# The petroleum resources on the Norwegian continental shelf 2001

NORWEGIAN PETROLEUM
DIRECTORATE

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# PREFACE

The Norwegian Petroleum Directorate shall contribute to creating the highest possible values for society from oil and gas activities, founded on a sound management of resources, safety and the environment.

It is therefore most important that the Directorate maintains an overview of, and assesses, the activities of the petroleum industry and the petroleum resources on the Norwegian shelf. This forms an important basis for appraising the most efficient ways of exploring, developing and recovering these resources.

The Norwegian Petroleum Directorate has unique access to facts regarding the activity, and compiling this information in a coherent and lucid manner helps to ensure that major and minor decisions in the petroleum sector are taken as far as possibly correctly.

This report presents an updated survey of the petroleum resources on the Norwegian shelf.

*Stavanger, June 2001*

Gunnar Berge
*Director General*

## Contents

# Introduction and summary

In this report, the Norwegian Petroleum Directorate presents an estimate, updated to 31st December 2000, of the total petroleum resources on the Norwegian continental shelf and forecasts for the future trend in the petroleum production, together with expentiture and environmental emissions. The Directorate points out, here, that exploration, development and operation are to a large extent controlled by future possibilities for gas sales. The challenges regarding continued success in improving recovery are, moreover, examined. The report provides a basis for a debate on future developments in the petroleum sector in Norway, since it examines the possibilities and limitations within the home market.

The updated estimate made by the Directorate for the total petroleum resources on the Norwegian shelf is 13.8 billion Sm$^3$ oil equivalents (o.e.). These resources are the sum of the discovered and undiscovered, recoverable resources, including quantities that have already been produced, and are made up of 6.1 billion Sm$^3$ oil, 7000 billion Sm$^3$ gas and 0.7 billion Sm$^3$ o.e. of condensate and NGL. The remaining recoverable resources are assessed at 10.8 billion Sm$^3$ o.e. The estimate of the total resources has risen by 0.4 billion Sm$^3$ o.e. from the estimate made last year. This is due to an increase in the resources linked to oil fields that are in production and a rise in expected gas resources in both discoveries and undiscovered resources.

The total resource base (recoverable oil, gas, NGL and condensate) has shown a positive trend over the last ten years. The estimate for the total recoverable resources has risen by more than 60 per cent since 1990. Developments in technology which have helped to increase the production of discovered reserves are the main reason for this. The upward adjustment of the estimate for undiscovered resources is another important reason for the increase in the total recoverable resources. The remaining recoverable resources now make up as much as the estimate for the entire resource base in 1995. We have produced 1.4 billion Sm$^3$ o.e during these six years.

Large quantities of undiscovered oil and gas resources remain on the Norwegian shelf. The North Sea is the best explored part of the Norwegian shelf. A natural trend in this area is a declining growth in resources and size of discoveries. However, the frequency of new discoveries is still high viewed in an international context. One reason for this is improved expertise and technology in acquiring, processing and interpreting seismic data. The growth in resources over the last ten years has been greatest in the Norwegian Sea. A number of substantial discoveries have been made and it is expected that future exploration will also reveal major discoveries. The resource calculations made by the Directorate show that there is also a significant potential for resources in the Barents Sea. The Barents Sea Project has provided greater geological understanding of the area and will be an aid to further mapping of the potential for resources in this area. Large parts of the Norwegian shelf have still not been investigated.

Oil production today stands at just over 3.1 million barrels a day, and is expected to remain at more than 3 million barrels a day for five years. The greatest uncertainty in the short term is the oil production from currently producing fields, which will account for almost 90 per cent of the production over the next five years. In the longer term, the uncertainty attached to undiscovered resources is of greatest significance.

The trend in the gas market is very important for the future level of activity on the Norwegian shelf and its potential value. Norway has appreciable resources of gas available for sale in the future. The total discovered resources of gas amount to 4100 billion Sm$^3$, the greatest contribution coming from large gas deposits. It is estimated that undiscovered resources of gas amount to 2 400 billion Sm$^3$, and large gas discoveries are also expected in the future. Current sales commitments for gas give a plateau in 2005 at approximately 70 billion Sm$^3$. It is expected that new contracts will be entered into, and the sale of gas on plateau can be substantially higher.

Between 40 and 60 billion NOK a year will be spent on capital expenditure and operating expenditure on the Norwegian shelf in the next 20 years. The future level of gas sales will have the greatest bearing on the level of activity. So far, investments have been dominated by large installations, pipeline systems and related facilities on land. Subsea installations linked to existing installations have become more common in recent years. In the 1990s, wells accounted for 20 per cent of the investments, but are expected to be responsible for 50 per cent or more in the next 10 years.

The basis for emission forecasts is expectations regarding production. Changes in the sale of gas will have the largest effect on the level of $CO_2$ and $NO_x$ emissions on the Norwegian shelf.

On average, the reserves in fields that are in production on the Norwegian shelf increased by 50 per cent compared with the volume estimated in the original, approved plan for development and operation (PDO). There has been a growth in reserves on both large and small fields. However, fields with a PDO dating from before 1991 have shown the largest increase in reserves. The estimate of oil volumes expected to be produced by these fields is almost 1 billion Sm$^3$ higher today than that from 1990. Developments in drilling technology, longer and horizontal wells, and not least the more precise location of wells than earlier, account for a large part of this increase in reserves. New seismic techniques have helped to provide better indications of where remaining quantities of recoverable oil can be found. The average expected recovery factor for oil fields that are in production and under development is calculated to be 44 per cent. The estimate for the recovery factor has not changed over the last three years. This breaks a continuous trend of annual upward adjustments throughout the 1990s. There are many reasons for this, but negative expectations regarding the price of oil and a related reduction in key personnel to reduce costs are no doubt foremost explanations. This trend has now turned, but the expertise is no longer easily available.

The greatest potential for achieving gains by improving the recovery factor is found in the large fields. The remaining in-place volumes in the ten largest fields amount to about 4 000 million Sm$^3$ of oil, nearly twice the quantity for all the remaining oil fields together.

The potential for improving the recovery factor in existing fields is time-critical and realising it is dependent on an intensification in the efforts to implement new technology on the parts of both the authorities and the companies. The way must be paved for creating and taking care of knowledge and of innovative groups and those using new approaches in both the companies and associated concerns. Conditions must also be improved for education and research, and for creating a positive framework around this industry that has oil reserves for at least 50 years and gas reserves for more than 100 years. Competent and enthusiastic specialists are needed to ensure that the Norwegian oil wealth, that is still largely in the ground, really will benefit the Norwegian people. We have been successful for the first 30 years. The choices we now make will decide the course of the next 50 - 100 years.

# 1. The resource account

## 1.1 Resource classification

The Norwegian Petroleum Directorate's resource account provides a survey of all the recoverable petroleum resources on the Norwegian continental shelf. It covers the quantities sold and delivered, the remaining resources and the undiscovered resources.

The petroleum resources are grouped in various classes, depending upon the position they occupy in the development chain from undiscovered resource, through new discoveries, development, production, and on to when production ceases. They are divided into three categories, reserves, resources and undiscovered resources. The classification system implies that each discovery and field can contain resources that are classified in different classes. The system contains 11 classes and is shown in Table 1.1 and Figure 1.1.

The estimates of resources in fields and discoveries are largely based on data reported annually by the oil companies. Those for undiscovered resources are based on the Directorate's own appraisal.

Based on experience gained with the classification system and the development of such classifications internationally, the Norwegian Petroleum Directorate has revised the system in co-operation with the oil companies. The new system is briefly described in Chapter 5 and came into force on 1st July 2001. However, the resource account for 2000 and the classification of the resources on which the analyses in this report are based have been drawn up on the basis of the old system.

## 1.2 Total petroleum resources

Table 1.2 summarises the originally recoverable petroleum resources on the Norwegian continental shelf. Figure 1.2 shows the distribution of the resources and

| Category | Class | Description |
|---|---|---|
| Discovered reserves and resources | 0 | Reserves where production has ceased |
| | 1 | Reserves in production |
| | 2 | Reserves with an approved development plan |
| | 3 | Resources in a late planning phase (approved development plan within two years) |
| | 4 | Resources in an early planning phase (approved development plan within ten years) |
| | 5 | Resources that may be developed in the long term |
| | 6 | Resources whose development is not very likely |
| | 7 | Resources in new discoveries whose evaluation is incomplete |
| | 8 | Resources from possible future measures to improve the recovery factor (measures that are not planned possible superseding present-day technology) |
| Undiscovered | 9 | Resources in mapped prospects |
| | 10 | Resources in leads |
| | 11 | Unmapped resources |

*Table 1.1 Resource classification (valid until 1st July 2001)*

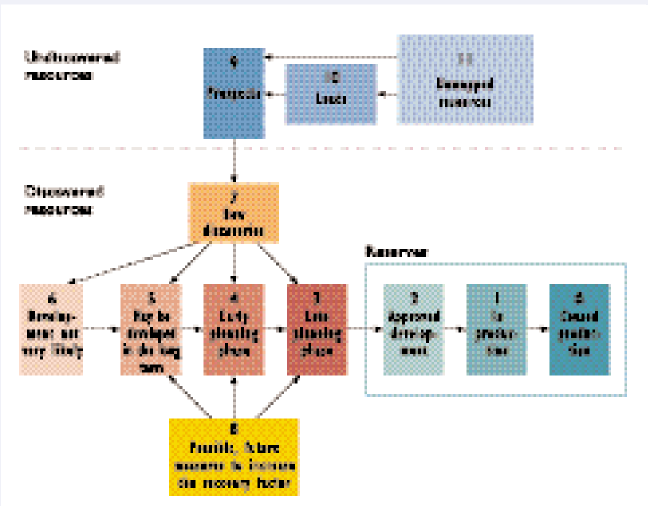


*Figure 1.1 Classification of the petroleum resources on the Norwegian continental shelf (valid until 1st July 2001)*



| Resource class | Originally recoverable petroleum resources on the Norwegian continental shelf. Status as of 31st Dec. 2000 | Oil Mill Sm³ | Gas Bill Sm³ | NGL Mill tonn | Cond. Mill Sm³ | Oil equiv. Mill Sm³ | Changes in the resources since 1999: Oil Mill Sm³ | Gas Bill Sm³ | NGL Mill tonn | Cond. Mill Sm³ | Oil equiv. Mill Sm³ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **FIELDS** | | | | | | | | | | |
| | **Reserves** | | | | | | | | | | |
| 0 | Production ceased | 33 | 114 | 4 | 1 | 154 | 0 | 0 | 0 | 0 | 0 |
| 1-2 | In production or with approved development plan | 3719 | 1822 | 134 | 141 | 5917 | 243 | 64 | 5 | 17 | 334 |
| | **Sum reserves** | **3751** | **1937** | **137** | **143** | **6071** | **243** | **64** | **5** | **17** | **334** |
| | Sold as of 31st Dec. 2000 | 2187 | 677 | 52 | 41 | 3005 | 181 | 50 | 3 | 6 | 244 |
| | Remaining reserves | 1564 | 1259 | 75 | 100 | 3067 | 62 | 14 | 2 | 11 | 90 |
| | **Resources** | | | | | | | | | | |
| 3 | Late planning phase | 102 | 111 | 6 | 0 | 224 | 10 | 1 | -2 | 0 | 7 |
| 4 | Early planning phase | 129 | 751 | 24 | 10 | 937 | 73 | -4 | 7 | 8 | 92 |
| 5 | May be developed in the long term | 19 | 62 | 4 | 0 | 89 | 3 | 25 | 4 | 0 | 36 |
| 6 | Development unlikely | 12 | 13 | 2 | 0 | 29 | 5 | 11 | 2 | 0 | 20 |
| | **Sum resources** | **263** | **937** | **36** | **10** | **1279** | **89** | **33** | **10** | **8** | **150** |
| | **Sum fields** | **4013** | **2874** | **164** | **153** | **7351** | **333** | **97** | **16** | **25** | **484** |
| | **Remaining reserves and resources** | **1826** | **2197** | **112** | **110** | **4346** | **151** | **47** | **12** | **19** | **240** |
| | **DISCOVERIES** | | | | | | | | | | |
| | **Resources** | | | | | | | | | | |
| 3 | Late planning phase | 92 | 348 | 29 | 98 | 593 | -135 | -74 | -2 | -24 | -235 |
| 4 | Early planning phase | 21 | 487 | 10 | 38 | 565 | 2 | 126 | 9 | 25 | 170 |
| 5 | May be developed in the long term | 54 | 267 | 1 | 29 | 392 | -15 | 6 | -4 | -13 | -30 |
| 6 | Development unlikely | 40 | 61 | 2 | 4 | 108 | 1 | -1 | 0 | 3 | 2 |
| 7 | New discoveries under evaluation | 20 | 95 | 0 | 0 | 115 | 19 | 56 | 0 | -36 | 39 |
| | **Sum resources** | **266** | **1258** | **41** | **169** | **1773** | **-130** | **113** | **3** | **-44** | **-54** |
| | **Sum fields and discoveries** | **4279** | **4132** | **205** | **322** | **9133** | **203** | **210** | **19** | **-18** | **430** |
| 8 | Possible future measures to improve recovery | 425 | 500 | | | 925 | -75 | 0 | 0 | 0 | -75 |
| 9-11 | Undiscovered resources | 1350 | 2400 | | | 3750 | 12 | 82 | 0 | 0 | 94 |
| | **Total recoverable resources** | **6054** | **7032** | **205** | **322** | **13798** | **138** | **292** | **19** | **-18** | **448** |
| | Sold as of 31st Dec. 2000 | 2187 | 677 | 52 | 41 | 3005 | 181 | 50 | 3 | 6 | 244 |
| | **Remaining reserves/resources** | **3867** | **6355** | **153** | **280** | **10793** | **-43** | **242** | **16** | **-24** | **205** |

As the figures are rounded off to the nearest whole figure, some sums may be wrong.
a The table shows the expected value
b Oil equivalents (o.e.). Oil, gas, condensate and NGL are converted using the factors stated below, and are then added together
Conversion factors
1000 Sm³ gas corresponds to 1 Sm³ o.e.
1 Sm³ oil corresponds to 1 Sm³ o.e.
1 Sm³ condensate corresponds to 1 Sm³ o.e.
1 ton NGL corresponds to 1.9 Sm³ o.e.
1 Sm³ = 6.29 barrels

*Table 1.2 Resource account for the Norwegian continental shelf as of 31st December 2000*

Figure 1.3 shows the uncertainty in the resource estimates. The total recoverable resources are estimated to be about 13.8 billion Sm³ o.e. Of these, 6.8 billion Sm³ o.e. are liquid and 7000 billion Sm³ are gas (Table 1.2). This is an increase of approximately 450 million Sm³ o.e. since 31st December 1999, when the new conversion factor for NGL (1.9 Sm³ o.e. per tonne) is used.

Twenty-two per cent of these resources have been sold and delivered. Recoverable reserves remaining in fields amount to 22 per cent, and resources in fields comprise 9 per cent. Discoveries and undiscovered resources make up 13 and 27 per cent, respectively, whereas possible future measures to improve the recovery factor give 7 per cent.

The distribution of the remaining, discovered resources among various resource classes is shown in Figure 1.4. Resources in fields that are in production comprise two-

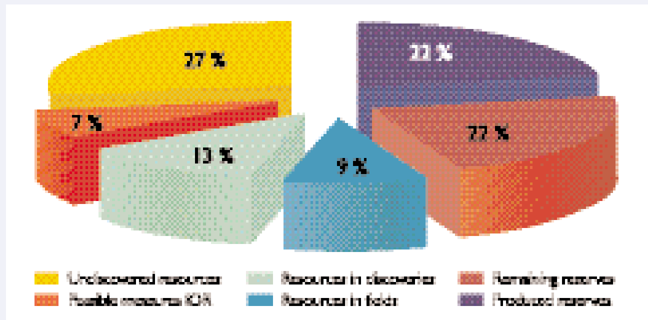


*Figure 1.2 Distribution of the originally recoverable petroleum resources on the Norwegian continental shelf*

thirds of the discovered resources, including quantities derived from possible future measures to improve the recovery factor. Five per cent are in fields that have been approved for development, but not yet been put into production, whereas discoveries comprise 28 per cent. The total oil resources on the Norwegian continental shelf are estimated at approximately 6 billion Sm³. Figure 1.5 shows the distribution of the recoverable oil resources including NGL and condensate, 34 per cent of which have been sold and delivered. The remaining recoverable oil reserves including NGL and condensate amount to 27 per cent, whereas specific projects and possible future measures to improve the recovery factor are estimated to represent 11 per cent of the total oil resources. Discoveries and undiscovered resources amount to 8 and 20 per cent, respectively.

The total gas resources on the Norwegian continental shelf are estimated at approximately 7 000 billion Sm³. Figure 1.6 shows the distribution of the recoverable gas resources.

Ten per cent of the gas resources have been sold and delivered. The remaining recoverable gas reserves amount to 18 per cent, whereas specific projects and possible future measures to improve the recovery factor are estimated to represent 20 per cent of the total gas resources. Discoveries and undiscovered resources amount to 18 and 34 per cent, respectively.

Three billion Sm³ o.e. have been sold and delivered as of 31st December 2000. This figure is made up of 2187 million Sm³ of oil, 677 billion Sm³ of gas, 41 million Sm³ of condensate and 52 million tonnes of NGL (Table 1.2).

The remaining recoverable resources amount to 10.8 billion Sm³ o.e. and have lower and upper uncertainty limits of 8 and 14.5 billion Sm³ o.e., respectively (Figure 1.3). The estimate for liquids (oil, NGL and condensate) is between 3.3 and 6.0 billion Sm³ o.e., with an expectation of 4.4 billion Sm³ o.e. The remaining recoverable gas resources are estimated to be between 4200 and 9200 billion Sm³, with an expectation of 6400 billion Sm³.

All told, 5.0 billion Sm³ o.e. of oil, NGL and condensate, and 4100 billion Sm³ o.e. of gas have been proved, amounting to 9.1 billion Sm³ o.e. The Directorate estimates that possible future measures to improve the recovery factor in discoveries and fields may give a further 425 million Sm³ of oil and 500 billion Sm³ of gas. The undiscovered resources are calculated to be 1.35 billion Sm³ of oil and 2400 billion Sm³ of gas.

### Definitions and conversion factors for oil and gas

***A deposit*** is an accumulation of petroleum in a geological unit delimited by rock types through structural or stratigraphical boundaries, interfaces between petroleum and water in the formation, or a combination of these, so that all the petroleum concerned is in pressure communication through liquid or gas.

***A discovery*** is a single petroleum deposit, or more than one deposit if they are proven in the same well, which testing, sampling or logging have shown are likely to contain mobile petroleum.

***A field*** is one or more discovery which the licensees have decided to develop and for which the authorities have approved, or granted exemption from, a plan for development and operation (PDO).

***Originally-in-place resources*** are petroleum resources which, following mapping by geological methods and calculation by geological and petroleum technological methods, are estimated to be in place in a deposit. This estimate must state the quantities under sales terms. Originally-in-place gas is divided into free gas and associated gas (dissolved in oil). Originally-in-place NGL means components dissolved in free gas, all of which will be converted to the NGL phase by current or planned gas processing.

***Originally recoverable resources and/or reserves*** comprise the total saleable or deliverable resources and/or reserves from the start to the cease of production, based on current understanding of the quantities in place and the recovery factor.

***Reserves*** comprise resources in classes 0, 1 and 2, i.e. originally recoverable reserves which the licensees have decided to develop and for which the authorities have approved, or granted exemption from, a PDO. A distinction may be drawn between reserves originally recoverable and remaining reserves.

***Play*** is a geographically and stratigraphically delimited area where a specific set of geological factors is present so that petroleum should be able to be discovered in recoverable quantities. Such geological factors are reservoir rocks, traps, mature source rocks and migration paths, and that the traps were formed before the migration of petroleum ceased. All discoveries and prospects within the same play are characterised by the specific set of geological factors in the play. Confirmed plays contain at least one discovery of recoverable quantities of petroleum. It is thus confirmed that the critical geological factors are simultaneously present for these plays. Unconfirmed plays are plays in which no petroleum has so far been discovered, either because exploration has still not started, or only dry wells have been drilled in the play.

