil field located southeast of the Ula field in the southern part of the North Sea. The sea depth in the area is 68 metres. The field has been developed with a remotely controlled wellhead facility without processing equipment.

Reservoir:
The reservoir consists of Upper Jurassic sandstones of the Ula Formation, deposited in a shallow marine environment. The reservoir lies at a depth of 4 100 - 4 200 metres and the reservoir characteristics are generally very good.

Recovery strategy:
The field is producing by pressure depletion and limited aquifer drive. The production went off plateau in 2002 and is now declining.

Transport:
The oil is transported to Ula through a new pipeline which was installed in 2007. After processing at Ula, the oil is exported in the existing pipeline system to Teesside via Ekofisk. The gas is used for gas injection on Ula to improve the oil recovery.

Status:
A multi-phase pump which has been installed and became operational in 2008, will reduce the wellhead pressure and increase recovery from Tambar. The potential for water injection and gas lift is continuously being considered. This work will continue in 2009.

Tambar Øst

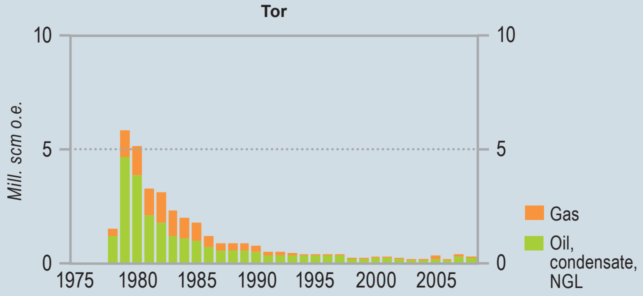
Blocks and production licences	Block 1/3 - production licence 065, awarded 1981 Block 2/1 - production licence 019 B, awarded 1977 Block 2/1 - production licence 300, awarded 2003	
Discovered	2007	
Development approval	28.06.2007	
On stream	02.10.2007	
Operator	BP Norge AS	
Licensees	BP Norge AS	46.20 %
	DONG E&P Norge AS	43.24 %
	Norske AEDC A/S	0.80 %
	Talisman Energy Norge AS	9.76 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	1.1 million scm oil	1.1 million scm oil
	0.1 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2009:** Oil: 1 000 barrels/day, Gas: 0.01 billion scm	
Investment	Total investment is expected to be NOK 1.1 billion (2009 values) NOK 1.1 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	

Development:
Tambar Øst has been developed with a production well drilled from the Tambar facility.

Reservoir:
The reservoir is in sandstones of Late Jurassic age, deposited in a shallow marine environment. The reservoir lies at a depth of 4 050 – 4 200 meters and the quality varies.

Recovery strategy:
The field is producing by pressure depletion and limited aquifer drive.

Transport:
The oil is transported to Ula via Tambar. After processing at Ula, the oil is exported in the existing pipeline system to Teesside via Ekofisk. The gas is used for gas injection in the Ula reservoir to improve oil recovery.



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 %
	Petoro AS	3.69 %
	StatoilHydro ASA	0.83 %
	StatoilHydro Petroleum AS	5.81 %
	Total E&P Norge AS	48.20 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	24.5 million scm oil	1.6 million scm oil
	11.0 billion scm gas	0.2 billion scm gas
	1.2 million tonnes NGL	
Production	**Estimated production in 2009:** Oil: 2 000 barrels/day, Gas: 0.01 billion scm	
Investment	Total investment is expected to be NOK 10.5 billion (2009 values) NOK 9.7 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

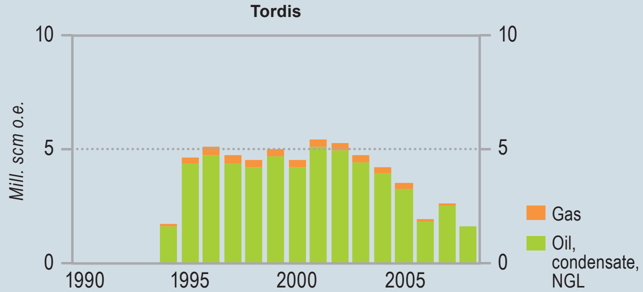
Development:
Tor is an oil field in the Ekofisk area in the southern part of the North Sea. The field has been developed with a combined wellhead and processing facility with transport through pipelines to the Ekofisk Center and further export. The sea depth in the area is about 70 metres.

Reservoir:
The main reservoir at Tor lies at a depth of approximately 3 200 metres and consists of fractured chalk of the Tor Formation of Late Cretaceous age. The Ekofisk Formation of Early Paleocene age also contains oil, but has poorer reservoir quality.

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. All five wells are producing with gas lift.

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:
The Tor facility has limited lifetime and it is being considered how to recover the remaining resources in the long term.



Tordis

Blocks and production licences	Block 34/7 - production licence 089, awarded 1984	
Discovered	1987	
Development approval	14.05.1991 by the Storting	
On stream	03.06.1994	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	10.50 %
	Idemitsu Petroleum Norge AS	9.60 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	2.80 %
	StatoilHydro ASA	28.22 %
	StatoilHydro Petroleum AS	13.28 %
	Total E&P Norge AS	5.60 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	59.7 million scm oil	7.1 million scm oil
	5.3 billion scm gas	1.5 billion scm gas
	1.7 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 17 000 barrels/day	
Investment	Total investment is expected to be NOK 14 billion (2009 values)	
	NOK 12.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

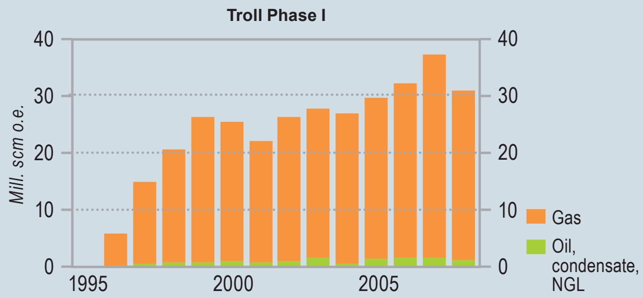
Development:
Tordis is an oil field located between the Snorre and Gullfaks fields in the Tampen area in the northern part of the North Sea. The sea depth in the area is approximately 200 metres. The field has been developed with a central subsea manifold tied back to Gullfaks C. Seven separate satellite 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 deposits: 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 of the Brent Group. The reservoir in Borg consists of Upper Jurassic sandstones, and the reservoir in 34/7-25 S consists of sandstones of the Brent Group and sandstones of Late Jurassic age. The Tordis reservoirs lie at a depth of 2 000 - 2 500 metres.

Recovery strategy:
Production is partially accomplished with pressure maintenance by water injection and natural aquifer drive. Pressure at Borg is fully maintained using water injection. Tordis Øst is recovered with pressure support from natural aquifer drive. Tordis IOR entails improved oil recovery through low pressure production.

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

Status:
The project Tordis IOR was completed in 2007 when a subsea separator was installed on the field and a well for injection of produced water into the Utsira formation was drilled. The project also included modifications on Gullfaks C for low pressure production. The Tordis subsea separator was shut down in May 2008 when a leakage to the sea bed from the injection well to the Utsira Formation was discovered. An alternative solution for injection of produced water is being considered.



Troll

The Troll field lies in the northern part of the North Sea about 65 kilometres west of Kollsnes. The water depth in the area is more than 300 metres. The field has huge gas resources and one of the largest oil volumes remaining on the Norwegian continental shelf. Troll comprises two main structures: Troll Øst and Troll Vest, and roughly two-thirds of the recoverable gas reserves lie in Troll Øst. A thin oil rim underlies the gas throughout the Troll field, but so far only in Troll Vest is this oil zone of sufficient thickness to be commercial, 11 to 27 metres. In 2007, an oil column of 6-9 metres was proven in the northern part of Troll Øst. A test production of oil from this part of Troll started in November 2008.
A phased development has been pursued, with Phase I recovering gas reserves in Troll Øst and Phase II focused on the oil reserves in Troll Vest. The gas reserves in Troll Vest will be developed in a future phase 3. The Troll licensees are conducting studies to plan for further development of the field. Troll was the largest producer of both oil and gas on the Norwegian continental shelf in the period 2000 – 2004.

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 085 C, 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 085 C, awarded 2002	
Discovered	1983	
Development approval	15.12.1986 by the Storting	
On stream	09.02.1996	
Operator	StatoilHydro ASA	
Licensees	A/S Norske Shell	8.10 %
	ConocoPhillips Skandinavia AS	1.62 %
	Petoro AS	56.00 %
	StatoilHydro ASA	20.80 %
	StatoilHydro Petroleum AS	9.78 %
	Total E&P Norge AS	3.69 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	1330.7 billion scm gas	995.0 billion scm gas
	25.7 million tonnes NGL	22.1 million tonnes NGL
	1.6 million scm condensate	
Production	**Estimated production in 2009:**	
	Gas: 28.7 billion scm, NGL: 1.08 million tonnes	
Investment	Total investment is expected to be NOK 81 billion (2009 values)	
	NOK 62 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Ågotnes	

Development:
Troll Phase I has been developed with Troll A which is a fixed wellhead and compression facility with a concrete substructure. Troll A is powered by electricity supplied from land. An updated development plan involving the transfer of gas processing to Kollsnes was approved in 1990. Kollsnes was separated from the unitised Troll field in 2004, and the Kollsnes terminal is currently operated by Gassco as part of the Gassled joint venture. The gas compression capacity at Troll A was increased in 2004/2005. The Troll Oseberg Gas Injection (TOGI) subsea template is also located at Troll Øst. Gas was exported to Oseberg for injection. The TOGI decommissioning plan involving removal of the subsea template, was approved in 2005.

Reservoir:
The gas and oil reservoirs in the Troll Øst and Troll Vest structures consist primarily of shallow marine sandstones of the Sognefjord Formation. Part of the reservoir is in the Fensfjord Formation below the Sognefjord Formation. The reservoir is of Late Jurassic age. The field consists of three relatively large rotated fault blocks. The fault block to the east constitutes Troll Øst. Pressure communication between Troll Øst and Troll Vest has been proven. Previously, the oil column in Troll Øst was mapped to be 0-4 metres. A well drilled in 2007 proved an oil column of 6 - 9 metres in the Fensfjord Formation in the northern segment of Troll Øst. The reservoir depth at Troll Øst is about 1 330 metres.

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.

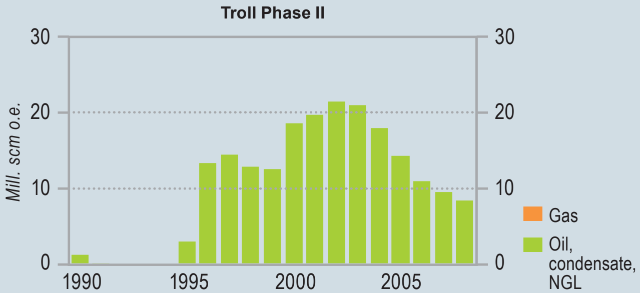
Status:
A test production of oil from the northern part of Troll Øst started in November 2008. The licensees will consider development of this area when experience from the test production is available.

Troll 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 085 C, 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 085 C, awarded 2002	
Discovered	1979	
Development approval	18.05.1992 by the Storting	
On stream	19.09.1995	
Operator	StatoilHydro Petroleum AS	
Licensees	A/S Norske Shell	8.10 %
	ConocoPhillips Skandinavia AS	1.62 %
	Petoro AS	56.00 %
	StatoilHydro ASA	20.80 %
	StatoilHydro Petroleum AS	9.78 %
	Total E&P Norge AS	3.69 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	244.5 million scm oil	45.8 million scm oil
Production	**Estimated production in 2009:** Oil: 122 000 barrels/day	
Investment	Total investment is expected to be NOK 104.5 billion (2009 values) NOK 84.8 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Troll Phase II has been developed with Troll B, a floating concrete accommodation and production facility, and Troll C, which is a steel-hulled, semi-submersible accommodation and production facility. The oil in Troll Vest is produced by means of several subsea templates tied back to Troll B and Troll C by flowlines. Troll Pilot, which was installed in 2000 at a depth of 340 meters, is a subsea facility which separates produced water prior to its re-injection into the reservoir. The Troll C facility is also utilised for production from the Fram field. The Troll C development was approved in 1997. There have been several PDO approvals in connection with various subsea templates at Troll Vest.

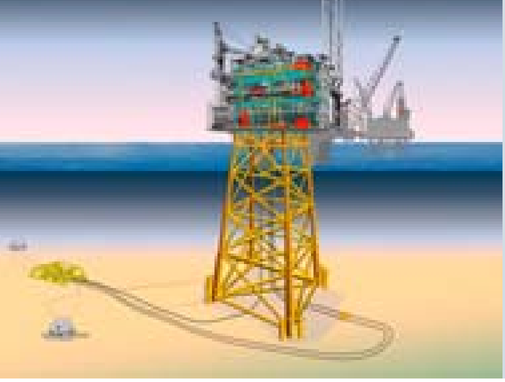
Reservoir:
The gas and oil in the Troll Øst and Troll Vest structures are found primarily in the Sognefjord Formation which consists of shallow marine sandstones of Late Jurassic age. Part of the reservoir is also in the underlying Fensfjord Formation. The field comprises three relatively large rotated fault blocks. The oil in the Troll Vest oil province is encountered in a 22–26 metre thick oil column overlain by a small gas cap, located at 1 360 metres depth. The Troll Vest gas province has an oil column of around 12-14 metres overlain by a gas column up to 200 metres in thickness. A significant volume of residual oil is encountered immediately below the Troll Vest oil column. In 2005 a minor oil discovery was made in the Jurassic Brent Group, located somewhat deeper than the main oil reservoir..

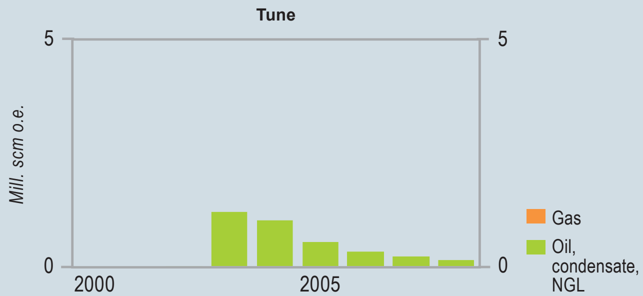


Recovery strategy:
The oil in Troll Vest is produced by means of long horizontal wells which penetrate the thin oil zone immediately above the oil-water contact. Here too, the recovery strategy is based primarily on pressure depletion, but this is accompanied by a simultaneous expansion of both the gas cap above the oil zone and the underlying water zone. In the Troll Vest oil province, some of the produced gas has been reinjected into the reservoir to optimise oil production. One important aspect of the strategy has been to recover the oil rapidly, since the volumes of oil that can be recovered will decrease as pressure drive declines at Troll Øst. For this reason, limits have been placed on the rates of gas production from Troll Øst.

Transport:
The 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 onwards by pipelines, partly to the Sture terminal, partly to Mongstad. The dry gas is transported 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 three mobile drilling facilities in activity. In total, more than 120 oil production wells have so far been drilled at Troll Vest. Over the last few years, decisions have been made every year to drill new production wells to increase the oil reserves in Troll, and there are still a number of wells in the drilling plan. Several multibranch wells have been drilled, with up to seven branches in the same well. In 2008 the licensees submitted a PDO which also included gas injection in Troll Vest. In addition, studies have been initiated with regard to water injection.





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	StatoilHydro Petroleum AS	
Licensees	Petoro AS	40.00 %
	StatoilHydro ASA	10.00 %
	StatoilHydro Petroleum AS	40.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	3.2 million scm oil	0.3 million scm oil
	18.0 billion scm gas	2.9 billion scm gas
	0.2 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 1 000 barrels/day, Gas: 0.77 billion scm, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 5.4 billion (2009 values) NOK 4.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

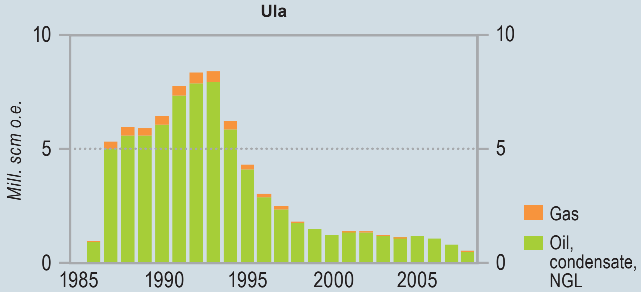
Development:
The Tune field is a gas condensate field located about 10 kilometres west of the Oseberg Field Centre in the northern part of the North Sea. The sea depth in the area is approximately 95 metres. The field has been developed with a subsea template with four production wells in the centre of the field. 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 (Tune Phase III).

Reservoir:
The reservoir consists of Middle Jurassic sandstones of the Brent Group and is divided into several inclined fault blocks. The reservoir depth is approximately 3 400 metres.

Recovery strategy:
The field is recovered by pressure depletion.

Transport:
The Tune subsea facility is connected to the Oseberg D facility by two flow lines. 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.

Status:
A new production well in the southern part of the field will be drilled in 2009. Drilling of several prospects around Tune has also been planned. Low pressure production on Tune has started.



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	80.00 %
	DONG E&P Norge AS	20.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	87.3 million scm oil	18.2 million scm oil
	3.9 billion scm gas	0.8 million tonnes NGL
	3.3 million tonnes NGL	
Production	**Estimated production in 2009:**	
	Oil: 10 000 barrels/day, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 27.8 billion (2009 values) NOK 23.6 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

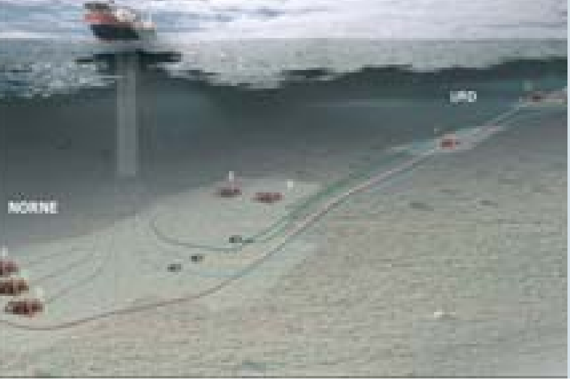
Development:
Ula is an oil field in the southern part of the North Sea. The sea depth in the area is 70 metres. The development consists of three conventional steel facilities for production, drilling and accommodation. The facilities are connected by bridges. The wellstream from Blane was tied to the Ula field for processing in September 2007.

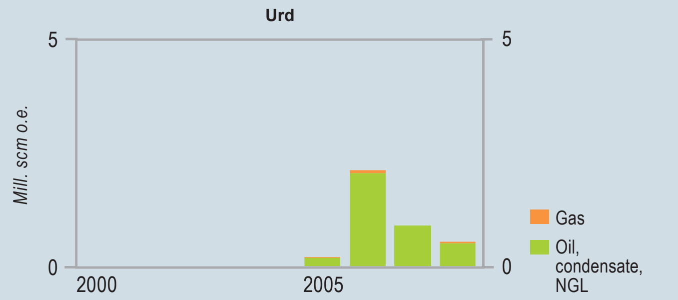
Reservoir:
The main reservoir is at a depth of 3 345 metres in the Upper Jurassic Ula Formation. The reservoir consists of three layers and two of them are producing well.

Recovery strategy:
Initially, oil was recovered by pressure depletion, but after some years water injection was implemented to improve recovery. Water alternating gas injection (WAG) started in 1998. As access to gas increased by processing production from Tambar at Ula, the WAG programme has been extended. The gas from Blane is also used for injection in Ula. Gas lift is used in some wells.

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:
Ula gas capacity was upgraded in 2008 with a new gas process and gas injection module (UGU) which will double the capacity. Based on the positive effect on oil recovery, evaluation is ongoing to expand the WAG program by drilling additional wells from 2009 and importing more gas for injection. There are plans to process the wellstream from 1/3-6 Oselvar and to buy the gas for injection to the Ula field from the end of 2011.





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	StatoilHydro ASA	
Licensees	Eni Norge AS	11.50 %
	Petoro AS	24.55 %
	StatoilHydro ASA	63.95 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	9.5 million scm oil	5.9 million scm oil
	0.3 billion scm gas	0.2 billion scm gas
Production	**Estimated production in 2009:**	
	Oil: 7 000 barrels/day	
Investment	Total investment is expected to be NOK 5.2 billion (2009 values)	
	NOK 4.8 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Harstad	

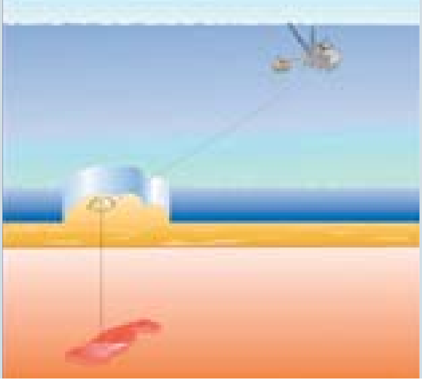
Development:
Urd is located northeast of Norne in the Norwegian Sea. The sea depth in the area is approximately 380 metres. The field comprises two oil filled deposits 6608/10-6 Svale and 6608/10-8 Stær. Urd has been developed with subsea templates tied back to the Norne vessel. In April 2008, an amended PDO for Norne and Urd was approved. The plan encompasses 6608/10-11 S Trost and a number of prospects in the area around Norne and Urd.

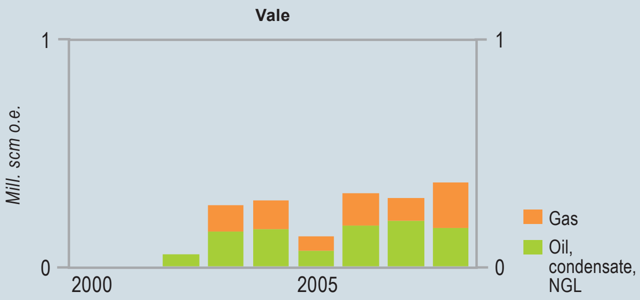
Reservoir:
The reservoir consists of Lower to Middle Jurassic sandstones of the Åre, Tilje and Ile formations at a depth of 1 800 - 2 300 metres.

