PETROLEUMRESOURCES ON THE NORWEGIAN CONTINENTAL SHELF

2009

Published by the
Norwegian Petroleum Directorate
Professor Olav Hanssens vei 10
P.O. Box 600
NO-4003 Stavanger
Telephone: +47 51 87 60 00
Telefaks: +47 51 55 15 71
postboks@npd.no
www.npd.no

Design/layout: Janne-Beth Carlsen N'Jai/
Graphic Centre, Norwegian Petroleum Directorate
Cover: Janne-Beth Carlsen N'Jai
Printed by: Kai Hansen, Stavanger
Paper: Arctic Volume 200/130 gr

NORWEGIAN PETROLEUM
DIRECTORATE

Preface

Nature has been generous and given the Norwegian continental shelf large petroleum resources. Without technology, expertise, willingness and ability to invest, predictable framework conditions and sound management, it would not have been possible to create the enormous values for society and industry that the petroleum activity has achieved since 1969.

To continue the value creation the industry and the authorities are faced with important decisions.

Oil production is falling, and to counteract this, the industry and the authorities must work together to ensure that all the profitable oil resources are produced. In a few years, gas production will exceed oil production. In addition, exploration is necessary for future production and is important for maintaining both the attractiveness of the Norwegian continental shelf and the technological expertise. It is important that future production is as energy efficient as possible.

The Norwegian Petroleum Directorate (NPD) has a unique access to facts about the petroleum activities. The NPD maintains an overview of the resources and follows up the activities on the Norwegian shelf. In this report, the Norwegian Petroleum Directorate presents an updated survey of the activities and discusses important future challenges.

Stavanger, August 2009

Bente Nyland
Director General

Contents

1 CHALLENGES ON THE NORWEGIAN CONTINENTAL SHELF

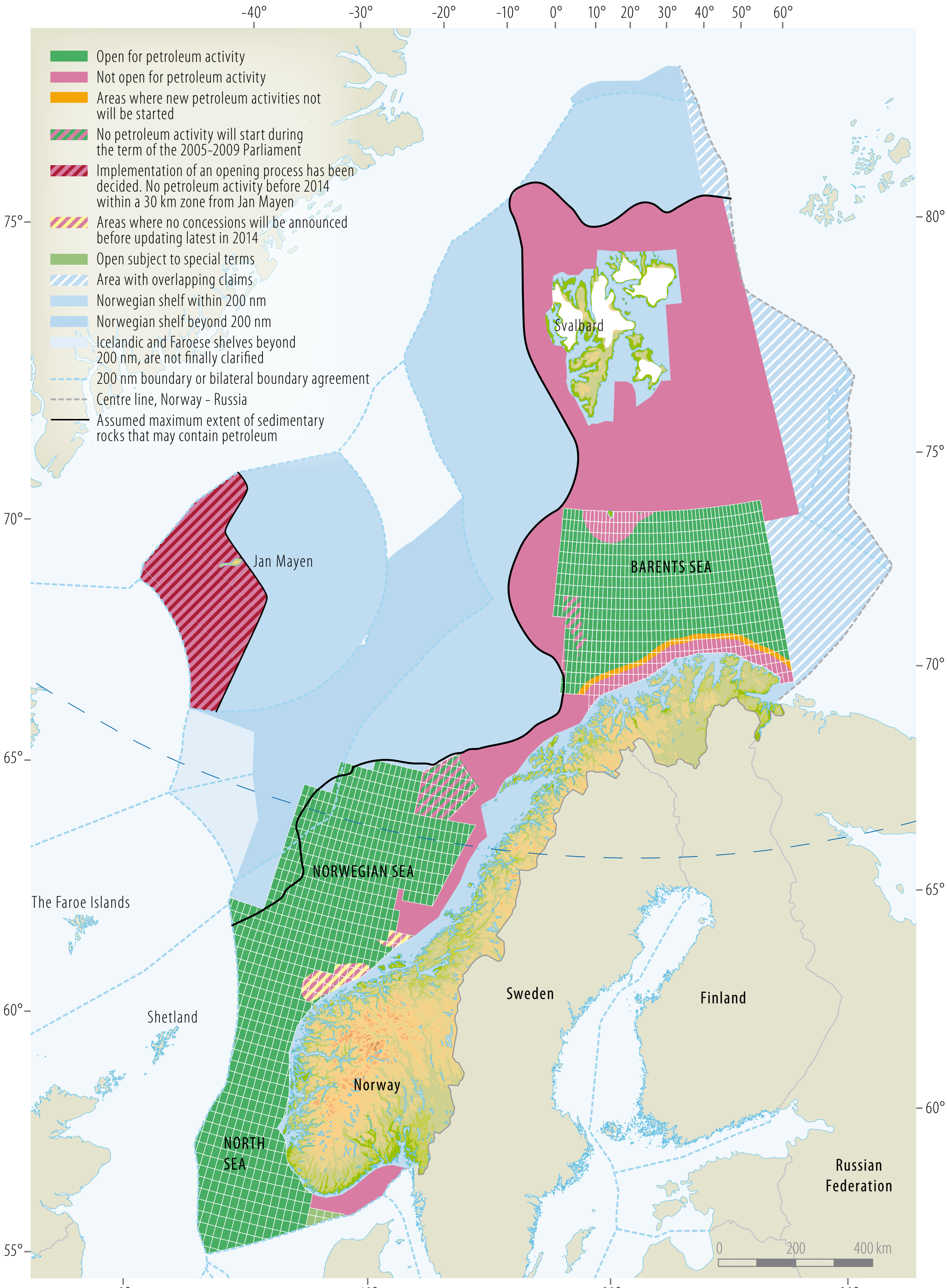


Figure 1.1 Status of petroleum activity areas on the Norwegian continental shelf as of 1 August 2009 (for details see White Paper no 8 (2005-2006) and no 37 (2008-2009))

Challenges on the shelf

The high oil price and favorable frame conditions have increased the attraction of the shelf in recent years. A great deal of exploration is taking place. Are major discoveries to be made in less explored areas? May technology and higher profitability make it possible to produce even more oil from existing fields? The Norwegian continental shelf is not unaffected by what takes place elsewhere in the world. A mature shelf needs even more energy-effective solutions.

This report from the Norwegian Petroleum Directorate presents facts about trends on the continental shelf. It is 40 years since Ekofisk, the first oil and gas field in Norway, was discovered and in this report the development is illustrated in ten-year periods from 1969 to 2009.

A predictable petroleum policy has been vital for everyone involved in the first 40 years. Many large discoveries were made in the early phase, production rose smoothly and the industry gradually gained access to new exploration acreage. The authorities have paved the way for the petroleum industry within predictable conditions. Recently, new driving forces have influenced the development; for instance, environmental issues have come to the forefront.

No new acreage has been made available for petroleum activity on the Norwegian continental shelf since 1994 (Figure 1.1). This is one of the reasons for the reduced growth in resources from new discoveries.

Discoveries are made, but most of them are small. However, it may still be possible to make large discoveries in less explored areas, such as in deep waters in the Norwegian Sea, in the Barents Sea and in areas that are yet not open.

Exploration wells are still being drilled in acreage allocated in the first licensing rounds, and a great deal of the production comes from discoveries made during the first 20 years. Discoveries made during the last ten years period contribute little to future production.

The uncertainty in the resource base is great, especially in the least explored areas. The Norwegian Petroleum Directorate has updated the estimate of undiscovered resources in the Barents Sea. The estimated volumes of oil and gas in place have risen, but distance to the market and recognition of the fact that reservoir properties are somewhat poorer than believed earlier have reduced the expectation of the proportion of petroleum that can be produced profitably.

Thirty eight per cent of the total estimated recoverable resources on the shelf have been produced. Twenty five per cent are reserves, and thus have approved plans for development. Recent years' reserves growth has been small and it may be difficult to reach the target set by the Norwegian Petroleum Directorate in 2005 to increase the oil reserves by 800 million Sm^3 of oil within 2015.

Gas production is rising while oil production is declining. Gas injection is an effective technology to improve oil recovery. When the gas is to be produced, at what rate and how this will influence oil recovery, are still key questions.

A mature shelf requires more energy. This leads to higher CO_2 emissions and a need to continually develop and employ means of reducing the emissions from energy production.

To increase the oil reserves, the industry must, develop technology and new strategies to recover residual oil. Stronger focus on technology may reap large benefits. However, extensive cooperation between the authorities and the petroleum industry will be needed to qualify and test new technologies on the fields.

Technological advances have led to development of discoveries beneath great water depths and far from shore, and more of the activities are now controlled from shore. The technological advances have also made a higher proportion of the resources profitable to recover. It is therefore important that both authorities and industry maintain focus on research and technological development in the petroleum sector.

2 VALUE CREATION IN FIELDS

In the course of 40 years, the petroleum industry has created values for more than 7000 billion NOK measured in present-day monetary value. Natural conditions have formed the basis and advances in technology and willingness to invest, together with prudent resource management, have given the good results.

A great deal of oil and gas remain in the fields, and values can be created for decades to come with predictable framework conditions and willingness to make the right decisions.

There is a great potential in increasing the oil reserves by improving and changing recovery strategies and by cost-saving measures and improved efficiency in the operations. Some of the challenges lie in appropriate use of gas, long-term management of the huge resources in chalk fields and finding and employing production techniques that enable the industry to produce more of the remaining oil profitably. Technology still needs to be developed and tested before advanced methods can be used on a full scale offshore.

40 years of oil and gas production

Oil and gas production from the Norwegian continental shelf started on the Ekofisk Field in 1971. Ekofisk was discovered in 1969. In the years that followed, a number of major discoveries were made. They were developed, and the production increased. By the end of 2008, oil and gas had been produced from 70 fields. Twelve fields are now closed, but new licensees are re-commencing production on the Yme Field.

Production rose smoothly during the first three decades up to 2000, when it reached a plateau. Since 2001, oil production has declined while gas production has risen. Despite declining oil production, the values created from the fields on the Norwegian continental shelf continue to be substantial. Figure 2.1 shows oil, gas, NGL (Natural Gas Liquids) and condensate production from 1971 to the end of 2008.

The large oil and gas fields have accounted for most of the production on the Norwegian continental shelf (Figure 2.2 and 2.3). By the end of 2008 Ekofisk, Statfjord, and Oseberg and Gullfaks fields had produced 1646 million Sm3, which represents half of the Norwegian oil production. The production from the largest oil fields has declined over the last 10 to 15 years, but many smaller fields help to reduce the fall in production.

The gas exports started in 1977 from the Frigg and Ekofisk fields, and two smaller fields, Cod and Vest Ekofisk, further south in the North Sea, added to the exports later the same year. The Troll Field has so far accounted for nearly a quarter of the total gas production, and in 2008 more

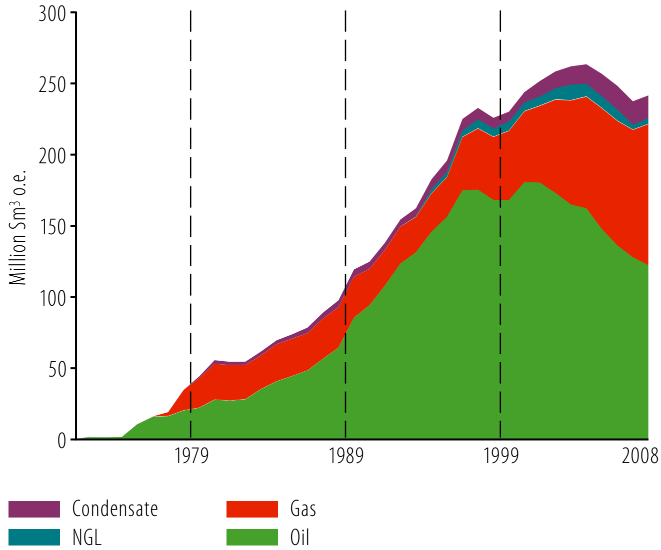


Figure 2.1 Historical petroleum production

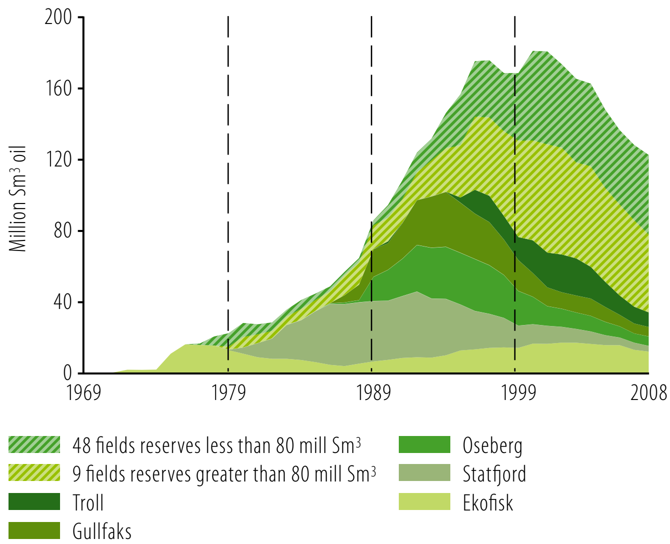


Figure 2.2 Oil production from 1971 to 2008 arranged according to fields and groups of fields

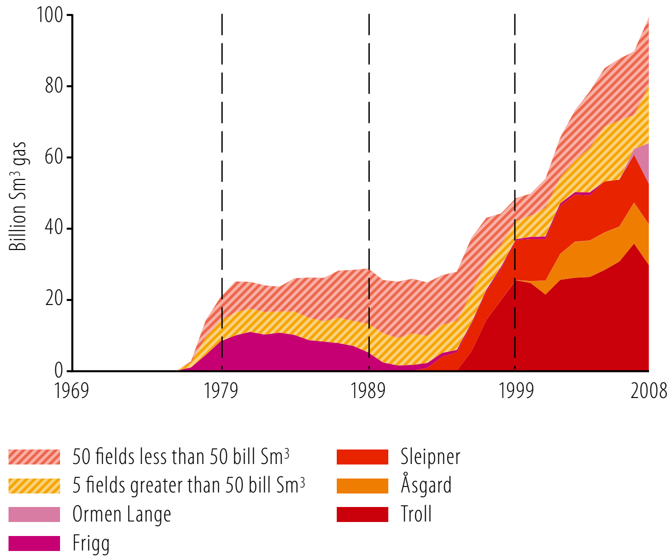


Figure 2.3 Gas production from 1977 to 2008 arranged according to fields and groups of fields

than 60 per cent of the production came from four fields: Troll, Sleipner, Åsgard and Ormen Lange.

Some gas production on the Norwegian shelf has come from oilfields as gas dissolved in oil, referred to as associated gas. The volume of associated gas will gradually decline in line with falling oil production and the closure of large fields. Oilfields which contain gas in overlying gas caps and large quantities of injected gas will gradually contribute to raise the gas production. The Oseberg and Statfjord fields are examples of this.

The Norwegian continental shelf is characterised by fields of varying dimensions. Figure 2.4 shows the proportion of the oil and gas reserves that have been produced and the originally assumed recoverable volumes in each field. The bubble size represents the remaining reserves. The number of discoveries and the progress in plans for development are shown on the left side of the graph. Large fields that have been in production for a long time predominate and there are no large discoveries to replace them.

Resource management

Estimates of how much oil and gas can be produced from the fields depend on natural conditions, the production strategy, the willingness and ability to use new technology, and the presence of a basis for taking decisions in a long-term perspective. Requirements for prudent production are laid out in the Petroleum Activities Act.

Prudent production – The Petroleum Activities Act § 4-1

Production of petroleum shall take place in such a manner that as much as possible of the petroleum in place in each individual petroleum deposit, or in several deposits in combination, will be produced. The production shall take place in accordance with prudent technical and sound economic principles and in such a manner that waste of petroleum or reservoir energy is avoided. The licensee shall carry out continuous evaluation of production strategy and technical solutions and shall take the necessary measures in order to achieve this.

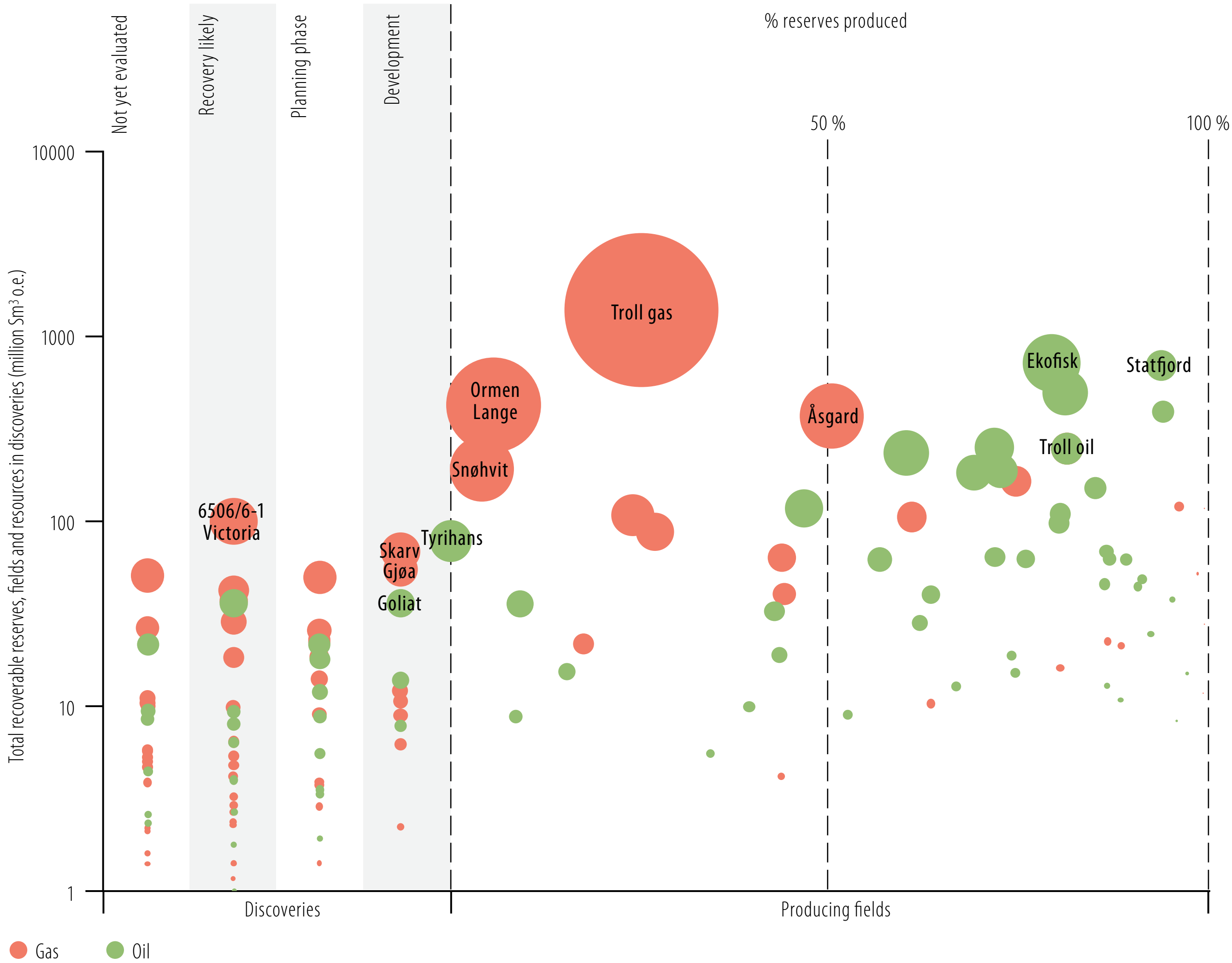


Figure 2.4 Total reserves versus the proportion of the reserves produced

Already at an early stage great attention was directed to the possibilities for continuously increasing the reserves from the fields. The Norwegian Petroleum Directorate, NPD, has always maintained extensive dialogue and cooperation with the licensees to achieve this. As a comparatively young oil nation, Norway has had the opportunity to reap the benefits of experience gained by other nations.   The Petroleum Activities Act reflects this; before a plan for developing a field (PDO) is approved, a licensee must submit an evaluation and a plan for enhanced recovery. Companies are also obliged to continually assess and implement necessary measures as production progresses. The NPD plays an important role to ensure that this is done in accordance with the Act.

Research programmes were initiated at an early date to build up expertise and develop technology. Today, Norwegian research institutions and companies are at the forefront internationally, not only in underwater technology but also in reservoir modelling and knowledge of advanced recovery techniques. The latter are decisive for the effort now required to obtain more oil from the fields.

Recovery factor for oil

The recovery factor for a field shows how much of the originally in-place resources the licensee at any one time has approved plans to produce. On average, fields on the Norwegian shelf have a recovery factor of 46 per cent for oil. This is high compared with oil provinces in other parts of the world.

Figure 2.5 shows the development of the average recovery factor for oil from the fields on the Norwegian continental shelf shelf. The recovery factor has remained relatively stable in recent years. The increase has been greatest for the large fields. They have sufficient resources to support new investments, and both wells and infrastructure are available. A small rise in the recovery factor may give substantial volumes of additional oil. For example, an increase of one per cent in the ten fields with most remaining resources gives nearly 60 million Sm³ more oil reserves, which is equal to the originally recoverable oil reserves in the Veslefrikk or Vigdis fields.

If currently approved plans are followed, more than half the originally in-place oil will be left in the reservoirs when the fields are closed down. It is probably possible to arrange for significantly higher recovery based on profitable production in a longer time perspective. Figure 2.6 shows how much oil has been produced from each field on the shelf, how much is expected to be produced on the basis of currently approved plans, and the size of the resources that will be left if the fields are closed down in accordance with the same plans.