***Oil equivalents*** (abbreviated o.e.) are used when oil, gas or NGL volumes are being added up. The term is linked with the amount of energy liberated through combustion of the various kinds of petroleum. Based on typical calorific values from the Norwegian continental shelf, the Directorate employs the following conversion factors:

**1000 Sm³ of gas corresponds to 1 Sm³ o.e.**
**1 Sm³ of oil corresponds to 1 Sm³ o.e.**
**1 tonne of NGL corresponds to 1.9 Sm³ o.e.**

**1 Sm³ = 6.293 barrels**
**1 Sm³ = 35.3 cubic feet**



The Annual Report of the Norwegian Petroleum Directorate and its web site on the Internet (fact pages) give a detailed survey of the discoveries and fields.

**Uncertainties in the resource estimates**
Some uncertainties are attached to the resource estimates for the individual deposits in the resource account. An expected volume is calculated for each deposit, and low and high estimates are also calculated, based on stochastic modelling. The uncertainty relates to several factors and is generally greatest for the non-proven deposits and those that are in an early evaluation phase. For such deposits, the uncertainty is attached to the mapping of the extent of the deposit, as well as its reservoir and production properties. For fields that are in production, the uncertainty will be linked with the behaviour of the reservoir and whether possible measures to improve the recovery factor will be implemented, and also their effect.

Just as there is uncertainty relating to the size of the individual deposit, uncertainty also exists regarding the size of the total resources, that is to say the sum of discovered and undiscovered resources. A calculation of the aggregated resources has been undertaken where, in addition to the base estimate, consideration has also been given to the distribution of probability for the volumes in each individual deposit.

**Resources in fields**
The total recoverable resources in fields are estimated at 7.4 billion Sm³ o.e., 3 billion Sm³ o.e of these having already been sold and delivered. The uncertainty of the remaining recoverable resources is estimated to range between 3.8 and 4.7 billion Sm³ o.e., with an expectation of 4.3 billion Sm³ o.e.

Resources in fields have risen by almost 500 million Sm³ o.e. since the end of 1999. The reason for half of this increase is that plans for development and operation (PDO) for the Grane, Kvitebjørn, Ringhorne and Tambar fields were approved in 2000. The reserves in some other fields have been adjusted upwards, and several discoveries have been made that are linked with existing fields. New projects to improve the recovery factor are being planned, particularly with regard to the chalk fields, Ekofisk and Valhall. Some of the potential in future measures to improve oil recovery has thus been implemented. The remaining recoverable resources related to fields comprise 1.8 billion Sm³ of oil, 2200 billion Sm³ of gas, 112 million tonnes of NGL and 110 million Sm³

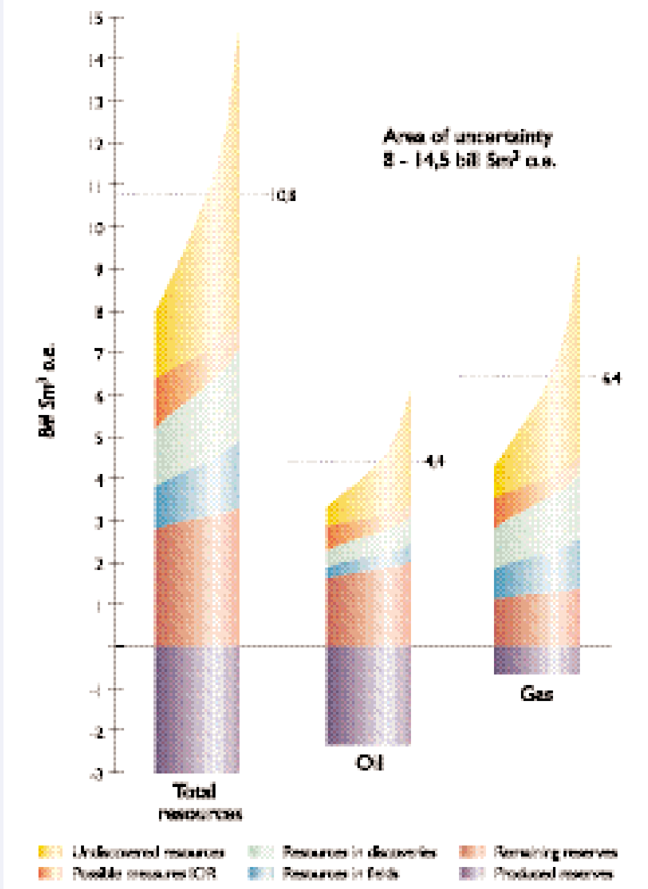

*Figure 1.3 Uncertainties in resource estimates*

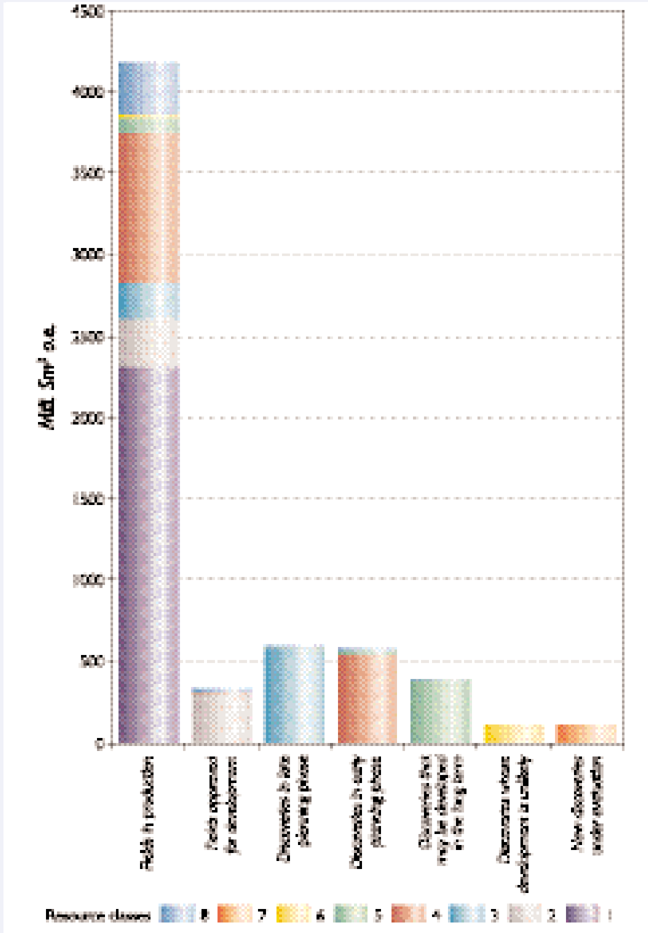
*Figure 1.4 Distribution of the remaining discovered resources*

of condensate, giving a total of 4.3 billion Sm³ o.e. At the end of 2000, 45 fields were in production, 7 were approved for development but not yet put into production, and production had ceased on 10 fields.

**Resources in discoveries**

The total recoverable resources in discoveries are estimated to lie between 1.4 billion Sm³ and 2.2 billion Sm³ o.e., with an expectation of 1.8 billion Sm³ o.e. (Table 1.2). This is a reduction of 54 million Sm³ o.e. since 1999, as several discoveries received field status after their PDO was approved and because resources in new discoveries are inadequate to balance those that have been transferred to the reserves category.

Seventy-nine discoveries have been recorded whose development has still not been approved. Of these, 14 and 12 are in their late or early planning phases, respectively. Most of these are expected to be developed in the course of ten years. Another 48 discoveries are being considered for development in the long term, but it is very uncertain whether these will be developed. The development of several discoveries depends upon the establishment of an infrastructure, the presence of buyers for gas, or technical solutions being found to enable the development of complicated reservoirs. A number of small discoveries have also been made whose recovery is considered unlikely.

**Resources from improved recovery**

Based on the Directorate's target to achieve an average recovery factor of 50 per cent of the oil and 75 per cent of the gas in Norwegian fields, the potential existing in possible future measures to improve the recovery factor has been calculated to amount to 425 million Sm³ of oil and 500 billion Sm³ of gas, totalling 0.9 billion Sm³ o.e. The licensees have indicated possible projects on individual fields that, together, amount to approximately 320 million Sm³ o.e. These are in resource classes 3 and 4.

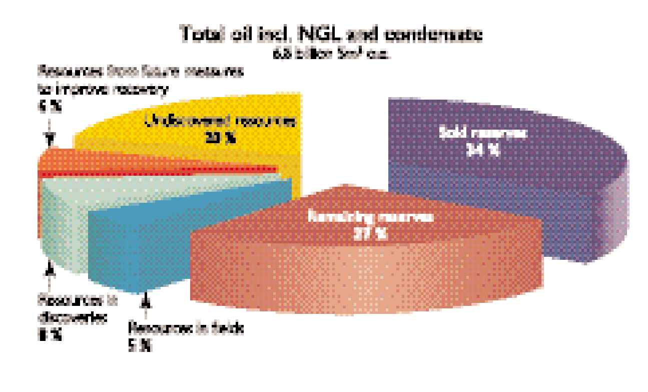


*Figure 1.5 Distribution of oil resources including NGL and condensate on the Norwegian continental shelf*

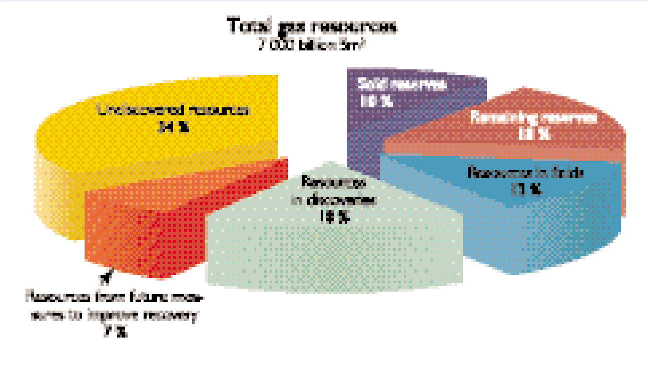


*Figure 1.6 Distribution of gas resources on the Norwegian continental shelf*



**Undiscovered resources**

The undiscovered resources in each of 58 plays have been calculated on the basis of knowledge about the discoveries and mapped prospects within the play. A statistical method enables the size of the hypothetical discoveries that can be made in the play to be calculated. This information is used to calculate the size of the future discovery. The total undiscovered resources are estimated to lie between 1.5 and 6.8 billion Sm³ o.e. with an expectation of 3.8 billion Sm³ o.e. The proportion of liquid is estimated to be 1.4 billion Sm³ with an area of uncertainty between 0.4 and 2.6 billion Sm³. Gas is estimated to lie between 700 and 4 700 billion Sm³ with an expectation of 2 400 billion Sm³. The estimate for the total undiscovered resources has risen by approximately 100 million Sm³ o.e. the last year.

Resources proven by drilling have been subtracted. The changes in the estimate primarily concern adjustments resulting from positive results of exploration taking place in the Norwegian Sea. Eighteen wells have been drilled there since 1998 and seven new discoveries have been made. Improved reliability in mapping and confirming good reservoir rocks at considerable depth has led to greater expectations of the potential for resources.

Exploratory drilling in the Barents Sea last year gave a very positive result. Oil was found in the Hammerfest Basin and the Nordkapp Basin. Even though considerable uncertainty attaches to the size of these discoveries, the results have raised the probability that recovery of oil and gas can take place in the Barents Sea.

Work is currently taking place to update the calculations of the basis for the undiscovered resources on the entire shelf in the North Sea, Norwegian Sea and Barents Sea. The results will be published later.

# 2. Growth in resources resulting from the exploration

## 2.1 Status of exploration

The area currently open for investigation comprises approximately 60 per cent of the Norwegian continental shelf. Awarded production licences cover 9 per cent of this area.

The basis for exploration within such a large area will differ with respect to the potential for resources, established infrastructures and environmental challenges.

There are still large volumes of undiscovered oil and gas on the Norwegian shelf. Figure 2.1 shows the distribution of discovered and undiscovered resources. Future exploration will take place in both established exploration areas like the North Sea and new ones like the Norwegian Sea. New challenges linked with understanding geological conditions and solving technological problems in deep water will arise. The North Sea is the best explored part of the Norwegian shelf. The geological conditions in large parts of the area are well understood, but no production licences have so far been awarded in some parts of the North Sea, such as the Skagerrak .

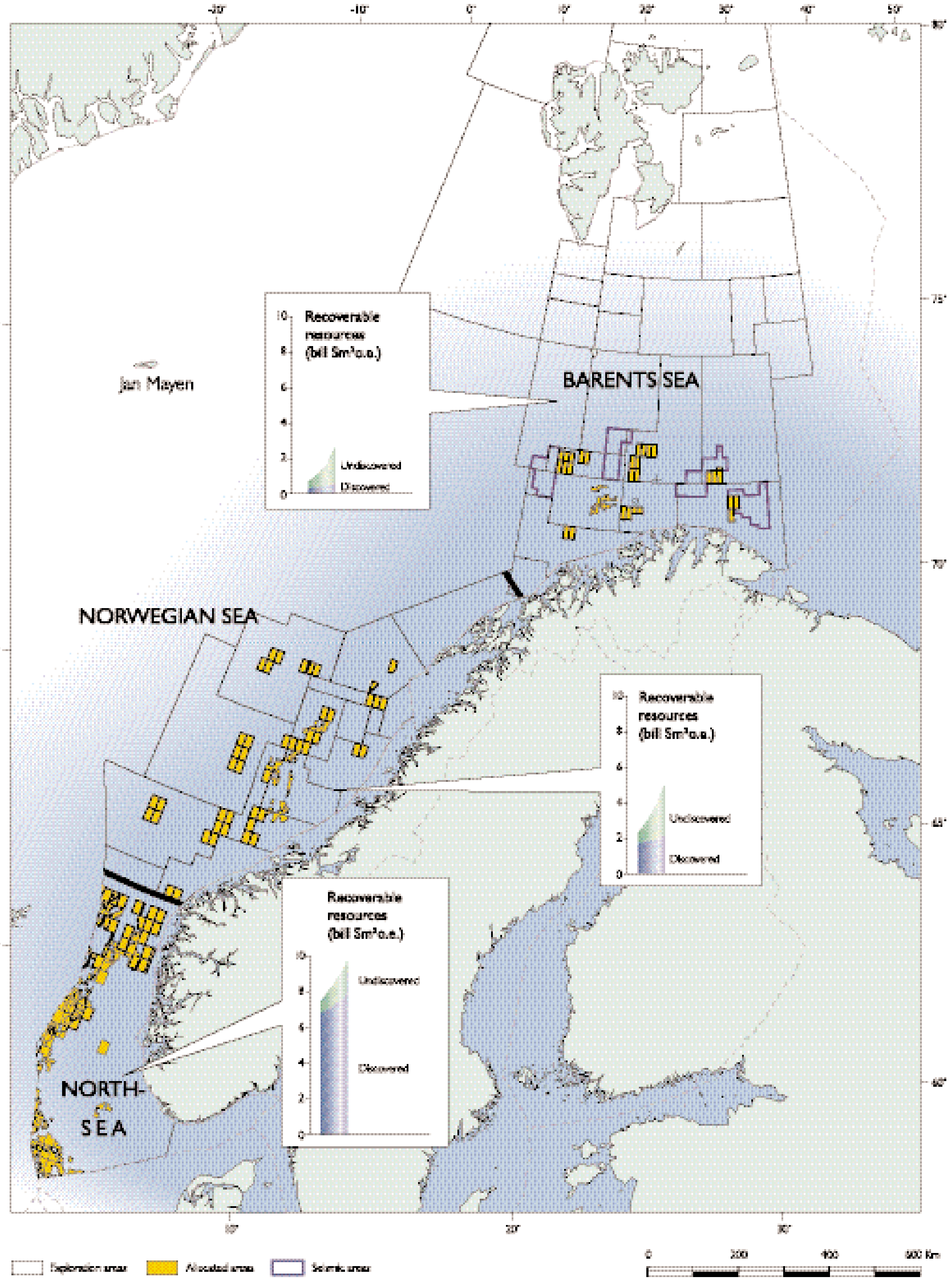


*Figure 2.1 Exploration status: discovered and undiscovered resources*

One of the main challenges in the North Sea is to find resources close to existing and planned infrastructures. Looked at from a resource management viewpoint, it is important that the parties concerned are encouraged to map and exploit relatively small discoveries that can utilise the infrastructure constructed for fields that are already in production. If small discoveries are not exploited while the large installations are still in production, there is a risk that it will never be profitable to recover some of them. Even very small discoveries will be able to offer good profitability if existing infrastructures are well utilised. The awarding of production licences and the exploration strategy in the North Sea will reflect these challenges, and the North Sea will probably remain important for exploration activity in the longer term, too.

Even though exploration activity has been and still is highest in the North Sea, the Norwegian Sea is the new growth area (Figure 2.2).

Figure 2.3 shows that most of the growth in resources arising from exploration activity on the shelf during the last nine years has been in the Norwegian Sea. A number of significant discoveries have been made in this area during the last five or six years. Several oil production facilities have also been established in the area, providing enhanced profitability for smaller discoveries that can be phased into these. Future exploration will enhance our understanding of the geology of the area and therefore lead to changes in estimates for the resource base. These factors are expected to increase the interest for exploration drilling on this part of the shelf.

The petroleum activity in the Barents Sea is faced with major challenges. Adjustments of the framework conditions for this region have been undertaken with a view to paving the way for further exploration.

Calculations of resources undertaken by the Directorate indicate a significant hydrocarbon potential in the Barents Sea. The area is large and the large quantities of 2D and 3D seismic acquired in connection with the Barents Sea Project, together with the results of the most recent drilling operations, will help to increase our understanding of the geology of the area and support further mapping of potential hydrocarbon traps.

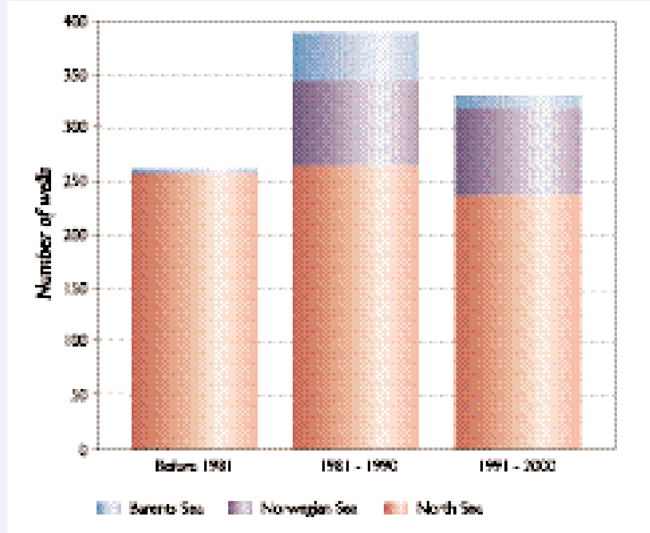


*Figure 2.2 Number of wildcat wells in the North Sea, Norwegian Sea and Barents Sea*

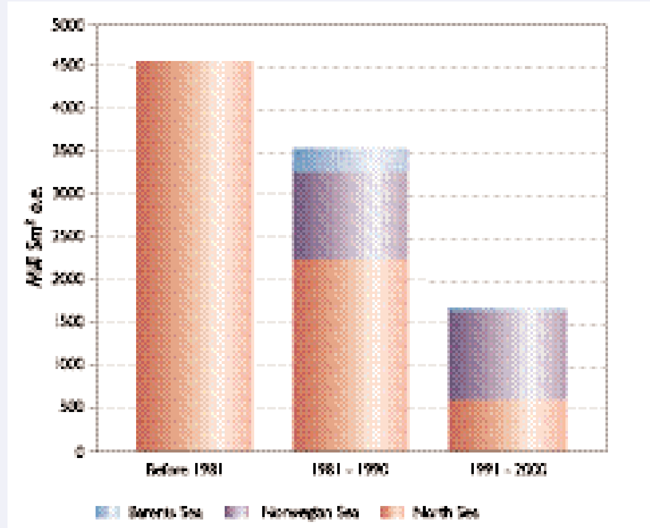


*Figure 2.3 Growth in resources deriving from exploration activity*

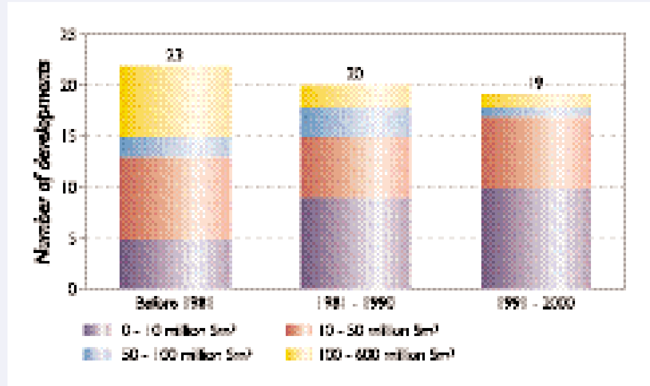


*Figure 2.4 Number of developments per year*

Three wildcat wells were completed in the Barents Sea last year, none having been drilled there since 1994. Hydrocarbons were found in two of the wells.