Recovery strategy:
Urd is recovered by water injection. Gas lift is installed in the wells to be able to produce at low reservoir pressure and high water cut.

Transport:
The wellstream is processed on the Norne vessel, and oil is stabilised and offloaded together with oil from the Norne field. The gas is exported to the Norne field and further in Åsgard Transport to Kårstø.

Status:
The production in 2008 has been better than expected from the Stær deposit, while the Svale deposit has produced less than expected due to lack of pressure support. A new water injection well has been drilled, and the oil production from the Svale deposit is expected to increase. The Melke Formation, located above the Svale and Stær deposits, is being thoroughly analysed for possible development in 2010 – 2011.





Vale

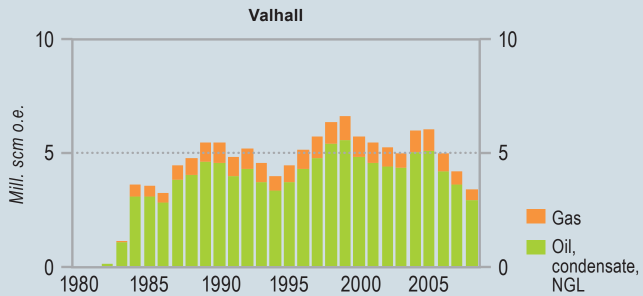
Blocks and production licences	Block 25/4 - production licence 036, awarded 1971	
Discovered	1991	
Development approval	23.03.2001 by the Crown Prince Regent in Council	
On stream	31.05.2002	
Operator	StatoilHydro Petroleum AS	
Licensees	Centrica Resources (Norge) AS	46.90 %
	StatoilHydro Petroleum AS	28.85 %
	Total E&P Norge AS	24.24 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	2.0 million scm oil	1.0 million scm oil
	2.2 billion scm gas	1.4 billion scm gas
Production	**Estimated production in 2009:**	
	Oil: 3 000 barrels/day, Gas: 0.17 billion scm	
Investment	Total investment is expected to be NOK 2.7 billion (2009 values)	
	NOK 2.6 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	

Development:
Vale is a gas and condensate field located 16 kilometres north of Heimdal in the northern part of the North Sea. The field has been developed with a subsea template tied back to Heimdal. The water depth in the area is approximately 115 metres.

Reservoir:
The reservoir consists of Middle Jurassic sandstones of the Brent Group. The reservoir depth is approximately 3 700 metres. The reservoir has very low permeability.

Recovery strategy:
The field is recovered by pressure depletion.

Transport:
The wellstream from Vale goes to Heimdal for processing and export.



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	
Licenseesl	BP Norge AS	28.09 %
	Enterprise Oil Norge AS	28.09 %
	Hess Norge AS	28.09 %
	Total E&P Norge AS	15.72 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	145.0 million scm oil	46.1 million scm oil
	26.4 billion scm gas	6.9 billion scm gas
	5.3 million tonnes NGL	2.2 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 41 000 barrels/day, Gas: 0.45 billion scm, NGL: 0.05 million tonnes	
Investment	Total investment is expected to be NOK 79.5 billion (2009 values) NOK 61.4 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

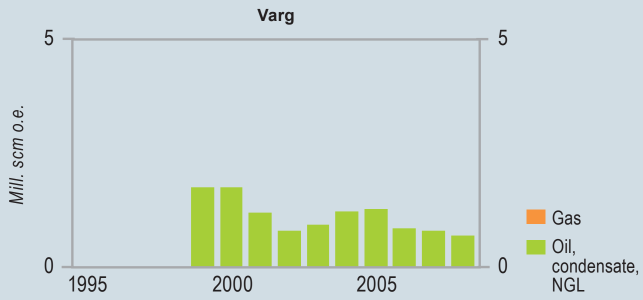
Development:
Valhall is an oil field located in the southern part of the North Sea. The sea depth in the area is about 70 metres. The field was originally developed with three facilities, for accommodation, drilling and production. In 1996, a wellhead facility (Valhall WP) with 19 slots for additional wells was installed. The four facilities are connected by bridges. A water injection facility was installed centrally on 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. 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. A PDO for Valhall redevelopment was approved on 14.06.2007.

Reservoir:
The Valhall field produces from chalk in the Tor and Hod formations of Late Cretaceous age. The reservoir depth is approximately 2 400 metres. The chalk in the Tor Formation is finegrained and soft, with pervasive fractures allowing oil and water to flow more easily. As a result of pressure depletion from production, the chalk has compacted, causing subsidence of the seabed at Valhall.

Recovery strategy:
Recovery originally took place by pressure depletion with compaction drive. 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:
In relation to current plans, there are significant possibilities for further increases in reserves by using all well slots and optimizing water injection. Further development of Valhall is to build a new field centre with processing plant and accommodation facilities. The new facility will get electric power supply from shore.



Varg

Blocks and production licences	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	Det norske oljeselskap ASA	5.00 %
	Petoro AS	30.00 %
	Talisman Energy Norge AS	65.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	15.1 million scm oil	3.9 million scm oil
Production	**Estimated production in 2009:**	
	Oil: 11 000 barrels/day	
Investment	Total investment is expected to be NOK 9.4 billion (2009 values)	
	NOK 8.2 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

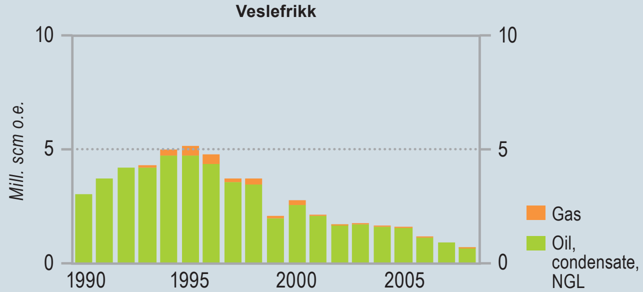
Development:
Varg is an oil field to the south of Sleipner Øst in the southern part of the North Sea. The sea depth in the area is 84 metres. The field has been developed with a production vessel (Petrojarl Varg) with integrated oil storage, and a connected wellhead facility (Varg A). The decommissioning plan for the field was approved in 2001, and the plan was to produce until the summer of 2002.

Reservoir:
The reservoir is in Upper Jurassic sandstones at a depth of approximately 2 700 metres. The structure is segmented by faults and includes several isolated substructures.

Recovery strategy:
Recovery takes place by means of water and gas injection. The smaller structures are produced by pressure depletion. All wells are producing by gas lift.

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

Status:
The operator is continuously evaluating means to increase the resources at Varg. Several prospects in the area are being evaluated. The Grevling prospect, approximately 18 kilometres north of Varg will be drilled in 2009. Measures to optimize the recovery are being considered, among others water alternating gas injection (WAG). Several wells are planned to be drilled in the coming years.



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	StatoilHydro ASA	
Licensees	Petoro AS	37.00 %
	RWE Dea Norge AS	13.50 %
	Wintershall Norge ASA	4.50 %
	StatoilHydro ASA	18.00 %
	Talisman Energy Norge AS	27.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	55.7 million scm oil	6.3 million scm oil
	3.8 billion scm gas	1.6 billion scm gas
	1.3 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 13 000 barrels/day	
Investment	Total investment is expected to be NOK 28.8 billion (2009 values) NOK 20.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

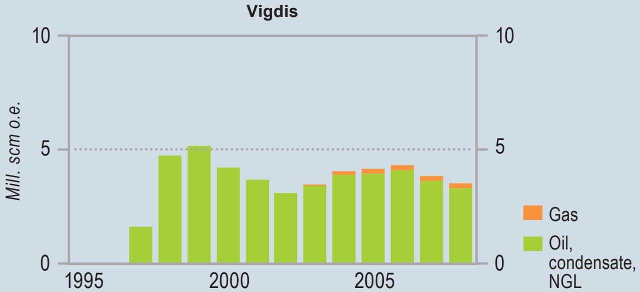
Development:
Veslefrikk is an oil field located about 30 kilometres north of Oseberg in the northern part of the North Sea. The sea depth is about 185 metres. The field is developed with two facilities, Veslefrikk A and Veslefrikk B. Veslefrikk A is a fixed steel wellhead facility with bridge connection to Veslefrikk B. Veslefrikk B is a semi-submersible facility for processing and accommodation. Veslefrikk B was upgraded in 1999 to handle 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 reservoirs consist of Jurassic sandstones of the Brent and Dunlin groups and the Statfjord Formation. The main reservoir is in the Brent Group and contains about 80 per cent of the reserves. The reservoir depths are between 2 800 - 3 200 metres.

Recovery strategy:
Production takes place with pressure support from water injection, and water alternating gas injection (WAG) in parts of the field.

Transport:
An oil pipeline is connected to the Oseberg Transport System (OTS) for transport to the Sture terminal. All gas is injected but may be exported through the Statpipe system to Kårstø and Emden.

Status:
Production from Veslefrikk is in the decline phase. The project, Veslefrikk 2020, is evaluating modification and upgrading of the facilities to prolong the lifetime of the field. Several methods to increase the oil recovery are being evaluated. An exploration well will be drilled early in 2009 in order to explore possible resources which may be tied to Veslefrikk.



Vigdis

Blocks and production licences	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	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	10.50 %
	Idemitsu Petroleum Norge AS	9.60 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	2.80 %
	StatoilHydro ASA	28.22 %
	StatoilHydro Petroleum AS	13.28 %
	Total E&P Norge AS	5.60 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	59.0 million scm oil	15.9 million scm oil
	1.8 billion scm gas	0.7 billion scm gas
	1.6 million tonnes NGL	0.9 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 52 000 barrels/day, Gas: 0.17 billion scm, NGL: 0.19 million tonnes	
Investment	Total investment is expected to be NOK 16.8 billion (2009 values)	
	NOK 15.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

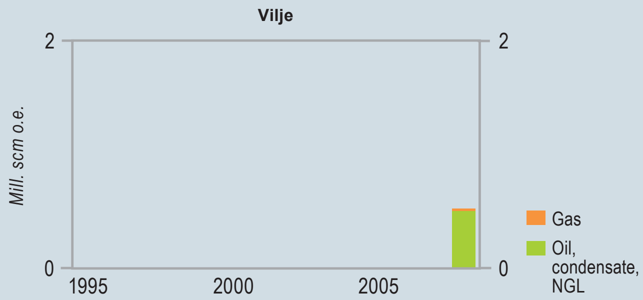
Development:
Vigdis is an oil field located between the Snorre and Gullfaks fields in the Tampen area in the northern part of the North Sea. The sea depth in the area is 280 metres. The field has been developed with subsea templates connected to Snorre A. The wellstream is routed to Snorre A through two flow lines. 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 discovery 34/7-23 S and adjoining deposits, was approved on 20.12.2002.

Reservoir:
The reservoirs consist of Middle Jurassic sandstones of the Brent Group, Lower Jurassic and Upper Triassic sandstones of the Statfjord Formation, and Upper Jurassic intra Draupne sandstones. The reservoirs are at a depth of 2 200 - 2 600 metres. The quality of the reservoirs is generally good.

Recovery strategy:
Production is based on partial pressure maintenance using water injection. Parts of the Vigdis reservoir will be affected by the pressure blowdown of the Statfjord field, and therefore a new water injection well has been drilled.

Transport:
Stabilised oil from Vigdis is sent from Snorre A to Gullfaks A for storage and export. The gas from Vigdis is used for injection at Snorre.

Status:
The operator is evaluating means to improve recovery from Vigdis. Two new wells for production and water injection were completed in 2008. It has been decided to increase the water injection on Vigdis with water supplied from Statfjord C. Equipment for low pressure production is being installed.



Vilje

Blocks and production licences	Block 25/4 - production licence 036 D, awarded 2008	
Discovered	2003	
Development approval	18.03.2005 by the King in Council	
On stream	01.08.2008	
Operator	StatoilHydro Petroleum AS	
Licensees	Marathon Petroleum Norge AS	46.90 %
	StatoilHydro Petroleum AS	28.85 %
	Total E&P Norge AS	24.24 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	8.3 million scm oil	7.8 million scm oil
	0.4 billion scm gas	0.4 billion scm gas
Production	**Estimated production in 2009:**	
	Oil: 21 000 barrels/day	
Investment	Total investment is expected to be NOK 2.1 billion (2009 values)	
	NOK 2.1 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	

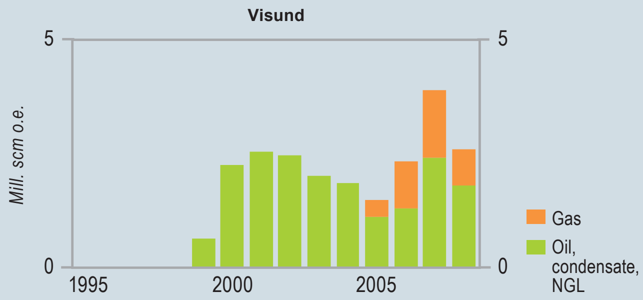
Development:
Vilje is a small oil field located in the northern part of the North Sea, north of the Heimdal field. The sea depth in the area is approximately 120 metres. The field has been developed with two subsea wells connected to Alvheim.

Reservoir:
The reservoir consists of turbidity sandstones in the Heimdal Formation of Paleocene age and lies approximately 2 150 metres below sea level.

Recovery strategy:
Production is accomplished by natural aquifer drive.

Transport:
The wellstream is routed by pipeline to Alvheim, where the oil is buoy-loaded to tankers.

Status:
Production started in May 2008.



Visund

Blocks and production licences	Block 34/8 - production licence 120, awarded 1985	
Discovered	1986	
Development approval	29.03.1996 by the Storting	
On stream	21.04.1999	
Operator	StatoilHydro ASA	
Licensees	ConocoPhillips Skandinavia AS	9.10 %
	Petoro AS	30.00 %
	StatoilHydro ASA	32.90 %
	StatoilHydro Petroleum AS	20.30 %
	Total E&P Norge AS	7.70 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	29.1 million scm oil	11.0 million scm oil
	47.2 billion scm gas	43.5 billion scm gas
	6.0 million tonnes NGL	5.7 million tonnes NGL
Production	**Estimated production in 2009:**	
	Oil: 25 000 barrels/day, Gas: 0.73 billion scm, NGL: 0.10 million tonnes	
Investment	Total investment is expected to be NOK 32.8 billion (2009 values)	
	NOK 22.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Bergen	
Main supply base	Florø	

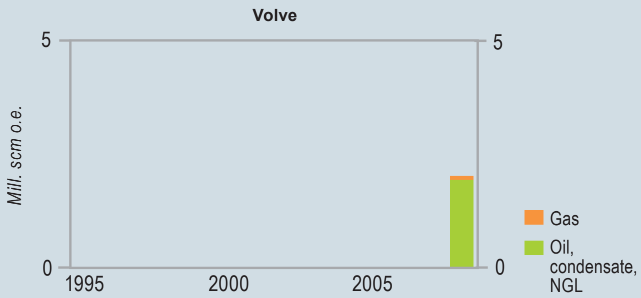
Development:
Visund is an oil field to the east of the Snorre field in the northern part of the North Sea. The sea depth in the area is 335 metres. The development includes a semi-submersible integrated accommodation, drilling and processing steel facility (Visund A). The northern part of Visund has been developed with a subsea template about 10 kilometres to the north of Visund A. The PDO for gas export was approved on 04.10.2002. The subsea template, Visund Nord, was closed down in 2006 after a gas leakage on the Visund A facility.

Reservoir:
Visund contains oil and gas in several tilted fault blocks with varying pressure and liquid systems. The reservoirs are in Middle and Lower Jurassic and Upper Triassic sandstones in the Brent Group and the Statfjord and Lunde formations. The reservoirs lie at a depth of 2 900 - 3 000 metres.

Recovery strategy:
Oil production is driven by gas injection and water alternating gas injection (WAG). 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 with oil from Gullfaks. Gas is exported to the Kvitebjørn gas pipeline and on to Kollsnes. At Kollsnes, NGL is separated out and the dry gas further exported to the market.

Status:
A challenge for Visund is to maintain reservoir pressure to optimize oil recovery before gas export levels increase. One measure being evaluated is to access more water to increase water injection. The gas export has been reduced. One exploration target near Visund was drilled in 2008 and proved additional resources which can be tied in to the field. An area development plan for new resources is expected to be prepared in 2009. An exploration target east of Visund Nord is planned to be drilled in 2009. A possible discovery may be tied to a new development of Visund Nord.



Volve

Blocks and production licences	Block 15/9 - production licence 046 BS, awarded 2006	
Discovered	1993	
Development approval	22.04.2005 by the Crown Prince Regent in Council	
On stream	12.02.2008	
Operator	StatoilHydro ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	30.40 %
	PA Resources Norway AS	10.00 %
	StatoilHydro ASA	49.60 %
	StatoilHydro Petroleum AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	13.6 million scm oil	11.8 million scm oil
	1.1 billion scm gas	1.0 billion scm gas
	0.2 million tonnes NGL	0.2 million tonnes NGL
	0.1 million scm condensate	0.1 million scm condensate
Production	**Estimated production in 2009:**	
	Oil: 43 000 barrels/day, Gas: 0.25 billion scm, NGL: 0.05 million tonnes, Condensate: 0.03 million scm	
Investment	Total investment is expected to be NOK 3.9 billion (2009 values)	
	NOK 2.8 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stavanger	

Development:
Volve is an oil field located in the southern part of the North Sea approximately eight kilometres north of Sleiper Øst. The sea depth in the area is about 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 in Jurassic sandstones of the Hugin Formation. The reservoir lies at a depth of 2 750 – 3 120 metres. The western part of the structure is heavily faulted and communication across the faults is uncertain.

Recovery strategy:
Volve is produced by water injection as the drive mechanism.

Transport:
The rich gas is transported to Sleipner A for further export.

Status:
The prospects Volve Sør and Volve Vestflanke, which are included in the PDO, will be drilled by extending new production wells. Volve Sør was drilled in November 2008, while Volve Vestflanke will be drilled in the first part of 2009.

Yttergryta

Blocks and production licences	Block 6507/11 - production licence 062, awarded 1981 Block 6507/11 - production licence 263 C, awarded 2008	
Discovered	2007	
Development approval	21.05.2008 by the King in council	
On stream	05.01.2009	
Operator	StatoilHydro ASA	
Licensees	Eni Norge AS	9.80 %
	Petoro AS	19.95 %
	StatoilHydro ASA	45.75 %
	Total E&P Norge AS	24.50 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	0.1 million scm oil	0.1 million scm oil
	1.6 billion scm gas	1.6 billion scm gas
	0.3 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2009:** Oil: 1 000 barrels/day, Gas: 0.31 billion scm, NGL: 0.05 million tonnes	
Investment	Total investment is expected to be NOK 1.4 billion (2009 values) NOK 1.4 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stjørdal	

Development:
The field is located approximately 5 kilometres north of Midgard and has been developed by a subsea template and one production well.

Reservoir:
The reservoir contains gas in Middle Jurassic sandstones of the Fangst Group and lies at a depth of 2 390 - 2 490 metres.

Recovery strategy:
The field is produced by pressure depletion.

Transport:
The gas is transported to the Midgard X template and further to Åsgard B for processing. Yttergryta has low CO_2 gas and is therefore suitable for blending in Åsgard Transport.

Status:
The field came on stream in January 2009.

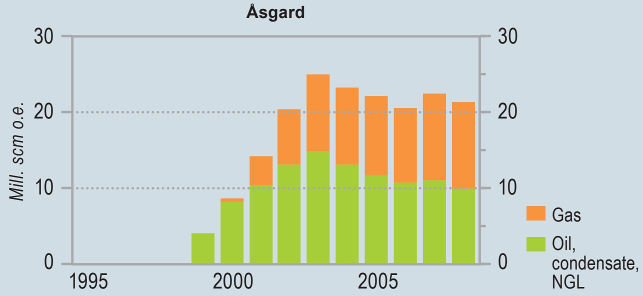
 

Åsgard

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	StatoilHydro ASA	
Licensees	Eni Norge AS	14.82 %
	ExxonMobil Exploration & Production Norway AS	7.24 %
	Petoro AS	35.69 %
	StatoilHydro ASA	34.57 %
	Total E&P Norge AS	7.68 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2008:**
	97.6 million scm oil	34.5 million scm oil
	185.9 billion scm gas	110.8 billion scm gas
	36.1 million tonnes NGL	23.0 million tonnes NGL
	16.0 million scm condensate	
Production	**Estimated production in 2009:** Oil: 88 000 barrels/day, Gas: 10.93 billion scm, NGL: 1.96 million tonnes	
Investment	Total investment is expected to be NOK 82.4 billion (2009 values) NOK 70.9 billion have been invested as of 31.12.2008 (2009 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

Development:
Åsgard is located centrally in the Norwegian Sea. The water depth in the area is 240-300 metres. The field has been developed with subsea completed wells tied back 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 and Yttergryta is processed. The Åsgard field has been developed in two phases. The liquid phase came on stream in 1999 and the gas export phase started on 01.10.2000. Åsgard includes the discoveries 6506/12-1 Smørbukk, 6506/12-3 Smørbukk Sør and 6507/11-1 Midgard.

Reservoir:
The Smørbukk deposit 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 of Jurassic age and contain gas, condensate and oil. The Smørbukk Sør deposit, with reservoir rocks in the Garn, Ile and Tilje formations of Early to Middle Jurassic ages, contains oil, gas and condensate. The Midgard deposit is divided into four structural segments with the main reservoir in the Middle Jurassic Garn and Ile formations. The reservoirs lie at depths down to 4 850 metres. The reservoir quality varies between the formations and there are large differences in porosity and permeability between the three deposits.