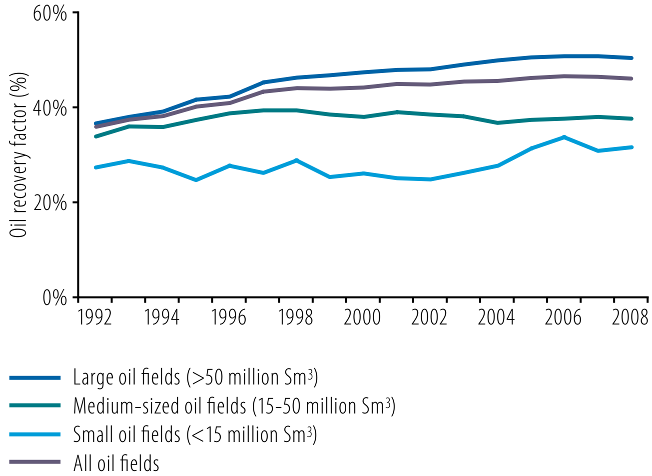


Figure 2.5 Trend in the average expected recovery factor for oil

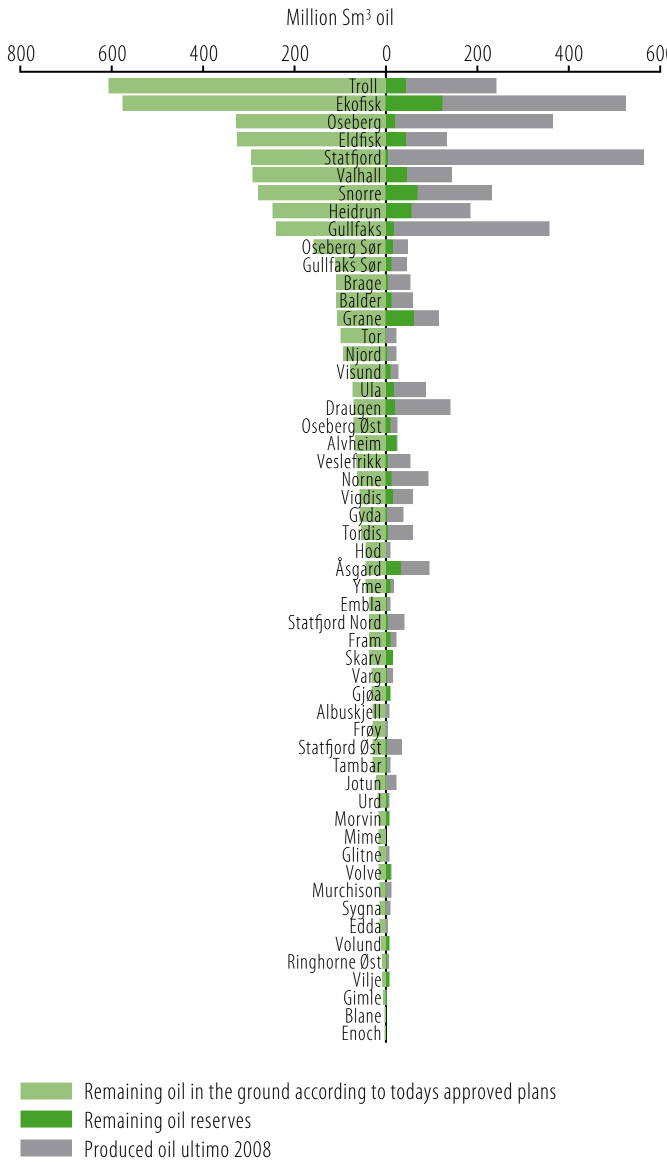


Figure 2.6 Distribution of produced oil, remaining oil reserves and oil resources that will be left if fields are closed down in accordance with currently approved plans

In most fields, the oil that is most readily available, technically and economically, has already been produced or is included in approved plans. To increase the reserves and plan activities, it is essential to know more about where in the reservoir the remaining oil is located and why it is not being produced. Mapping the reservoir using repeated seismic (4D seismic) has proved a valuable way of showing how the liquids move within the reservoir over time, and thus where the remaining oil is located.

Mobile and immobile oil

Remaining oil may be broadly divided into two categories; mobile and immobile oil. The oil that has been produced so far is mainly mobile; that is, it moves towards the production wells in response to the drainage technique that is in use. Oil which is not forced out of the pores by injection of water or gas is called immobile oil.

Figure 2.7 shows where oil and water are distributed in the pores in the reservoir after part of it has been flooded with water. It shows that the remaining oil is trapped in pores connected to each other with narrow openings, pore throats.

Mobile oil may be recovered with more wells and more and lengthy use of water or gas injection, whereas immobile oil does not become mobile unless it is displaced by something with which it can blend and thus begin to flow. This requires other techniques than those which are currently used, such as injection of CO_2 or chemicals. Injection of hydrocarbon gas that is miscible with oil under given reservoir conditions may also have such an effect. When immobile oil is recovered, more of the originally mobile oil will be recovered simultaneously.

In 2007, the NPD performed a survey of the volumes of remaining oil in 41 fields on the Norwegian shelf to obtain a basis for evaluating the methods on which research and field studies should concentrate so that more of the oil could be produced in the long term. The results were based on data reported by the oil companies and showed that, on average, more than half the remaining oil was mobile (Figure 2.8). They also showed that the ten largest fields contain more immobile than mobile oil.

From resources to reserves – time criticality

Licensees are continually striving to increase the reserves, either through measures to raise the recovery factor or by exploring in areas near existing fields, thus increasing the reserves in the form of additional resources. Both are often time-critical if vacant capacity for processing and transport is to be utilised within the lifetime of the existing infrastructure.

In 2005, the NPD set a target of a gross growth of five billion barrels (800 million Sm³) oil reserves during the

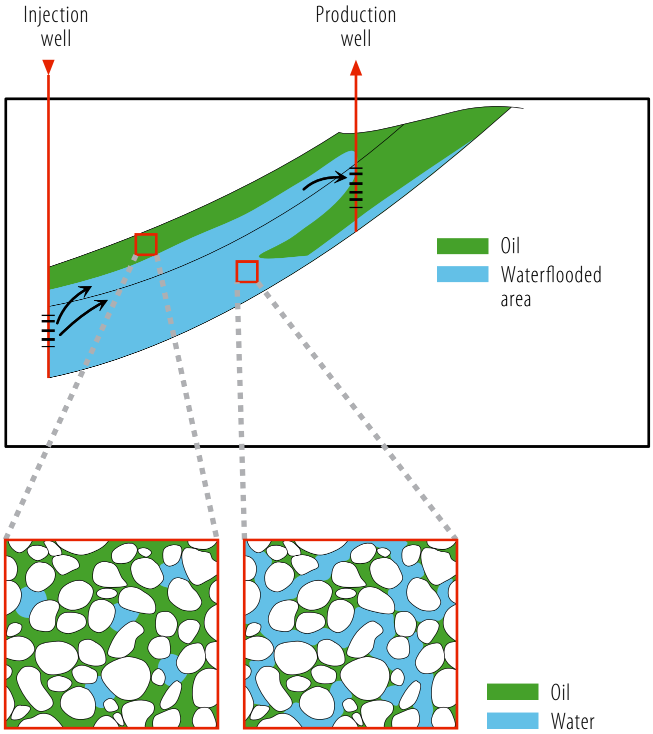


Figure 2.7 Cross-section of a reservoir showing an example of the distribution of liquids (water and oil) at the pore level following flooding with water

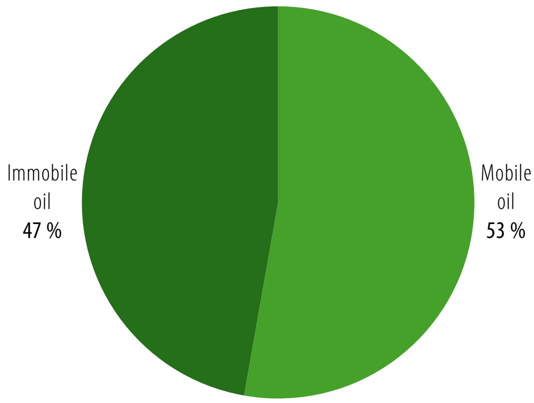


Figure 2.8 Estimated distribution of mobile and immobile oil remaining in 41 fields

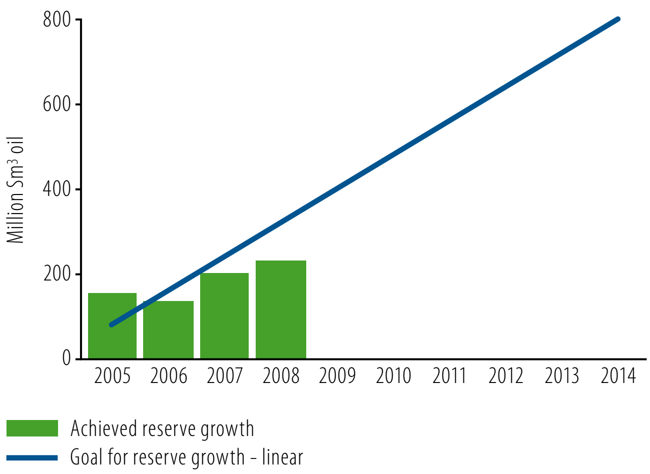


Figure 2.9 Trend in the annual growth of oil reserves compared with the NPD target

period 2005 – 2015. To achieve this target, it is expected that some three-quarters of the increase must come from projects on fields that are already operating. During the first four years of this 10-year period, the oil reserves have grown by 232 million Sm^3, but as reserves only rose by 29 million Sm^3 in 2008, the target may be difficult to attain by 2015 (Figure 2.9).

Even though the price of oil has been very high over the past three years, licensees of fields on the Norwegian continental shelf have not succeeded in taking decisions on major, new projects that will significantly increase the reserves. This is worrying and may have negative consequences for the long-term resource management.

Experience shows that reserves deriving from projects that help to improve recovery in fields are put into production quicker than those deriving from development of new discoveries (Figure 2.10).

Efficient utilisation of existing infrastructure is of great value as production from several fields and give the facilities a longer life. Phasing in additional resources at the right time helps to extend the operation of the large fields, thus enabling more oil and gas to be recovered profitably.

Approximately half of the oil from the Norwegian continental shelf is transported by ship via buoy loading; the rest goes in pipelines from the fields. Oil from quite a number of new fields is transported to large, older fields for export. The production from neighbouring fields is handled and transported via field centres such as Statfjord and Gullfaks. The Åsgard Field is a significant exporting site in the Norwegian Sea. Figure 2.11 shows which fields export via the Gullfaks infrastructure.

Problems may arise when a field centre for different reasons permanently or temporary falls out, for example if its technical or economic lifetime ends. This is relevant in the case of Statfjord, and at the moment export from the Snorre area is being particularly affected. The NPD has been the driving force to find good solutions for the entire area, across production licences with different owners.

Still many possibilities

A concerted effort is needed to counteract the drop in oil production and attend to the long-term management of the oil and gas resources. This could create substantial values for society. Expertise, research and technological advances, along with ability and willingness in the oil companies to enter projects that may increase the reserves in the fields, are important issues and the efforts need to be concentrated.

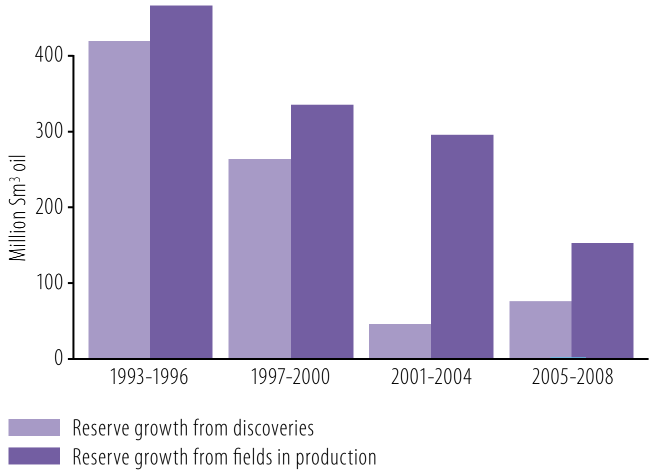


Figure 2.10 Historical growths in reserves

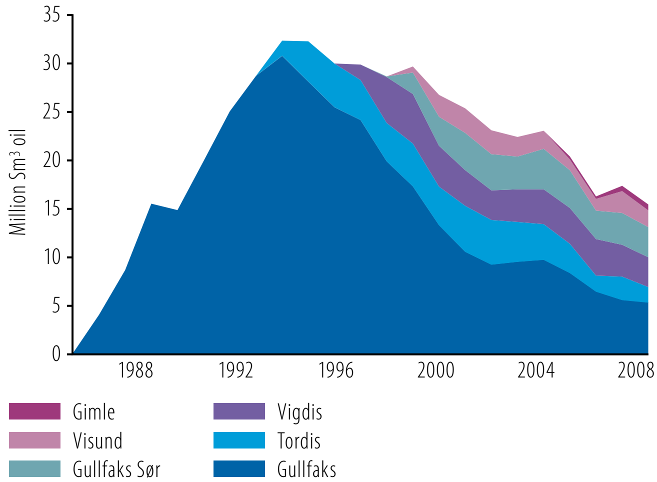


Figure 2.11 Volumes of oil from surrounding fields exported via the Gullfaks Field

Education and recruitment are among the most important challenges for the petroleum industry in the years to come. At the same time, it is vital to retain expertise and experience built up over time, especially staff with knowledge of factors influencing recovery from the reservoirs, reservoir engineers and geologists.

There is a need for more research and technological development within the industry. This is important for continuous proper and environmental sustainable resource management, and will create value for the society in the future. Climate for research (White Paper no. 30 (2008-2009)) underlines the importance of *"ensuring that petroleum research is well looked after and places emphasis on making the sector more environment-friendly"*. The next few years are critical for making important choices that can enable the recovery of significantly more oil and gas. Technologically, this is absolutely possible. The aim is to start using more efficient, lower-cost techniques which have a better environmental profile than those available today.

The remaining oil resources are not as readily accessible as those which have been produced, but they have already been proved, and the infrastructure and many wells are already in place on the fields. The complexity and size of recent discoveries implies that the potential for increasing reserves in producing fields is substantially higher in the short term than an increase from new discoveries. This does not just apply to the Norwegian continental shelf; the situation is the same elsewhere in the world. The recognition of this, along with forecasts of a shortage of petroleum in the years ahead, has resulted in renewed and growing interest for advanced methods of enhancing oil recovery.

Use of gas

All fields on the Norwegian continental shelf contain both gas and oil. This means that recovery of gas and oil cannot be viewed independently of one another. When recovery plans for a field are to be approved, a decision must also be taken on how to use the gas; that is, when is it going to be produced, at what rate and how will this influence the recovery of oil? The objective is to obtain the highest possible total value from fields in a long-term, socio-economic perspective.

Use of gas

Sale – produced gas is processed, and is sold and exported as various gas products which are transported in pipelines or ships.

Injection – gas is used to maintain the reservoir pressure, to displace oil and to stabilise oil columns. The same effect may be obtained by postponing gas production.

Flaring – burning of gas on installations. Flaring is only permitted necessary for safety purposes and when related to extraordinary events.

Power production – gas is used as fuel in gas turbines, engines or boilers offshore and in gasworks onshore.

The Troll Field has a large gas cap which helps to stabilise the thinner oil columns in the field so that they do not move upwards into the cap when pressure is lowered during production. This means that if gas is tapped too early or too rapidly, large quantities of oil may be lost. Over the years, the authorities have worked a lot with these problems together with the licensees and have demanded data to be gathered, reports and decisions to safeguard both the oil and the gas resources, and hence the long term value creation.

In the case of an oilfield, the decision on whether gas or water is to be injected to maintain the pressure and increase the oil production must be made already when spudding takes place. Water injection is employed to support the pressure on many Norwegian oilfields. Gas injection is used on fields like Oseberg, Grane and the oil reservoirs in Åsgard. On Oseberg, the licensees have postponed the start of full gas export several times because continued injection made it profitable to produce substantial additional volumes of oil. It may also be relevant to start or increase gas injection in a field late in the course of production if new information shows that this will improve oil recovery. Decisions on the use of oil and gas are based on both reservoir studies and economic considerations.

The Statfjord Late-phase Project started in earnest in 2008. Water and gas injection were stopped, and all the wells are now used to produce water, gas and oil. Before the field is closed down, the intention is to produce as much as possible of the gas which was earlier injected for pressure support, the gas which is dissolved in the remaining oil and the remaining oil.

The Statfjord Field will be one of the fields with the highest recovery factor on the Norwegian shelf when it closes. An important reason for this is that both water and gas were injected right from the start, and flexibility in relation to optimal drainage strategies was continually employed.

When important decisions on how to use gas are to be taken, the authorities will generally apply a more long-term perspective than the licensees, who will put more emphasis on rapid payback and generally wish to produce the gas for sale as quickly as possible. The decisions are often difficult because uncertainty will always be present and it is impossible to know how much oil can be produced with the various solutions. It is therefore important that all future possibilities are investigated before important decisions are taken.

Historically, gas has been re-injected because there was no export opportunities as the oil was to be produced. Also in such cases, gas injection will generally lead to improved oil recovery. The gas is not lost when it is injected; most of it can be produced again, either for re-injection or for sale. The first gas injection on the Norwegian shelf took place on Ekofisk in February 1975. Gas was injected because the pipeline to Emden was not completed. A similar situation occurred when production began on Statfjord. Absence of export possibilities led to gas injection in one of the two reservoirs on the field. Positive results and experience from Statfjord have subsequently formed a basis for gas injection in many other fields on the shelf.

Gas has been injected in 28 fields on the Norwegian shelf (Figure 2.12), and 561 billion Sm^3 of gas had been injected by the end of 2008. Nearly 60 per cent has been injected in the three fields Oseberg, Statfjord and Åsgard.

Gas will continue to be injected on the Norwegian shelf. It is planned that some 300 billion Sm^3 of gas will be injected up to 2030. In addition, companies are currently working on gas injection projects which may result in another 50 billion Sm³ gas being used for injection.

Efficient gas injection
The NPD has undertaken a review of the fields on the Norwegian continental shelf where gas has been injected, or there are approved plans of gas injection. Gas injection is efficient and has led to the production of approximately 260 million Sm³ more oil than water injection or depressurisation would have given from the same fields. Approved plans for future gas injection will lead to 60-100 million Sm³ extra oil by use of this method.

Cooperation, research and use of fields
Cooperation between the authorities and the licensees, and among different licensees, has been and is important for development on the Norwegian shelf. The authorities have contributed to research and development through good framework conditions and funding. The unique culture for openness and knowledge sharing, experience and technology has been successful for the Norwegian petroleum industry.

In the 1980s and 1990s, both the authorities and the industry wanted much of the research effort to concentrate on developing technologies to increase oil production. For instance, substantial research was performed to develop advanced methods that could improve water and gas injection processes. Laboratory results demonstrated a significant potential that could be exploited if enough effort was put into adapting the methods for use in fields. The problem now is that the technologies too rarely are tested in pilot trials offshore. This needs to be done to reduce the uncertainty regarding the efficiency of the methods under real conditions.

There may be many reasons why companies resist implementing pilot projects, but important ones are that they may prove both expensive and hazardous. In addition, oil companies have limited personnel and physical capacity on individual installations. A pilot trial therefore competes with other projects which maintain at increasing the production in a more reliable and cheaper way, for instance drilling new production wells and thus give better short-term cash flow. If technology is not tested, qualified and taken into use, there is a great risk that appreciable volumes of oil will never be produced and substantial values will be lost. The authorities note that the high oil price in 2007 and 2008 has given the companies an incentive to prioritise on short-term measures rather than paving the way for possible increased production in the long term.

The NPD believes that if companies and owners of production licences cooperate, it may be easier to carry out

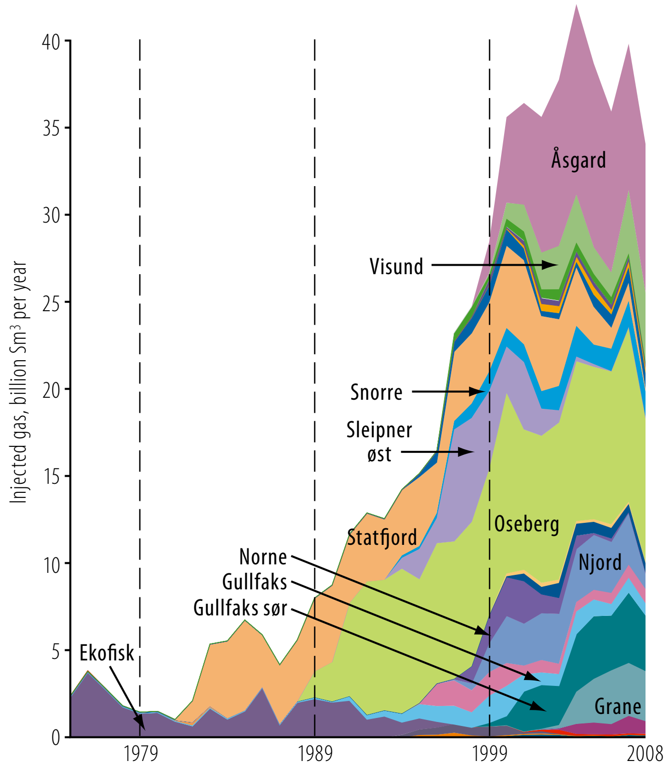


Figure 2.12 Historical gas injection in fields on the Norwegian shelf

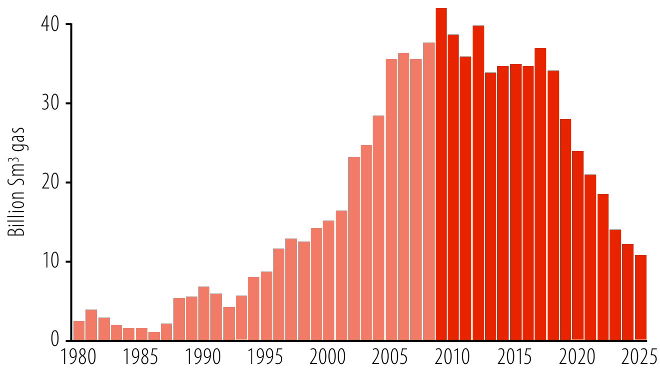


Figure 2.13 Historical gas injection and forecasts for gas injection on the Norwegian shelf (based on approved plans)

Injection of natural gas gives a total of 320 – 360 million Sm³ more oil from the Norwegian shelf.

Important decisions regarding the use of gas:
- The timing and rate of export of injected gas. If the gas is produceed too early and too quickly, large volumes of oil and large values, may be lost.
- New gas injection projects. This may raise oil production and value creation from the Norwegian shelf.

pilot trials of advanced production methods. Afterwards they may cooperate on their possible use on the fields.

In autumn 2008, FORCE (Forum for Reservoir Characterisation, Reservoir Engineering and Exploration), took a new initiative to construct projects around pilot trials and the use of new technology. Through FORCE, the companies are encouraged to set in motion work processes to establish opportunities for projects and cooperation.

FORCE started in 1995, with the oil companies and the NPD as members and the Norwegian Research Council as an observer. As of 1 August 2009, FORCE has 35 members. The secretariat is in the NPD. The prime tasks of the FORCE cooperation are to help to increase the reserves and to prioritise on activities which may increase the exploration success and the production of oil and gas.

FORCE must

- make an active effort to qualify more IOR techniques and use technological advances to help to realise new IOR volumes.
- help to increase exploration efficiency and the quality and credibility of the resource estimates on the Norwegian shelf.

The development of technology and expertise from pilot trials has created enormous values, and the importance of such trials extends far beyond the individual field. For instance, before water injection started on Ekofisk, a pilot trial was carried out to study its effects on the chalk bedrock. Experience gained from Ekofisk was a contributory factor behind the introduction of water injection on Eldfisk and Valhall, too. Similarly, decisive pilot trials on oil production from horizontal wells in thin oil zones were performed before the oil development on the Troll Field could be approved.