**From discovery to development**

In the 1970s, 1980s and 1990s, production began on 23, 20 and 19 discoveries, respectively (Figure 2.4), an average of two developments a year. There is reason to believe that this tendency will not change noticeably in the future. The Directorate's forecast for future production is based on two developments a year by periodisation of undiscovered resources.

Figure 2.5 shows the production and forecasts for discoveries made in the 1970s, 1980s and 1990s, respectively. The figure shows that production from discoveries made in the last ten years is expected to add less to the total production from the Norwegian shelf than discoveries from previous ten-year periods. This is because they are, on average, smaller.

## 2.2 Frequency of discoveries

Discoveries have been made in 230 of the 630 wildcat wells drilled on the Norwegian continental shelf. This is a frequency of 37 per cent, a good result by international standards.

Figure 2.6 shows the frequency of discoveries and the average number each year. The frequency is rising and has stood at more than 40 per cent on average in the last 10-year period. There are several reasons for this, but an important one is the advances that have taken place in acquiring, processing and interpreting seismic data in the last ten years. The greatest improvement in the exploration phase has been the shift from 2D to 3D seismic, since this has given more and better data as a basis for taking decisions on whether to undertake exploration drilling, and has therefore led to more precise exploration.

Figure 2.7 illustrates the great increase in the number of line kilometres of seismic shot during the 1990s. The figure also shows that an ever-increasing proportion of the seismic is being shot north of 62° N. These figures include seismic shot to improve the mapping of existing fields.

Figure 2.8 shows an example of the enhancement in resolution and depiction of detail when a shift is made from 2D to 3D and to 4C seismic, thus providing more

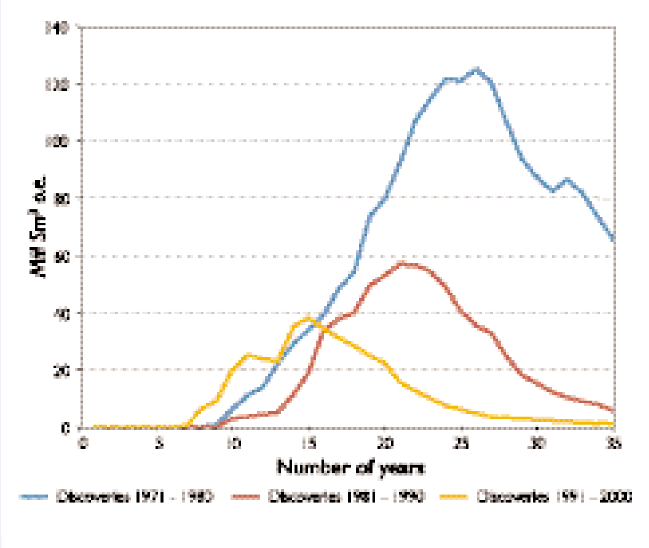


*Figure 2.5 Normalised production and the forecasts for discoveries in the period 1971 to 2000*

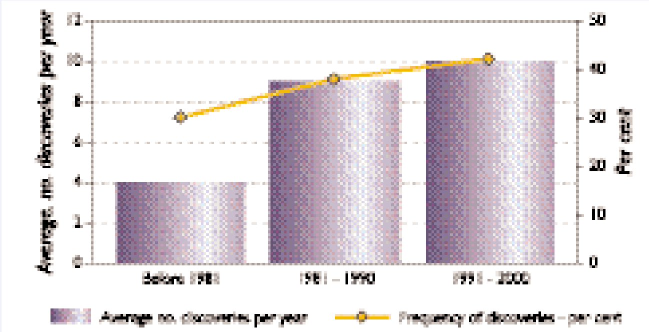


*Figure 2.6 Frequency and average number of discoveries per year*

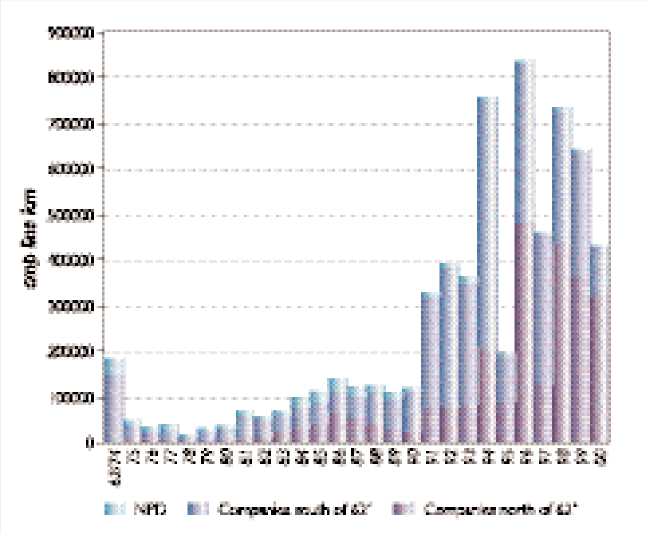


*Figure 2.7 Seismic data acquired on the Norwegian continental shelf in the period 1962 to 2000*



precise knowledge before drilling. The development in seismic work has helped to secure more precise exploration and hence increased the frequency of discoveries.

## 2.3 Exploration during the last nine years

The Norwegian Petroleum Directorate has undertaken an analysis of the exploration activity over the last nine years. The exploration in the last three years has been compared with that in the two foregoing three-year periods. Such analyses are undertaken regularly to learn more about the trend in the creation of value brought about by the exploration work. Together with other information, this will provide a basis for drawing up the exploration strategy on the shelf. This strategy and the activity should reflect the challenges facing us in each individual area.

The resource estimates for discoveries that have been put into production are much more reliable than for those that have not been developed. In general, the uncertainty in the resource estimates is greatest when the discovery is made, and decreases later. The value of the discovery is stated as the net present value. The resource estimate is the basis for calculating this value. The net present value estimates are therefore more unreliable for discoveries made late in the nine-year period than for those made early in the period. This makes it difficult to compare resource estimates in discoveries made in different years. The resource estimates and net present value of discoveries made in 2000 are specially uncertain.

**Growth in resources**

Figure 2.9 shows that the growth in resources has been greatest in the Norwegian Sea. The strong growth in the

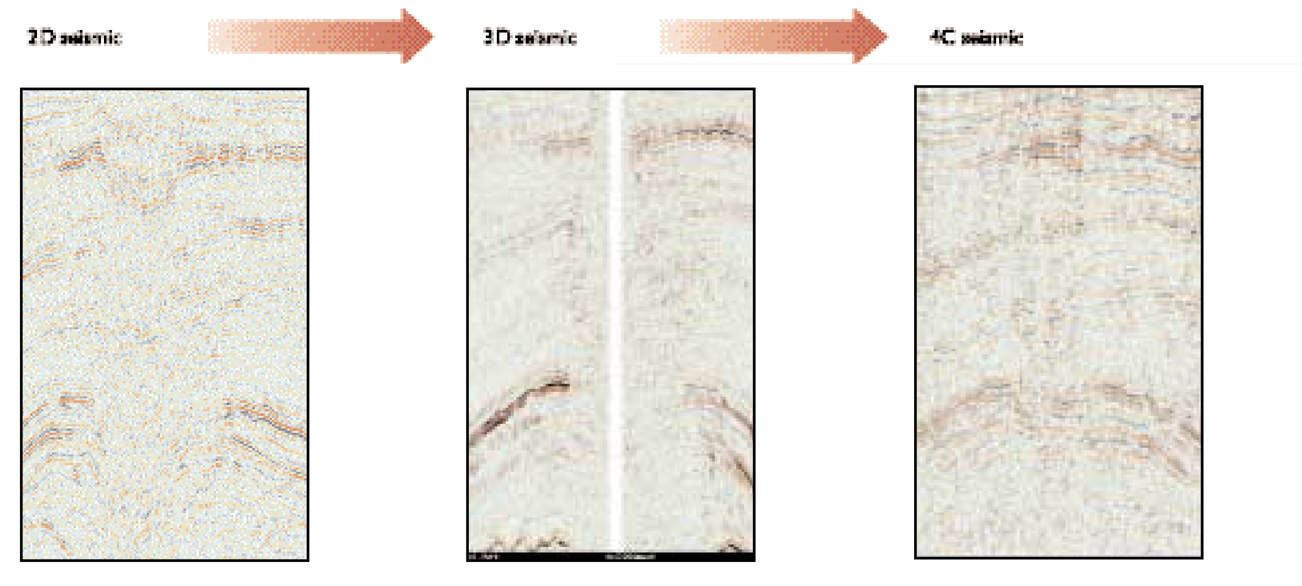


*Figure 2.8 Subsea multicomponent seismic (source BP)*

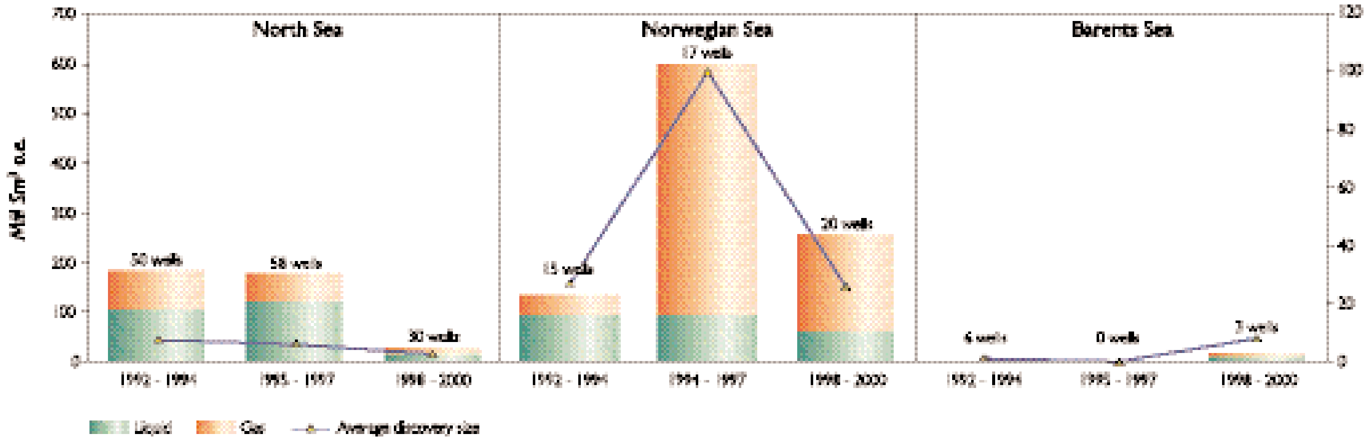


*Figure 2.9 Recovered resources proven in 1992 to 2000 and the total number of completed wildcat wells*

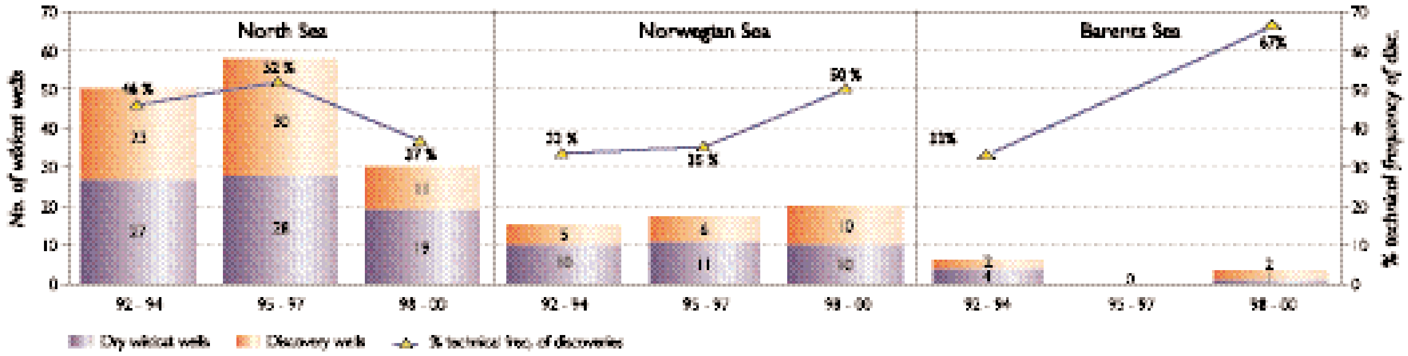


*Figure 2.10 Wildcat wells and frequency of discoveries in 1992 to 2000*

second three-year period is explained by the discovery of Ormen Lange in 1997; this has an expected resource estimate of 400 billion $Sm^3$ of gas.

The growth in resources in the North Sea is declining. The exploration activity in the last three years has brought a lower growth in resources in the North Sea than in the other three-year periods. The average size of discoveries in the North Sea has been declining throughout the period. Twenty per cent of the discoveries in the last three years were related to existing fields.

**Exploration activity**

The drilling activity in the North Sea has decreased during the last three-year period. Figure 2.10 also shows that the frequency of discoveries has dropped in this period compared to the foregoing three-year periods. However, it is still high by international standards.

Drilling activity in the Norwegian Sea is increasing, but is lower than in the North Sea. During the last three years, 20 of 53 wildcat wells have been drilled in the Norwegian Sea, but the frequency of discoveries in this period has been higher than in the North Sea. It has been 50 per cent in the last three years, a very high figure by international standards.

**Exploration expenditure**

Figure 2.11 shows the trend in the exploration expenditure. The exploration expenditure for each exploration well spudded in the last three-year period is higher than in the foregoing three-year periods. One reason for the increase in the Norwegian Sea is the high proportion of wildcat wells drilled in deep water and in complicated reservoirs.

**Exploration profitability**

Figure 2.12 shows the calculated profitability of exploration during the period 1992 to 2000, expressed as the net present value of the expected cash flow. The prices of petroleum products are based on the assumptions in the Long-term Programme for 2002-2005 (St. meld. no. 30 for 2000-2001). The present values are calculated on a pre-tax basis and with a 7 per cent discount rate. The figure shows that the calculated profitability from exploration has been declining in both the North Sea and the Norwegian Sea in 1992 to 2000. All told, the exploration activity during this period has revealed a potential of 67 billion NOK-2000 in the North Sea and 117 billion NOK-2000 in the Norwegian Sea.

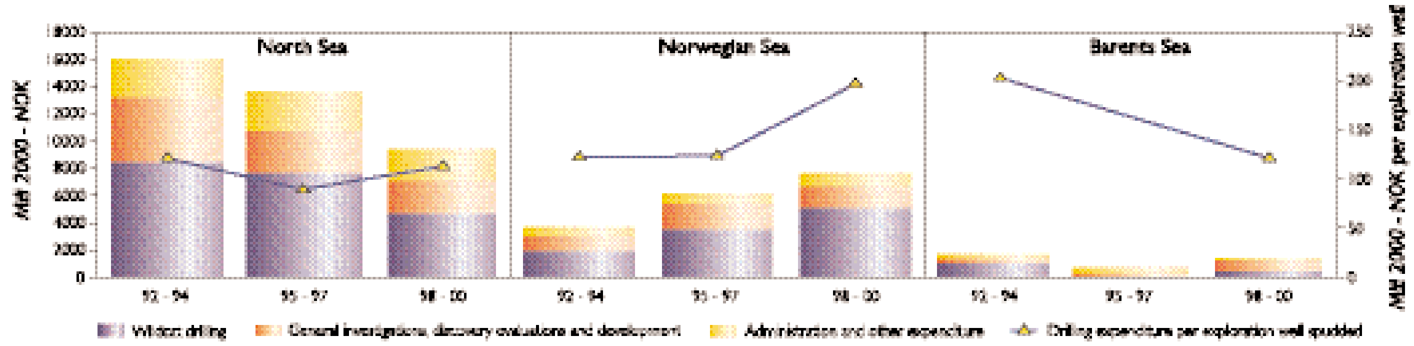


*Figure 2.11 Exploration expenditure in the period 1992 to 2000*

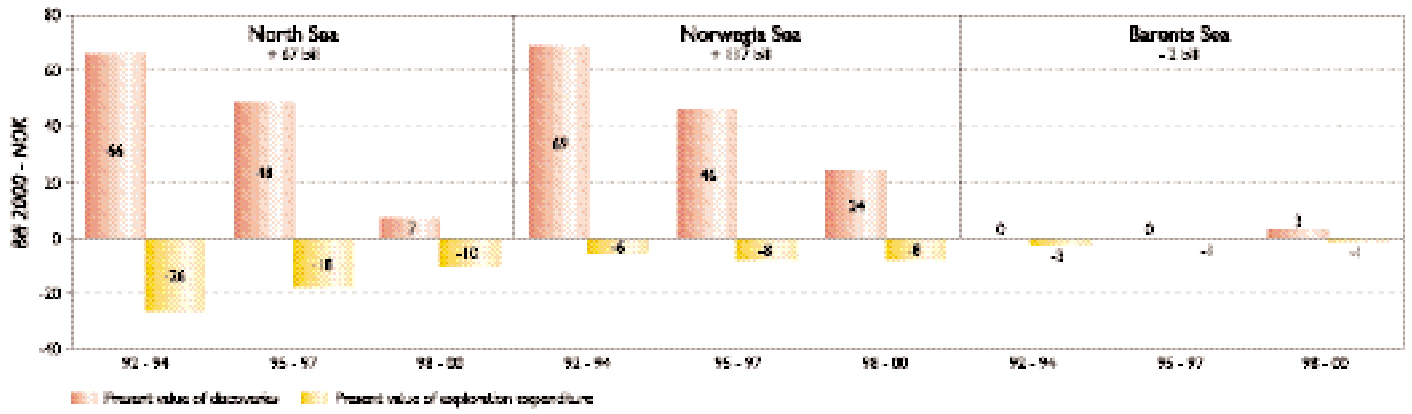


*Figure 2.12 Profitability of exploration on the Norwegian continental shelf in the period 1992 to 2000*

# 3. Resource development

The total resource base (recoverable oil, gas, NGL and condensate) has shown a positive trend during the last ten years (Figure 3.1). The estimate for the total recoverable resources has risen by more than 60 per cent since 1990. The remaining recoverable resources now amount to as much as the entire resource base estimated in 1995. Undiscovered resources are at the same level now as in 1990, even though many new discoveries were made in the 1990s.

One reason for this is an upward adjustment of the estimate for undiscovered resources, based on a thorough review in 1995 of the information available; this estimate has been regularly updated since then. Large quantities of seismic data, including 3D seismic, have been acquired in the last ten years. This has led to more precise exploration drilling.

The increase in the proven resources in discoveries and fields is first and foremost a consequence of new technology, in part technological leaps. Fewer wells and more precise drilling can now reach large parts of the reservoirs, and the re-use of wells by drilling laterally to new locations has reduced drilling costs. The further refinement of seismic methods aids the mapping of the remaining petroleum volumes. The possibility to extensively use gas for injection has been decisive for facilitating recovery.

The Norwegian Petroleum Directorate believes growth will continue, but this depends on the willingness of both the oil companies and the authorities to make a considerable effort and to take risks.

## 3.1 Trends in resources and reserves

Figure 3.2 shows how the volume of oil and gas resources in discoveries from the 8th to the 14th allocation rounds has changed. The appreciation factor is calculated relative to the volume of the discovery. The figure compares the resource estimates made by operators when the production licence was awarded, prior to drilling, after the discovery, in the years succeeding the discovery up to a possible development, and in 2000.