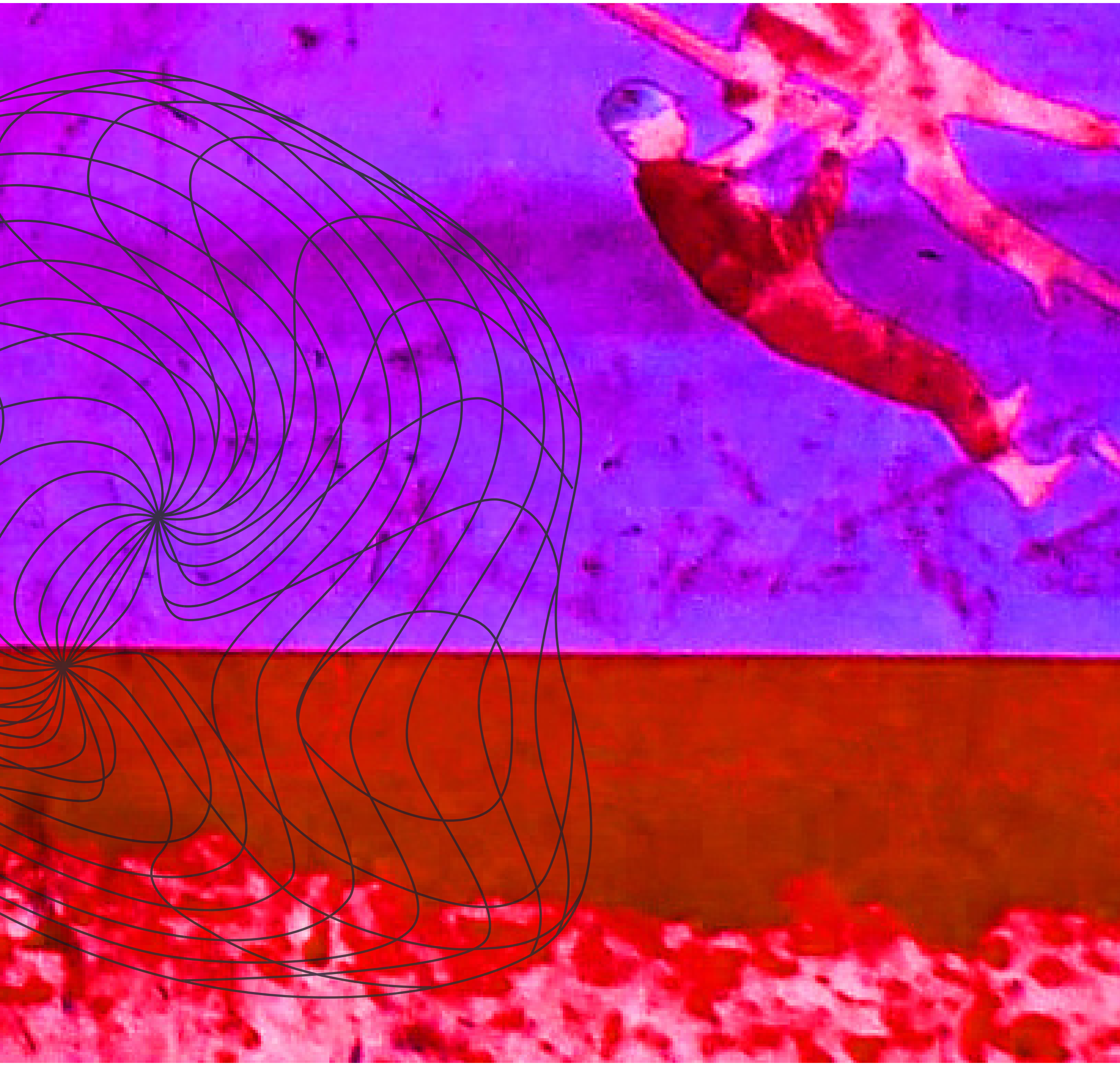


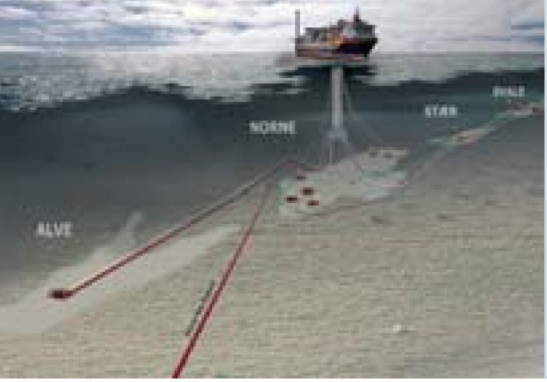
Recovery strategy:
The Smørbukk and Smørbukk Sør deposits are produced with gas injection. The Midgard deposit is produced by pressure depletion. There is a thin oil zone (11.5 m) below the gas cap in the Midgard deposit, but at the time there are no plans to produce the oil. Studies are ongoing to maintain an optimal flow in the pipeline from the Midgard deposit to Åsgard to ensure that a stable supply of low CO_2 gas from the Midgard deposit and Mikkel can be blended with high CO_2 gas from Kristin in Åsgard Transport to Kårstø.

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. The condensate from Åsgard is being sold as oil (Halten Blend).

Status:
Most of the production wells have been drilled, and efforts are being made to increase recovery from the field. It has been decided to tie Morvin into Åsgard. Yttergryta has been tied to Åsgard and came on stream in January 2009. In addition, measures to increase production of low CO_2 gas from the Midgard deposit are being considered. Other deposits containing low CO_2 gas in the area are being explored.

12 Fields under development





Alve

Blocks and production licences	Block 6507/3 - production licence 159 B, awarded 2004	
Discovered	1990	
Development approval	16.03.2007 by the King in Council	
Operator	StatoilHydro ASA	
Licensees	DONG E&P Norge AS	15.00 %
	StatoilHydro ASA	85.00 %
Recoverable reserves	**Original:**	
	1.3 million scm oil	
	5.5 billion scm gas	
	1.1 million tonnes NGL	
Investment	Total investment is expected to be NOK 2.7 billion (2009 values)	
	NOK 2.6 billion have been invested as of 31.12.2008 (2009 values)	

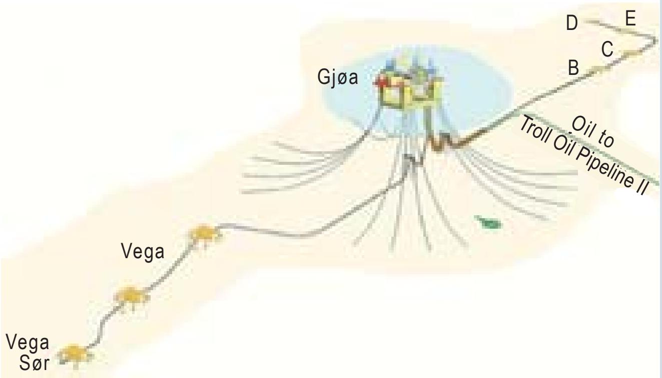
Development:
Alve is a gas and condensate field located about 16 kilometres southwest of Norne. The sea depth in the area is about 370 meters. The development concept is a standard subsea template with four well slots and one production well.

Reservoir:
The reservoir is in Middle Jurassic sandstones in the Garn and Not formations. The reservoir lies at a depth of about 3 600 metres. There are also resources in the Ile and Tilje formations that may be developed later.

Recovery strategy:
The reservoir will be produced by pressure depletion.

Transport:
Alve will be tied to the Norne vessel by a pipeline. The gas will be transported via the Norne pipeline to Åsgard Transport and further to Kårstø for export.

Status:
Alve came on stream 19 March 2009.



Gjøa

Blocks and production licences	Block 35/9 - production licence 153, awarded 1988 Block 36/7 - production licence 153, awarded 1988	
Discovered	1989	
Development approval	14.06.2007 by the Storting	
Operator	StatoilHydro ASA	
Licensees	A/S Norske Shell	12.00 %
	GDF SUEZ E&P Norge AS	30.00 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	8.00 %
	StatoilHydro ASA	20.00 %
Recoverable reserves	**Original:** 11.1 million scm oil 32.6 billion scm gas 5.6 million tonnes NGL	
Investment	Total investment is expected to be NOK 28.8 billion (2009 values) NOK 14.2 billion have been invested as of 31.12.2008 (2009 values)	

Development:
Gjøa is located about 40 kilometres north of the Fram field. The sea depth in the area is 360 metres. StatoilHydro is operator for the development phase, while GDF SUEZ E&P Norge will take over the operatorship at production start-up. The development comprises five subsea templates tied to a semi-submersible production and processing facility.
The Gjøa facility will get power supply from shore.

Reservoir:
The reservoir contains gas over a relatively thin oil zone in Jurassic sandstones in the Viking, Brent and Dunlin groups. The field contains several tilted fault segments with partly uncertain communication and varying reservoir quality. The reservoir depth is about 2 200 metres.

Recovery strategy:
The reservoir will be produced by pressure depletion.

Transport:
Stabilized oil will be exported in a new 55 kilometres long pipeline which will be connected to Troll Oljerør II, for further transport to Mongstad. The rich gas will be exported in a new 130 kilometres long pipeline to the FLAGS transport system on the UK continental shelf, for further transport to St. Fergus.

Status:
Production is expected to start in the autumn of 2010.

Morvin

Blocks and production licences	Block 6506/11 - production licence 134 B, awarded 2000	
	Block 6506/11 - production licence 134 C, awarded 2006	
Discovered	2001	
Development approval	25.04.2008 by the King in Council	
Operator	StatoilHydro ASA	
Licensees	Eni Norge AS	30.00 %
	StatoilHydro ASA	64.00 %
	Total E&P Norge AS	6.00 %
Recoverable reserves	**Original:**	
	9.3 million scm oil	
	3.2 billion scm gas	
	0.7 million tonnes NGL	
Investment	Total investment is expected to be NOK 7.6 billion (2009 values)	
	NOK 2.3 billion have been invested as of 31.12.2008 (2009 values)	

Development:
Morvin is located approximately 20 kilometres north of Kristin and 15 kilometres west of Åsgard. The sea depth in the area is 350 metres. The field will be developed with two subsea templates tied to Åsgard B.

Reservoir:
The reservoir consists of a rotated and tilted fault block in the northwestern part of the Halten Terrace at a depth of 4 500 - 4 700 metres. The discovery well was drilled in 2001 and proved oil in Middle Jurassic sandstones in the Garn and Ile formations. The reservoir in the Garn formation contains relatively homogenous sandstones while the reservoir in the Ile formation is more heterogeneous.

Recovery strategy:
The reservoir will be recovered by pressure depletion.

Transport:
The wellstream from Morvin will be sent through a 20 kilometres long pipeline to Åsgard for processing and further transport.

Status:
Planned start of production is in late 2010.

Skarv

Blocks and production licences	Block 6507/2 - production licence 262, awarded 2000	
	Block 6507/3 - production licence 159, awarded 1989	
	Block 6507/3 - production licence 212 B, awarded 2002	
	Block 6507/5 - production licence 212, awarded 1996	
	Block 6507/6 - production licence 212, awarded 1996	
Discovered	1998	
Development approval	18.12.2007 by the Storting	
Operator	BP Norge AS	
Licensees	BP Norge AS	23.84 %
	E.ON Ruhrgas Norge AS	28.08 %
	PGNiG Norway AS	11.92 %
	StatoilHydro ASA	36.16 %
Recoverable reserves	**Original:**	
	16.5 million scm oil	
	41.5 billion scm gas	
	5.4 million tonnes NGL	
Investment	Total investment is expected to be NOK 36.8 billion (2009 values)	
	NOK 8.7 billion have been invested as of 31.12.2008 (2009 values)	

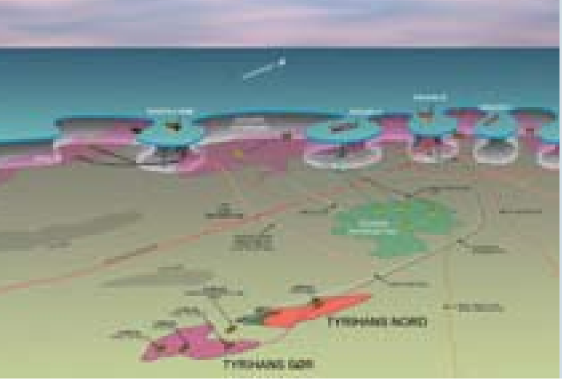
Development:
Skarv is located about 35 kilometres southwest of the Norne field in the northern part of the Norwegian Sea. The development comprises the deposits 6507/5-1 Skarv and 6507/3-3 Idun. The sea depth in the area is between 250-450 metres. The development concept is a floating production facility (FPSO) connected to five subsea templates.

Reservoir:
The reservoirs in Skarv contain gas and condensate in Middle and Lower Jurassic sandstones in the Garn, Ile and Tilje formations. There is also an underlying oil zone in the Skarv deposit in the Garn and Tilje formations. The Garn Formation has good reservoir quality, while the Tilje Formation has relatively poor quality. The reservoirs are divided into several fault segments and lie at a depth of 3 300-3 700 metres.

Recovery strategy:
In the Garn and Tilje formations, gas reinjection is planned for the first years in order to increase oil recovery.

Transport:
The oil will be buoy-loaded to tankers, while gas will be exported in a new 80 kilometres long pipeline connected to the Åsgard Transport system.

Status:
The production vessel and templates are under construction and are planned to be completed in the autumn of 2010. Originally planned start of drilling in the summer of 2009 may be postponed due to delayed construction of a drilling rig. Start of production is expected in 2011.



Tyrihans

Blocks and production licences	Block 6406/3 - production licence 073 B, awarded 2004	
	Block 6406/3 - production licence 091, awarded 1984	
	Block 6407/1 - production licence 073, awarded 1982	
Discovered	1983	
Development approval	16.02.2006 by the Storting	
Operator	StatoilHydro ASA	
Licensees	Eni Norge AS	6.23 %
	ExxonMobil Exploration & Production Norway AS	11.75 %
	StatoilHydro ASA	58.84 %
	Total E&P Norge AS	23.18 %
Recoverable reserves	**Original:**	
	29.6 million scm oil	
	35.5 billion scm gas	
	6.5 million tonnes NGL	
Investment	Total investment is expected to be NOK 15.6 billion (2009 values)	
	NOK 10 billion have been invested as of 31.12.2008 (2009 values)	

Development:
Tyrihans is located in the Norwegian Sea about 25 kilometres southeast of the Åsgard field. The sea depth in the area is about 270 metres. Tyrihans comprises the discoveries 6407/1-2 Tyrihans Sør which was discovered in 1983 and 6407/1-3 Tyrihans Nord discovered in 1984. The development concept is five subsea templates tied to Kristin, four for production and gas injection and one for water injection.

Reservoir:
Tyrihans Sør has an oil column with a condensate rich gas cap. Tyrihans Nord contains gas condensate with an underlying oil zone. The Garn Formation of Middle Jurassic age constitutes the main reservoir in both deposits and lies at about 3 500 metres. The reservoir is homogenous and the quality is good.

Recovery strategy:
In the first years, the recovery is based on gas injection from Åsgard B into Tyrihans Sør. In addition subsea pumps will be used for injection of sea water to increase recovery. It has also been decided to produce the oil zone in Tyrihans Nord.

Transport:
Oil and gas from Tyrihans will be transported in pipeline to Kristin for processing and further transport.

Status:
Start of production is planned for 1st quarter of 2009

Vega

Blocks and production licences	Block 35/11 - production licence 248, awarded 1999	
	Block 35/8 - production licence 248, awarded 1999	
Discovered	1981	
Development approval	14.06.2007 by the Storting	
Operator	StatoilHydro Petroleum AS	
Licensees	Petoro AS	40.00 %
	StatoilHydro ASA	20.00 %
	StatoilHydro Petroleum AS	40.00 %
Recoverable reserves	**Original:**	
	9.4 billion scm gas	
	0.5 million tonnes NGL	
	1.7 million scm condensate	
Investment	Total investment is expected to be NOK 5.0 billion (2009 values)	
	NOK 1.6 billion have been invested as of 31.12.2008 (2009 values)	

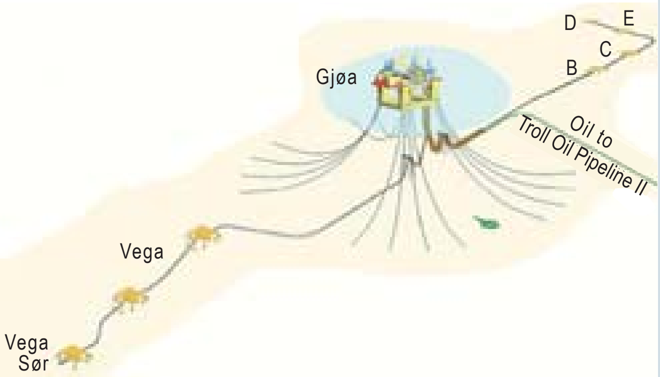
Development:
Vega is located north of the Fram field in the northern part of the North Sea. The sea depth in the area is about 370 metres. The field comprises two separate gas and condensate deposits, proven by 35/8-1 in 1981 and 35/8-2 in 1982. A combined PDO for Vega and Vega Sør was approved by the authorities in June 2007. The field is developed with two subsea templates tied to the process facility at Gjøa.

Reservoir:
The reservoirs are in Middle Jurassic sandstones in the Brent group, with high temperature and high pressure and relatively low permeability. The reservoir depth is about 3 500 metres.

Recovery strategy:
The field will be produced by pressure depletion.

Transport:
The wellstream will be sent in a pipeline to Gjøa for processing. Oil and condensate will be sent from Gjøa in a new pipeline tied to Troll Oljerør II for further transport to Mongstad. The rich gas will be exported in a new pipeline to Far North Liquids and Associated Gas System (FLAGS) at the UK continental shelf for further transport to St. Fergus.

Status:
The production is expected to start in the autumn of 2010.



Vega Sør

Blocks and production licences	Block 35/11 - production licence 090 C, awarded 2005	
Discovered	1987	
Development approval	14.06.2007 by the Storting	
Operator	StatoilHydro Petroleum AS	
Licensees	Bayerngas Norge AS	25.00 %
	GDF SUEZ E&PNorge AS	15.00 %
	Idemitsu Petroleum Norge AS	15.00 %
	StatoilHydro ASA	20.00 %
	StatoilHydro Petroleum AS	25.00 %
Recoverable reserves	**Original:**	
	7.4 billion scm gas	
	0.4 million tonnes NGL	
	2.4 million scm condensate	
Investment	Total investment is expected to be NOK 2.9 billion (2009 values)	
	NOK 0.9 billion have been invested as of 31.12.2008 (2009 values)	

Development:
Vega Sør is a gas and condensate field located near the Fram field. The sea depth in the area is about 370 metres. A combined PDO for Vega and Vega Sør was approved by the authorities in June 2007. The development concept for gas and condensate is a subsea template tied to Vega.

Reservoir:
The field contains gas and condensate with an oil zone in the upper part of the Brent Group of Middle Jurassic age. The reservoir depth is approximately 3 500 metres.

Recovery strategy:
The field will be produced by pressure depletion.

Transport:
The well stream will be sent in a pipeline from Vega Sør via the subsea templates on Vega to Gjøa for processing. Oil and condensate will be sent from Gjøa in a new pipeline tied to Troll Oljerør II for further transport to Mongstad. The rich gas will be exported in a new pipeline to the Far North Liquids and Gas System (FLAGS) on the British continental shelf for further transport to St. Fergus.

Status:
The production is expected to start in the autumn of 2010. Development of the oil zone will be considered in connection with the discovery 35/11-13 located east of Vega Sør.

Volund

Blocks and production licences	Block 24/9 - production licence 150, awarded 1988	
Discovered	1994	
Development approval	18.01.2007 by the King in Council	
Operator	Marathon Petroleum Norge AS	
Licensees	Lundin Norway AS	35.00 %
	Marathon Petroleum Norge AS	65.00 %
Recoverable reserves	**Original:**	
	7.2 million scm oil	
	0.6 billion scm gas	
Investment	Total investment is expected to be NOK 3.4 billion (2009 values)	
	NOK 1.3 billion have been invested as of 31.12.2008 (2009 values)	

Development:
Volund is an oil field located south of Alvheim. The sea depth in the area is 120 - 130 metres.
The field is being developed with three subsea wells connected to Alvheim.

Reservoir:
The reservoir is sandstone intrusions in the Balder formation of Eocene age at a depth of about 2 000 metres.

Recovery strategy:
Volund will be produced with water injection as drive mechanism.

Transport:
The wellstream will be routed in a pipeline to Alvheim for buoy-loading.

Status:
Start of production is expected in November 2009.

Yme

Blocks and production licences	Block 9/2 - production licence 316, awarded 2004	
	Block 9/5 - production licence 316, awarded 2004	
Discovered	1987	
Development approval	11.05.2007 by the King in Council	
Operator	Talisman Energy Norge AS	
Licensees	Det norske oljeselskap ASA	10.00 %
	Lotos Exploration and Production Norge AS	10.00 %
	Wintershall Norge AS	10.00 %
	Talisman Energy Norge AS	70.00 %
Recoverable reserves*	**Original:**	**Remaining as of 31.12.2008**
	18.8 million scm oil	10,9 scm oil
Investment*	Total investment is expected to be NOK 9.4 billion (2009 values)	
	NOK 5.4 billion have been invested as of 31.12.2008 (2009 values)	

** Include original and new development*

Development:
Yme is located in the south-eastern part of the North Sea at a sea depth of 77-93 metres. Yme is the first oil field on the Norwegian continental shelf to be redeveloped after having been shut-down. The field was initially developed in 1995, by production licence 114 operated by Statoil. The production period lasted from 1996 to 2001, when operation of the field was considered to be unprofitable. New licensees in production licence 316 operated by Talisman, decided in 2006 to recover the remaining resources with a new jack-up production facility. The facility is placed on a storage tank for oil at the sea bed above the Gamma structure. The Beta structure is being developed with subsea wells.