Pilot projects to increase production are also given priority by the OG_{21} ("Oil and gas in the 21st century") strategic committee set up by the Ministry of Petroleum and Energy. In OG_{21}, authorities, oil companies, the supply industry, universities and research institutes work together to develop and implement strategies for essential research and development of technology for the petroleum industry. As a contribution towards implementing the strategy from OG_{21}, the Research Council has gathered most of its activities in petroleum related research in the Petromaks programme. This embraces both long-term pure research and applied user-steered research. In its strategic plan (details at www.og21.org), the OG_{21} committee presupposes that the authorities will increase their share of the funding required to develop new technology to 600 million NOK per year. This has so far not taken place.

Injection techniques for enhanced recovery

Advanced injection techniques exist that have not been tested on a large scale on offshore fields, which may help to increase oil production. Their potential has been demonstrated through use on shore, for example in the USA and China. In some fields, such methods have raised the recovery factor by approximately five to ten per cent. Recent research shows that combinations of several techniques can give even better results. Experience gained from onshore fields cannot be directly transferred to offshore fields due to aspects as well density and layout and operational logistics.

Injection of water with a low salt content (low salinity) has proved to have a positive effect on oil production in some fields. The physical and chemical processes that take place in the reservoir are still not fully understood, but research is underway to explain the effect. The method has been tested on shore in Alaska with, in part, good results. It is now being studied on the Norwegian shelf, partly by testing core samples from fields, and some fields have given promising results. The use of this method on a large scale in a Norwegian field will require desalination of seawater in a special plant or transportation of fresh water to the field.

CO_2 injection may also increase oil production. Plans are in hand to store large quantities of CO_2 beneath the North Sea in connection with Carbon Capture and Storage (CCS). Fields on the Norwegian shelf should be able to derive benefit from this to gain access to sufficiently large volumes of CO_2 to use for increased production. Reservoir studies, especially in Gullfaks and Ekofisk, show that CO_2 injection may give substantially more oil production.

The possible use of CO_2 to increase offshore oil production has challenges. For instance, CO_2 dissolved in water is corrosive, and several fields that are potential users of CO_2 injection have old installations, and materials used in their production equipment are not designed for this kind of well flow. Substantial modifications and investments must therefore be made on the installations and in the wells.

Polymers are chemicals consisting of long molecules. The viscosity of the injection water increases if polymers are added, and may therefore more efficiently displace the oil. The production of immobile oil may be possible by use of surfactants or surface active agents, which reduce surface tensions between oil and water or oil and gas. These are examples of chemical-based technologies which may be effective in increasing oil production. Challenges related with adsorption, temperature tolerance and stability are associated with these technologies, which are also costly and thwarted with logistical difficulties. The environmental effects may also be challenging, but efforts are being made to develop "greener", more environment-friendly alternatives where the processes are designed so that the added chemicals stay in the reservoir and none or only minimal amounts reach the production wells.

Other technological development
Technical solutions for oil and gas production are continually being developed. In Norway, this has led to technology for activities in increasingly deeper water and for resources which are difficult to produce because they are small, have poor production properties or are located far from existing infrastructure.

Fields on the Norwegian continental shelf have normally been developed with fixed or floating installations built of steel or concrete. Nowadays, an increasing number of fields are developed using subsea wells. Oil and gas processing takes place on offshore installations or onshore plants that may be located more than 150 km from the subsea field. Subsea installations can be used in areas with water depth up to 1000 to 2000 metres. Ormen Lange and Snøhvit are examples of developments based on such technology.

Development and implementation of more efficient subsea production technology will be a key driver for increased value creation. Technology that makes it possible to transport well flows over large distances between subsea installations and reception plants, while still ensuring a high recovery factor and good reservoir management is one example. Subsea compressors and separation equipment represent important advances, not least for gas production from the Norwegian continental shelf. The work that is taking place to qualify gas compressors to raise the supply ability and the recovery factor on Ormen Lange, Snøhvit and Åsgard are examples of this.

High rig costs make subsea well interventions expensive, and such measures required to improve production are not always given priority in a tight rig market in competition with the drilling of exploration and production wells. Some fields consequently loose reserves. Increased use and development of lighter intervention vessels may help to ease the situation.

A gradual pressure drop in reservoir zones occurs on most fields in production and may lead to major problems for drilling operations. Pressure-balanced and underbalanced drilling has been developed to meet these challenges, and has been used on, for example, Gullfaks and Kvitebjørn with good results. It is expected that more fields can make use of such technology.

Operations where information technology enables the use of real-time data are called Integrated Operations (IO). Personnel on land and on the field get simultaneous access to the same information, such as drilling, well and processing data, or information on parameters for operation and maintenance. This offers possibilities for more rapid and improved decision processes, and hence more efficient operations and better profitability. The technology needed for IO is largely developed. It is important to increase the use of IO by using more integrated operations centres in order to fully utilise the potential for better teamwork and cooperation and value creation.

Long-term resource management in chalk fields
The chalk fields, Ekofisk, Eldfisk, Tor, Valhall and Hod, in the southern part of the North Sea, still have large quantities of oil and gas which can be profitably produced. Ekofisk, Eldfisk and Valhall are three of the six fields on the shelf which will have most oil left in the ground when present-day reserves have been produced (Figure. 2.6)

It takes longer to produce oil and gas from chalk fields than from sandstone fields on the shelf. Chalk is very tight and fine grained, and gives low permeability. Figure 2.14 compares the course of production in the Ekofisk Field (chalk) and the Statfjord Field (sandstone). A larger proportion of the total oil reserves are produced per year from Statfjord than from Ekofisk. Production from chalk fields takes a long time, and this is a key element in the long-term management of the resources in these fields.

Chalk is compressed when the reservoir pressure is reduced as a consequence of the production. Even though this takes place about 3000 metres below the seabed, the effect is displaced up to the seabed, causing it to sink. The seabed has so far sunk about nine metres in the central part of Ekofisk and is expected to continue to sink.

One consequence of the subsidence is that many wells collapse after having produced for some years. New wells need to be drilled continuously to maintain production and injection. Compaction of the reservoir also helps to squeeze out more oil.

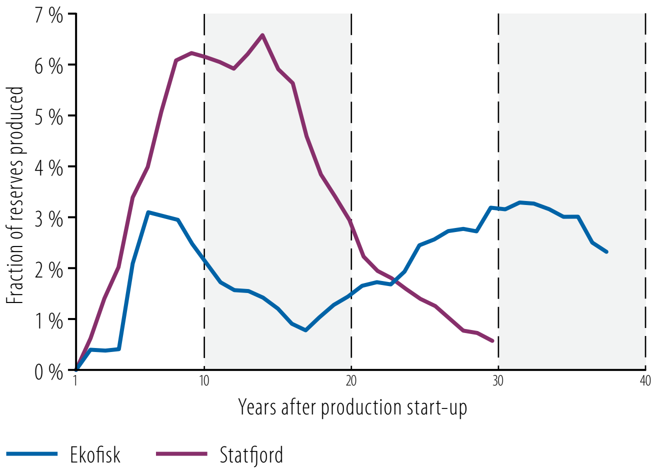


Figure 2.14 Comparison of the proportion of the oil reserves produced per year from Ekofisk and Statfjord

The subsidence has major consequences for the fixed installations on the seabed. Some infrastructure in the area has to be replaced to maintain long-term, reliable and profitable production. This work has begun and must be completed in the coming years. It is also necessary to evaluate whether it is worthwhile to re-open the four chalk fields which have been closed down in the Ekofisk area.

The chalk fields were developed using pressure depletion as the drainage strategy. Water injection started on Ekofisk in 1987 and made it possible to produce more than double the amount of oil originally expected. After water injection proved successful on Ekofisk, it has gradually been employed on Eldfisk and Valhall, too. Long-term management of the considerable resources in the chalk fields requires water injection everywhere on the Ekofisk, Eldfisk and Valhall fields. It must also be considered for several of the smaller Cretaceous fields.

Even though water injection has proved effective on Ekofisk, it has its limitations, too. Large resources continue to be left because a substantial part of the oil is considered to be immobile and water injection will not mobilise it. It has been estimated that slightly more than 50 per cent of the remaining oil on Ekofisk may be produced using water injection. Even though the time perspective for water injection is long and the reserves are further increased by drilling more wells, techniques must be assessed that can contribute to recover some of the immobile oil. Nitrogen injection and air injection are two of the methods considered for Ekofisk, but they have been shelved for the present for economic and technical reasons. CO_2 injection may have a great potential and currently seems to be the most promising method, in addition to water injection.

Energy consumption and the environment

The greatest environmental challenges as the oil and gas production is declining in existing fields are the growing volumes of produced water and the need for energy to compress gas.

Compared with the value of produced petroleum and its energy content, the total consumption of energy on the shelf is small, approximately one per cent of the total content of energy in the oil and gas that is exported.

When oil and gas are produced, they are accompanied by original formation water and injected seawater. Gradually, as the oil is produced, the reservoir fills with water. Water makes up a significant proportion of the total well flow (Figure 2.15). In 2000-2008, the total volume of produced water rose by about 60 per cent, and just over 170 million m^3 of water are now produced each year.

The water that is produced along with oil and gas contains residues of oil, other organic and inorganic components and remains of added chemicals. This water is separated and treated before being either re-injected into the reservoirs or discharged into the sea. Stringent demands are placed on the treatment of produced water; for instance, the maximum oil content permitted was reduced from 40 mg to 30 mg per litre of water in 2007.

The total energy consumption on the shelf is rising slightly, partly because of the growing water production. Treatment of the produced water contributes to a rise in the energy consumption per produced unit of petroleum. In the case of gas production, compression of gas for pressure support and export is the most significant energy-consuming activity. As the natural pressure in the reservoirs sinks, more energy is required to keep up the export volumes.

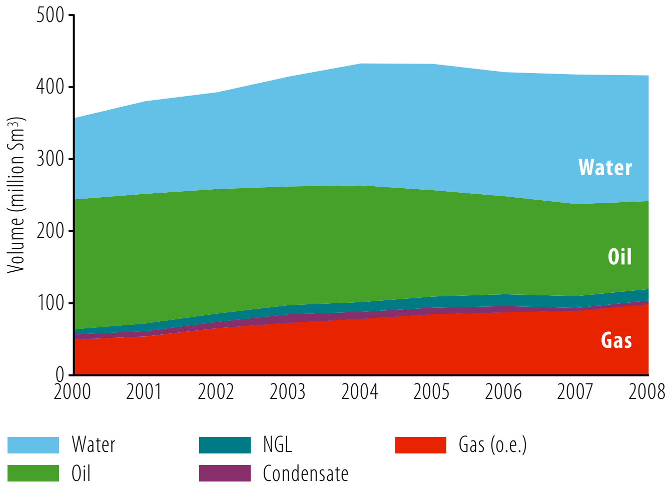


Figure 2.15 Total production of petroleum and water

Subsea separation and injection

The world's first full-scale subsea installation to separate water from the well flow started on the Tordis Field in the North Sea in 2007. The separated water was injected through a separate well into a water-filled formation below the field. A corresponding pilot project had previously been successfully carried out on the Troll Field.

The subsea separator on the Tordis Field was closed down in May 2008 when a leakage to the seabed from the injection well was discovered. The NPD's evaluation of the leakage has shown that the sandy formation that was planned for injection was not present above the Tordis Field. However, the separation plant functioned as intended.

The technology marks a breakthrough for a new generation of subsea solutions in the oil industry.

Several technologies exist to reduce undesirable water production and circulation while simultaneously increasing the oil and gas production, and these have been tested on the Norwegian continental shelf. Subsea separation and reinjection, for instance, reduce the large volumes of produced water that otherwise would have to be transported to the installation for treatment. Mechanical plugs and cementing water-bearing zones have been used for a long time. A less thoroughly tested technology is to add chemical systems to the injection water in order to block the zones in which the water flows. The water is forced to go to other parts of the reservoir instead of circulating in the same parts, thus enabling more oil to be displaced by the injected water.

This technology has been tested on fields on the Norwegian continental shelf; for instance, a sodium silicate system was tested on Gullfaks in the 1990s. This "glass" system does not contain toxic components and has no negative environmental impact, unlike other chemical systems which may have such repercussions if they are re-produced.

In 1991, a tax was introduced on CO_2 emissions from the petroleum industry on the Norwegian continental shelf which resulted in a reduction of emissions per produced unit for a period. However, in recent years, this trend has reversed because a large part of the production comes from fields in late production phase, where increasing volumes of water or gas may be circulating (Figure. 2.16). The large increase from 2006 to 2007 is mainly a result of increased flaring from the Snøhvit plant in connection with start-up problems on the field. The CO_2 emissions per produced unit vary from one field to another and during the lifetime of a field. The level depends partly on factors in the reservoir, development and production strategies, technological solutions and the transport distance to the market.

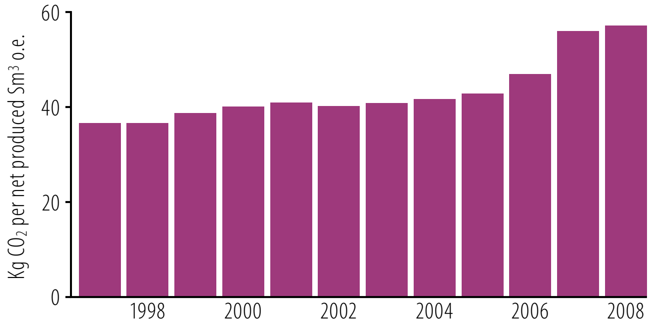
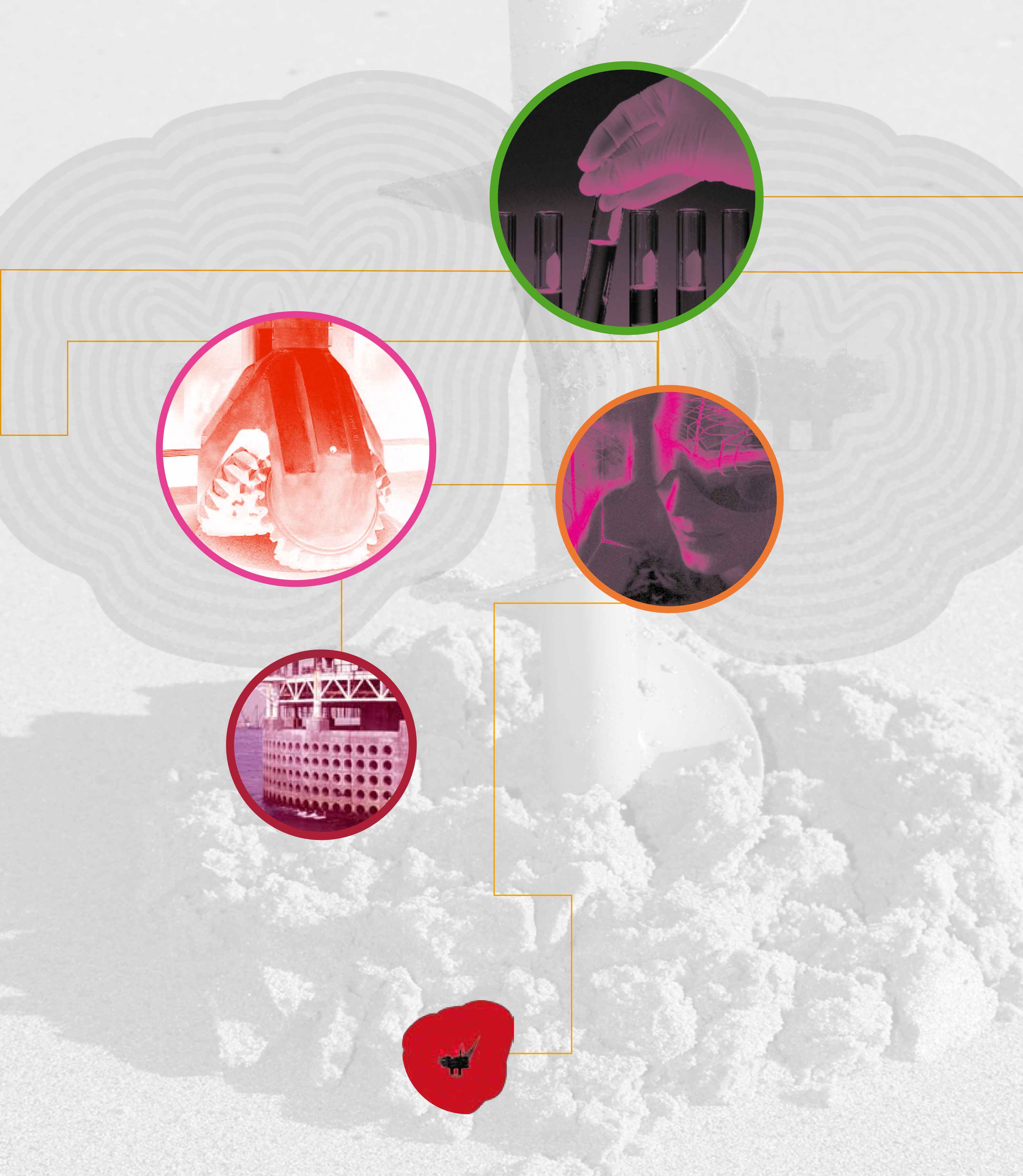


Figure 2.16 Emissions of taxable CO_2 per produced unit

CO_2 emissions from Norwegian petroleum activity are low compared to the rest of the world. Average greenhouse gas emissions in the world's total petroleum activity in 2006 were approximately 125 kg CO_2 per produced Sm^3 o.e. , whereas in Norway 47 kg and 56 kg of CO_2 were emitted per produced Sm^3 o.e. in 2006 and 2008, respectively.

The CO_2 emissions from the energy production can be reduced by using more heat energy and power from shore. This can result in the CO_2 emissions increasing less over time than the increasing need for energy should call for. In 2008, 10 to 15 per cent of the energy requirements of the petroleum sector were met by electric power from the grid. This proportion will rise when Gjøa, Goliat and Valhall begin to use power from shore. The expected energy requirements for the already electrified Troll A and Ormen Lange fields will, over time, also help to ensure that a larger part of the energy production for the Norwegian petroleum sector takes place without direct emissions of CO_2.

3 EXPLORATION



Access to acreage

The Norwegian continental shelf, extending from the baseline to the limit recommended by the UN Commission on the Limits of the Continental Shelf, amounts to 2.2 million km^2. About half of this acreage has bedrock in which petroleum may be found, and half of that has been opened for petroleum activity. The areas that have not been opened are parts of the Barents Sea, coastal waters in the Norwegian Sea, the area around Jan Mayen and most of the Skagerrak. Work takes place for many years before the Norwegian Parliament decides which areas are to be opened. The authorities gather seismic data and undertake shallow drilling, mapping and assessment of potential areas, mainly to select the most prospective ones, which can then be made available to the industry. Acreage which it is planned to open must undergo environmental impact assessment.

Acquiring seismic data

Seismic data are acquired to map the geological conditions under the seabed and are fundamental for investigating the possibility of finding petroleum. Of the many geophysical techniques (such as gravimetry, magnetometry and electromagnetism), only seismic is currently capable of supplying sufficiently detailed information to form a basis for continuing with exploration drilling. Electromagnetic survey (EM) measures the electrical resistance or resistivity and is a comparatively new geophysical technique used as a supplement to seismic. Oil and gas have high resistivity. In a structure that has already been mapped using seismic, EM may give supplementary information on the structure that contains oil and gas.

It is also most important to gather seismic data from fields that are already being operated, both to find out where the remaining oil and gas are located and to drill with greater precision. Seismic acquisition (4D seismic) may therefore be undertaken repeatedly in the same area and above the same oilfield. To avoid gathering duplicate data, seismic data are released in accordance with specific rules.

Seismic data can be acquired subject to either an exploration or a production licence, and the licensee must give the Norwegian Petroleum Directorate (NPD), the Directorate of Fisheries, the Norwegian Institute of Marine Research and the Norwegian Ministry of Defence prior notification of the work. These bodies report back with specific information on fishing and other relevant matters prior to each acquisition. The NPD coordinates these responses and provides the licensee with advice on the activity in question. The requirements that have to be met chiefly concern fishing and the advisable distance to be maintained from fishing vessels. A fisheries expert must also be on the seismic vessel to help to prevent conflicts from arising.

The authorities started acquiring seismic data as early as 1969. The NPD has had this task since 1972 and has

§3.1. Opening of areas

Prior to the opening of new areas with a view to granting production licences, an evaluation shall be undertaken of the various interests involved in the relevant area. In this evaluation, an assessment shall be made of the impact of the petroleum activities on trade, industry and the environment, and of possible risks of pollution, as well as the economic and social effects that may be a result of the petroleum activities.

The opening of new areas is a matter which shall be put before local public authorities, central trade and industry associations and other organisations which may be presumed to have a particular interest in the matter.

Furthermore it shall be made known through public announcement which areas are planned to be opened for petroleum activities, and the nature and extent of the activities in question. Interested parties shall be given a period of time of no less than 3 months to present their views. The Ministry decides on the administrative procedure to be followed in each individual case.

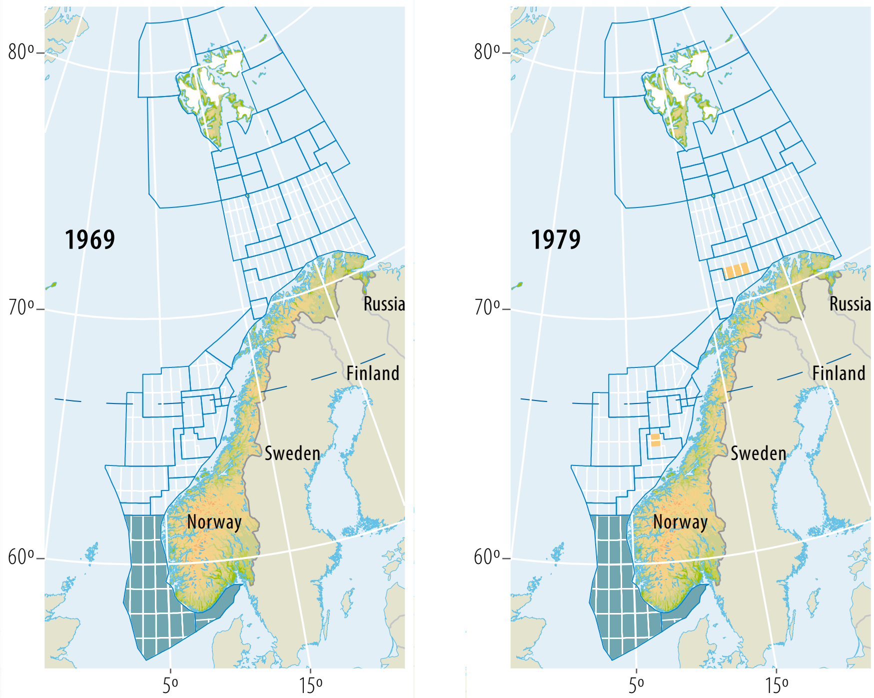


Figure 3.1 Stepwise opening of the Norwegian shelf in ten-year sequences since 1969. Red areas: restriction in already opened areas

gathered data in areas where petroleum activity is still not permitted, such as around Jan Mayen, in the northern Barents Sea and off Lofoten and Vesterålen. Such work stopped off Lofoten and Vesterålen in 1989, but was resumed in 2007 at the request of the Norwegian Parliament and Government.