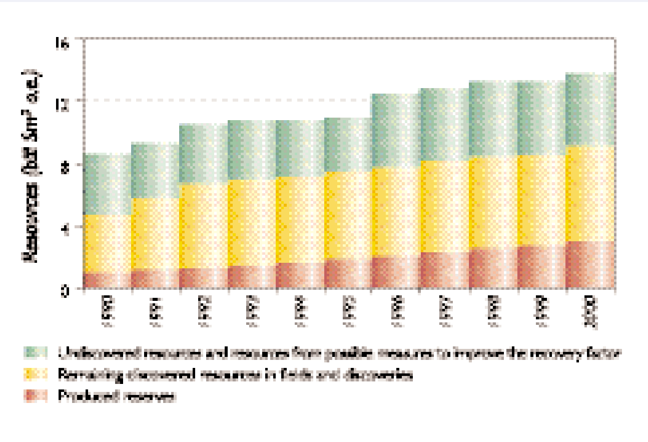


*Figure 3.1 Changes in the resource base. Total recoverable oil, gas, NGL and condensate*

| Category | Volume (Sm³ o.e.) |
|---|---|
| Small | < 15 million |
| Medium | 15-50 million |
| Large | >50 million |

*Table 3.1 Size categories for discoveries and fields used in the report*



Since discoveries on the Norwegian shelf vary immensely in size and reservoir properties, they have been separated in this figure into three size categories according to their volume (see Table 3.1).

Experience shows that, in the case of small discoveries, very optimistic estimates of volumes are generally made prior to exploration drilling. The total estimate for the resources in such discoveries is then halved after a time. Many of the smallest discoveries are not developed, and their resource base declines.

The estimates for medium-sized discoveries are also optimistic before discoveries are actually made. After a discovery is made, the estimate increases again. A medium-sized discovery is large enough to financially justify developing the resource base. Statistics show that, after fifteen years, the estimate for the resources in these discoveries has doubled relative to the volume at discovery.

The estimate of resources at the time the largest discoveries were made corresponds more closely with present estimates and with the estimate at the time the licence was awarded. These discoveries have then experienced a growth in their resources beyond the estimate made during the exploration period. Some of the largest discoveries on the Norwegian shelf were made in the early 1970s.

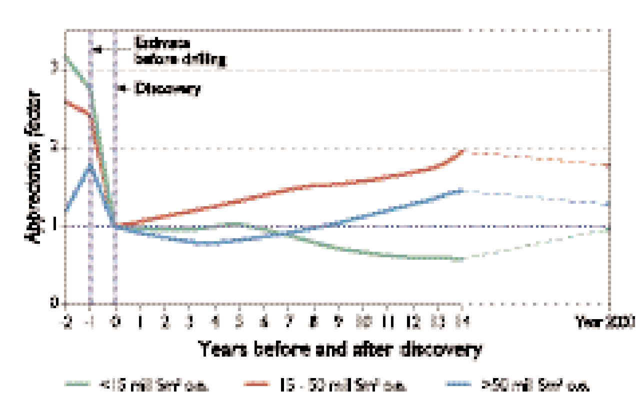


*Figure 3.2 The appreciation factors for oil and gas in relation to discovery volumes, the years after discovery and 2000*

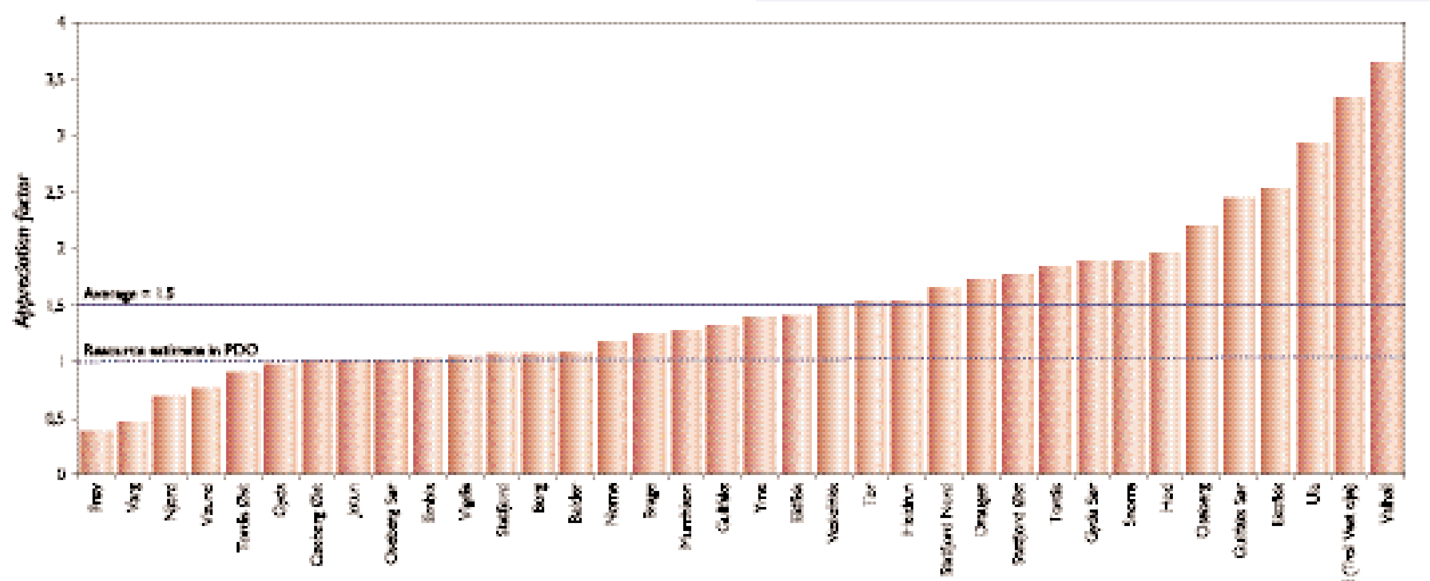


Figure 3.3 shows how the oil reserves have changed relative to estimates supplied as part of the decision-making process in connection with development plans. On average, the estimate of the reserve has risen by 50 per cent relative to that put forward in the plan. In recent years, there has been a particularly marked growth in the reserves on the Ekofisk, Ula, Valhall and Troll fields.

*Figure 3.3 The appreciation factor for oil reserves in relation to the reserves estimated in the PDO*

Only a few fields have seen a drop in the estimate of their reserves compared with that stated in their PDO.

The estimates of reserves for fields in the years prior to and following the onset of production are shown in Figure 3.4. The trend for the three size categories is seen to be quite similar. The estimates of the oil reserves rise before stabilising. Medium-sized fields have shown the highest average growth in their reserves in the first few years following the onset of production. Small fields have also shown a growth in their reserves. Discoveries that are developed and put into production usually show a positive growth in their reserves relative to that predicted in their PDO. Experience shows that the PDO estimate is generally too conservative.

Figure 3.5 compares the average growth up to the start of production, in 1990 and in 2000. Here, too, the change in the reserves is compared with the estimate of the reserves given in the approved PDO. The increase in the estimate of the reserves from the start of production up to 2000 is greatest for the largest fields. Fields with a long production history also showed an increase in their reserves during the 1990s. This is not shown in Figure 3.4 for fields that have had a longer production history than ten years.

Over the last ten years, all categories of fields have, on

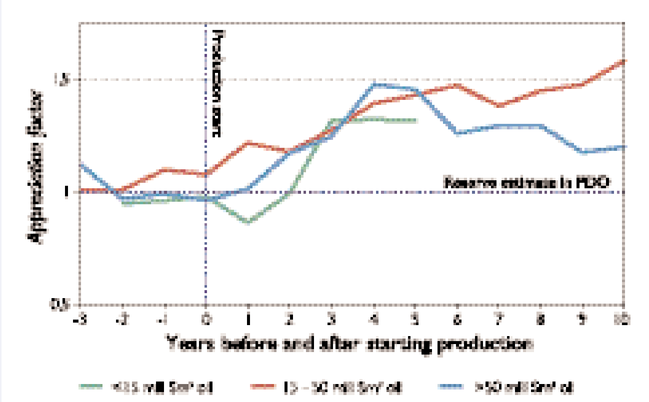


*Figure 3.4 The appreciation factor for oil reserves for small, medium and large fields in relation to the estimates stated in the approved PDO*

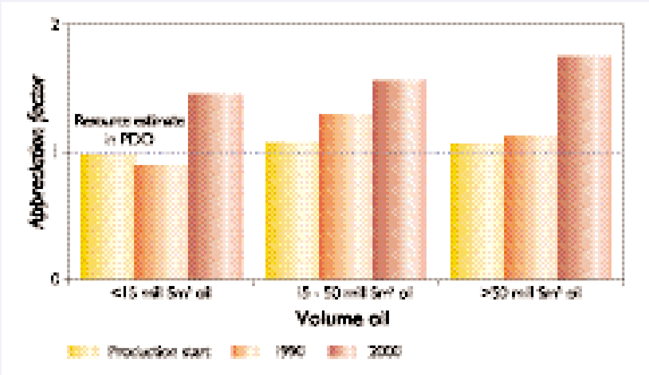


*Figure 3.5 The appreciation factor for oil reserves at the start of production, in 1990 and in 2000 in relation to the estimates stated in the approved PDO*

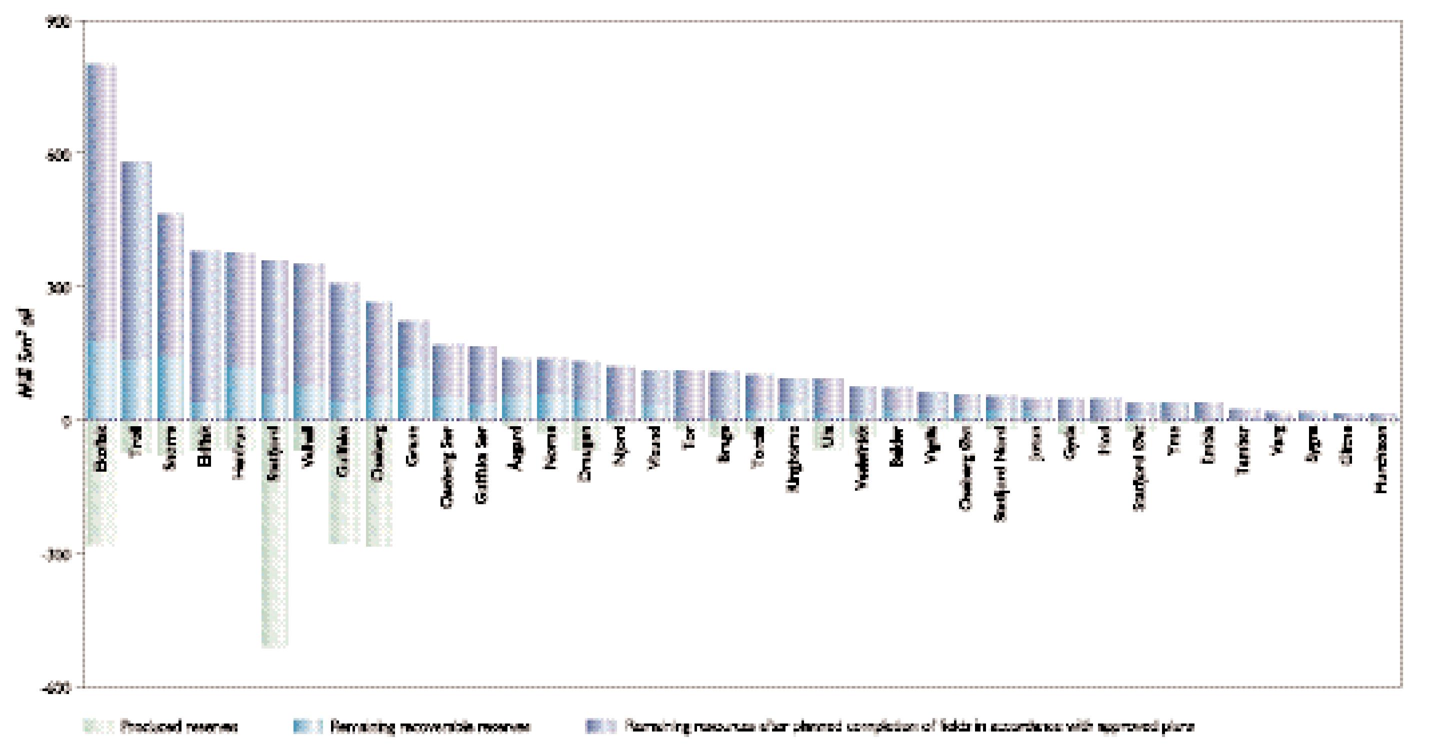


*Figure 3.6 Remaining oil resources after planned completion of fields in accordance with approved plans, remaining recoverable reserves and volumes produced from fields on the Norwegian shelf*



average, had an increase in the growth of their reserves. This is partly because improved and less costly drilling and well technology has enabled the drilling of more wells, horizontal wells and longer wells. This, combined with a better understanding of the reservoirs, has led to larger portions of the reservoir being drained and the recovery factor has risen correspondingly.

Large in-place volumes of oil still remain in the fields on the shelf. Figure 3.6 shows that there is a potential for a further increase in the reserves on the Norwegian shelf. The resources are shown as the volume produced, the remaining recoverable reserves and the remaining in-place resources for which no decision to produce has so far been taken.

## 3.2 Recovery factors for oil fields

Based on this year's resource account and the oil reserves as of 31st December 2000, the expected average recovery factor for oil on the Norwegian shelf is calculated as 44 per cent (Figure 3.7). It is calculated on the basis of approved reserves (resource classes 1 and 2) in fields, related to the relevant in-place volumes. The number of oil fields on the shelf is shown in brackets for each year.

From 1990 to 1997, the expected average recovery factor for oil rose by almost 10 per cent, but it has remained on the same level in the last three years. This is mainly because many of the fields seem to have reached a techno-economic limit for a further increase in their reserves. Even though some of the new fields have a high recovery factor, this is insufficient to counteract the effect of several fields having reduced the estimates of their reserves.

The expected recovery factor varies from field to field, and significant differences exist between sandstone and chalk reservoirs. The expected average recovery factor for sandstone fields is 47 per cent. The Statfjord field, which has already produced 60 per cent of its in-place volume and aims to achieve a further recovery beyond the planned 66 per cent, is an example of an oil field that has very high recovery, also on a world-wide basis. The approved plans for the chalk fields on the Norwegian continental shelf have an expected average recovery factor of 35 per cent. The generally more compact reservoirs and slower depletion mechanisms of chalk fields do not necessarily need to lead to a lower average recovery factor in the long term. One of the chalk fields, Ekofisk, the field that has produced for the longest time on the Norwegian continental shelf, has recently raised its expected recovery factor to more than 40 per cent.

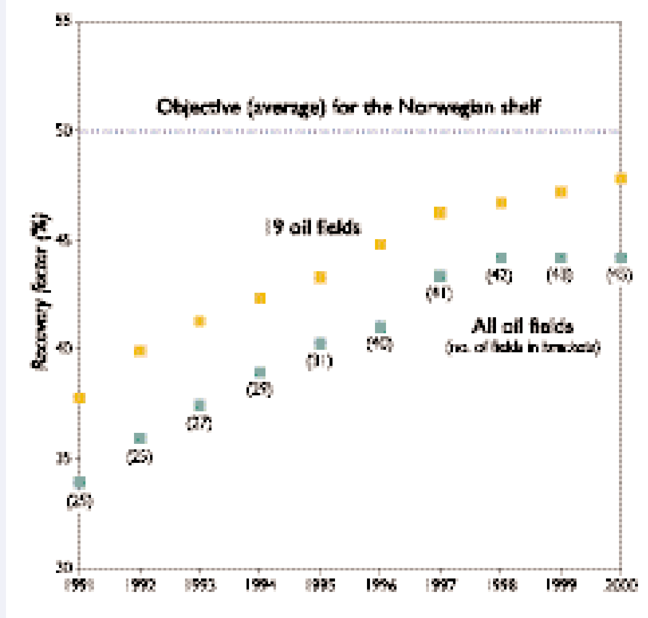


*Figure 3.7 The average expected recovery factors for all the oil fields on the Norwegian shelf and for 19 oil fields that were approved for development prior to 1991. The figures in brackets denote the number of oil fields on the shelf each year. The Directorate aims to achieve an average recovery factor of 50 per cent for the fields.*

Figure 3.7 also shows the trend in the recovery factors for 19 oil fields, all of which were approved for development prior to or during 1991. The recovery factors for these 19 oil fields, which have the longest production history on the shelf, are still increasing.

A long production history gives greater knowledge about fields. Combined with the development of new and improved methods of data processing and modelling, this knowledge has led to the phasing-in of additional resources. At the same time, projects to improve oil recovery have started. The oil companies on the Norwegian shelf have been at the forefront when it comes to developing and implementing new technology in connection with mapping, developing and recovering petroleum. This has characterised the Norwegian shelf and led to a continually increasing creation of value.

Among the oldest oil fields are a significant number of the largest fields on the Norwegian shelf. Seven large oil fields, all of which were approved for development before 1991, now have 40 per cent of the in-place oil and 57 per cent of the predictably recoverable reserves. These are the Draugen, Ekofisk, Eldfisk, Gullfaks, Oseberg, Snorre and Statfjord fields.

To maintain the pressure, at the same time as the oil is displaced, water or gas injection, or a combination of these, is now taking place on most fields. Water injection has contributed particularly strongly to greatly increasing the recoverable reserves on the Ekofisk field, and expectations are high that this will also prove to be the case on Valhall, for which a decision has now been taken to begin water injection.

Gas injection also makes a significant contribution to the high average recovery factor. With few exceptions, all oil fields will have a technical potential for improved recovery using gas injection. A better understanding of the technical mechanisms in reservoirs when such injection is employed will, however, be required to reduce the uncertainties regarding predictions and the basis for decision making. The optimal level for utilising gas to improve oil recovery on the shelf has probably still not been reached.

The increase in the average recovery factor in recent years has been higher for the largest fields on the shelf than the smaller ones.

Figure 3.8 shows that, at present, the expected recovery factor for large fields is, on average, 10 per cent and 20 per cent higher than for medium-sized and small fields,

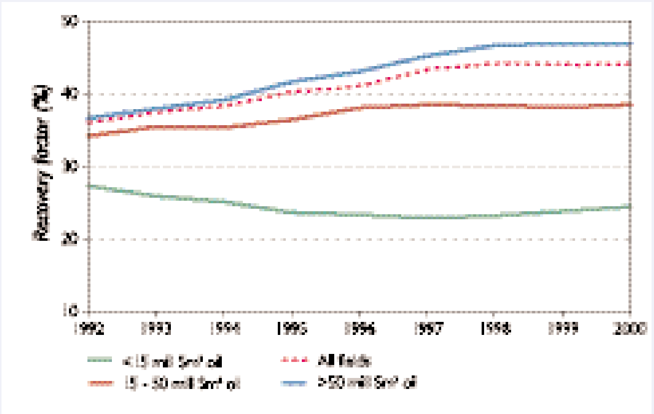


*Figure 3.8 Average expected recovery factors for large, medium and small fields (see Table 3.1), and all fields combined*



respectively. The smaller fields have an expected recovery factor that is, on average, lower. They are also more vulnerable to experiencing a possible down-side, and it is often not profitable to drill new wells. Small fields that only have pressure depletion attain a lower recovery factor. There are great variations within each group. Several medium-sized and large fields have an expected recovery factor in excess of 50 per cent. Even a new, small field like Sygna has a planned production that will give a recovery factor of more than 50 per cent.

Most large fields have been developed with a permanently located installation with its own drilling facility, in recent years also with subsea wells. The average recovery factor for fields with a subsea installation is lower than for those with their own installation. Of the large fields that only have a subsea installation, Norne is alone in having an expected recovery factor in excess of 50 per cent. Approximately half of the smaller fields have been developed with subsea wells. Achieving improved recovery from several of these fields is difficult. A drilling platform or vessel is required to drill new wells and perform well maintenance, and there is less flexibility for changing the recovery strategy than is the case with fixed installations.

The resource base for smaller fields is sometimes inadequate for it to be profitable to employ new technology or drill several new wells. Approximately 70 per cent of all plans to improve oil recovery come from the ten largest fields. Each of these has in-place volumes of more than 200 million $Sm^3$ of oil, and together they amount to a volume of 4 000 million $Sm^3$ of oil (Figure 3.6). This is almost twice that of all the other oil fields together. The potential for value creation that can be realised by increasing the recoverable reserves in the largest fields is therefore very great.