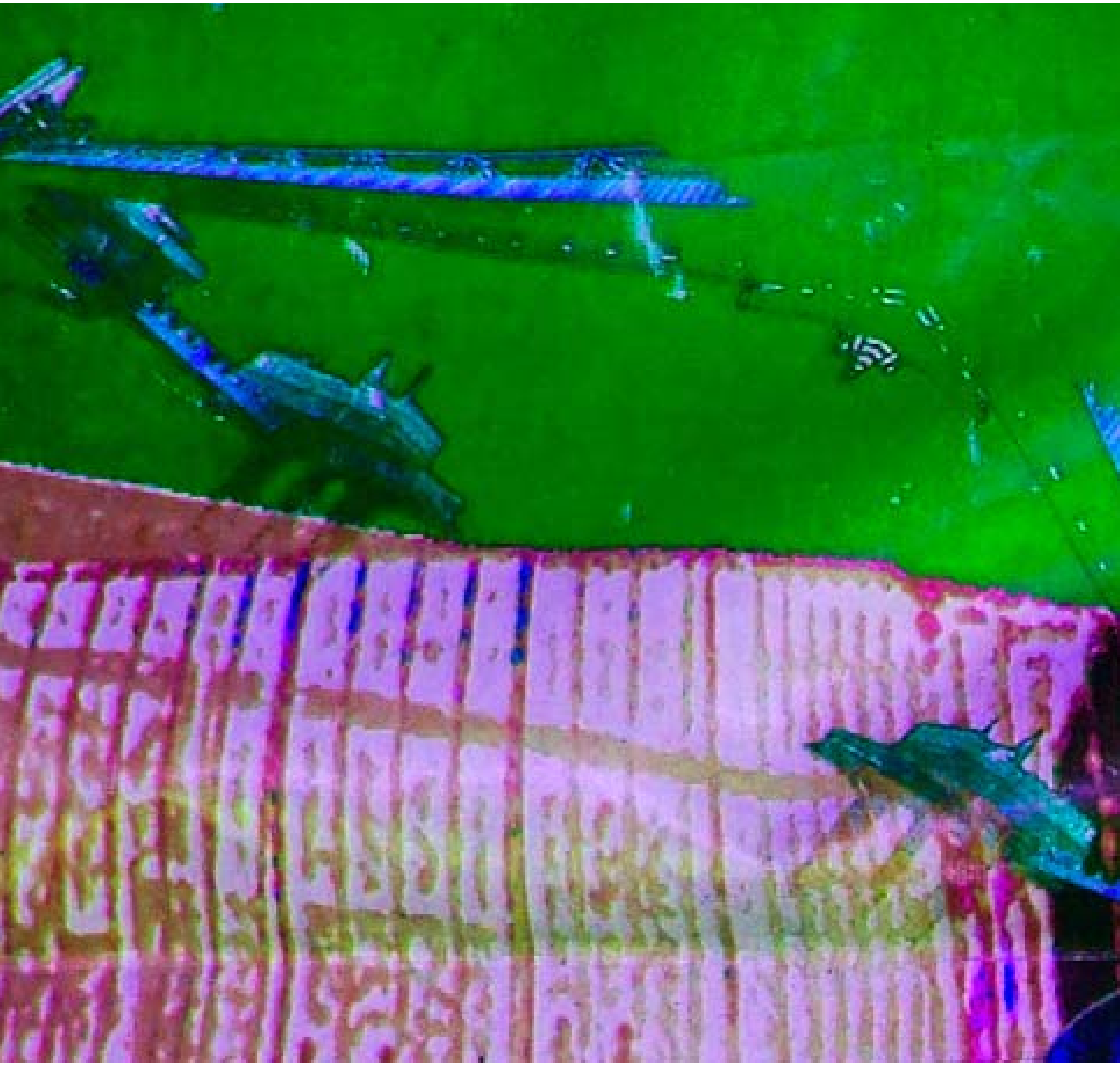
Reservoir:
Yme contains two separate main structures, Gamma and Beta, comprising five discoveries. The reservoir is in Middle Jurassic sandstones in the Sandnes Formation at a depth of approximately 3 150 metres.

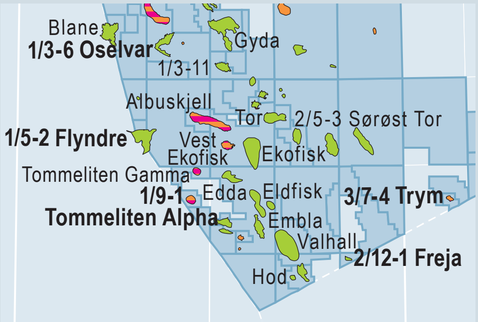
Recovery strategy:
Yme will mainly be produced with water injection as drive mechanism. Excess gas may also be injected together with water in one well.

Transport:
The well stream will be processed at the Yme facility and the oil will be stored in the subsea tank for export via buoy-loading to tankers. Excess gas is planned to be injected.

Status:
Start of production is expected in the autumn of 2009.

13 Future developments





This list does not comprise discoveries included in existing fields as of 31.12.08.

Development decided by the licensees

3/7-4 Trym	Production licence 147, Operator: DONG E&P Norge AS
Resources	Oil: 4.2 million scm, Condensate: 1.1 million scm

3/7-4 Trym was discovered in 1990 and is located three kilometres from the border to the Danish continental shelf. The sea depth in the area is approximately 65 metres. The discovery contains gas and condensate in sandstones of Late Jurassic and Middle Jurassic age and lies on the same salt induced structure as the Danish field Lulita. The deposits are assumed to be separated by a fault zone on the Norwegian side of the border, but there might be pressure communication in the water zone. A PDO was submitted to the authorities 21.10.2008. The development concept for the discovery is a subsea template tied to the Harald facility on the Danish side of the border. The well stream will be processed on the Harald facility for further transport.

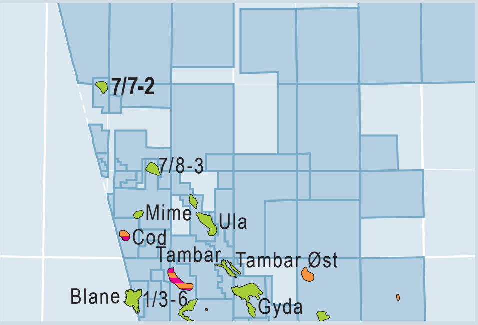
Discoveries in the planning phase

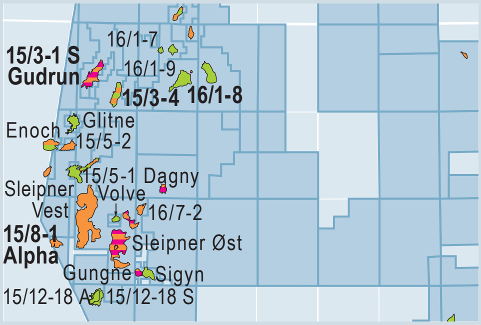
1/3-6 Oselvar	Production licence 274, Operator: DONG E&P Norge AS
Resources	Oil: 4.4 million scm, Gas: 4.8 billion scm

1/3-6 Oselvar was discovered in 1991 and is located 21 kilometres southwest of the Ula field, and 24 kilometres northwest of the Gyda field. The sea depth in the area is approximately 70 metres. The discovery contains oil with a gradual transition to gas via a condensate phase. The reservoir lies at a depth of 2 900 – 3 250 metres. A PDO was submitted to the authorities 09.03.2009. The discovery will be produced by pressure depletion. The development concept is a subsea development tied to Ula. The gas will be used for injection in Ula WAG, and the oil will go via Ula to Ekofisk for further transport. Planned production start is in 4th quarter of 2011.

1/5-2 Flyndre	Production licence 018 C, Operator: Maersk Oil PL 018 C AS
Resources	Oil: 0.2 million scm

1/5-2 Flyndre was discovered in 1974 at the border between the Norwegian and the British sector and lies at a depth of approximately 70 metres. The discovery contains oil and associated gas in chalk in the Ekofisk, Tor and Hod formations of Cretaceous age, and in sandstones of Paleocene age. Four wells have been drilled, one on the Norwegian side and three on the British side. The majority of the resources are on the British continental shelf. According to plan, a PDO will be submitted to the authorities during 2009. Most likely development concept is a subsea template tied to facilities on the British side. Start of production is expected in 2012.





1/9-1 Tommeliten Alpha	Production licence 044, Operator: ConocoPhillips Skandinavia AS
Resources	Oil: 8.1 million scm, Gas: 12.8 billion scm, NGL: 0.5 million tonnes

1/9-1 Tommeliten Alpha was discovered in 1977. 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 UK sector. The discovery contains gas and condensate in Upper Cretaceous chalk at a depth of 3 500 metres. Four appraisal wells have been drilled on the discovery, the most recent being 1/9-7 in 2003. The licensees are evaluating the resource base and alternative development concepts. Production may start in 2014 at the earliest.

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

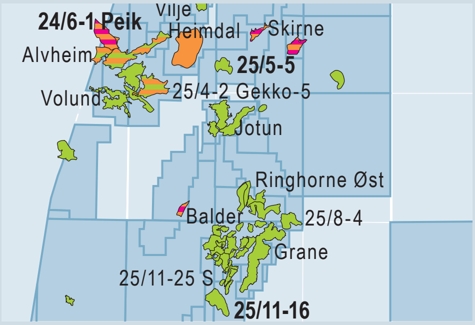
2/12-1 Freja was discovered in 1987, close to the border between the Danish and Norwegian sectors. The sea depth in the area is 70 metres. The reservoir is in Upper Jurassic sandstones. The reservoir lies at a depth of about 4 900 metres, and contains oil and associated gas. 2/12-1 Freja is located in 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 neighbouring Gert deposit on the Danish side of the border. The development concept is a subsea template connected to Valhall or to a facility in the Danish sector.

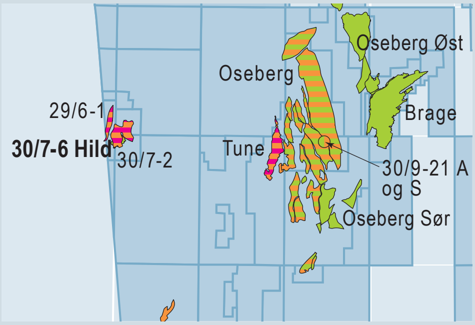
7/7-2	Production licence 148, Operator: Lundin Norway AS
Resources	Oil: 3.3 million scm

The 7/7-1 discovery was made in 1992 and appraisal wells were drilled in 1993 and 2008. The discovery is located 43 kilometres northwest of the Ula field, and 22 kilometres northeast for the nearest relevant facility on the British sector. The sea depth in the area is approximately 80 metres. The reservoir lies at a depth of approximately 3 300 metres and is in sandstones of the Ula Formation of Late Jurassic age. Planned development concept is a subsea development tied to Ula or to a facility in the British sector.

15/3-1 S Gudrun	Production licence 025, Operator: StatoilHydro ASA
Resources	Oil: 9.9 million scm, Gas: 13.0 billion scm, NGL: 1.4 million tonnes

15/3-1 S Gudrun was discovered in 1975, approximately 40 kilometres north of the Sleipner fields. The sea depth in the area is approximately 110 metres. The reservoir contains oil and gas in Upper Jurassic sandstones, at a depth of 4 000–4 500 metres. According to the plan, 15/3-1 S Gudrun will be developed together with the discovery 15/3-4, which is located ten kilometres to the southeast of 15/3-1 S Gudrun. Several development solutions with tie-in to facilities both on Norwegian and British side have been evaluated. In January 2009 the licensees decided that 15/3-1 S Gudrun will be developed with a process facility tied to the Sleipner fields. A PDO is planned to be submitted to the authorities in the autumn of 2009. Production may start in 2013.





15/3-4	Production licence 025, Operator: StatoilHydro ASA
Resources	Oil: 1.8 million scm, Gas: 1.3 billion scm, NGL: 0.3 million tonnes

The 15/3-4 discovery was made in 1981, approximately 10 kilometres southeast for 15/3-1 S Gudrun. The sea depth in the area is approximately 110 metres. The discovery contains oil in sandstones of Middle to Late Jurassic age, at a depth of approximately 3 800 metres. The appraisal well 15/3-5 was drilled in 1983. 15/3-4 Sigrun will according to plan be developed together with 15/3-1 S Gudrun. Planned development concept is a subsea template tied to 15/3-1 S Gudrun. A PDO is planned to be submitted to the authorities in the autumn of 2009. Production may start in 2013.

15/8-1 Alpha	Production licence 046, Operator: StatoilHydro ASA
Resources	Gas: 2.0 billion scm, NGL: 0.3 million tonnes, Condensate: 1.2 million scm

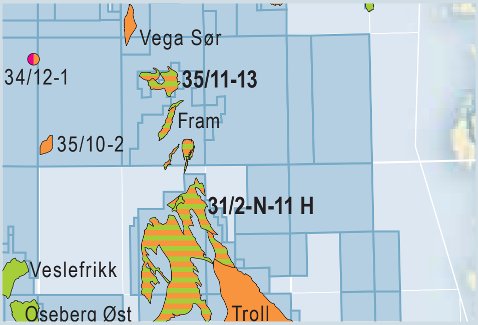
15/8-1 Alpha was discovered in 1982, west of the Sleipner fields, approximately two kilometres from the border between the Norwegian and British sector. The sea depth in the area is approximately 110 metres. The discovery contains gas, NGL and condensate in sandstones of the Hugin Formation of Middle Jurassic age. The reservoir lies at a depth of 3 650–3 950 metres. According to plan, a PDO will be submitted to the authorities in June 2009. The licensees are considering a development concept with a subsea template tied to existing facilities in the area, most likely to the Sleipner fields.

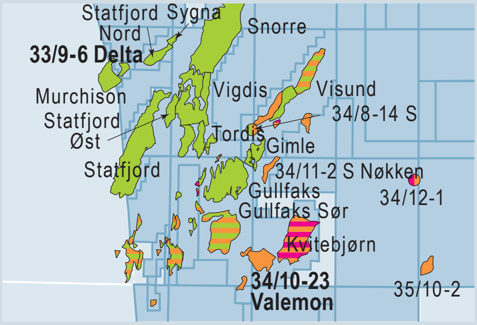
16/1-8	Production licence 338, Operator: Lundin Norway AS
Resources	Oil: 19.0 million scm, Gas: 2.4 billion scm

The 16/1-8 discovery was made in 2007, approximately 30 kilometres south of Grane and Balder. The sea depth in the area is approximately 100 metres. The discovery contains gas and oil in sandstones and conglomerates of Jurassic and Upper Triassic age, deposited on alluvial plains. The reservoir lies at a depth of 1 900 – 1 990 metres and the discovery well proved an oil column of approximately 40 metres. The licensees are considering a stand-alone development with a floating facility. Earliest start of production is 2013.

24/6-1 Peik	Production licence 088, Operator: Lundin Norway AS
Resources	Gas: 2.5 billion scm, Condensate: 0.7 million scm

24/6-1 Peik was discovered in 1985, approximately 18 kilometres west of Heimdal and straddles the border to the British sector. The sea depth in the area is approximately 120 metres. An appraisal well 9/15a-1 was drilled in 1987 on the British side. The reservoir contains sandstones in the Vestland Group of Middle Jurassic age. The reservoir lies at a depth of approximately 4 500 metres and contains gas and condensate under high pressure. The discovery will be developed with a subsea facility tied to Heimdal or to the Bruce field in British sector. The drainage strategy is pressure depletion.





25/5-5	Production licence 102, Operator: Total E&P Norge AS
Resources	Oil: 1.9 million scm

The 25/5-5 discovery was made in 1995, eight kilometres east of the Heimdal field. The sea depth in the area is approximately 120 metres. The reservoir is in Paleocene sandstones in the Heimdal Formation, deposited as turbidity currents from the west. The discovery well proved an oil column of 18 metres approximately 2 130 metres below sea level. The discovery is located close to existing infrastructure. The operator is re-evaluating the resource basis.

25/11-16	Production licence 169, Operator: StatoilHydro Petroleum AS
Resources	Oil: 5.5 million scm, Gas: 0.1 billion scm

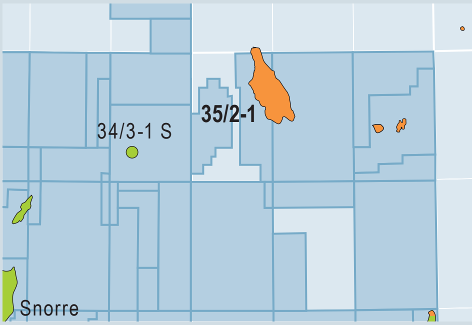
The 25/11-16 discovery was made in 1992 west of the Grane field. The sea depth in the area is approximately 120 metres. The well proved oil and associated gas at a depth of approximately 1 750 metres in Paleocene sandstones in the Heimdal Formation. The sandstones are deposited as turbidites from the west. The most likely development concept is subsea templates tied back to Grane. The discovery may come on stream in 2013.

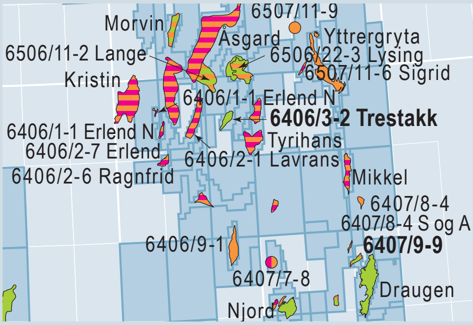
30/7-6 Hild	Production licence 040, 043, Operator: Total E&P Norge AS
Resources	Oil: 3.3 million scm, Gas: 15.4 billion scm, NGL: 0.8 million tonnes, Condensate: 2.0 million scm

30/7-6 Hild was discovered in 1978, near the border to the British sector. The sea depth in the area is 100–120 metres. The reservoir is structurally complex, with gas at high temperatures and high pressure. There are three reservoirs in Middle Jurassic sandstones in the Brent Group at a depth of 3 700–4 400 metres. Oil has also been proven in a more shallow reservoir at a dept of approximately 1 750 metres. The licensees are evaluating different development concepts and are planning to drill an appraisal well in 2009/2010 to ensure selection of the best possible development concept.

31/2-N-11 H	Production licence 054, Operator: StatoilHydro Petroleum AS
Resources	Oil: 0.4 million scm.

The 31/2-N-11 H discovery was made in 2005 in the northern part of Troll Vest. The reservoir is in Middle Jurassic sandstones in the Brent Group and lies stratigraphically below the reservoirs in Troll. The reservoir depth is approximately 1 900 metres. The oil will be produced by a subsea template connected to Troll C.





33/9-6 Delta	Production licence 037 D, Operator: Wintershall Norge ASA
Resources	Oil: 0.1 million scm

The 33/9-6 Delta discovery was made in 1976 and is located between Murchison and Statfjord Nord. The reservoir is in Middle Jurassic sandstones in the Brent Group. The development concept may be a production well drilled from the Murchison facility in the British sector. An appraisal well is now being drilled.

34/10-23 Valemon	Production licence 050, 193, Operator: StatoilHydro ASA
Resources	Gas: 39.8 billion scm, Condensate: 9.5 million scm

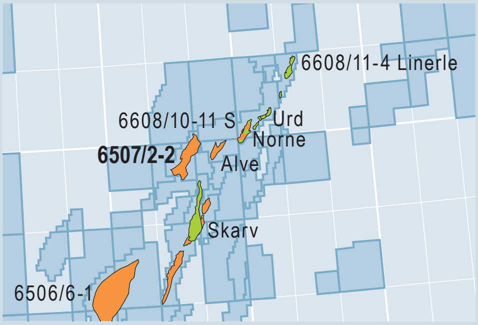
34/10-23 Valemon was discovered in 1985 and is located in blocks 34/11 and 34/10, west of the Kvitebjørn field. The sea depth in the area is approximately 135 metres. Five exploration wells have been drilled on the discovery and gas has been proven in four of them. The discovery has a complex structure with many faults. The reservoirs consist of Middle Jurassic sandstones in the Brent Group and Lower Jurassic sandstones in the Cook Formation at a depth of approximately 4 000 metres, with high pressures and high temperatures. The operator completed remapping of the discovery in 2008. Decision on development concept will be based on the updated resource estimates. Concept selection is planned in the spring of 2009, and the most likely development concept is a fixed installation.

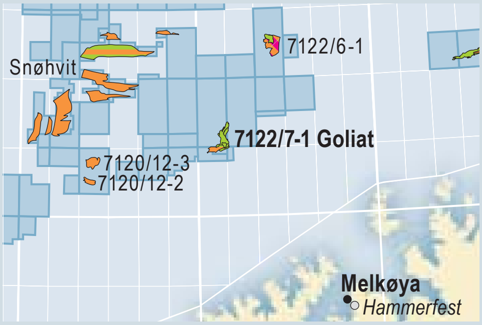
35/2-1	Production licence 318, Operator: StatoilHydro Petroleum AS
Resources	Gas: 21.2 billion scm

The 35/2-1 discovery was made in 2005 and is located west of Florø, approximately 100 kilometres northeast of the Gullfaks field. The sea depth in the area is about 380 metres. The discovery contains methane. The reservoir is unconsolidated Pleistocene sandstones in the Nordland Group, 580 metres below the sea level. The shallow reservoir implies low pressure and drilling is challenging. The licensees are considering drilling an appraisal well in 2009 and are evaluating possible development concepts. Earliest expected production start is 2013.