The petroleum activity and the fishing industry have existed side by side for many years. The high activity in the petroleum industry in recent years has also led to more seismic data being acquired. Because it was felt that the level of conflict between the fishing industry and seismic firms was increasing, a working group of representatives from the Directorate of Fisheries and the NPD was set up in autumn 2007. It submitted its Final Report on 1 April 2008. Its recommendations led to a number of measures being introduced, including the following:

1. The Norwegian Pollution Control Authority, the Directorate of Fisheries and the NPD will cooperate to investigate the frightening and damaging effects of seismic audio signals and to propose measures to curb them
2. A new, interactive system for notifying about seismic investigations
3. A course for fishery experts on seismic vessels
4. Specification of areas to be investigated, including the turning zone, and notification of any changes
5. Coordination of investigations

Other measures are also being considered, including a requirement that seismic vessels carry satellite transmitters so that they can be tracked.

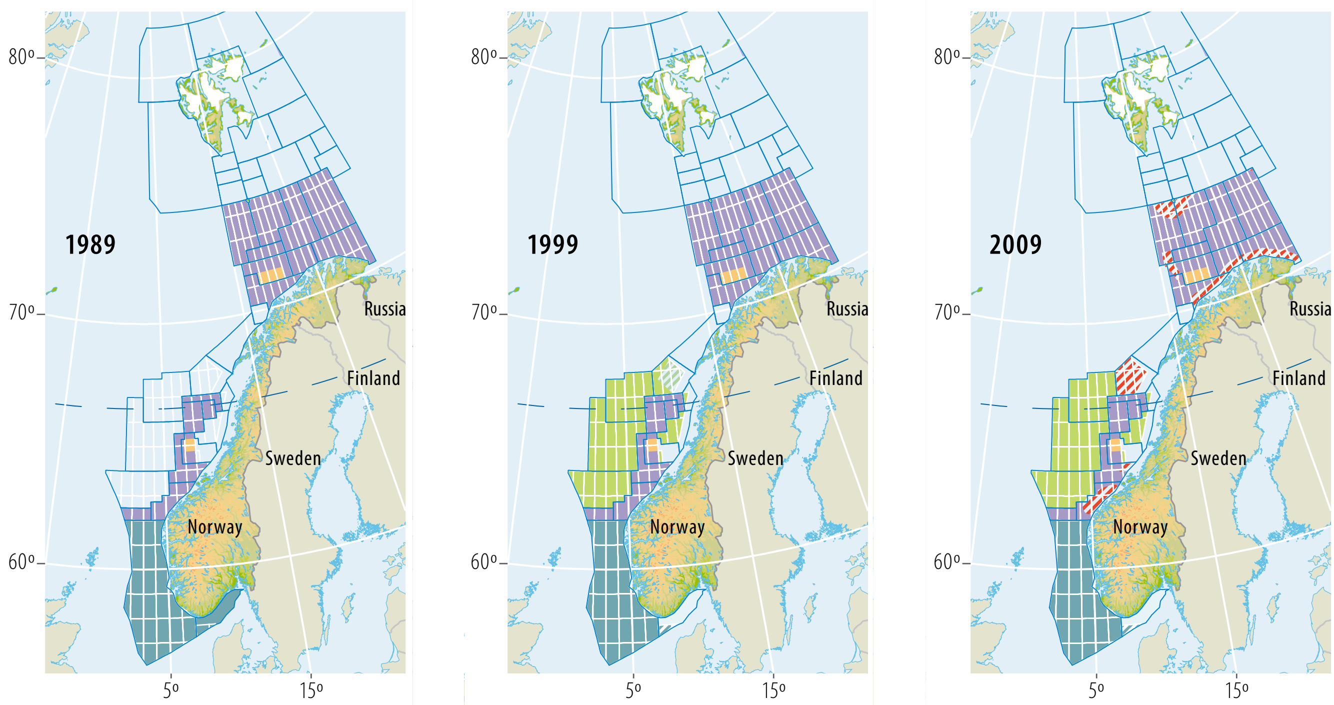
Environmental impact assessments

An environmental impact assessment evaluates the commercial and environmental impacts of potential petroleum activity, including risks of pollution and financial and social effects. The 1985 Petroleum Act made such assessments mandatory and §3.1 deals with the opening of new areas and environmental impact assessments.

Sequential exploration

The Norwegian continental shelf has been opened for petroleum activity in stages since 1965 (sequential exploration). Results and experience gained from one area are thus utilised to open new areas. Knowledge and experience from the North Sea were put to use when the first blocks on Haltenbanken and Tromsøflaket were announced in June 1979. Information that is already available is always used for future exploration. This avoids drilling unnecessary wells.

Figure 3.1 illustrates the sequential opening of the Norwegian shelf from the status in 1969, when Ekofisk was discovered, and each tenth year after that. Only the North Sea was open for petroleum activity from 1969 to 1979. Areas north of 62°N were opened from 1979 to



1989. The first allocation in the Barents Sea took place in 1980 and the first discovery, 7120/8-1 Askeladd, was made there in 1981 and is included in the Snøhvit development.

Deepwater areas in the Norwegian Sea and the western part of Nordland VI were opened for petroleum activity in 1994. Permission has been given to drill a limited number of wildcat wells in part of Nordland VI. Two production licences were awarded there in 1996, and 3D seismic was acquired and a well was drilled, which was dry. The Skagerrak was closed in this period. In 2001, the Government temporarily closed all of Nordland VI and the southern part of the Barents Sea, but, with some exceptions, the latter was re-opened in 2003.

No new areas have been opened for petroleum activity since 1994 (Figures 3.2 and 3.3). The White Paper no 8 (2005-2006) concerning the overall management of the marine environment in the Barents Sea and the waters off Lofoten which was published in 2006, has put limitations on areas that were opened earlier. It designated certain areas as especially valuable and vulnerable in environmental and resource contexts (Figure 3.4). Any petroleum activity there must be debated again in Parliament in 2010, when the management plan will be reviewed.

The period up to 2010 will be used to close knowledge gaps by evaluating new information and new data that have become available. The Government has decided that the NPD must undertake geological mapping in Nordland VII and Troms II. The NPD has gathered seismic data during the summers of 2007, 2008 and 2009 (Figure 3.5).

The Ministry of the Environment published a White Paper on the overall management of the Norwegian Sea in May 2009 (White Paper no 37 (2008-2009)). The framework for the petroleum activity was approved by the Parliament in June 2009 and is shown in figure 3.6.

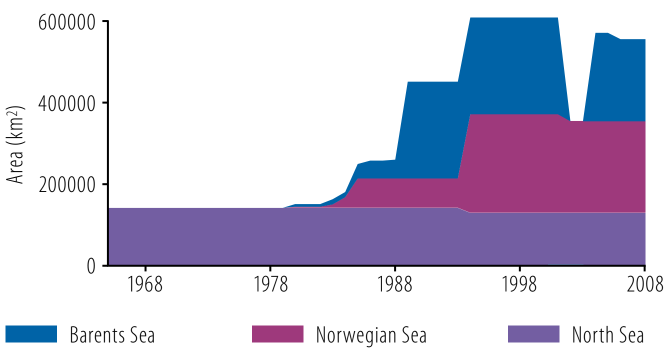


Figure 3.2 Sequential opening of acreage for petroleum activity in 1965-2008

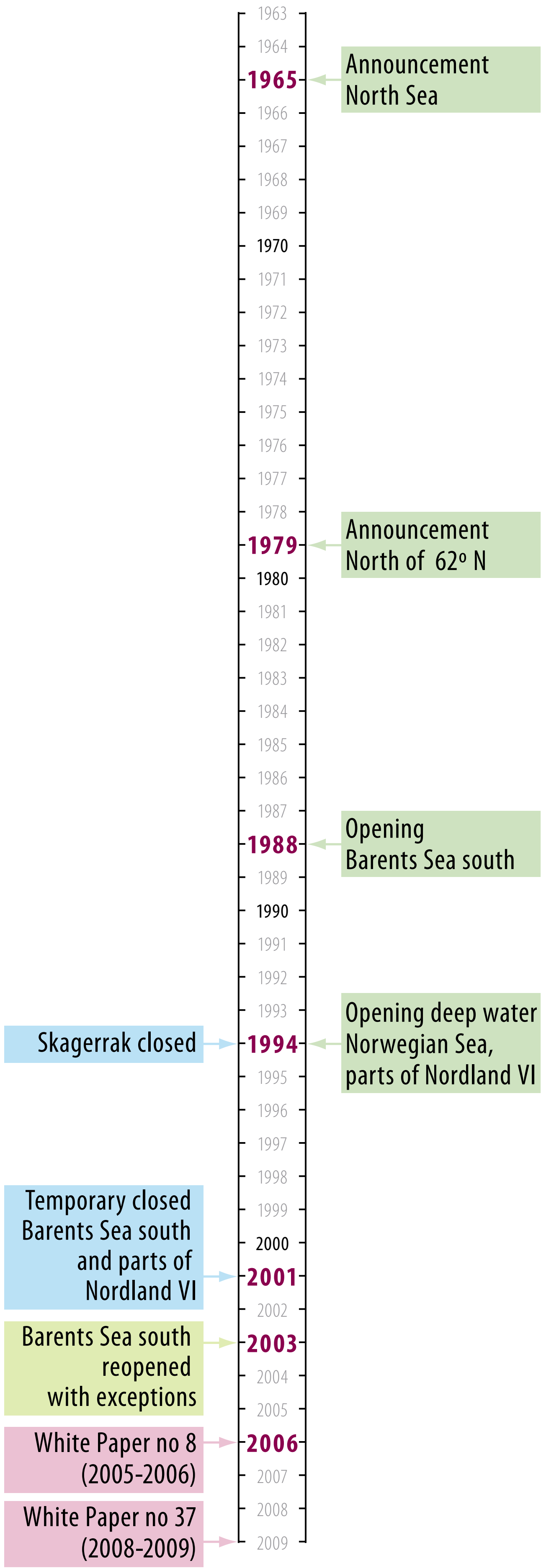
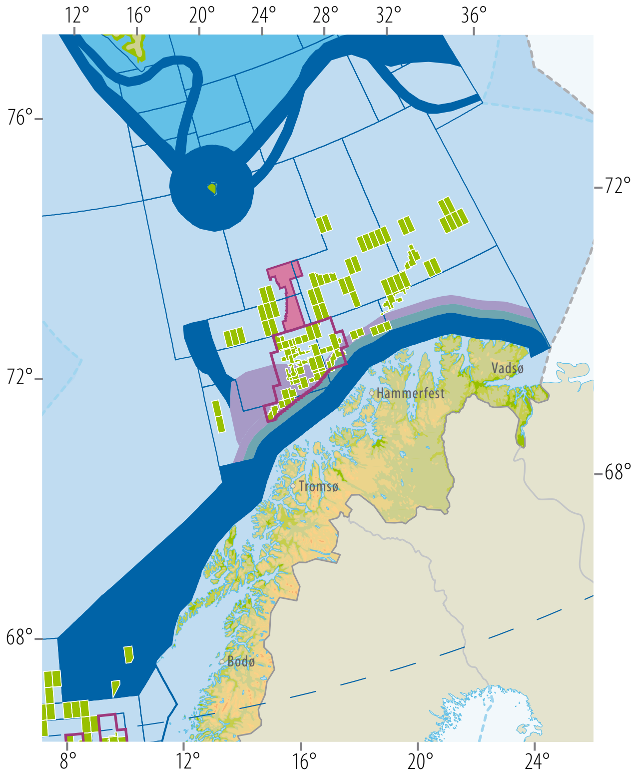


Figure 3.3 Timeline from 1965 to 2008 for events associated with what is available for petroleum activity at any one time



Area where no petroleum activity will be permitted during the term of the 2005-2009 Parliament.

Area where no new petroleum activity will be permitted

Area where no exploration drilling in oil-bearing formations will be permitted 1 March - 31 August

Variable extent of the marginal ice zone

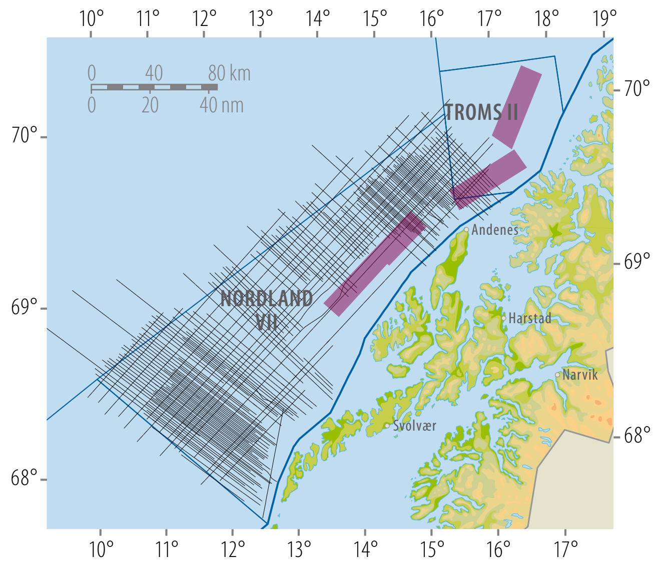
Baseline

APA box

Production licenses

Seismic area

Figure 3.4 Limits for petroleum activity in the Barents Sea and off Lofoten

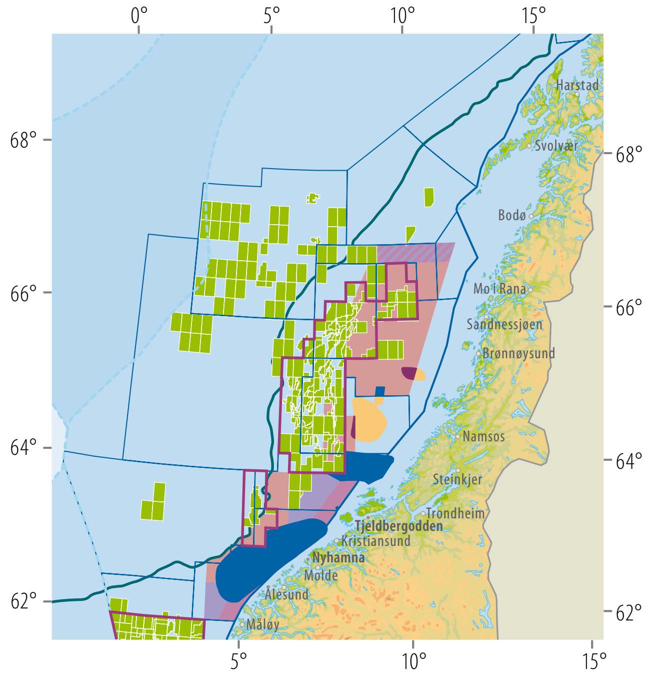


2D seismic acquired by the NPD in 2007 and 2008

3D seismic acquired by the NPD in 2008 and 2009

Baseline

Figure 3.5 Acquisition of seismic data in Nordland VII and Troms II



No concession rounds to be announced before management plan update (2014 at latest)

No exploration drilling in oil-bearing formations in spawning, breeding and moulting seasons (1 April - 31 August)

No exploration drilling in oil-bearing formations in breeding and moulting seasons (1 April - 31 August)

No exploration drilling in oil-bearing formations when fish eggs and larvae are present (1 April - 15 June)

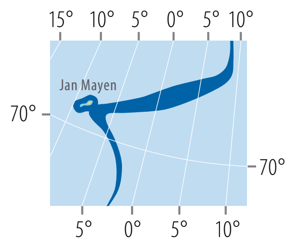
No exploration drilling in oil-bearing formations in spawning season (1 February - 1 June). No seismic surveys in spawning migration and spawning season (1 January - 1 May)

500 metre depth contour. No seismic surveys in the exploration phase landward of this line 1 January - 1 April. Does not apply to site surveys

APA box

Production licences

Baseline



No petroleum activities before the management plan is updated (2014 at latest). Does not preclude the use of Jan Mayen in connection with petroleum activities outside this zone.

Figure 3.6 Limits for petroleum activity in the Norwegian Sea. (Source: White Paper no 37 (2008-2009))

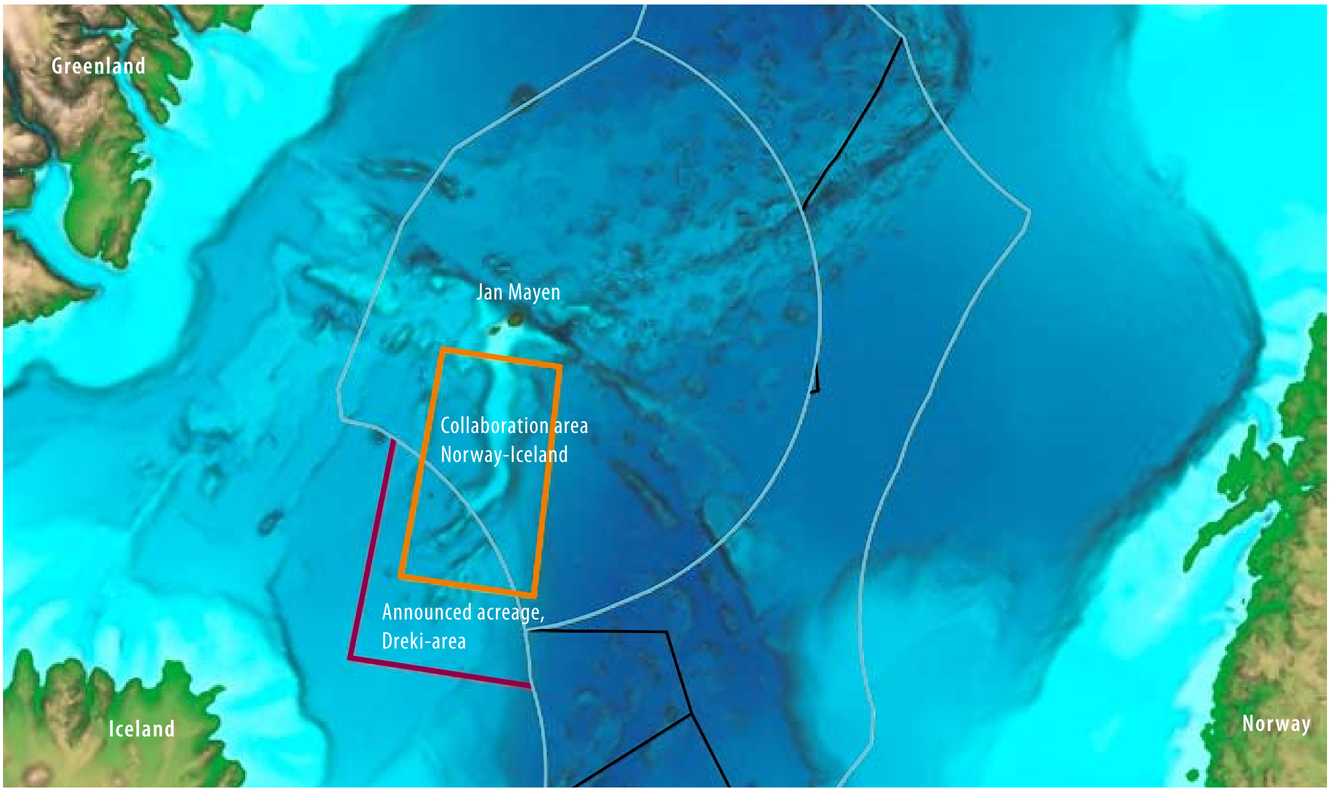


Figure 3.7 The first licensing round in Iceland

The continental shelf around Jan Mayen (Figure 3.7) is relevant for Norway after Iceland announced its first licensing round in January 2009.

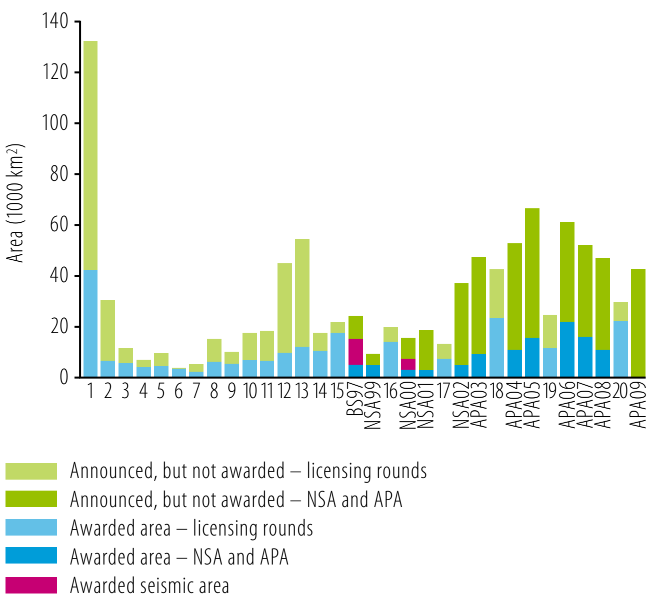


Figure 3.8 Announced and awarded acreage on the Norwegian continental shelf

Awards of new licenses

Within the areas that have been opened for petroleum activity, companies are mainly able to apply for production licences in licensing rounds and through the scheme for Awards in Predefined Areas (APA). They can also obtain acreage by purchasing or exchanging shares in production licences.

The whole of the North Sea was announced in the first licensing round, and in acreage this was the largest round that has been announced. The next largest ordinary licensing round was the 13th, which is shown in figure 3.8.

Licensing rounds

Prior to the announcement of a new licensing round, companies are invited to nominate blocks which they think should be included in the round. Based on this, the NPD makes recommendations to the Ministry of Petroleum and Energy regarding which blocks should be announced. This recommendation is based on the following criteria:

- the nominations made by the companies
- the NPD's geological evaluation of the areas
- avoiding areas with great geological dependence (sequential exploration)
- including areas with a potential for interesting exploration of new and/or different geological plays

Jan Mayen and Iceland

The Jan Mayen Ridge is a microcontinent that extends from the island of Jan Mayen to the southern point of Iceland (Fig. 3.7). Two episodes of seafloor spreading were important for its geological development:

1. A great deal of volcanic activity took place 55 million years ago when the North Atlantic was developing in the Early Eocene, and a vast area was covered by basalt (lava).
2. The microcontinent of Jan Mayen was part of East Greenland until 25 million years ago (Late Oligocene) when it broke away and reached its present position between Greenland and Norway.