The annual reports submitted to the authorities by the operators provide a basis for tracking the development of planned projects to improve oil recovery. Figure 3.9 shows the development in the expected average recovery factor for all fields that are now operating, or whose development has been approved. The same group of fields is compared each year. The official resource estimate is used for those with approved plans for development and operation.

The resources that are in their early or late planning phases, classes 3 and 4, include specific projects to improve the recovery factor for the fields, as well as to identify additional volumes that can be phased in to the same fields. Plans to develop new discoveries are not

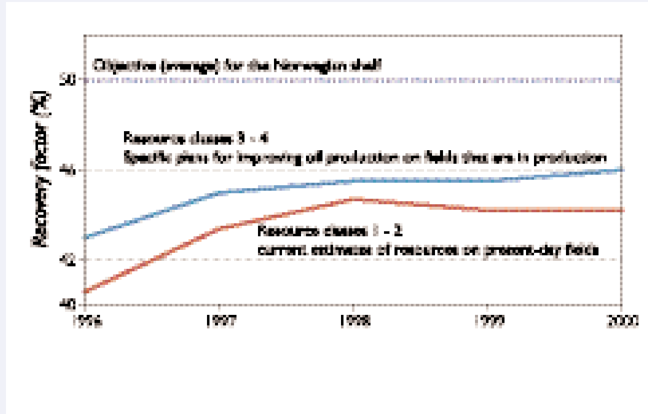


*Figure 3.9 Expected average recovery factor for fields that are in production or have an approved development plan, and the expected recovery factor when specific plans to improve recovery on the same fields are included*

included. The oil companies have reported projects in the planning phase that give a couple of percentage points improvement in the recovery factor. It is important to make these projects realisable.

The following three challenges exist as regards oil production and the strategy for recovery in the future:

1. A great effort is still required to achieve the expectation of an average recovery factor of 44 per cent that will be in keeping with present-day decisions. As of 31st December 2000, oil has been produced that corresponds to an average recovery factor of 29 per cent.

2. Specific projects that are being planned to improve recovery must be focused upon and funding must be provided to develop them so that they can be implemented on the fields.

3. If the goal that fields are to have an average recovery factor of 50 per cent is to be attained, new technological efforts based on long-term development work will be needed.

### 3.3 Oil field development

The trend in production on the fields, along with the related trend in expenditure, is shown in Figure 3.10. The way production and expenditure expectations have changed is shown in the form of forecasts dated 1990, 1996 and 2000. Oil fields approved for development prior to 1991 have experienced a massive increase in their reserves. The estimate of the volume expected to be produced from these fields is more than 1 billion $Sm^3$ higher today than in 1990. The increase applies to virtually all the fields. Production on oil fields approved after 1991 has so far not shown the same trend. The expected volume produced, and hence the recovery factor, for these fields has not changed significantly.

Oil production on oil fields approved for development prior to 1991 was substantially higher in the 1990s than was envisaged in 1990. The figure also shows that the forecasts were adjusted upwards in 1996 and 2000. Capital expenditure has been essential to realise improved recovery projects. Such projects have therefore also led to capital expenditure being higher in the 1990s than previously forecasted. Operational expenditure is not normally significantly affected by the production level. However, several fields approved for development prior

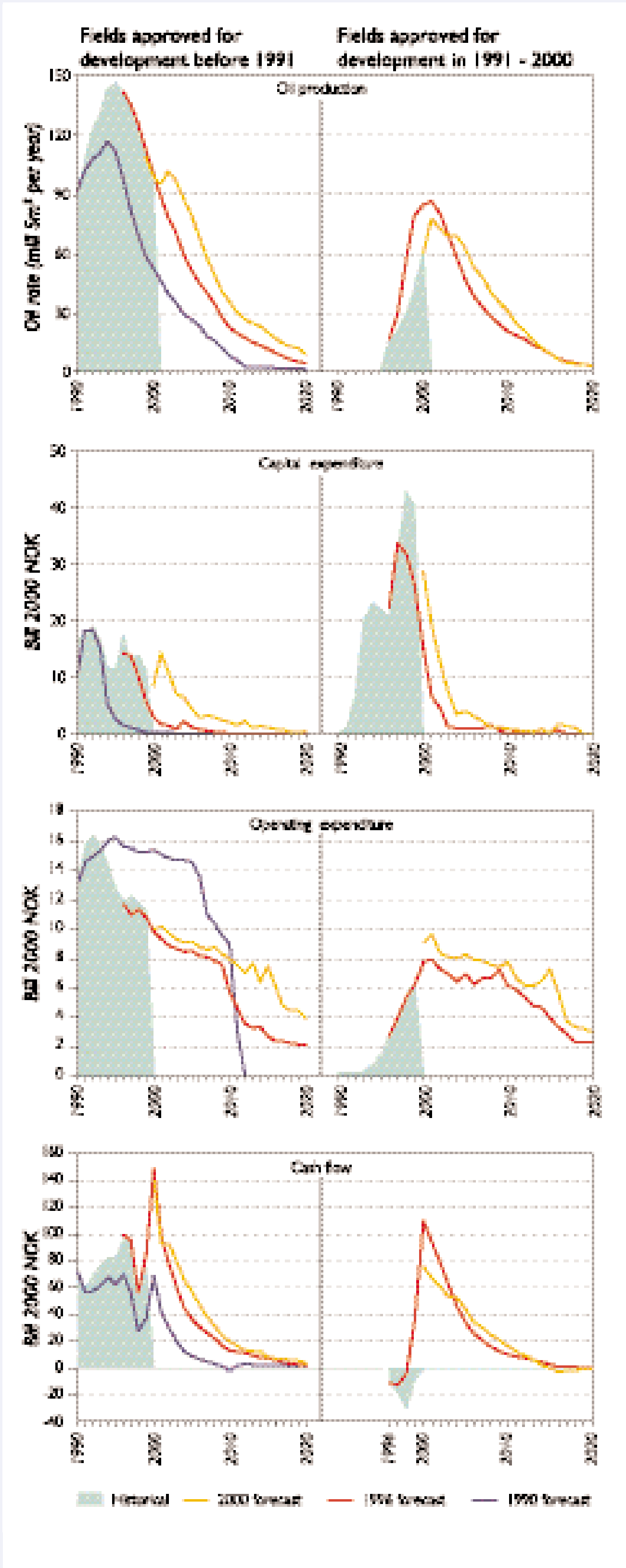


*Figure 3.10 Forecasts and historical data for oil fields approved for development before and after 1991*



to 1991 experienced substantial reductions in expenditure due to specially targeted saving campaigns. The cash flow for these fields was therefore significantly higher in the 1990s than it would have been if production and expenditure had been as expected. Present-day expectations with regard to oil production and expenditure will also help to produce a higher cash flow in the future than previous forecasts suggested, assuming the price of oil remains as expected.

The fields approved for development after 1991 have not had an equally long production history. The figure shows that capital expenditure on these fields has been high because several have been undergoing development. The capital expenditure for several of them has been higher than expected owing to cost overruns during the development period. Delays in starting production on these fields have also led to lower production in the 1990s than previously assumed. The figure moreover shows that the expected operational expenditure has also been adjusted upwards. The sum of the changes in production and expenditure has been negative with respect to the cash flow during the 1990s and that expected in the future.

For fields that have only been producing for a few years, companies do not normally plan projects to improve recovery whose implementation will not be required for several years. After experience has been gained, from production, there such projects will also become relevant for these fields, but more efficient utilisation of existing technology, and new technology, will probably be needed to gain a growth in the reserves on these newer fields. Technology from which the mature fields have benefited is already built into the basic forecasts for the new fields. Moreover, improved recovery from several of these fields may be difficult and expensive to achieve since they have been developed using subsea wells.

The technology required to develop several of the discoveries made early in the 1970s and 1980s was unavailable at that time. For instance, in the 1980s, it was regarded as impossible to produce oil from the Troll oil zone, but this now stands out as a great success that will give 213 million $Sm^3$ of oil, according to currently approved plans.

### 3.4 Future potential

A significant potential for exploitable resources still exists on the Norwegian shelf if adequate effort is made and favourable conditions are provided. In the case of the large fields, which contain the largest resources, the timing of the availability of new technological solutions will be important.

Technological development in recent years has focused upon extracting the mobile oil that remains, i.e. that which can be reached with new wells and/or using water or gas for non-miscible injection. More remains to be achieved here and it must still be focused upon. However, the immobile oil may provide a large, valuable additional potential, and it was also the target for much of the research effort at the end of the 1980s and the beginning of the 1990s. The immobile oil trapped in pores in the reservoir makes up part of the remaining oil. In some fields, less of this oil than expected has been extracted after the reservoir was flooded with water, but large volumes can nevertheless be recovered with the help of new forms of recovery technology, such as miscible gas injection, air injection, flooding with surfactants or other new techniques.

A renewed effort on research and technological development is required if we are to make use of the great potential for resources in the future. Less petroleum research has taken place in Norway in recent years. The drop in government-funded research has been particularly marked, but the companies have also spent less. An effort must be made to ensure that this research is not dependent upon short-term fluctuations in the price of oil, as we have experienced in recent years, and high priority must be put on recovery-related reservoir research and technological development.

To maintain experience and knowledge of the Norwegian shelf, we cannot afford, from a national viewpoint, to experience that the industry reduces its workforce each time the price of oil takes a downward swing. The Norwegian oil and gas industry is not an almost completed chapter. Currently known discoveries and fields ensure oil for at least 50 years and gas for at least 100 years. There will undoubtedly be a great need for highly qualified personnel to maintain this activity, and the way must be paved to be able to meet the recruitment needs through targeted input of effort.

# 4. Forecasts

## 4.1 Total production and total expenditure

The historical and expected total petroleum production from the Norwegian continental shelf and the historical and forecasted expenditures are shown in Figure 4.1. Production is still rising, and is expected to reach a plateau at approximately 280 million Sm$^3$ o.e. a year in 2002 to 2005, after which an average annual decline of 3 per cent is expected. As of 31st December 2000, 3 billion Sm$^3$ o.e. had been produced and sold from the Norwegian shelf. This is one-fifth of the resource base. The oil production that began in 1971 on the Ekofisk field accounts for 75 per cent of the total petroleum production to date.

Gas sales from the shelf started in 1977. Approximately 60 billion Sm$^3$ of gas are expected to be sold in 2001. The share of gas in the total production is expected to rise from 20 to 50 per cent around 2020.
This forecast depends upon the level of future gas sales from the Norwegian shelf. This report assumes that the market for Norwegian gas will stand at 90 billion Sm$^3$ a year, in which case the total production level on the shelf, reckoned in oil equivalents, will remain higher than it was in 1990 for another 30 years.

Slightly more than 1 600 billion NOK have been spent on the Norwegian shelf. Up to 2020, capital and operational expenditures are expected to amount to a further 1 100 billion NOK or so. All told, approximately 2 000 billion NOK will be spent on Norwegian petroleum activity from today up to 2050.

## 4.2 Oil production

**Uncertainties in oil production forecasts**
The Norwegian Petroleum Directorate receives annual reports from the operators giving resource figures, pro-

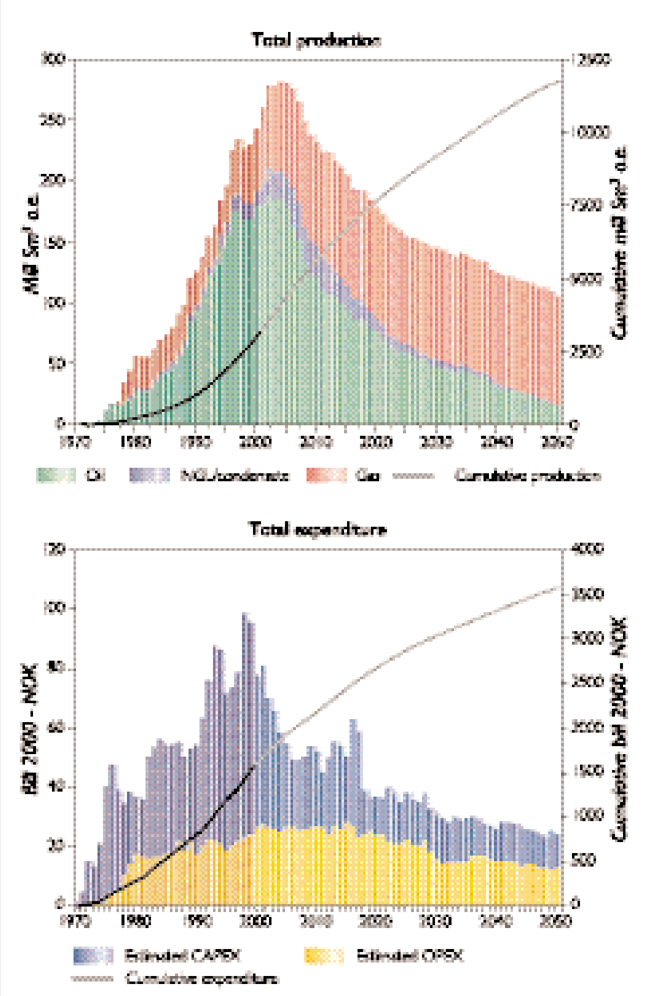

*Figure 4.1 Historical and forecasted petroleum production and expenditure*



duction forecasts, expenditure, tariffs and environmental emissions from fields that are in production and being developed, and for projects and discoveries which are expected to be developed within ten years. This material provides the basis for forecasting future income and expenses in connection with the Revised National Budget.

The accuracy of the short-term and long-term production forecasts for the Norwegian shelf has varied. The Directorate began systematically evaluating the uncertainties in the oil forecasts in 1995.

In Figure 4.2, long-term production forecasts are compared with actual production. At the beginning of Norwegian oil history, actual production was considerably less than both the operators and the authorities forecasted. This continued until the mid-1980s. Between 1985 and 1995, the long-term forecasts for oil production were significantly underestimated. In this period, they did not take adequate regard for the development and implementation of new technology and improved knowledge about the reservoirs. The forecasts at that time only covered production from proven discoveries, but from 1995 onwards they also included both undiscovered resources and possibilities for recovery over and beyond what the operators planned.

The short-term forecasts, or forecasts for oil production one to two years ahead, have mostly been overestimated from the 1970s up to today. Apart from the end of the 1980s and the beginning of the 1990s, when the large fields experienced an extension of their plateau period, there has been a tendency to overestimate production on almost all the fields. In recent years, the Directorate has made its own forecasts to compensate for the systematic overestimation on the part of the operators for the total oil production on the Norwegian shelf. According to the Directorate's estimates for the production, the gap between the forecasted figure and actual production has been less than 1 per cent in three of the last six years.

Figure 4.3 compares the forecast with the uncertainty stated in 1995 and actual oil production up to 2000. It shows that production throughout the period has been somewhat lower than the 1995 forecast, but well inside the area of uncertainty stated in 1995.

Figure 4.4 shows the cumulative forecast for the oil production along with the uncertainty evaluation from 1996. The total expected production in 1996 to 2010 has not changed significantly since the analysis in 1996.

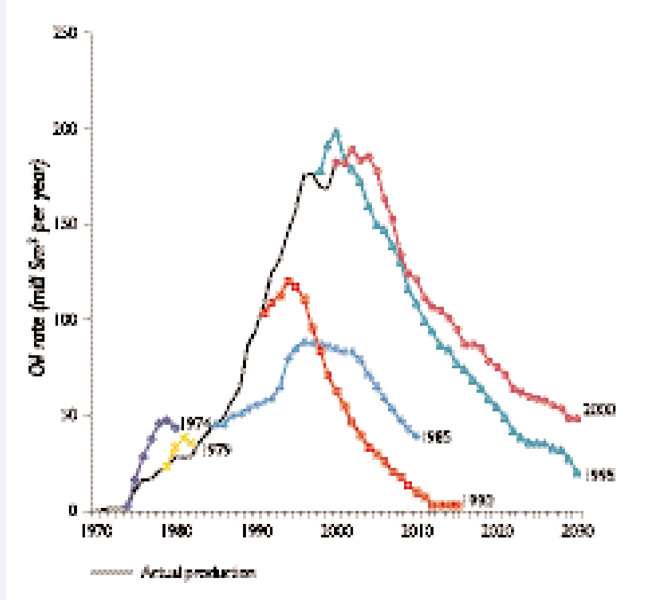

*Figure 4.2 Historical forecasts for oil production compared with actual oil production to sell oil*

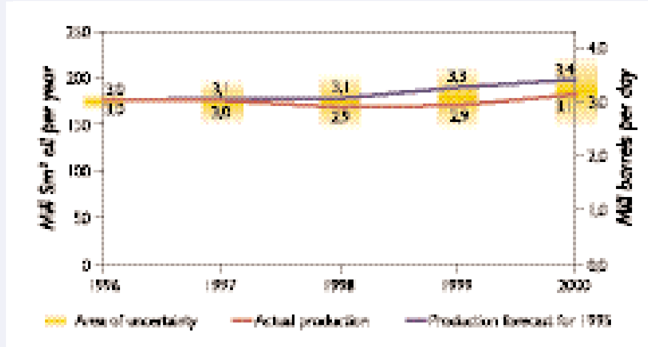

*Figure 4.3 Comparison between the production forecast for 1995 and actual oil production until 2000*

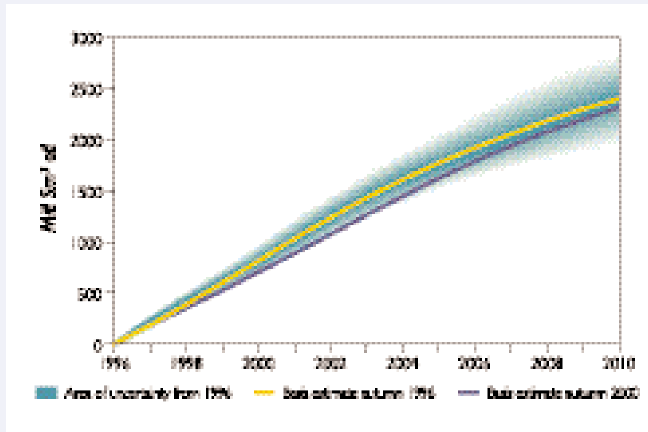
*Figure 4.4 Comparison between forecasts of cumulative oil production from 1996 and 2000*
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A connection exists between the estimates of resources on the various oil fields as a consequence of technological development, the price of oil, methodological errors in the estimates, strategic evaluations in each oil company, and so on. To evaluate the long-term uncertainty in the total production from fields in production and approved for development, a calculation algorithm is used that predicts a gradual transition from no correlation between the estimates today to complete dependence between the estimates at the end of the period (10-15years).

**Forecasts for oil production**

***Expected oil production in 2001 to 2005***
The forecast and the uncertainty evaluation for the total sale of oil are shown in Figure 4.5. Oil production for 2001 is estimated to lie between 170 and 195 million $Sm^3$, with an expectation of 182 million $Sm^3$ (3.1 million barrels a day). Oil production in 2000 was also 182 million $Sm^3$. Norwegian oil production is, moreover, expected to remain at this level throughout the period. The uncertainty in the oil production for 2002 is expected to be between 165 and 205 million $Sm^3$ (2.9 to 3.6 million barrels a day). Production in 2005 is expected to lie at about the same level as now.

Figures 4.6 and 4.7 show the forecast and the expected distribution for the oil production in 2001 to 2005. More than 900 million $Sm^3$ of oil are expected to be produced in this five-year period, along with some 50 million $Sm^3$ of condensate. Almost 90 per cent of the production is expected to come from fields that are in production today and 8 per cent from fields that were approved for development by 31st December 2000.

The largest uncertainty in the production forecast for the next five years relates to fields that are producing today. Unlike oil production at the beginning of the 1990s, the current forecast is based on still more fields with differing degrees of maturity. As many as 45 fields produce oil and gas now. Future forecasting is therefore less sensitive to major fluctuations in individual forecasts than earlier ones were when a few large fields dominated the course of production.