35/11-13	Production licence 090 B, Operator: StatoilHydro Petroleum AS
Resources	Oil: 6.4 million scm, Gas: 2.1 billion scm

The 35/11-13 discovery was made in 2005 north of the Fram field. The sea depth in the area is approximately 360 metres. The reservoir contains oil with a gas cap in Upper Jurassic sandstones at a depth of approximately 3 100 metres. The appraisal well 35/11-14 S, drilled in the autumn of 2006, proved oil and gas in a new fault segment and gave important additional information about the discovery. The development concept is expected to be subsea templates tied to Troll B. The production may start in 2012.





6406/3-2 Trestakk	Production licence 091, 091 B, Operator: StatoilHydro ASA
Resources	Oil: 8.8 million scm, Gas: 2.2 billion scm, NGL: 0.5 million tonnes

6406/3-2 Trestakk was discovered in 1984 and is located centrally on the Halten Terrace. The sea depth in the area is approximately 300 metres. The reservoir contains Middle Jurassic sandstones in the Garn Formation at a depth of 3 900–4 000 metres. Appraisal well 6406/3-4, drilled in 1986, penetrated the water zone in the Garn Formation. Large differences in the reservoir quality between the two wells in the Garn Formation are due to the formations belonging to different sedimentary facies. The operator is preparing a PDO for the Trestakk deposit. Possible development concepts are tie-in to Åsgard A or Åsgard B. Gas for injection can be supplied from Åsgard A.

6407/9-9	Production licence 093, Operator: A/S Norske Shell
Resources	Oil: 0.3 million scm, Gas: 1.1 billion scm

The 6407/9-9 discovery was made in 1999 and is located approximately 7 kilometres northwest of Draugen. The reservoir contains oil and gas in the Ile and Ror formations. The development plan implies production from one well tied to the Draugen facility. The main purpose of the development of 6407/9-9 is to produce gas for power generation at Draugen. The production may start in 2013.

6507/2-2 Marulk	Production licence 122, Operator: Eni Norge AS
Resources	Oil: 0.7 million scm, Gas: 10.1 billion scm, NGL: 1.7 million tonnes

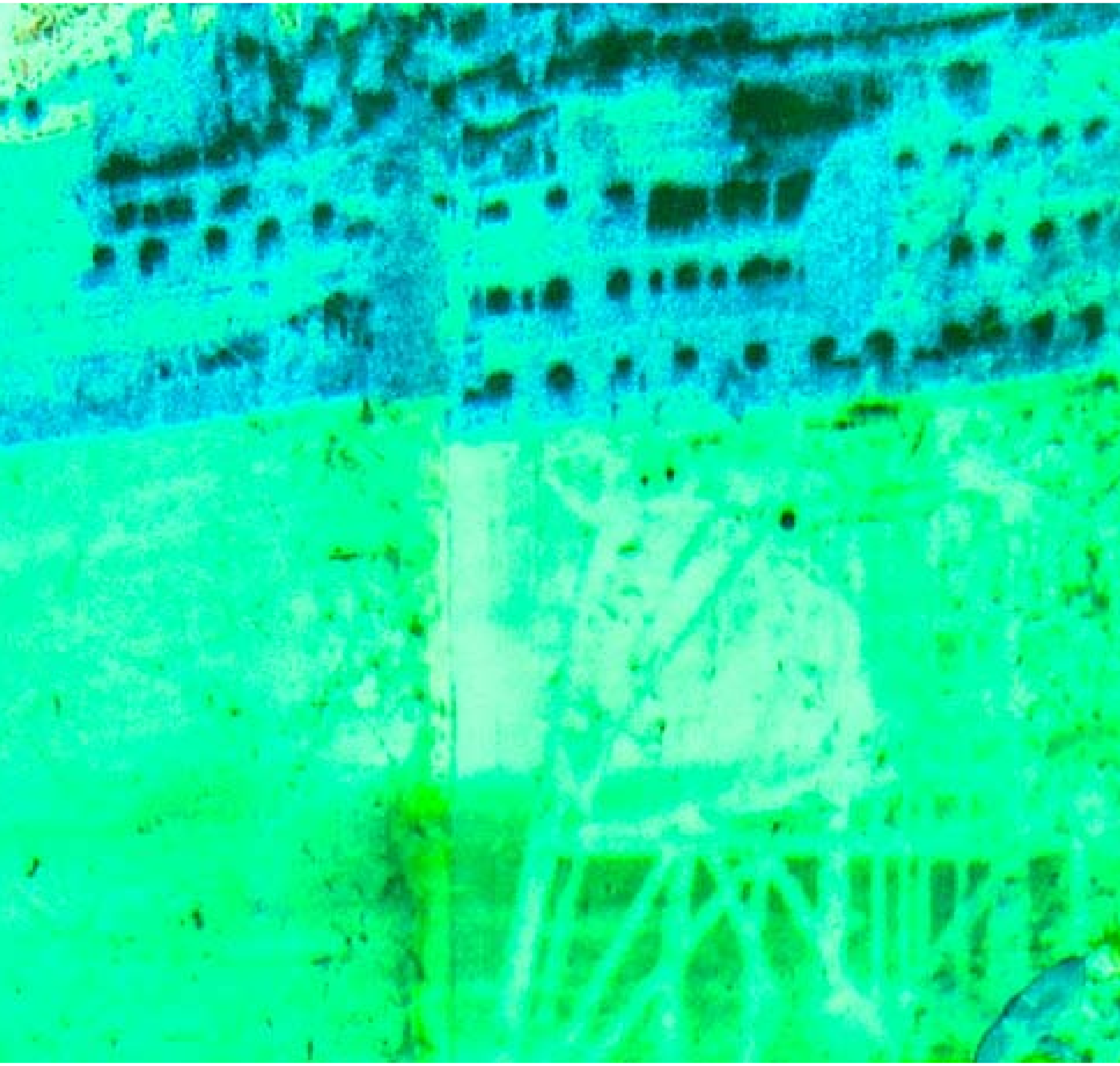
6507/2-2 Marulk was discovered in 1992 by Norsk Hydro and lies 25 – 30 kilometres southwest of Norne. The sea depth in the area is approximately 370 metres. The reservoir contains gas and condensate in sandstones in the Lysing and Lange formations of Cretaceous age. An appraisal well 6507/2-4 was drilled in the winter of 2007/2008 and proved additional gas and condensate resources. A PDO is expected to be submitted to the authorities in 2010. The most likely development concept is a subsea facility tied to the Norne vessel for processing and further transport of gas to Kårstø via existing pipelines. Earliest start of production is 2012.

7122/7-1 Goliat	Production licence 229, 229 B, Operator: Eni Norge AS
Resources*	Oil: 30.5 million scm, Gas: 7.4 billion scm, NGL: 0.4 million tonnes

** Includes resources in RC 5*

7122/7-1 Goliat was discovered in 2000 and is located 50 kilometres southeast of Snøhvit and 85 kilometres northwest of Hammerfest in the southwestern part of the Barents Sea. The sea depth in the area is 360–420 metres. The first exploration well proved oil in sandstones in the Realgrunnen subgroup of the Late Triassic to Early Jurassic ages, approximately 1 100 metres below sea level. Appraisal well 7122/7-3 proved hydrocarbons in three different levels. In addition to oil and gas in the Realgrunnen subgroup, oil was proven in the Snadd Formation and oil and gas in the Kobbe Formation, both of Middle Triassic age. Further appraisal drilling was carried out with wells 7122/7-4 S and 7122/7-5 A. These wells also proved hydrocarbons in the Kobbe Formation and a small oil discovery in the Klappmyss Formation in the southern segment. The development concept for Goliat is a floating production and storage facility tied to subsea wells. A PDO was submitted to the authorities in February 2009.

14 Fields where production has ceased



Fields where production has ceased

The fields in this summary are not in production as of 31 December 2008. However, there are plans for new development for some of these fields. Yme is being re-developed, see description in chapter 12 Fields under development.

Albuskjell

Block	1/6 and 2/4
Development approval	25.04.1975
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	26.05.1979
Production ceased	26.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 7.4 million scm, Gas: 15.6 billion scm, NGL: 1.0 million tonnes

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

Cod

Block	7/11
Development approval	04.05.1973
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	26.12.1977
Production ceased	05.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
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 ongoing.

Edda

Block	2/7
Development approval	25.04.1975
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	02.12.1979
Production ceased	05.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
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 ongoing.

Frigg

Block	25/1
Development approval	13.06.1974
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 26 September 2003 and Storting White Paper No. 38 (2003–2004)
On stream	13.09.1977
Production ceased	26.10.2004
Operator at time of cessation	Total E & P Norge AS
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 29 May 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	15.05.1995
Production ceased	05.03.2001
Operator at time of cessation	TotalFinaElf Exploration AS
Total production over field lifetime	Oil: 5.6 million scm, Gas: 1.6 billion scm, Condensate: 0.1 million scm

Status: The acreage was re-awarded in 2006 as production licence 364. The present operator is Det norske oljeselskap ASA. A PDO for re-development has been submitted to the authorities and is under consideration.

Lille-Frigg

Block	25/2
Development approval	06.09.1991
Cessation plan/ decommissioning	Storting Proposition No. 53 (1999–2000) and in Storting White Paper No. 47 (1999–2000)
On stream	13.05.1994
Production ceased	25.03.1999
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Oil: 1.3 million scm, Gas: 2.2 billion scm

Status: The acreage was re-awarded in 2006 as production licence 362. The present operator is StatoilHydro Petroleum AS. An exploration well has been drilled in a down-faulted structure next to the field and has proven additional resources.

Mime

Block	7/11
Development approval	06.11.1992
Cessation plan/ decommissioning	Storting Proposition No. 15 (1996–1997) and in Storting White Paper No. 47 (1999–2000)
On stream	01.01.2003
Production ceased	04.11.1993
Operator at time of cessation	Norsk Hydro Produksjon AS
Total production over field lifetime	Oil: 0.4 million scm, Gas: 0.1 billion scm

Status: The acreage was re-awarded in 2003 as production licence 301. The present operator is Talisman Energy Norge AS. An appraisal well was drilled in 2007, but the well was dry. A decision on re-development or relinquishment is expected during 2009.

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
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Gas: 11.6 billion scm, Condensate: 0.1 million scm

Status: The acreage was re-awarded in 2007 as production licence 415. The present operator is StatoilHydro Petroleum AS. There are plans for a joint development of the remaining gas resources in Nordøst Frigg and Odin.

Odin

Block	30/10
Development approval	18.07.1980
Cessation plan/ decommissioning	Storting Proposition No. 50 (1995–1996) and in Storting White Paper No. 47 (1999–2000)
On stream	01.04.1984
Production ceased	01.08.1994
Operator at time of cessation	Esso Exploration and Production Norway AS
Total production over field lifetime	Gas: 27.3 billion scm, Condensate: 0.2 million scm

Status: The acreage was re-awarded in 2007 as production licence 415. The present operator is StatoilHydro Petroleum AS. There are plans for a joint development of the remaining gas resources in Nordøst Frigg and Odin.

Tommeliten Gamma

Block	1/9
Development approval	12.06.1986
Cessation plan/ decommissioning	Storting Proposition No. 53 (1999-2000) and in Storting White Paper No. 47 (1999–2000)
On stream	03.10.1988
Production ceased	05.08.1998
Operator at time of cessation	Den norske stats oljeselskap a.s.
Total production over field lifetime	Oil: 3.9 million scm, Gas: 9.7 billion scm, NGL: 0.5 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 21 December 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	31.05.1977
Production ceased	25.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 12.2 million scm, Gas: 26.0 billion scm, NGL: 1.4 million tonnes

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

Øst Frigg

Block	25/1 and 25/2
Development approval	14.12.1984
Cessation plan/ decommissioning	Storting Proposition No. 8 (1998–1999) and in Storting White Paper No. 47 (1999–2000)
On stream	01.10.1988
Production ceased	22.12.1997
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Gas: 9.2 billion scm, Condensate: 0.1 million scm

Status: No activity.

15 Pipelines and onshore facilities

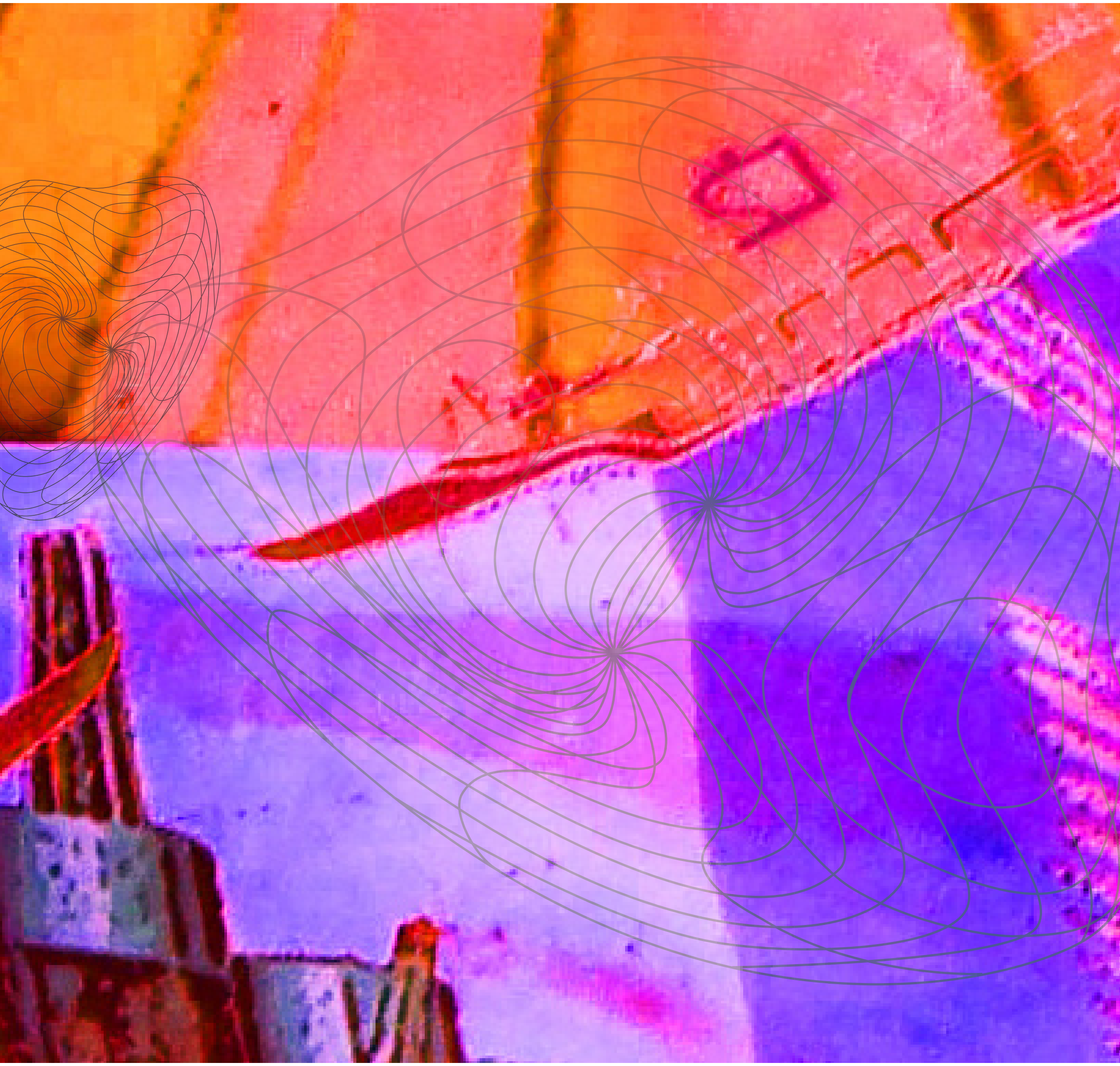


Figure 15.1 Existing and projected pipelines
(Source: Norwegian Petroleum Directorate)

The transport capacities are based on standard assumptions for pressure and gas energy content, maintenance downtime and operational flexibility

Gassled pipelines

Operator: Gassco AS

Licensees:

Petoro AS[1]	38.459 %
StatoilHydro ASA	20.474 %
StatoilHydro Petroleum AS	11.628 %
Total E&P Norge AS	7.783 %
ExxonMobil Exploration and Production Norway AS	5.286 %
Mobil Development Norway AS	4.142 %
Norske Shell Pipelines AS	3.974 %
Norsea Gas AS	2.726 %
ConocoPhillips Skandinavia AS	1.996 %
Eni Norge AS	1.525 %
A/S Norske Shell	1.345 %
DONG E&P Norge AS	0.662 %

[1] Petoro is the licensee for the State's Direct Financial Interest (SDFI). Petoro's participating interest in Gassled will be increased by approximately 8 per cent with effect from 1 January 2011, and the other parties' participating interests will be adjusted with effect from the same date.

In the spring of 2001, the government asked the relevant companies to establish 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: Europipe I, Europipe II, Franpipe, Norpipe, Oseberg Gas Transport, Statpipe, Tampen Link, Vesterled, Zeepipe, Åsgard Transport, Langeled, Norne Gas Transport System, Kvitebjørn Gas pipeline, Kollsnes gas processing plant and Kårstø gas and condensate processing plant. Gassled is organised into various zones for access and tariffs. Gassco coordinates and controls the flow of gas through a network of pipelines about 7 800 kilometres long, and handles 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, ending at Emden in Germany. Europipe I came into operation in 1995. The pipeline has a diameter of 40 inches, is 620 kilometres long and has a capacity of about 45-54 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 22.7 billion (2009 value). In addition to the pipeline, investments also include the terminal in Dornum and the Europipe Metering Station (EMS) 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 658 kilometres from Kårstø to Dornum in Germany, Europipe Receiving Facilities (ERF), and became operational in 1999. With a capacity of about 74 million scm per day, Europipe II has been built for an operating life of 50 years. Total investment at start-up was approximately NOK 10.2 billion (2009 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 in accordance with 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 Dunkerque in France. The Gassled partnership owns 65 per cent of the terminal, while GDF SUEZ owns 35 per cent. The pipeline became operational in 1998. Franpipe has a capacity of about 54 million scm per day. It has been built for an operating life of 50 years. The total investment at start-up was approximately NOK 10.6 billion (2009 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 pipeline 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. In 2007 a bypass was installed at H7, and H7 has now been shut down. The transport capacity is approximately 32 million scm per day without using the compressor capacity on the B11 riser facility. Capacity will increase to 44 million scm per day if the B11 compressors are used. Norpipe has been built for an operating life of at least 30 years. An application for extension of the lifetime of both Norpipe Gas pipeline and B11 is being considered by the authorities. Total investment at start-up was approximately NOK 28.2 billion (2009 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 (HRP). 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 2.1 billion (2009 value).

Statpipe

This 880-kilometres pipeline system includes a riser facility and a gas processing plant at Kårstø. The system 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 24 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 the main facility at Heimdal (HMP) to Draupner S, with a capacity of about 30 million scm per day. The third is a 36-inch pipeline running for roughly 203 kilometres from Draupner S to Ekofisk-Y, 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 48.7 billion (2009 value).

Tampen Link

The pipeline Tampen Link starts at the Statfjord field and ends at the FLAGS pipeline, 1.4 kilometres south of the Brent Alpha facility. About 15.5 kilometres of the new gas export pipeline lie on the British side of the border. Tampen Link was included in Gassled in 2007. The pipeline has a diametre of 32 inches, runs for 23 kilometres and has a capacity of approximately 25 million scm per day. The capacity is dependent upon inlet conditions at the connection points in the Statfjord area. Total investment at start-up was approximately 2.1 billion 2009-NOK. The investments include, in addition to the pipeline, necessary modifications on Statfjord B. Tampen Link has been built for an operating life of 30 years. (See plan for installation and operation referred to in St.prp. No. 53 (2004-2005).

Vesterled

This 32-inch pipeline runs for about 360 kilometres from the Heimdal riser facility (HRP) to the receiving terminal at St. Fergus in the UK and became operational in 1978. It has a capacity of approximately 38.0 million scm per day. Total investment in Vesterled at start-up was approximately NOK 34.4 billion (2009 value). In addition to the pipeline, this total investment includes investments associated with construction of the St. Fergus terminal.

(Agreement between Norway and the UK concerning amendments to the Frigg treaty of 10 May 1976. Referred to in St.prp. No. 73 (1998–1999) and Recommendation No. 219 (1998–1999)).

Zeepipe

Zeepipe I comprises a 40-inch pipeline running for about 813 kilometres from Sleipner (SLR) to the receiving terminal in Zeebrugge, Belgium. The terminal in Zeebrugge belongs to a separate partnership, with the Gassled partners holding 49 per cent and the Belgian Fluxys company holding 51 per cent. Zeepipe I became operational in 1993 and has a capacity of roughly 42 million scm per day. Zeepipe I also includes a 30-inch pipeline between Sleipner (SLR) 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 299 kilometres long and has a capacity of 72 million scm per day.

Zeepipe II B starts at the Kollsnes gas treatment plant and ends at Draupner E. The pipeline became operational in 1997. Zeepipe II B has a 40-inch diameter, runs for about 301 kilometres and 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 25.7 billion (2009 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 approximately 69 million scm per day. Åsgard Transport is built for an operating life of 50 years. Total investment at start-up was approximately NOK 11.2 billion (2009 value).

Langeled

The Langeled gas transport system runs from the onshore facilities for Ormen Lange at Nyhamna, via a tie-in point at the Sleipner riser facility to a new receiving terminal at Easington on the eastern coast of the UK. The system comprises a 42-inch pipeline from Nyhamna to the Sleipner riser (northern leg) and a 44-inch line from Sleipner to Easington (southern leg). Capacity is approximately 80 million scm per day in the northern leg and about 70 million scm per day in the southern leg.

The system has an overall length of roughly 1 200 kilometres. The southern pipeline became operational in October 2006, with the northern pipeline following in October 2007. Norsk Hydro was the operator for the development phase of the southern leg, while Gassco AS is the operator for the development phase of the northern leg and the operating phase of the whole transport system. Langeled was included in Gassled in the autumn of 2006. Total investment at start-up was approximately NOK 18.1 billion (2009 values).