The petroleum potential of Jan Mayen is unknown, but all the essential geological prerequisites for the formation of petroleum may be present, just as they are in East Greenland and the Møre Basin. Sediments which may contain petroleum may have been deposited before the North Atlantic opened, that is, prior to the formation of the basalt (in the Mesozoic to Early Eocene). Younger sediments deposited above the basalt may also contain petroleum.

The NPD acquired about 5800 km of 2D seismic from the Jan Mayen area in 1979, 1985 and 1988, and these data have been made openly available in four packages. Seismic data were also gathered commercially on the Icelandic part of the ridge in 2001 and 2008.

In 1981, Norway and Iceland entered into an agreement concerning the continental shelf in the area between Iceland and Jan Mayen, and an area for cooperation was established on both sides of the partition line. The two nations drew up an agreement in 2008 to share the petroleum resources and jointly participate in production licences in this area. This agreement was signed in conjunction with the announcement by Iceland of its first licensing round on 22 January 2009. The acreage that was announced covers 42 700 km^2 and is part of what Iceland has named the Dreki area. 12 720 km^2 of this area are within the area which the two nations agreed to cooperate on, and a clause in the agreement enables Norway to have 25 per cent of the shares in production licences there. When the deadline for applications expired on 15 May 2009, three companies, Sagex Petroleum, Lindir Exploration and Aker Exploration, had applied for production licences. In July it was announced that Aker has withdrawn its application. Allocation is planned to take place in the last quarter of 2009.

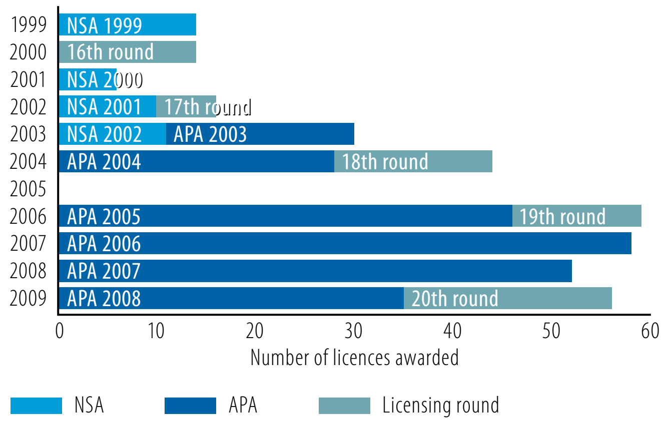


Figure 3.9 Annual awards since 1999

The Ministry of the Environment and the Ministry of Fisheries also submit their evaluations of the proposed blocks to the Ministry of Petroleum and Energy, which decides which blocks will be announced on the basis of all the contributions.

The present government aims at a more transparent petroleum policy. In line with this, prior to the 20th licensing round, the Ministry of Petroleum and Energy published a map showing all the blocks which companies had nominated. 46 companies nominated a total of 300 blocks. The NPD recommended that 104 of these could be announced, and this list was submitted to 148 bodies for public comment. When the deadline expired, 55 comments were received. In addition, for the first time, evaluations of fishery and environmental issues made by relevant government agencies were published. The result of this process was that 79 blocks or parts of blocks were announced. The companies applied for 72 of these, and 63 blocks or parts of blocks were allocated, divided among 21 production licences.

Awards in Predefined Areas

The purpose behind the Awards in Predefined Areas (APA) is to prove resources close to planned and existing infrastructures to be able to produce them efficiently before the infrastructures cease to be used. In addition, predictability in the awarding of acreage is important. The APA scheme also simplifies the procedure for new companies wishing to take part in activities on the Norwegian shelf. This scheme replaced the scheme North Sea Awards (NSA).

The acreage that was announced increased up to APA 2005. However, there is now an obvious declining trend from APA 2005 up to and including APA 2009 for available acreage. The same trend is seen for awarded acreage after a peak in APA 2006 (Figure 3.8).

Figure 3.9 shows the number of awards per year since 1999. The largest number was in 2006. 660 production licences have been awarded on the Norwegian shelf, and 240 of these have been through the APA scheme. 38 wells have been drilled and seven discoveries made in licences awarded under the scheme.

The Ministry of Petroleum and Energy has started to evaluate the APA scheme. Various parties were invited to comment. Many of them, including the NPD, have responded and the Ministry is now considering their comments.

The APA scheme has, according to the NPD, led to:

- increased and more rapid exploration of mature areas
- more new companies contribute to the exploration the Norwegian shelf
- the industry is assured regular access to prospective acreage

- more rapid relinquishment of acreage to the authorities
- more predictability through more regular awards

New companies have received a significant proportion of the awards under the APA scheme (Table 3.1). Figure 3.10 shows the number of shares awarded to various kinds of companies.

Efficient exploration of acreage is important to ensure access to resources. To avoid companies retaining acreage that is not actively worked on, the APA scheme is designed to make companies explore areas quickly. In most cases, they have only two years to decide whether they wish to drill a well. If they do not wish to drill, they must relinquish all the acreage. This is termed a drill or drop commitment. Drill or drop has also been introduced in the ordinary licensing rounds. Experience so far shows that between 45 and 50 per cent of the awards are relinquished in their entirety when the decision to drill or drop is taken (Figure 3.11).

Exploration in frontier areas

Wildcat wells drilled in areas lacking infrastructure have not come up to the expectations of the authorities and the companies in recent years, particularly those in deep water (deeper than 600 metres) in the Norwegian Sea, which was opened for exploration in 1994.

23 wildcat wells have been drilled in deep water in the Norwegian Sea. Table 3.2 and figure 3.12 show their status and

New companies	4Sea Energy, Aker Exploration, Bayerngas Norge, BG Norge, Bridge Energy, Centrica, Concedo, Dana, Det norske, Discover, DONG, Edison, Endeavour, Faroe, GDF SUEZ, Genesis, Lotos, Lundin, Mærsk, Marathon, Nexen, Noreco, North Energy, PGNIG, Premier, Repsol, Rocksource, E.ON Ruhrgas, Sagex, Skagen 44, Skeie, Spring, Talisman, VNG, Wintershall
Small and medium-sized companies	AEDC, Hess Norge, Idemitsu, OMV, Petro-Canada, RWE-DEA, Svenska Petroleum
Large companies	BP, Chevron, ConocoPhillips, Eni, ExxonMobil, Shell, Total
Large, Norwegian companies	Petoro, StatoilHydro

Table 3.1 Company categories

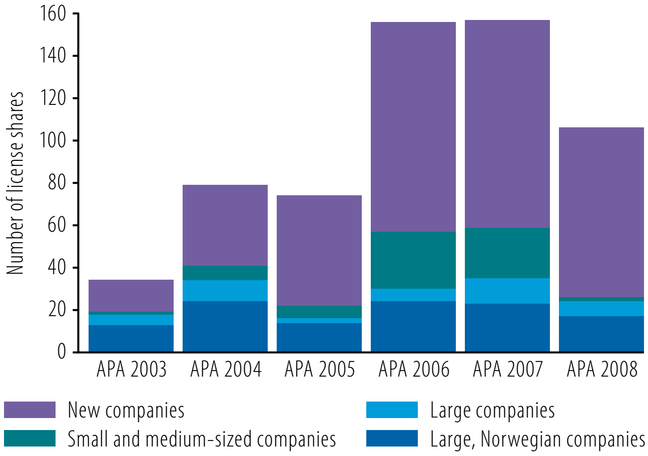


Figure 3.10 Shares to different kinds of companies in APA 2003 to APA 2008

Round/year	PL / operator	Well	Well completal	Prospect	Status	Discovery
15/1996	209 (Hydro)	6305/5-1	1997			Ormen Lange
	209 (Hydro)	6305/1-1	1998			
	210 (Shell)	6505/10-1	1998	Helland Hansen	Relinguished	
	215 (Saga)	6704/12-1	1999	Gjallar	Relinguished	
	217 (Statoil)	6706/11-1	1998	Vema	Relinguished	
	218 (BP)	6707/10-1	1997		Operator: StatoilHydro	"Luva"
	218 (StatoilHydro)	6706/12-1	2008			"Snefrid Sør"
	218 (StatoilHydro)	6707/10-2 S	2008			"Haklang"
	218 (StatoilHydro)	6707/10-2 A	2008			"Haklang"
16/2000	251 (Statoil)	6302/6-1	2005		Relinguished	"Tulipan"
	253 (Hydro)	6403/10-1	2002	Solsikke	Relinguished	
	254 (BP)	6404/11-1	2002	Havsule	Relinguished	
17/2002	264 (Esso)	6706/6-1	2003		Operator: Eni	"Hvitveis"
	281 (Statoil)	6405/7-1	2003		Relinguished	Ellida
	281 (Statoil)	6405/10-1	2007		Relinguished	"Midnattsol"
	283 (Hydro)	6605/8-1	2005		Partly relinguished	"Stetind"
	283 (StatoilHydro)	6605/8-2	2008	Stetind sør	Partly relinguished	
18/2004	322 (Statoil)	6403/6-1	2006	Edvarda	Relinguished	
	324 (Eni)	6504/5-1	2007	Gemini	Relinguished	
	327 B (StatoilHydro)	6705/10-1	2009			"Asterix"
	326 (Shell)	6603/12-1	2009			"Gro"
	328 (StatoilHydro)	6605/1-1	2009	Obelix		
	329 (Eni)	6607/2-1	2007	Cygnus		

Table 3.2 Wildcat wells in deep water in the Norwegian Sea

location. The first wells were drilled in prospects thought to contain large resources. This is a typical strategy for exploration in new areas. Several wells gave discoveries, but they were significantly smaller than expected prior to the drilling.

The first deepwater blocks in the Norwegian Sea were awarded in the 15th licensing round in 1996. The production licences where Ormen Lange was found were awarded in this round. Ormen Lange is so far the only discovery in deep water that is in production. Production began in 2007, ten years after the field was discovered.

2009 is an exciting year for exploration in deep water in the Norwegian Sea. As of 1 August 2009, three wildcat wells have been completed. Well 6605/1-1 in production licence 328 was dry, but gas was found in 6705/10-1 in production licence 327 B. The operator, StatoilHydro, is considering developing the discovery along with neighbouring finds. This may help to pave the way for gas infrastructure in deep water. In June 2009 the operator Shell completed the well 6603/12-1 which discovered gas in the "Gro" prospect in production licence 326. The uncertainty related to the size of the discovery is considerable. Further appraisal must be performed to clarify the resource potential.

Eight production licences were awarded in deep water in the Norwegian Sea in the 20th licensing round. Considerable volcanic activity has affected the bedrock in the area near the two westernmost licences, limiting the seismic imaging of the geology beneath the lava and making it particularly difficult to map the prospectivity.

In recent years, wells have been drilled in areas without infrastructure in the Barents Sea and the North Sea. Many have been defined as dry. Oil was proven in well 7222/6-1 S ("Obesum") in 2008, but the appraisal well did not give the expected result. Wells 9/4-5 Kogge and 11/5-1 Loshavn in the southeastern part of the North Sea were dry. A gas discovery was made in well 35/2-1 ("Peon") in the northern part of the North Sea. Plans are now in hand for its possible development, and an appraisal well was drilled in 2009.

Exploration history and statistics

The large fields, Sleipner, Statfjord and Gullfaks were discovered during the first ten years after Ekofisk was proven, and all four are still in production. Most of the other large fields on the shelf were found between 1979 and 1984 (Figure 3.13). The curve for the growth in resources shows that, apart from Ormen Lange, there has been little growth in the past 25 years.

The number of wildcat wells drilled per year has varied a great deal since 1969 (Figure 3.13). In 2008, 36 wildcat wells were drilled on the Norwegian shelf, the highest number in a single year. Altogether 1242 wildcat and appraisal wells have been drilled on the Norwegian shelf.

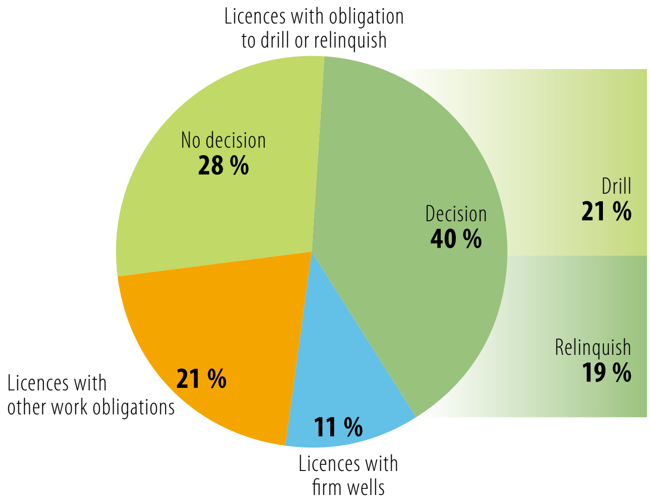


Figure 3.11 Types of work programme in licences awarded from 1999 to 2008 (awards made in APA 2008 and the 20th licensing round are not included

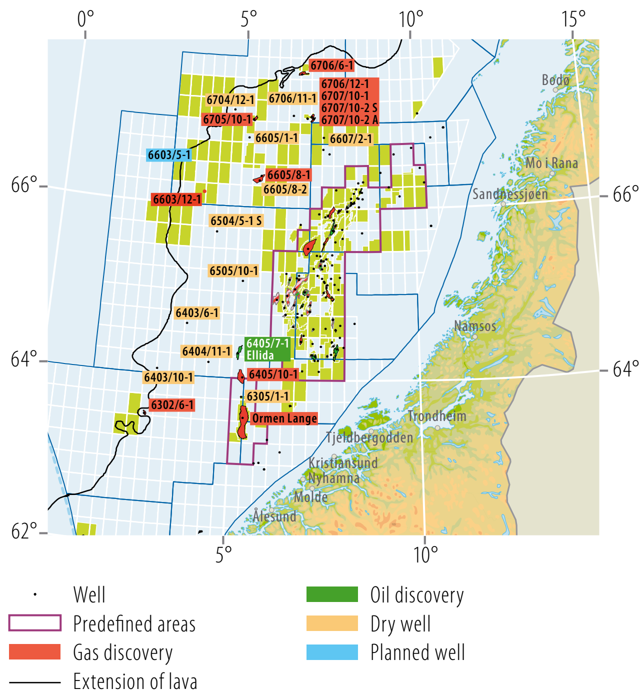


Figure 3.12 Wells and discoveries in deep water in the Norwegian

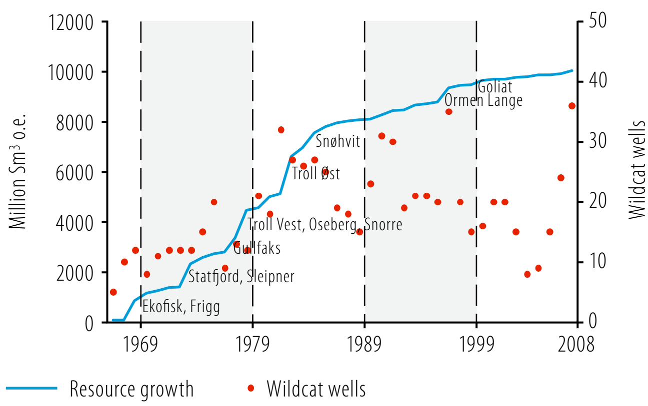


Figure 3.13 Growth in resources and number of wildcat wells drilled from 1969 to 2008

The annual growth in resources exceeded the annual production in the first two ten-year periods (Figure 3.14). It was particularly high in 1983 when Troll Øst was discovered. 1988 was the first year when production exceeded the growth in resources. Apart from some years in the early-1990s and in 1997, annual production has exceeded the annual growth in resources.

Following the good ten-year periods from 1969 to 1988, there has been a large reduction in the proven resources during the next two ten-year periods (Figure 3.15). Moreover, the proportion of small discoveries (less than five million Sm³ o.e.) has increased. Such discoveries made up six per cent of the proven resources in 1989-1998, whereas they have comprised 13 per cent in the last ten-year period.

On average, around 10 years pass from a discovery is made to the onset of its production. When the petroleum production from the fields is related to the year they were discovered, it transpires that it has so far largely taken place in fields discovered between 1969 and 1989 (Figure 3.16). This is because less oil and gas have been found in the last 20 years. Ormen Lange is the largest discovery since 1989.

The low growth in resources during recent ten-year periods contributes little to forecasted production. Considerable uncertainty surrounds the forecasts, particularly as regards non-proven (undiscovered) resources, where the NPD assumes that 30 exploration wells will be drilled each year, resulting in discoveries of varying size, and the average time lapse from discovery to production start is ten years. An additional prerequisite is that new production licences are awarded regularly, as has been the normal practice so far.

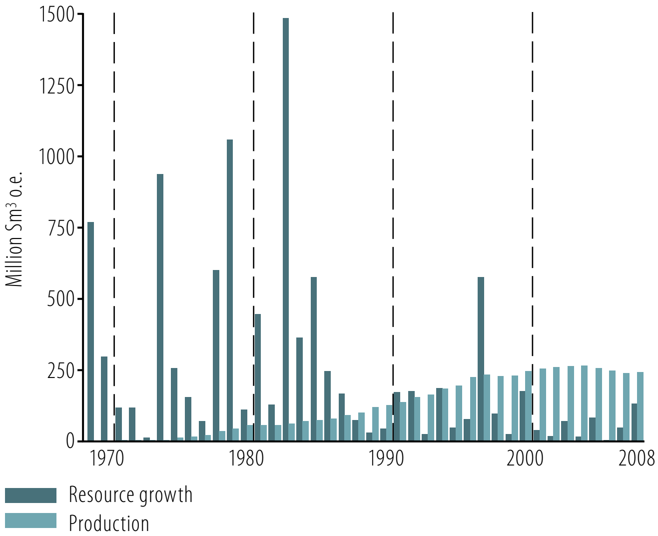


Figure 3.14 The annual growth in resources and the annual production in 1969 to 2008

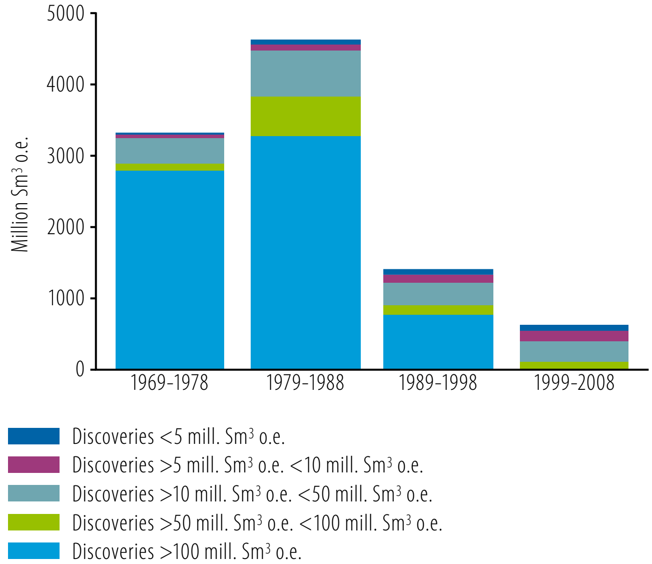


Figure 3.15 Resources in discoveries proven in ten-year periods from 1969 to 2008, arranged according to size

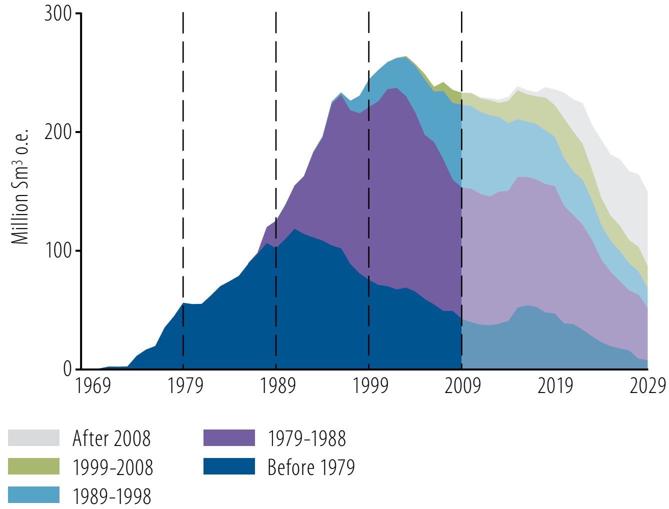


Figure 3.16 Historical and forecasted petroleum production arranged according to the discovery year

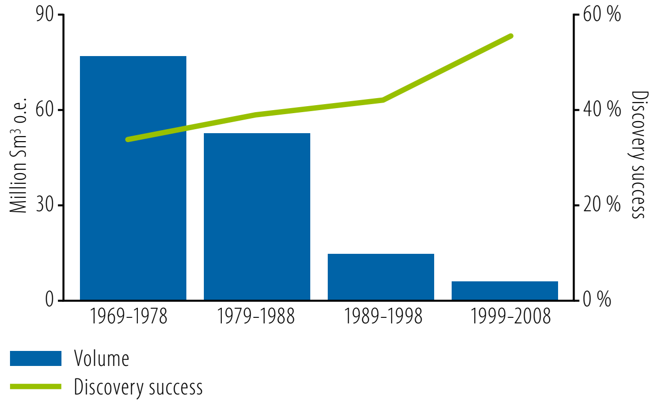


Figure 3.17 The average size of discoveries and the discovery rate in the ten-year periods from 1969 to 2008

Better knowledge of the geology and advances in technology lead to a higher discovery success, but the average size of the discoveries declines (Figure 3.17). The number of wildcat wells was lowest from 1969 to 1978 and highest from 1989 to 1998 (Figure 3.18). The discovery rate has been high since 1969, but was lowest in the first ten-year period. It has been relatively high in the last ten-year period.

Many exploration wells (wildcat and appraisal wells) are still being drilled in acreage awarded in the first to the third licensing rounds (Figure 3.19). Exploration wells in acreage awarded more than 20 years ago comprise 44 per cent of the wells drilled in the last ten-year period.

The trend in the exploration activity

The number of exploration wells per year provides a good measure of the exploration activity. The record was set in 2008 when 56 exploration wells were spudded. Figure 3.20 illustrates the significant rise in the total exploration costs in the last five years. Drilling accounts for the greatest share in the exploration costs and is a result of both increased exploration and a rise in the general level of costs.

Apart from 2008, the number of purchases and exchanges of shares has dropped during the last five-year period (Figure 3.21). The decline is probably due to the high and rising price of oil in the same period. The increase in purchases in 2008 can probably be explained as an effect of the market for purchasing and exchanging shares having grown. The number of pre-qualified companies on the Norwegian shelf has risen from 34 in 2004 to 79 in 2008.