Figure 4.8 shows that the share of the oil production on the Norwegian shelf for which the four large fields, Ekofisk, Gullfaks, Oseberg and Statfjord, were responsible has been extremely high, but is now declining greatly. In 1990, these fields accounted for about 75 per cent of the total Norwegian oil production. In 2001,

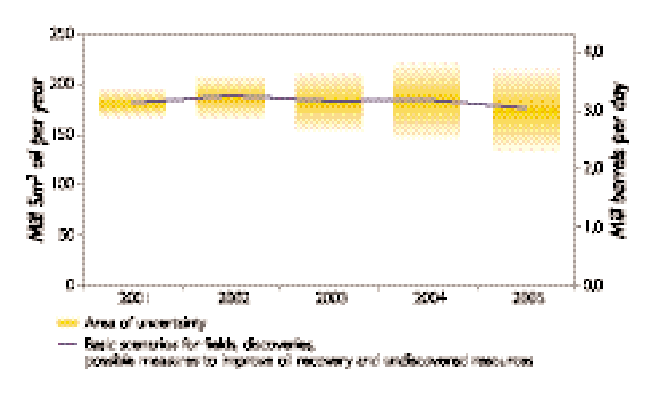

*Figure 4.5  Forecasts and uncertainties for the total sale of oil*

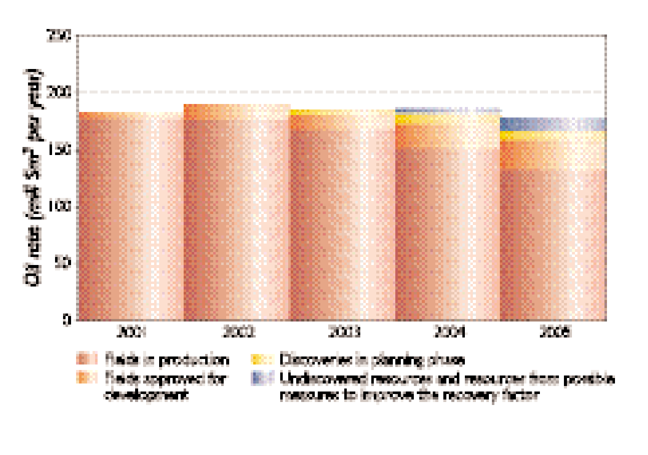

*Figure 4.6  Forecast of oil production in 2001 - 2005*

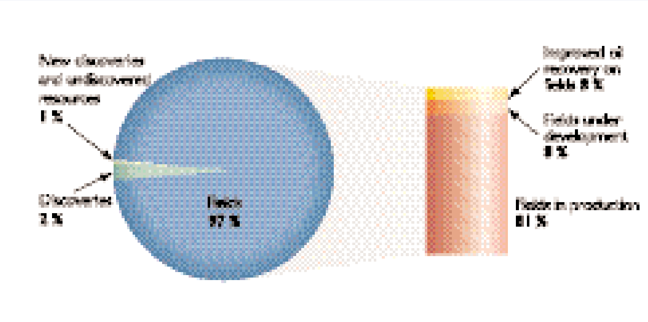
*Figure 4.7  Distribution of expected oil production, 1.0 billion $Sm^3$, in 2001 to 2005*



their share is expected to be less than a fifth. The uncertainty in the oil production during the next five years is linked with the time when a number of fields will enter their decline phase and how great the reduction in production on these fields will be. At the present time, only 25 per cent of the oil production comes from fields in the decline phase, but in 2005 as much as 75 per cent will come from such fields. There is also uncertainty related to when production will start on fields that are being developed. These will account for nearly 10 per cent of the production in the next five years.

***Expected oil production in 2006 to 2020***
Figure 4.9 shows the forecast for the total, cumulative oil production, with the uncertainty, for 2001 to 2020. Between 2.1 and 3.2 billion $Sm^3$ of oil are expected to be produced in this period, with an expectation of 2.6 billion $Sm^3$.

Figure 4.10 shows the annual distribution of the expected oil production in 2006 to 2020. More than 1.6 billion $Sm^3$ of oil, and also 160 million $Sm^3$ of condensate, are expected to be produced in this period. More than 60 per cent of this production is expected to come from fields that were already in production or approved for development on 31st December 2000. A third of this is expected to derive from existing and possible future measures to improve the recovery factor. Ten per cent of the production in this period is expected to come from the development of existing discoveries, and it is assumed that almost 30 per cent will come from future discoveries (undiscovered resources).

The long-term forecast for oil and condensate production is shown in Figure 4.11. Fields that are in production today are expected to provide most of the production before 2010, but towards the end of the period, currently undiscovered resources will be most important and will make up the largest proportion of the production, and hence the largest uncertainty.

The largest uncertainty in the future production from fields that are currently in production or approved for development rests in the effect of possible future measures to improve the recovery factor. All the fields that are now in production or approved for development will be in their decline phase in 2010. The uncertainty in the production from these fields concerns how effective measures to reduce the rate of decline on these fields prove to be. Current plans show that these fields have an expected average recovery factor of 44 per cent. The aim of the Directorate is that 50 per cent of the in-place oil will be recovered.

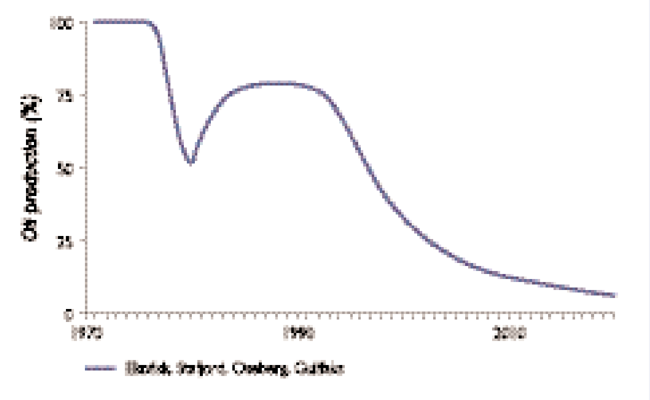
*Figure 4.8  Proportion of the oil production that derives from the Ekofisk, Statfjord, Gullfaks and Oseberg fields*

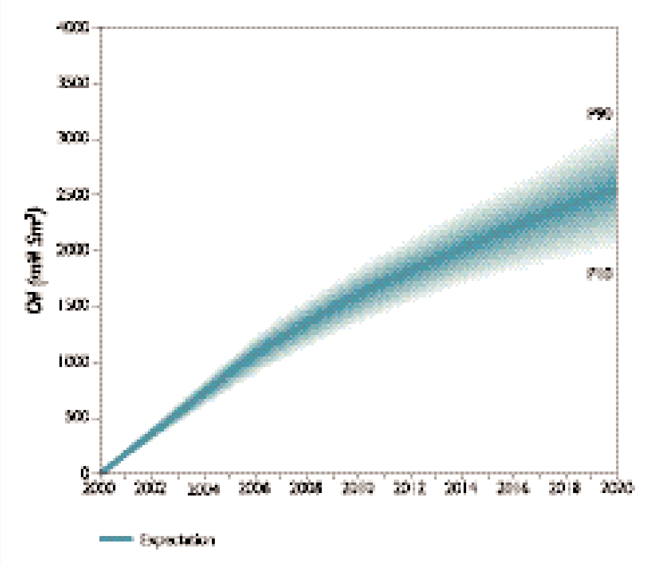
*Figure 4.9  Cumulative oil production with area of uncertainty*

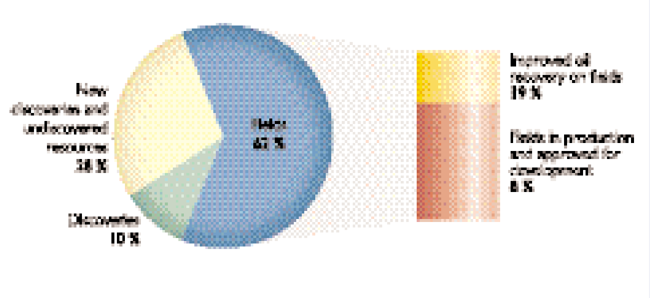
*Figure 4.10  Distribution of expected oil production, 1.6 billion $Sm^3$, in 2006 to 2020*

Twenty-six development projects are in their planning phase. Their total resources are estimated at just over 100 million Sm³ of oil and 210 million Sm³ of condensate and NGL. Production from some of these deposits is expected to start in 2003. The largest uncertainty in the production of liquids is linked to when production will actually start. The largest liquid discoveries that are in their planning phase are Kristin, Skarv and Snøhvit, which account for 50 per cent of the oil, condensate and NGL resources. These discoveries depend upon the sale of gas before a decision on their development is taken. Experience has revealed a tendency for discoveries to be put into production later than planned. Nearly all the fields that were expected to be put into production before 2000 began producing at least 6 months to a year later than predicted.

Undiscovered resources account for the greatest uncertainty in the forecasts for oil production in the long term. The Directorate has produced forecast for oil production from the undiscovered oil production on the Norwegian continental shelf annually since 1995 in connection with the Revised National Budget.

Figure 4.12 shows the forecast of oil production for undiscovered oil resources. Up to 2012, it is expected that production will only take place from prospects that have already been mapped now.

## 4.3 Gas production

The total volume of gas remaining is estimated at 6 400 billion Sm³, the range of uncertainty being 4 200 to 9 200 billion Sm³. This includes both discovered and undiscovered resources.

### Gas forecasts

Norway has commitments to sell about 1460 billion Sm³ of gas. Figure 4.13 shows these commitments distributed according to field contracts, allocated supply contracts and non-allocated supply contracts. They reach a plateau in 2005 at approximately 70 billion Sm³. However, new commitments are expected to be entered into so that gas sales on plateau can be substantially higher and the plateau level be maintained considerably longer than the figure indicates. Figure 4.14 shows various scenarios for the trend in Norwegian gas sales.

About half of the gas resources derive from undiscovered resources and possible measures to improve gas recov-

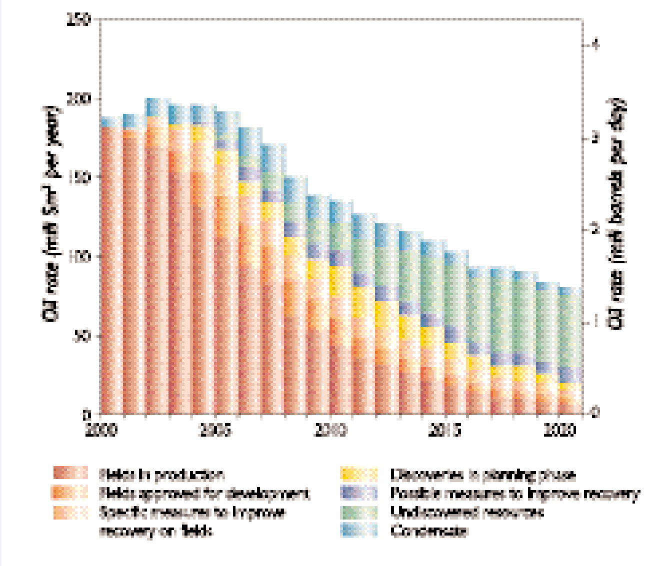


*Figure 4.11 Long-term forecast of oil and condensate production*

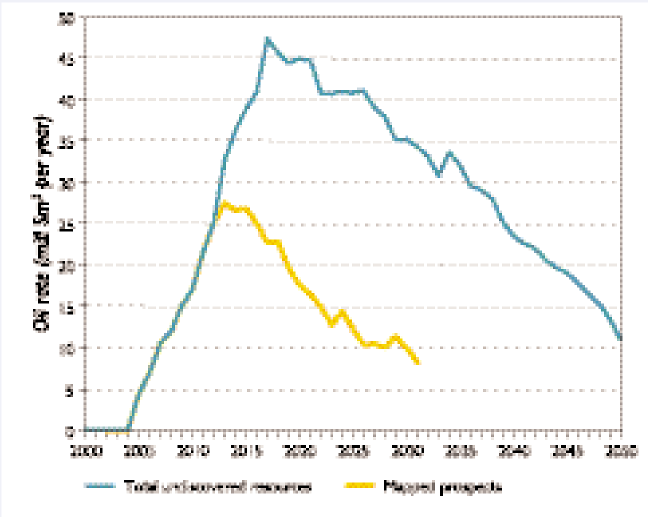


*Figure 4.12 Forecast of oil production from undiscovered resources*

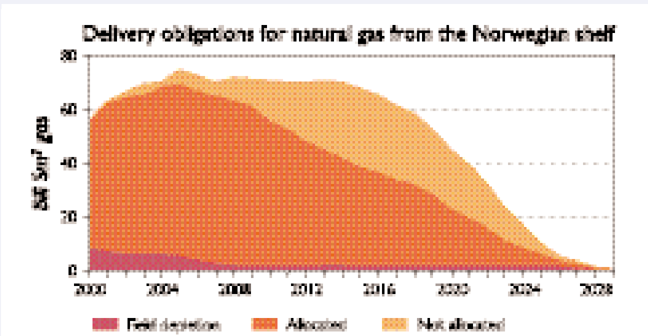


*Figure 4.13 Committed sales for deliveries from the Norwegian shelf*



ery. Further technological development will be the key to both finding and developing new gas fields.

In addition to an increased use of gas on land in Norway, LNG (liquified natural gas) and GTL (conversion of gas to liquid) can help to increase the sale of gas. Access to alternative markets will give greater flexibility in the gas production. New technology in these areas will have a positive effect on the exploration for, and development of, small oil discoveries with associated gas.

### Gas for injection

Almost 40 billion Sm³ of gas were injected into fields in 2000, mainly to improve the recovery of oil. The amount of gas injected on the shelf has increased in recent years, the Åsgard, Njord, Gullfaks and Visund fields being largely responsible for this. In 2001, it is planned to inject nearly 45 billion Sm³ of gas. According to the forecast, a plateau will be reached in 2002. Gas injection generally gives only temporary postponement of gas production that can be sold.

### Gas resources viewed geographically

Figure 4.16 summarises the total remaining gas resources distributed according to areas and degree of maturity. Figure 4.15 explains the geography and the designations used in Figures 4.16-4.18.

Gas resources are regarded as mature in fields that are in production or approved for development. The pro-portion of mature gas resources varies from 97 per cent in the Troll area to 0 per cent north of the Halten Bank. 38 per cent of the remaining gas resources are regarded as mature.

Figure 4.17 shows the proportion of unsold gas out of the total, proven gas resources in the various areas. The basis for the calculations are the remaining gas resources after subtraction of gas that is subject to field-depletion contracts and allocated supply contracts. The remaining gas resources include 359 billion Sm³ of gas that has been sold, but not allocated. (In this figure, the gas resources have been corrected for the thermal value.)

About 55 per cent of the total, remaining, proven gas resources have not been sold. The proportion of unsold gas varies from 33 per cent in the Sleipner-Frigg area to 100 per cent in the Møre and Vøring Basins.

The total undiscovered gas resources are estimated at 2 400 billion Sm³. This figure is based on analyses of 58 identified plays within geographically and stratigraphi-

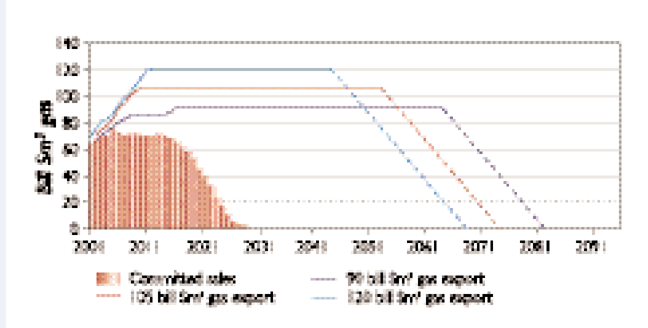


*Figure 4.14 Scenarios for future gas sales*

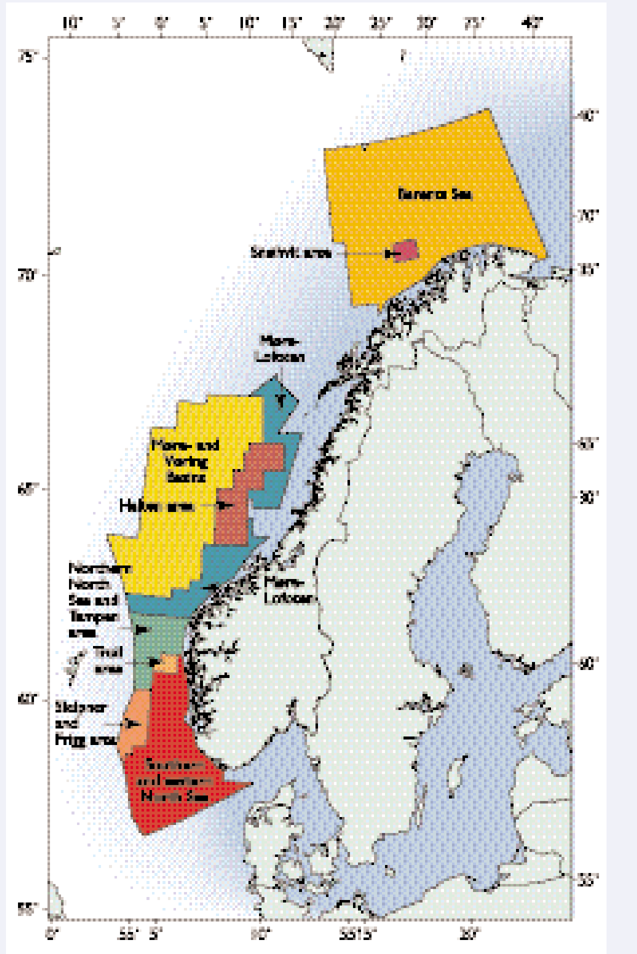


*Figure 4.15 Map of the Norwegian shelf showing the areas described in figures 4.16-4.18*

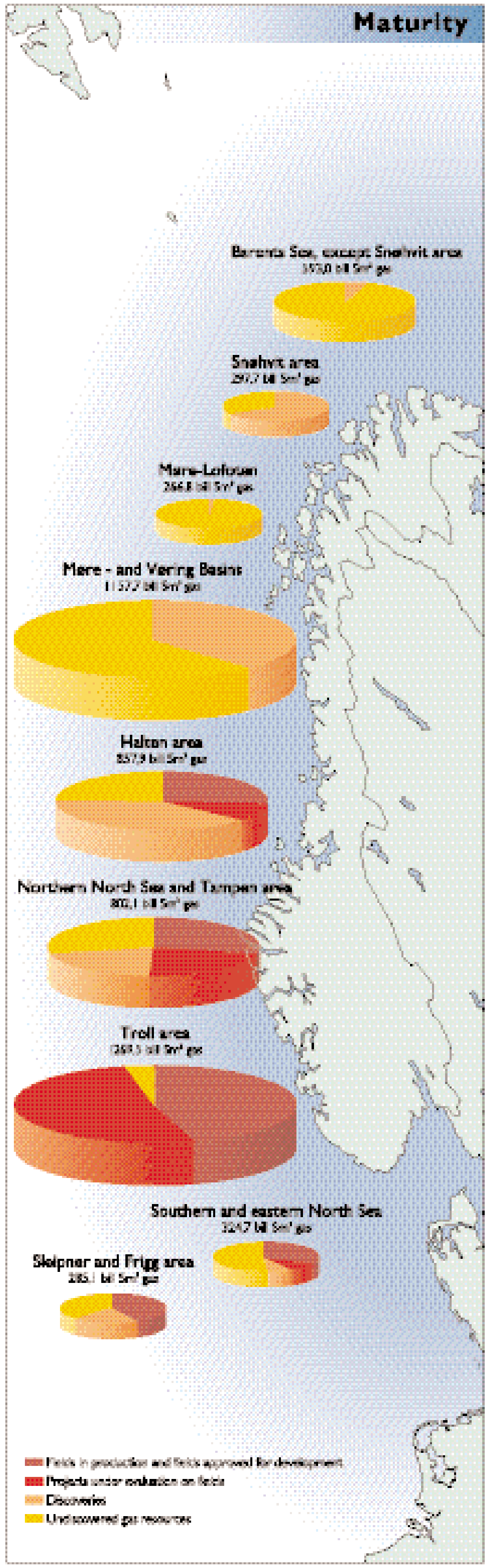


*Figure 4.16 The total remaining gas resources apportioned according to geographical areas and extent of maturity*