Norne Gas Transport System (NGTS)

The 16 inch pipeline runs for about 126 kilometres and connects the Norne field to Åsgard Transport. The pipeline has a capacity of approximately 3.6 billion scm per year. The Norne Gas Transport System has been built for an operating life of 50 years. The pipeline became operational in 2001. Total investment at start-up was approximately NOK 1.3 billion (2009 values). Norne Gas Transport System was included in Gassled as of 01.01.2009.

Kvitebjørn Gas Pipeline

The 30 inch pipeline runs for about 147 kilometres and transports rich gas from Kvitebjørn and Visund to Kollsnes. The pipeline has a capacity of approximately 26.5 million scm per day and became operational in 2004, at the same time as the Kvitebjørn field. Total investment at start-up was approximately NOK 954 million 2002-values. There are plans to include the pipeline in Gassled in the autumn of 2009.

Kollsnes gas processing plant

The gas processing plant at Kollsnes 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 two pipelines 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 for processing 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 was put into operation from 1 October 2006.

Kårstø gas and condensate processing plant

Rich gas and unstabilised condensate are transported to Kårstø. At the processing plant, these products are separated to dry gas and to six different liquid products. In addition to methane the rich gas contains the components ethane, propane, normal butane, iso-butane and naphtha. The products are separated and stored for shipping. The dry gas, which largely contains methane and ethane, is transported by two pipelines from Kårstø, Europipe II to Germany and Statpipe to Draupner. The Kårstø condensate facility receives unstabilised condensate from the Sleipner fields. 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 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 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	47.88%
	BP Norge AS	18.36%
	A/S Norske Shell	26.20%
	Chevron Norge AS	7.56%
Investment	Total investment at start-up was approximately NOK 1.2 billion (2009 value)	
Operating lifetime	The technical operating lifetime is 50 years	
Capacity	Approximately 2 billion scm per year	

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	StatoilHydro Petroleum AS
Licensees	As for the Grane field
Investment	Total investment at start-up was approximately NOK 0.3 billion (2009 value)
Operating lifetime	The technical operating life is 30 years
Capacity	Approximately 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	StatoilHydro Petroleum AS	
Licensees	Petoro AS	43.60 %
	ExxonMobil Exploration and Production Norway AS	25.60 %
	StatoilHydro Petroleum AS	24.40 %
	ConocoPhillips Skandinavia AS	6.40 %
Investment	Total investment at start-up was approximately NOK 1.7 billion (2009 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%
	StatoilHydro ASA	19.06%
	ConocoPhillips Skandinavia AS	18.13%
	Eni Norge AS	5.00%
Investment	Total investment at start-up was approximately NOK 3.1 billion (2009 value) in pipelines and the terminal	
Operating lifetime	The licence expires on 31 December 2020	
Capacity	Approximately 2 billion scm gas per year	

This 16-inch gas pipeline runs for 250 kilometres from the Heidrun field in the Norwegian Sea to Tjeldbergodden, where StatoilHydro ASA and ConocoPhillips Skandinavia 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 are approximately 0.7 billion scm per year.

Heidrun Gas Export

Operator	StatoilHydro ASA[1]	
Licensees	Petoro AS	58.16%
	ConocoPhillips Skandinavia AS	24.31%
	StatoilHydro ASA	12.41%
	Eni Norge AS	5.12%
Investment	Total investment at start-up was approximately NOK 1.0 billion (2009 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	StatoilHydro ASA	
Licensees	StatoilHydro ASA	43.55 %
	Petoro AS	30.00 %
	StatoilHydro Petroleum AS	15.00 %
	Total E&P Norge AS	5.00 %
	Enterprise Oil Norge AS	6.45 %
Investment	Total investment at start-up was approximately NOK 0.5 billion (2009 value)	
Operating lifetime	The technical operating lifetime is 25 years	
Capacity	Approximately 10 000 scm per day	

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 the Y-connection on Troll Oil Pipeline II. The pipeline became operational in the second half of 2004.

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%
	StatoilHydro ASA	15.00%
	Eni Norge AS	6.52%
	StatoilHydro Petroleum AS	3.50%
	Petoro AS	5.00%
Investment	Total investment at start-up was approximately NOK 17.4 billion (2009 value)	
Operating lifetime	The pipeline has been designed for an operating life 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 128 776 scm 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	StatoilHydro Petroleum AS	
Licensees	Petoro AS	48.38%
	StatoilHydro Petroleum AS	22.24%
	StatoilHydro ASA	14.00%
	Total E&P Norge AS	8.65%
	Mobil Development Norway AS	4.33%
	ConocoPhillips Skandinavia AS	2.40%
Investment	Total investment at start-up was approximately NOK 10.2 billion. (2009 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	StatoilHydro ASA	
Licensees	StatoilHydro ASA	49.60%
	ExxonMobil Exploration and Production Norway AS	30.40%
	StatoilHydro Petroleum AS	10.00%
	Total E&P Norge AS	10.00%
Investment	Total investment at start-up was approximately NOK 1.7 billion. (2009 value)	
Capacity	32 000 scm oil per day	

This 20-inch pipeline transports unstabilised condensate from Sleipner A to Kårstø.

Troll Oil Pipeline I

Operator	StatoilHydro ASA	
Licensees	Petoro AS	55.77%
	StatoilHydro ASA	20.85%
	StatoilHydro Petroleum AS	9.73%
	A/S Norske Shell	8.29%
	Total E&P Norge AS	3.71%
	ConocoPhillips Skandinavia AS	1.66%
Investment	Total investment at start-up was approximately NOK 1.3 billion. (2009 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	StatoilHydro ASA	
Licensees	Petoro AS	55.77%
	StatoilHydro ASA	20.85 %
	StatoilHydro Petroleum AS	9.73%
	A/S Norske Shell	8.29%
	Total E&P Norge AS	3.71%
	ConocoPhillips Skandinavia AS	1.66%
Investment	Total investment at start-up was approximately NOK 1.2 billion.(2009 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 transport oil over the 80 kilometres from Troll C to the terminal at Mongstad. The plan for installation and operation was approved 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 licence period for the pipeline lasts to 2023. The oil pipeline from Gjøa will be connected to Troll Oil Pipeline II, and oil from Gjøa, Vega and Vega Sør will use available capacity in the pipeline.

Onshore facilities

Mongstad crude oil terminal

Owner	StatoilHydro 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.

Ormen Lange onshore facility

Owner	As for the Ormen Lange field.

The process plant for Ormen Lange at Nyhamna is a conventional plant for gas drying, compression, gas export, condensate separation/stabilisation/storage and fiscal measurement of gas and condensate. The condensate is being exported by ship from Nyhamna. The plant became operational in September 2007. The land facility has been designed for an operating life of 30 years, while part of the main infrastructure has been designed for 50 years. The plant has a capacity of 70 million scm dry gas per day gas at a receiving pressure of 90 bar.

Snøhvit onshore facility

Owner	As for the Snøhvit field.

The unprocessed well stream from the Snøhvit field is transported through a 143 kilometres long pipeline to the facility at Melkøya for processing and export. Condensate, water and CO2 are separated from the well stream on the onshore facility before the natural gas is being cooled down to liquid form (LNG) and stored in dedicated tanks. The pipeline became operational in 2007 and has an available technical capacity of 7.7 million scm per year. Power is normally supplied by five gas turbines at the facility. Condensate and LPG products are stored in tanks for export. Separated CO_2 is sent in return to the Snøhvit field and injected into a separate formation below the oil and gas.

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 StatoilHydro Petroleum AS (the refrigerated LPG storage and transfer system to ships) and Vestprosess DA (export facility to Vestprosess).

The Sture oil terminal receives oil and condensate via the pipeline from the Oseberg A facility 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 jet-ties 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.

A fractionation plant which came in operation 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	StatoilHydro ASA	81.70 %
	ConocoPhillips Skandinavia AS	18.30 %

The methanol plant at Tjeldbergodden began production on 5 June 1997. Gas deliveries through the Haltenpipe total 0.7 billion scm annually, which yield 830.000 tonnes of methanol.

An air separation plant, Tjeldbergodden Luftgassfabrikk DA, has been built in connection with the methanol facility. This company has also constructed a small gas fractionation and liquefaction plant with an annual capacity of 35 million scm.

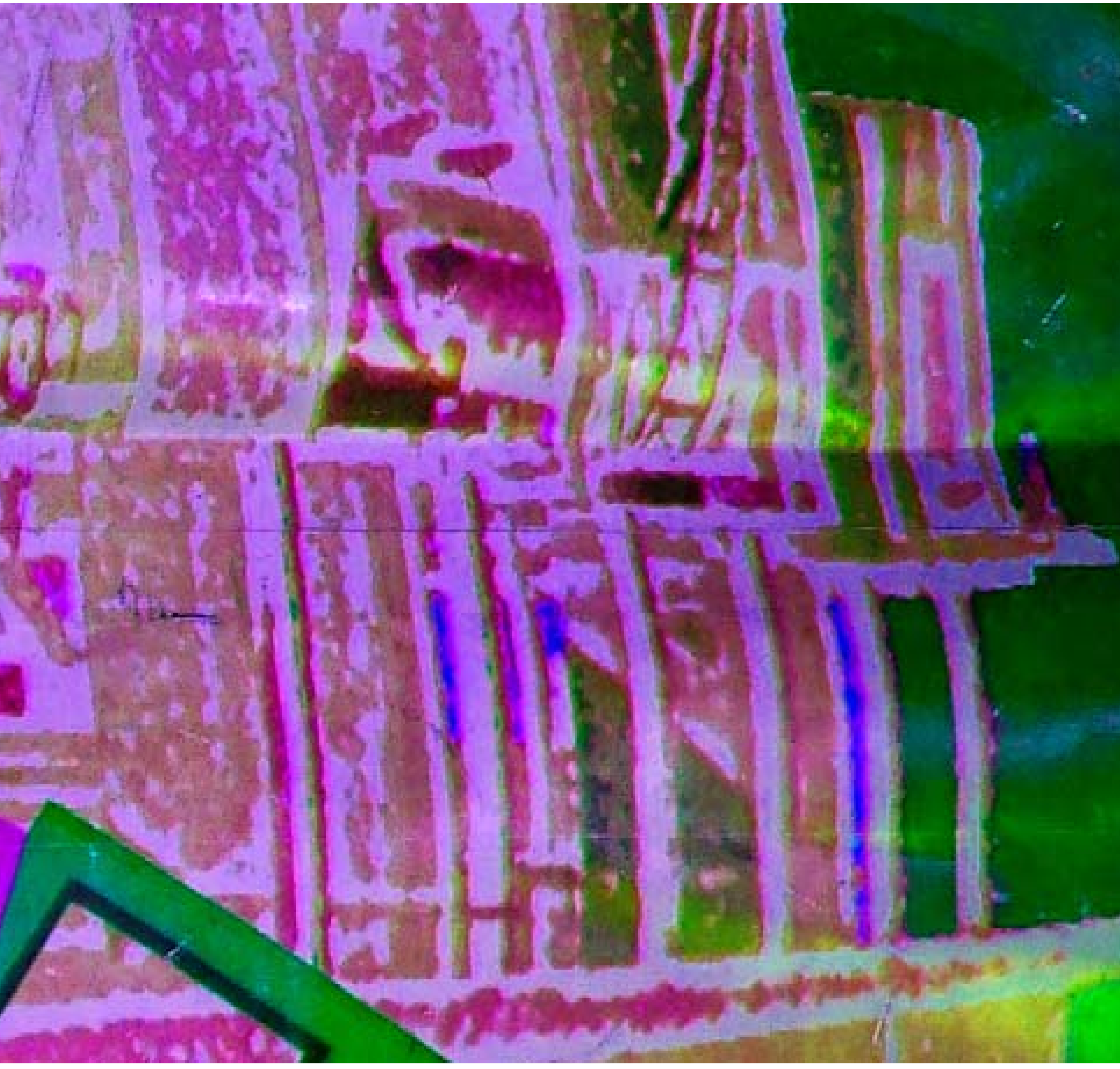
Vestprosess

Owner	Petoro AS	41.00 %
	StatoilHydro ASA	17.00 %
	StatoilHydro Petroleum AS	17.00 %
	Mobil Exploration Norway Inc	10.00 %
	A/S Norske Shell	8.00 %
	Total E&P Norge AS	5.00 %
	ConocoPhillips Skandinavia AS	2.00 %

The Vestprosess DA partnership owns and operates a gas transport system and a gas separation facility for NGL. 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.

Appendix

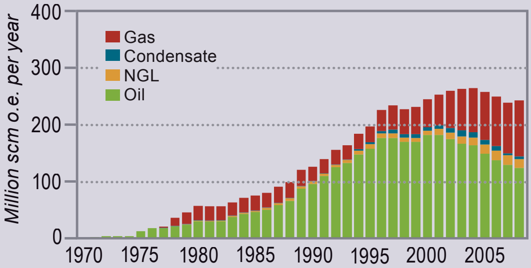


Appendix 1 Historical statistics

Table 1.1 The state's revenues from petroleum activities (MNOK)

Year	Ordinary tax	Special tax	Production fee	Area fee	Environ-mental taxes	Net cash flow SDFI	Dividend StatoilHydro
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	41465	64316	2481	983	2862	125439	5746
2002	32512	52410	1320	447	3012	74785	5045
2003	36819	60280	766	460	3056	67482	5133
2004	43177	70443	717	496	3309	80166	5222
2005	61589	103294	360	224	3351	98602	8139
2006	78015	133492	42	2308	3405	125523	12593
2007	70281	116233	0	764	3876	112336	16448
2008	88802	150839	0	1842	3684	153759	16940

(Source: Norwegian Public Accounts and account figures for SDFI)



Total petroleum production

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

Table 1.2 Petroleum production on the Norwegian continental shelf, million standard cubic meter oil equivalents

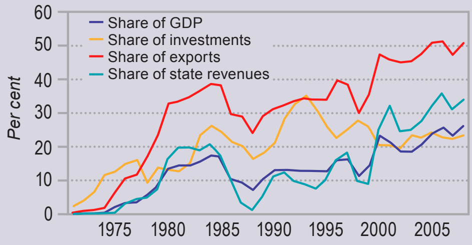
Year	Oil	Gas	Condensate	NGL	Total production
1970					
1971	0.4	0.0	0.0	0.0	0.4
1972	1.9	0.0	0.0	0.0	1.9
1973	1.9	0.0	0.0	0.0	1.9
1974	2.0	0.0	0.0	0.0	2.0
1975	11.0	0.0	0.0	0.0	11.0
1976	16.2	0.0	0.0	0.0	16.2
1977	16.6	2.7	0.0	0.0	19.3
1978	20.6	14.2	0.0	0.0	34.9
1979	22.5	20.7	0.0	1.1	44.3
1980	28.2	25.1	0.0	2.4	55.8
1981	27.5	25.0	0.0	2.2	54.7
1982	28.5	24.0	0.0	2.3	54.8
1983	35.6	23.6	0.0	2.7	62.0
1984	41.1	26.0	0.1	2.6	69.8
1985	44.8	26.2	0.1	3.0	74.0
1986	48.8	26.1	0.1	3.8	78.8
1987	57.0	28.2	0.1	4.1	89.3
1988	64.7	28.3	0.0	4.8	97.9
1989	86.0	28.7	0.1	4.9	119.7
1990	94.5	25.5	0.0	5.0	125.1
1991	108.5	25.0	0.1	4.9	138.5
1992	124.0	25.8	0.1	5.0	154.8
1993	131.8	24.8	0.6	5.5	162.7
1994	146.3	26.8	2.8	7.1	183.1
1995	156.8	27.8	3.7	7.9	196.3
1996	175.4	37.4	4.4	8.2	225.5
1997	175.9	43.0	6.4	8.1	233.3
1998	168.7	44.2	6.0	7.4	226.3
1999	168.7	48.5	6.5	7.0	230.7
2000	181.2	49.7	6.3	7.2	244.4
2001	180.9	53.9	6.6	10.9	252.3
2002	173.6	65.5	8.0	11.8	259.0
2003	165.5	73.1	11.1	12.9	262.5
2004	162.8	78.5	9.1	13.6	264.0
2005	148.1	85.0	8.4	15.7	257.2
2006	136.6	87.6	8.0	16.7	248.8
2007	128.3	89.7	3.5	16.6	238.0
2008	122.7	99.23	4.2	16.0	242.1

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

Table 1.3 Value creation, exports, employment, investment and exploration costs

Year	Gross product (MNOK)	Export value (MNOK)	Numbers of employees	Investment incl. exploration costs (MNOK)	Exploration costs (MNOK)
1971	12	75	NA	691	
1972	207	314	200	1 192	
1973	258	504	300	2 326	
1974	1 056	1 089	900	5 138	
1975	4 218	3 943	2 200	7 291	
1976	6 896	7 438	2 700	9 270	
1977	8 617	8 852	4 000	10 589	
1978	14 835	15 117	6 100	9 228	
1979	23 494	24 788	7 900	9 061	
1980	44 285	44 638	9 700	10 119	
1981	55 189	52 432	12 200	14 462	4 133
1982	61 891	57 623	13 100	15 909	5 519
1983	73 298	68 082	13 900	27 028	5 884
1984	90 092	82 504	15 800	32 244	7 491
1985	97 347	90 098	17 700	32 839	7 830
1986	59 988	57 239	18 000	33 155	6 654
1987	59 574	58 301	17 800	35 247	4 951
1988	49 966	51 720	18 700	29 680	4 151
1989	76 768	76 681	18 600	31 957	5 008
1990	95 400	92 451	19 200	32 223	5 137
1991	101 346	101 015	19 700	43 065	8 137
1992	102 578	101 187	20 900	49 512	7 680
1993	107 542	108 463	22 300	57 579	5 433
1994	112 623	113 099	22 500	54 653	5 011
1995	120 198	121 169	21 700	48 583	4 647
1996	165 444	167 200	23 000	47 878	5 455
1997	180 594	177 825	24 000	62 494	8 300
1998	129 098	128 807	28 000	79 216	7 577
1999	176 591	173 428	27 000	69 096	4 993
2000	340 640	326 658	29 000	53 589	5 274
2001	325 333	322 291	32 000	57 144	6 815
2002	283 462	283 343	31 000	54 000	4 476
2003	295 356	291 220	29 000	64 362	4 134
2004	361 262	347 926	30 000	71 473	4 010
2005	465 341	439 881	32 000	88 478	7 537
2006	555 628	511 352	31 000	95 740	11 718
2007	543 409	508 954	35 000	109 298	17 921
2008	660 097	603 848	41 900	122 756	23 314

(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 investment	Share of state's total revenues
1971	0.01	0.21	2.33	0.05
1972	0.18	0.79	4.03	0.12
1973	0.19	1.04	6.56	0.16
1974	0.40	1.82	11.61	0.25
1975	2.09	6.36	12.56	0.38
1976	3.28	10.54	14.86	3.07
1977	3.52	11.68	15.92	4.38
1978	5.63	17.23	9.27	4.77
1979	8.35	23.47	13.68	7.31
1980	13.58	32.80	13.03	16.27
1981	14.41	33.58	12.69	19.76
1982	14.48	34.80	15.00	19.90
1983	15.66	36.69	23.71	18.86
1984	17.31	38.55	26.18	20.74
1985	16.90	38.16	24.26	17.50
1986	10.01	29.29	21.43	10.13
1987	9.17	28.91	20.04	3.21
1988	7.33	23.99	16.27	1.02
1989	10.74	28.99	18.15	5.20
1990	12.96	31.28	23.20	11.14
1991	13.06	32.60	28.49	12.25
1992	12.87	33.51	32.65	9.49
1993	12.83	34.12	35.23	8.50
1994	12.82	33.76	30.76	7.24
1995	12.74	33.83	25.67	10.06
1996	16.02	39.69	24.58	16.14
1997	16.14	38.42	25.33	18.15
1998	11.32	30.00	28.17	9.56
1999	14.24	35.49	25.07	8.93
2000	23.00	47.39	21.88	25.07
2001	21.17	45.82	21.46	32.07
2002	18.50	44.96	21.65	24.50
2003	18.53	45.35	23.17	24.80
2004	20.73	47.49	23.58	27.25
2005	23.92	50.66	23.87	32.01
2006	25.70	50.86	23.35	35.72
2007	23.74	47.89	22.82	30.70
2008	26.01	50.48	23.28	33.55

(Source: Statistics Norway, Ministry of Finance)

Appendix 2 The petroleum resources

(per 31.12.2008)

Table 2.1 Historical production from fields in production and fields with ceased production