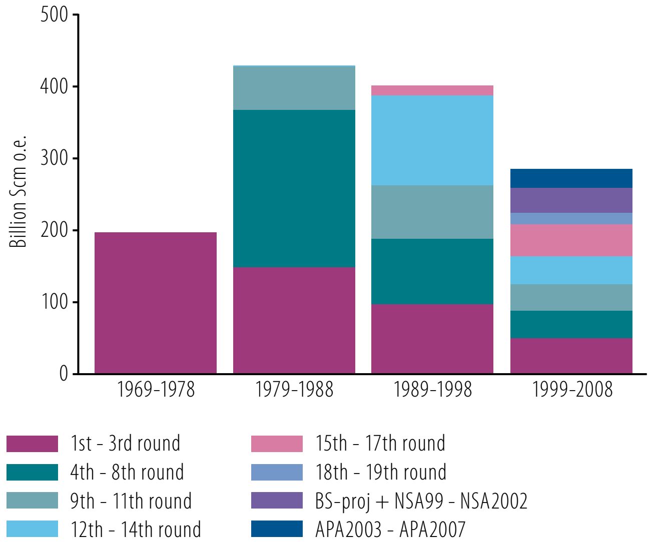


Figure 3.19 The number of exploration wells arranged according to licensing rounds in the ten-year periods from 1969 to 2008

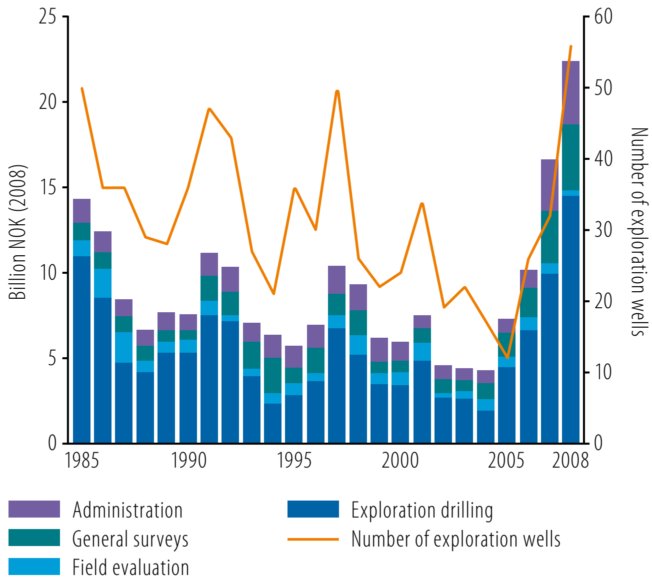


Figure 3.20 The total exploration costs and the number of exploration wells per year from 1985 to 2008

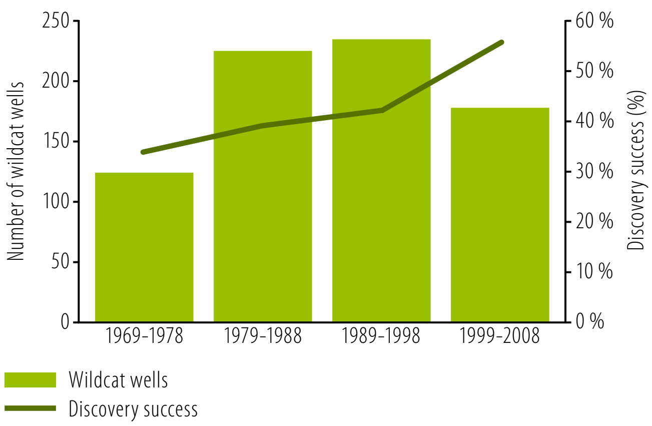


Figure 3.18 The number of wildcat wells and the discovery rate in the ten-year periods from 1969 to 2008

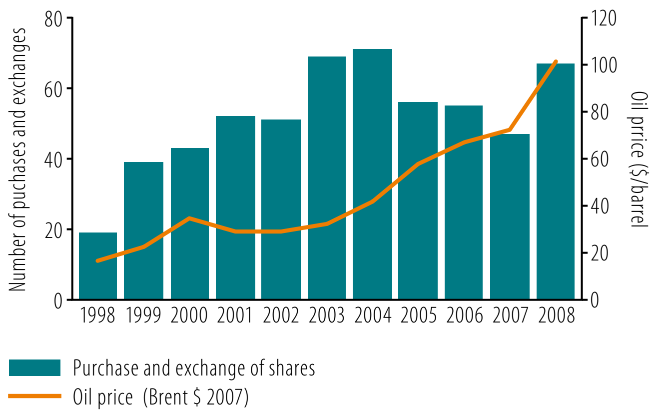
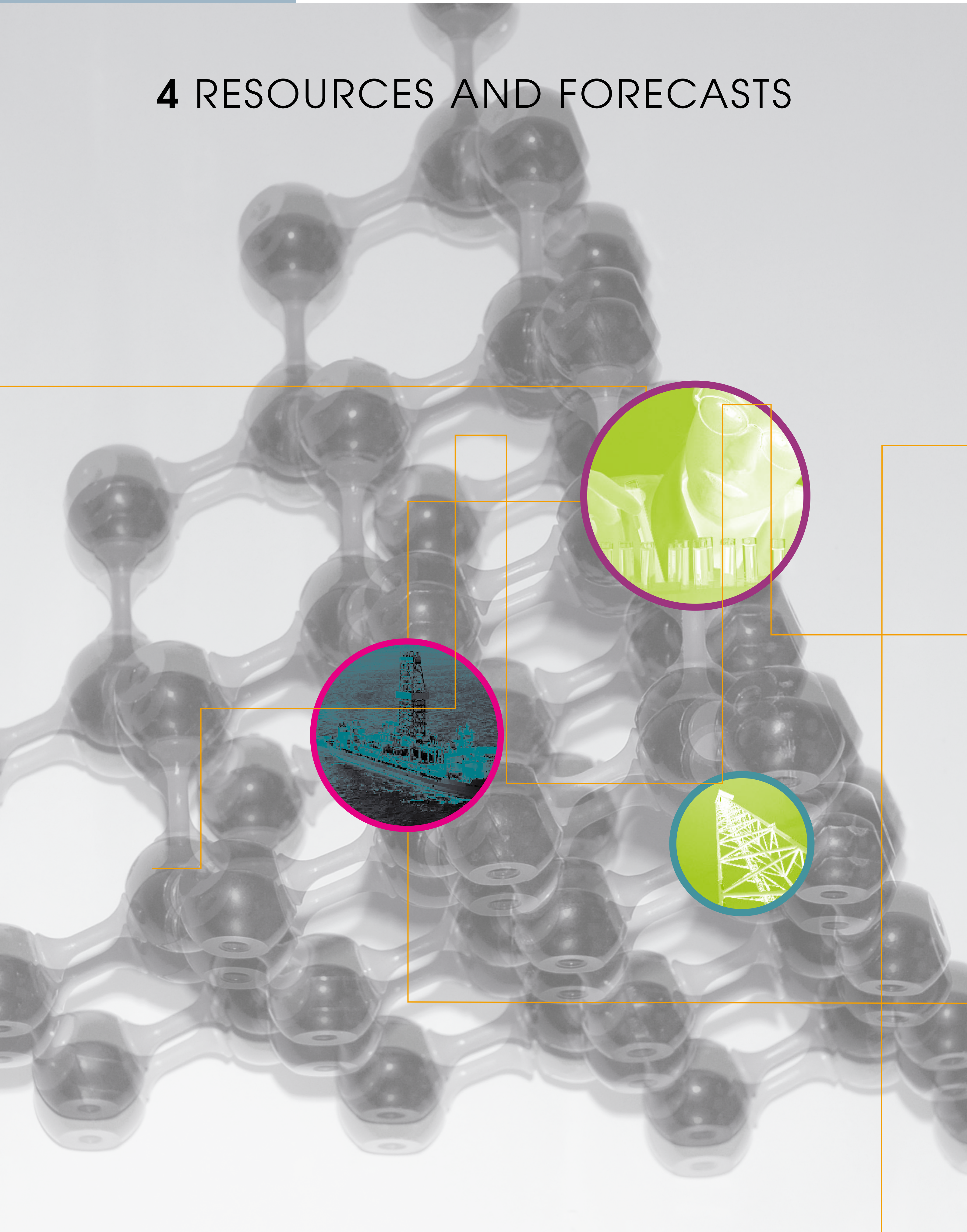


Figure 3.21 Purchase and exchange of shares on the Norwegian shelf from 1989 to 2008

4 RESOURCES AND FORECASTS



It is impossible to determine the future oil and gas production from the Norwegian continental shelf. The estimates are based on assumptions about geology, technical conditions in reservoirs, costs, technological development and knowledge, and profitability.

The Norwegian Petroleum Directorate's, resource account gives an overview of the total recoverable petroleum resources, including produced and undiscovered resources. It is prepared annually and the estimates represent what is expected to be produced under given preconditions. The most important of these are that the industry is given the opportunity to explore where the resources can be found and that the companies decide to produce what they discover.

The resource account covers every part of the Norwegian continental shelf except the area of overlapping claims in the Barents Sea and the continental shelf around Jan Mayen. Other areas that are not currently open for petroleum activity are therefore included in the account.

The resource account is based on the NPD's resource classification (see details at www.npd.no). The classification covers the recoverable petroleum quantities, both proven and still not proven - the undiscovered resources.

The classification reflects where the petroleum quantities linked to a project are in the value chain: undiscovered, in discoveries, being developed, in production and when production ceases (Fig. 4.1). A single field may therefore have projects in more than one resource category.

Resources are a collective term for technically recoverable petroleum quantities, which the classification divides into three main classes: reserves, contingent resources and undiscovered resources.

- *Reserves:* remaining petroleum quantities approved for production.
- *Contingent resources:* proven petroleum quantities requiring clarification and decisions before approval for production.
- *Undiscovered resources:* unproven petroleum quantities which it is assumed to be proven when exploration takes place.

As of 31.12.2008, the total recoverable resources in the resource account (Figure 4.2 and Table 4.1) were calculated to be between 10 and 17 billion Sm^3 oil equivalents (o.e.), with 13.4 billion Sm^3 o.e. as the expected value; 5.1 billion Sm^3 o.e. had been produced. The expected value for the remaining proven resources was 5.0 billion Sm^3 o.e. and for undiscovered resources 3.4 billion Sm^3 o.e. After 42 years exploration and 37 years production it is still uncertain how much of the proven resources can be economically recovered and how large the undiscovered resources are.

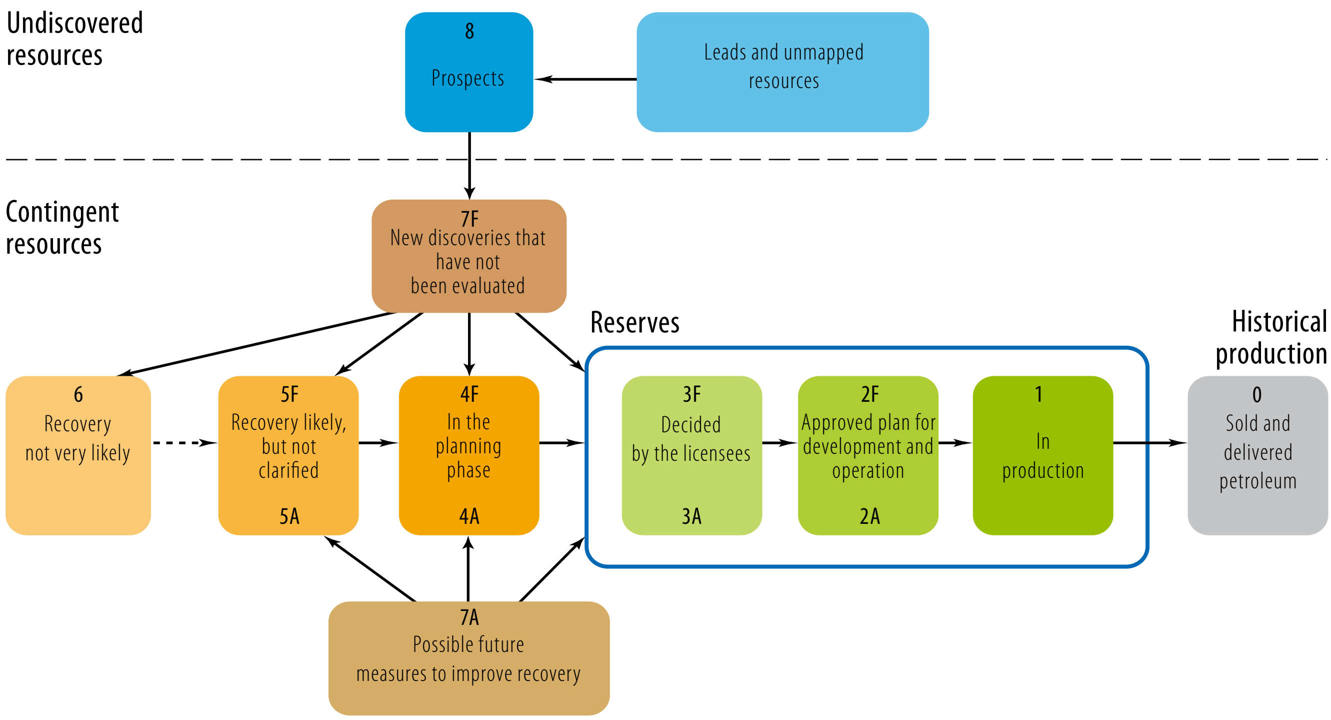


Figure 4.1 The Norwegian Petroleum Directorate's classification of the petroleum resources

Undiscovered resources

According to the resource account, about a quarter of the expected resources on the Norwegian shelf are still not proven. The NPD regularly prepares new estimates of the undiscovered petroleum resources. This report presents new estimates for undiscovered resources in the Barents Sea. New estimates for the North Sea and the Norwegian Sea will be given in the updated resource account by the end of 2009.

The estimates of the undiscovered resources on the Norwegian shelf are based on analyses of petroleum plays and were last updated in 2006. Plays are defined on the basis of geological criteria. A play is confirmed when a discovery is made, which increases the probability that more discoveries will be made. The expectations attached to the confirmed play are enhanced, and the estimate for undiscovered resources generally also rises. A detailed account of the plays and the technique used to calculate the resource potential are given in the Resource Report for 2007.

Updated estimate for undiscovered resources in the Barents Sea

The resource estimate for the Barents Sea covers the whole Barents Sea except the area of overlapping claims. It is based on an analysis of 23 plays whose reservoirs span a geological age stretching from the Devonian to the Neogene, i.e. the last 400 million years (Figure 4.3). In 2006, six of the 23 plays had been confirmed by discoveries. Exploration activity has been high in the Barents Sea since 2006. Eighteen wells have been drilled and our knowledge of the area has grown. Eight plays are now confirmed and 15 remain unconfirmed.

The two plays confirmed since 2006 have reservoir rocks of Triassic age and these reservoirs have been thoroughly studied by mapping and drilling. However, several of the new discoveries are small, some considerably smaller than was assumed prior to the drilling. Partly for this reason, the NPD has reduced the expectation of future, large discoveries in the Triassic in the southern part of the Barents Sea. Recent mapping, nevertheless, shows that there are more prospects (possible targets for drilling) in these plays than hitherto recorded.

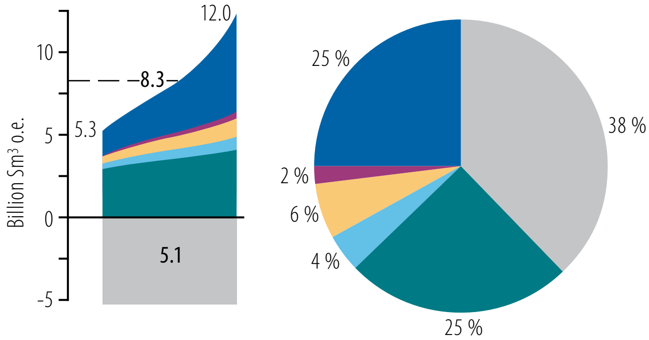


Figure 4.2 Distribution of the total recoverable petroleum resources as of 31.12.2008

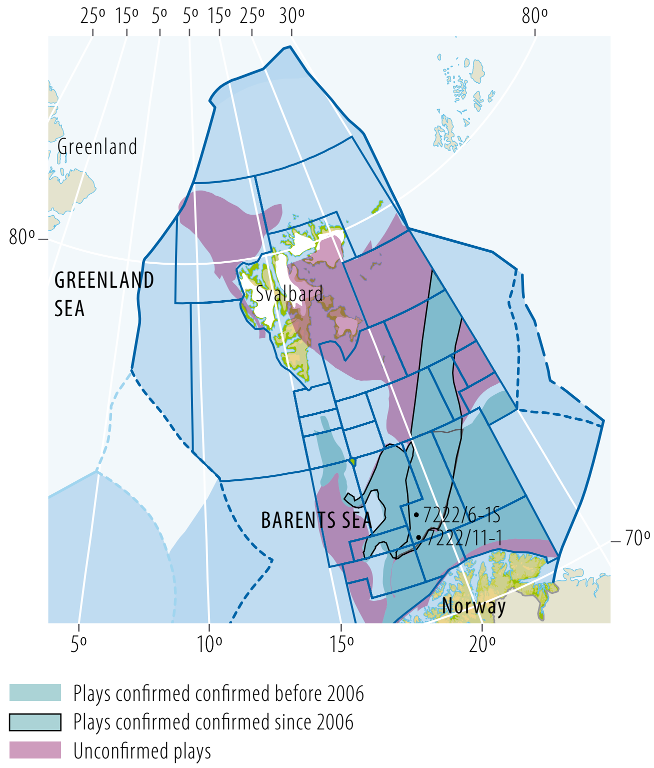


Figure 4.3 Plays in the Barents Sea

Total recoverable resources Project status	Oil mill Sm³	Gas bill Sm³	NGL mill tonn	Condensate mill Sm³	Total mill Sm³ o.e.
Sold and delivered	3405	1333	116	96	5055
Reserves	919	2215	120	43	3407
Contingent resources in fields	333	181	28	5	572
Contingent resources in discoveries	210	512	14	27	775
Possible measures for increased recovery	145	77			222
Undiscovered resources	1260	1875		265	3400
Sum total	**6273**	**6193**	**277**	**437**	**13431**

Table 4.1 Resource account as of 31.12.2008

The expectation for the undiscovered resource volumes in Jurassic reservoirs in the south western part of the Barents Sea has risen. The Snøhvit field is part of the play, and several small discoveries have also been made in recent years. Many oil companies have performed thorough mapping and investigations in connection with both the APA scheme and licensing rounds, and several new prospects have been identified. Better knowledge means that the uncertainty is reduced (Figure 4.4).

In general, estimates of undiscovered recoverable resources are very uncertain. The uncertainty is particularly great for the Barents Sea because large areas have few data and no exploration wells. The potential for finding substantial volumes of liquid and gas is nevertheless high. Based on the 23 plays, there is assumed to be an 80 per cent probability of finding between 205 and 2100 million Sm³ o.e. in the Barents Sea. This means that there is a 90 per cent probability for at least 205 million Sm³ o.e. (low estimate), but not more than a 10 per cent probability for more than 2100 million Sm³ o.e. (high estimate).

The statistical expectation value is 910 million Sm³ o.e., but this estimate is very uncertain. More knowledge has, nevertheless, reduced the uncertainty since 2006.

Following drilling results and new mapping, the expectation of the volume of undiscovered, in-place petroleum is higher now than previously assumed. The expectation figure is, nevertheless, somewhat lower for undiscovered recoverable resources than it was in 2006 (Figure 4.5) owing to assumptions of a reduction in the recovery factor.

The reservoir properties are somewhat poorer in the Barents Sea than in the North Sea and the Norwegian Sea. On the whole, the reservoir pressure is also lower, leading to somewhat smaller recoverable volumes. Technical and environmental challenges in arctic regions give more stringent constraints and higher costs. Longer distances to the markets also raise the costs. As all these factors influence the development and recovery solutions the recovery factor in the Barents Sea is now somewhat lower than previously assumed, despite significant technological advances.

The analysis shows that nearly half the undiscovered resources are thought to be liquid, i.e. oil and condensate. The proportions of liquids and gas are approximately the same as in previous analyses (Figure 4.6).

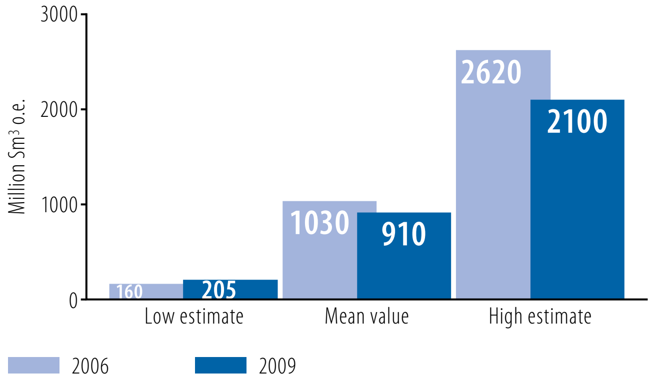


Figure 4.4 The range of uncertainty for the estimate of the total undiscovered recoverable resources in the Barents Sea

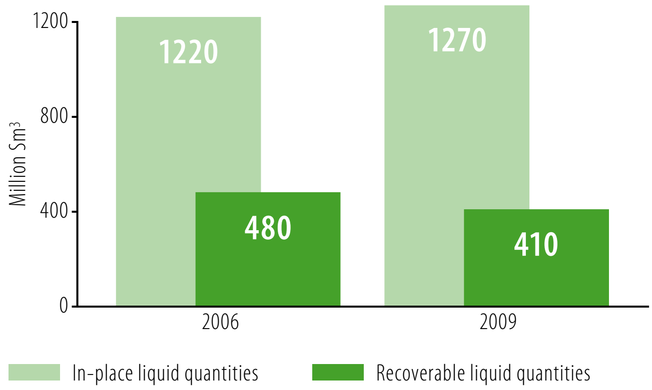


Figure 4.5 The expectation value of in-place, recoverable volumes of liquid

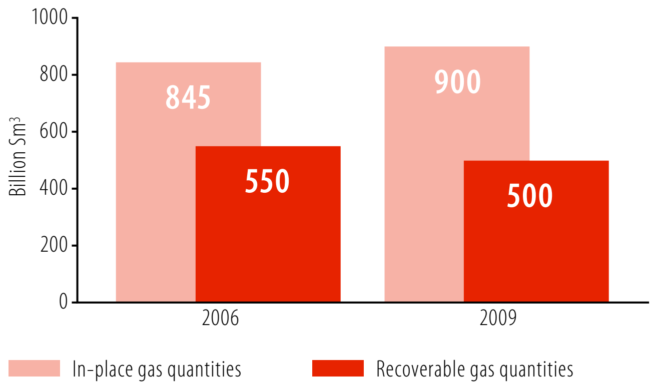


Figure 4.6 The expectation value of in-place, recoverable volumes of gas

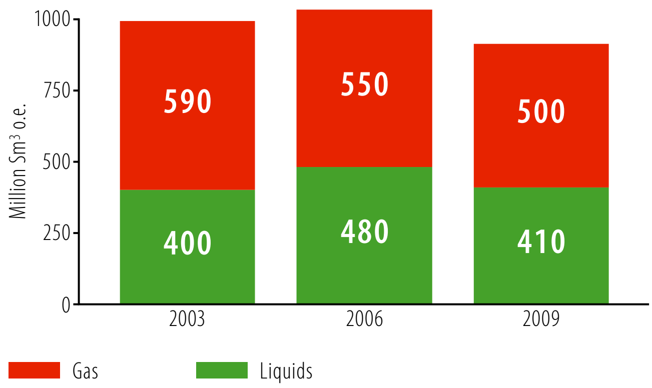


Figure 4.7 Proportions of liquids and gas in the Barents Sea

Proven recoverable resources

The expectation value of the proven recoverable resources is 10.1 billion Sm³ o.e. and can be divided into:

i) Remaining, proven, recoverable resources (including reserves)
ii) Sold and delivered petroleum quantities

The Norwegian shelf has now produced 5.1 billion Sm³ o.e. and approximately the same amount, 5.0 billion Sm³ o.e., has been proven but not yet produced. The estimates change over time depending on how much is proven by exploration and how much is produced (Figure 4.7). 85 per cent of the remaining proven resources are found in existing fields; the rest are in discoveries.