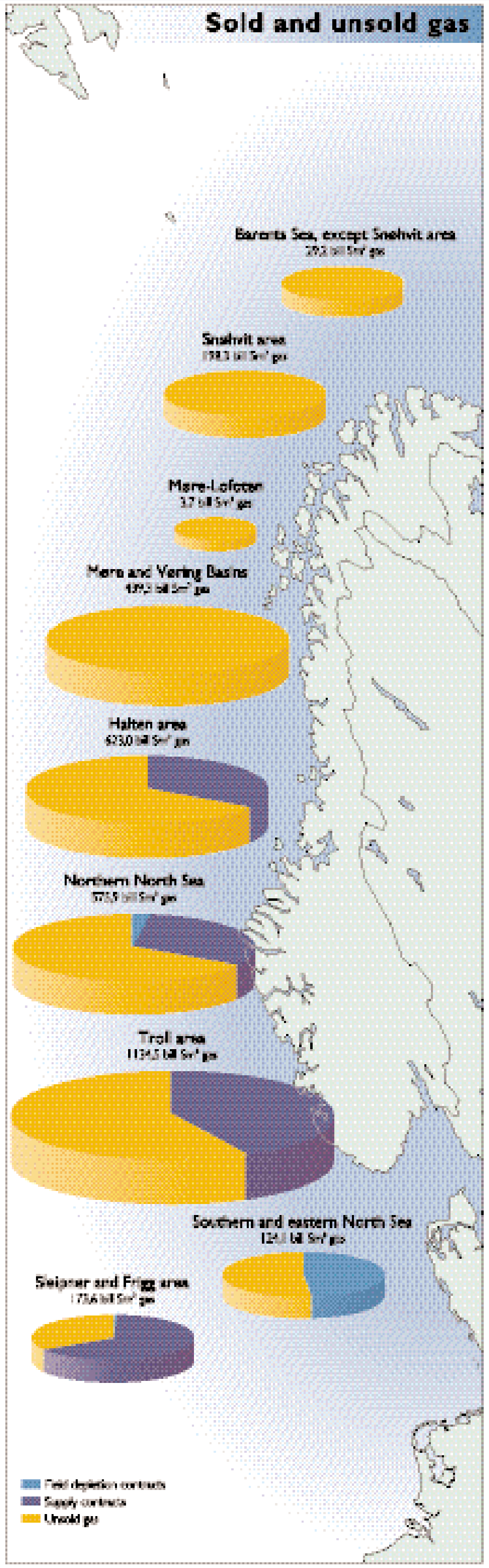


*Figure 4.17 Proportion of the total discovered gas resources apportioned according to geographical areas*

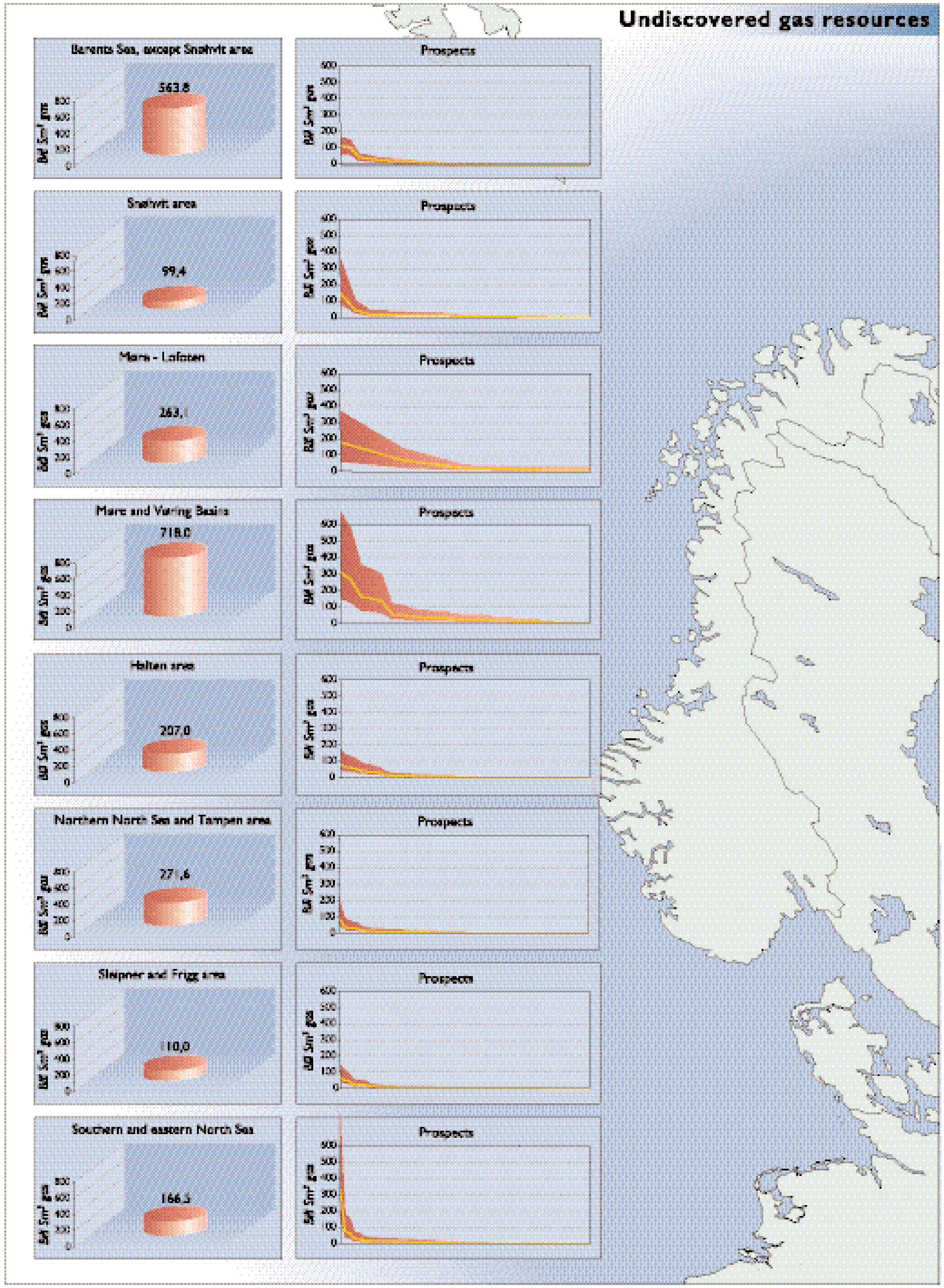


*Figure 4.18 Undiscovered gas resources apportioned according to geographical areas*

cally delimited areas or units. An analysis has been done to illustrate the possible gas resources that can be found in the future and where they will most likely be located. Figure 4.18 shows the distribution of undiscovered gas resources. The majority are in less mature areas like the Barents Sea (except the Snøhvit area) and the Møre and Vøring Basins.

Substantial gas resources are also expected to be found in more mature areas, such as the Halten area, the northern North Sea including the Tampen area, and southern and eastern parts of the North Sea.

Figure 4.18 also shows prospects in the various areas, ranked according to size. The probability of making a discovery in the various prospects in a particular area may vary from 1 to 90 per cent. Hence, substantial uncertainties exist regarding whether discoveries will be made. As regards their size, there also proves to be significant uncertainties when comparison is made with the original estimates prior to drilling. This is illustrated in Figure 3.2. However, Figure 4.18 is able to say something about the size if a discovery is made. The largest discoveries are expected in the Møre and Vøring Basins, where a gas discovery close to the size the Ormen Lange discovery is likely on a statistical basis.

Significant gas discoveries can also be expected in immature areas in the Møre-Lofoten region and the south-eastern North Sea. Gas discoveries approaching 80-90 billion Sm³ can be expected in the northern North Sea and the Halten area. In the northern part of the North Sea, including the Tampen area, and in the Halten area, there are statistical expectations of gas discoveries containing up to 75 per cent of the resources in the Frigg field.

## 4.4 Expenditures

### Capital expenditure (CAPEX)

More than 700 billion NOK will be invested over the next 20 years, between 20 and 40 billion NOK annually. It is expected that more than 900 billion NOK will be invested over the next 50 years (see Figure 4.1). So far, just over 1 100 billion NOK have been invested on the Norwegian shelf.

Most of the capital expenditure to date has concerned large installations, but recently it has been more usual for developments to consist of subsea installations connected to existing fields. Future developments are



expected to consist of smaller facilities, largely of subsea type. In the longer term, production may also be controlled from land. Figures 4.19 and 4.20 show the distribution of capital expenditure between wells, installations, pipelines and facilities on land. New wells will account for a relatively larger share of the capital expenditure in the future. From 2001 to 2010, almost half the capital expenditure will concern wells, whereas from 1990 to 2000 only 20 per cent funded wells.

Capital expenditure over the next five years is expected to be less than in 2001. In certain years, it may approach close to the present level, as a consequence of several large developments taking place simultaneously. All told, it is expected that nearly 200 billion NOK will be invested over the next five years. Figure 4.21 shows the distribution of capital expenditure in 2001 to 2005. Capital expenditure in fields that are in production or approved for development will account for 70 per cent in this period. Half of this regards investment that have been decided upon in fields that are in production, and a third investment in fields that are being developed.

Approximately 500 billion NOK are expected to be invested on the Norwegian shelf from 2005 to 2020. Figure 4.22 shows the expected distribution of capital expenditure during this period. Fields in production and approved for development, discoveries in their planning phase and development of future discoveries from undiscovered resources will each account for just less than a third of this figure.

**Uncertainties in the capital expenditure estimates**

The uncertainty in the estimate of the total capital expenditure on the Norwegian shelf is shown in Figure 4.23. It is stated as a high and a low forecast for individual years. The capital expenditure for 2000 and 2001 is estimated to be 51.5 and 52.4 billion NOK, respectively. Historically, the discrepancy between the forecast and the actual capital expenditure made in the succeeding year has been ± 6 per cent.

A capital expenditure of between 20 and 40 billion NOK a year is expected from 2005 to 2020. The uncertainty in the first part of the period will be dominated by uncertainties in connection with discoveries that are in their planning phase. In the longer term, it will be dominated by uncertainties related to undiscovered resources.

The largest discoveries in the planning phase are gas discoveries whose development depends upon the gas

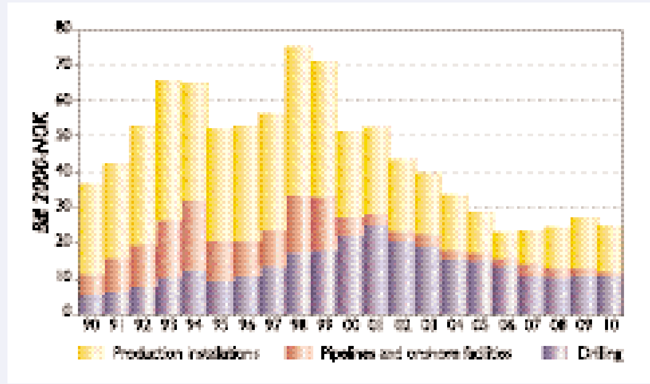


*Figure 4.19 Distribution of capital expenditure among wells: installations, pipelines and onshore*

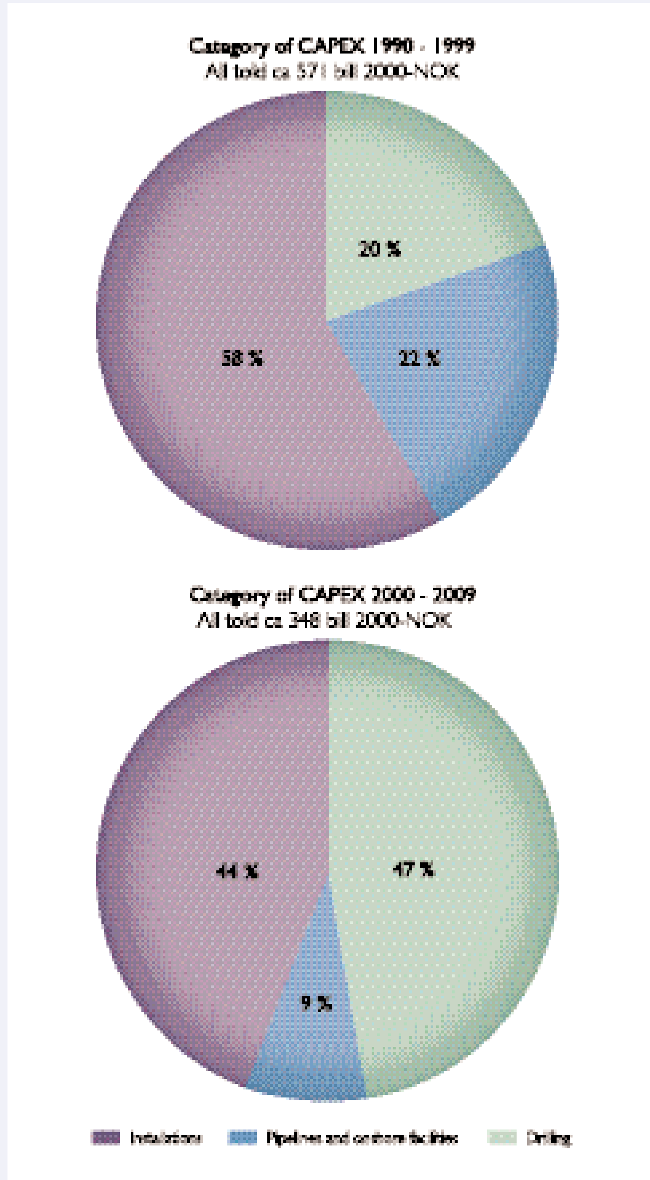


*Figure 4.20 Distribution of capital expenditure*

being sold. This concerns, for example, the Ormen Lange, Snøhvit and Skarv discoveries. The level of capital expenditure in the years ahead therefore depends upon how much gas is sold from the Norwegian shelf. Investments that concern discoveries may also be changed because development projects change in size due to the choice of simpler or more complex solutions, this often being influenced by expectations regarding the price of oil.

In the longer term, the number and size of developments of new discoveries have most bearing on the total capital expenditure. Great uncertainty is attached to these forecasts. This applies to how many discoveries are made, how large they are, how soon they can be developed and what they will cost. Experience shows that exploration activity is a function of the price of oil, implying that oil companies largely place emphasis on cash flow. The Norwegian Petroleum Directorate believes that a more long-term perspective would have led to a more rational management of resources.

There are many indications that several of the large, new, future discoveries will be of gas and condensate. Their development will depend upon the sale of gas, and some of the prospects may be competitors to current gas discoveries.

**Operating expenditure (OPEX)**
The operating expenditure in 2001 and 2002 is predicted to be 26.2 and 25 billion NOK, respectively (excluding cessation expenditure). It is expected to remain stable at between 25 and 30 billion NOK a year.

The greatest uncertainties attached to the operating expenditure in the long term relate to the number of new discoveries that will be approved for development and what kind of development is chosen. Stand-alone field centres will give significantly higher operating expenditure than satellite developments. After several years in the 1990s when operating expenditure dropped, it will now have to rise again to pay for the maintenance of ageing installations. The total operating expenditure will also be influenced by the time chosen to cease production on the largest fields or replace production installations with new ones that have lower operating expenditure, as was done on the Ekofisk field.

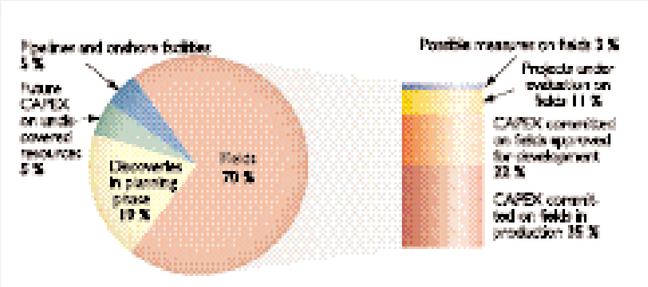

*Figure 4.21 Expected distribution of capital expenditure in 2001 to 2005*

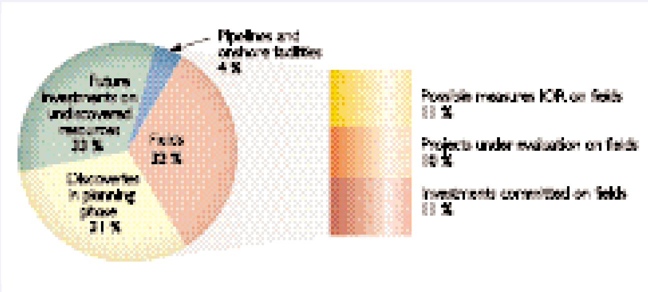

*Figure 4.22 Expected distribution of capital expenditure in 2005 to 2020*

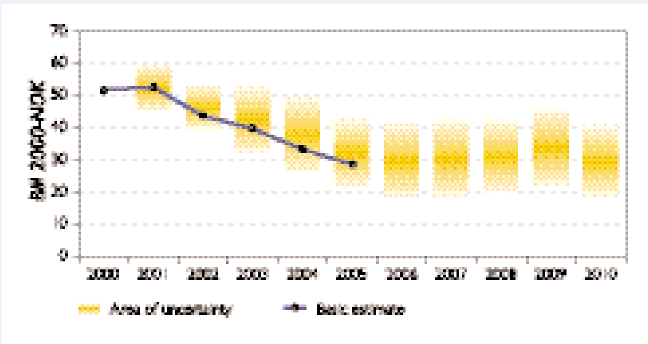

*Figure 4.23 Future total capital expenditure on the Norwegian shelf. including uncertainty assessments*



## 4.5 Emissions to air

Emissions to air and discharges to the sea from producing fields, fields under development and discoveries expected to be developed within ten years (resource classes 1-4) are reported annually to the authorities. Emissions that must be reported are carbon dioxide ($CO_2$) and nitrogen oxides ($NO_x$) deriving from power generation and flaring, and volatile organic hydrocarbons (nmVOC) and methane ($CH_4$) chiefly from offshore storage and loading.

**Forecasts for emissions of $CO_2$ and $NO_x$**
Emission forecasts are based on expected production profiles. The emissions of $CO_2$ and $NO_x$ on the Norwegian shelf mainly derive from the energy required to run the installations. The emission of $CO_2$ is expected to increase from around 11 million tonnes in 2000 to about 13.7 million tonnes in 2005 and will then decrease (Figures 4.24 and 4.25). Emissions from fields that are producing or approved for development will dominate in the first few years, after which those deriving from production from present-day discoveries and undiscovered projects will make up an increasing proportion of the total emissions.

The forecasts for emissions from fields that are producing and approved for development are mainly based on current technology. However, a 1 per cent reduction in the emissions of $CO_2$ and $NO_x$, caused by improved technology, from 2004 onwards has been included (resource classes 1-4). In the case of resources in class 5, more energy-efficient production combined with low-$NO_x$ turbines are expected to result in significantly lower emissions of $NO_x$ per unit produced.

The main uncertainties connected with the emission forecasts are caused by changes in the level of gas export from the Norwegian shelf and the onset of production for certain projects. Furthermore, the Kyoto Protocol is intended to come into force in 2008, and pursuant to this Norwegian obligations must be met by 2012. Norwegian obligations pursuant to the Gothenburg Protocol must be met by 2010. Hence, the years from 2008 to 2012 will be extremely important for the nation's international obligations. In these years, the activity level will affect the need for measures to reduce emissions. As a consequence of less activity during this period, the emissions of $CO_2$ are expected to decrease from about 12.5 to 11.4 million tonnes (Figure 4.24).