Field	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill scm o.e.	Year of discovery[2]
Albuskjell	7.4	15.5	1,0		24.8	1972
Cod	2.9	7.3	0.5		11.2	1968
Edda	4.8	2.0	0.2		7.2	1972
Frigg		116.2		0.5	116.6	1971
Frøy	5.6	1.6		0.1	7.3	1987
Lille-Frigg	1.3	2.2		0.0	3.5	1975
Mime	0.4	0.1	0.0		0.5	1982
Nordøst Frigg		11.6		0.1	11.7	1974
Odin		27.3		0.2	27.5	1974
Tommeliten Gamma	3.9	9.7	0.6		14.6	1978
Vest Ekofisk	12.2	26.0	1.4		40.8	1970
Øst Frigg		9.2		0.1	9.3	1973
Historical production	**38.3**	**228.6**	**3.7**	**0.9**	**274.9**	
Alvheim	2.3	0.1			2.4	1998
Balder[a]	45.7	1.0			46.7	1967
Blane	0.2		0.0		0.2	1989
Brage	50.1	2.8	1.0		54.8	1980
Draugen	121.9	1.4	2.0		127.1	1984
Ekofisk	402.8	135.8	12.3		562.0	1969
Eldfisk	89.3	37.6	3.7		133.9	1970
Embla	9.7	3.3	0.4		13.7	1988
Enoch	0.1	0.0			0.1	1991
Fram	13.1	0.4	0.0		13.5	1992
Gimle	1.7	0.1	0.0		1.8	2004
Glitne	7.9				7.9	1995
Grane	52.8				52.8	1991
Gullfaks[b]	340.0	22.7	2.8		368.1	1978
Gullfaks Sør[c]	33.6	24.0	2.9		63.1	1978
Gungne[3]		12.2	1.6	4.5	19.8	1982
Gyda[d]	34.7	5.9	1.9		44.1	1980
Heidrun[e]	127.3	11.5	0.5		139.8	1985
Heimdal	6.5	44.2			50.7	1972
Hod	9.0	1.6	0.2		11.1	1974
Huldra	4.6	13.8	0.1		18.6	1982
Jotun	21.8	0.9			22.6	1994
Kristin	9.7	10.4	2.2	2.1	26.5	1997
Kvitebjørn	7.3	14.6	1.3		24.3	1994
Mikkel	1.5	8.8	2.4	2.2	17.0	1987
Murchison	13.6	0.3	0.3	0.0	14.6	1975

Field	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1)] mill scm o.e.	Year of discovery[2)]
Njord	23.0	2.1			25.0	1986
Norne	80.5	5.8	0.7		87.6	1992
Ormen Lange		13.1		1.1	14.2	1997
Oseberg[f)]	345.2	21.4	5.7		377.5	1979
Oseberg Sør	34.6	5.4			40.0	1984
Oseberg Øst	17.1	0.3			17.3	1981
Ringhorne Øst	4.5	0.1			4.6	2003
Sigyn		4.5	1.8	5.0	12.9	1982
Skirne	1.2	5.3			6.5	1990
Sleipner Vest and Øst[3) g)]		148.3	18.7	58.0	241.8	1974
Snorre	163.5	5.9	4.5		177.9	1979
Snøhvit		2.5	0.1	0.6	3.4	1984
Statfjord	558.6	58.7	15.4	0.3	646.9	1974
Statfjord Nord	35.4	2.2	0.8		39.1	1977
Statfjord Øst	33.9	3.6	1.3		39.9	1976
Sygna	9.6				9.6	1996
Tambar and Tambar Øst[4)]	8.0		0.2		8.4	1983
Tor	22.9	10.8	1.2		35.9	1970
Tordis[h)]	52.6	3.8	1.4		59.1	1987
Troll[i)]	198.7	335.7	3.5	4.3	545.4	1979
Tune	2.9	15.1	0.1		18.2	1996
Ula	69.1	3.9	2.6		77.9	1976
Urd	3.6	0.1	0.0		3.8	2000
Vale	1.0	0.8			1.8	1991
Valhall	98.9	19.5	3.1		124.4	1975
Varg	11.2				11.2	1984
Veslefrikk	49.4	2.2	1.2		53.9	1981
Vigdis	43.1	1.1	0.7		45.5	1986
Vilje	0.5	0.0			0.5	2003
Visund	18.1	3.7	0.2		22.2	1986
Volve	1.8	0.1	0.0	0.0	2.0	1993
Yme	7.9				7.9	1987
Åsgard	63.1	75.1	13.1	17.1	180.2	1981
Producing fields	**3 367.1**	**1 104.5**	**112.0**	**95.4**	**4 779.7**	
Total sold and delivered	**3 405.4**	**1 333.1**	**115.7**	**96.3**	**5 054.6**	

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.
4) Production from Tambar and Tambar Øst are metered collectively

(Source: Norwegian Petroleum Directorate)

a) Balder also includes Ringhorne
b) Gullfaks also includes Gullfaks Vest
c) Gullfaks Sør also include Gulltopp, Gullveig, Rimfaks and Skinnfaks
d) Gyda also includes Gyda Sør
e) Heidrun also includes Tjeldbergodden
f) Oseberg also includes Oseberg Vest
g) Sleipner Øst also includes Loke
h) Tordis also include Tordis Øst and Borg
i) Troll also includes TOGI

Table 2.2 Reserves in fields in production and fields with approved plans for development and operation

Field	Reserves mill. scm o.e.	Year of discovery[5)]	Operator at 31.12.2008	Production licence/ unit area
Alve[1)]	8.8	1990	StatoilHydro ASA	159 B
Alvheim	35.6	1998	Marathon Petroleum Norge AS	036 C, 088 BS, 203
Balder	61.9	1967	ExxonMobil Exploration & Production Norway AS	001
Blane	0.9	1989	Talisman Energy Norge AS	Blane
Brage	61.5	1980	StatoilHydro Petroleum AS	Brage
Draugen	149.2	1984	A/S Norske Shell	093
Ekofisk	712.2	1969	ConocoPhillips Skandinavia AS	018
Eldfisk	186.3	1970	ConocoPhillips Skandinavia AS	018
Embla	18.7	1988	ConocoPhillips Skandinavia AS	018
Enoch	0.4	1991	Talisman North Sea Limited	Enoch
Fram	32.5	1992	StatoilHydro Petroleum AS	090
Gimle	5.5	2004	StatoilHydro ASA	Gimle
Gjøa[1)]	54.5	1989	StatoilHydro ASA	153
Glitne	8.3	1995	StatoilHydro ASA	048 B
Grane	116.2	1991	StatoilHydro Petroleum AS	Grane
Gullfaks	390.1	1978	StatoilHydro ASA	050
Gullfaks Sør	105.2	1978	StatoilHydro ASA	050
Gungne	22.3	1982	StatoilHydro ASA	046
Gyda	48.6	1980	Talisman Energy Norge AS	019 B
Heidrun	230.9	1985	StatoilHydro ASA	Heidrun
Heimdal	51.7	1972	StatoilHydro Petroleum AS	036 BS
Hod	12.8	1974	BP Norge AS	033
Huldra	21.0	1982	StatoilHydro ASA	Huldra
Jotun	24.4	1994	ExxonMobil Exploration & Production Norway AS	Jotun
Kristin	62.8	1997	StatoilHydro ASA	Haltenbanken Vest
Kvitebjørn	107.2	1994	StatoilHydro ASA	193
Mikkel	40.1	1987	StatoilHydro ASA	Mikkel
Morvin[1)]	13.8	2001	StatoilHydro ASA	134 B
Murchison	15.0	1975	CNR International (UK) Limited	Murchison
Njord	39.9	1986	StatoilHydro Petroleum AS	Njord
Norne	109.1	1992	StatoilHydro ASA	Norne
Ormen Lange	423.2	1997	A/S Norske Shell	Ormen Lange
Oseberg[2)]	491.0	1979	StatoilHydro Petroleum AS	Oseberg
Oseberg Sør	62.1	1984	StatoilHydro Petroleum AS	Oseberg Sør
Oseberg Øst	27.9	1981	StatoilHydro Petroleum AS	053
Rev[1)]	6.2	2001	Talisman Energy Norge AS	038 C
Ringhorne Øst	9.0	2003	ExxonMobil Exploration & Production Norway AS	Ringhorne Øst

Field	Reserves mill. scm o.e.	Year of discovery[5)]	Operator at 31.12.2008	Production licence/ unit area
Sigyn	16.0	1982	ExxonMobil Exploration & Production Norway AS	072
Skarv[1)]	68.3	1998	BP Norge AS	Skarv
Skirne	10.3	1990	Total E&P Norge AS	102
Sleipner Vest	162.5	1974	StatoilHydro ASA	Sleipner Vest
Sleipner Øst	119.9	1981	StatoilHydro ASA	Sleipner Øst
Snorre	249.5	1979	StatoilHydro ASA	Snorre
Snøhvit	190.7	1984	StatoilHydro ASA	Snøhvit
Statfjord	687.5	1974	StatoilHydro ASA	Statfjord
Statfjord Nord	45.3	1977	StatoilHydro ASA	037
Statfjord Øst	44.0	1976	StatoilHydro ASA	Statfjord Øst
Sygna	10.8	1996	StatoilHydro ASA	Sygna
Tambar	12.8	1983	BP Norge AS	065
Tambar Øst	1.3	2007	BP Norge AS	Tambar Øst
Tor	37.7	1970	ConocoPhillips Skandinavia AS	Tor
Tordis	68.3	1987	StatoilHydro ASA	089
Troll[3)]	1 625.6	1979	StatoilHydro Petroleum AS	Troll
Troll[4)]		1983	StatoilHydro ASA	Troll
Tune	21.6	1996	StatoilHydro Petroleum AS	190
Tyrihans[1)]	77.6	1983	StatoilHydro ASA	Tyrihans
Ula	97.5	1976	BP Norge AS	019
Urd	9.9	2000	StatoilHydro ASA	128
Vale	4.2	1991	StatoilHydro Petroleum AS	036
Valhall	181.5	1975	BP Norge AS	Valhall
Varg	15.1	1984	Talisman Energy Norge AS	038
Vega[1)]	12.1	1981	StatoilHydro Petroleum AS	248
Vega Sør[1)]	10.6	1987	StatoilHydro Petroleum AS	090 C
Veslefrikk	62.0	1981	StatoilHydro ASA	052
Vigdis	63.7	1986	StatoilHydro ASA	089
Vilje	8.7	2003	StatoilHydro Petroleum AS	36
Visund	87.6	1986	StatoilHydro ASA	Visund
Volund[1)]	7.8	1994	Marathon Petroleum Norge AS	150
Volve	15.2	1993	StatoilHydro ASA	046 BS
Yme[1)]	18.8	1987	Talisman Energy Norge AS	316
Yttergryta[1)]	2.2	2007	StatoilHydro ASA	62
Åsgard	368.1	1981	StatoilHydro ASA	Åsgard

1) Fields with approved development plans where production had not started at 31.12.2008
2) Resources in Oseberg also include Oseberg Vest
3) The resources include the total resources for Troll
4) The resources are included in the row above
5) The year the discovery well was drilled

(Source: Norwegian Petroleum Directorate)

Table 2.3 Original recoverable reserves and remaining reserves in fields

	Original reserves[1]					Remaining reserves[4]				
	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[2] mill scm o.e.	Oil mill. scm	Gas bill.scm	NGL mill. tonnes	Condensate mill.scm	Oil equiv.[2] mill.scm o.e.
Alve[3]	1.3	5.5	1.1	0.0	8.8	1.3	5.5	1.1	0.0	8.8
Alvheim	27.5	8.1	0.0	0.0	35.6	25.2	7.9	0.0	0.0	33.1
Balder[a]	60.0	1.9	0.0	0.0	61.9	14.2	0.9	0.0	0.0	15.1
Blane	0.9	0.0	0.0	0.0	0.9	0.7	0.0	0.0	0.0	0.7
Brage	55.1	3.9	1.3	0.0	61.5	5.0	1.2	0.2	0.0	6.6
Draugen	143.1	1.5	2.4	0.0	149.2	21.2	0.1	0.4	0.0	22.1
Ekofisk	528.5	156.1	14.5	0.0	712.2	125.7	20.4	2.2	0.0	150.2
Eldfisk	135.1	43.5	4.0	0.0	186.3	45.9	5.9	0.4	0.0	52.4
Embla	12.0	5.6	0.6	0.0	18.7	2.4	2.2	0.2	0.0	5.0
Enoch	0.4	0.0	0.0	0.0	0.4	0.3	0.0	0.0	0.0	0.3
Fram	23.9	8.4	0.1	0.0	32.5	10.8	8.0	0.1	0.0	19.0
Gimle	4.0	1.1	0.2	0.0	5.5	2.3	1.0	0.2	0.0	3.7
Gjøa[3]	11.1	32.6	5.6	0.0	54.5	11.1	32.6	5.6	0.0	54.5
Glitne	8.3	0.0	0.0	0.0	8.3	0.3	0.0	0.0	0.0	0.3
Grane	116.2	0.0	0.0	0.0	116.2	63.4	0.0	0.0	0.0	63.4
Gullfaks[b]	360.1	24.2	3.0	0.0	390.1	20.1	1.5	0.2	0.0	22.0
Gullfaks Sør[c]	47.9	45.7	6.1	0.0	105.2	14.3	21.7	3.2	0.0	42.1
Gungne	0.0	14.6	1.9	4.0	22.3	0.0	2.3	0.3	0.0	2.9
Gyda[d]	38.8	6.2	1.9	0.0	48.6	4.1	0.3	0.0	0.0	4.5
Heidrun[e]	186.0	41.6	1.7	0.0	230.9	58.7	30.1	1.2	0.0	91.1
Heimdal	7.1	44.6	0.0	0.0	51.7	0.7	0.3	0.0	0.0	1.0
Hod	10.2	1.8	0.4	0.0	12.8	1.2	0.2	0.1	0.0	1.7
Huldra	4.9	15.9	0.1	0.0	21.0	0.3	2.1	0.0	0.0	2.4
Jotun	23.6	0.8	0.0	0.0	24.4	1.8	0.0	0.0	0.0	1.8
Kristin	23.9	26.0	5.7	2.1	62.8	14.1	15.5	3.5	0.0	36.3
Kvitebjørn	27.4	74.0	3.0	0.0	107.2	20.1	59.4	1.7	0.0	82.8
Mikkel	4.6	21.9	6.0	2.3	40.1	3.1	13.0	3.6	0.0	23.1
Morvin[3]	9.3	3.2	0.7	0.0	13.8	9.3	3.2	0.7	0.0	13.8
Murchison	14.6	0.4	0.0	0.0	15.0	0.9	0.1	0.0	0.0	1.0
Njord	25.2	10.7	2.1	0.0	39.9	2.3	8.6	2.1	0.0	14.9
Norne	94.9	11.0	1.7	0.0	109.1	14.4	5.2	1.0	0.0	21.5
Ormen Lange	0.0	394.7	0.0	28.5	423.2	0.0	381.6	0.0	27.4	409.0
Oseberg[f]	366.4	107.0	9.3	0.0	491.0	21.1	85.6	3.5	0.0	113.5
Oseberg Sør	50.6	10.8	0.4	0.0	62.1	16.0	5.4	0.4	0.0	22.1
Oseberg Øst	27.4	0.4	0.1	0.0	27.9	10.3	0.1	0.1	0.0	10.6
Rev[3]	0.0	4.7	0.4	0.8	6.2	0.0	4.7	0.4	0.8	6.2
Ringhorne Øst	8.8	0.2	0.0	0.0	9.0	4.3	0.1	0.0	0.0	4.4
Sigyn	0.0	6.6	2.9	3.9	16.0	0.0	2.1	1.1	-1.1	3.1
Skarv[3]	16.5	41.5	5.4	0.0	68.3	16.5	41.5	5.4	0.0	68.3

	Original reserves[1)]					Remaining reserves[4)]				
	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[2)] mill scm o.e.	Oil mill. scm	Gas bill.scm	NGL mill. tonnes	Condensate mill.scm	Oil equiv.[2)] mill.scm o.e.
Skirne	2.1	8.2	0.0	0.0	10.3	0.9	3.0	0.0	0.0	3.8
Sleipner Vest	0.0	117.7	8.3	29.1	162.5					
Sleipner Øst[g)]	0.0	67.4	13.4	26.9	119.9					
Sleipner Vest and Sleipner Øst[5)]						0.0	36.8	3.0	-2.0	40.5
Snorre	234.3	6.5	4.6	0.0	249.5	70.8	0.6	0.1	0.0	71.6
Snøhvit	0.0	160.6	6.3	18.1	190.7	0.0	158.1	6.2	17.5	187.3
Statfjord	565.2	76.7	24.0	0.0	687.5	6.6	18.1	8.5	0.0	40.9
Statfjord Nord	40.9	2.6	0.9	0.0	45.3	5.5	0.4	0.2	0.0	6.2
Statfjord Øst	37.0	4.0	1.5	0.0	44.0	3.2	0.4	0.3	0.0	4.1
Sygna	10.8	0.0	0.0	0.0	10.8	1.2	0.0	0.0	0.0	1.2
Tambar	9.7	2.6	0.3	0.0	12.8					
Tambar Øst	1.1	0.1	0.0	0.0	1.3					
Tambar and Tambar Øst[6)]						2.8	2.7	0.1	0.0	5.7
Tor	24.5	11.0	1.2	0.0	37.7	1.6	0.2	0.0	0.0	1.8
Tordis[h)]	59.7	5.3	1.7	0.0	68.3	7.1	1.5	0.3	0.0	9.2
Troll[i)]	244.5	1 330.7	25.7	1.6	1 625.6	45.8	995.0	22.1	-2.7	1 080.2
Tune	3.2	18.0	0.2	0.0	21.6	0.3	2.9	0.1	0.0	3.4
Tyrihans[3)]	29.6	35.5	6.5	0.0	77.6	29.6	35.5	6.5	0.0	77.6
Ula	87.3	3.9	3.3	0.0	97.5	18.2	0.0	0.8	0.0	19.6
Urd	9.5	0.3	0.0	0.0	9.9	5.9	0.2	0.0	0.0	6.1
Vale	2.0	2.2	0.0	0.0	4.2	1.0	1.4	0.0	0.0	2.4
Valhall	145.0	26.4	5.3	0.0	181.5	46.1	6.9	2.2	0.0	57.1
Varg	15.1	0.0	0.0	0.0	15.1	3.9	0.0	0.0	0.0	3.9
Vega[3)]	0.0	9.4	0.5	1.7	12.1	0.0	9.4	0.5	1.7	12.1
Vega Sør[3)]	0.0	7.4	0.4	2.4	10.6	0.0	7.4	0.4	2.4	10.6
Veslefrikk	55.7	3.8	1.3	0.0	62.0	6.3	1.6	0.1	0.0	8.1
Vigdis	59.0	1.8	1.6	0.0	63.7	15.9	0.7	0.9	0.0	18.3
Vilje	8.3	0.4	0.0	0.0	8.7	7.8	0.4	0.0	0.0	8.2
Visund	29.1	47.2	6.0	0.0	87.6	11.0	43.5	5.7	0.0	65.4
Volund[3)]	7.2	0.6	0.0	0.0	7.8	7.2	0.6	0.0	0.0	7.8
Volve	13.6	1.1	0.2	0.1	15.2	11.8	1.0	0.2	0.1	13.2
Yme[3)]	18.8	0.0	0.0	0.0	18.8	10.9	0.0	0.0	0.0	10.9
Yttergryta[3)]	0.1	1.6	0.3	0.0	2.2	0.1	1.6	0.3	0.0	2.2
Åsgard	97.6	185.9	36.1	16.0	368.1	34.5	110.8	23.0	-1.1	187.9
Total	**4 286.5**	**3 315.6**	**232.3**	**137.7**	**8 181.0**	**919.4**	**2 211.1**	**120.6**	**43.1**	**3 402.8**

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 started at 31.12.2008
4) A negative remaining reserves figure for a field is a result of the product not being reported under original reserves. This applies to produced NGL and condensate
5) Gas production from Gungne, Sleipner Vest and Øst are metered collectively
6) Production from Tambar and Tambar Øst are metered collectively

a) Balder also includes Ringhorne
b) Gullfaks also includes Gullfaks Vest
c) Gullfaks Sør includes Gulltopp,Gullveig, Rimfaks and Skinfaks
d) Gyda also includes Gyda Sør
e) Heidrun also includes Tjeldbergodden
f) Oseberg also includes Oseberg Vest
g) Sleipner Øst also include Loke
h) Tordis also includes Tordis Øst and Borg
i) Troll also includes TOGI

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)]
3/7-4 Trym	0.0	4.2	0.0	1.1	5.4	1990
Total	**0.0**	**4.2**	**0.0**	**1.1**	**5.4**	

(Source: 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)]
1/3-6	4.4	4.8	0.0	0.0	9.2	1991
1/5-2 Flyndre	0.2	0.0	0.0	0.0	0.2	1974
1/9-1 Tommeliten Alpha	8.1	12.8	0.5	0.0	21.9	1977
15/3-1 S Gudrun	9.9	13.0	1.4	0.0	25.5	1975
15/3-4	1.8	1.3	0.3	0.0	3.7	1982
15/8-1 Alpha	0.0	2.0	0.3	1.2	3.9	1982
16/1-8	19.0	2.4	0.0	0.0	21.4	2007
2/12-1 Freja	2.9	0.6	0.0	0.0	3.5	1987
24/6-1 Peik	0.0	2.5	0.0	0.7	3.1	1985
25/11-16	5.5	0.1	0.0	0.0	5.7	1992
25/5-5	1.9	0.0	0.0	0.0	1.9	1995
30/7-6 Hild	3.3	15.4	0.8	2.0	22.3	1978
31/2-N-11 H	0.4	0.0	0.0	0.0	0.4	2005
33/9-6 Delta	0.1	0.0	0.0	0.0	0.2	1976
34/10-23 Valemon	0.0	39.8	0.0	9.5	49.2	1985
35/11-13	6.4	2.1	0.0	0.0	8.6	2005
35/2-1	0.0	21.2	0.0	0.0	21.2	2005
6406/3-2 Trestakk	8.8	2.2	0.5	0.0	11.9	1986
6407/9-9[3)]	0.3	1.1	0.0	0.0	1.4	1999
6507/2-2	0.7	10.1	1.7	0.0	14.0	1992
7/7-2	3.3	0.0	0.0	0.0	3.3	1992
7122/7-1 Goliat[4)]	30.6	7.4	0.4	0.0	38.7	2000
Total	**107.6**	**139.0**	**5.9**	**13.3**	**271.2**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the discovery well was drilled
3) 6407/9-9 has resources in categories 4 og 5
4) 7122/7-1 Goliat has resources in categories 4 and 5