Discoveries

By the end of 2008, 73 discoveries remained undeveloped. These contain an estimated 775 million Sm³ o.e., amounting to about six per cent of the total resources (Figure 4.8). Two-thirds of these resources are gas. The six largest discoveries contain 40 per cent of all the resources. The largest discovery is 6506/6-1 Victoria. Figure 4.8 shows the discovery portfolio ranked according to the size of the recoverable volumes and shows that there is a large range in size.

The resources in discoveries rose by 129 million Sm³ o.e. in 2008. Twenty-five new discoveries were made, 13 in the North Sea, eight in the Norwegian Sea and four in the Barents Sea. Fifteen of these were made in areas near infrastructures, 12 in the North Sea and three in the Norwegian Sea. Evaluation of these discoveries continues and considerable uncertainty is attached to the resource estimates. New operators have taken over five discoveries in relinquished production licences and plan to perform new assessments of possibilities for developing the discoveries.

Many of the discoveries on the Norwegian continental shelf were proven in the 1970s. The reasons why the discoveries are not yet developed are most frequently uncertainty in the resource base and costs, problems associated with multiphase transport over long distances and lack of possibilities for gas delivery. Figure 4.9 shows the discoveries arranged according to the year they were found, their size and their maturity.

The largest discovery, 6506/6-1 Victoria, was made in the Norwegian Sea in 2000 and has an expected recoverable volume of 89 billion Sm³ of gas. The resource estimate is uncertain. This discovery is thwart with difficulties, including partially impervious rocks, the gas has a high CO_2 content, pressure is high (800 bars), the reservoir temperature is high (about 200° C) and the water depth is 5000 metres. Total E&P Norge AS, the operator, started drilling an appraisal well during spring 2009 which will give important new information on the discovery.

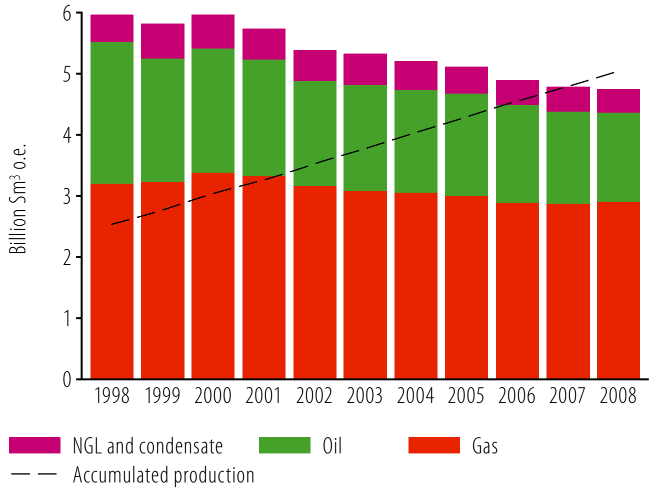


Figure 4.8 Annual estimates of the remaining, proven, recoverable resources (1998-2008)

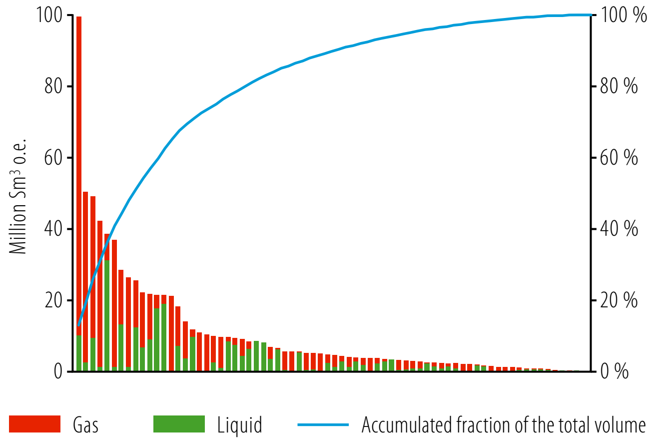


Figure 4.9 Discoveries whose development has still not been agreed, ranked according to their recoverable volumes

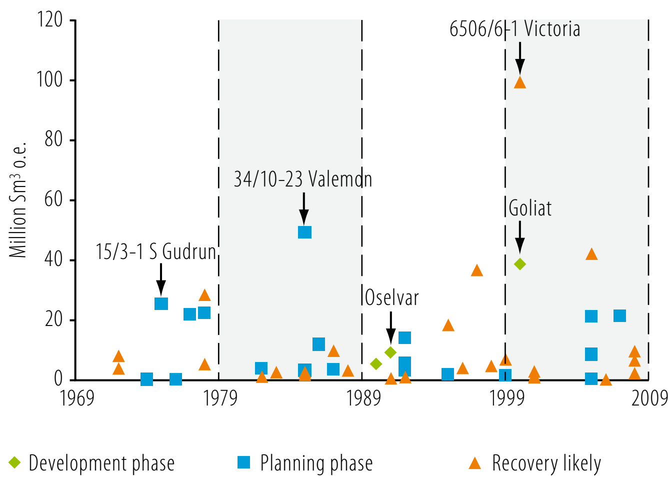


Figure 4.10 Discoveries arranged according to the year they were found, their size and their maturity

Contingent resources in fields

Contingent resources in fields comprise 572 million Sm^3 o.e., or four per cent of the total petroleum resources (Figure 4.2). They have risen by 34 million Sm^3 o.e. during the past year. This resource category covers resources found in new parts of fields and in projects for improved recovery in fields. In addition, the resource account contains 222 million Sm^3 o.e. of possible resources in future measures to raise the recovery factor. These include drilling and maintenance of wells, changing the drainage strategy to, for example, low-pressure production, and more water and gas injection.

Reserves

Reserves are the portion of the remaining recoverable and saleable volumes for which a decision to develop has been taken, or which are already in production. Approximately a quarter of the total resources are reserves (Figure 4.2).

Resources are ultimately defined as reserves as new projects for development or improved recovery are agreed by licensees. Two new fields in the Norwegian Sea, Morvin and Yttergryta, had their plans for development and operation (PDO) approved in 2008. In June 2009, PDOs for Oselvar and Goliat were approved.

Sold and delivered

By the end of 2008, oil, gas, NGL and condensates were produced from 60 fields on the Norwegian shelf. By 1 August 2009, production had started in the Yttergryta, Alve and Tyrihans fields in the Norwegian Sea and the Rev Field in the North Sea. Later this year, production is planned to start in the Volund field in the North Sea.

In 2008 123 million Sm^3 of oil were produced. Ekofisk, Grane and Snorre had the highest production with ten, eight and five per cent of the total production, respectively.

Large fields have been the predominant contributors to the oil production, but this has changed in recent years. In 2000, 72 per cent of the oil production came from 11 fields with a daily production that exceeded 100 000 barrels (Figure 4.10). Six years later (Figure 4.10), 55 per cent came from eight fields with high production (100 000 barrels/day). In 2008, only five fields had such a high production, and they were responsible for 36 per cent of the oil production (Figure 4.10). At the same time, the number of small fields producing less than 50 000 barrels/day has increased smoothly. More fields have been put into production and most of these are relatively small.

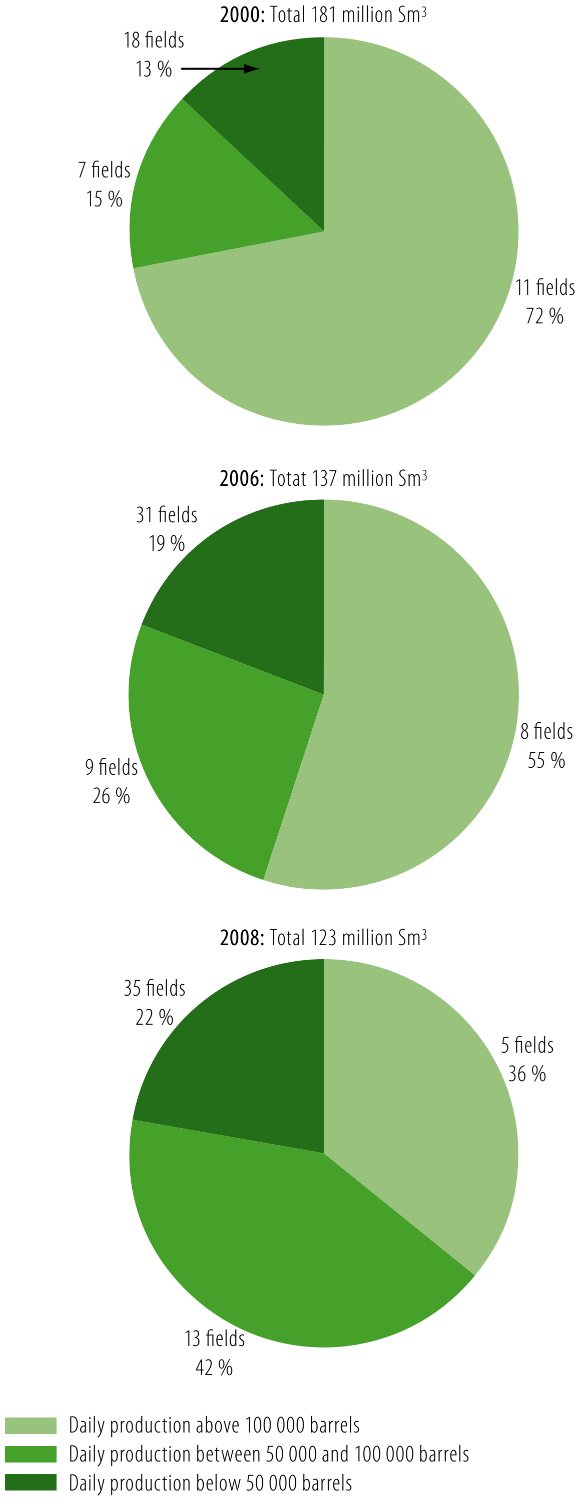


Figure 4.11 Annual oil production arranged in fields with varying daily production

The gross gas production in 2008 was 141.3 billion Sm^3, 99.2 billion Sm^3 of which were sold, 33.8 billion Sm^3 injected and 4.2 billion Sm^3 were used as fuel or were flared. The remaining 4.1 billion Sm^3 were wet gas products.

Wet gas - a collective term for several fluid petroleum qualities consisting of ethane, propane, butane and naphtha, often including small amounts of heavy hydrocarbons. The gas is partly liquid at atmospheric pressure.

The gas production is also characterised by few fields with high production being responsible for a large part of the total production. However, the gas fields do not experience a decline in production like the largest oilfields, except for the Frigg field where production ceased in 2004. Troll and Sleipner have maintained a daily production of more than 20 million Sm^3 since the start, and Åsgard and Ormen Lange had an equally high daily production in 2008. The number of fields producing less than five million Sm^3 daily is rising. Figure 4.11 shows gas-producing fields arranged according to their daily production in 2000, 2006 and 2008.

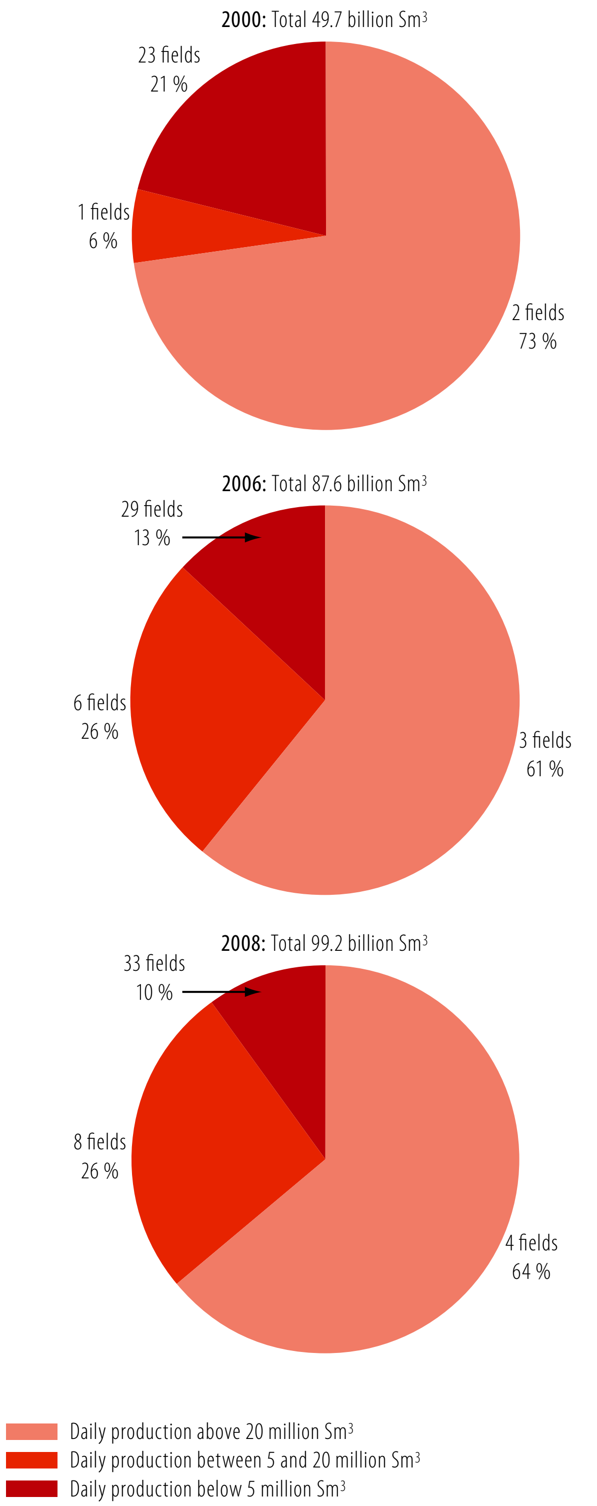


Figure 4.12 Annual gas production arranged in fields with varying daily production

Forecasts

Each year, the NPD prepares forecasts for production, costs, investments and emissions. These are based on the NPD's assessments of data reported by the operators.

The forecasts are uncertain. The most fundamental uncertainty concerns how much oil and gas the Norwegian shelf contains. When oil and gas discoveries are made, considerable uncertainty still remains as to how large a proportion of the proven resources can be technically produced and when production will take place. In addition, fluctuations in the rig market, capacity in the industry, expected gas sales and the expected start-up time for projects are key factors when the forecasts are prepared.

In the short term, the uncertainty in the forecast is mainly linked to how much are produced from each field, deliver regularity it delivers and the efficiency in the in-phasing of new wells and other projects on the fields. In addition, it is uncertain when new fields will start production and the productivity from these fields. In the long-term forecast, the uncertainty increases as the undiscovered resources are gradually making up a larger proportion of the expected future production. The uncertainty is naturally greatest in areas that have still not been opened for petroleum activity. In addition to uncertainty regarding the volume of the petroleum resources there, it is also uncertain when these areas will be made available for petroleum activity.

The perspective for Norwegian petroleum activity is still long term. More than half of the assumed recoverable resources have not been produced. It is still possible to make large discoveries and to improve the recovery from fields that are currently producing. The Norwegian shelf has a reputation for developing and starting to use new technology. What will future technological development give?

The Norwegian shelf is not unaffected by the global situation. Population trends and economic growth are driving forces for energy demands. Security of supplies and energy requirements are key aspects in the future. How will climate issues and measures to counteract climate change influence events in the next 25 years? What will happen to the prices of oil and gas? Initiative and ability to develop new petroleum reserves are affected by Norway's willingness to pave the way through its allocation practice and stable regulatory environment and also on the international level through the prices of oil and gas, for example.

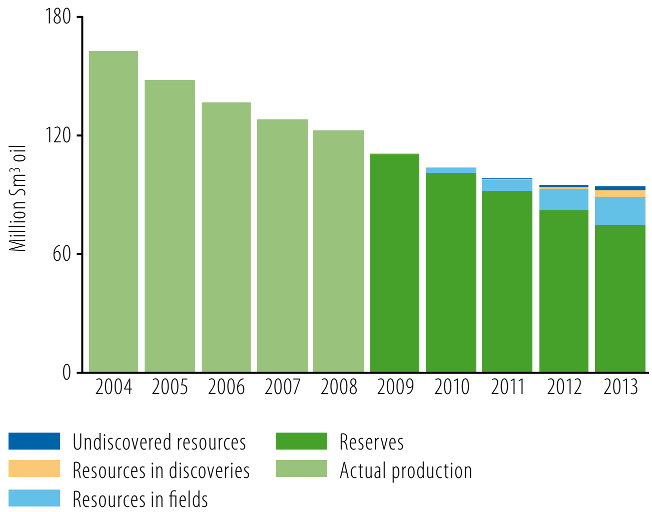


Figure 4.13 Historical figures and forecast for oil production up to 2013

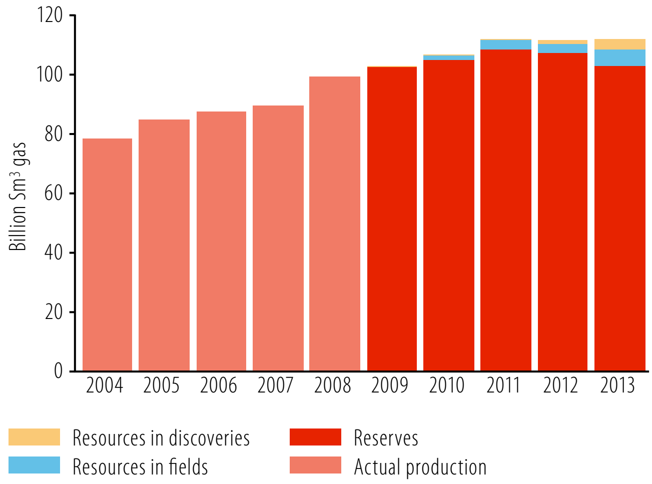


Figure 4.14 Historical figures and forecast for gas sales up to 2013

Short-term petroleum production forecast (2009-2013)

Oil production is declining. The production on the Norwegian continental shelf is expected to be about 111 million Sm^3 (1.91 million barrels per day) in 2009. It was 123 million Sm^3 in 2008.

The NPD expects about 503 million Sm^3 of oil to be produced and sold from 2009 to 2013 inclusive (Fig. 4.12). The forecast shows that oil production will decline from about 111 million Sm^3 o.e. in 2009 to about 94 million Sm^3 o.e. in 2013, a reduction of about 10 per cent compared with the previous forecast. The main reasons for this reduction are postponement of new projects and lower expectation as to how many new production wells will be drilled. The NPD expects planned projects for improved recovery in fields to start towards the end of the period.

As oil production decreases, gas production and gas sale from the Norwegian shelf continue to increase. Nearly 110 GSm^3 more gas are expected to be sold in the five-year period of 2009 – 2013 than in the previous five-year period. This represents an increase of 25 per cent (Figure 4.13).

The gas sales the next five years will mainly come from fields that are already in production. Only a small proportion is expected to be a result of measures to improve recovery in fields, new developments and undiscovered resources. The largest new contributors to gas sales in this period are Gjøa and Skarv, which plan to start production in 2010 and 2011, respectively.

Condensate and NGL are heavy components of the gas in the reservoir which are produced together with the gas. A processing plant separates NGL and condensate from the sales gas. The production of oil, condensate and NGL is generally termed liquid production. The proportion of NGL and condensate in the liquid production has risen recently as a result of the growing gas production (Figure 4.14). NGL and condensate production is expected to remain unchanged for the next five years and make up between 15 and 20 per cent of the liquid production.

Forecasts are uncertain. Even the oil production forecast for the next five years is decidedly uncertain (Figure 4.15), mainly due to uncertainty on the ability of the fields to supply oil, when new fields will start delivering and regularity.

Figure 4.15 Historical figures and forecasts for the production of oil, NGL and condensate up to 2013

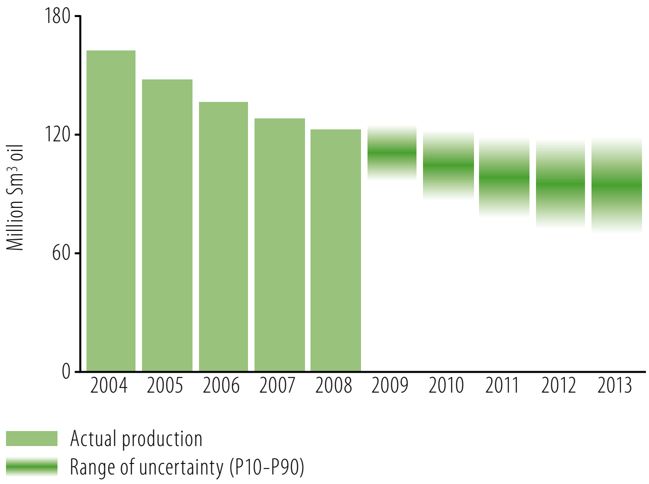


Figure 4.16 Uncertainty in the oil production forecast

Investments- and operating costs forecasts

Investment in the Norwegian shelf is at a historically high level. Great fluctuations in oil and gas prices have lead to more uncertainty about future investment levels. The figures which the Petroleum Directorate have relied upon are based on estimates supplied by the operators prior to the major drop in the oil price in autumn 2008. The NPD has considered these estimates and expects the investments to continue as planned in the short term, but some new projects are likely to be postponed.