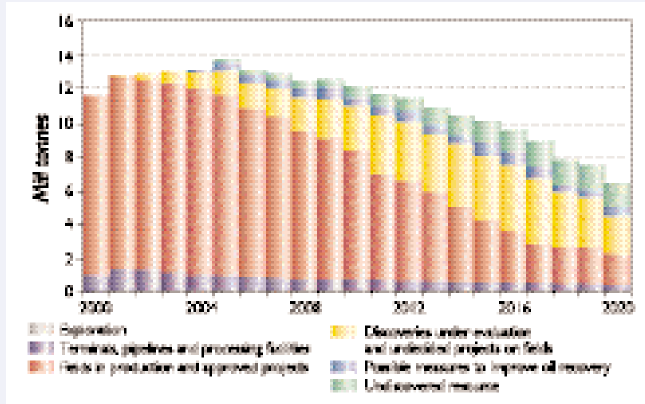

*Figure 4.24 Forecasts for emissions of $CO_2$*

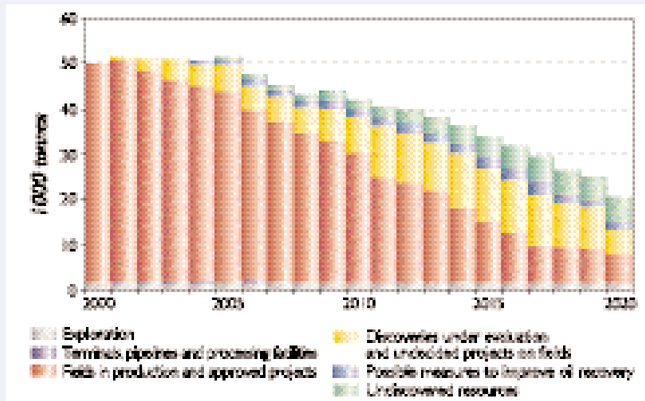

*Figure 4.25 Forecasts for emissions of $NO_x$*

The proportion of the emissions linked to petroleum activity may also be significantly changed if processing plants are moved onshore, hence falling outside the definition of petroleum activity. For example, in the case of the potential development of the Snøhvit discovery, a processing plant on land will be largely looked upon as utilisation, and emissions are not included in the emission forecasts. Changes in the rate of recovery will also influence the emission level forecasted.

**Forecasts for emissions of nmVOC and $CH_4$**

Emissions of nmVOC and $CH_4$ chiefly occur during temporary storage and offshore loading of oil and condensate. Consequently, the level of these emissions largely follows the oil production. As a result of gradually decreasing production, emissions from producing-fields reduce throughout the forecast period (Figures 4.26 and 4.27). The emissions contributed by discoveries and projects that are being planned increase over time, due to increase in production.

As a consequence of an order given by the Norwegian Pollution Control Authority (SFT) regarding the reduction of nmVOC from offshore loading, it is expected that the total emissions of nmVOC will be significantly reduced during the period covered by the forecast (Figure 4.26). This emission is expected to drop from around 240 000 tonnes of nmVOC in 2001, before measure to reduce it are implemented. When the full effect of the decision is expected at the end of 2005, the total emission of nmVOC is expected to be about 73 000 tonnes. The emission is expected to be further reduced as a result of declining production. The emissions of $CH_4$ will depend upon chosen technology.

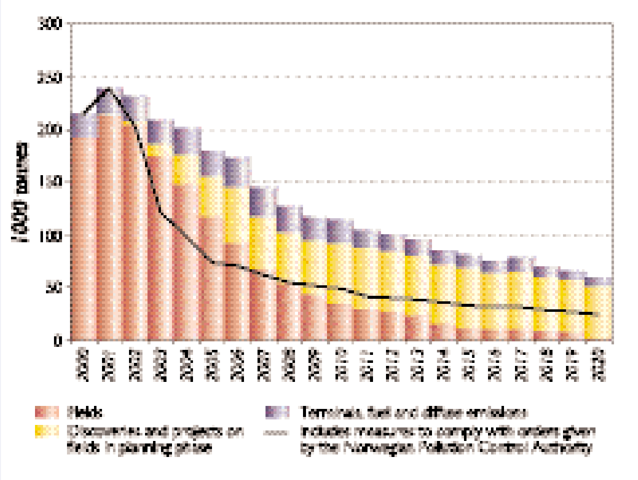


*Figure 4.26 Forecasts for emissions of nmVOC*

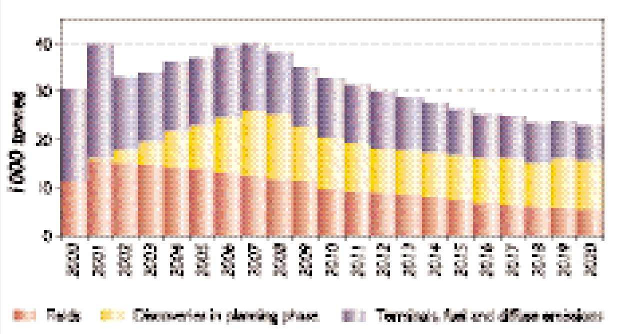


*Figure 4.27 Forecasts for emissions of $CH_4$*



# 5. Revised classification system

The management of the petroleum resources on the continental shelf is an important task for the authorities. One of the Directorate's main responsibilities is to maintain an overview of all the petroleum resources.

The classification of the petroleum resources forms the basis for analyses which ensure that the authorities have the most reliable basis possible for planning measures that ensure that the resources are well managed and to forecast future production and activity. Such classification can be performed in various ways, depending on the requirement; for instance, the need for

- resource management for the authorities,
- resource management for the oil companies,
- investment purposes for the company owners.

Even though the classification requirements differ, the authorities and the industry have in recent years become increasingly aware of the need to develop a more uniform system. This has, in part, been reflected in the publication in February 2000 by the World Petroleum Congress (WPC), the Society of Petroleum Engineers (SPE) and the American Association of Petroleum Geologists (AAPG) of a resource classification system that goes a long way towards making uniform classification possible.

In connection with the Norwegian Petroleum Directorate's annual updating of the resource account for the expected recoverable resources, it is important to have an unambiguous system for classifying the resources. Such a system, which reflected the maturity of the resources, was revised in 1996. Based on experience gained in using this system, and in co-operation with the oil companies through the "Forum for Forecasting and UNcertainty Evaluation related to Petroleum Production" (FUN), the Directorate has now decided to revise the classification system. This revision takes the maturity principle applied in the current system a step further and approaches the proposal made by WPC, SPE and AAPG. The revised system (see Table 5.1 and Figure 5.1) thus

| Resource class | Project status category | | |
|---|---|---|---|
| Historical production ( S ) | 0 | | Sold and delivered petroleum |
| Reserves ( R ) | 1 | | Reserves in production |
| | 2 | F<br>A | Reserves with an approved plan for development and operation |
| | 3 | F<br>A | Reserves which the licensees have decided to recover |
| Conditional resources ( C ) | 4 | F<br>A | Resources in the planning phase |
| | 5 | F<br>A | Resources whose recovery is likely, but not clarified |
| | 6 | | Resources whose recovery is not very likely |
| | 7 | F<br>A | Resources that have not been evaluated |
| Undiscovered resources ( P ) | 8 | | Resources in prospects |
| | 9 | | Resources in leads, and unmapped resources |

**F** = *original estimate of oil and gas resources*
**A** = *additional resources*

*Table 5.1 Revised resource classification system*

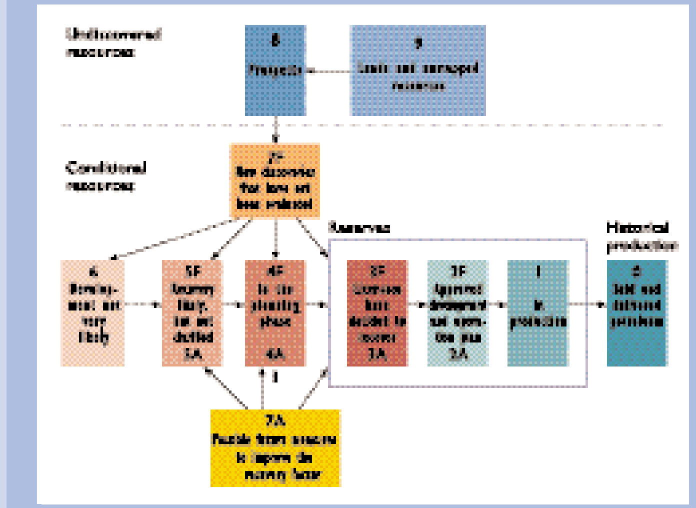


*Figure 5.1 Revised system for classifying the petroleum resources on the Norwegian continental shelf*

replaces the one described in "Classification of the petroleum resources on the Norwegian continental shelf", published in July 1997.

Among the aims of this revision have been

- to strengthen the connection between resource categories and formal decisions by the authorities and the holders of the production licences,
- to harmonise the classification system with existing international systems based on the maturity of resources, in order to facilitate communication and exchange of data,
- to approach industrial standards and at the same time take care of the needs of the authorities from a management viewpoint,
- that the revised system will follow the main structure of the system presented in February 2000 by WPC, SPE and AAPG, and at the same time take care of and develop the main features of the Directorate's former system,
- that the revised system will be implemented on July 1st 2001 when reporting to the Revised National Budget for 2002.

Table 5.1 and the appendix explain the individual project status categories.

## 5.1 Changes from the former classification system

Both the former and the revised classification systems of the Norwegian Petroleum Directorate are based on the maturity of the resources relative to their recovery, and are therefore quite similar. However, some differences exist.

Sold and delivered volumes (historical production) were included in the reserves in the old system. The revised system distinguishes historical production as a separate class and category. The term reserves in the revised system covers the remaining recoverable resources in fields that are in production and resources that it has been decided will be recovered. This is in keeping with the international use of the term. The reserve class also includes quantities which the licensees have decided to develop, but the authorities have still not approved. This particularly affects gas connected with the Troll field,



| Former resource classification | | | | | | | Revised resource classification (July 2001) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Resource class | | Oil bill Sm³ | Gas bill Sm³ | NGL bill tonnes | Condensate bill Sm³ | Total bill Sm³ o.e. | Project status category | | Oil bill Sm³ | Gas bill Sm³ | NGL bill tonnes | Condensate bill Sm³ | Total bill Sm³ o.e. |
| | | | | | | | 0 | Sold and delivered | 2.19 | 477 | 0.03 | 0.04 | 3.00 |
| 0 | Production ceased | 0.03 | 114 | 0.00 | 0.00 | 0.15 | | | | | | | |
| 1 | In production | 3.44 | 1572 | 0.11 | 0.09 | 5.31 | 1 | In production | 1.29 | 980 | 0.06 | 0.05 | 2.44 |
| | | | | | | | 2F | | 0.18 | 200 | 0.01 | 0.04 | 0.44 |
| | | | | | | | 2A | | 0.10 | 50 | 0.01 | 0.01 | 0.17 |
| 2 | Development approved | 0.28 | 250 | 0.01 | 0.05 | 0.61 | 2 | Approved plan for development and operation | 0.28 | 250 | 0.01 | 0.05 | 0.61 |
| | | | | | | | 3F | | 0.02 | 57 | 0.01 | 0.00 | 0.09 |
| | | | | | | | 3A | | 0.01 | 734 | 0.02 | 0.00 | 0.79 |
| | | | | | | | 3 | Licensees have decided to recover | 0.05 | 790 | 0.02 | 0.00 | 0.88 |
| | **Sum reserves** | **3.75** | **1937** | **0.13** | **0.14** | **6.07** | | **Sum reserves** | **1.62** | **2020** | **0.10** | **0.10** | **3.93** |
| | | | | | | | 4F | | 0.11 | 791 | 0.03 | 0.12 | 1.08 |
| | | | | | | | 4A | | 0.15 | 71 | 0.01 | 0.01 | 0.25 |
| 3 | Late planning phase | 0.19 | 458 | 0.01 | 0.10 | 0.80 | 4 | In planning phase | 0.26 | 862 | 0.04 | 0.13 | 1.33 |
| | | | | | | | 5F | | 0.07 | 261 | 0.00 | 0.03 | 0.36 |
| | | | | | | | 5A | | 0.05 | 149 | 0.01 | 0.02 | 0.23 |
| 4 | Early planning phase | 0.15 | 1226 | 0.03 | 0.05 | 1.49 | 5 | Recovery likely, but not clarified | 0.11 | 409 | 0.01 | 0.04 | 0.58 |
| 5 | May be developed in the long term | 0.13 | 341 | 0.01 | 0.03 | 0.51 | | | | | | | |
| 6 | Development not very likely | 0.05 | 75 | 0.00 | 0.00 | 0.14 | 6 | Recovery not very likely | 0.08 | 69 | 0.00 | 0.00 | 0.15 |
| 7 | New discoveries | 0.02 | 95 | 0.00 | 0.00 | 0.11 | 7F | New discoveries | 0.02 | 95 | 0.00 | 0.00 | 0.11 |
| | | | | | | | 7A | Possible future measures to improve the recovery factor | 0.43 | 500 | 0.00 | 0.00 | 0.93 |
| | | | | | | | 7 | Have not been evaluated | 0.44 | 595 | 0.00 | 0.00 | 1.04 |
| | **Sum resources** | **0.53** | **2195** | **0.08** | **0.18** | **3.05** | | **Sum conditional resources** | **0.90** | **1936** | **0.06** | **0.18** | **3.12** |
| | Sum proven resources | 4.28 | 4132 | 0.21 | 0.32 | 9.12 | | Sum reserves and conditional resources | 2.52 | 3956 | 0.15 | 0.28 | 7.05 |
| 8 | Possible future measures to improve the recovery factor | 0.43 | 500 | 0.00 | 0.00 | 0.93 | | | | | | | |
| 9-11 | Undiscovered resources | 1.35 | 2400 | 0.00 | 0.00 | 3.75 | 8-9 | Undiscovered resources | 1.35 | 2400 | 0.00 | 0.00 | 3.75 |
| Sum total recoverable resources | | 6.05 | 7032 | 0.21 | 0.32 | 13.80 | Sum total recoverable resources | | 6.05 | 7032 | 0.21 | 0.32 | 13.80 |

*Table 5.2 Resource account as of 31st December 2000. Comparison of the former and revised resource classification systems*

where most of the resources are now classified as reserves. The distinction drawn between resources and undiscovered resources has also been changed so that resources linked with future measures to improve the recovery factor are now included in conditional resources in the category "not evaluated".

The difference is further illustrated in Table 5.2 where the resource account as of 31st December 2000 is shown in accordance with both the former and the revised classification systems. The figures in the separate resource categories (except category 2) in the two systems cannot be directly compared because the definitions of the categories are somewhat different. Nevertheless, the compilation does illustrate where the resources fit into the two systems. Categories 3, 4, 5 and 6 in the revised system cannot be compared directly with categories 3, 4, 5 and 6 in the former system, because category 3 in the revised system lacks an equivalent in the former system. Moreover, some deposits that used to be placed in category 3 are now divided between the revised categories 3 and 4, and some deposits from the former category 4 have been moved to the revised category 5.

## Project status category, a new classification system valid from 1st July 2001

**Category 0**
**Sold and delivered petroleum**
Petroleum resources in deposits that have been produced and have passed the reserves reference point. It includes quantities produced from fields that are in production as well as from fields that have been permanently closed down.

**Category 1**
**Reserves in production**
Remaining, recoverable, marketable and deliverable quantities of petroleum which the licensees have decided to recover, and which are covered by plans for development and operation (PDO) which the authorities have approved or given exemption from. Should production be temporarily shut down, the reserves must, nevertheless, be added to this category. The reserves in this category are shown by subtracting the sold and delivered petroleum quantities from the originally recoverable reserves.

Quantities of gas covered by approved plans for development and operation and on hold in fields from which delivery has started are also reckoned as reserves in this category.

**Category 2**
**Reserves with an approved plan for development and operation**

**Category 2 F**
Recoverable quantities of petroleum described under category 1, but which have not been put into production.

**Category 2 A**
Additional (or deducted) reserves that are in categories 1 or 2F, which are a consequence of projects to improve production, and which have the same status as regards decisions as reserves in category 2F.

**Category 3**
**Reserves which the licensees have decided to recover**

**Category 3 F**
Recoverable, marketable and deliverable quantities of petroleum which the licensees have decided to recover, but for which the authorities have not yet approved a PDO or granted exemption therefrom. This category also contains supplementary reserves from new deposits with the same status as regards decisions, and which can be connected to fields in categories 1 and 2.

The category also covers quantities of petroleum (mainly gas) that have been held back, but which can be sold without significant investments at a later date.

**Category 3 A**
Additional (or deducted) quantities of petroleum in categories 1, 2 or 3F, which are a consequence of projects to improve production and which the licensees have decided to recover, but for which the authorities have not yet approved a PDO or granted exemption therefrom.

The category also covers quantities of petroleum (mainly gas) that have been held back, but which can be sold without significant investments at a later date.

**Category 4**
**Resources in the planning phase**

**Category 4 F**
Discovered, recoverable, petroleum resources which are expected to be covered by a PDO or granted exemption therefrom, and where specific activity is taking place with a view to clarifying whether development will be implemented. Development is expected to be decided by the licensees within about 4 years. This category also contains supplementary resources which can be connected to existing fields that have reserves in categories 1 and 2, and discoveries that have reserves in class 3.

**Category 4 A**
Additional (or deducted) quantities of petroleum in categories 1, 2, 3 or 4F, which are a consequence of projects to improve production and which have the same status as regards decisions as resources in category 4F.

**Category 5**
**Resources whose recovery is likely, but not clarified.**

**Category 5 F**
Discovered, recoverable petroleum resources whose recovery is likely, but not clarified. This category contains discovered, recoverable petroleum resources which are not being considered for development at the moment, but which can be developed in due course. It also contains supplementary resources from new deposits which can be tied in to fields and discoveries with resources in categories 1, 2, 3 and 4, but where matters regarding recovery have still not been clarified.

**Category 5 A**
Additional (or deducted) quantities of petroleum that are in categories 1, 2, 3, 4 or 5F, which are a consequence of projects to improve production, and which have the same status as regards decisions as resources in category 5F.

**Category 6**
**Resources whose recovery is not very likely**
Discovered, recoverable petroleum resources which are not expected to be profitably recoverable even in the long term, and resources in small, untested discoveries whose recovery seems unlikely. Option values will normally be included in assessments of profitability. The option values emerge as a result of uncertainties related to future recovery factors (price, technology, etc.), and where recovery of the resource is considered to be an option (a right, but not an obligation) that will be realised only if the situation develops sufficiently favourably.

This category contains petroleum resources that require substantial changes in technology, prices, etc., to be recovered profitably, and where it is not very likely that the changes required will take place.

**Category 7**
**Resources that have not been evaluated**

**Category 7 F**
Recoverable petroleum resources in new discoveries where discovery evaluation report has not yet been submitted to the authorities, so that only a provisional resource estimate exists.

**Category 7 A**
Recoverable petroleum resources in fields and discoveries which have resources in categories 1, 2, 3, 4 or 5 and which may be recoverable with the help of production techniques beyond those that are considered to be conventional, or with the help of known methods which there is still no basis for employing.

For the individual field or discovery, this estimate of the resource will typically be based on rough valuations. There may be great uncertainty as to whether the measures can be implemented. Estimates are normally only stated for the total potential of the measures, not in respect of individual measures.

(This class covers resources which were previously categorised as "Resources from possible future measures to increase the recovery factor".)

**Category 8**
**Resources in prospects**
Undiscovered, recoverable quantities of petroleum in mapped prospects that have not been discovered. It is uncertain whether the estimated resources are present. They have been risk-weighted, i.e. they reflect estimated volumes multiplied by the probability of making a discovery. This probability must be stated.

**Category 9**
**Resources in leads, and unmapped resources**
Undiscovered, recoverable petroleum resources attached to leads. It is uncertain whether the leads, and if so the estimated resources, are actually present. The resource estimates reflect estimated volumes multiplied by the probability of making a discovery. This probability must be stated. The unmapped, recoverable resources are calculated by analysing plays. The total resources of the plays include both discovered and undiscovered resources. The unmapped resources are the difference between the aggregated resources of the plays and the discovered and mapped resources.

**"First oil/gas" (F) :**
The petroleum resource is given the designation First (F) if it is linked to the initial recovery project for the relevant petroleum-in-place. First (F) is used for categories 2, 3, 4, 5 and 7. Supplementary resources (additional to petroleum initially in place) are also given the designation F.

**"Additional oil/gas" (A) :**
Petroleum resources are given the designation Additional (A) if they are linked to measures intended to improve production relative to initial plans. The A resources are normally positive, but may also be negative, for instance in cases where oil recovery improvements require gas consumption, or where the improved production aims at accelerating production or reducing production costs. Additional (A) resources are used for categories 2, 3, 4, 5 and 7.