(Source: 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]
15/5-1 Dagny	13.3	15.3	0.0	0.0	28.5	1978
15/5-2	0.0	4.9	0.0	0.4	5.3	1978
16/1-9	8.6	1.1	0.0	0.0	9.7	2008
16/7-2	0.0	0.6	0.1	0.4	1.2	1982
17/12-1 Bream	8.1	0.0	0.0	0.0	8.1	1972
2/5-3 Sørøst Tor	3.1	0.9	0.0	0.0	3.9	1972
25/11-25 S	6.3	0.3	0.0	0.0	6.6	2008
25/8-4	1.0	0.0	0.0	0.0	1.0	1992
34/11-2 S Nøkken	1.2	2.7	0.1	0.0	4.1	1996
35/8-3	0.0	2.7	0.0	0.6	3.2	1988
6/3-1 PI	0.9	1.8	0.0	0.0	2.7	1985
6406/1-1 Erlend N.	0.3	1.1	0.0	0.0	1.4	2001
6406/2-1 Lavrans	3.7	11.1	1.9	0.0	18.4	1995
6406/2-6 Ragnfrid	1.7	2.1	0.5	0.0	4.7	1998
6406/2-7 Erlend	2.2	3.4	0.7	0.0	6.9	1999
6406/9-1	0.0	40.8	0.0	1.4	42.2	2005
6407/6-6	0.0	1.4	0.2	0.5	2.4	2008
6506/11-2 Lange	0.4	0.2	0.0	0.0	0.6	1991
6506/12-3 Lysing	1.5	0.3	0.0	0.0	1.8	1985
6506/6-1	0.0	89.3	2.8	5.0	99.6	2000
6507/11-6 Sigrid	0.4	1.9	0.3	0.0	2.9	2001
6507/11-9	0.0	1.4	0.2	0.4	2.3	2008
6507/7-13	0.9	0.0	0.0	0.0	1.0	2001
6608/10-11 S	0.0	0.2	0.0	0.0	0.2	2006
6707/10-1	0.0	35.5	0.0	1.3	36.8	1997
7/8-3	2.6	0.1	0.0	0.0	2.7	1983
7122/6-1	1.2	8.7	0.0	0.0	9.8	1987
Total	**57.2**	**227.8**	**6.9**	**10.0**	**308.1**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the discovery well was drilled

(Source: Norwegian Petroleum Directorate)

Table 2.7 Resources in discoveries that have not been evaluated

Discovery	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv. [1] mill. scm o.e.	Year of discovery[2]
1/3-11	1.5	0.9	0.0	0.0	2.3	2008
15/12-18 S	0.9	0.0	0.0	0.0	0.9	2007
16/1-7	0.6	0.1	0.0	0.0	0.7	2004
16/2-3	0.0	1.9	0.0	0.3	2.2	2007
25/10-8	1.4	3.2	0.0	0.0	4.7	1997
25/4-3	0.8	4.5	0.0	0.0	5.3	1974
30/9-21 S	1.5	1.0	0.0	0.1	2.6	2008
34/12-1	0.0	7.3	0.7	1.3	9.9	2008
34/3-1 S	8.4	0.0	0.0	0.0	8.4	2008
34/8-14 S	2.9	1.5	0.0	0.0	4.4	2008
35/10-2	0.0	1.6	0.0	0.0	1.6	1996
6405/10-1	0.0	1.9	0.0	0.2	2.1	2007
6407/7-8	0.0	5.3	0.0	0.5	5.7	2008
6407/8-4 S	0.0	1.4	0.0	0.0	1.4	2008
6706/12-1	0.0	3.7	0.0	0.1	3.8	2008
6707/10-2 S	0.0	11.0	0.0	0.0	11.0	2008
7120/12-2	0.0	10.3	0.0	0.0	10.3	1981
7120/12-3	0.0	5.7	0.0	0.0	5.7	1983
7125/4-1	7.3	2.0	0.0	0.1	9.4	2007
7222/11-1	0.0	5.0	0.0	0.0	5.0	2008
7222/6-1 S	17.7	3.8	0.0	0.0	21.5	2008
7224/6-1	0.0	0.0	0.0	0.0	0.0	2008
7226/11-1	2.5	48.0	0.0	0.0	50.5	1988
7226/2-1	0.0	24.9	0.0	1.4	26.3	2008
Total	**45.4**	**145.1**	**0.7**	**3.9**	**195.8**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the discovery well was drilled

(Source: 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 418 active production licences and 421 operatorships. This is due to the fact that StatoilHydro ASA and StatoilHydro Petroleum AS share operatorship in production licences 085 and 085 B, while Maersk Oil Norway AS and StatoilHydro Petroleum AS share operatorship in production licence 296. In addition, Gassco AS is the operator for large parts of the gas pipeline network. Please visit our fact pages at www.npd.no for more information.

Table 3.1 Operators and licensees per February 2008

Operator/licensee	Operatorship in production license	Licensee in production license	Licensee in field
A/S Norske Shell	8	20	8
Aker Exploration AS	2	17	
BG Norge AS	15	20	
BP Norge AS	11	14	7
Centrica Resources (Norge) AS	9	21	3
ConocoPhillips Skandinavia AS	14	38	23
DONG E & P Norge AS	6	33	9
Dana Petroleum Norway AS	2	16	3
Det norske oljeselskap ASA	29	55	7
Discover Petroleum AS	1	9	
E.ON Ruhrgas Norge AS	5	29	2
Endeavour Energy Norge AS	4	21	2
Eni Norge AS	14	48	18
ExxonMobil Exploration and Production Norway AS	10	51	26
GDF SUEZ E&P Norge AS	2	33	5
Hess Norge AS	1	15	4
Idemitsu Petroleum Norge AS	1	15	7
Lotos Exploration and Production Norge AS	2	8	1
Lundin Norway AS	19	34	3
Maersk Oil Norway AS	2	11	
Maersk Oil PL 018C Norway AS	1	1	
Marathon Petroleum Norge AS	8	12	3
Nexen Exploration Norge AS	10	11	
Norwegian Energy Company ASA	5	31	
OMV (Norge) AS	5	7	
Petro-Canada Norge AS	5	17	
Premier Oil Norge AS	2	10	1
RWE Dea Norge AS	3	33	8
Rocksource ASA	3	6	
StatoilHydro ASA	103	179	57
StatoilHydro Petroleum AS	68	110	45
Talisman Energy Norge AS	19	38	10
Total E&P Norge AS	13	76	41
Wintershall Norge AS	5	14	
Wintershall Norge ASA	14	45	4

Other licensees	Production licence	Field
4Sea Energy AS	2	
Altinex Oil Norway AS	10	2
Bayerngas Norge AS	7	1
Brigde Energy AS	10	
Chevron Norge AS	5	1
Concedo ASA	6	
Edison International Spa	6	
Enterprise Oil Norge AS	6	7
Faroe Petroleum Norge AS	21	
Genesis Petroleum Norway AS	5	
Norske AEDC A/S	1	2
North Energy AS	2	
PA Resources Norway AS	10	1
PGNiG Norway AS	4	1
Petoro AS	131	47
Repsol Exploracion S.A	1	
Sagex Petroleum Norge AS	5	
Serica Energy Norge AS	2	
Skagen 44 AS	5	
Skeie Energy AS	7	1
Spring Energy Norway AS	5	
Svenska Petroleum Exploration AS	6	2
VNG Norge AS	8	

(Source: Norwegian Petroleum Directorate)

Appendix 4 List of addresses

GOVERNMENT BODIES

The Ministry of Petroleum and Energy
P.O. Box 8148 Dep, 0033 Oslo
Tel. +47 22 24 90 90. Fax +47 22 24 95 65
www.regjeringen.no/oed

The Norwegian Petroleum Directorate
P.O. Box 600, 4003 Stavanger
Tel. +47 51 87 60 00. Fax +47 51 55 15 71
www.npd.no

The Harstad office
P.O. Box 787, 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, 0030 Oslo
Tel. +47 22 24 90 90. Fax +47 22 24 87 11
www.regjeringen.no/aid

The Petroleum Safety Authority Norway
P.O. Box 599, 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, 0030 Oslo
Tel. +47 22 24 90 90. Fax +47 22 24 95 10
www.regjeringen.no/fin

The Ministry of the Environment
P.O. Box 8013 Dep, 0030 Oslo
Tel. +47 22 24 90 90. Fax +47 22 24 95 60
www.regjeringen.no/md

OPERATORS

A/S Norske Shell
P.O. Box 40, 4098 Tananger
Tel. +47 51 69 30 00. Fax +47 51 69 30 30
www.shell.com

Aker Exploration AS
P.O. Box 580 Sentrum, 4003 Stavanger
Tel. +47 51 21 48 00. Fax +47 51 21 48 01
www.akerexploration.com

BG Norge AS
P.O. Box 780 Sentrum, 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, 4065 Stavanger
Tel. +47 52 01 30 00. Fax +47 52 01 30 01
www.bp.no

Centrica Resources (Norge) AS
P.O. Box 520, 4003 Stavanger
Tel. +47 51 50 65 20. Fax +47 51 50 65 49
www.centrica.com

ConocoPhillips Skandinavia AS
P.O. Box 3, 4064 Tananger
Tel. +47 52 02 00 00. Fax +47 52 02 66 00
www.conocophillips.no

Dana Petroleum Norway AS
P.O. Box 128, 1325 Lysaker
Tel.+47 67 52 90 20. Fax +47 62 52 90 30
www.dana-petroleum.com

Det norske oljeselskap ASA
Nedre Bakklandet 58 C, 7014 Trondheim
Tel. +47 90 70 60 00. Fax +47 73 53 05 00
www.detnor.no

Discover Petroleum AS
P.O. Box 690, 9257 Tromsø
Tel.+47 85 22 08 80. Fax +47 77 69 06 91
www.discoverpetroleum.com

DONG E & P Norge AS
P.O. Box 450 Sentrum, 4002 Stavanger
Tel. +47 51 50 62 50. Fax +47 51 50 62 51
www.dong.no

Endeavour Energy Norge AS
P.O. Box 1989 Vika, 0125 Oslo
Tel. +47 22 01 04 70. Fax +47 22 01 04 71
www.endeavourcorp.com

Eni Norge AS
P.O. Box 101 Forus, 4064 Stavanger
Tel. +47 52 87 48 00. Fax +47 52 87 49 30
www.eninorge.no

E.ON Ruhrgas Norge AS
P.O. Box 640 Sentrum, 4003 Stavanger
Tel. +47 51 51 74 00. Fax +47 51 51 74 10
www.eon-ruhrgas-norge.com

ExxonMobil Exploration and Production Norway AS
P.O. Box 60 Forus, 4064 Stavanger
Tel. +47 51 60 60 60. Fax +47 51 60 66 60
www.exxonmobil.no

GDF SUEZ E & P Norge AS
P.O. Box 242 Forus, 4066 Stavanger
Tel. +47 52 04 46 00. Fax +47 52 04 46 01
www.gdfsuezep.no

Hess Norge AS
P.O. Box 130, 4065 Stavanger
Tel. +47 51 31 54 00. Fax +47 51 31 54 10
www.hess.com

Idemitsu Petroleum Norge AS
P.O. Box 215 Skøyen, 0213 Oslo
Tel. +47 23 25 05 00. Fax +47 23 25 05 01
www.idemitsu.no

Lotos Exploration and Production Norge AS
Vassbotnen 1, 4313 Sandnes
Tel. +47 94 14 89 00
www.lotosupstream.no

Lundin Norway AS
Strandveien 50 D, 1366 Lysaker
Tel. +47 67 10 72 50. Fax +47 67 10 72 51
www.lundin-petroleum.com

Maersk Oil Norway AS
P.O. Box 8014, 4068 Stavanger
Tel. +47 52 00 28 00. Fax +47 52 00 28 01
www.maerskoil.com

Maersk Oil PL 018 C Norway AS
c/o Mærsk Oil Norway AS

Marathon Petroleum Norge AS
P.O. Box 480 Sentrum, 4002 Stavanger
Tel. +47 51 50 63 00. Fax +47 51 50 63 01
www.marathon.com

Nexen Exploration Norge AS
P.O. Box 130, 4065 Stavanger
Tel. +47 51 30 21 00. Fax +47 51 30 21 99
www.nexeninc.com

Norwegian Energy Company AS (NORECO)
P.O. Box 550 Sentrum, 4003 Stavanger
Tel. +47 99 28 39 00. Fax +47 51 53 33 33
www.noreco.no

OMV (Norge) AS
P.O. Box 130, 4065 Stavanger
Tel. +47 52 97 70 00. Fax +47 52 97 70 10
www.omv.com

Petro-Canada Norge AS
P.O. Box 269 Sentrum, 4002 Stavanger
Tel. +47 51 21 50 00. Fax +47 51 21 50 99
www.petro-canada.com

Premier Oil Norge AS
P.O. Box 800 Sentrum, 4004 Stavanger
Tel. +47 51 21 31 00. Fax +47 51 21 31 01
www.premieroil.no

Rocksource ASA
Munkedamsveien 45, oppg. A, 0250 Oslo
Tel. +47 22 94 77 70. Fax +47 22 94 77 71
www.rocksource.com

RWE Dea Norge AS
P.O. Box 243 Skøyen, 0213 Oslo
Tel. +47 21 30 30 00. Fax +47 21 30 30 99
www.rwe-dea.no

StatoilHydro ASA
4035 Stavanger
Tel. +47 51 99 00 00, Fax +47 51 99 00 50
www.statoilhydro.com

StatoilHydro Petroleum AS
4035 Stavanger
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www.statoilhydro.com

Talisman Energy Norge AS
P.O. Box 649 Sentrum, 4003 Stavanger
Tel. +47 52 00 20 00. Fax +47 52 00 15 00
www.talisman-energy.com

Total E&P Norge AS
P.O. Box 168 Sentrum, 4001 Stavanger
Tel. +47 51 50 30 00. Fax +47 51 72 66 66
www.total.no

Wintershall Norge AS
P.O. Box 775 Sentrum, 0106 Oslo
Tel. +47 21 06 35 30. Fax +47 21 06 35 31
www.wintershall.com

Wintershall Norge ASA
P.O. Box 230 Sentrum, 4001 Stavanger
Tel. +47 51 50 63 50. Fax +47 51 50 63 51
www.revus-energy.no

OTHER LICENSEES

4Sea Energy AS
P.O. Box 250, 4002 Stavanger
Tel.+47 51 56 53 00. Fax +47 51 21 32 09
www.4sea.no

Altinex Oil Norway AS
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Tel. +47 99 28 39 00. Fax +47 51 53 33 33
www.altinexoil.no

Bayerngas Norge AS
P.O. Box 73, 0216 Oslo
Tel. +47 22 52 99 00. Fax +47 22 52 99 01
www.bayerngasnorge.com

Bridge Energy AS
P.O. Box 279, 1379 Nesbru
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www.bridge-energy.no

Chevron Norge AS
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Tel.+47 22 13 56 60. Fax +47 22 13 56 96
www.chevron.com

Concedo ASA
Torvveien 1, 1383 Asker
Tel. +47 40 00 62 55. Fax +47 66 78 99 93
www.concedo.no

Edison International Norway Branch
P.O. Box 130, 4065 Stavanger
Tel. +47 52 97 71 00. Fax +47 52 97 71 49

Enterprise Oil Norge AS
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Tel. +47 51 69 30 00. Fax +47 51 69 30 30
www.shell.com

Faroe Petroleum Norge AS
P.O. Box 309, 4002 Stavanger
Tel. +47 51 21 51 00. Fax +47 51 21 51 01
www.faroe-petroleum.com

Genesis Petroleum Norway AS
P.O. Box 156, 1371 Asker
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www.genesis-petroleum.com

Norske AEDC A/S
P.O. Box 207 Sentrum, 4001 Stavanger
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North Energy AS
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www.northenergy.no

PA Resources Norway AS
Munkedamsveien 45 E, 0250 Oslo
Tel. +47 21 56 76 00. Fax +47 21 56 76 01
www.paresources.se

Petoro AS
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www.petoro.no

PGNiG Norway AS
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Spring Energy Norway AS
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Other companies

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www.gassco.no

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	litres
	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

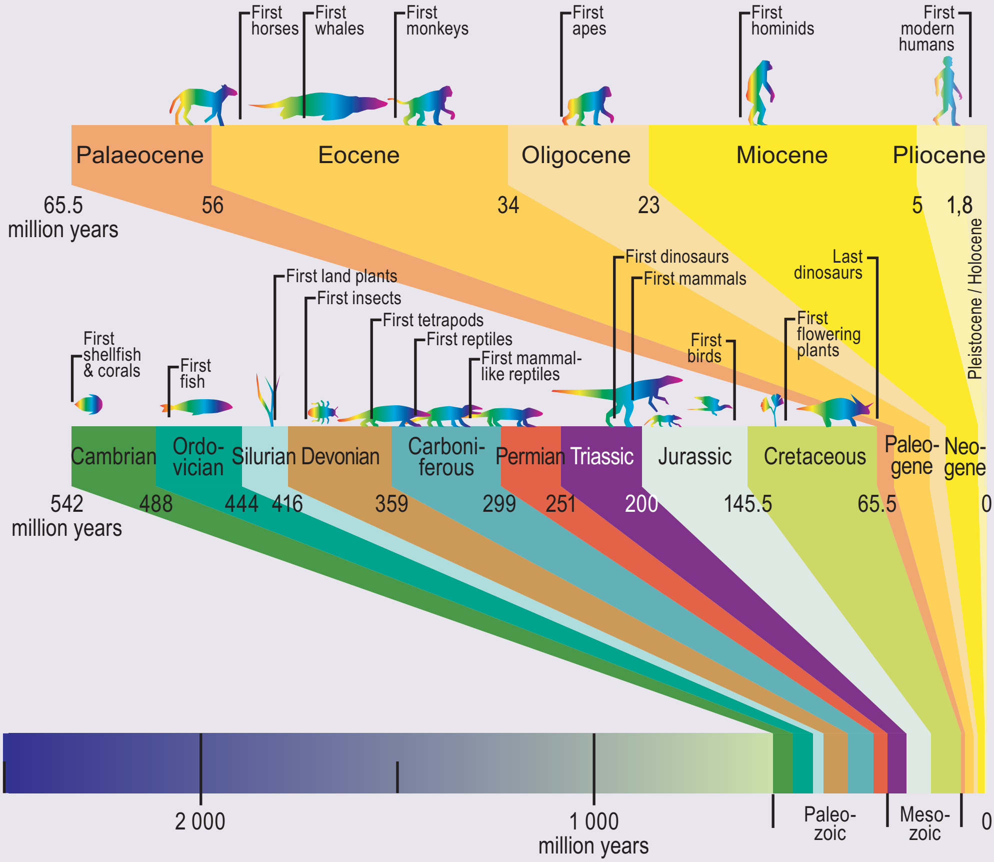
Conversion factors for volume

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

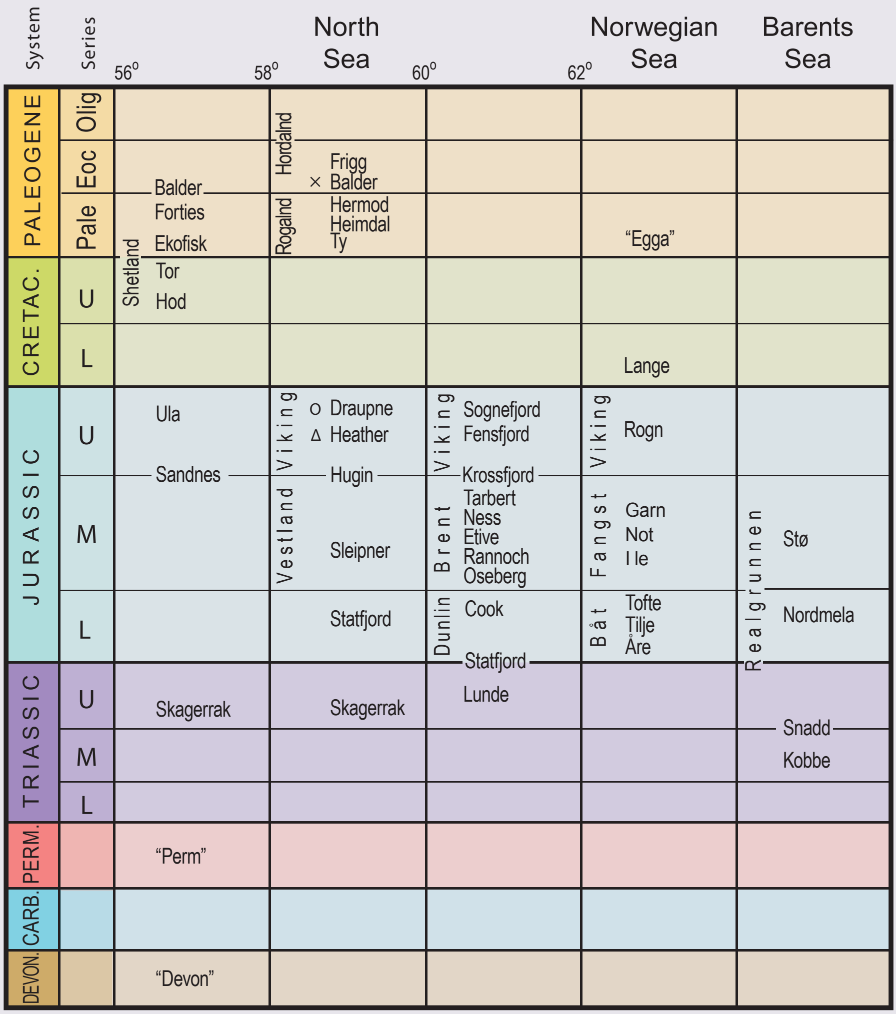
Conversion factors between various units of energy

			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



Appendix 7 Reservoir and Lithostratigraphy



× Balder - intra Balder sandstone

o Draupne - intra Draupne sandstone

Δ Heather - intra Heather sandstone

"Egga" - informal unit

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