Investments are expected to exceed 140 billion NOK in 2009 (Figure 4.16). Investments linked to exploration are likely to be cut in the coming years, whereas other investments will remain stable. Investments linked to further development of fields make up about 75 per cent of the total investments and concern both installations and drilling.

The investment forecasts are uncertain on two counts: will projects be carried out as planned, and what will be the future trend in costs? Whereas some sectors of the mainland economy have experienced a rapid fall in investment activity, investments do not fall steeply in the NPD's investment forecast. This very clearly shows that investments in the petroleum sector are a strong impulse for growth in the Norwegian economy.

Operating costs have risen substantially in recent years, but are expected to stabilise at around 50 to 60 billion NOK in the years ahead (Figure 4.17).

Long-term forecast for the petroleum production

The NPD expects 4.9 billion Sm³ o.e. to be produced in the next 20 years (Figure 4.19). This compares with a production of 5.1 billion Sm³ o.e. from 1971 to 2008.

The petroleum production is expected to remain comparatively stable until 2020 when a decline will set in. Oil production is already dropping, but the rising production of gas has so far maintained an overall high production level.

After 2020, a larger proportion of the production is expected to come from undiscovered resources. This proportion increases year by year and is expected to be just above 40 per cent in 2030. The production forecast for undiscovered resources is based on estimates of volumes made by the NPD and on assumptions that 30 exploration wells will be drilled each year, that the drilling will result in discoveries of varying size and that the average time elapsing from a discovery to the start of production is 10 years. Moreover, new production

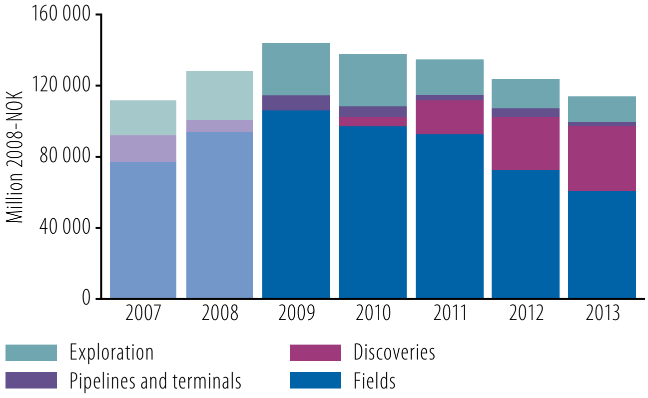


Figure 4.17 Forecasts for investments in fields, discoveries, pipelines, on-shore facilities and exploration up to 2013

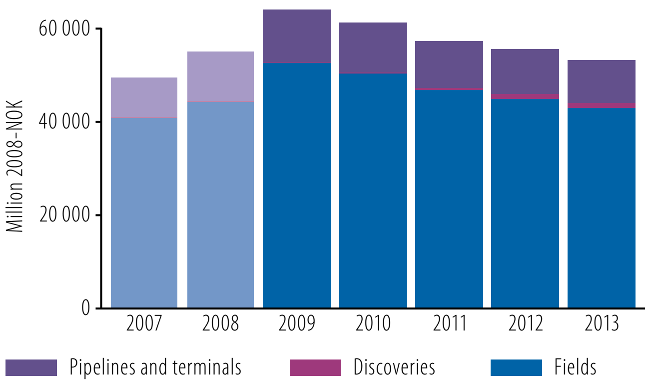


Figure 4.18 Forecasts for operating costs for fields, discoveries, pipelines and onshore facilities up to 2013

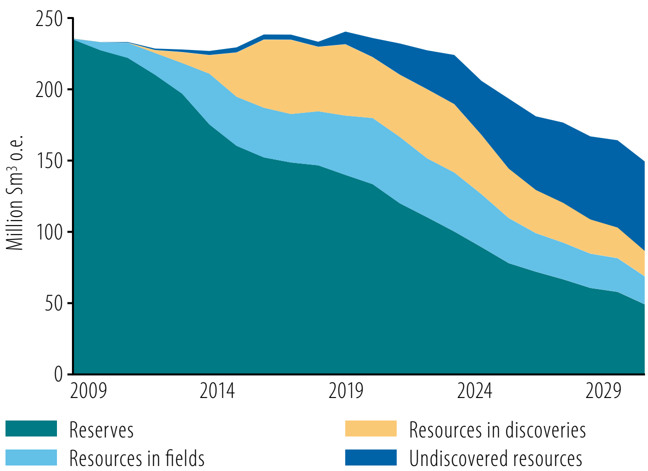


Figure 4.19 Forecast for the petroleum production from the Norwegian shelf up to 2030

licences must be awarded regularly, as has been the normal practice so far. The estimate of the undiscovered resources covers all parts of the Norwegian continental shelf except the area of overlapping claims in the Barents Sea and the continental shelf around Jan Mayen.

The forecast presupposes that sufficient volumes of oil and gas are discovered that can be produced profitably and most of the petroleum must be found in the coming 10 to 15 years.

Experience shows that an average of 11 years elapses from discovery to production. Figure 4.20 shows the year of production start-up and the average lead time. Discoveries near existing infrastructure will generally be put into production quite soon, whereas other discoveries may remain undeveloped for several years for various reasons. As figure 4.8 shows, some discoveries made more than 30 years ago are still not developed.

Figure 4.21 shows the production forecast for production up to 2030 arranged according to the decade when the discoveries were made. 43 per cent of the production up to 2030 will come from fields discovered in 1979 to 1988. For example, Troll, Heidrun and Snorre were discovered in this period and will contribute to the production during the forecast period. By comparison, only eight per cent of the production will come from discoveries made during the last ten-year period. The discoveries made in this period were small. No new areas have been opened since 1994, which might be one reason why there have been no large discoveries the last period. Exploration activity has been high in recent years, but has mainly taken place in well-explored areas.

The predicted increase in production after 2014 from deposits found in the first ten-year period results from an expectation that several discoveries made before 1979 will be put into production then.

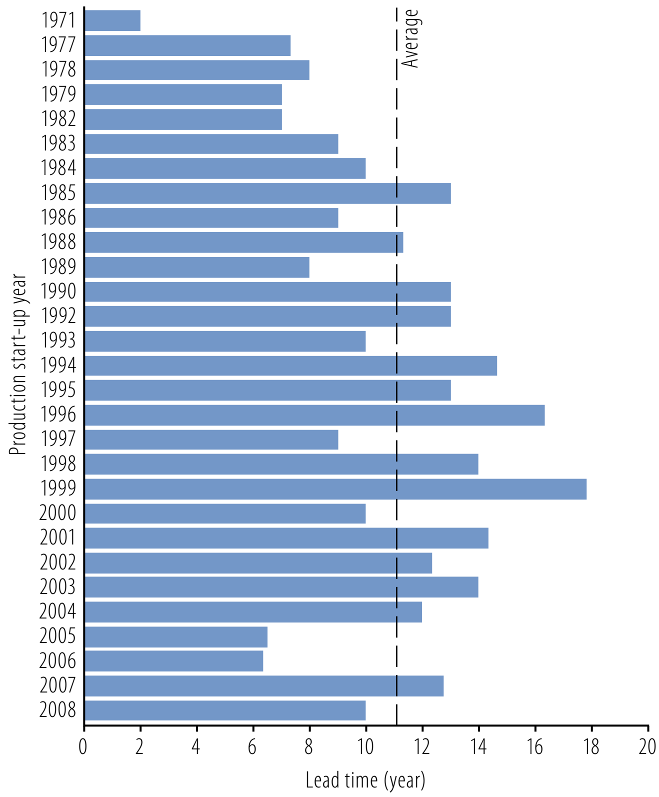


Figure 4.20 Average lead time from discovery to production start for fields on the Norwegian shelf

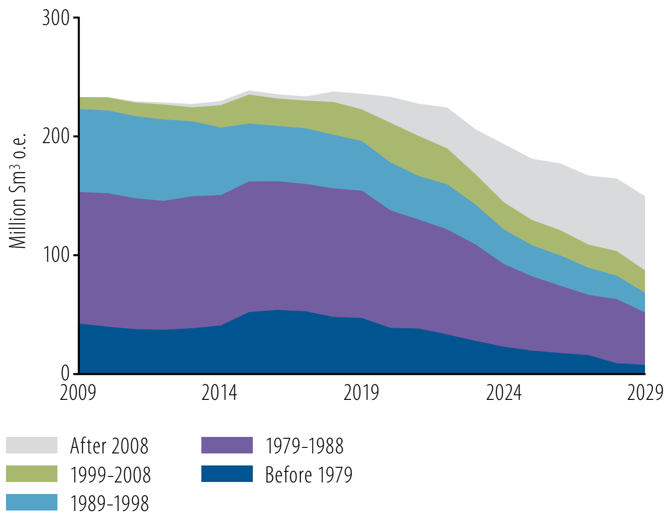


Figure 4.21 Forecast for the petroleum production up to 2030 arranged according to when the discovery was made

Emissions from the petroleum activity

The most important emission sources in the petroleum activity are energy production and flaring. The emissions chiefly consist of carbon dioxide (CO_2), nitrogen oxides (NO_x), volatile organic compounds (nmVOC) and methane (CH_4). CH_4 and nmVOC stem from, among other things, evaporation of crude oil during loading and storage. CO_2 and NO_x are emitted in connection with combustion processes.

Oil and gas production from the Norwegian continental shelf is subject to stringent demands. Technological demands, emission permits and economic constraints like the NO_x and CO_2 taxes help to ensure that emissions are kept as low as possible. The emissions from Norwegian petroleum activity are therefore among the lowest in the world compared with the scale of the production.

The petroleum industry in Norway has paid a tax for its CO_2 emissions since 1991. From 1 January 2008, the petroleum industry has also been obliged to buy quotas on the European quota market (European Union Emissions Trading Scheme – EU ETS). Since the EU ETS quota prices are lower than the pre-2008 Norwegian CO_2 tax level, the authorities have decided to maintain the CO_2 tax on a level which means that the sum of the European quota price and the Norwegian CO_2 tax approximately reflects the historical level of the cost of emissions in Norway. As the quota price in EU ETS is determined by supply and demand, the total price per unit of CO_2 which the operators on the shelf must pay varies through the year. The result of maintaining a CO_2-tax adjusted to the quota price is that CO_2 emissions in Norway are more expensive than corresponding ones in other European countries.

The Gothenburg Protocol requires Norway to reduce its annual NO_x emissions to 156 000 tonnes by 2010. This amounts to a reduction of about 41 000 tonnes, or 20 per cent, relative to the emissions in 2005. As one means of meeting this obligation, a tax has been levied on the NO_x emissions since 2007. In 2009, the charge is NOK 15 850 per tonne NO_x. A NOx fund for Norwegian Business and Industry was set up in 2008, which is intended to finance measures to reduce emissions. The trade organisations taking part club together and can apply for money to help pay for measures to reduce emissions. The contributions to the fund replace the NO_x-tax. Fourteen organisations now contribute to the NO_x Fund, including the Norwegian Oil Industry Association. The principal task for the fund is to finance specific measures which

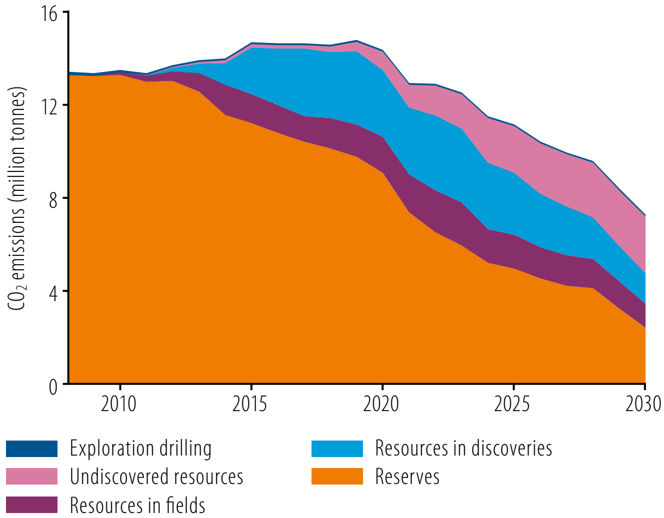


Figure 4.22 Forecast for CO_2 emissions from the petroleum sector

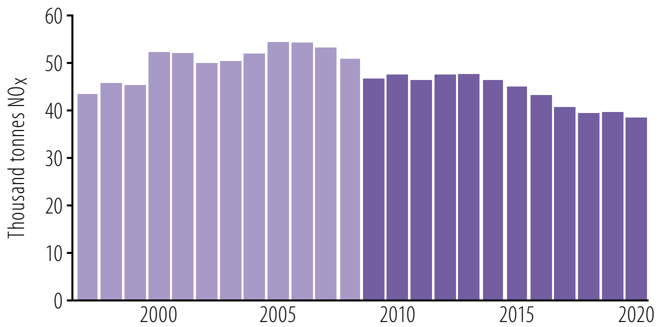


Figure 4.23 Historical NO_x emissions and forecast for the petroleum sector

reduce the emissions. In 2009, the industry is required to implement measures to reduce NO_x emissions by 4000 tonnes.

Emission forecasts

The petroleum activity is currently responsible for some 31 per cent of CO_2 emissions in Norway. Emissions are expected to rise gradually until 2020 and thereafter decline. The forecast predicts that a gradually increasing proportion of the emissions will come from undiscovered resources, from discoveries and from projects to improve recovery on fields. The forecast allows for shore-based power to the Valhall and Gjøa fields. Conversion of existing installations to utilise power from land will normally be expensive. The use of such power must therefore be evaluated in each case.

Figure 4.19 shows the forecasts for CO_2 emissions from the petroleum sector up to 2030. Further reductions in the CO_2 emissions from Norwegian petroleum activity can to some extent take place by saving energy and using new technology. In its forecast, the NPD has assumed that new technology will be introduced in the future.

Power from shore and capture and storage of CO_2 (CCS) are technologies which may make a significant contribution towards reducing emissions from the petroleum sector. In some cases, power from shore will be cost-effective, but in other instances substantially higher investments will be required. Figure 4.19 shows how power from shore to some of the new developments may reduce the emission curve, but this will first and foremost be relevant in the long term.

The petroleum activity is currently responsible for 24 per cent of the NO_x emissions in Norway. These emissions peaked in 2005 and the forecast predicts that they will continue to decline in the years ahead. The higher proportion of modern, low-NO_x turbines that have been installed and increasing amounts of power from shore help to achieve this reduction (Figure 4.20).

Low-NO_x turbines are now being installed in new developments, and such turbines which are also able to run on diesel are being tested. Power from shore for some new fields along with low-NO_x turbines are expected to reduce NO_x emissions in the future. In the case of some installations, it may be necessary to seek a balance between minimising NO_x emissions and minimising CO_2 emissions. The current regulatory regime provides motivation for minimising CO_2 emissions.

nmVOC derives from emissions of non-combusted hydrocarbons. For instance, evaporation in oil storage facilities may give emissions of nmVOC. These emissions have been significantly reduced in recent years (Figure 4.21), partly through recycling of nmVOC. The figure forecasts that nmVOC emissions will continue to drop.

More water will be produced in the coming years (Figure 4.22), but the proportion of produced water discharged into the sea after being treated is expected to drop gradually; it will be re-injected instead. Increased injection of produced water is partly a result of the demand for a physical zero emission from the petroleum activity north of 62ºN. However, reducing these discharges helps to increase the need for energy.

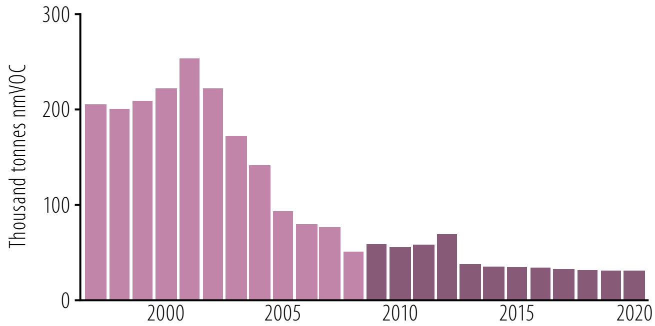


Figure 4.24 Historical nmVOC emissions and forecast for the petroleum sector

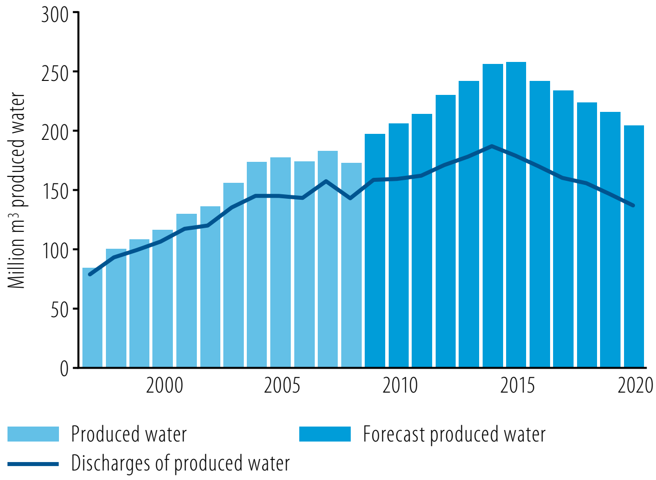


Figure 4.25 Historical water production and discharges of produced water and forecast for the petroleum sector

Conversion tables:

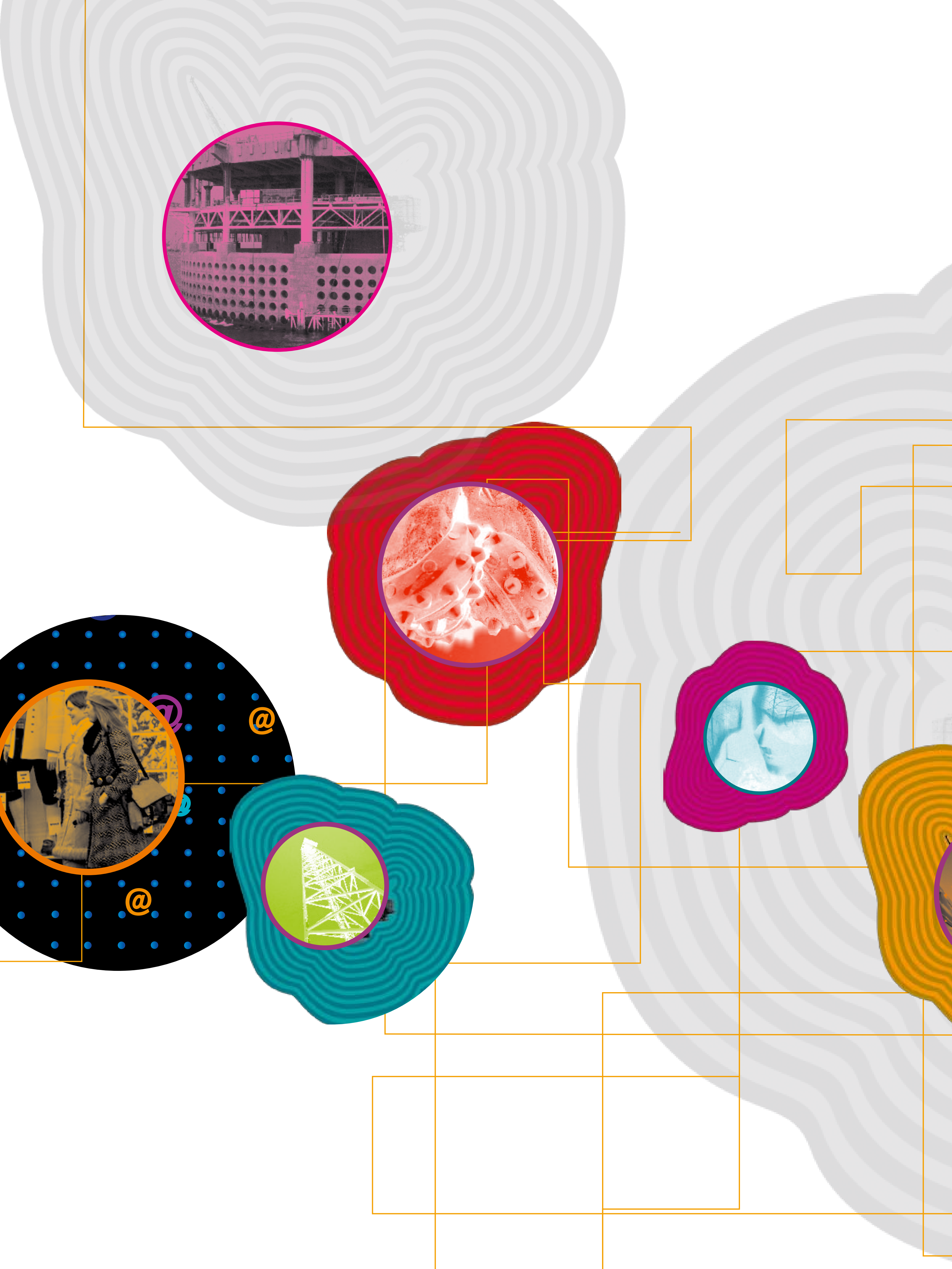
	1 Sm^3 of oil	= 1.0 Sm^3 o.e.	
	1 Sm^3 of condensate	= 1.0 Sm^3 o.e.	
	1000 Sm^3 of gas	= 1.0 Sm^3 o.e.	
	1 tonne of NGL	= 1.9 Sm^3 NGL = 1.9 Sm^3 o.e.	

Gas	1 cubic foot	1 000.00	Btu
	1 cubc metre	9 000.00	kcal
	1 cubic metre	35.30	cubic feet

Crude oil	1 Sm^3	6.29	barrels
	1 Sm^3	0.84	toe
	1 tonne	7.49	barrels
	1 barrel	159.00	litres
	1 barrel/day	48.80	tonnes/yr
	1 barrel/day	58.00	Sm^3 per yr

	MJ	**kWh**	**TKE**	**TOE**	**Sm^3 natural gas**	**Barrel crude oil**
1 MJ, megajoule	1	0.278	0.0000341	0.0000236	0.0281	0.000176
1 kWh, kilowat hour	3.60	1	0.000123	0.000085	0.0927	0.000635
1 TKE, tonne coal equivalent	29 300	8 140	1	0.69	825	5.18
1 TOE, tonne oil equivalent	42 300	11 788	1.44	1	1 190	7.49
1 Sm^3 natural gas	40.00	9.87	0.00121	0.00084	1	0.00629
1 barrel crude oil (159 litres)	5 650	1 569	0.193	0.134	159	1

NORWEGIAN PETROLEUM
DIRECTORATE



ISBN 978-82-7257-036-0